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MAR 24 2010

PUBLIC SERVICE
COMMISSION

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 COMPANY RESPONSES TO
COMMISSION STAFF THIRD SET OF DATA REQUESTS

March 24, 2010

AFFIDAVIT

Errol K Wagner, upon being first duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Errol K Wagner

Errol K Wagner

Commonwealth of Kentucky	)	
	)	Case No. 2009-00459
County of Franklin	)	

23rd Sworn to before me and subscribed in my presence by Errol K Wagner, this the day of March, 2010.

Judy K Rosquist

Notary Public

My Commission Expires: January 23, 2013

AFFIDAVIT

Timothy C. Mosher, upon being first duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

T. C. Mosher

Timothy C. Mosher

Commonwealth of Kentucky)
) Case No. 2009-00459
County of Franklin)

Sworn to before me and subscribed in my presence by Timothy C. Mosher, this the 23rd day of March, 2010.

Judy K Rosquist

Notary Public

My Commission Expires: January 23, 2013

AFFIDAVIT

David M. Roush, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

David M. Roush

State of Ohio)
) Case No. 2009-00459
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by David M. Roush this 22nd day of March 2010.

Susan C. Wilson
Notary Public

My Commission Expires April 5, 2011

NOTARY PUBLIC STATE OF OHIO

SUSAN C. WILSON
Notary Public, State of Ohio
My Commission Expires April 5, 2011

AFFIDAVIT

Dennis W. Bethel, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Dennis W Bethel

Dennis W. Bethel

State of Ohio)
) Case No. 2009-00459
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Dennis W. Bethel this 22nd day of March 2010.

Susan C. Wilson

Notary Public

My Commission Expires April 5, 2011

NOTARY PUBLIC STATE OF OHIO

SUSAN C. WILSON
Notary Public, State of Ohio
My Commission Expires April 5, 2011

AFFIDAVIT

Ranie K Wohnhas, upon being first duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Ranie K. Wohnhas

Ranie K Wohnhas

Commonwealth of Kentucky	)	
	)	Case No. 2009-00459
County of Franklin	)	

23rd Sworn to before me and subscribed in my presence by Ranie K Wohnhas, this the day of March, 2010.

Judy K. Rosquist

Notary Public

My Commission Expires: January 23, 2013

AFFIDAVIT

James E. Henderson, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

James E. Henderson

James E. Henderson

State of Ohio)
)ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by James E. Henderson this 22nd day of March 2010.

Sharon Hutchens

Notary Public

My Commission Expires 11/17/2014

NOTARY PUBLIC STATE OF OHIO

Sharon Hutchens
Notary Public-State of Ohio
My Commission Expires
November 17, 2014

AFFIDAVIT

Everett G Phillips, upon being first duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Everett G. Phillips

Everett G. Phillips

Commonwealth of Kentucky)
) Case No. 2009-00459
County of Boyd)

Sworn to before me and subscribed in my presence by Everett G. Phillips, this the 22 day of March, 2010.

Notary Public

My Commission Expires: 4/5/2011

Kentucky Power Company

REQUEST

Refer to Volume 2 of Kentucky Power's application, Section Ill, pages 392 and 400 of 488, Rider ECS-C&E and Rider EPCS. The last sentence on these pages states that, if requested, Kentucky Power will make real time pulse metering data available "for an additional fee." Provide the amount of the fee, how it was calculated, and its location in Kentucky Power's proposed tariff.

RESPONSE

The fee is not a single pre-established amount. The one-time fee is based upon the actual cost of the required modifications to the Company's equipment to make metering pulses available to the customer. Significant variables in the potential cost are the type of existing meter, the pulses that the customer wishes to receive (i.e. kWh, reactive, end of interval), and whether isolation relays are required. Depending upon these variables, the cost can range from $150 to $1,750.

If the Commission believes it would be clearer, language could be added to the end of that sentence stating "... for an additional one-time fee at the Company's cost."

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Refer to the Direct Testimony of David M. Roush, pages 4 — 6, and Exhibit DMR-1, regarding the customer annualization adjustment.

a. Exhibit DMR-1, page 3, shows the derivation of the operating ratio used to calculate the expense portion of the customer annualization adjustment. Identify "OML Workpaper" which is listed as one source for the adjusted labor expense.

b. Clarify that the adjusted labor expense of $26,300,126 on page 3 of the exhibit does not include the cost of employee benefits.

c. Provide an operating ratio calculation in which adjusted salaries and wages, adjusted employee benefits, and regulatory commission expenses are deducted from the adjusted operations and maintenance expense of $453,834,609.

RESPONSE

a. Please see the attached page 2 to this response.

b. The adjusted labor expense does not include employee benefits, except for the benefit-related component of the Adjustments shown on Section V, Workpaper S-4, page 32.

c. Please see the attached page 3 to this response.

WITNESS: David M Roush

	TOTAL ELECTRIC UTILITY			KENTUCKY P.S.C. JURISDICTION			Labor Adjustment		
	Total O&M Labor	A&G Excluding Regulatory	Total A&G (on OML)	Retail Allocation Factor	Total O&M Labor	Total A&G	Wages	Benefits	Savings Plan
Production									
Operation									
Account 500	$ 3,877,089		$ 3,789,429	0.986000	$ 3,822,810	$ 3,736,377			
Account 501	$ 266,673		$ 260,644	0.987000	$ 263,206	$ 257,256			
Account 502	$ 873,796		$ 854,040	0.986000	$ 861,563	$ 842,937 1/			
Account 505	$ 21,352		$ 20,869	0.986000	$ 21,053	$ 20,598 1/			
Account 506	$ 2,254,253		$ 2,203,285	0.986000	$ 2,222,693	$ 2,172,439			
Account 507	$ -		$ -		$ -	$ -			
Total Operation	$ 7,293,163		$ 7,128,267		$ 7,191,325	$ 7,029,607	$225,906	$(27,535)	$ 10,821
Maintenance									
Account 510	$ 142,579		$ 139,355	0.986000	$ 140,583	$ 137,404			
Account 511	$ 135,084		$ 132,030	0.986000	$ 133,193	$ 130,182			
Account 512 - Dem Related	$ 931,436		$ 910,376	0.986000	$ 918,396	$ 897,631			
Account 512 - Ener Related	$ 1,808,082		$ 1,767,202	0.987000	$ 1,784,577	$ 1,744,228			
Account 512 - Total	$ 2,739,518		$ 2,677,578			$ -			
Account 513	$ 1,033,182		$ 1,009,822	0.986000	$ 1,018,717	$ 995,684			
Account 514	$ 283,679		$ 277,265	0.986000	$ 279,707	$ 273,383			
Account 515	$ -		$ -		$ -	$ -			
Account 555	$ -		$ -		$ -	$ -			
Account 556	$ -		$ -		$ -	$ -			
Account 557	$ -		$ -		$ -	$ -			
Total Maintenance	$ 4,334,042		$ 4,236,050		$ 4,275,173	$ 4,178,513	$134,299	$(16,370)	$ 6,433
Total Production	$11,627,205		$11,364,317		$11,466,498	$11,208,119	$360,205	$(43,905)	$ 17,254
Demand-Related	$ 9,552,450		$ 9,336,471		$ 9,418,715	$ 8,343,100	$295,877	$(36,064)	$ 14,172
Energy-Related	$ 2,074,755		$ 2,027,846		$ 2,047,783	$ 2,865,019	$ 64,328	$ (7,841)	$ 3,081
Transmission									
Operation	$ 435,691		$ 425,840			$ -			
Maintenance	$ 906,524		$ 886,028			$ -			
Total Transmission	$ 1,342,215		$ 1,311,868	0.986000	$ 1,323,424	$ 1,293,502	$ 41,574	$ (5,067)	$ 1,991
Distribution									
Operation	$ 2,210,962		$ 2,160,973						
Maintenance	$ 6,715,190		$ 6,563,361						
Total Distribution	$ 8,926,152		$ 8,724,334	0.998000	$ 8,908,300	$ 8,706,885	$279,842	$(34,110)	$ 13,404
Total Customer Accounts	$ 1,559,167		$ 1,523,915	0.999989	$ 1,559,150	$ 1,523,898	$ 48,979	$ (5,970)	$ 2,346
Total Customer Service & Informational	$ 391,237		$ 382,391	0.999989	$ 391,233	$ 382,387	$ 12,290	$ (1,498)	$ 589
SUBTOTAL Excl. A&G	$23,845,976			0.991723	$23,648,605		$742,890	$(90,550)	$ 35,584
Administrative & General									
Operation	$ 1,159,409								
Maintenance	$ 820,576								
Total Other Administrative & General	$ 1,979,985	$23,306,825	$23,306,825	0.991723	$ 1,963,597	$23,114,792			
Regulatory A&G	$ -		$ 1,088	1.000000	$ -	$ 1,088			
Total A&G Incl. Regulatory	$ 1,979,985		$23,307,913		$ 1,963,597	$23,115,880			
Total Labor Payroll	$25,825,961				$25,612,202		$742,890	$(90,550)	$ 35,584

1/ A&G in Accounts 502 and 505 is energy-related.

KENTUCKY POWER COMPANY
DEVELOPMENT OF OPERATING RATIO
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

Line No.	Description	Amount	Source
1	Operating Revenues		
2	Sales of Electricity	$ 503,263,399	Sec. V, Sch.4, P.1, Col.(3), line 1
3	System Integration Agreement Adjustment	12,698,792	Sec.V, WP S-4, p.3, line 12
4	Capacity Charge Revenue Adjustment	(5,181,547)	Sec.V, WP S-4, p.4, line 16
5	Net Merger Savings Adjustment	5,218,680	Sec.V, WP S-4, p.5, line 15
6	Annualized Fuel Adjustment	(10,989,239)	Sec.V, WP S-4, p.6, line 8
7	Customer Migration Adjustment	1,721,710	Sec.V, WP S-4, p.24, line 10
8	Intercompany Revenue Billing Adjustment	508,868	Sec V, WP S-4, p.43, line 3
9	Green Power Revenue Adjustment	(434)	Sec.V, WP S-4, p.44, line 3
10	Total	$ 507,240,229	Sum of Line 2 through Line 9
11	Operating Expenses		
12	Adjusted Operation & Maintenance *	$ 453,865,828	Sec. V, Sch.4, P.1, Line 4. Col.(5) less Sec. V, WP S-4, P.45, Line 2, Col.(3)
13	Adjusted Labor Expense	26,300,126	OML Workpaper, plus Sec.V, WP S-4, p.32
13a	A&G Salaries	5,965,156	Account 920 (Perbooks x Juris Factor**)
13b	Administrative Expenses Transferred	(1,013,089)	Account 922 (Perbooks x Juris Factor**)
13c	Employee Pensions & Benefits	6,810,826	Account 926 (Perbooks x Juris Factor**)
13d	Regulatory Commission Expenses	1,088	Account 928 (Perbooks)
13e	Incentive Compensation Plan Adjustment	1,399,386	Sec. V, WP S-4, Page 13
13f	Amortization fo Rate Case Expense	187,000	Sec. V, WP S-4, Page 17
13g	Pension and OPEB Expense Adjustment	470,219	Sec. V, WP S-4, Page 25
13h	Elimination of Safety Focus Incentive Exp.	(208,239)	Sec. V, WP S-4, Page 40
14	Adjusted O&M Less Labor Expense	$ 413,953,354	Line 12 - Line 13 through Line 13h
15	Operating Ratio		
16	Operating Ratio	81.61%	Line 14 / Line 10

* Corrected as indicated in KIUC 1st Set - Item No. 57
** Jurisdictional Factor for A&G excluding Regulatory from OML Workpaper = 99.1723%

Kentucky Power Company

REQUEST

Refer to the Direct Testimony of Errol K. Wagner. At page 7, lines 11 to14, he states that Kentucky Power's member load ratio ("MLR") is 7.069 percent based on its highest non-coincident peak to the total of all members' highest non-coincident peaks. However, at page 35, lines 6 to 9, he states that the 7.069 percent is based on the AEP System-East Zones' total peak demand of 23,680 MW at September 30, 2009.

a. Explain whether 23,680 MW is the total peak demand of the AEP System-East Zone or the sum of the non-coincident peaks of the members.

b. Provide a schedule showing the calculation of the MLR for each member of the AEP System-East Zone as of September 30, 2009 and as of February 28, 2010.

RESPONSE

a. The 23,680 MW is the sum of the non-coincident peak demands of the AEP-East Zone.

b. Please see the attached page for the September 30, 2009 actual calculation of the MLR for each member of the AEP System-East Zone. The February 2010 actual calculation of the MLR for each member of the AEP System-East Zone will not be available until the first week of April 2010. The Company will provide the requested information when available.

WITNESS: Errol K Wagner

ACTUAL

INTERCHANGE POWER STATEMENT

FOR THE MONTH OF

September 2009

STATEMENT OF SETTLEMENT TO BE MADE
FOR ELECTRIC POWER AND ENERGY RECEIVED AND DELIVERED
APPLICABLE TO SEPTEMBER 2006 BUSINESS

Pursuant to the Interconnection Agreement, dated July 6, 1951,

as Amended

by and among

Appalachian Power Company (APCo),

Columbus Southern Power Company (CSP),

Indiana Michigan Power Company, (I&M),

Kentucky Power Company (KPCo),

Ohio Power Company (OPCo),

and with

American Electric Power Service Corporation

as Agent.

Prepared by:
AEP Energy Services
Wholesale Commercial Accounting Group

APPENDIX I

AMERICAN ELECTRIC POWER SYSTEM
MEMBER LOAD RATIO SUMMARY

MONTH ENDING 08/31/2009

OPERATING COMPANY PERCENTAGE
September 2009

APPALACHIAN	KENTUCKY	INDIANA	OHIO	COLUMBUS
0.35084	0.07069	0.17927	0.21326	0.18594

Internal (MLR) MLR MONTHLY MAXIMUM
60-MINUTE INTEGRATED MEGAWATT DEMAND
EXCLUDE AEP SYSTEM SALES

		APPALACHIAN			KENTUCKY			INDIANA			OHIO			COLUMBUS		
MO/YR	TOTAL	DA	HR	PEAK	DA	HR	PEAK	DA	HR	PEAK	DA	HR	PEAK	DA	HR	PEAK
08/09	19980	10	15	5786	10	16	1163	10	14	4076	10	14	4888	17	15	4067
07/09	18507	28	15	5415	27	16	1081	28	15	3803	16	16	4419	16	16	3789
06/09	19645	19	17	5362	19	16	1147	25	14	4245	25	15	4682	25	16	4209
05/09	16376	28	14	4662	22	15	1000	27	16	3400	28	13	3957	27	16	3357
04/09	16952	08	07	5314	08	07	1141	07	10	3181	07	08	4156	27	16	3160
03/09	20564	03	08	7381	03	08	1556	02	09	3397	02	20	4670	02	20	3560
02/09	21624	05	08	7941	05	08	1585	04	09	3556	04	21	4832	05	08	3710
01/09	22616	16	08	8308	16	09	1674	15	19	3728	20	10	4972	15	20	3934
12/08	20929	22	09	7423	22	09	1527	21	19	3608	22	11	4691	22	19	3680
11/08	19327	19	08	6939	22	09	1392	17	19	3272	19	20	4431	19	19	3293
10/08	17869	30	08	6020	30	08	1212	30	07	3230	30	07	4307	15	19	3100
09/08	21010	04	16	6126	02	16	1204	02	18	4227	03	17	5050	03	16	4403

Internal (MLR) MAXIMUM 60-MINUTE
INTEGRATED MW DEMAND EXPERIENCED
DURING PRECEDING 12-MONTHS
EXCLUDE AEP SYSTEM SALES

	TOTAL	APPALACHIAN	KENTUCKY	INDIANA	OHIO	COLUMBUS
	23680	8308	1674	4245	5050	4403
DATE/TIME		01/16/09 HR 08	01/16/09 HR 09	06/25/09 HR 14	09/03/08 HR 17	09/03/08 HR 16

Notes

OP and CSP loads for January 2009, were revised due to an underlying change in the Buckeye load. The change did not create a new MLR peak.

Buckeye hourly actual loads were reloaded for March 2009, on May 26, 2009. There was no impact to the hourly CSP and OP loads.

Kentucky Power Company

REQUEST

Refer to the response to Item 1 of Commission Staff's Second Data Request ("Staff's Second Request"). Provide the calculations for the proposed energy charges and demand charges, if applicable, for the new tariffs RS-TOD2, SGS-TOD, and LGS-TOD. This response should be provided in electronic format with the formulas intact and unprotected.

RESPONSE

Please see the Company's response to KIUC First Set Item No. 12. The electronic files were provided as follows:

Tariff	Electronic File Name
RS-TOD2	KIUC First Set - Item No. 12 - Page 13 to 14.xls
SGS-TOD	KIUC First Set - Item No. 12 - Page 17 to 18.xls
LGS-TOD	KIUC First Set - Item No. 12 - Page 23 to 29.xls

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Refer to the response to Item 2 of Staff's Second Request, page 3 of 3.

a. Provide the reason for the large increase in Sales for Resale from 2007 to 2008 and the large decrease from 2008 to 2009.

b. Provide the reason for the large increase in Account 4540002, Rent from Elect Property-NAC, from 2007 to 2008 and the large decrease from 2008 to 2009.

RESPONSE

a. The increase in Sales for Resale from 2007 to 2008 was due primarily to higher prices in the summer of 2008 in the PJM region and AEP utilized its available generation fleet to sell excess generation. KPCO is allocated its MLR portion of Off-System Sales (OSS) relating to third parties or PJM.

In 2009, when OSS were made, AEP was not able to sell the power at the higher prices seen in 2008 since demand was softer in the PJM market. Because of the weak market it also meant the margins on the sales were also lower.

b. Rent from Electric Property recorded in account 4540002 increased from 2007 to 2008 because in August 2008 Kentucky Power billed a third party $5.7 million for unauthorized pole attachments during the period 1999 through 2006. In 2009, pole attachment revenue returned to more normal levels.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to the response to Item 3 of Staff's Second Request.

a. The first paragraph states that the increase in charges from Appalachian Power Company ("APCO") is due to payments of $.9 million and $1.0 million made on behalf of Kentucky Power for a transformer and substation.

    (1) Describe in detail the $.9 million payment made on behalf of Kentucky Power.
    (2) Explain why the amount for the transformer was expensed rather than capitalized.

b. The second paragraph states that the increase in charges from Indiana Michigan Power ("I&M") is due to employee labor and storm damage restoration expenses of $.2 million related to severe storms in Kentucky in January and February 2009. State whether these expenses are included for recovery through rates elsewhere in Kentucky Power's application.

c. The third paragraph states that the increase in charges from Public Service Company of Oklahoma is due primarily to employee labor and storm damage restoration expenses of $.3 million related to the February 2009 storm. State whether these expenses are included for recovery through rates elsewhere in the application.

RESPONSE

a. (1) The expenses relate to the transformer and related materials purchased for the construction of a sub-station in Dwale, KY for a third party. The major components of the expenses were materials (87.6%), outside services (6.2%) and internal charges (6.2%).

a. (2) All the costs were expensed because this was work performed for a third party. Kentucky Power billed the third party $1.6 million for this project during the test year which is recorded as other electric revenues and is included in the cost of service.

b. The $.2 million charged from Indiana Michigan Power is part of the Company's major storm cost deferral adjustment that the Company is requesting a three year recovery and amortization period (See Company's Adjustment Section V, Workpaper S-4, Page 20). Because the Company is requesting a three year average level of major storm costs to be included in the cost-of-service, the result is two thirds of these expense amounts have been excluded.

c. The $.3 million charged from Public Service Company of Oklahoma is part of the Company's major storm cost deferral adjustment that the Company is requesting a three year recovery and amortization period (See Company's Adjustment Section V, Workpaper S-4, Page 20). Because the Company is requesting a three year average level of major storm costs to be included in the cost-of-service, the result is two thirds of these expense amounts have been excluded.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to the response to Item 4 of Staff's Second Request, the RS tab of the electronic spreadsheet. Cells D25 to D33 reference a spreadsheet titled "B&A Surcharges." Provide this spreadsheet in electronic form with the formulas intact and unprotected.

RESPONSE

Please see the attached file on the enclosed CD (Staff Third Set - Item No. 7 - Attachment 1). For additional detail regarding the calculation of the surcharge amounts, please see the attached file on the enclosed CD (Staff Third Set - Item No. 7 - Attachment 2).

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Refer to the response to Item 5 of Staff's Second Request.

a. Refer to the response to 5.a.

(1) Confirm that metered kWh in the test year were 23,089,257 more than the kWh for which Kentucky Power showed revenues. If not, explain.
(2) Explain the difference of 23,089,257 between metered and billed kWh. State in the response whether this difference would include line loss.

b. Refer to the response to 5.b. State whether $9,513,955 is the actual amount billed through the fuel adjustment clause in the test year. If no, provide the actual amount billed through the fuel adjustment clause in the test year and explain in greater detail what the $9,513,955 represents and how it was calculated.

RESPONSE

a. (1) Test year metered kWh on a billed and accrued (calendar month) basis was 23,089,257 higher than the amount of kWh which when multiplied by test year rates, produced the billed and accrued sales revenue as shown on the Company's books.

a. (2) Since both values represent kWh at the meter, the difference would not be due to line losses. Since the Company does not bill on a calendar month basis, the Company must calculate unbilled kWh and revenues on a monthly basis in order to record billed and accrued kWh and revenues which are synchronized with expenses which are recorded on a calendar month basis. Given this calculation, it is not always possible to match book billed and accrued revenues by multiplying billed and accrued kWh times the monthly rates. The net effect of this item is to increase the Company's test year revenues.

b. The amount of $9,513,955 was not the actual amount billed through the fuel adjustment clause during the test year. During the test year, the Company increased the basing point of fuel from $0.0212 per kWh to $0.0284 per kWh as shown on Exhibit EKW-4. Volume 2, Section III, page 10 uses the base rates in effect at the end of the test year which include the higher basing point of fuel. As such, the test year fuel adjustment clause revenue was recalculated as if the higher basing point were in effect all year. That is how the $9,513,955 was calculated. The detail is shown in the file provided on the enclosed CD in response to Staff Third Set - Item No. 7 - Attachment 2.

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Refer to the response to Item 10 of Staff's Second Request. The request, among other things, called for Kentucky Power to quantify the benefits of the cost saving measures, etc. identified in the response; however, the last sentence in the response states that "Savings have not been quantified." Explain whether the response means that (a) the benefits cannot be quantified or (b) Kentucky Power had not quantified the benefits before receiving the data request and made no attempt to do so for its response to the request. If the answer is the latter, provide Kentucky Power's best estimate of the amount of the savings associated with each measure.

RESPONSE

We have not quantified any direct savings for our customers from the cost saving measures we have taken since our last base rate case. Rather these measures have produced efficiencies and established best practices that have allowed us to focus resources on reliability programs that benefit the customer. Our reliability spend in each of the years since our last base rate case has been higher than the level in the last rate case. Further, although the Company believes savings resulted from these measures, it is not able at this time to provide a reasonable estimate.

WITNESS: Timothy C Mosher

Kentucky Power Company

REQUEST

The response to Item 26 of Staff's Second Request does not satisfy the request. Provide the relevant testimony and exhibits from FERC Docket No. ER09- 1279 which provide the description and calculation that were the subject of the original request.

RESPONSE

The Company regrets that the Commission found the response unsatisfactory. See attached testimony and exhibit from FERC Docket No. ER09-1279. The cost decrease that Kentucky Power Company will experience results from the combination of a number of factors, including the allocation of AEP East transmission revenues to each AEP East operating company based on their share of the AEP transmission revenue requirement, a change in the allocation of transmission charges from MLR to 12CP, and the elimination of the present bulk transmission settlement method under the AEP Transmission Agreement. All of the changes and the monetary effect of them are described in Mr. Bethel's testimony and exhibit in Docket ER09-1279. See, Column (f), Kentucky Power Row in Net Change From Trans. Agreement Modification Area, Page 1 of 5 of Exhibit AEP-210 for the 2009 period.

WITNESS: Dennis W Bethel

Exhibit AEP-200

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power Service Corporation	)	Docket No. ER09-____-000
On behalf of:	)	
Appalachian Power Company	)	
Columbus Southern Power Company	)	
Indiana Michigan Power Company	)	
Kentucky Power Company	)	
Kingsport Power Company	)	
Ohio Power Company	)	
Wheeling Power Company	)	
Collectively, the "AEP East Companies"	)	

PREPARED DIRECT TESTIMONY OF

DENNIS W. BETHEL

ON BEHALF OF THE AEP EAST COMPANIES

June 5, 2009

INDEX OF EXHIBITS

**Exhibit AEP-200: Prepared Direct Testimony of Dennis W. Bethel,
On Behalf of the AEP East Companies**

TABLE OF CONTENTS

Exhibit AEP-201: Existing AEP Transmission Agreement, in Clean Format;

Exhibit AEP-202: Revised AEP Transmission Agreement, in Black-lined Format;

Exhibit AEP-203: AEP East Companies' Transmission Cost of Service and Comparison of Retail Transmission Rates Present and Proposed;

Exhibit AEP-204: Comparison of Variation in Using MLR, 1CP, and 12 CP

Exhibit AEP-205: Summary of Agreement Modification Impacts for 2008 and 2009

Exhibit AEP-206: Summary of Revenue, Demand, Energy and Other Allocation Ratios

Exhibit AEP-207: Settlements under the Present Transmission Agreement

Exhibit AEP-208: Cost Impact Comparison of Present and Revised Allocations – 1 CP

Exhibit AEP-209: Cost Impact Comparison of Present and Revised Allocations - MLR

Exhibit AEP-210: Cost Impact Comparison of Present and Revised Allocations – 12 CP

Work Papers for Exhibits AEP-206 and AEP-207

I. INTRODUCTION

Q. BY WHOM ARE YOU EMPLOYED, AND IN WHAT CAPACITY?

A. My name is Dennis W. Bethel. I am employed by American Electric Power Service Corporation ("AEPSC" or "AEP"), as Managing Director – Regulated Tariffs. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. PLEASE REVIEW YOUR TRAINING AND EXPERIENCE IN ELECTRIC UTILITY SERVICE MATTERS RELEVANT TO THIS PROCEEDING?

A. In 1973, I earned a Bachelor of Science Degree in Electrical Engineering from the University of Evansville (Indiana). I began my career with AEP, at Indiana Michigan Power Company (I&M), that same year, as a commercial and industrial customer service engineer. In 1977 I transferred to I&M's rate department. In 1980 I transferred to AEPSC, where I have held positions in Rate Research and Design, System Transactions, Transmission Operations, and Regulated Tariffs. At I&M I worked directly with customers on new and expanded service, was responsible for retail and wholesale contract development and administration, cost of service studies, rate design, fuel clause adjustments and other regulatory analyses. In the AEPSC Rate Research and Design Division, from 1980 to 1988, I performed and supervised cost of service and rate design studies and testified in a number of retail rate cases on those topics for several of the AEP East Companies. In 1988 I transferred to the Systems Transactions Department where I was responsible for power, interconnection and transmission-related agreements and tariffs. In 1991 was promoted to Manager – Interconnection Agreements. During this time I helped to develop and support AEP's first Open Access Transmission Tariff ("OATT") filed in Docket No. ER93-540-000. In 1997 I moved to the Transmission Operations Department as Manager – Transmission Contracts and Regulatory Support, a position that was functionally separated from the merchant operations function. In June 2000, the merger of AEP and Central and Southwest Corporation was approved, and I was named Director – Transmission and Interconnection Services in the AEPSC Regulatory Services Department. In that position I was responsible for the development and implementation of transmission, interconnection and related agreements, tariffs and policies on behalf of the AEP companies in the three regions where we provide service, SPP, PJM and ERCOT. I assumed my present position in July 2005. As Managing Director- Regulated Tariffs, I direct a staff that is responsible for cost of service studies, rate design, agreements and tariffs for retail and regulated wholesale services through out the eleven-state AEP service area. I frequently represent AEP in Regional Transmission Organization ("RTO") forums, particularly relating to the transmission tariffs, rate design, and related committee matters in the Southwest Power Pool ("SPP") and PJM.

Q. **HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY UTILITY REGULATORY COMMISSIONS?**

A. Yes. I have previously submitted testimony or affidavits on transmission and related services before the Federal Energy Regulatory Commission ("Commission") in Dockets ER93-540, ER98-2786, EL02-111, et al, EL01-73, EL05-74, EL05-121, EL07-101, and ER05-751, the AEP East Companies last rate case for transmission service under the PJM OATT ("PJM Tariff" or "Tariff"). In presently open Dockets

No. ER07-1069 and ER08-1329, I sponsor formula rates and protocols for inclusion in, respectively, the SPP OATT, on behalf of Public Service Company of Oklahoma and Southwestern Electric Power Company, and in the PJM OATT, on behalf of the AEP East Companies. I have also provided expert testimony on various electric cost-of-service and rate design issues before the utility regulatory commissions of Michigan, Kentucky, Ohio, Oklahoma, Tennessee, Virginia, and West Virginia. I am registered as a Professional Engineer in the States of Indiana and Ohio.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony discusses and supports the proposed changes to the Transmission Agreement, the rationale behind the cost and revenue allocation methods specified in the revised Transmission Agreement, and the changes in cost and revenue allocations that each of the AEP East Companies will experience after the changes take effect. I will also address the characteristics and cost impacts of two cost allocation methods that were also considered by the AEP East Companies.

Q. ARE YOU SPONSORING ANY EXHIBITS?

Yes. In addition to this Testimony, I am sponsoring the following Exhibits:

Exhibit AEP-201: Existing AEP Transmission Agreement, in Clean Format;

Exhibit AEP-202: Revised AEP Transmission Agreement, in Black-lined Format;

Exhibit AEP-203: AEP East Companies' Transmission Cost of Service and Comparison of Retail Transmission Rates Present and Proposed;

Exhibit AEP-204: Comparison of Variation in Using MLR, 1CP, and 12 CP.

Exhibit AEP-205: Summary of Agreement Modification Impacts for 2008 and 2009;

Exhibit AEP-206: Summary of Revenue, Demand, Energy and Other Allocation Ratios;

Exhibit AEP-207: Settlements under the Present Transmission Agreement;

Exhibit AEP-208: Cost Impact Comparison of Present and Revised Allocations – 1 CP;

Exhibit AEP-209: Cost Impact Comparison of Present and Revised Allocations – MLR; and

Exhibit AEP-210: Cost Impact Comparison of Present and Revised Allocations – 12 CP

III. DISCUSSION OF THE PROPOSED AGREEMENT CHANGES

Q. PLEASE BRIEFLY DESCRIBE THE SCOPE OF THE PROPOSED CHANGES TO THE TRANSMISSION AGREEMENT.

A. Since its inception, the Transmission Agreement has had one purpose, to effect a sharing of the participating AEP East Companies' ("Members") costs of owning and operating Bulk Transmission facilities. The Members originally intended Bulk Transmission facilities to include extra high voltage ("EHV") transmission lines and station facilities operating at 345 kV and higher voltages, but in its final order in Docket No. ER84-348, the Commission directed the Members, in 1989, to include transmission lines operating at 138 kV and higher and all facilities, without regard to voltage, at transmission stations that contain at least some EHV facilities.

Since that time, some very significant changes have occurred in the provision and regulation of transmission and transmission-related services, affecting the electric industry generally, and the AEP East Companies in particular. The two most significant changes are the advent of open access transmission service, pursuant to Orders 888, 889, and their successors, and the AEP East Companies' relinquishment of functional control of their transmission facilities to the PJM RTO. The scope of the changes to the Transmission Agreement proposed by the AEP East Companies is consistent with the significance of the changes in the provision and regulation of transmission service in the twenty years since the Commission's Order approving it. The proposed changes recognize that, pursuant to the PJM Open Access Transmission Tariff ("OATT", or "PJM OATT"), the AEP East Companies, and other Load Serving Entities ("LSEs") in the AEP Zone of PJM, now share the cost of the AEP East Companies' transmission facilities of all voltages, including those operated at voltages below 138 kV. Further, while the Transmission Agreement included only the five largest AEP East Companies, all seven of them own and operate transmission facilities that are used to provide transmission service under the OATT. The proposed Transmission Agreement changes also recognize that, as a result of open access and RTO participation, the AEP East Companies now are obligated to provide certain transmission-related ("ancillary") services, and to purchase such services and additional RTO supplied services. Accordingly, the proposed Transmission Agreement changes address the allocation of OATT-based transmission related costs and revenues among all seven of the AEP East Companies.

Q. **PLEASE SUMMARIZE THE CHANGES TO THE TRANSMISSION AGREEMENT.**

A. As can be seen by examination of Exhibits AEP-201 and AEP-202, the significant changes, by Agreement section are as follows:

- The Preamble, is amended to include Kingsport Power Company and Wheeling Power Company as Members, and recognize the Members' participation in the PJM RTO;

- Article 1, Description of Transmission System, is amended to recognize all transmission facilities of the Members, and delete the provisions defining and providing for periodic updates to investments of the Members in Bulk Transmission Facilities;
- Article 4, Agent's Responsibilities, amends the Agent's Responsibilities to recognize the changed nature of Settlements under the revised agreement;
- Article 5, Description of Factors Associated With Settlements, is deleted;
- Article 6, Settlements, is rewritten consistent with RTO participation, and renumbered as Article 5;
- Article 7, Taxes, amends the provisions for recovery of settlement related taxes to recognize the OATT as the recovery mechanism, and is renumbered as Article 6;
- Article 8, Billing and Payments, is replaced with provisions describing the Allocation Principles for transmission related costs and revenues and is renumbered and renamed the section as Article 7, Allocation Principles;
- Article 9, Modification, is amended to include the Agent, that is, the AEP Service Corporation, among those that may call for a reconsideration of the terms and conditions of the Agreement, and is renumbered as Article 8
- Article 10, Effective Date and Term of This Agreement, is modified consistent with the Commission's Order approving the Agreement in Docket No. ER84-348, and is renumbered as Article 9;
- Article 11, Termination of Special Facilities Agreement, is deleted as no longer relevant;
- Article 12, Regulatory Authorities, is renumbered as Article 10;

- Article 13, Assignment, is renumbered as Article 11;
- The signature page is amended to add Kingsport and Wheeling Power Companies' signature lines; and
- Appendix I is added. It is a new attachment, in the form of a table summarizing the costs and revenues to be allocated under the Transmission Agreement, the allocation methods to be used, and describing the expense and revenue accounts where the Members will record the costs and revenues so allocated.

Q. OF THE CHANGES YOU HAVE SUMMARIZED, WHICH IS THE MOST SIGNIFICANT?

A. The most significant change is the replacement of the present bulk transmission investment cost sharing method, specified in Articles 5 and 6, with the comprehensive transmission cost and revenue allocations, contained in new Article 5 and Appendix I.

Q. DO THE PROPOSED CHANGES AFFECT THE WHOLESALE TRANSMISSION RATES CHARGED TO ANY CUSTOMER?

A. No. I think it is important to point out that the proposed changes do not affect the rates for transmission or related services that the AEP East Companies as a group or any other LSE currently is charged by PJM under its OATT. The rates for transmission and related services in the AEP Zone of PJM already reflect the rolled-in costs of all transmission facilities operated by the seven AEP East Companies. What will change, as a result of the new settlement process embodied in the revised Transmission Agreement, is the share of transmission related costs and revenues that will be allocated to each of the AEP East Companies. This means that, while the

AEP Companies' net costs for retail service will be changed, no wholesale transmission customers will be affected.

Q. **YOU MENTIONED THAT THE NEW APPENDIX I TO THE TRANSMISSION AGREEMENT SUMMARIZES THE PROPOSED ALLOCATION OF TRANSMISSION RELATED COSTS AND REVENUES AMONG THE AEP EAST COMPANIES. PLEASE EXPLAIN WHETHER ALL OF THOSE COSTS AND REVENUES ARE SHARED TODAY, AND IF SO HOW.**

A. The AEP East Companies do share all of the transmission related costs and revenues that come to them by way of the PJM LSE and PJM Transmission Owner settlements today. Except for two minor items, the charges billed to the AEP East Companies by PJM for transmission service and the revenues paid to them for use of the AEP transmission system are allocated among the AEP East Companies by the Member Load Ratio ("MLR"), the same allocation method used in the present Transmission Agreement.

Q. **WHAT TYPE OF ALLOCATION METHOD IS THE MLR?**

A. The MLR is a peak demand allocation method that has been used by the AEP East Companies since 1951 to share costs related to generation capacity under the AEP Interconnection Agreement "Generation Pool". The MLR is calculated monthly based on the non-coincident peak demands of each of the five largest AEP East Companies during the previous twelve months. The MLR load includes each Members' retail and firm sales for resale load. The load of Kingsport Power Company ("KgPCo") is included in the MLR of Appalachian Power Company

("APCo"), while the load of Wheeling Power Company ("WPCo") is included in the load of Ohio Power Company ("OPCo"). The highest peak demand of each Member during the last twelve months are summed, and then each Member's MLR is calculated as its peak demand in the previous twelve months divided by the sum of the five Members' non-coincident peaks. Unlike a single coincident peak or 1 CP, demand allocation basis such as the PJM Network Service Peak Load ("NSPL") billing unit, the MLR recognizes the seasonal diversity among the AEP East Companies' loads by incorporating each company's peak demand during the past twelve months, whether it occurs in the winter or summer.

Q. **WHAT IS THE NET EFFECT OF THE PRESENT METHODS OF ALLOCATING TRANSMISSION RELATED COSTS AND REVENUES AMONG THE AEP EAST COMPANIES?**

A. The net effect of the allocations used presently by the AEP East Companies is to cause the charges PJM makes to the AEP East Companies for transmission and related services provided by the AEP East Companies to be offset by the revenues they receive from PJM for those same services. As a result, the Companies' net costs for transmission and related services are made up of (1) each Company's cost to own and operate the transmission facilities that each has constructed, (2) their receipts or payments under the Transmission Agreement, (3) the revenues from non-affiliates they receive, and (4) the charges related to services provided by other transmission owners. I will refer to these net transmission costs as "Residual Costs" in discussing the costs that each AEP East Company presently incurs on behalf of their retail customers.

Q. **PLEASE IDENTIFY EACH OF THE COMPONENTS OF TRANSMISSION COST AND REVENUE THAT WILL BE AFFECTED BY THE PROPOSED MODIFICATION OF THE TA?**

A. The following table summarizes the transmission related costs and revenues experienced by the AEP Companies:

Item	Table 1: Items of Both Expense and Revenue	Billed By	Revenue To:
1	AEP Transmission Agreement Payments and Receipts	AEP	Surplus Cos.
2	Network Integration Transmission Service (NITS)	PJM	AEP Cos.
3	Scheduling, System Control and Dispatch Service (Sch. 1A)	PJM	AEP Cos.
4	RTO Start-Up Cost Recovery Charges (SCRC)	PJM	AEP Cos.
5	PJM Expansion Cost Recovery Charges (ECRC, Sch. 13)	PJM	AEP Cos. 48%
6	PJM Transmission Enhancement Charges (Sch. 12)	PJM	Various
	Additional Revenue and Credit Expense Items		
7	PJM Point-to-Point Transmission Service Credits	PJM	AEP Cos.
8	Grandfathered Transmission Service (Pre-PJM Contracts)	AEP	AEP Cos.
Underlying Cost of Service for AEP Provided Services			
a	Owning and operating the AEP transmission system	Note: Each of the AEP Companies accounts for their own plant, capital and expense for these services.	
b	Performing AEP System Control and Dispatch Operations		
c	Amortization of Deferred RTO Start-up Expenses		
d	Amortization of Deferred PJM Expansion Cost Funding		

Q. **WHAT TRANSMISSION RELATED COSTS ARE THE AEP EAST COMPANIES PERMITTED TO RECOVER THROUGH THEIR RETAIL RATES?**

A. There is no consistent basis for determining the cost of transmission service among the retail jurisdictions served by the AEP Companies. In Ohio, Columbus Southern Power Company ("CSP") and OPCo are permitted to charge, through a Transmission Cost Recovery Rider ("TCRR"), the share of the PJM OATT costs billed to the AEP Companies that they incur on behalf of retail customers. Ohio adopted this method as a step toward the introduction of retail supply competition. As in some other states that have unbundled retail tariffs, the OATT rate is used as the transmission charge so that retail customers experience the same costs for transmission and related services whether they buy their power from the local utility or another competitive supplier.

The Tennessee Public Service Commission has also recently approved a transmission cost adjustment that permits KgPCo to recover its share of the charges billed to the AEP East Companies by PJM, which charges are allocated to KgPCo pursuant to a Power Purchase Agreement (PPA) with APCo.

The other AEP Companies' retail rates presently in effect in Kentucky, Michigan, Virginia and West Virginia reflect the Residual Costs of transmission and related services where the companies' jurisdictional costs of owning and operating the transmission system are adjusted by the net cost or credit resulting from jurisdictional allocation of transmission service charges and revenues from third parties and AEP affiliates. Although AEP's retail rates in Virginia presently reflect Residual Costs (separated into OATT and retail cost components), Virginia regulation now permits the recovery of OATT-based costs, as in Ohio.

The Indiana Utilities Regulatory Commission recently approved an RTO Cost Tracker that will periodically adjust retail rates for changes in a number of PJM charges and credits, including some of the items listed above; however, I&M's Indiana base rates still reflect the company's Residual Cost to own and operate its transmission facilities, net of affiliate and third party revenues.

Q. **WITH THE PRESENT MIX OF RETAIL RATE MAKING METHODS, ARE THE AEP EAST COMPANIES ABLE TO RECOVER ALL THEIR TRANSMISSION RELATED COSTS?**

A. No. Presently, the AEP East Companies are experiencing a significant transmission cost recovery short-fall. The sum of the transmission and related revenues that the AEP East Companies are able to include in retail rates, together with the revenues they receive from non-affiliates is less than their cost of service for transmission and related services.

Q. **WILL THE COST RECOVERY SHORT-FALL PROBLEM BE AMELIORATED BY THE APPROVAL OF THE TRANSMISSION AGREEMENT CHANGES PROPOSED IN THIS PROCEEDING?**

A. The proposed changes will create the conditions necessary to ameliorate the problem, but retail rate changes will still be required. The cost recovery issue is primarily a result of the way transmission related costs and revenues are allocated among the AEP Companies. If the cost and revenue allocation changes proposed in this case are approved, the Residual Cost of transmission service determined by states that may continue to set retail rates that way, will come more closely into line with the RTO-based costs allowed in Ohio, Tennessee and Virginia.

Q. **CAN YOU QUANTIFY THE MAGNITUDE OF THE COST RECOVERY PROBLEM, AND ILLUSTRATE THE RETAIL RATE IMPACTS THAT WOULD RESULT IF THE PROPOSED SOLUTION IS APPROVED AND THE RETAIL RATES OF EACH AEP COMPANY ARE ADJUSTED TO REFLECT THE REALLOCATED COSTS AND REVENUES?**

A. Yes. Exhibit AEP-203 illustrates (i) the Residual Costs that each AEP Company experiences today to provide transmission service on behalf of retail customers (line 8), calculated as the approximate total cost of service experienced by the AEP Companies for transmission and related services that they provide (line 6), plus the net charge or credit they experience from the present allocation of costs and revenues among them (line 7); (ii) the approximate cost each Company is able to include in retail rates (line 11); and (iii) the Residual Costs they would each experience with the transmission cost and revenue allocations proposed in this proceeding (line 13).

Comparing the totals of lines 8 and 11, it can be seen that the cost recovery short-fall problem is approximately $58 million per year. It can also be seen that this problem is not merely the result of Ohio and Tennessee charging retail customers based on the PJM OATT. The problem instead results from the Bulk Transmission settlement method in the present Transmission Agreement, and the allocation of other transmission related costs and revenues using the same method, e.g., MLR. The proposed Transmission Agreement changes will fix the problem by allocating transmission costs among the Companies based on their use of each service, and sharing revenues based on each Company's cost to provide the service. With the present settlements and allocations, the Companies are being charged for services on a load share basis, but they are not receiving revenues in proportion to the costs of the services they provide.

Q. PLEASE EXPLAIN THE SIGNIFICANCE OF THE $/kW-Month VALUES SHOWN IN EXHIBIT AEP-203.

A. Those values are important in demonstrating the reasonableness of the proposed changes. The first set of values on line 10 shows each AEP East Company's Residual Cost of transmission per kilo-Watt (kW) of monthly peak demand, based on present settlements and allocations. The variation in the per kW costs that the Companies need to recover from retail customers, is presently more than 200%. As shown, the costs vary from a low of $1.59/kW-month for I&M to a high of $3.27/kW-month for KgPCo. The values on line 12 represent the average cost per kW of demand that the Companies are permitted to recover from retail customers. Those values show the same wide variation, although the CSP and OPCo values are lower than the actual residual cost to the Ohio Companies. Comparing lines 10 and 12, one sees that even with the Ohio cost recovery limited to the PJM OATT costs, as presently allocated using the MLR method, the transmission costs charged to Ohio retail customers is higher than for APCo and I&M customers. Finally, line 14 shows that the proposed cost and revenue allocations will equalize the per-kW transmission and related costs among the AEP Companies.

Q. WHAT LOGIC SHOULD DRIVE THE CHOICE OF COST AND REVENUE SHARING METHODS IN A POOLING ARRANGEMENT AMONG SISTER COMPANIES SUCH AS THE AEP EAST COMPANIES?

A. Costs should be allocated proportionate to the amount of service that each Member uses, typically measured by relative contributions to total peak demand; however, there are various methods that can be used to measure relative contributions to peak demand. The choice among reasonable alternative cost allocation methods should consider factors such as administrative efficiency and stability of the relative cost shares the allocation methods will produce.

Revenues for transmission and related services should be allocated proportionate to the costs that each Member incurs in making its facilities and services available to its affiliates, and in this case the RTO, such that when all sources of transmission revenues are taken into account, e.g., wholesale and retail, each Member will receive revenues equal to its cost of service.

Q. WHAT BILLING BASIS DOES PJM USE TO CHARGE LOAD SERVING ENTITIES FOR TRANSMISSION AND RELATED SERVICES?

A. PJM uses the prior year single peak or 1CP demand method to charge LSEs for network transmission service ("NTS"), expansion cost recovery charge ("ECRC") and RTO start up cost recovery charge ("SCRC"), and to allocate revenue credits for point-to-point transmission service among NITS customers. PJM charges Transmission Owner Scheduling, System Control and Dispatch Service based on delivered energy.

Q. WHAT COSTS ARE BEING COLLECTED THROUGH THE ECRC AND SCRC RATES?

A. The ECRC rates are billed by PJM to recover the costs that PJM originally charged to the AEP East Companies, Commonwealth Edison Company and the Dayton Power and Light Company to fund the expansion of the RTO's operations in order to accommodate the addition of new zones in 2004 and 2005. ECRC rates are charged to loads in all zones of PJM, except the Dominion Virginia Power Zone. Dominion also funded a share of the PJM expansion costs, but elected not to participate in the region-wide recovery of the costs. The SCRC rate is a charge that recovers the AEP East Companies' direct costs for RTO development and start-up. That charge is only billed to the AEP East Companies and other NITS customers in the AEP Zone. The ECRC and SCRC rates collect the underlying PJM expansion and AEP RTO start-up costs and carrying costs over the periods that the costs are being amortized, ten years and fifteen years, respectively.

Q. WHAT METHOD DO THE AEP EAST COMPANIES PROPOSE TO USE TO SHARE COSTS THAT PJM BILLS BASED ON THE PRIOR YEAR 1CP DEMANDS?

A. The AEP East Companies propose to use the twelve month average coincident peak or 12CP method to allocate the costs billed to them as a group by PJM using the 1CP method.

Q. PLEASE EXPLAIN WHY AEP IS PROPOSING THE 12CP METHOD.

A. The 12 CP method will result in more stable cost sharing among the AEP Companies than other alternatives. Rate stability is an important consideration for customers, state regulators and for AEP. Exhibit AEP-204 shows the relative stability of several alternative demand allocation methods, on an actual basis from 2005 through 2008, and as projected for 2009. The exhibit shows (1) the present MLRs, (2) the MLRs with KgPCo and WPCo separated from APCo and OPCo, the seven-Member MLRs, (3) the annual 1CP load ratios, and (4) the 12CP load ratios for each of the AEP East Companies. The exhibit calculates the year to year percentage changes, the maximum annual deviation, and the range of deviations. Over the five years, the 1CP would cause four companies to have single year cost allocation shifts of 20% to more than 33%. Cost variations under the seven-Member MLR method would be relatively low, topping out at 13%. Cost allocation variances under the 12CP method would be the smallest. Similar differences appear when the high to low annual allocation percentage ranges are compared. APCo's 1CP share would range from a high of 34.18% to a low of 26.84%, a 7.34% spread, while the largest spread for 12CP is only 2.85% for I&M. Again the seven-Member MLR comes in second, with a 3.5% spread for APCo.

Q. WHY DOES THE 1CP METHOD CAUSE INSTABILITY IN THE SHARING OF TRANSMISSION COSTS AMONG THE AEP EAST COMPANIES?

A. The 1CP transmission billing demand is inherently less stable than the 12CP method because it measures each customer's load in only one hour of the year. When applied to individual customers, the 1CP method can result in cost allocations reflecting anywhere from zero to 100% of a customer's annual peak load. When applied to utilities like the AEP East Companies that serve the diversified load of many customers, the 1CP can still produce significant variability in cost allocations when the annual peak occurs in the summer than when it occurs in the winter. That is exactly what happened this year in the AEP Zone of PJM. The 1CP in 2007, which was used for billing purposes in 2008, was a summer peak. The 1CP for 2008, that is the network integration transmission service (NITS) billing demand in the AEP Zone during 2009, was a winter demand peak. Three of the AEP East Companies, APCo, KPCo and KgPCo, typically have their annual peak in the winter, while the others typically peak in the summer. Thus, in a year like 2009, when a change from summer peak allocations to winter peak allocations occurs, costs will be shifted from the summer peaking companies to the winter peaking companies. Of course the reverse will occur when the peak again occurs in the summer.

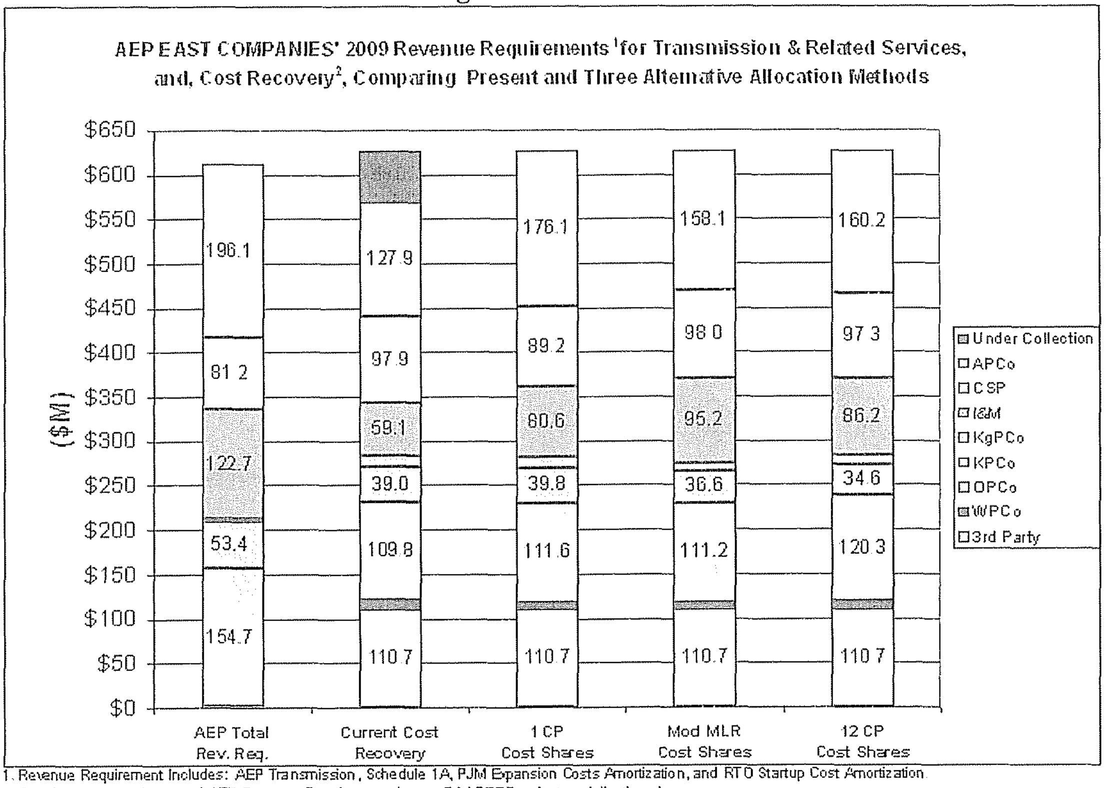
Q. CAN YOU ILLUSTRATE HOW THE NET TRANSMISSION COSTS OF EACH OF THE AEP EAST COMPANIES WOULD CHANGE UNDER THE 12CP AND ALTERNATIVE ALLOCATION METHODS?

A. Yes. Figure 1 shows in bar graph form, from left to right, (1) the total transmission service revenue requirement of the AEP East Companies, (2) the approximate amounts they are currently able to reflect in retail rates, the costs they would experience if the Transmission Agreement changes as proposed are approved, but assuming (3) that the 1CP method is used to share transmission service costs, (4) that the modified 7-Member MLR method is used, and (5) if the 12CP method, as proposed is used.

Q. PLEASE DESCRIBE FIGURE 1.

A. Last year, in Docket No. ER08-1329, the AEP East Companies filed a transmission formula rate, which was accepted, effective as of March 1, 2009, subject to refund after settlement and potential hearing processes. The first bar graph in Figure 1 shows that the transmission and related services revenue requirements of the various AEP East Companies total $612.5 million based on the proposed formula rate. Based on the billing demands effective during 2009, non-affiliates, or third parties, would pay approximately $110.7 million of the AEP Companies' cost of transmission and related services.

Figure 1



1 Revenue Requirement Includes: AEP Transmission, Schedule 1A, PJM Expansion Costs Amortization, and RTO Startup Cost Amortization
2 Cost Recovery totals exceed AEP Revenue Requirement due to PJM RTEP project socialization charges

The AEP East Companies would be responsible for the remainder. The second bar graph shows the present situation with regard to retail cost recovery, and the under-recovery problem. The other bar graphs show the relative costs that each of the AEP East Companies would experience if transmission service costs are allocated by the 1CP method, the seven member MLR method or the 12CP method, and illustrate the concept that the under-recovery issue will be resolved if the changes proposed in the Transmission Agreement are approved.

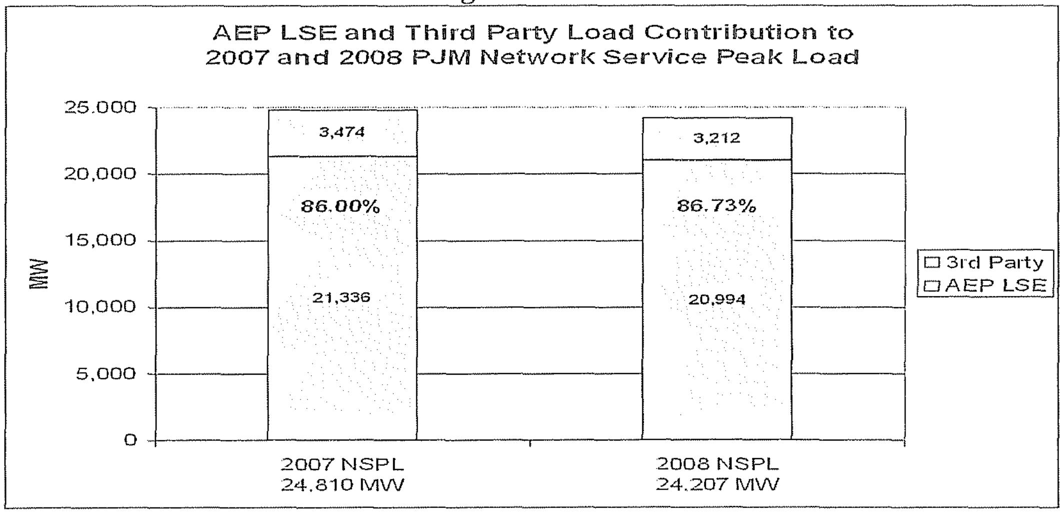
IV. COMPARISON OF ALTERNATIVE ALLOCATION METHODS

Q. HAVE YOU PREPARED A MORE DETAILED ANALYSIS OF THE IMPACTS THE COST AND REVENUE ALLOCATION CHANGES WILL HAVE ON THE AEP EAST COMPANIES?

A. Yes. Exhibit AEP-205 summarizes three cost impact analyses contained in Exhibits AEP- 208, AEP-209 and AEP-210 that show, respectively, the revenues that each AEP East Company would share as a Transmission Owner and the expenses each would incur as an LSE under the Transmission Agreement as it stands today, and as modified in this proceeding if transmission costs are shared by the AEP East Companies, as LSEs, based on the 1CP Method (Exhibit AEP-208), by the MLR method adjusted to allocate costs to all seven of the AEP East Companies based on their peak retail loads (Exhibit AEP-209), and based on the 12CP method (Exhibit AEP-210). The AEP East Companies are proposing in this proceeding to adopt the 12CP method for transmission and related service cost allocations, other than the PJM Schedule 1A charges that are based on energy deliveries.

As can be seen by summary Exhibit AEP-205, in total, the AEP Companies presently receive more revenue from PJM as Transmission Owners than they pay as LSEs, and based on the rates and billing demands effective during 2008, those net receipts were about $104 million. In 2009, even recognizing the annualized effect of the higher rates that started March 1, the net receipts will be lower, at about $96.5 million. There are two primary reasons the for the reduction in net receipts, (1) the AEP East Companies' share of the AEP transmission costs increased, because the AEP Companies' share of the 2008 winter peak demand is larger than their share of the 2007 summer peak demand, as shown in the following graph (Figure 2), and (2) the AEP Companies are being charged 15% of the cost of new PJM transmission projects that are being socialized under PJM OATT Schedule 12, Transmission Enhancements.

Figure 2

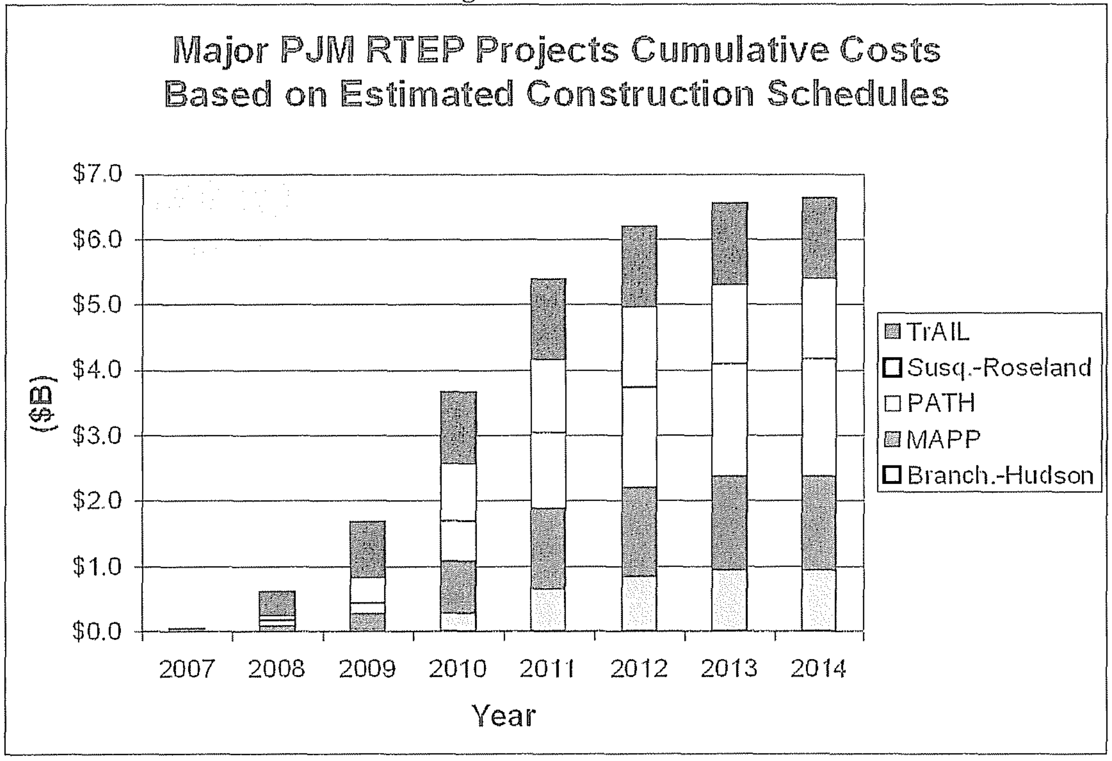


In 2008 PJM began charging the AEP Companies for socialized RTEP projects. So far those charges have not been significant, compared to the cost of the AEP East Companies' facilities; however, those charges are increasing quite rapidly. The 2009 cost impact analyses, summarized in Exhibit AEP-205, include about $14 million for Schedule 12 charges. The $14 million estimate is based on Schedule 12 charges experienced so far in 2009, but several major projects will receive increases in their revenue requirements during 2009, based on inclusion of CWIP in the rate base. AEP does not know with any certainty how much the Schedule 12 charges will actually be during 2009, but estimates of the charges show that they could be as much three times the amount reflected in the analyses.

Q. HAVE YOU PERFORMED AN ANALYSIS TO PROJECT THE SCHEDULE 12 CHARGES EXTENDING BEYOND 2009?

A. Yes. Figure 3 shows the trajectory of PJM capital spending on major PJM Regional Transmission Expansion Plan ("RTEP") projects, for which socialized cost recovery has been approved. Figure 3 illustrates an explosive growth pattern for such projects.

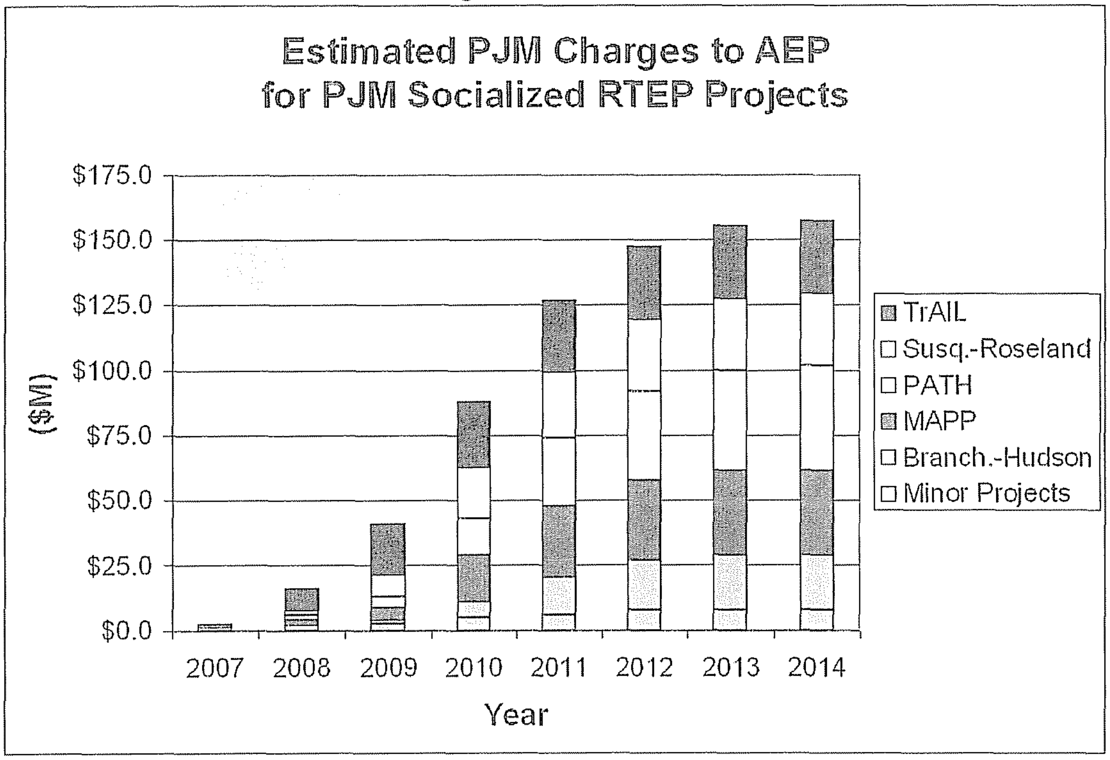
Figure 3



Q. WHAT IS THE BASIS OF THE PROJECTED SPENDING, AND HOW MUCH MIGHT THE AEP COMPANIES ULTIMATELY BE CHARGED FOR THOSE PROJECTS?

A. The spending projections in Figure 3 are based on the estimated cost and in-service dates of the RTEP projects, as published by PJM. The estimated start-to-end spending projection for the various projects has been developed using estimated spending schedules that assume most of the costs will be incurred in the middle and last years of the construction schedules. Figure 4 shows that the AEP Companies might expect to see Schedule 12 charges increase to about $160 million per year over the next six years, assuming a 15% annual carrying charge rate, and current recovery of construction work in-progress costs for the largest projects. Actual carrying costs may be less than 15% during construction, but the figure is likely to yield a conservative estimate of annual costs once the projects are in service.

Figure 4



Q. **PLEASE CONTINUE WITH YOUR DISCUSSION OF Exhibit AEP-205.**

A. Exhibit AEP-205 distills a lot of information derived in Exhibits AEP-208, AEP-209 and AEP-210. The exhibit is understood most easily by tracking through the numbers from top to bottom three columns at a time. Note that the line descriptions apply to all columns, and are arranged in three blocks. The block header "Present Allocation" refers to the present application of the five-company MLR to all costs and revenues, except for the two minor exceptions noted earlier, the ECRC and the SCRC related expenses and revenues which are shared by transmission pole-mile ratios. The Block header "Proposed Allocation" refers to allocations under a modified Transmission Agreement where revenues are allocated based on each AEP East Companies' revenue requirement for each service, and costs are allocated proportionate to relevant measures of load.

The first three columns of numbers under the Header "Summary of Impact, 1CP Cost Allocation, (Exhibit AEP-207)" shows the Present Allocations for each AEP East Company during 2008 and 2009 and the differences in the top block of rows, then the Proposed Allocation for 2008 and 2009 and the differences in the middle block of rows. Bear in mind that on this exhibit the values represent the net of revenues received by and expenses charged to the Members in RTO settlements. The bottom block of rows shows the changes that would result in 2008 and 2009 from replacing the present Transmission Agreement and allocation methods, with the proposed load-based allocation of costs and revenue requirement-based allocations of revenues. The first block of columns show that if the 1CP method were to be used for transmission service cost allocations, the Net Transmission Cost for APCo would increase by $46.5 million from 2008 to 2009 because of the change from a summer peak to a winter peak. The one year change for CSP is $28 million. Two other companies would change by more than $10 million from 2008 to 2009 using the 1CP method.

Moving across to the next block of columns, and tracking down through the rows, one can see that if the seven-Member MLR method is used, instead of the 1CP method, the largest year to year change is reduced by about 2/3 to $18.1 million. The last block of columns shows the results for the 12CP method. The 2008 to 2009 cost changes are slightly larger for the 12CP method than for the 7-Member MLR, but over a longer period of time, as illustrated by Exhibit AEP-204, the 12CP will be the most stable of the methods.

Q. **PLEASE DESCRIBE EXHIBITS AEP-206 THROUGH AEP-210?**

A. Exhibits AEP-206 and AEP-207 summarize the allocation factors and other data underlying the analyses in Exhibits AEP-208 through AEP-210. Page 1 of Exhibit AEP-206 shows the revenue requirements of each AEP East Company for transmission and PJM Schedule 1A service pursuant both to the rates effective before and after March 1, 2009. Also shown there are the revenue requirements for RTO Start-up and PJM Expansion costs. Page 2 of Exhibit AEP-206 summarizes the AEP East Companies' demand allocation percentages for 2008 and 2009 under the three methods discussed earlier. Page 3 of Exhibit AEP-206 summarizes the energy allocation factors for 2008 and 2009 used to allocate the PJM Schedule 1A service charges. Page 4 of Exhibit AEP-206 summarizes Other Operating revenue and transmission costs that are presently directly assigned. Page 5 of Exhibit AEP-206 summarizes transmission charges to KgPCo and WPCo in 2008 and 2009 under their PPAs with APCo and OPCo, respectively.

Q. **WHAT INFORMATION DOES EXHIBIT AEP-207 PROVIDE?**

A. Exhibit AEP-207 summarizes the going-level monthly settlements under the Transmission Agreement as it presently operates. In 2008 the total payments by Deficit Members was $68.4 million, with $54.9 million paid by CSP and $13.5 million paid by OPCo. The Surplus Members, APCo, I&M and KPCo, received $28.7 million, $37.7 million and $1.9 million, respectively. Exhibit AEP-205 shows that the Transmission Agreement settlements for 2008 and 2009, based on the investments as of January 2009, would increase slightly to about $71.5 million.

Q. **HOW ARE EXHIBITS AEP-208 THROUGH AEP-210 STRUCTURED?**

A. Each of the Exhibits AEP-208, AEP-209 and AEP-210 consist of 5 pages. The first page summarizes the information developed on pages 2 through 5. Page 1 looks similar to Exhibit AEP-205, but displays different information. Page 1 of Exhibits AEP-208 through AEP-210 each have three blocks of rows and three blocks of columns. The blocks of rows tabulate Present Allocations, Proposed Allocations and the differences as in Exhibit AEP-205, but the first block of columns shows revenues ("T-Related"), costs ("LSE Related"), and the net cost or receipt for each AEP East Company for 2008. The middle block of columns shows revenues ("T-Related"), costs ("LSE Related"), and the net cost or receipt for each AEP East Company for 2009. Then the third block of columns shows the change from 2008 to 2009 in the revenues and costs, and in the net cost or receipt for each AEP East Company. The "Present Allocation" values are the same in all three exhibits, as are the revenue allocations in the "Proposed Allocation" sections. What is different about Exhibits AEP-208, AEP-209 and AEP-210 is the "Proposed Allocation" for transmission service costs and the ECRC and SCRC amounts. In Exhibit AEP-208, the transmission costs are allocated using the 1CP method, in Exhibit AEP-209 the seven-Member MLR method is used to allocate transmission costs, and in Exhibit AEP-210, the 12CP method is employed.

Page 2 of each of the three Exhibits shows present, proposed and differences in the allocation of 2008 revenues (T-Related). Page 3 shows present, proposed and differences in the allocation of 2008 costs (LSE-Related). Pages 4 and 5 of each Exhibit AEP-208 through AEP-210 shows the same allocations and differences as pages 2 and 3, but for the 2009 revenues and costs.

V. CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A. The AEP Companies initiated the AEP Transmission Agreement in 1984 with the goal of levelizing the cost of bulk transmission investments that they each had made and planned to make. Over time, events and new goals have over-taken the Companies and the agreement, resulting in wide differences in per kW costs for transmission service among the AEP East Companies, and a significant cost recovery short-fall. The AEP East Companies have studied the issues, considered the relative affects of several alternative courses of action, and have agreed, pursuant to the terms of the Transmission Agreement, that the agreement should be modified, as has been proposed in this proceeding. My study of the issues and impacts, presented in the for-going testimony, and attached exhibits, lead me to conclude that the proposed changes are consistent with the principles of cost allocation, and the Commission's policies, will improve equity in the sharing of costs among the AEP East Companies and stability in the costs of their customers. For these and other reasons that Mr. Baker and I have discussed, I recommend that the changes to the Transmission Agreement, reflected in Exhibit AEP-202, be accepted and made effective upon their approval by Order of the Commission.

Q. DO YOU HAVE ANYTHING FURTHER TO ADD?

A. At this time I do not.

AEP Transmission Agreement
Cost Impact Comparison of Present and Revised Allocations - 12CP
Proformed 2008 Cost Sharing vs. Proposed 2009 Cost Sharing
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Present Allocation:

	2008 Revenues and Costs with Calendar 2008 Allocations			2009 Projected Revenues, Costs and Allocations			Comparison 2008 vs. 2009 Proformed 2008 vs. Projected 2009		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Company	Total T-Related	Total LSE-Related	Total T & LSE Related	Total T-Related	Total LSE-Related	Total T & LSE Related	(d)-(a) T-Related	(e)-(b) LSE-Related	(g)+(h) AEP Net
Appalachian Power	($205,218)	$136,454	($68,764)	($224,474)	$156,245	($68,229)	($19,256)	$19,792	$536
Columbus Southern Power	($45,932)	$85,142	$39,209	($56,948)	$97,933	$40,985	($11,016)	$12,792	$1,776
Indiana & Michigan Power	($147,990)	$82,393	($65,596)	($159,085)	$95,518	($63,567)	($11,096)	$13,125	$2,029
Kingsport Power	$0	$9,696	$9,696	$0	$10,988	$10,988	$0	$1,292	$1,292
Kentucky Power	($45,953)	$31,073	($14,880)	($51,035)	$36,688	($14,347)	($5,082)	$5,615	$533
Ohio Power	($105,586)	$93,786	($11,800)	($120,998)	$109,833	($11,165)	($15,412)	$16,047	$635
Wheeling Power	$0	$8,091	$8,091	$0	$8,773	$8,773	$0	$682	$682
Total	($550,679)	$446,635	($104,043)	($612,541)	$515,979	($96,562)	($61,862)	$69,344	$7,482

12CP Allocation:

Company	Total T-Related	Total LSE-Related	Total T & LSE Related	Total T-Related	Total LSE-Related	Total T & LSE Related	Total T-Related	Total LSE-Related	Total T & LSE Related
Appalachian Power	($194,505)	$136,594	($57,912)	($196,316)	$160,186	($36,130)	($1,810)	$23,592	$21,782
Columbus Southern Power	($62,162)	$85,941	$23,778	($81,185)	$97,275	$16,090	($19,023)	$11,335	($7,688)
Indiana & Michigan Power	($111,162)	$76,299	($34,863)	($122,427)	$86,189	($36,238)	($11,265)	$9,890	($1,375)
Kingsport Power	($2,344)	$7,479	$5,135	($2,725)	$9,696	$6,971	($380)	$2,217	$1,836
Kentucky Power	($44,525)	$30,874	($13,652)	($53,381)	$34,578	($18,803)	($8,856)	$3,704	($5,151)
Ohio Power	($132,893)	$103,218	($29,675)	($154,755)	$120,344	($34,411)	($21,861)	$17,125	($4,736)
Wheeling Power	($3,086)	$6,231	$3,145	($1,753)	$7,712	$5,959	$1,333	$1,481	$2,814
Total	($550,679)	$446,635	($104,043)	($612,541)	$515,979	($96,562)	($61,862)	$69,344	$7,482

Net Change From Trans. Agreement Modification:

(Proposed - Present) Company	Net T-Related	Net LSE-Related	Net T & LSE Related	Net T-Related	Net LSE-Related	Net T & LSE Related	Net T-Related	Net LSE-Related	Net T & LSE Related
Appalachian Power	$10,713	$140	$10,853	$28,159	$3,940	$32,099	$17,446	$3,801	$21,246
Columbus Southern Power	($16,230)	$799	($15,431)	($24,237)	($658)	($24,895)	($8,007)	($1,457)	($9,464)
Indiana & Michigan Power	$36,828	($6,094)	$30,734	$36,658	($9,329)	$27,330	($169)	($3,235)	($3,404)
Kingsport Power	($2,344)	($2,217)	($4,562)	($2,725)	($1,293)	($4,017)	($380)	$925	$545
Kentucky Power	$1,428	($199)	$1,228	($2,346)	($2,110)	($4,457)	($3,774)	($1,911)	($5,685)
Ohio Power	($27,307)	$9,432	($17,875)	($33,757)	$10,511	($23,246)	($6,449)	$1,078	($5,371)
Wheeling Power	($3,086)	($1,861)	($4,947)	($1,753)	($1,062)	($2,814)	$1,333	$799	$2,133
Total	$0	($0)	($0)	($0)	($0)	$0	($0)	($0)	$0

AEP Transmission Agreement
Cost Impact Comparison of Present and Revised Allocations - 12CP
Revenues and Costs October 2007 - September 2008
$(000)

AEP as a Transmission Owner - Revenue Allocations

Present Allocation:

Company	A Total Sched. 1A (Credit)	a1 Third Party Sched. 1A (Credit) (MLR)	a2 Sched. 1A AEP LSE (Credit) (MLR)	a3 Sched. 1A Formula (Credit) (DA)	B Total T-Svc. (Credit)	b1 Third Party NTS (Credit) (MLR)	b2 NTS AEP LSE (Credit) (MLR)	b3 NTS AEP Formula (Credit) (DA)	C TEA Charge (Credit)	D GFA PTP (Credit) (MLR)	E ECRC (Credit) (TPM)	F SCRC (Credit) (TPM)	Total T-Related
Appalachian Power	($3,920)	($1,011)	($2,822)	($87)	($169,457)	($16,875)	($146,981)	($5,600)	($26,813)	($3,638)	($708)	($682)	($205,218)
Columbus Southern Power	($2,272)	($590)	($1,647)	($35)	($97,614)	($9,852)	($85,806)	($1,956)	$56,634	($2,124)	($283)	($272)	($45,932)
Indiana & Michigan Power	($2,431)	($569)	($1,586)	($276)	($106,328)	($9,487)	($82,634)	($14,207)	($36,081)	($2,045)	($563)	($541)	($147,990)
Kingsport Power	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Kentucky Power	($821)	($215)	($599)	($7)	($35,369)	($3,585)	($31,221)	($563)	($8,655)	($773)	($171)	($164)	($45,953)
Ohio Power	($2,661)	($702)	($1,959)	$0	($113,737)	($11,714)	($102,024)	$0	$14,916	($2,525)	($804)	($774)	($105,586)
Wheeling Power	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	($12,105)	($3,087)	($8,614)	($405)	($522,505)	($51,512)	($448,666)	($22,326)	$0	($11,106)	($2,529)	($2,434)	($550,679)

12CP Allocation:

Company	A Total Sched. 1A (Credit) (ARR S1)	a1 Third Party Sched. 1A (Credit) (ARR S1)	a2 Sched. 1A AEP LSE (Credit) (ARR S1)	a3 Sched. 1A Formula (Credit) (ARR S1)	B Total T-Svc. (Credit) (ATRR)	b1 Third Party NTS (Credit) (ATRR)	b2 NTS AEP LSE (Credit) (ATRR)	b3 NTS AEP Formula (Credit) (ATRR)	C Eliminate TEA Charge (Credit)	D GFA PTP (Credit) (ATRR)	E ECRC (Credit) (ARR ECRC)	F SCRC (Credit) (ARR SCRC)	Total T-Related
Appalachian Power	($3,476)	($887)	($2,474)	($116)	($185,491)	($18,287)	($159,278)	($7,926)	$0	($3,943)	($903)	($692)	($194,505)
Columbus Southern Power	($1,338)	($341)	($952)	($45)	($59,051)	($5,822)	($50,706)	($2,523)	$0	($1,255)	($221)	($297)	($62,162)
Indiana & Michigan Power	($2,812)	($717)	($2,001)	($94)	($105,281)	($10,379)	($90,403)	($4,499)	$0	($2,238)	($317)	($513)	($111,162)
Kingsport Power	($62)	($16)	($44)	($2)	($2,224)	($219)	($1,910)	($95)	$0	($47)	($11)	$0	($2,344)
Kentucky Power	($501)	($128)	($357)	($17)	($42,768)	($4,216)	($36,724)	($1,827)	$0	($909)	($196)	($151)	($44,525)
Ohio Power	($3,860)	($984)	($2,746)	($129)	($124,732)	($12,297)	($107,105)	($5,330)	$0	($2,651)	($870)	($780)	($132,893)
Wheeling Power	($55)	($14)	($39)	($2)	($2,957)	($292)	($2,539)	($126)	$0	($63)	($11)	$0	($3,086)
Total	($12,105)	($3,087)	($8,614)	($405)	($522,505)	($51,512)	($448,666)	($22,326)	$0	($11,106)	($2,529)	($2,434)	($550,679)

Net Change:

(Proposed - Present) Company	A Total Sched. 1A (Credit) (Net)	a1 Third Party Sched. 1A (Credit) (Net)	a2 Sched. 1A AEP LSE (Credit) (Net)	a3 Sched. 1A Formula (Credit) (Net)	B Total T-Svc. (Credit) (Net)	b1 Third Party NTS (Credit) (Net)	b2 NTS AEP LSE (Credit) (Net)	b3 NTS AEP Formula (Credit) (Net)	C Eliminate TEA (Net)	D GFA PTP (Credit) (Net)	E ECRC (Credit) (Net)	F SCRC (Credit) (Net)	Net T-Related
Appalachian Power	$444	$125	$348	($29)	($16,034)	($1,412)	($12,297)	($2,325)	$26,813	($304)	($195)	($10)	$10,713
Columbus Southern Power	$934	$249	$695	($10)	$38,563	$4,030	$35,100	($567)	($56,634)	$869	$62	($25)	($16,230)
Indiana & Michigan Power	($382)	($149)	($415)	$182	$1,047	($892)	($7,769)	$9,708	$36,081	($192)	$245	$28	$36,828
Kingsport Power	($62)	($16)	($44)	($2)	($2,224)	($219)	($1,910)	($95)	$0	($47)	($11)	$0	($2,344)
Kentucky Power	$320	$87	$243	($10)	($7,399)	($632)	($5,503)	($1,265)	$8,655	($136)	($25)	$13	$1,428
Ohio Power	($1,199)	($282)	($788)	($129)	($10,995)	($583)	($5,082)	($5,330)	($14,916)	($126)	($65)	($7)	($27,307)
Wheeling Power	($55)	($14)	($39)	($2)	($2,957)	($292)	($2,539)	($126)	$0	($63)	($11)	$0	($3,086)
Total	$0	($0)	$0	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0

AEP Transmission Agreement
Cost Impact Comparison of Present and Revised Allocations - 12CP
Revenues and Costs October 2007 - September 2008
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AEP as a Load Serving Entity - Cost Allocations

Present Allocation:

Company	G Sched. 1A AEP LSE Charge (MLR)	H Total NTS & Trans. Enh. Charge (MLR)	h1 NTS AEP LSE Charge (MLR)	h2 Sch. 12 Trans. Enh. Charge (MLR)	I Total PTP (Credit) (MLR)	i1 Third Party PTP Firm (Credit) (MLR)	i2 Third Party PTP Non-Firm (Credit) (MLR)	J PPA Charge (Credit)	K ECRC Charge (TPM)	L SCRC Charge (TPM)	Total LSE-Related
Appalachian Power	$2,822	$148,111	$146,981	$1,131	($5,759)	($3,985)	($1,774)	($9,696)	$373	$603	$136,454
Columbus Southern Power	$1,647	$86,466	$85,806	$660	($3,362)	($2,326)	($1,036)	$0	$149	$241	$85,142
Indiana & Michigan Power	$1,586	$83,269	$82,634	$636	($3,238)	($2,240)	($997)	$0	$296	$479	$82,393
Kingsport Power	$0	$0	$0	$0	$0	$0	$0	$9,696	$0	$0	$9,696
Kentucky Power	$599	$31,462	$31,221	$240	($1,223)	($847)	($377)	$0	$90	$145	$31,073
Ohio Power	$1,959	$102,808	$102,024	$785	($3,997)	($2,766)	($1,231)	($8,091)	$423	$685	$93,786
Wheeling Power	$0	$0	$0	$0	$0	$0	$0	$8,091	$0	$0	$8,091
Total	$8,614	$452,117	$448,666	$3,451	($17,579)	($12,165)	($5,415)	$0	$1,331	$2,153	$446,635

12CP Allocation:

Company	G Sched. 1A AEP LSE Charge (MWH)	H Total NTS & Trans. Enh. Charge (12CP)	h1 NTS AEP LSE Charge (12CP)	h2 Sch. 12 Trans. Enh. Charge (12CP)	I Total PTP (Credit) (12CP)	i1 Third Party PTP Firm (Credit) (12CP)	i2 Third Party PTP Non-Firm (Credit) (12CP)	J Eliminate PPA Charge (Credit)	K ECRC Charge (12CP)	L SCRC Charge (12CP)	Total LSE-Related
Appalachian Power	$2,548	$138,359	$137,303	$1,056	($5,380)	($3,723)	($1,657)	$0	$407	$659	$136,594
Columbus Southern Power	$1,609	$87,045	$86,380	$664	($3,384)	($2,342)	($1,042)	$0	$256	$414	$85,941
Indiana & Michigan Power	$1,470	$77,237	$76,647	$590	($3,003)	($2,078)	($925)	$0	$227	$368	$76,299
Kingsport Power	$157	$7,558	$7,500	$58	($294)	($203)	($91)	$0	$22	$36	$7,479
Kentucky Power	$536	$31,314	$31,075	$239	($1,218)	($843)	($375)	$0	$92	$149	$30,874
Ohio Power	$2,140	$104,331	$103,535	$796	($4,057)	($2,807)	($1,249)	$0	$307	$497	$103,218
Wheeling Power	$152	$6,274	$6,226	$48	($244)	($169)	($75)	$0	$18	$30	$6,231
Total	$8,614	$452,117	$448,666	$3,451	($17,579)	($12,165)	($5,415)	$0	$1,331	$2,153	$446,635

Net Change:

(Proposed - Present) Company	G Total 1A AEP LSE Charge (Net)	H Total NTS & Trans. Enh. Charge (Net)	h1 NTS AEP LSE Charge (Net)	h2 Sch. 12 Trans. Enh. Charge (Net)	I Total PTP (Credit) (Net)	i1 Third Party PTP Firm (Credit) (Net)	i2 Third Party MLR Non-Firm (Net)	J Eliminate PPA (Net)	K ECRC (Credit) (Net)	L SCRC (Credit) (Net)	Net LSE-Related
Appalachian Power	($274)	($9,752)	($9,678)	($74)	$379	$262	$117	$9,696	$34	$56	$140
Columbus Southern Power	($38)	$579	$574	$4	($22)	($16)	($7)	$0	$107	$174	$799
Indiana & Michigan Power	($116)	($6,032)	($5,986)	($46)	$235	$162	$72	$0	($69)	($111)	($6,094)
Kingsport Power	$157	$7,558	$7,500	$58	($294)	($203)	($91)	($9,696)	$22	$36	($2,217)
Kentucky Power	($63)	($148)	($147)	($1)	$6	$4	$2	$0	$2	$4	($199)
Ohio Power	$181	$1,523	$1,511	$12	($59)	($41)	($18)	$8,091	($116)	($188)	$9,432
Wheeling Power	$152	$6,274	$6,226	$48	($244)	($169)	($75)	($8,091)	$18	$30	($1,861)
Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($0)

AEP Transmission Agreement
Cost Impact Comparison of Present and Revised Allocations - 12CP
Proformed for Rates Effective March 1, 2009 and 2009 Load Shares
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AEP as a Transmission Owner - Revenue Allocations

Present Allocation:

Company	A Total Sched. 1A (Credit)	a1 Third Party Sched. 1A (Credit) (MLR)	a2 Sched. 1A AEP LSE (Credit) (MLR)	a3 Sched. 1A Formula (Credit) (DA)	B Total T-Svc. (Credit)	b1 Third Party NTS (Credit) (MLR)	b2 NTS AEP LSE (Credit) (MLR)	b3 NTS AEP Formula (Credit) (DA)	b4 Sch. 12 Trans. Enh. Charge (MLR)	C TEA Charge (Credit)	D GFA PTP (Credit) (MLR)	E ECRC (Credit) (TPM)	F SCRC (Credit) (TPM)	Total T-Related
Appalachian Power	($3,158)	($840)	($2,246)	($73)	($188,738)	($17,840)	($165,086)	($5,740)	($73)	($27,703)	($3,488)	($726)	($662)	($224,474)
Columbus Southern Power	($1,839)	($493)	($1,318)	($29)	($109,366)	($10,466)	($96,853)	($2,005)	($43)	$56,858	($2,046)	($290)	($264)	($56,948)
Indiana & Michigan Power	($1,987)	($479)	($1,280)	($229)	($118,847)	($10,166)	($94,079)	($14,561)	($41)	($35,161)	($1,988)	($577)	($526)	($159,085)
Kingsport Power	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Kentucky Power	($682)	($184)	($492)	($6)	($40,701)	($3,912)	($36,196)	($577)	($16)	($8,553)	($765)	($175)	($159)	($51,035)
Ohio Power	($2,181)	($594)	($1,587)	$0	($129,337)	($12,608)	($116,677)	$0	($51)	$14,560	($2,465)	($824)	($751)	($120,998)
Wheeling Power	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	($9,848)	($2,589)	($6,923)	($336)	($586,988)	($54,992)	($508,890)	($22,882)	($224)	$0	($10,751)	($2,591)	($2,362)	($612,541)

12CP Allocation:

Company	A Total Sched. 1A (Credit) (ARR S1)	a1 Third Party Sched. 1A (Credit) (ARR S1)	a2 Sched. 1A AEP LSE (Credit) (ARR S1)	a3 Sched. 1A Formula (Credit) (ARR S1)	B Total T-Svc. (Credit) (ATRR)	b1 Third Party NTS (Credit) (ATRR)	b2 NTS AEP LSE (Credit) (ATRR)	b3 NTS AEP Formula (Credit) (ATRR)	b4 Sch. 12 Trans. Enh. Charge (ATRR)	C Eliminate TEA Charge (Credit)	D GFA PTP (Credit) (ATRR)	E ECRC (Credit) (ARR ECRC)	F SCRC (Credit) (ARR SCRC)	Total T-Related
Appalachian Power	($3,518)	($925)	($2,473)	($120)	($187,762)	($17,591)	($162,780)	($7,319)	($72)	$0	($3,439)	($926)	($671)	($196,316)
Columbus Southern Power	($860)	($226)	($604)	($29)	($78,375)	($7,343)	($67,947)	($3,055)	($30)	$0	($1,436)	($226)	($288)	($81,185)
Indiana & Michigan Power	($1,235)	($325)	($868)	($42)	($118,204)	($11,074)	($102,477)	($4,608)	($45)	$0	($2,165)	($325)	($498)	($122,427)
Kingsport Power	($42)	($11)	($30)	($1)	($2,623)	($246)	($2,274)	($102)	($1)	$0	($48)	($11)	$0	($2,725)
Kentucky Power	($764)	($201)	($537)	($26)	($51,330)	($4,809)	($44,500)	($2,001)	($20)	$0	($940)	($201)	($146)	($53,381)
Ohio Power	($3,386)	($890)	($2,380)	($116)	($147,027)	($13,774)	($127,465)	($5,731)	($56)	$0	($2,693)	($891)	($758)	($154,755)
Wheeling Power	($43)	($11)	($30)	($1)	($1,668)	($156)	($1,446)	($65)	($1)	$0	($31)	($11)	$0	($1,753)
Total	($9,848)	($2,589)	($6,923)	($336)	($586,988)	($54,992)	($508,890)	($22,882)	($224)	$0	($10,751)	($2,591)	($2,362)	($612,541)

Net Change:
(Proposed - Present)

Company	A Total Sched. 1A (Credit) (Net)	a1 Third Party Sched. 1A (Credit) (Net)	a2 Sched. 1A AEP LSE (Credit) (Net)	a3 Sched. 1A Formula (Credit) (Net)	B Total T-Svc. (Credit) (Net)	b1 Third Party NTS (Credit) (Net)	b2 NTS AEP LSE (Credit) (Net)	b3 NTS AEP Formula (Credit) (Net)	b4 Sch. 12 Trans. Enh. Charge (Net)	C Eliminate TEA (Net)	D GFA PTP (Credit) (Net)	E ECRC (Credit) (Net)	F SCRC (Credit) (Net)	Net T-Related
Appalachian Power	($359)	($85)	($227)	($47)	$976	$249	$2,305	($1,579)	$1	$27,703	$49	($200)	($10)	$28,159
Columbus Southern Power	$979	$267	$713	($1)	$30,991	$3,124	$28,905	($1,051)	$13	($56,858)	$611	$64	($24)	($24,237)
Indiana & Michigan Power	$752	$154	$412	$187	$644	($908)	($8,398)	$9,953	($4)	$35,161	($177)	$252	$27	$36,658
Kingsport Power	($42)	($11)	($30)	($1)	($2,623)	($246)	($2,274)	($102)	($1)	$0	($48)	($11)	$0	($2,725)
Kentucky Power	($82)	($17)	($45)	($20)	($10,629)	($897)	($8,304)	($1,424)	($4)	$8,553	($175)	($26)	$13	($2,346)
Ohio Power	($1,205)	($297)	($793)	($116)	($17,690)	($1,166)	($10,788)	($5,731)	($5)	($14,560)	($228)	($67)	($6)	($33,757)
Wheeling Power	($43)	($11)	($30)	($1)	($1,668)	($156)	($1,446)	($65)	($1)	$0	($31)	($11)	$0	($1,753)
Total	$0	$0	($0)	$0	$0	($0)	($0)	$0	$0	$0	($0)	($0)	$0	($0)

AEP Transmission Agreement
Cost Impact Comparison of Present and Revised Allocations - 12CP
Proformed for Rates Effective March 1, 2009 and 2009 Load Shares
$(000)

AEP as a Load Serving Entity - Cost Allocations

Present Allocation:

	G	H	h1	h2	I	i1	i2	J	K	L	
Company	Sched. 1A AEP LSE Charge (MLR)	Total NTS & Trans. Enh. Charge (MLR)	NTS AEP LSE Charge (MLR)	Sch. 12 Trans. Enh. Charge (MLR)	Total PTP (Credit) (MLR)	Third Party PTP Firm (Credit) (MLR)	Third Party PTP Non-Firm (Credit) (MLR)	PPA Charge (Credit)	ECRC Charge (TPM)	SCRC Charge (TPM)	Total LSE-Related
Appalachian Power	$2,246	$169,731	$165,086	$4,645	($5,703)	($3,946)	($1,757)	($10,988)	$368	$591	$156,245
Columbus Southern Power	$1,318	$99,578	$96,853	$2,725	($3,346)	($2,315)	($1,031)	$0	$147	$236	$97,933
Indiana & Michigan Power	$1,280	$96,726	$94,079	$2,647	($3,250)	($2,249)	($1,001)	$0	$293	$470	$95,518
Kingsport Power	$0	$0	$0	$0	$0	$0	$0	$10,988	$0	$0	$10,988
Kentucky Power	$492	$37,215	$36,196	$1,019	($1,250)	($865)	($385)	$0	$89	$142	$36,688
Ohio Power	$1,587	$119,960	$116,677	$3,283	($4,031)	($2,789)	($1,241)	($8,773)	$418	$671	$109,833
Wheeling Power	$0	$0	$0	$0	$0	$0	$0	$8,773	$0	$0	$8,773
Total	$6,923	$523,210	$508,890	$14,320	($17,579)	($12,165)	($5,415)	$0	$1,315	$2,111	$515,979

12CP Allocation:

	G	H	h1	h2	I	i1	i2	J	K	L	
Company	Sched. 1A AEP LSE Charge (MWH)	Total NTS & Trans. Enh. Charge (12CP)	NTS AEP LSE Charge (12CP)	Sch. 12 Trans. Enh. Charge (12CP)	Total PTP (Credit) (12CP)	Third Party PTP Firm (Credit) (12CP)	Third Party PTP Non-Firm (Credit) (12CP)	Eliminate PPA Charge (Credit)	ECRC Charge (12CP)	SCRC Charge (12CP)	Total LSE-Related
Appalachian Power	$2,062	$162,520	$158,072	$4,448	($5,461)	($3,779)	($1,682)	$0	$408	$656	$160,186
Columbus Southern Power	$1,306	$98,637	$95,938	$2,700	($3,314)	($2,293)	($1,021)	$0	$248	$398	$97,275
Indiana & Michigan Power	$1,197	$87,356	$84,965	$2,391	($2,935)	($2,031)	($904)	$0	$220	$352	$86,189
Kingsport Power	$125	$9,837	$9,568	$269	($331)	($229)	($102)	$0	$25	$40	$9,696
Kentucky Power	$448	$35,079	$34,119	$960	($1,179)	($816)	($363)	$0	$88	$142	$34,578
Ohio Power	$1,665	$121,978	$118,640	$3,338	($4,098)	($2,836)	($1,262)	$0	$307	$492	$120,344
Wheeling Power	$121	$7,802	$7,589	$214	($262)	($181)	($81)	$0	$20	$31	$7,712
Total	$6,923	$523,210	$508,890	$14,320	($17,579)	($12,165)	($5,415)	$0	$1,315	$2,111	$515,979

Net Change:
(Proposed - Present)

	G	H	h1	h2	I	i1	i2	J	K	L	
Company	Total 1A AEP LSE Charge (Net)	Total NTS & Trans. Enh. Charge (Net)	NTS AEP LSE Charge (Net)	Sch. 12 Trans. Enh. Charge (Net)	Total PTP (Credit) (Net)	Third Party PTP Firm (Credit) (Net)	Third Party MLR Non-Firm (Net)	Eliminate PPA (Net)	ECRC (Credit) (Net)	SCRC (Credit) (Net)	Net LSE-Related
Appalachian Power	($184)	($7,211)	($7,013)	($197)	$242	$168	$75	$10,988	$40	$64	$3,940
Columbus Southern Power	($11)	($941)	($915)	($26)	$32	$22	$10	$0	$101	$162	($658)
Indiana & Michigan Power	($83)	($9,370)	($9,114)	($256)	$315	$218	$97	$0	($73)	($117)	($9,329)
Kingsport Power	$125	$9,837	$9,568	$269	($331)	($229)	($102)	($10,988)	$25	$40	($1,293)
Kentucky Power	($44)	($2,136)	($2,078)	($58)	$72	$50	$22	$0	($1)	($1)	($2,110)
Ohio Power	$78	$2,018	$1,963	$55	($68)	($47)	($21)	$8,773	($112)	($179)	$10,511
Wheeling Power	$121	$7,802	$7,589	$214	($262)	($181)	($81)	($8,773)	$20	$31	($1,062)
Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($0)

Kentucky Power Company

REQUEST

Refer to the response to Item 35, part b. of Staff's Second Request.

a. Confirm whether it is a correct reading of the response to conclude that I&M has not filed a transmission adjustment tariff with the Indiana Commission for approval. If this is correct, explain why.

b. The response indicates that I&M's case with the Michigan Commission was scheduled for "pre-hearing" in late February. Provide a description of "pre-hearing" as used in this context and state when a decision on the case is expected.

c. Confirm whether it is a correct reading of the response to conclude that APCO has not filed a transmission adjustment tariff with the West Virginia Commission for approval. If this is correct, explain why.

RESPONSE

a. Indiana has approved an RTO cost adjustment tariff (RTO Tracker) for I&M which presently tracks RTO charges other than Network Transmission Service for the AEP Zone. AEP anticipates pursuing expansion of the Indiana RTO Tracker to cover all transmission-related costs in a future proceeding.

b. On 1-27-2010 I&M filed its case in chief with the Michigan Public Service Commission (MPSC). The term "pre - hearing" in late February means a conference was held by the MPSC to establish a procedural schedule for the case. The company expects to receive an order on or before January 26, 2011.

c. A similar transmission adjustment tariff has not yet been filed for APCO with the West Virginia Public Service Commission. The West Virginia Commission has approved tracking some transmission related items including various miscellaneous PJM transmission accounts, the AEP East Transmission Agreement Settlements and third party revenues through the expanded net energy cost (ENEC) mechanism. AEP anticipates pursuing a mechanism to cover all transmission-related costs in a future proceeding.

WITNESS: Dennis W Bethel

Kentucky Power Company

REQUEST

Refer to the responses to Item 40 of Staff's Second Request and Item 29 of the Kentucky Industrial Utility Customers' ("KIUC") first data request.

a. $5,650,647 is the target amount of "incentive compensation" for the test year. Provide a breakdown of this amount showing the amount for Kentucky Power employees and the amount for American Electric Power Service Corporation ("AEPSC") employees with the portion of these amounts derived from each of the 12 incentive plans shown in the same manner as the actual test year amount is shown in the response to the KIUC request.

b. $990,858 is the target amount of "long term incentive compensation" for the test year. Provide a breakdown of this amount showing the amount for Kentucky Power employees and the amount for AEPSC employees with the portion of these amounts derived from each of the 12 incentive plans shown in the same manner as the actual test year amount is shown in the response to the KIUC request.

RESPONSE

a. & b. Please see response to KIUC 2-9. The $5,650,647 and $990,858 are broken down by incentive plan by Kentucky Power employees and AEPSC employees in the column titled "Incentive @ 1 Payout".

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to the response to Item 53 of Staff's Second Request, which states that Kentucky Power is proposing to limit street lighting service on metal or concrete poles to existing locations because it receives very few requests for new metal or concrete poles.

a. Describe the disadvantages of installing lights on metal and concrete poles.

b. If the proposal is approved, describe the options that would remain for a customer who requests street lighting on a metal or concrete pole.

RESPONSE

a. The disadvantages to installing lights on metal or concrete poles are the high cost of such poles and the customer's preferences for various decorative pole types other than the Company's standard pole type for such installations.

b. Customer's will still have the option of selecting the type of pole upon which the street light is installed, as they currently do, under the Special Facilities provision of Tariff S.L.

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Refer to the response to Item 55 of Staff's Second Request, which states that the meter cost is $319 and that the $3.55 monthly charge "includes a return on the investment, a return of the investment (depreciation), taxes and administrative and general expense based upon a 30-year useful life."

a. Describe how the $319 cost will be accounted for to insure that it will not inadvertently be included in rate base in future rate proceedings.

b. Describe how the return, depreciation, taxes and administrative and general costs will be accounted for so that they are not "double-recovered" through base rates in the future.

c. Provide the calculation of the $3.55 monthly charge.

d. Provide the basis for the 30-year useful life.

RESPONSE

a. The total cost of the meter would be included in rate base in the same way that meters for new customers are included in rate base. The customer is not purchasing the meter, but is simply paying a higher monthly customer charge which reflects the fact that the meter required for the tariff is $319 more expensive than the meter required for the standard tariff.

b. There is no potential double recovery. The costs associated with the more expensive meter are reflected in the customer charge for the tariff. This is no different from current practice wherein the customer charge for a tariff that has a demand meter is higher than the customer charge for tariff that has a meter that only registers monthly kWh.

c. The calculation of the $3.55 monthly charge was provided on page 13 of 61 of the Company's response to Staff 1st Set Data Request - Item No. 8-c. The electronic file was provided as KIUC First Set - Item No. 12 - Page 13 to 14.xls.

d. The 30-year useful life is approximately equivalent to the 27-year life for investment in meter plant recorded in account 370 that was the basis for the current Commission-approved depreciation rates.

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Refer to the response to Item 59 of Staff's Second Request. Provide a sample annual filing for Tariff TA and BAF.

RESPONSE

See the attached four pages for a sample annual filing for Tariff T.A. and the Balancing Adjustment Factor filing under Tariff T.A. All values shown are for illustration purposes only.

WITNESS: David M Roush

Exhibit 1

Kentucky Power Company
Transmission Adjustment Tariff
Rate Design
Twelve Months Ending July 31, 2011

Line No. (1)	Description (2)	Amount (3)
1	Total KPCo Amount (Exhibit 2)	$43,400,000
2	Allocation Factor - GP-Trans	0.986
3	KPSC Jurisdictional Amount (Ln 1 x Ln 2)	$42,792,400
4	Transmission Cost in Base Rates	49,514,393
5	Transmission Adjustment (Ln 3 - Ln 4)	($6,721,993)
6	Revenues excluding OL and SL	$623,000,000
7	Transmission Adjustment Factor	-1.07897%

Exhibit 2

Kentucky Power Company
Transmission Adjustment Tariff
Total Company Cost Estimate
Twelve Months Ending July 31, 2011

Line No. (1)	Account (2)	Description (3)	Amount (4)
1	4561035	Network Intergration Transmission Service (NITS) Charges	$39,000,000
2	4561005	Firm and Non-Firm Point to Point (PTP) Transmission Revenues	-$1,000,000
3	4561036	Ancillary Service Schedule 1A Charges	$1,000,000
4	5650012	PJM Transmission Enhancement Charges	$1,300,000
5	5614001	PJM Administrative Charges	$1,300,000
6	5614007	PJM Administrative Charges	$0
7	5618001	PJM Administrative Charges	$200,000
8	5757001	PJM Administrative Charges	$1,300,000
9	4561002	RTO Formation Cost Recovery Charges	$200,000
10	4561003	PJM Expansion Cost Recovery Charges	$100,000
11		Total (Ln. 1 through Ln. 10)	$43,400,000

Kentucky Power Company
Transmission Adjustment Tariff - Balancing Adjustment Factor
Rate Design
Eleven Months Ending July 31, 2011
Reconciliation Period: Twelve Months Ended July 31, 2010

Line No. (1)	Description (2)	Amount (3)
1	Reconciliation Amount (Exhibit 2 BAF)	$578,007
2	Revenues excluding OL and SL	$570,000,000
3	Transmission Adjustment Factor	0.10140%

Exhibit 2 (BAF)

KPSC Case No. 2009-00459
Commission Staff 3rd Set of Data Requests
Order March 11, 2010
Item No. 15
Page 5 of 5

Kentucky Power Company
Transmission Adjustment Tariff - Balancing Adjustment Factor
Reconciliation Period: Twelve Months Ended July 31, 2010

Line No.	Description	G/L Account	August	September	October	November	December	January	February	March	April	May	June	July	Total
1	Tariff T.A. Rider Revenues														
2	Billed Revenue		600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	
3	Estimated Billed Revenue (proration)														
4	Prior Month Estimated Billed Revenue		-	-	-	-	-	-	-	-	-	-	-	-	
5	Unbilled Revenue		100,000	150,000	50,000	100,000	150,000	150,000	100,000	50,000	(50,000)	50,000	100,000	100,000	
6	Prior Month Unbilled Revenue		-	(100,000)	(150,000)	(50,000)	(100,000)	(150,000)	(150,000)	(100,000)	(50,000)	50,000	(50,000)	(100,000)	
7	Total Revenue (Ln. 2 through Ln. 6)		700,000	650,000	500,000	650,000	650,000	600,000	550,000	550,000	500,000	700,000	650,000	600,000	7,300,000
8	Tariff T.A. Costs														
9	Network Intergration Transmission Service (NITS) Charges	4561035	3,250,000	3,250,000	3,250,000	3,250,000	3,250,000	3,250,000	3,250,000	3,250,000	3,250,000	3,250,000	3,250,000	3,250,000	
10	Firm and Non-Firm Point to Point (PTP) Transmission Revenues	4561005	(83,333)	(83,333)	(83,333)	(83,333)	(83,333)	(83,333)	(83,333)	(83,333)	(83,333)	(83,333)	(83,333)	(83,333)	
11	Ancillary Service Schedule 1A Charges	4561036	83,333	83,333	83,333	83,333	83,333	83,333	83,333	83,333	83,333	83,333	83,333	83,333	
12	PJM Transmission Enhancement Charges	5650012	108,333	108,333	108,333	108,333	108,333	108,333	108,333	108,333	108,333	108,333	108,333	108,333	
13	PJM Administrative Charges	5614001	108,333	108,333	108,333	108,333	108,333	108,333	108,333	108,333	108,333	108,333	108,333	108,333	
14	PJM Administrative Charges	5614007	-	-	-	-	-	-	-	-	-	-	-	-	
15	PJM Administrative Charges	5618001	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	
16	PJM Administrative Charges	5757001	108,333	108,333	108,333	108,333	108,333	108,333	108,333	108,333	108,333	108,333	108,333	108,333	
17	RTO Formation Cost Recovery Charges	4561002	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,667	
18	PJM Expansion Cost Recovery Charges	4561003	8,333	8,333	8,333	8,333	8,333	8,333	8,333	8,333	8,333	8,333	8,333	8,333	
19	Total Company (Ln. 9 through Ln. 18)		3,616,667	3,616,667	3,616,667	3,616,667	3,616,667	3,616,667	3,616,667	3,616,667	3,616,667	3,616,667	3,616,667	3,616,667	43,400,000
20	Allocation Factor - GP-Trans		0.986	0.986	0.986	0.986	0.986	0.986	0.986	0.986	0.986	0.986	0.986	0.986	0.986
21	Total Retail (Ln. 19 x Ln. 20)		3,566,033	3,566,033	3,566,033	3,566,033	3,566,033	3,566,033	3,566,033	3,566,033	3,566,033	3,566,033	3,566,033	3,566,033	42,792,400
22	Transmission Costs Included in Base Rates ($49,514,393 Annual KPCo Retail)		(4,126,199)	(4,126,199)	(4,126,199)	(4,126,199)	(4,126,199)	(4,126,199)	(4,126,199)	(4,126,199)	(4,126,199)	(4,126,199)	(4,126,199)	(4,126,199)	(49,514,393)
23	Current month Balance (Over) Under Recovery (Ln. 7 + Ln. 21 + Ln. 22)		139,834	89,834	(60,166)	89,834	89,834	39,834	(10,166)	(10,166)	(60,166)	139,834	89,834	39,834	
24	Cumulative Balance (Over) Under Recovery		139,834	229,668	169,502	259,336	349,170	389,003	378,837	368,671	308,505	448,339	538,173	578,007	578,007

Kentucky Power Company

REQUEST

Refer to the response to Item 61 of Staff's Second Requests. Explain why capacity charges increased 79 percent from 2005 to 2009.

RESPONSE

KPCo's deficit increased from 274,300 kW in September 2005 to 400,500 kW in September 2009 or an increase of approximately 46%. This increase was primarily due to the increase in the Primary Capacity kW Reservation from 1,724,300 kW in September 2005 to 1,853,500 kW in September 2009 because of changes in the Primary Member Capacity.and the MLR.

In addition the monthly equalization capacity rate increased from $9.42599 per kW in September 2005 to $11.9806 per kW in September 30 2010 or an increase of approximately 27%. This increase was primarily due to the increase in OPCo's environmental investment at its plants to comply with the Federal Clean Air Act as Amended.(See the Attached Schedules)

WITNESS: Errol K Wagner

AEP AMERICAN® ELECTRIC POWER

Date September 2009

Subject East Interchange Power Statement and Related Data
September 2009 Actual

Reviewer: David B. Roberts (Bruce)
11/2/2009

Approved D. J. Kulha
11/2/2009

To See Distribution List

Enclosed is the East Interchange Power Statement and Related Data, issued pursuant to the AEP Interconnection Agreement, indicating actual data for the month of September 2009.

ACTUAL: September 2009

CALCULATION OF MEMBER PRIMARY CAPACITY SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,321,000	0.35084	9,199,000	(2,878,000)
KPCO	1,453,000	0.07069	1,853,500	(400,500)
I&M	5,155,000	0.17927	4,700,500	454,500
OPCO	8,450,000	0.21326	5,591,700	2,858,300
CSP	4,841,000	0.18594	4,875,300	(34,300)
TOTAL	26,220,000	1.00000	26,220,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)	(2)			(3)
APCO	(2,878,000)	*****	+	*****	(34,480,283)
KPCO	(400,500)	*****	+	*****	(4,798,246)
I&M	454,500	10.54	+	3.52	6,390,270
OPCO	2,858,300	8.43	+	3.22	33,299,195
CSP	(34,300)	*****	+	*****	(410,936)

EQUALIZATION CAPACITY RATE: 11.9806
(This is the average $/kW rate paid by deficit members.)

NOTES:

* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

AMERICAN ELECTRIC POWER

AEP: America's Energy Partner℠

Date November 1, 2005

Subject East Interchange Power Statement and Related Data September 2005 Actual

From R. L. Reed

To See Distribution List

Enclosed is the East Interchange Power Statement and Related Data, issued pursuant to the AEP Interconnection Agreement, indicating actual data for the month of September 2005.

R. L. Reed / JKm

R. L. Reed

Enclosures

cc:

T.M. Dooley	-Arena 3	J. Geels	-Arena 3
T.D. Busby	-Arena 4	J.V. Gilbert	-Arena 4
N.M. Lycakis	-Arena 4	P.A. May	-Arena 4
T.R. Myers	-Arena 4	K.D. Pearce	-Arena 4
R.P. Quaintance	-Arena 4	D.B. Roberts	-Arena 4
D.L. Woodruff	-Arena 4	S.E. Molnar	-Arena 4
C.E. Zebula	-Arena 5	B.X. Tierney	-Arena 5
L.L. Dieck	-1RP23	K.W. Potts	-1RP23
J.C. Baker	-1RP23	J.H. Reif	-1RP26
Deloitte & Touche	-1RP26	M.W. Marano	-1RP28
W.S. Robinson	-1RP28	O.J. Sever	-1RP28
J. Sloat	-1RP28	S.C. Weaver	-1RP28
R.E. Munczinski	-1RP28	K.E. Walker	-1RP30
D. Waldo	-Charleston	D.E. Richey	-Canton
M.P. Ryan	-Ft. Wayne	K. Curry	-Ft. Wayne
E.K. Wagner	-Frankfort	T.C. Mosher	-Frankfort
R.G. Ronk	-Roanoke	T.L. Stephens	-Richmond

Intra-System

ACTUAL: September 2005

CALCULATION OF MEMBER PRIMARY CAPACITY SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	5,899,000	0.31188	7,244,700	(1,345,700)
KPCO	1,450,000	0.07423	1,724,300	(274,300)
I&M	5,100,000	0.18470	4,290,400	809,600
OPCO	8,100,000	0.24836	5,769,100	2,330,900
CSP	2,680,000	0.18083	4,200,500	(1,520,500)
TOTAL	23,229,000	1.00000	23,229,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)		(2)		(3)
APCO	(1,345,700)	*****	+	*****	(12,684,559)
KPCO	(274,300)	*****	+	*****	(2,585,550)
I&M	809,600	9.40	+	3.93	10,791,968
OPCO	2,330,900	5.32	+	2.75	18,810,363
CSP	(1,520,500)	*****	+	*****	(14,332,222)

EQUALIZATION CAPACITY RATE: 9.4259929947
(This is the average $/kW rate paid by deficit members.)

NOTES:
* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

Kentucky Power Company

REQUEST

Refer to page 2 of the response to Item 63 of Staff's Second Request. The schedule of uncollectible accounts appears to indicate that, in the 12-month periods ended September 2008 and September 2009, the two highest months for net charge offs were July and August. However, in the 12 months ended September 2007, the two highest months were July and October. Explain whether there was a specific reason for October rather than August being one of the two highest months during this period.

RESPONSE

The October 2006 net charge off amount included the effect of the Shamrock Coal Company bankruptcy.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to the response to Item 69 of Staff's Second Request.

a. The response to part c. of the request states that Big Sandy Unit 1 operates on a four-year outage cycle while Big Sandy Unit 2 is on a three-year outage cycle. For how long has each of the units been on its current outage cycle?

b. The last paragraph on page 2 of the response, referring to the 2007 — 2009 timeframe cited in the request, states that there were no scheduled maintenance outages on either Big Sandy unit in 2009. However, the schedule of maintenance expenses for that timeframe on page 3 of the response lists "O & M Outage — Routine" in the amount of $1,801,663 during the period ended September 30, 2009. Clarify whether there was or was not a scheduled maintenance outage at the Big Sandy Station during that period and describe the nature of the "O & M Outage — Routine."

c. Refer to page 3 of the response. In each of the two most recent 12-month periods, the largest amount of unplanned maintenance expense is on the line for "NOMI.' Identify "NOMI" and explain why this has been the category with the greatest amount of expense in the two latest time periods.

d. The unplanned maintenance expense was substantially greater in the two most recent 12-month periods (2008 and 2009) compared to the 2007 period. Provide a detailed explanation for the increases in 2008 and 2009 compared to 2007.

RESPONSE

a. Big Sandy Unit No. 1 has been operating on a four year maintenance outage cycle since 2000 Big Sandy Unit No. 2 has been operating on a three year maintenance outage cycle since 2000.

b. There was not a scheduled maintenance outage at the Big Sandy Plant during the 2009 calendar year. The approximately $1.8 Million recorded during the September 2009 test year was for parts and work performed associated with the 2008 outage.

c. & d. NOMI are "non-outage" maintenance O&M projects. These projects are day to day maintenance work performed to repair items within the plant. Another category of O&M the Company currently has is the BCO (Base Cost of Operations). The cost of operating the plant is collected in this category. Prior to 2007 both the NOMI cost and the BCO costs were collected in one category. Starting in 2008 the Company started collecting these costs into the different categories to help in management decisions.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to the response to Item 75 of Staffs Second Request.

a. Refer to 75.b, page 1 of 4.

(1) Are specific vehicles assigned to individual employees?

(2) The response states that "[t]he total annual cost per vehicle is then divided by 1,165 productive hours (2,080 hours less an average vacation time, sick time, training time, safety meeting time, plus other nonproductive time) to arrive at an hourly rate." Explain whether all employees who use the vehicles in question would use vacation leave, sick leave, and other "nonproductive time" at the same time. If no, explain why the vehicles would not be available to employees not taking vacation or sick leave and, therefore, why the total annual cost per vehicle should not be divided by 2,080 hours rather than 1,165 hours.

(3) State whether the vehicles in question are used by employees who work overtime. If so, provide the average annual number of overtime hours worked over the past three years during which the vehicles were used.

b. Refer to 75.c, page 4 of 4.

(1) Provide the calculations for the fringe benefit rates shown.

(2) State whether the fringe benefit hourly rates were calculated using 1,165 hours. If yes, provide the fringe benefit hourly rates using 2,080 hours.

RESPONSE

a. (1) Employees who perform this type of work are assigned a specific vehicle.

a. (2) No. All employees who perform this type of work (Specialists) who use this class of vehicles (Class 24) do not use vacation leave or sick leave at the same time. However, most of the other nonproductive time such as holidays, safety meeting and training time occur at the same time.

For employees who perform this type of work, the vehicle is a tool just like a computer is a tool for an office employee. Specialists typically do not wait on fellow employees to take vacation or sick time to obtain access to a vehicle to perform their daily duties. If an employee is off work due to sick time or vacation time and another employee's vehicle is out of service, the sick time or vacation time employee's vehicle would be used that day and be charged to the work performed by the non-sick time or non-vacation time employee.

The 2,080 hours is arrived at taking 52 weeks times 40 hours per week. The following hours should be removed from that total: holiday hours of 72, personal hours of 24, average vacation hours of 160, average training hours of 40, and other nonproductive hours such as breaks and clean up of 115 hours to arrive at the net productive hours of 1,669. The Company believes that using a productive hour amount of 1,165 is reasonable considering the fact there are other nonproductive hours not accounted for by holiday, personal time, vacation time, etc. For example, occasionally an employee's vehicle will be down for maintenance and there will be no other vehicle available. It would be inappropriate to use 2,080 hours in calculating the vehicle hourly rate when the vehicles are not in operation eight hours per day, five days a week, 52 weeks per year.

a. (3) The vehicles in question are used by employees who work overtime. The annual average number of overtime hours worked per employee over the past three years for the employees which perform this type of work and use this class of vehicle is 157 hours per year.

b. (1) The calculations for the fringe benefits rates are shown on pages 3 through 5 of this response.

b. (2) No.

WITNESS: Errol K Wagner

Kentucky Power Company
Calculation of Fringe Benefit Rates

FICA TAXES

Month/Year	Productive labor	Non-Prod Labor Loading	OT/NTL	Fringe Load Basis	FICA 4081002	Actual Monthly Rate	Actual YTD Rate	FICA Rate
Jul 2008	1,042,914.430	260,107.540	449,561.450	1,752,583.420	154,361.268	8.808	8.808	
Aug 2008	1,750,926.440	436,970.100	500,684.670	2,688,581.210	128,846.700	4.792	6.377	
Sep 2008	1,082,520.120	236,495.850	547,197.740	1,866,213.710	148,177.920	7.940	6.839	
Oct 2008	1,190,130.020	267,081.690	293,139.650	1,750,351.360	118,840.150	6.790	6.829	
Nov 2008	1,200,042.450	269,923.550	242,793.310	1,712,759.310	107,962.610	6.303	6.736	
Dec 2008	1,041,475.070	173,324.830	289,628.260	1,504,428.160	247,913.230	16.479	8.036	
Jan 2009	1,490,456.370	301,428.100	1,012,833.610	2,804,718.080	131,485.760	4.688	7.369	
Feb 2009	1,095,308.100	216,770.090	1,190,490.180	2,502,568.370	217,245.770	8.681	7.567	
Mar 2009	1,200,463.040	240,464.410	(28,394.890)	1,412,532.560	95,931.521	6.791	7.506	
Apr 2009	1,138,451.560	228,448.950	151,811.870	1,518,712.380	122,577.130	8.071	7.550	
May 2009	1,161,943.050	232,008.330	417,296.380	1,811,247.760	136,687.380	7.547	7.550	
Jun 2009	1,086,767.710	217,710.500	261,929.390	1,566,407.600	159,428.460	10.178	7.730	**7.650**
	14,481,398.360	3,080,733.940	5,328,971.620	22,891,103.920	1,769,457.899			

Federal Unemployment Insurance (FUI)

Month/Year	Productive labor	Non-Prod Labor Loading	Fringe Load Basis	FUI 4081003	Actual Monthly Rate	Actual YTD Rate	FUI Rate
Jul 2008	1,042,914.430	260,107.540	1,303,021.970	131.000	0.010	0.010	
Aug 2008	1,750,926.440	436,970.100	2,187,896.540	156.610	0.007	0.008	
Sep 2008	1,082,520.120	236,495.850	1,319,015.970	82.820	0.006	0.008	
Oct 2008	1,190,130.020	267,081.690	1,457,211.710	57.140	0.004	0.007	
Nov 2008	1,200,042.450	269,923.550	1,469,966.000	4.340	0.000	0.006	
Dec 2008	1,041,475.070	173,324.830	1,214,799.900	0.000	0.000	0.005	
Jan 2009	1,490,456.370	301,428.100	1,791,884.470	14,765.740	0.824	0.141	
Feb 2009	1,095,308.100	216,770.090	1,312,078.190	1,192.930	0.091	0.136	
Mar 2009	1,200,463.040	240,464.410	1,440,927.450	75.740	0.005	0.122	
Apr 2009	1,138,451.560	228,448.950	1,366,900.510	0.000	0.000	0.111	
May 2009	1,161,943.050	232,008.330	1,393,951.380	(3.190)	0.000	0.101	
Jun 2009	1,086,767.710	217,710.500	1,304,478.210	0.000	0.000	0.094	**0.100**
	14,481,398.360	3,080,733.940	17,562,132.300	16,463.130			

State Unemployment Insurance (SUI)

Month/Year	Productive labor	Non-Prod Labor Loading	Fringe Load Basis	SUI 4081007	Actual Monthly Rate	Actual YTD Rate	SUI Rate
Jul 2008	1,042,914.430	260,107.540	1,303,021.970	112.150	0.009	0.009	
Aug 2008	1,750,926.440	436,970.100	2,187,896.540	134.070	0.006	0.007	
Sep 2008	1,082,520.120	236,495.850	1,319,015.970	68.420	0.005	0.007	
Oct 2008	1,190,130.020	267,081.690	1,457,211.710	52.300	0.004	0.006	
Nov 2008	1,200,042.450	269,923.550	1,469,966.000	11.750	0.001	0.005	
Dec 2008	1,041,475.070	173,324.830	1,214,799.900	0.000	0.000	0.004	
Jan 2009	1,490,456.370	301,428.100	1,791,884.470	12,815.670	0.715	0.123	
Feb 2009	1,095,308.100	216,770.090	1,312,078.190	1,491.060	0.114	0.122	
Mar 2009	1,200,463.040	240,464.410	1,440,927.450	8,938.410	0.620	0.175	
Apr 2009	1,138,451.560	228,448.950	1,366,900.510	0.000	0.000	0.159	
May 2009	1,161,943.050	232,008.330	1,393,951.380	(4.000)	0.000	0.145	
Jun 2009	1,086,767.710	217,710.500	1,304,478.210	536.790	0.041	0.138	**0.100**
	14,481,398.360	3,080,733.940	17,562,132.300	24,156.620			

Kentucky Power Company
Calculation of Fringe Benefit Rates

Workers Compensation

Month/Year	Productive labor	Non-Prod Labor Loading	Fringe Load Basis	Work Comp 9260006	Actual Monthly Rate	Actual YTD Rate	Work Comp Rate
Jul 2008	1,042,914.430	260,107.540	1,303,021.970	6,111.340	0.469	0.469	
Aug 2008	1,750,926.440	436,970.100	2,187,896.540	9,318.390	0.426	0.442	
Sep 2008	1,082,520.120	236,495.850	1,319,015.970	16,661.540	1.263	0.667	
Oct 2008	1,190,130.020	267,081.690	1,457,211.710	38,306.930	2.629	1.123	
Nov 2008	1,200,042.450	269,923.550	1,469,966.000	(7,952.770)	-0.541	0.807	
Dec 2008	1,041,475.070	173,324.830	1,214,799.900	37,704.900	3.104	1.119	
Jan 2009	1,490,456.370	301,428.100	1,791,884.470	(6,917.560)	-0.386	0.868	
Feb 2009	1,095,308.100	216,770.090	1,312,078.190	5,363.470	0.409	0.818	
Mar 2009	1,200,463.040	240,464.410	1,440,927.450	15,132.170	1.050	0.843	
Apr 2009	1,138,451.560	228,448.950	1,366,900.510	26,900.240	1.968	0.946	
May 2009	1,161,943.050	232,008.330	1,393,951.380	8,327.270	0.597	0.916	
Jun 2009	1,086,767.710	217,710.500	1,304,478.210	(1,604.324)	-0.123	0.839	**0.800**
	14,481,398.360	3,080,733.940	17,562,132.300	147,351.596			

Pensions

Month/Year	Productive labor	Non-Prod Labor Loading	Fringe Load Basis	Total Pen 926xxxx	Actual Monthly Rate	Actual YTD Rate	Pension Rate
Jul 2008	1,042,914.430	260,107.540	1,303,021.970	38,895.920	2.985	2.985	
Aug 2008	1,750,926.440	436,970.100	2,187,896.540	38,110.920	1.742	2.206	
Sep 2008	1,082,520.120	236,495.850	1,319,015.970	38,236.920	2.899	2.396	
Oct 2008	1,190,130.020	267,081.690	1,457,211.710	38,175.920	2.620	2.448	
Nov 2008	1,200,042.450	269,923.550	1,469,966.000	37,830.920	2.574	2.472	
Dec 2008	1,041,475.070	173,324.830	1,214,799.900	38,035.920	3.131	2.561	
Jan 2009	1,490,456.370	301,428.100	1,791,884.470	104,728.330	5.845	3.109	
Feb 2009	1,095,308.100	216,770.090	1,312,078.190	105,002.330	8.003	3.642	
Mar 2009	1,200,463.040	240,464.410	1,440,927.450	103,799.870	7.204	4.022	
Apr 2009	1,138,451.560	228,448.950	1,366,900.510	104,331.510	7.633	4.354	
May 2009	1,161,943.050	232,008.330	1,393,951.380	105,087.510	7.539	4.627	
Jun 2009	1,086,767.710	217,710.500	1,304,478.210	105,219.510	8.066	4.882	**4.900**
	14,481,398.360	3,080,733.940	17,562,132.300	857,455.580			

Group Insurances

Month/Year	Productive labor	Non-Prod Labor Loading	Fringe Load Basis	Total Ins 926xxxx	Actual Monthly Rate	Actual YTD Rate	Ins Rate
Jul 2008	1,042,914.430	260,107.540	1,303,021.970	226,058.050	17.349	17.349	
Aug 2008	1,750,926.440	436,970.100	2,187,896.540	226,561.330	10.355	12.966	
Sep 2008	1,082,520.120	236,495.850	1,319,015.970	226,019.030	17.135	14.109	
Oct 2008	1,190,130.020	267,081.690	1,457,211.710	225,883.060	15.501	14.433	
Nov 2008	1,200,042.450	269,923.550	1,469,966.000	224,592.060	15.279	14.593	
Dec 2008	1,041,475.070	173,324.830	1,214,799.900	221,765.900	18.255	15.090	
Jan 2009	1,490,456.370	301,428.100	1,791,884.470	227,899.840	12.718	14.695	
Feb 2009	1,095,308.100	216,770.090	1,312,078.190	251,534.040	19.171	15.182	
Mar 2009	1,200,463.040	240,464.410	1,440,927.450	195,145.310	13.543	15.007	
Apr 2009	1,138,451.560	228,448.950	1,366,900.510	221,651.680	16.216	15.118	
May 2009	1,161,943.050	232,008.330	1,393,951.380	223,855.810	16.059	15.199	
Jun 2009	1,086,767.710	217,710.500	1,304,478.210	221,563.360	16.985	15.331	**15.300**
	14,481,398.360	3,080,733.940	17,562,132.300	2,692,529.470			

Kentucky Power Company
Calculation of Fringe Benefit Rates

Savings

Month/Year	Productive labor	Non-Prod Labor Loading	OT/NTL	Fringe Load Basis	Sav Contrib 926xxxx	Actual Monthly Rate	Actual YTD Rate	Sav Contrib Rate
Jul 2008	1,042,914.430	260,107.540	449,561.450	1,752,583.420	70,989.931	4.051	4.051	
Aug 2008	1,750,926.440	436,970.100	500,684.670	2,688,581.210	99,711.730	3.709	3.844	
Sep 2008	1,082,520.120	236,495.850	547,197.740	1,866,213.710	48,297.970	2.588	3.472	
Oct 2008	1,190,130.020	267,081.690	293,139.650	1,750,351.360	64,113.880	3.663	3.514	
Nov 2008	1,200,042.450	269,923.550	242,793.310	1,712,759.310	63,468.110	3.706	3.547	
Dec 2008	1,041,475.070	173,324.830	289,628.260	1,504,428.160	41,393.970	2.751	3.441	
Jan 2009	1,490,456.370	301,428.100	1,012,833.610	2,804,718.080	97,679.170	3.483	3.449	
Feb 2009	1,095,308.100	216,770.090	1,190,490.180	2,502,568.370	101,657.120	4.062	3.542	
Mar 2009	1,200,463.040	240,464.410	(28,394.890)	1,412,532.560	22,193.684	1.571	3.387	
Apr 2009	1,138,451.560	228,448.950	151,811.870	1,518,712.380	59,393.150	3.911	3.428	
May 2009	1,161,943.050	232,008.330	417,296.380	1,811,247.760	68,570.350	3.786	3.458	
Jun 2009	1,086,767.710	217,710.500	261,929.390	1,566,407.600	115,704.740	7.387	3.727	**3.700**
	14,481,398.360	3,080,733.940	5,328,971.620	22,891,103.920	853,173.805			

Other Post Retirement (OPEB)

Month/Year	Productive labor	Non-Prod Labor Loading	Fringe Load Basis	Total OPEB 926xxxx	Actual Monthly Rate	Actual YTD Rate	OBEP Rate
Jul 2008	1,042,914.430	260,107.540	1,303,021.970	92,274.083	7.082	7.082	
Aug 2008	1,750,926.440	436,970.100	2,187,896.540	82,516.080	3.771	104.199	
Sep 2008	1,082,520.120	236,495.850	1,319,015.970	82,516.080	6.256	101.645	
Oct 2008	1,190,130.020	267,081.690	1,457,211.710	82,516.080	5.663	98.958	
Nov 2008	1,200,042.450	269,923.550	1,469,966.000	82,516.080	5.613	96.394	
Dec 2008	1,041,475.070	173,324.830	1,214,799.900	82,516.080	6.793	94.406	
Jan 2009	1,490,456.370	301,428.100	1,791,884.470	176,953.500	9.875	91.726	
Feb 2009	1,095,308.100	216,770.090	1,312,078.190	176,953.500	13.487	89.951	
Mar 2009	1,200,463.040	240,464.410	1,440,927.450	144,403.710	10.022	88.008	
Apr 2009	1,138,451.560	228,448.950	1,366,900.510	160,969.160	11.776	86.290	
May 2009	1,161,943.050	232,008.330	1,393,951.380	166,103.570	11.916	84.619	
Jun 2009	1,086,767.710	217,710.500	1,304,478.210	166,103.570	12.733	83.139	**8.500**
	14,481,398.360	3,080,733.940	17,562,132.300	1,496,341.493			

Kentucky Power Company

REQUEST

Refer to the response to Item 76 of Staff's Second Request concerning the proposed adjustment for interest on customer deposits and Section V, Schedule 4, page 1 of the application. Provide the amount of customer deposits included in the "Customer Advance and Deposit" amount of $17,378,824 shown on line 23 of Schedule 4, page 1.

RESPONSE

The amount of customer deposits is $17,319,382.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to the response to Item 77 of Staff's Second Request. Given the circumstances associated with a major storm event, explain how Kentucky Power insures that the amounts it is charged for restoration work performed by third-party contractors are reasonable and/or reflective of the "market" for such work.

RESPONSE

Resources are obtained either from other Investor Owned Utilities (IOUs) or contractors. Under the mutual assistance agreements between IOUs, the responding company's assistance is not for profit. The wages and equipment cost reflects that IOU's internal hourly rates with their appropriate multipliers. As for contractor resources, AEP's approach is to utilize blanket contractors first, emergency contractors second and finally non-contractor vendors. For the blanket and emergency contractors we have already established a contract with the best rates for AEP-KYPCo. For those non-contractor vendors we review cost prior to bringing them on our property and accept these resources based on travel, cost and needs.

Blanket contractors are those whom we have on our property or one of our sister companies for that year or multiple years. Kentucky Power's current blanket contractor is Davis H. Elliot. Emergency contractors are those whom work for another IOU but not an AEP blanket contractor (generally in proximity to Kentucky Power, i.e. EonUS, Duke) and could be released to AEP. A non-contract vendor is a contractor that we don't use as a blanket nor have an emergency contract with. These are usually our last choice and may come from an IOU that is not a neighboring IOU or member of one of the Regional Mutual Assistance Groups that we are members.

Before any payment is made to any of these contractors all invoices are reviewed and verified against daily documents recorded during the storm to ensure all payments are appropriate to the agreement between Kentucky Power and the contractor.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to the response to Item 78 of Staff's Second Request, which states that post-test year merit wage and salary increases constitute a known and measurable adjustment and will be a part of Kentucky Power's expenses in the first year that new rates will be in effect. Explain why, from a theoretical ratemaking perspective, post-test year adjustments for revenue increases due, for example, to customer growth, should not be made as well as post-test-year adjustments for expense increases.

RESPONSE

From a theoretical ratemaking perspective, any known and measurable adjustment both expense and revenue should be made as a post-test -year adjustment. In the direct testimony of David M. Roush on page 5, lines 1 thru11, he describes revenue changes (both increases and decreases) for specific customers. Some of the adjustments reach beyond the test year. Kentucky Power has tried to be consistent in its use of known and measurable post-test year expense and revenue adjustments.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to the response to Item 81 of Staff's Second Request, pages 7 — 8 in Section II of Exhibit JEH-1 of the Direct Testimony of James E. Henderson and pages 104 and 105 of 350 of the depreciation study filed with the testimony,

a. The testimony reflects that Kentucky Power maintains salvage and removal costs not by primary account, but at the functional plant level. It states that "In order to determine gross salvage, gross removal and net salvage percentages for individual plant accounts, the original cost retirements were detailed by account . . . and, based on judgement, gross salvage and cost of removal percentages were selected for each account so that the gross salvage and gross removal would approximate the total functional percentages . . ." Explain in detail how judgment was applied to develop, from the gross removal percentage of 29 percent for transmission plant, the gross removal percentages for the individual transmission plant accounts shown on page 104 of the depreciation study, which range from 0 to 75 percent.

b. Explain in detail how judgment was applied to develop, from the gross salvage percentage of 12 percent for transmission plant, the gross removal percentages for the individual transmission plant accounts shown on page 105 of the depreciation study, which range from 0 to 15 percent.

RESPONSE

a. Kentucky Power currently maintains salvage and removal costs at the functional level. I am recommending that, in the future, Kentucky Power should apply depreciation rates at the primary plant account level and therefore should also account for salvage and removal costs at the primary plant account level. The gross salvage percentage recommendations by primary plant will, in total, equal the 29 percent gross removal cost for the transmission function. The assumptions, by account, as stated below are based on my knowledge and experience in performing depreciation studies for companies that do maintain the salvage and cost of removal by primary plant account.

For Account 352 Structures, I assumed that any removal costs would be minor and would probably involve mostly travel time.

For Account 353, Station Equipment, I assumed that the removal of motors, transformers, compressors and all other station equipment that may need to be replaced would require both labor and transportation costs.

For Account 354, Towers & Fixtures, I assumed that the equipment and labor costs including the possible use cranes remove the towers as well as the labor and transportation costs would be significant in relation to the original cost of the towers retired.

For Account 355, Poles and Fixtures, I assumed that the equipment and labor cost of removing the poles and the transportation costs, including transporting the poles back to the storeroom for disposal would be significant in relation to the original installed cost of the poles.

For Account 356, Overhead Conductor and Devices, I assumed that labor and transportation costs would be incurred in removing the conductor and transporting it back to the storeroom.

For Account 357, Underground Conduit and Account 358, Underground Conductor, I assumed this equipment would likely be retired in place. Therefore a 0% net removal was assigned to these accounts.

b. The question asks for an explanation of how judgment was used to develop from the gross salvage percentage of 12% for the transmission plant function, removal percentages for the individual accounts. The following answer explains how the salvage percentages, which the Company assumes was intended, for the individual accounts were developed from the gross salvage value of 12% for the transmission function.

For Account 352, Structures, I assumed that some salvage would be received from the scrap of electric, plumbing and fencing materials.

For Account 353, Station Equipment, I assumed salvage would be obtained from the reuse of material as well as from the scrap sales of conductor, breakers, instrument transformers and station transformers.

For Account 354, Towers and Fixtures, I assumed that scrap salvage should be expected from the towers.

For Account 355, Poles and Fixtures, I assumed salvage would be expected from the reuse of crossarms and insulators.

For Account 356, Overhead Conductor and Devices, I assumed salvage would be expected from the sale of the conductor and the reuse of circuit breakers, insulators and switches.

For Accounts 357, Underground Conduit, and 358, Underground Conductor, I assumed the equipment would be retired in place and no salvage would be received.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

Refer to Kentucky Power's response to Item 70 of KIUC's first data request. State whether it is Kentucky Power's position that it should recover a larger transmission expense $49,514,393) if the method of recovery is through base rates only and a lesser amount ($42,475,930) if the method of recovery is through a combination of base rates and a rider. If yes, explain the reasoning behind this position.

RESPONSE

Yes.

The Company's proposal is two-fold.

(1) The Company believes that the Company's transmission costs should be based upon charges under PJM's Tariff (the Open Access Transmission Tariff and the Operating Agreement) instead of the embedded cost of Transmission.

(2) The Company believes that given the nature of these costs and their potential to change due to FERC action, it is appropriate to track and reconcile these costs through proposed Tariff T.A.

If the first premise is not accepted, then the second premise and Tariff T.A. are moot and the Company's adjusted test year level of embedded transmission costs should be included in base rates.

If the first premise is accepted then the second premise should be also. The Company believes that the first and second premise are logically consistent and tied together for all the reasons stated in Witness Bethel's testimony.

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Refer to the response to Item 76.c. of the first data request of KIUC and Section V, Workpaper S-4, pages 15 and 20 of Kentucky Power's application.

a. Confirm that, while the expenses associated with the three major storms that occurred during the test year were deferred as a regulatory asset in accordance with the Commission's ruling in Case No. 2009-00352, the entries to establish the regulatory [asset] occurred after the test year.

b. Confirm that subtracting the amount on Workpaper S-4, page 15, line 1, column 3 in the application of $2,115,867 from the corresponding amount of $12,424,094 on the revised Workpaper S-4 on page 3 of the data response provides the amount of $10,308,227, which is the amount established as a regulatory asset per Case No. 2009-00352 and which is the subject of the proposed amortization adjustment on Workpaper S-4, page 20.

c. The costs incurred by Kentucky Power for the three major storms are included in its test year. The intent of the adjustment on Workpaper S-4, page 15, is to normalize the test year storm damage expense apart from the costs of the three major storms, which are to be recovered via the proposed amortization adjustment on Workpaper S-4, page 20. Therefore, it appears the correct normalization adjustment would be determined as follows:

(1) Test year storm expense (excluding expense of three major storms);
(2) Plus amounts for two prior periods shown on page 1, lines 2 and 3;
(3) Divided by three to result in three-year average of storm expense;
(4) Subtract test year storm expense (including expense of major storms); and
(5) Resulting amount equals the adjustment to reduce test year expense.

RESPONSE

a. The Company confirms that $10,306,227 of the $12,423,094, the total cost of the three major event storms that occurred during the test year ending September 2009, was deferred as a regulatory asset in accordance with the Commission's ruling in Case No. 2009-00352 and the entry to establish the regulatory asset occurred after the test year.

b. The Company confirms this statement.

c. The Company agrees with the methodology provided in part (c) of the data request. The response to Item No. 76, page 3 combined the correct normalization adjustment with the amortization adjustment. Pages 2 and 3 of this response demonstrates both the normalization and amortization adjustments respectively and page 4 combines the two adjustments on one schedule. The net amount shown on page 4 is the same amount as when the net amounts on pages 2 and 3 are combined.

The Company, in its response to KPSC 1st Set Item No. 43, included the estimated costs associated with the two major event storms that occurred during December 2009. Pages 5 through 7 of this response demonstrates the same Major Storms normalization and amortization adjustments with the two December major storms estimated costs included since these December 2009 Major event storms are known and measurable.

WITNESS: Ranie K Wohnhas

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

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	$2,116,867	1.00	$2,116,867
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			$2,714,859
5	Three Year Average (Ln 4/ 3)			$904,953
6	Test Year Storm Damage Expense			$12,423,094
7	Adjustment to O&M for Storm Damage Normalization			($11,518,141)
8	Allocation Factor - GP-TOT			0.991
9	KPSC Jurisdictional Amount (Ln 7 X Ln 8)			($11,414,478)

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

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

Kentucky Power Company
Amortization of Major Storm Cost Deferral
Test Year Twelve Months Ended 9/30/2009

Ln No (1)	Description (2)	Storm Cost Deferral Excludes In-House Non-Incremental Labor (3)	Constant Dollar Index 1/ (4)	Expense in 2009 Dollars (5)
1	YTD September 30, 2009	$ 10,306,227	1.00	$ 10,306,227
2	Total	$ 10,306,227		$ 10,306,227
3	Number of Amortization Periods			3
4	Annual Amortization Amount (Ln 2 / Ln 3)			$ 3,435,409
5	Allocation Factor - GP-TOT			0.991
6	KPSC Jurisdiction Amount (Ln 4 X Ln 5)			$ 3,404,490
7	Deferred Tax (Ln 6 X .35)			$ 1,191,572

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

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/ 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

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

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	$2,116,867	1.00	$2,116,867
2	December 8, 2009 Wind Storm	$820,738	1.00	$820,738
3	December 18, 2009 Snow Storm	$13,228,090	1.00	$13,228,090
4	12 ME September 30, 2008	$51,497	1.03	$53,042
5	12 ME September 30, 2007	$461,822	1.18	$544,950
6	Three Year Total Storm Damage			$16,763,687
7	Three Year Average (Ln 6 / 3)			$5,587,896
8	Test Year Storm Damage Expense			$12,423,094
9	Adjustment to O&M for Storm Damage Normalization			($6,835,198)
10	Allocation Factor - GP-TOT			0.991
11	KPSC Jurisdictional Amount (Ln 9 X Ln 10)			($6,773,681)

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

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

Kentucky Power Company
Amortization of Major Storm Cost Deferral
Test Year Twelve Months Ended 9/30/2009

Ln No (1)	Description (2)	Storm Cost Deferral Excludes In-House Non-Incremental Labor (3)	Constant Dollar Index [1/] (4)	Expense in 2009 Dollars (5)
1	YTD September 30, 2009	$ 10,306,227	1.00	$ 10,306,227
2	Total	$ 10,306,227		$ 10,306,227
3	Number of Amortization Periods			3
4	Annual Amortization Amount (Ln 2 / Ln 3)			$ 3,435,409
5	Allocation Factor - GP-TOT			0.991
6	KPSC Jurisdiction Amount (Ln 4 X Ln 5)			$ 3,404,490
7	Deferred Tax (Ln 6 X .35)			$ 1,191,572

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

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	December 8, 2009 Wind Storm	$820,738	1.00	$820,738
3	December 18, 2009 Snow Storm	$13,228,090	1.00	$13,228,090
4	12 ME September 30, 2008	$51,497	1.03	$53,042
5	12 ME September 30, 2007	$461,822	1.18	$544,950
6	Three Year Total Storm Damage			$27,069,914
7	Three Year Average (Ln 6 / 3)			$9,023,305
8	Test Year Storm Damage Expense			$12,423,094
9	Adjustment to O&M for Storm Damage Normalization			($3,399,789)
10	Allocation Factor - GP-TOT			0.991
11	KPSC Jurisdictional Amount (Ln 9 X Ln 10)			($3,369,191)

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

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

Kentucky Power Company

REQUEST

Refer to Kentucky Power's response to Item 16 of the Attorney General's first data request ("AG's First Request"). State whether this response means that $48,200 should be excluded from expenses because it is included in storm expense recorded as a regulatory asset for which Kentucky Power is requesting recovery.

RESPONSE

The $48,200 is part of the Company's major storm cost deferral adjustment for which the Company is requesting a three year recovery and amortization period (See Company's Adjustment Section V, Workpaper S-4, Page 20). Because the Company is requesting a three year average level of major storm costs to be included in the cost-of-service, two thirds of the $48,200 expense amount has been excluded.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to the response to Item 34 of the AG's First Request, which states that AMI is not included in its proposal. State whether Kentucky Power currently has the ability to remotely disconnect or reconnect meters. If so, state whether it remotely disconnects and reconnects customers, the amount charged to customers, and the location of the charge in Kentucky Power's current or proposed tariff.

RESPONSE

The Company does not currently have the ability to remotely disconnect or reconnect meters.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Refer to pages 2 and 3 of the response to Item 53 of the AG's First Request, which includes information for the 64 months from October 2004 through January 2010.

a. As of November 2008, Kentucky Power's 13-month average return on equity ("ROE") was 10.38 percent. December 2008, one of 13 months in the response in which Kentucky Power had a net loss, showed a net loss of $11.5 million. The next largest net loss was $2.2 million in September 2009, the last month of the test year. Provide the primary reasons for why December 2008's net loss was roughly equal to the sum of the net losses in all the other months in which net losses were incurred.

b. Kentucky Power's 13-month average ROE for the periods ended October and November 2009 were less than the 2.9 percent test year ROE. Since the December 2008 net loss dropped out, the average ROEs for the periods ended December 2009 and January 2010 have been between 5.5 and 6.0 percent. Given these circumstances, explain in detail why the 12 months ended September 2009 should be considered a representative test period for use in this rate case.

RESPONSE

a. The Company believes there is no relation between the amount of the Company's December, 2008 net loss and the sum of its net losses in all other months in which net losses were incurred. Thus, the Company has no reason to conclude it is anything other than a coincidence that the two amounts are "roughly equal."

b. The Company filed its Application on December 29, 2009. The test year period was selected in accordance with the Commission's regulations and the Company's ability to assemble the financial and other information necessary to file an application that comports with the Commission's filing requirements.

In uncertain economic times the financial results of any twelve-month period may vary from the results of twelve month periods ended during the immediately preceding and succeeding calendar months. The Company sought to account for these types of fluctuations through its proposed test-year adjustments. With these adjustments, the Company believes the adjusted test year data is representative and may be used to establish fair, just and reasonable rates for the Company during the period the proposed rates will be in effect.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to the response to Item 5 of the AG's first data request to Kentucky Power in Case No. 2009-00545.2 The response discusses the degree to which the time-of-day pricing built into the terms of the proposed wind energy contract provides a form of hedging for time-of-day price risk and how the wind purchases serve as a hedge against environmental risk. Considering the political considerations, policy issues, and company-specific business decisions which affect the implementation of a possible future federal renewable portfolio standard or the time to acquire renewable energy resources, explain in detail why it would not be appropriate for these and other risks associated with the proposed wind energy contract to be shared by ratepayers and shareholders in some fashion.

RESPONSE

Many of the Company's decisions to incur long-term contractual obligations such as the wind renewable energy purchase agreement ("Wind REPA") require the assessment of political considerations, policy issues, and company-specific business decisions. For example, the decision to enter into the extension of the Rockport power purchase agreement required the resolution of equally difficult decisions regarding environmental, political and economic conditions in the future. Similarly, and although involving a short time period, the Company must consider similar issues (and others) in deciding whether to enter into a coal purchase contract, the length and other terms of the contract, or whether to purchase coal in the spot market.

The Company's Application seeks only to recover its net cost in connection with the Wind REPA. As is the case with its fuel costs, Kentucky Power is not seeking to recover any Company "profit" as part of the Wind REPA costs to be recovered. It thus is no more appropriate for the risks associated with the Wind REPA to be shared between ratepayers and Kentucky Power than it would be share to the risks associated with, and to provide a profit to the Company in connection with, a coal contract.

WITNESS: Errol K Wagner