Realization Sharing Calculations

	East Detail	East Realization	West Realization	Total Realization	West Share of Realization	East Share of Realization	Eastern Funds To West	Account Number
Bookout Purchases	($303,407,225)		($555,462)					
Energy Purch. - B/O Margin Reclass (Note 1)	$0		$370,887					
Purchases Commission	($77,275)							
Bookout Sales	$309,396,745		$829,156					
Less Tractebel Sale	$0							
Energy Sales - B/O Margin Reclass (Note 1)	$8,850,978		($9,029)					
Sales Commission	($95,968)							
Exercised Option - Purchases	($840,000)							
Exercised Purchase Option Premiums	($64,753)		$81,553					
Exercised Option - Sales	$2,184,000							
Exercised Sales Option Premiums	$653,164		($438,124)					
Non-Dedicated Spark Gas Commission	($4,166)		($1,552)					
Non-Dedicated Spark Gas Paribas Futures	$976,699		($872,601)					
Non-Dedicated Spark Gas ABN Amro Futures Reclass	$0		$0					
Dedicated Spark Gas in ERCOT on 9 Companies	($2,791,104)		($1,039,673)					
Non-Dedicated Swaps - Net	($3,220,913)		($1,199,775)					
Power Swaps - Net	($7,138,084)							
Paribas Power Commissions	($828,864)		($308,748)					
Power Futures (REFCO)	$1,046,473		$389,806					
Power Future Accruals (REFCO)	$0		$0					
Buckeye Excess Energy Credit	($2,287,007)							
Dow Sales - Associated	$0							
		$2,352,700	($2,553,562)	($200,862)	($54,525)	($146,357)	$2,499,057	4470.117
Dow Purchases - Associated	($202,200)		$0					
		($202,200)	$0	($202,200)	($54,883)	($147,317)	($54,883)	5550.044
ECR/ICR Realizations	$30,861,944		$8,833,269					
Less Purchase Demand Charge	($1,222,248)		$2,646,552					
Non-Dedicated Seymour Energy Sales	$0		($4,676,441)					
Less Realization on Dedicated Transactions	($3,749,432)							
Unit Power - CP&L	$2,746,809							
SO2 Realizations	$11,124,875							
NOx Realizations	$2,741							
Transmission Purchases	($305,148)							
Total ECR/ICR Realization		$39,259,541	$8,803,380	$46,062,921	$12,502,812	$33,560,109	$5,699,432	4470.026
Spot Energy Sales (G/L to Invoice Adjustments)	$23,090							
Transmission Congestion (G/L to Invoice A.J)	($921,348)							
Transmission Loss Credit (OSS)	$134,106							
Transmission Congestion Credits (OSS)	$4,866,609							
Spot Purchases from PJM Transmission Service	$1,725,817							
Operating Reserve Charge/Credit	$437,278							
Capacity Credit Market	($2,806)							
...nt-to-Point Transmission	($55,201)							
...work Int Transm Svc Chg (Buckeye-Other)	$11,564							
...TR Revenues	$775,573							
Transmission Owner System Control & Dispatch	($35,025)							
Non-ECR Energy Sales	$12,103,712							
Non-EGR Purchased Power OSS	($14,596,188)							
Meter Correction Charges (OSS)	($887)							
SECA Transmission Expense	($1,590,340)							
		$2,875,954		$2,875,954	$780,617	$2,095,337	$780,617	4470.118
PJM Purchases with AEP as Agent	($72,353)							
Transmission Congestion Credits	$0							
FTR Auction Charges	$0							
		($72,353)		($72,353)	($19,639)	($52,714)	($19,638)	5550.045
PJM Scheduling System Control & Dispatch	($459,524)							
		($459,524)		($459,524)	($124,728)	($334,796)	($124,728)	5560.004
Total		$43,754,118	$4,249,798	$48,003,916	$13,029,654	$34,974,262	$8,779,856	

Total West Realizations	$4,249,798
Total AEP Realizations	$48,003,916
Eastern AEP's Share of Total Realization	$34,974,262
Western AEP's Share of Total Realization	$13,029,654
	$48,003,916
Eastern AEP Funds to Western AEP	$8,779,856

Realization Sharing Ratios

Base Year	$0	0.00%
Capacity	$48,003,916	100.00%
	$48,003,916	100.00%

Base Year Realizations

Eastern AEP Realization	$252,860,378	90.97%
Western AEP Realization	$25,095,575	9.03%
	$277,955,953	100.00%

Capacity (MW) Realization Sharing

25,304,000	72.86%
9,427,000	27.14%
34,731,000	100.00%

Realization Sharing Calculations

EASTERN FUNDS TO WESTERN AEP
ALLOCATION BY OPERATING COMPANY

	MLR	ACCOUNT NO. 4470.117	ACCOUNT NO. 5550.044	ACCOUNT NO. 4470.026	ACCOUNT NO. 4470.118	ACCOUNT NO. 5550.045	ACCOUNT NO. 5560.004	TOTAL OF ALL ACCOUNTS
APCO	0.31188	779,406	(17,117)	1,777,539	243,459	(6,125)	(38,900)	2,738,262
KPCO	0.07423	185,505	(4,074)	423,069	57,945	(1,458)	(9,259)	651,728
I&M	0.18470	461,576	(10,137)	1,052,685	144,180	(3,627)	(23,037)	1,621,640
OPCO	0.24836	620,666	(13,631)	1,415,511	193,874	(4,878)	(30,977)	2,180,565
CSP	0.18083	451,904	(9,924)	1,030,628	141,159	(3,551)	(22,555)	1,587,661
TOTAL	1.00000	2,499,057	(54,883)	5,699,432	780,617	(19,639)	(124,728)	8,779,856

Note 1: Current month margin reclassified between trading and non-trading due to non-trading transactions being booked out with trading transactions.

ACTUAL
October 2005

APPENDIX IX
Page 1 of 2

PJM CHARGES TRANSFERRED FROM MARKET TO AEP

PJM CHARGE DESCRIPTION	ACCOUNT NO.	AP AMT	KP AMT	IM AMT	OP AMT	CS AMT	AEP AMT TOTAL	SIA	BUCKEYE CREDITS/ CHARGES	PJM CHARGES FOR SIA SHARING
ALLOCATION OF AEP (NON-ECR) CHARGES										
Operating Reserve (Internal)	4470108	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8,070,530	na		
Operating Reserve (OSS)	4470098	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(448,829)	4470118		(448,829)
Transmission Congestion Credits (Internal)	4470101	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(22,606,868)	na		
Transmission Congestion Credits (OSS)	4470100	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(4,840,058)	4470118		(4,840,058)
Transmission Congestion Credits (BGE + PEPCO)	5560018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	5560045		-
Transmission Congestion Credits - Speculative (OSS)	4470109	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(1,441,183)	4470118		(1,441,183)
Regulation	4470095	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	na		
Regulation	5550067	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,448,818	na		
Spinning Reserve	4470096	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(93,433)	na		
Transmission Loss Credit (Internal *)	4470114	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(322,330)	na		
Transmission Loss Credit (OSS *)	4470094	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(134,144)	4470118		(134,144)
ALLOCATION OF E/L TO INVOICE ADJUSTMENTS										
Spot Energy Sales	4470124	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(23,090)	4470118		(23,090)
Transmission Congestion - Explicit (not allocated)	4470128	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(96,841)	4470118		(96,841)
Transmission Congestion - Duquesne Load (Actual)	4470126	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(40,165)	4470118		(40,165)
TOTAL PJM CHARGES TRANSFERRED FROM MARKET TO AEP (ACTUAL)		(10,480,033)	(2,484,334)	(1,204,432)	(5,349,568)	(4,076,381)	(23,602,777)			(7,100,707)
TOTAL PJM CHARGES TRANSFERRED FROM MARKET TO AEP (ESTIMATED)		(10,016,093)	(2,383,911)	(929,650)	(5,030,134)	(3,807,394)	(22,115,317)			
TOTAL PJM CHARGES TRANSFERRED FROM MARKET TO AEP (ADJUSTMENT)	(1)	(463,940)	(100,423)	(274,782)	(319,451)	(268,895)	(1,487,460)			

ACTUAL
October 2005

APPENDIX IX
Page 2 of 2

PJM CHARGES (NON-ECR) FROM INVOICE

PJM CHARGE DESCRIPTION	ACCOUNT NO.	AP AMT	KP AMT	IM AMT	OP AMT	CS AMT	AEP AMT TOTAL	SIA	BUCKEYE CREDITS/ CHARGES	PJM CHARGES FOR SIA SHARING
Transmission Congestion - Implicit - LSE	4470093	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	na		
Transmission Loss Credit (OSS *)	4470094	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	39	4470118		39
Regulation - Net Revenue	4470095	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	na		
Spinning Reserve Charges (Unallocated) - Net Revenue	4470096	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	46,840	na		
Synchronous Condensing Charges (Unallocated) - Net Revenue	4470097	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	na		
Operating Reserve (OSS)	4470098	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	44,281	4470118		44,281
Capacity Credit Market Credits (Unallocated)	4470099	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(26)	4470118	[redacted]	8,806
Transmission Congestion Credits (OSS)	4470100	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(4,884)	4470118		(4,884)
FTR Auction Charges (Internal)	4470101	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(13,708)	na		
Auction Revenue Rights	4470102	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	na		
Reactive Supply and Voltage Control from Generation Sources Service Charges (Unallocated) - Net Revenue	4470104	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	na		
Black Start Service Charges (Unallocated) - Net Revenue	4470106	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	na		
Point-to-Point Transmission Service Charges (OSS)	4470106	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88,201	4470118	[redacted]	88,201
Network Integration Transmission Service Charges (Buckeye-Other)	4470107	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,412,142	4470118	[redacted]	(11,564)
Operating Reserve (Internal)	4470108	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	186,217	na		
FTR Revenue - Speculative	4470109	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	613,410	4470118		618,410
Transmission Owner Scheduling System Control and Dispatch Service Charges (OSS *)	4470110	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82,281	4470118	[redacted]	35,024
Non-ECR Phys. Sales - OSS (BGE, PEPCO)	4470112	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	4470118		-
Transmission Loss Credit (Internal *)	4470114	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	794	na		
Meter Correction Charges (OSS)	4470115	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	587	4470118		587
Meter Correction Charges (Internal)	4470116	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(248,067)	na		
SECA Transmission Expense	4470119	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,801,057	4470118	[redacted]	1,890,240
Incremental Spot Energy OSS not in ECR	4470124	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	4470118		-
Incremental - Explicit Congestion-OSS not in ECR	4470128	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	4470118		-
Incremental - Implicit Congestion-OSS not in ECR	4470126	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	4470118	[redacted]	1,078,054
Network Integration Transmission Service Charges (Affiliate)	4560069	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	na		
Point-to-Point Transmission Service Charges (Transmission)	4560060	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(215,760)	na		
Transmission Owner Scheduling System Control and Dispatch Service Charges (Affiliate)	4560061	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	na		
Point-to-Point Transmission Service Charges-Affiliate	4560063	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	na		
Transm. Dist/Meter Serv. Rev-Affil.	4560068	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	na		
FTR Auction Charges (BGE + PEPCO) -	5550035	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	5560045	[redacted]	-
Emergency Energy Purchases	5560036	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	na		
Capacity Deficiency - Reliability Assurance	5560037	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	na		
Energy Imbalance Credits (OSS)	5560039	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(98,318)	na		
Energy Imbalance Credits (Internal)	5550040	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(3,091)	na		
Synchronous Condensing Charges (Unallocated) - Net Expense	5550041	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	362,532	na		
Reactive Supply and Voltage Control from Generation Sources Service Charges (Unallocated) - Net Expense	5560042	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	898,191	na		
Black Start Service Charges (Unallocated) - Net Expense	5560043	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8,243	na		
Regulation - Net Expense	5560007	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(26,387)	na		
PJM Scheduling System Control and Dispatch Service Charges (OSS *)	5560002	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	605,228	5560004	[redacted]	459,884
PJM Scheduling System Control and Dispatch Service Charges (Internal *)	5560003	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2,398,181	na		
Transitional Market Expansion Charges	5670006	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	na		
Expansion Cost Recovery Charges/Credits	4560065	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	187,948	na		
Buckeye Excess Energy Credit	5550036	-	-	-	-	-	-	4470117	8,287,007	8,287,007
Spot Purchases from PJM	4470131	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(1,728,817)			(1,728,817)
TOTAL PJM CHARGES (NON-ECR) FROM INVOICE (ACTUAL)		2,021,328	481,221	1,200,777	1,424,844	1,364,204	6,496,791			
TOTAL PJM CHARGES (NON-ECR) FROM INVOICE (ESTIMATED)		2,781,240	664,475	1,412,307	2,238,318	1,810,089	8,945,449			
TOTAL PJM CHARGES TRANSFERRED FROM MARKET TO AEP (ADJUSTMENT)	(1)	(761,912)	(183,254)	(186,530)	(814,074)	(445,885)	(2,449,658)			4,478,808

Notes
(1) The results shown on this appendix are tabulated for system settlement on IX, page 1, lines VI and VII.

OFFSET OF BUCKEYE PASS-THROUGH CHARGES ASSOCIATED WITH PJM

PJM CHARGE DESCRIPTION	ACCOUNT NO.	AP AMT	KP AMT	IM AMT	OP AMT	CS AMT	BUCKEYE TOTAL
Regulation (Revenue)	4470095						-
Spinning Reserve	4470096	(152)	(36)	(90)	(121)	(88)	(488)
Operating Reserve - OSS	4470098	(104,518)	(24,876)	(61,897)	(83,231)	(60,600)	(335,122)
Capacity Credit Market	4470099	883	210	523	703	512	2,831
Allegheny Transmission Congestion	4470101						-
Reactive Supply and Voltage Control (Revenue)	4470104						-
Black Start Service (Revenue)	4470105						-
Point-To-Point Transmission Service	4470106						-
NITS / Other Supporting Facilities	4470107	(506,401)	(120,528)	(299,898)	(403,264)	(293,615)	(1,623,706)
Operating Reserve - LSE	4470108	39,722	9,454	23,524	31,632	23,031	127,364
Transmission Owner Scheduling (Expense)	4470110	(14,740)	(3,508)	(8,729)	(11,738)	(8,546)	(47,262)
Seams Elimination Cost Assignment Charges	4470119	(65,718)	(15,642)	(38,919)	(52,334)	(38,104)	(210,717)
PJM Service Fee	4560064	(37,216)	(8,858)	(22,040)	(29,637)	(21,578)	(119,329)
Expansion Cost Recovery	4560085	(2,289)	(552)	(1,818)	(2,599)	(915)	(8,173)
Emergency/Economic Load Response Program	5550036						-
Excess Energy Credit - OSS	5550038	711,010	169,226	421,071	566,200	412,248	2,279,756
AEP Inadvertent / AEP Power Factor - OSS	5550039	17,966	4,276	10,640	14,307	10,417	57,606
AEP Inadvertent / AEP Power Factor - LSE	5550040						-
Synchronous Condensing	5550041	(7,086)	(1,686)	(4,196)	(5,642)	(4,108)	(22,719)
Reactive Supply and Voltage Control (Expense)	5550042	(15,478)	(3,684)	(9,166)	(12,325)	(8,974)	(49,626)
Black Start Service (Expense)	5550043	(1,303)	(310)	(772)	(1,038)	(756)	(4,179)
Excess Energy Credit - LSE	5550048						-
Regulation (Expense)	5550057	(56,350)	(13,412)	(33,371)	(44,873)	(32,672)	(180,679)
PJM Scheduling System Control and Dispatch Service - OSS	5560002	(45,440)	(10,815)	(26,910)	(36,186)	(26,347)	(145,698)
PJM Scheduling System Control and Dispatch Service - LSE	5560003						-
Transitional Market Expansion / Expansion Integration	5570006						-
TOTAL OFFSET OF BUCKEYE PASS-THROUGH CHARGES (ACTUAL)		(87,110)	(20,740)	(52,051)	(70,145)	(50,094)	(280,140)
TOTAL OFFSET OF BUCKEYE PASS-THROUGH CHARGES (ESTIMATED)		(211,740)	(50,403)	(125,878)	(169,423)	(122,338)	(679,782)
TOTAL OFFSET OF BUCKEYE PASS-THROUGH CHARGES (JULY 2005 ADJUSTMENT)		(0)	0				-
TOTAL OFFSET OF BUCKEYE PASS-THROUGH CHARGES (AUGUST 2005 ADJUSTMENT)		1,708	407	990	1,320	990	5,414
TOTAL OFFSET OF BUCKEYE PASS-THROUGH CHARGES (SEPTEMBER 2005 ADJUSTMENT)		559	132	327	440	321	1,772
TOTAL OFFSET OF BUCKEYE PASS-THROUGH CHARGES (ADJUSTMENT)	(1)	126,891	30,201	75,144	101,038	73,555	406,829

BUCKEYE SHARE OF PJM CONGESTION CHARGES

PJM CHARGE DESCRIPTION	ACCOUNT NO.	AP AMT	KP AMT	IM AMT	OP AMT	CS AMT	AEP AMT TOTAL
Transmission Implicit Congestion Charge	4470126	336,223	80,024	199,117	267,745	194,945	1,078,054
TOTAL BUCKEYE SHARE OF PJM CONGESTION CHARGES (ACTUAL)		336,223	80,024	199,117	267,745	194,945	1,078,054
TOTAL BUCKEYE SHARE OF PJM CONGESTION CHARGES (ESTIMATED)		327,575	77,966	193,995	260,858	189,930	1,050,324
TOTAL BUCKEYE SHARE OF PJM CONGESTION CHARGES (ADJUSTMENT)	(1)	8,648	2,058	5,122	6,887	5,015	27,730

Note:
(1) The results shown on this appendix are tabulated for system settlement on IPS, page 1, Items VIII and IX.

Kentucky Power Company

REQUEST

Refer to the Company's response to KIUC 1-45. Please provide the cost of dismantling each of the units indicated as retired on the attached schedule. If this information is not available, then please explain why it is not available and describe the Company's efforts to obtain the information. In addition, if this information is not available, then please describe how CSP and I&M accounted for the cost of removal in their property accounting records.

RESPONSE

The work orders that recorded the plant retirements have been destroyed. In accordance with the FERC Record Retention Catalog, removal work orders are not required to be maintained after 6 years of the plant retirement.

CSP and I&M accounted for the cost of removal as explained in response to the Attorney General's First Set of Data Requests, Question No. 123.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

Refer to the Company's response to KIUC 1-58. The Company's response to Staff 2-83 does not provide the information requested. Please respond to KIUC 1-58. More specifically, provide the following information:

a. Please describe the criteria relied upon to select the gross salvage and cost of removal percentages selected for each FERC account referred to above as based on "judgment".

b. Please describe why the same gross salvage and cost of removal percentages were not used for each of the FERC accounts within each functional plant level given that individual account data was not available.

c. Please provide a copy of all analysis performed that would help to justify the selection of the above referenced percentages by individual FERC account.

RESPONSE

a. The basis for the gross salvage and removal percentages for each FERC account are stated in the summary page of the depreciation study workpapers for each FERC account.

b. It is not reasonable to assume that the same gross salvage and cost of removal would apply equally to each plant account. The current depreciation study recommends that the Company apply depreciation rates to the individual FERC accounts and, just as an different average service life is recommended for each account, it is appropriate to recomment salvage and removal percentages for each account based on the nature of the investments in each account.

c. All analyses by account performed are contained in the depreciation study workpapers for each account.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

Refer to the response to AG Request No. 166. The files provided do not explain how the cost of removal reserve was calculated (the numbers are hardcoded). Please explain how these amounts are calculated and provide the embedded cost of removal amounts by account.

RESPONSE

The Company's current depreciation rates identify a removal cost for only the Production Plant function. The amount of removal costs embedded in the Production Plant functional depreciation reserve was determined using the following formula:

Gross Removal % / (100%-Net Salvage %) x Accumulated Depreciation

Based on the Company's last depreciation study approved in Case No. 91-066, the cost of removal and gross salvage percentages included in the approved depreciation rates are as follows:

Gross Removal % = 24%
Gross Salvage % = 2%
Net Salvage Percent = -22%

The removal costs were calculated for the total Production Plant function. The amounts were not identified by account.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

Refer to the Company's response to KIUC 1-24. Please provide the information requested on CD. The request for copies of the studies does not extend to the underlying workpapers and voucher reviews, which should substantially reduce any concerns regarding volume. The studies should include the summary results and any supporting schedules that show the derivation of the lead/lag days.

RESPONSE

Attached on a CD are the summary results.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

With regard to the response to AG First Set, Item No. 64, Part C, please describe the methodology used to develop the 29.66% decline in congestion costs and the 19.28% decline in FTR revenues due to the operation of the W-J Ferry 765 kV line. Please provide supporting workpapers for the percentages.

RESPONSE

The change in AEP related congestion and FTR revenue that results as a consequence of the operation of the Wyoming-Jackson Ferry 765 kV line has been estimated by simulating two cases and taking the difference. Case 1 assumes no Wyoming-Jackson Ferry line; Case 2 assumes the line is operational. Each case was simulated with PROMOD-TAM, a production-costing model with embedded dc load flow module.

The regional context for the simulations is the PJM 'footprint'. The time period used in the simulations is May 2005 through July 2005. The May through July time period is used in order to take advantage of the availability of historical data – PJM loads, fuel prices, unit outages, transactions – in the two simulated cases. These historical data are identical in each case.

PROMOD-TAM is a commercial, chronological production-costing model with embedded dc load flow module. The PJM footprint transmission topology is an input in the model simulations. The topology differs between the two cases by the addition of the Wyoming-Jackson Ferry 765 kV line. In each case, the software simulates the hourly, security-constrained commitment and dispatch of generating units to satisfy bus loads within the model's transmission area, the PJM footprint in this set of simulations. The model calculates the least cost hourly commitment and dispatch that satisfies the hourly bus loads without violating the transmission flow constraints, and as such, represents for each case the hypothetically optimal operation of the system. As part of the solution, the model produces hourly LMPs, bus generation, transmission flows, etc.

The effect of the Wyoming-Jackson Ferry 765 kV line is taken to be the difference between the total AEP related congestion and FTR revenues in the two cases. The percentage changes are found by dividing the change in AEP related congestion and FTR value by the respective Case 1 values and multiplying by 100.

The output files from the PROMOD-TAM model and subsequent workpapers associated with this Item are included on the attached CD consisting of pages 2 through 135.
WITNESS: Robert W Bradish

Kentucky Power Company

REQUEST

With regard to the electronic spreadsheet provided by the Company in support of Mr. Bethel' exhibits entitled "Bethel KY Exhibits and MLR For DR", tab "DWB-1 pg1-PTP", line 10, please provide an explanation for the 23.42783% "% of Point-to-Point Revenue to AEP after April 1, 2006". Provide supporting work papers for the 23.42783% value.

RESPONSE

The "% of Point-to-Point Revenue to AEP after April 1, 2006" is the ratio PJM will use to allocate Border PTP revenues to the PJM Zones after April 1, 2006. The ratio is calculated as the AEP East Zone transmission revenue requirement as of April 1, 2006, per the filed settlement in Docket No. ER05-751-000, divided by the total PJM transmission revenue requirement per PJM OATT H-A adjusted to reflect the referenced settlement in Docket No. ER05-751-000. A copy of the settlement agreement was provided in response to PSC Staff 2nd set, item 22.

There are no additional workpapers as the calculation is performed in the referenced cell of the Excel spreadsheet.

WITNESS: Dennis W Bethel

Kentucky Power Company

REQUEST

With regard to the response to Staff 2nd Set, Item No. 6, please explain in detail the ratemaking treatment and accounting that will accompany a specific KPCO off-system sale. In particular, please address the following:

a. If KPCO makes such a sale, does AEP schedule the sale with PJM, sell the energy to PJM at LMP, then purchase the energy required for the sale from PJM at LMP, and finally, then sell to the third party buyer at the agreed contractual sale price. If this is the case, please confirm. If not, please provide the correct explanation.

b. How is the decision made within AEP regarding whether a third party sale is specifically assigned to an operating company (e.g., KPCO) or made as an AEP system sale, with the margins allocated to all AEP East Companies.

RESPONSE

a. In simplistic form, Item 53, page 3 provides a diagram of the function of PJM. The diagram represents, in a general manner, how value flows from a settlement perspective. However, the oversimplification provided in the diagram does not capture the efforts and value added by AEPSC in pursuing off-system sales.

AEPSC, on behalf of Kentucky Power Company and the other four east generating operating companies, explicitly adds value by actively trading and optimizing AEP's eastern generating fleet. AEPSC provides this service through a number of means. As stated in the response to Staff 2-5, the Commercial Operations group (AEPSC) makes daily decisions that impact the level of off-system sales the company achieves. Commercial Operations focuses on analyzing the cost and revenue drivers associated with operating in the PJM market and aligns behaviors to minimize costs and maximize revenues.

For example, with regards to offering available generation to PJM, Commercial Operations supplements PJM's unit commitment process with its own analysis to determine when units should be committed for start-up and shut down due to unit operating conditions and characteristics. Included in the analysis is whether or not AEP needs a physical hedge, and the magnitude of that hedge, in the real-time market to hedge against the volatility of the real-time prices. This analysis is used to protect AEP against PJM charges associated with deviations in generating requirements from the day-ahead awards versus the real-time dispatch. Once a unit has been committed and is being dispatched in real-time, Commercial Operations has in place real-time monitoring of dispatch accuracy to ensure plants are performing as requested and AEPSC dispatchers are optimizing the value from the inter-hour price volatility by adjusting unit output to maximize revenue when price is greater than cost and maximize purchases when price is less than cost.

AEPSC also provides bidding strategies to facilitate the award (or commitment) for its generating units. Although, AEP has lower cost coal units, congestion and reliability constraints may eliminate AEP's units from being dispatched. Therefore, AEPSC continuously evaluates short-term market fundamentals against unit cost profiles in an effort to optimize utilization of available generation to serve both native load and to provide off-system sales while covering the costs incurred to run the units.

In addition to day-to-day operations, AEPSC engages in marketing activities to pursue off-system sales opportunities both within and outside of the PJM market including SPP, ERCOT and MISO.

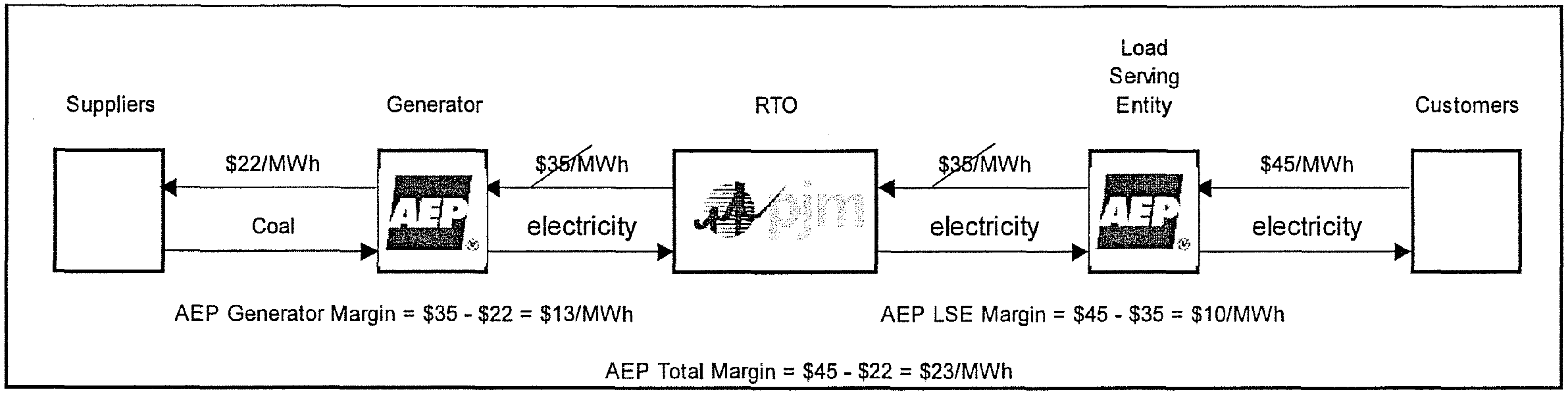
From the Load Serving Entity perspective, AEPSC has detailed weather and load forecasting functions that produce hourly load forecasts for bidding into the PJM market. Accurate load forecast is critical to managing the Company's operating reserve exposure that results from real-time deviations from the day-ahead settlement results.

Post operating day, Commercial Operations runs its own shadow settlement process on a daily basis as a way to monitor the accuracy of the PJM invoice and to request compensation from PJM when there are discrepancies.

These types of value maximizing activities outlined above are what lie behind the simple settlement concept imbedded in the question and highlighted on page 3 of Item 53. It is the combined impact of the above activities that enables AEPSC to add value through off-system sales, and Kentucky Power Company to realize its share.

b. If the selling price is negotiated with a third party (invariably a market-based price), or conforms with a market-based RTO's operating agreement (e.g. PJM), then that off-system sale is considered an AEP System pool sale, resulting in the MLR sharing of costs, revenues and margins among all five member companies of the AEP (east) Interconnection Agreement. Recently, several municipal utilities have chosen to tie the price of their firm requirements to a particular AEP operating company's embedded fixed and variable costs. Under this scenario, the sale is considered company-specific and the third party's load is added to that Company's internal load (according to Article 5.2 of the AEP Interconnection Agreement) to derive that Company's MLR load. However, that Company alone assumes the supply responsibilities for that load, as well as the revenues and margins resulting from that supply.

WITNESS: Robert W Bradish


Suppliers
Generator
RTO
Load Serving Entity
Customers
$22/MWh
Coal
$35/MWh
electricity
$35/MWh
electricity
$45/MWh
electricity
AEP
pjm
AEP
AEP Generator Margin = $35 - $22 = $13/MWh
AEP LSE Margin = $45 - $35 = $10/MWh
AEP Total Margin = $45 - $22 = $23/MWh

Kentucky Power Company

REQUEST

With regard to a new 150mW transaction to supply Indiana Municipal Utilities, entered on or about October 7, 2005 by I&M, has this transaction been included in the projected MLR computations used by KPCO in its filing in this case? If not, is the Company intending to update its filing to reflect this transaction? If not, why not?

RESPONSE

No, that transaction was not included in the projected MLR computations, inasmuch as those projections were developed in August 2005 and that transaction was not known at that time. The Company does not intend to update its filing. The filing is based on actual data and known and measurable quantities/changes as of a date certain. Changes beyond that date can occur ad infinitum.

WITNESS: Errol Wagner

Kentucky Power Company

REQUEST

With regard to a new 40mW transaction to supply the City of Lebanon, Ohio, entered on or about August 22, 2005 by AEP, has this transaction been included in the projected MLR computations used by KPCO in its filing in this case? If not, is the Company intending to update its filing to reflect this transaction? If not, why not?

RESPONSE

The above transaction does not have any effect on the Company's MLR or the MLRs of the other four AEP operating companies. The transaction is an off-system sale.

WITNESS: Errol Wagner