PPL ELECTRIC UTILITIES CORPORATION

EXHIBIT JMK 2

FUNCTIONALIZATION & ASSIGNMENT OF CERTAIN RATE BASE, OPERATING REVENUE AND OPERATING EXPENSE ITEMS

FUTURE TEST YEAR ENDING DECEMBER 31, 2004

This section groups and assigns to functional categories those items of rate base, operating revenue and operating expense which cannot be entered directly into the cost allocation studies from Exhibit Future 1. Wherever appropriate, the classification of accounts is shown.

Because it is not feasible to analyze directly all distribution plant accounts as of December 31, 2004, the results of an analysis of the accounts as of December 31, 2003 were applied to the December 31, 2004 account balances. Distribution expense assignments were developed in a similar manner.

The tables in this section are organized and referenced, wherever possible, to show the development of computer program inputs from Exhibit Future 1.

PPL ELECTRIC UTILITIES CORPORATION

SUMMARY
FUNCTIONALIZATION OF PLANT IN SERVICE

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004
($000)

Line No.	FUNCTION/ACCOUNT	INPUT	PLANT ACCOUNTS	PLANT IN SERVICE
1	INTANGIBLE PLANT	Q95	301-303	22,392
	TRANSMISSION PLANT			
2	TRANSMISSION FUNCTION	Q20	350-359	975,327
	DISTRIBUTION PLANT			
3	LAND		360.2	10,983
4	LAND RIGHTS		360.4	56,890
5	STRUCTURES & IMPROVEMENTS		361	24,499
6	STATION EQUIPMENT		362	243,642
7	POLES,TOWERS AND FIXTURES		364.0	685,372
8	OVERHEAD CONDUCTORS & DEVICES		365	536,718
9	UNDERGROUND CONDUIT		366	114,911
10	UNDERGROUND CONDUCTORS & DEVICES		367	286,456
11	LINE TRANSFORMERS		368	335,902
12	SERVICES		369	466,085
13	METERS		370	245,495
14	AREA LIGHTING FIXTURES		371	5,590
15	*STREET LIGHTING*		373	78,593
16	TOTAL DISTRIBUTION PLANT			3,091,137
17	GENERAL PLANT	Q88	389-399	335,346
18	TOTAL ELECTRIC PLANT IN SERVICE			4,424,202

PPL ELECTRIC UTILITIES CORPORATION

% OF ACCOUNT TOTAL

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2003

Line No.	SUBFUNCTION	TOTAL	LAND Acct 360.2	LAND RIGHTS Acct 360.4	STRUCTURES AND IMPROVEMENTS Acct 361	STATION EQUIPMENT Acct 362
	DISTRIBUTION PLANT					
	SUBSTATIONS					
1	PRIMARY		79.72	0.65	97.62	98.46
2	SECONDARY		1.84	(0.00)	2.38	1.54
3	TOTAL SUBSTATIONS		81.56	0.65	100.00	100.00
	OVERHEAD LINES					
4	PRIMARY		5.50	29.66		
5	SECONDARY DEMAND COMPONENT		4.81	25.92		
6	SECONDARY CUSTOMER COMPONENT		7.59	40.86		
7	STREET & AREA LIGHTING		0.54	2.91		
8	TOTAL OVERHEAD LINES		18.44	99.35		
	UNDERGROUND LINES					
9	PRIMARY					
10	SECONDARY DEMAND COMPONENT					
11	SECONDARY CUSTOMER COMPONENT					
12	TOTAL UNDERGROUND LINES					
	LINE TRANSFORMERS					
13	DEMAND COMPONENT					
14	CUSTOMER COMPONENT					
15	TOTAL LINE TRANSFORMERS					
	SERVICES					
16	DEMAND COMPONENT					
17	CUSTOMER COMPONENT					
18	TOTAL SERVICES					
19	METERS					
20	AREA LIGHTING FIXTURES					
21	STREET LIGHTING					
22	TOTAL		100.00	100.00	100.00	100.00

	SUBFUNCTION	POLES,TOWERS & FIXTURES Accl 364	OVERHEAD CONDUCTORS & DEVICES Accl 365	UNDERGROUND CONDUIT Accl 366	UNDERGROUND CONDUCTORS & DEVICES Accl 367
	DISTRIBUTION PLANT				
23	SUBSTATIONS				
24	PRIMARY				
	SECONDARY				
	TOTAL SUBSTATIONS				
26	OVERHEAD LINES				
27	PRIMARY	30.85	28.57		
28	SECONDARY DEMAND COMPONENT	25.50	26.86		
29	SECONDARY CUSTOMER COMPONENT	38.44	44.57		
	STREET & AREA LIGHTING	5.21	0.00		
	TOTAL OVERHEAD LINES	100.00	100.00		
31	UNDERGROUND LINES				
32	PRIMARY			19.16	19.16
33	SECONDARY DEMAND COMPONENT			41.66	41.66
	SECONDARY CUSTOMER COMPONENT			39.18	39.18
	TOTAL UNDERGROUND LINES			100.00	100.00
35	LINE TRANSFORMERS				
36	DEMAND COMPONENT				
	CUSTOMER COMPONENT				
	TOTAL LINE TRANSFORMERS				
38	SERVICES				
39	DEMAND COMPONENT				
	CUSTOMER COMPONENT				
	TOTAL SERVICES				
41					
	METERS				
	AREA LIGHTING FIXTURES				
	STREET LIGHTING				
	TOTAL	100.00	100.00	100.00	100.00

	SUBFUNCTION	LINE TRANSFORMER Acct 368	SERVICES Acct 369	METERS Acct 370	AREA LIGHTING FIXTURES Acct 371	STREET LIGHTING Acct 373
	DISTRIBUTION PLANT					
	SUBSTATIONS					
	PRIMARY					
	SECONDARY					
	TOTAL SUBSTATIONS					
	OVERHEAD LINES					
	PRIMARY					
	SECONDARY DEMAND COMPONENT					
45	SECONDARY CUSTOMER COMPONENT					
46	STREET & AREA LIGHTING					
47	TOTAL OVERHEAD LINES					
	UNDERGROUND LINES					
48	PRIMARY					
49	SECONDARY DEMAND COMPONENT					
50	SECONDARY CUSTOMER COMPONENT					
	TOTAL UNDERGROUND LINES					
52						
	LINE TRANSFORMERS					
	DEMAND COMPONENT	30.13				
53	CUSTOMER COMPONENT	69.87				
55	TOTAL LINE TRANSFORMERS	100.00				
56	SERVICES					
	DEMAND COMPONENT		1.59			
	CUSTOMER COMPONENT		98.41			
58	TOTAL SERVICES		100.00			
59	METERS			100.00		
	AREA LIGHTING FIXTURES				100.00	
61	STREET LIGHTING					100.00
62	TOTAL	100.00	100.00	100.00	100.00	100.00

PPL ELECTRIC UTILITIES CORPORATION

SUBFUNCTIONALIZATION & CLASSIFICATION OF DISTRIBUTION PLANT

BY ACCOUNT BASED ON PLANT % BREAKDOWN TO SUBFUNCTION

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

($000)

Line No.	SUBFUNCTION	Input	TOTAL	LAND Acct 360.2	LAND RIGHTS Acct 360.4	STRUCTURES AND IMPROVEMENTS Acct 361	STATION EQUIPMENT Acct 362
	DISTRIBUTION PLANT						
	SUBSTATIONS						
1	PRIMARY	Q28	272,932	8,756	370	23,916	239,890
2	SECONDARY	Q29	4,537	202	0	583	3,752
3	TOTAL SUBSTATIONS		277,469	8,958	370	24,499	243,642
	OVERHEAD LINES						
4	PRIMARY	Q32	362,255	604	16,874		
5	SECONDARY DEMAND COMPONENT	Q33D	334,207	528	14,746		
6	SECONDARY CUSTOMER COMPONENT	Q33C	526,751	834	23,245		
7	STREET & AREA LIGHTING	Q34	37,422	59	1,655		
8	TOTAL OVERHEAD LINES		1,260,635	2,025	56,520		
	UNDERGROUND LINES						
9	PRIMARY	Q36	76,902				
10	SECONDARY DEMAND COMPONENT	Q37D	167,210				
11	SECONDARY CUSTOMER COMPONENT	Q37C	157,255				
12	TOTAL UNDERGROUND LINES		401,367				
	LINE TRANSFORMERS						
13	DEMAND COMPONENT	Q38D	101,207				
14	CUSTOMER COMPONENT	Q38C	234,695				
15	TOTAL LINE TRANSFORMERS		335,902				
	SERVICES						
16	DEMAND COMPONENT	Q39D	7,411				
17	CUSTOMER COMPONENT	Q39C	458,674				
18	TOTAL SERVICES		466,085				
19	METERS	Q43	245,495				
20	AREA LIGHTING FIXTURES	Q46	5,590				
21	STREET LIGHTING	Q47	78,593				
22	TOTAL		3,091,136	10,983	56,890	24,499	243,642

PPL ELECTRIC UTILITIES CORPORATION

SUBFUNCTIONALIZATION & CLASSIFICATION OF DISTRIBUTION PLANT

BY ACCOUNT BASED ON PLANT % BREAKDOWN TO SUBFUNCTION

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004
($000)

	SUBFUNCTION	POLES,TOWERS & FIXTURES Acct 364	OVERHEAD CONDUCTORS & DEVICES Acct 365	UNDERGROUND CONDUIT Acct 366	UNDERGROUND CONDUCTORS & DEVICES Acct 367
	DISTRIBUTION PLANT				
	SUBSTATIONS				
23	PRIMARY				
24	SECONDARY				
25	TOTAL SUBSTATIONS				
	OVERHEAD LINES				
26	PRIMARY	211,437	153,340		
27	SECONDARY DEMAND COMPONENT	174,770	144,163		
28	SECONDARY CUSTOMER COMPONENT	263,457	239,215		
29	STREET & AREA LIGHTING	35,708	0		
30	TOTAL OVERHEAD LINES	685,372	536,718		
	UNDERGROUND LINES				
31	PRIMARY			22,017	54,885
32	SECONDARY DEMAND COMPONENT			47,872	119,338
33	SECONDARY CUSTOMER COMPONENT			45,022	112,233
34	TOTAL UNDERGROUND LINES			114,911	286,456
	LINE TRANSFORMERS				
35	DEMAND COMPONENT				
36	CUSTOMER COMPONENT				
37	TOTAL LINE TRANSFORMERS				
	SERVICES				
38	DEMAND COMPONENT				
39	CUSTOMER COMPONENT				
40	TOTAL SERVICES				
41	METERS				
42	AREA LIGHTING FIXTURES				
43	STREET LIGHTING				
44	TOTAL	685,372	536,718	114,911	286,456

PPL ELECTRIC UTILITIES CORPORATION

SUBFUNCTIONALIZATION & CLASSIFICATION OF DISTRIBUTION PLANT

BY ACCOUNT BASED ON PLANT % BREAKDOWN TO SUBFUNCTION

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

($000)

	SUBFUNCTION	LINE TRANSFORMERS Acct 368	SERVICES Acct 369	METERS Acct 370	AREA LIGHTING FIXTURES Acct 371	STREET LIGHTING Acct 373
	DISTRIBUTION PLANT					
45	PRIMARY					
46	SECONDARY					
47	TOTAL SUBSTATIONS					
	OVERHEAD LINES					
48	PRIMARY					
49	SECONDARY DEMAND COMPONENT					
50	SECONDARY CUSTOMER COMPONENT					
51	STREET & AREA LIGHTING					
52	TOTAL OVERHEAD LINES					
	UNDERGROUND LINES					
53	PRIMARY					
54	SECONDARY DEMAND COMPONENT					
55	SECONDARY CUSTOMER COMPONENT					
56	TOTAL UNDERGROUND LINES					
	LINE TRANSFORMERS					
57	DEMAND COMPONENT	101,207				
58	CUSTOMER COMPONENT	234,695				
59	TOTAL LINE TRANSFORMERS	335,902				
	SERVICES					
60	DEMAND COMPONENT		7,411			
61	CUSTOMER COMPONENT		458,674			
62	TOTAL SERVICES		466,085			
63	METERS			245,495		
64	AREA LIGHTING FIXTURES				5,590	
65	STREET LIGHTING					78,593
66	TOTAL	335,902	466,085	245,495	5,590	78,593

PPL ELECTRIC UTILITIES CORPORATION

SUMMARY
FUNCTIONALIZATION OF RESERVE FOR DEPRECIATION
FOR COST ALLOCATION PURPOSES
YEAR ENDED DECEMBER 31, 2004
($000)

Line No.	FUNCTION/ACCOUNT	INPUT	PLANT ACCOUNTS	TOTAL	PLANT
1	INTANGIBLE PLANT	H95	301-303	8,940	8,940
	TRANSMISSION PLANT				
2	TRANSMISSION FUNCTION	H20	350-359	414,872	414,872
	DISTRIBUTION PLANT				
3	LAND		360.2	-	-
4	LAND RIGHTS		360.4	23,296	23,296
5	STRUCTURES & IMPROVEMENTS		361	11,348	11,348
6	STATION EQUIPMENT		362	89,131	89,131
7	POLES, TOWERS & FIXTURES		364	216,968	216,968
8	OVERHEAD CONDUCTORS & DEVICES		365	212,174	212,174
9	UNDERGROUND CONDUIT		366	27,669	27,669
10	UNDERGROUND CONDUCTORS & DEVICES		367	101,521	101,521
11	LINE TRANSFORMERS		368	142,464	142,464
12	SERVICES		369	242,087	242,087
13	METERS		370	44,430	44,430
14	AREA LIGHTING FIXTURES		371	3,044	3,044
15	STREET LIGHTING		373	45,036	45,036
16	TOTAL DISTRIBUTION PLANT			1,159,168	1,159,168
17	GENERAL PLANT	H88	389-399	127,274	127,274
18	TOTAL DEPRECIATION & AMORTIZATION RESERVE			1,710,254	1,710,254

PPL ELECTRIC UTILITIES CORPORATION

SUBFUNCTIONALIZATION & CLASSIFICATION OF DISTRIBUTION RESERVE FOR DEPRECIATION

BY ACCOUNT BASED ON PLANT % BREAKDOWN TO SUBFUNCTION

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

($000)

Line No.	SUBFUNCTION	INPUT	TOTAL	LAND 360.2	LAND RIGHTS 360.4	STRUCTURES & IMPROVEMENTS 361	STATION EQUIPMENT 362
	DISTRIBUTION PLANT						
	SUBSTATIONS						
1	PRIMARY	H28	98,986		151	11,078	87,758
2	SECONDARY	H29	1,643		0	270	1,373
3	TOTAL SUBSTATIONS		100,629		151	11,348	89,131
	OVERHEAD						
4	PRIMARY	H32	134,462		6,910		
5	SECONDARY DEMAND COMPONENT	H33D	118,354		6,038		
6	SECONDARY CUSTOMER COMPONENT	H33C	187,486		9,519		
7	STREET LIGHTING	H34	11,982		678		
8	TOTAL OVERHEAD LINES		452,284		23,145		
	UNDERGROUND LINES						
9	PRIMARY	H36	24,752				
10	SECONDARY DEMAND COMPONENT	H37D	53,821				
11	SECONDARY COMPANY COMPONENT	H37C	50,617				
12	TOTAL UNDERGROUND LINES		129,190				
	LINE TRANSFORMERS						
13	DEMAND COMPONENT	H38D	42,924				
14	CUSTOMER COMPONENT	H38C	99,540				
15	TOTAL LINE TRANSFORMERS		142,464				
	SERVICES						
16	DEMAND COMPONENT	H39D	3,849				
17	CUSTOMER COMPONENT	H39C	238,238				
18	TOTAL SERVICES		242,087				
19	METERS	H43	44,430				
20	AREA LIGHTING FIXTURES	H46	3,044				
21	STREET LIGHTING	H47	45,036				
22	TOTAL		1,159,164		23,296	11,348	89,131

PPL ELECTRIC UTILITIES CORPORATION

SUBFUNCTIONALIZATION & CLASSIFICATION OF DISTRIBUTION RESERVE FOR DEPRECIATION

BY ACCOUNT BASED ON PLANT % BREAKDOWN TO SUBFUNCTION

FOR COST ALLOCATION PURPOSES
($000)

	SUBFUNCTION	POLES, TOWERS & FIXTURES 364	OVERHEAD CONDUCTORS & DEVICES 365	UNDERGROUND CONDUIT 366	U. G. CONDUCTORS & DEVICES 367
	DISTRIBUTION PLANT				
	SUBSTATIONS				
23	PRIMARY				
24	SECONDARY				
25	TOTAL SUBSTATIONS				
	OVERHEAD				
26	PRIMARY	66,935	60,618		
27	SECONDARY DEMAND COMPONENT	55,327	56,990		
28	SECONDARY CUSTOMER COMPONENT	83,402	94,566		
29	STREET LIGHTING	11,304	0		
30	TOTAL OVERHEAD LINES	216,968	212,174		
	UNDERGROUND LINES				
31	PRIMARY			5,301	19,451
32	SECONDARY DEMAND COMPONENT			11,527	42,294
33	SECONDARY COMPANY COMPONENT			10,841	39,776
34	TOTAL UNDERGROUND LINES			27,669	101,521
	LINE TRANSFORMERS				
35	DEMAND COMPONENT				
36	CUSTOMER COMPONENT				
37	TOTAL LINE TRANSFORMERS				
	SERVICES				
38	DEMAND COMPONENT				
39	CUSTOMER COMPONENT				
40	TOTAL SERVICES				
41	METERS				
42	AREA LIGHTING FIXTURES				
43	STREET LIGHTING				
44	TOTAL DISTRIBUTION	216,968	212,174	27,669	101,521

PPL ELECTRIC UTILITIES CORPORATION

SUBFUNCTIONALIZATION & CLASSIFICATION OF DISTRIBUTION RESERVE FOR DEPRECIATION

BY ACCOUNT BASED ON PLANT % BREAKDOWN TO SUBFUNCTION

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

($000)

	SUBFUNCTION	LINE TRANSFORMERS 368	SERVICES 369	METERS 370	AREA LIGHTING FIXTURES 371	STREET LIGHTING 373
	DISTRIBUTION PLANT					
	SUBSTATIONS					
45	PRIMARY					
46	SECONDARY					
47	TOTAL SUBSTATIONS					
	OVERHEAD					
48	PRIMARY					
49	SECONDARY DEMAND COMPONENT					
50	SECONDARY CUSTOMER COMPONENT					
51	STREET LIGHTING					
52	TOTAL OVERHEAD LINES					
	UNDERGROUND LINES					
53	PRIMARY					
54	SECONDARY DEMAND COMPONENT					
55	SECONDARY COMPANY COMPONENT					
56	TOTAL UNDERGROUND LINES					
	LINE TRANSFORMERS					
57	DEMAND COMPONENT	42,924				
58	CUSTOMER COMPONENT	99,540				
59	TOTAL LINE TRANSFORMERS	142,464				
	SERVICES					
60	DEMAND COMPONENT		3,849			
61	CUSTOMER COMPONENT		238,238			
62	TOTAL SERVICES		242,087			
63	METERS			44,430		
64	AREA LIGHTING FIXTURES				3,044	
65	STREET LIGHTING					45,036
66	TOTAL DISTRIBUTION	142,464	242,087	44,430	3,044	45,036

Line No.

PPL ELECTRIC UTILITIES CORPORATION

SUMMARY

OPERATION AND MAINTENANCE EXPENSES

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004
($000)

Line No.	EXPENSES	INPUT	ACCOUNTS	EXPENSE	
1	TRANSMISSION		560-573		15,056
2	ANCILLARIES				60,305
3	TOTAL	G20			75,361
	DISTRIBUTION				
	SUPERVISION & ENGINEERING		580,590	21,081	
	LOAD DISPATCHING		581	759	
	SUBSTATIONS		582,591,592	9,723	
	OVERHEAD LINES		583,593	39,218	
	UNDERGROUND LINES		584,594	9,103	
	SERVICES		593,594	5,688	
	LINE TRANSFORMERS		595	2,477	
	MISCELLANEOUS & RENTS		588,589	18,670	
	METERS		586,597	8,503	
	STREET LIGHTING		585,596,598	5,550	
	CUSTOMER INSTALLATIONS		587	6,860	
4	TOTAL DISTRIBUTION				127,831
5	CUSTOMER ACCOUNTS		901-905		54,211
6	CUSTOMER SERVICE AND INFORMATIONAL	G64	908-910		13,597
7	SALES	G65	911-916		6,591
8	ADMINISTRATIVE AND GENERAL		920-935		125,180
9	TOTAL OPERATION AND MAINTENANCE EXPENSES				402,771

PPL ELECTRIC UTILITIES CORPORATION

ASSIGNMENT OF WAGES AND SALARIES

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004
($000)

Line No.	Account	DESCRIPTION	TOTAL AMOUNT	INPUT
		TRANSMISSION EXPENSE		
1	560-567	TRANSMISSION OPERATION	1,595	
2	568-573	TRANSMISSION MAINTENENCE	2,830	
3		TOTAL TRANSMISSION EXPENSE	4,426	K904
		DISTRIBUTION EXPENSE		
4	580-589	DISTRIBUTION OPERATION	30,843	
5	590-598	DISTRIBUTION MAINTENANCE	21,061	
6		TOTAL DISTRIBUTION EXPENSE	51,903	K906
7	901-905	CUSTOMER ACCOUNTS EXPENSE	23,076	K920
8	907-910	CUSTOMER SERVICE & INFORMATIONAL EXP	1,594	K922
9	911-916	SALES EXPENSE	1,654	K924
10		TOTAL EXCLUDING A & G	82,653	K929
		ADMINISTRATIVE AND GENERAL EXPENSE		
11	920-930	ADMIN AND GENERAL - OPERATION	3,629	
12	935	ADMIN AND GENERAL - MAINTENANCE	43	
13		TOTAL ADMIN AND GENERAL EXPENSE	3,672	K930
14		TOTAL WAGES AND SALARIES	86,325	K939,K433

PPL ELECTRIC UTILITIES CORPORATION

DISTRIBUTION EXPENSE ACCOUNTS AMOUNTS

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

($000)

Line No.	ACCOUNT	DESCRIPTION OF ACCOUNT	AMOUNT
		DISTRIBUTION OPERATON	
1	580	SUPERVISION & ENGINEERING	15,770
2	581	LOAD DISPATCHING	759
3	582	STATION EXPENSE	654
4	583	OVERHEAD LINES EXPENSE	4,337
5	584	UNDERGROUND LINES EXPENSE	3,753
6	585	STREET LIGHTING & SIGNAL SYSTEMS	546
7	586	METER EXPENSE	8,412
8	587	CUSTOMER INSTALLATION EXPENSE	6,860
9	588	MISCELLANEOUS DISTRIBUTION EXPENSE	12,003
10	589	RENTS	6,868
11		TOTAL OPERATION	59,961
		DISTRIBUTION MAINTENANCE	
12	590	SUPERVISION & ENGINEERING	5,311
13	591	MAINTENANCE OF STRUCTURES	57
14	592	MAINTENANCE OF STATION EQUIPMENT	9,011
15	593	MAINTENANCE OF SERVICES	34,892
16	593.5	MAINTENANCE OF OVERHEAD SERVICES	1,850
17	594	MAINTENANCE OF UNDERGROUND LINES	5,346
18	594.3	MAINTENANCE OF UNDERGROUND SERVICES	137
19	594.6	MAINTENANCE OF UNDERGROUND OTHER SERVICES	3,696
20	595	MAINTENANCE OF LINE TRANSFORMERS	2,477
21	596	MAINTENANCE OF STREET LIGHTING	3,732
22	597	MAINTENANCE OF METERS	91
23	598	MAINTENANCE OF MISCELLANEOUS DISTRIBUTION PLANT	1,272
24		TOTAL MAINTENANCE	67,871
25		TOTAL DISTRIBUTION EXPENSE	127,832

Line No.

PPL ELECTRIC UTILITIES CORPORATION

SUBFUNCTIONALIZATION OF DISTRIBUTION EXPENSES ACCOUNTS

PRORATION OF SUPERVISION AND ENGINEEERING ACCOUNTS

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

($000)

Line No.	ACCOUNT	DISTRIBUTION OPERATION ACCOUNT TOTAL	LABOR	MATERIAL	ACCOUNT 580 PRORATION TOTAL	FUNCTIONAL ASSIGNMENT
	580	15,770				
1	582	654	656	(3)	500	SUBSTATIONS
2	583	4,337	3,187	1,150	2,429	OVERHEAD LINES
3	584	3,753	3,061	693	2,332	UNDERGROUND LINES
4	585	546	57	489	44	STREET LIGHTING
5	586	8,412	5,011	3,401	3,819	METERS
6	587	6,860	3,276	3,585	2,498	CUST INSTALLATIONS
7	588,589	18,870	5,445	13,425	4,150	MISCELLANEOUS
8	TOTAL(EXCL. 580,581)	43,432	20,693	22,739	15,770	

Line No.	ACCOUNT	DISTRIBUTION MAINTENANCE ACCOUNT TOTAL	LABOR	MATERIAL	ACCOUNT 590 PRORATION TOTAL	FUNCTIONAL ASSIGNMENT
	590	5,311				
9	591	57	18	39	5	SUBSTATIONS
10	592	9,011	3,465	5,547	1,047	SUBSTATIONS
11	593	34,892	6,891	28,001	2,082	OVERHEAD LINES
12	593.5	1,850	756	1,094	228	OVERHEAD SERVICES
13	594	5,346	1,789	3,556	541	UNDERGROUND LINES
14	594.3	137	52	85	16	UNDERGROUND SERVICES
15	594.6	3,696	1,241	2,455	375	UG. OTHER SERVICES
16	595	2,477	1,868	609	564	LINE TRANSFORMERS
17	596	3,732	1,024	2,708	309	STREET LIGHTING
18	597	91	55	36	17	METERS
19	598	1,272	422	851	127	STREET LIGHTING
20	TOTAL(EXCL. 590)	62,560	17,579	44,981	5,311	

DISTRIBUTION MAINTENANCE					
SUBSTATION TOTAL	---	---	---	1,052	SUBSTATIONS
STREET LIGHTING TOTAL	---	---	---	436	STREET LIGHTING
SERVICES TOTAL	---	---	---	819	SERVICES

ACCOUNT 580 PRORATED OVER LABOR COMPONENT OF ACCOUNTS 582-588.
ACCOUNT 590 PRORATED OVER LABOR COMPONENT OF ACCOUNTS 591-598.

Line No.

PPL ELECTRIC UTILITIES CORPORATION

SUBFUNCTIONALIZATION OF DISTRIBUTION OPERATION EXPENSE

BY ACCOUNT BASED ON TOTAL PLANT $ BREAKDOWN TO SUBFUNCTION

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

($000)

Line No.	SUBFUNCTION	TOTAL	ACCOUNT 580	581	582	583	584
	SUBSTATIONS						
1	PRIMARY	11,197	492	106	643		
2	SECONDARY	186	8	2	11		
3	TOTAL SUBSTATIONS	11,383	500	108	654		
	OVERHEAD LINES						
4	PRIMARY	13,182	724	148		1,292	
5	SECONDARY-DEMAND COMP.	11,553	634	129		1,133	
6	SECONDARY-CUSTOMER COMP	18,206	1,000	204		1,785	
7	STREET LIGHTING	1,294	71	14		127	
8	TOTAL OVERHEAD LINES	44,235	2,429	496		4,337	
	UNDERGROUND LINES						
9	PRIMARY	2,324	447	30			719
10	SECONDARY-DEMAND COMP.	5,053	972	65			1,564
11	SECONDARY-CUSTOMER COMP	4,751	914	61			1,470
12	TOTAL UNDERGROUND LINES	12,128	2,332	156			3,753
	SERVICES						
13	DEMAND COMPONENT	100					
14	CUSTOMER COMPONENT	6,201					
15	TOTAL SERVICES	6,301					
16	TOTAL			759	654	4,337	3,753

Line No.	SUBFUNCTION	TOTAL	ACCOUNT 585	586	587	588,589
	LINE TRANSFORMERS					
17	DEMAND COMPONENT	916				
18	CUSTOMER COMPONENT	2,125				
19	TOTAL LINE TRANSFORMERS	3,041				
20	MISC. DIST. EXPENSE & RENTS	23,020	4,150			18,870
21	METERS	12,338	3,819		8,412	
22	STREET LIGHTING	6,030	44	546		
23	CUSTOMER INSTALLATIONS	9,356	2,496			6,860
24	TOTAL	127,832	15,770	546	8,412	6,860 / 18,870

PPL ELECTRIC UTILITIES CORPORATION

SUBFUNCTIONALIZATION OF DISTRIBUTION MAINTENANCE EXPENSE

BY ACCOUNT BASED ON TOTAL PLANT $ BREAKDOWN TO SUBFUNCTION

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

($000)

	SUBFUNCTION	ACCOUNT 590	591	592	593	594
	SUBSTATIONS					
25	PRIMARY	1,035	56	8,864		
26	SECONDARY	17	1	147		
27	TOTAL SUBSTATIONS	1,052	57	9,011		
	OVERHEAD LINES					
28	PRIMARY	620			10,398	
29	SECONDARY-DEMAND COMP.	544			9,113	
30	SECONDARY-CUSTOMER COMP	857			14,361	
31	STREET LIGHTING	61			1,020	
32	TOTAL OVERHEAD LINES	2,082			34,892	
	UNDERGROUND LINES					
33	PRIMARY	104				1,024
34	SECONDARY-DEMAND COMP.	225				2,227
35	SECONDARY-CUSTOMER COMP	212				2,094
36	TOTAL UNDERGROUND LINES	541				5,346
	SERVICES					
37	DEMAND COMPONENT	10			29	61
38	CUSTOMER COMPONENT	609			1,820	3,772
39	TOTAL SERVICES	619			1,850	3,833
40	TOTAL		57	9,011	36,741	9,179

	SUBFUNCTION	ACCOUNT 595	596	597	598
	LINE TRANSFORMERS				
41	DEMAND COMPONENT	170	746		
42	CUSTOMER COMPONENT	394	1,731		
43	TOTAL LINE TRANSFORMERS	564	2,477		
44	MISC. DIST. EXPENSE & RENTS				
45	METERS	17		91	
46	STREET LIGHTING	436	3,732		1,272
47	CUSTOMER INSTALLATIONS				
48	TOTAL	5,311	2,477	3,732	91	1,272

49	SUM DIST PLANT SUBS, OVERHEAD	1,957,328,645
50	AND UNDERGROUND LINES (auto)	23C22+23C30+23C37

Line No.

PPL ELECTRIC UTILITIES CORPORATION

SUBFUNCTIONALIZATION OF DISTRIBUTION OPERATION EXPENSE

% OF ACCOUNT TOTAL

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2003

Line No.	SUBFUNCTION	ACCOUNT 580	581	582	583	584
	SUBSTATIONS					
1	PRIMARY	2.67	14.05	98.37		
2	SECONDARY	0.04	0.23	1.63		
3	TOTAL SUBSTATIONS	2.71	14.28	100.00		
	OVERHEAD LINES					
4	PRIMARY	5.35	19.44		29.85	
5	SECONDARY-DEMAND COMP.	4.67	16.99		26.09	
6	SECONDARY-CUSTOMER COMP	7.36	26.77		41.13	
7	STREET LIGHTING	0.53	1.91		2.93	
8	TOTAL OVERHEAD LINES	17.91	65.11		100.00	
	UNDERGROUND LINES					
9	PRIMARY	2.80	3.95			19.16
10	SECONDARY-DEMAND COMP.	6.08	8.59			41.66
11	SECONDARY-CUSTOMER COMP	5.72	8.07			39.18
12	TOTAL UNDERGROUND LINES	14.60	20.61			100.00
	SERVICES					
13	DEMAND COMPONENT					
14	CUSTOMER COMPONENT					
15	TOTAL SERVICES					
16	TOTAL		100.00	100.00	100.00	100.00

Line No.	SUBFUNCTION	ACCOUNT 585	586	587	588,589
	LINE TRANSFORMERS				
17	DEMAND COMPONENT				
18	CUSTOMER COMPONENT				
19	TOTAL LINE TRANSFORMERS				
20	MISC. DIST. EXPENSE & RENTS	30.30			100.00
21	METERS	20.71	100.00		
22	STREET LIGHTING	0.23	100.00		
23	CUSTOMER INSTALLATIONS	13.54		100.00	
24	TOTAL	100.00	100.00	100.00	100.00

PPL ELECTRIC UTILITIES CORPORATION

SUBFUNCTIONALIZATION OF DISTRIBUTION MAINTENANCE EXPENSE

% OF ACCOUNT TOTAL

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2003

	SUBFUNCTION	ACCOUNT				
		590	591	592	593	594
	SUBSTATIONS					
25	PRIMARY	17.39	98.37	98.37		
26	SECONDARY	0.29	1.63	1.63		
27	TOTAL SUBSTATIONS	17.68	100.00	100.00		
	OVERHEAD LINES					
28	PRIMARY	12.51			28.34	
29	SECONDARY-DEMAND COMP.	10.94			24.77	
30	SECONDARY-CUSTOMER COMP	17.23			39.05	
31	STREET LIGHTING	1.23			2.78	
32	TOTAL OVERHEAD LINES	41.91			94.94	
	UNDERGROUND LINES					
33	PRIMARY	1.74				11.17
34	SECONDARY-DEMAND COMP.	3.78				24.28
35	SECONDARY-CUSTOMER COMP	3.56				22.84
36	*TOTAL UNDERGROUND LINES*	9.08				58.29
	SERVICES					
37	DEMAND COMPONENT	0.19			0.08	0.66
38	CUSTOMER COMPONENT	11.59			4.98	41.05
39	TOTAL SERVICES	11.78			5.06	41.71
40	TOTAL		100.00	100.00	100.00	100.00

	SUBFUNCTION	ACCOUNT			
		595	596	597	598
	LINE TRANSFORMERS				
41	DEMAND COMPONENT	3.55	30.13		
42	CUSTOMER COMPONENT	8.24	69.87		
43	TOTAL LINE TRANSFORMERS	11.79	100.00		
44	MISC. DIST. EXPENSE & RENTS				
45	METERS	0.44		100.00	
46	STREET LIGHTING	7.32	100.00		100.00
47	CUSTOMER INSTALLATIONS				
48	TOTAL	100.00	100.00	100.00	100.00

PPL ELECTRIC UTILITIES CORPORATION

SUBFUNCTIONALIZATION OF DISTRIBUTION OPERATION EXPENSE

BASED ON O & M % BREAKDOWN TO SUBFUNCTION

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

($000)

Line No.	SUBFUNCTION	INPUT	TOTAL	ACCOUNT 580	581	582	583	584
	SUBSTATIONS							
1	PRIMARY	G28	11,015	421	107	643		
2	SECONDARY	G29	182	6	2	11		
3	TOTAL SUBSTATIONS		11,197	427	109	654		
	OVERHEAD LINES							
4	PRIMARY	G32	13,362	844	148		1,295	
5	SECONDARY-DEMAND COMP.	G33D	11,678	736	129		1,132	
6	SECONDARY-CUSTOMER COMP	G33C	18,409	1,161	203		1,784	
7	STREET LIGHTING	G34	1,312	84	15		127	
8	TOTAL OVERHEAD LINES		44,761	2,825	495		4,338	
	UNDERGROUND LINES							
9	PRIMARY	G36	2,308	442	30			719
10	SECONDARY-DEMAND COMP.	G37D	5,018	959	65			1,564
11	SECONDARY-CUSTOMER COMP	G37C	4,718	902	61			1,470
12	TOTAL UNDERGROUND LINES		12,044	2,303	156			3,753
	SERVICES							
13	DEMAND COMPONENT	G39D	100					
14	CUSTOMER COMPONENT	G39C	6,214					
15	TOTAL SERVICES		6,314					
16	TOTAL				759	654	4,337	3,753

	SUBFUNCTION	INPUT		ACCOUNT 585	586	587	588,589
	LINE TRANSFORMERS						
17	DEMAND COMPONENT	G38D	935				
18	CUSTOMER COMPONENT	G38C	2,169				
19	TOTAL LINE TRANSFORMERS		3,104				
20	MISC. DIST. EXPENSE & RENTS	G42	23,648	4,778			18,870
21	METERS	G43	11,792	3,266		8,412	
22	STREET LIGHTING	G46	5,975	36	546		
23	CUSTOMER INSTALLATIONS	G47	8,995	2,135			6,860
24	TOTAL		127,830	15,770	546	8,412	6,860	18,870

PPL ELECTRIC UTILITIES CORPORATION

SUBFUNCTIONALIZATION OF DISTRIBUTION MAINTENANCE EXPENSE

BASED ON O & M % BREAKDOWN TO SUBFUNCTION

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

($000)

	SUBFUNCTION	ACCOUNT 590	591	592	593	594
	SUBSTATIONS					
25	PRIMARY	924	56	8,865		
26	SECONDARY	15	1	147		
27	*TOTAL SUBSTATIONS*	939	57	9,012		
	OVERHEAD LINES					
28	PRIMARY	664			10,412	
29	*SECONDARY-DEMAND COMP.*	581			9,101	
30	SECONDARY-CUSTOMER COMP	915			14,347	
31	STREET LIGHTING	65			1,021	
32	*TOTAL OVERHEAD LINES*	2,225			34,881	
	UNDERGROUND LINES					
33	PRIMARY	92				1,025
34	SECONDARY-DEMAND COMP.	201				2,229
35	SECONDARY-CUSTOMER COMP	189				2,096
36	TOTAL UNDERGROUND LINES	482				5,350
	SERVICES					
37	DEMAND COMPONENT	10			29	61
38	CUSTOMER COMPONENT	616			1,830	3,768
39	TOTAL SERVICES	626			1,859	3,829
40	TOTAL		57	9,011	36,741	9,179

	SUBFUNCTION	ACCOUNT 595	596	597	598
	LINE TRANSFORMERS				
41	DEMAND COMPONENT	189	746		
42	CUSTOMER COMPONENT	438	1,731		
43	*TOTAL LINE TRANSFORMERS*	627	2,477		
44	MISC. DIST. EXPENSE & RENTS				
45	METERS	23		91	
46	STREET LIGHTING	389	3,732		1,272
47	CUSTOMER INSTALLATIONS				
48	TOTAL	5,311	2,477	3,732	91	1,272

Line No.

PPL ELECTRIC UTILITIES CORPORATION

ASSIGNMENT OF ADMINISTRATIVE AND GENERAL EXPENSES

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

($000)

	ACCOUNT	DESCRIPTION	TOTAL	METER READING	COLLECTION	UNCOLLECTIBLE ACCTS - TRANS	PROPERTY DAMAGE DISTRIBUTION	UNCOLLECTIBLE ACCTS - OTHER	BALANCE
1	901	SUPERVISION	449	-	-	-	-	-	449
2	902	METER READING EXPENSES - LARGE POWER	224	224	-	-	-	-	-
3		METER READING EXPENSES - OTHER	10,194	10,194					
4	903CR	CUSTOMER RECORDS	17,178	-	-	-	-	-	17,178
5	903CE	COLLECTION EXPENSES	6,240		6,240	-		-	
6	904T	UNCOLLECTIBLE ACCOUNTS TRANSMISSION	0			-	-		
7	904D	PROPERTY DAMAGE DISTRIBUTION	1,269				1,269		
8	904 by RATE	UNCOLLECTIBLE ACCOUNTS	16,231	-		-	-	16,231	-
9	905	MISC. CUSTOMER ACCOUNTS EXPENSES	2,425	-	-	-		-	2,425
10	901-905	TOTAL	54,211	10,418	6,240	-	1,269	16,231	20,053
		INPUT LABELS		G50	G51	G52	G53	G54	G55

Line No.

PPL ELECTRIC UTILITIES CORPORATION

ASSIGNMENT OF ADMINISTRATIVE AND GENERAL EXPENSES

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004
($000)

Line No.	ACCOUNT	DESCRIPTION	AMOUNT	INPUT
1	928	REGULATORY COMMISSION EXPENSE - PPUC	4,155	G70
2		REGULATORY COMMISSION EXPENSE - FERC	108	G71
3		TOTAL REGULATORY COMMISSION EXPENSE	4,263	
4	926	EMPLOYEE BENEFITS	27,215	G73
5	920-935	OTHER ADMINISTRATIVE AND GENERAL	93,702	G75
6		SUBTOTAL	120,917	
7		TOTAL ADMINISTRATIVE AND GENERAL	125,180	

Line No.

PPL ELECTRIC UTILITIES CORPORATION

SUMMARY

FUNCTIONALIZATION OF DEPRECIATION EXPENSE

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

($000)

	FUNCTION/ACCOUNT	INPUT	PLANT ACCOUNTS	TOTAL	PER BOOKS	MISC ADJ.
1	INTANGIBLE PLANT	GD95		4,764	4,764	0
2	TRANSMISSION PLANT	GD20	350-359	17,457	17,457	0
	DISTRIBUTION PLANT			wgl/jmk manual		
3	LAND		360.2	0	0	0
4	LAND RIGHTS		360.4	1,060	1,060	0
5	STRUCTURES & IMPROVEMENTS		361	312	312	-
6	STATION EQUIPMENT		362	4,407	4,407	-
7	POLES, TOWERS & FIXTURES		364	15,980	15,980	-
8	OVERHEAD CONDUCTORS & DEVICES		365	12,345	12,345	-
9	UNDERGROUND CONDUIT		366	2,105	2,105	-
10	UNDERGROUND CONDUCTORS & DEVICES		367	8,221	8,221	-
11	LINE TRANSFORMERS		368	8,842	8,842	-
12	SERVICES		369	12,101	12,101	-
13	METERS		370	8,775	8,775	-
14	AREA LIGHTING FIXTURES		371	225	225	-
15	STREET LIGHTING		373	4,085	4,085	-
16	TOTAL DISTRIBUTION PLANT			78,459	78,459	-
17	GENERAL PLANT	GD88	389-399	7,940	7,940	0
18	TOTAL DEPRECIATION EXPENSE			108,620	108,620	-

PPL ELECTRIC UTILITIES CORPORATION

SUBFUNCTIONALIZATION OF DISTRIBUTION DEPRECIATION EXPENSE

BY ACCOUNT BASED ON PLANT % BREAKDOWN TO SUBFUNCTION

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

($000)

Line No.	SUBFUNCTION	INPUT	TOTAL	LAND 360.2	LAND RIGHTS 360.4	STRUCTURES AND IMPROVEMENTS 361	STATION EQUIPMENT 362
	SUBSTATIONS						
1	PRIMARY	GD28	4,615		7	305	4,303
2	SECONDARY	GD29	112		-	7	105
3	TOTAL SUBSTATIONS		4,727		7	312	4,408
	OVERHEAD LINES						
4	PRIMARY	GD32	8,772		315		
5	SECONDARY DEMAND COMPONENT	GD33D	7,666		275		
6	SECONDARY CUSTOMER COMPONE	GD33C	12,078		433		
7	STREET LIGHTING	GD34	864		31		
8	TOTAL OVERHEAD LINES		29,380		1,054		
	UNDERGROUND LINES						
9	PRIMARY	GD36	1,978		-		
10	SECONDARY DEMAND COMPONENT	GD37D	4,302		-		
11	SECONDARY CUSTOMER COMPONE	GD37C	4,046		-		
12	TOTAL UNDERGROUND LINES		10,326		-		
	LINE TRANSFORMERS						
13	DEMAND COMPONENT	GD38D	2,664				
14	CUSTOMER COMPONENT	GD38C	6,178				
15	TOTAL LINE TRANSFORMERS		8,842				
	SERVICES						
16	DEMAND COMPONENT	GD39D	192				
17	CUSTOMER COMPONENT	GD39C	11,909				
18	TOTAL SERVICES		12,101				
19	METERS	GD43	8,775				
20	AREA LIGHTING FIXTURES	GD46	225				
21	STREET LIGHTING	GD47	4,085				
22	TOTAL		78,461		1,060	312	4,407

PPL ELECTRIC UTILITIES CORPORATION

SUBFUNCTIONALIZATION OF DISTRIBUTION DEPRECIATION EXPENSE

BY ACCOUNT BASED ON PLANT % BREAKDOWN TO SUBFUNCTION

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

($000)

	SUBFUNCTION	POLES,TOWERS & FIXTURES 364	OVERHEAD CONDUCTORS AND DEVICES 365	UNDERGROUND CONDUIT 366	UNDERGROUND CONDUCTORS & DEVICES 367
	SUBSTATIONS				
23	PRIMARY				
24	SECONDARY				
25	TOTAL SUBSTATIONS				
	OVERHEAD LINES				
26	PRIMARY	4,930	3,527		
27	SECONDARY DEMAND COMPONENT	4,075	3,316		
28	SECONDARY CUSTOMER COMPONENT	6,143	5,502		
29	STREET LIGHTING	833	-		
30	TOTAL OVERHEAD LINES	15,981	12,345		
	UNDERGROUND LINES				
31	PRIMARY			403	1,575
32	SECONDARY DEMAND COMPONENT			877	3,425
33	SECONDARY CUSTOMER COMPONENT			825	3,221
34	TOTAL UNDERGROUND LINES			2,105	8,221
	LINE TRANSFORMERS				
35	DEMAND COMPONENT				
36	CUSTOMER COMPONENT				
37	TOTAL LINE TRANSFORMERS				
	SERVICES				
38	DEMAND COMPONENT				
39	CUSTOMER COMPONENT				
40	TOTAL SERVICES				
41	METERS				
42	AREA LIGHTING FIXTURES				
43	STREET LIGHTING				
44	TOTAL	15,980	12,345	2,105	8,221

PPL ELECTRIC UTILITIES CORPORATION

SUBFUNCTIONALIZATION OF DISTRIBUTION DEPRECIATION EXPENSE

BY ACCOUNT BASED ON PLANT % BREAKDOWN TO SUBFUNCTION

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

($000)

	SUBFUNCTION	LINE TRANSFORMERS 368	SERVICES 369	METERS 370	AREA LIGHTING FIXTURES 371	STREET LIGHTING 373
	SUBSTATIONS					
45	PRIMARY					
46	SECONDARY					
47	TOTAL SUBSTATIONS					
	OVERHEAD LINES					
48	PRIMARY					
49	SECONDARY DEMAND COMPONENT					
50	SECONDARY CUSTOMER COMPONENT					
51	STREET LIGHTING					
52	TOTAL OVERHEAD LINES					
	UNDERGROUND LINES					
53	PRIMARY					
54	SECONDARY DEMAND COMPONENT					
55	SECONDARY CUSTOMER COMPONENT					
56	TOTAL UNDERGROUND LINES					
	LINE TRANSFORMERS					
57	DEMAND COMPONENT	2,664				
58	CUSTOMER COMPONENT	6,178				
59	TOTAL LINE TRANSFORMERS	8,842				
	SERVICES					
60	DEMAND COMPONENT		192			
61	CUSTOMER COMPONENT		11,909			
62	TOTAL SERVICES		12,101			
63	METERS			8,775		
64	AREA LIGHTING FIXTURES				225	
65	STREET LIGHTING					4,085
66	TOTAL	8,842	12,101	8,775	225	4,085

PPL ELECTRIC UTILITIES CORPORATION

EXHIBIT JMK 2

ALLOCATION FACTORS

FUTURE TEST YEAR ENDING DECEMBER 31, 2004

This section identifies the rate schedules that make up the rate classes used in the jurisdictional allocation studies and all the allocation factors used in those studies. Generally, allocators are derived from three classes – direct assignments, program generated, and calculated (demand, and customer-related). The development of specific calculated allocators is shown in this section.

PPL ELECTRIC UTILITIES CORPORATION

EXHIBIT JMK 2

CUSTOMER CLASS DESIGNATIONS & ABBREVIATIONS

FUTURE PERIOD – YEAR ENDING DECEMBER 31, 2004

Rate Classes	Abbreviations	PUC Jurisdictional Rate Schedules
Residential Service	RS	RS, RTD
Residential Service - Thermal Storage	RTS	RTS
Small General Service	GS-1	GS-1, BL
Large General Service - Secondary	GS-3	GS-3, IS-1
Large General Service - 12 kV	LP-4	LP-4
Large General Service - 66 kV	LP-5	LP-5
Large General Service - 66 kV Standby	Standby	Standby
Large General Service – Electric Propulsion	LPEP	LPEP
Interruptible Service by Agreement	ISA	ISA
Commercial and Industrial Heating	GH	GH-1, GH-2
Street and Area Lighting	SL/AL	SA, SM, SHS, SE TS, SI1

PPL ELECTRIC UTILITIES CORPORATION

DETERMINATION OF CUSTOMER ALLOCATORS

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

Line No.	RATE CLASS	ALLOCATOR LABEL	END OF YEAR CUSTOMERS C10	SECONDARY CUSTOMERS C30
1	RS		1,151,910	1,151,910
2	RTS		14,342	14,342
3	GS-1,BL		137,064	137,064
4	GS-3,IS-1		21,352	21,352
5	LP-4		866	0
6	IS-P		34	0
7	LP-5		95	0
8	IS-T		33	0
9	LP-6		4	0
10	LPEP		1	0
11	ISA		1	0
12	GH		3,611	3,611
13	SL/AL		1,270	1,270
14	L5-S		6	0
15	TOTAL PPUC		1,330,588	1,329,548
16	66 KV RESALE		9	0
17	12 KV RESALE		9	0
18	TOTAL SYSTEM		1,330,606	1,329,548

Line No.

PPL ELECTRIC UTILITIES CORPORATION

DETERMINATION OF METER ALLOCATION FACTOR CW1

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

($000)

Line No.	RATE CLASS	RATE DESIGNATION	METERING TYPE	ESTIMATED METER COST	CUSTOMERS	ESTIMATED METER INVESTMENT	SUMMARY ($000)
1	RS,RTD	RSO	A	105.85	1,116,884	118,222,171	
2		RWO(R)	B	459	245	112,455	
3		RW1	C	354	187	66,198	
4		RTD	C	354	268	94,872	
5		RTS	C	354	13,944	4,936,176	
6	TOTAL				1,131,528	123,431,872	123,432
7	GS-1,BL	GS-1	A	105.85	58,511	6,193,389	
8		G1-D	D	111	72,677	8,067,147	
9		G1-T	C	354	848	300,192	
10		G1-F	E	4120	18	74,160	
11		G1-V	A	105.85	689	72,931	
12		G1-C	B	459	84	38,556	
13		BL	-	-	30	-	
14	TOTAL				132,857	14,746,375	14,746
15	GS-3,IS-1	GS-3	F	827	2,516	2,080,732	
16		G3-T	G	846	18,210	15,405,660	
17		G3-V	A	105.85	47	4,975	
18		G3-C	H	1,632	92	150,144	
19		IS-1	F	827	4	3,308	
20	TOTAL				20,869	17,644,819	17,645
21	LP-4	LP-4	I	4,141	472	1,954,552	
22		L4-T	I	4,141	436	1,805,476	
23		IS-P	J	5,043	36	181,548	
24		L4-C	K+I	5,979	5	29,895	
25	TOTAL				949	3,971,471	3,971
26	LP-5,6	LP-5	J	15,750	37	582,750	
27		L5-T (plus 17,778)	J	15,750	68	1,088,778	
28		L5-S	J	15,750	9	141,750	
29		LP-6	J	29,461	1	29,461	
30		L6-T	J	29,461	3	88,383	
31		IS-T (minus 1167)	J	17,668	33	581,877	
32		LPEP	J	60,335	1	60,335	
33		ISA	J	233,820	1	233,820	
34	TOTAL				153	2,807,154	2,807
35	GH	GH-1	F	827	901	745,127	
36		H1-T	G	846	83	70,218	
37		H1-P	E	4,120	-		
38		H1-Q	I	4,141	-		
39		GH-2	F	827	1,682	1,391,014	
40		H2-R	F	827	856	707,912	
41	TOTAL				3,522	2,914,271	2,914
42	SL/AL	SL/AL	NONE		1,243	-	-
43	TOTAL				1,291,121	165,515,962	165,515

Line No.

PPL ELECTRIC UTILITIES CORPORATION

DETERMINATION OF METER ALLOCATION FACTOR CW1

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004
($000)

Line No.	RATE CLASS	INVESTMENT PP&L STUDY	INVESTMENT PRORATED	INDICATED METER COST	CUSTOMERS	AVERAGE METER COST $/CUSTOMER
1	RS	118,496	175,563	175,563	1,151,910	152.41
2	RTS	4,936	7,313	7,313	14,342	509.90
3	GS-1	14,746	21,848	21,848	137,064	159.40
4	GS-3	17,645	26,143	26,143	21,352	1,224.41
5	LP-4	3,789	5,614	5,614	866	6,480.88
6	IS-P	182	269	269	34	7,837.65
7	LP-5	1,672	2,477	2,477	95	26,070.64
8	IS-T	582	862	862	33	26,432.96
9	LP-6	118	175	175	4	42,585.61
10	LPEP	60	89	89	1	86,427.11
11	ISA	234	346	346	1	335,997.52
12	GH	2,914	4,317	4,317	3,611	1,195.57
13	SL/AL	0	0	0	1,270	0
14	L5-S	142	210	210	6	36,125.41
15	TOTAL PPUC	165,515	245,227	245,227	1,330,588	
16	RES 69	197		197	9	
17	RES 12	72		72	9	
18	TOTAL RESALE	268		268	18	
19	TOTAL INCLUDING RESALE	165,784		245,495	1,330,606	

Line No.

PPL ELECTRIC UTILITIES CORPORATION

DETERMINATION OF METER ALLOCATION FACTOR CW1

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

($000)

Line No.	RATE CLASS	AVERAGE METER COST $/CUSTOMER	CUSTOMERS	INDICATED METER INVESTMENT	ALLOCATOR CW1
1	RS	152.41	1,151,910	175,563	175,371
2	RTS	509.90	14,342	7,313	7,305
3	GS-1,BL	159.40	137,064	21,848	21,824
4	GS-3,IS-1	1,224.41	21,352	26,143	26,114
5	LP-4	6,480.88	866	5,614	5,608
6	IS-P	7,837.65	34	269	269
7	LP-5	26,070.64	95	2,477	2,474
8	IS-T	26,432.96	33	862	861
9	LP-6	42,585.61	4	175	175
10	LPEP	86,427.11	1	89	89
11	ISA	335,997.52	1	346	346
12	GH	1,195.57	3,611	4,317	4,312
13	SL/AL	0	1,270	0	0
14	L5-S	36,125.41	6	210	210
15	TOTAL PPUC		1,330,588	245,226	244,958
16	RES 69		9	197	197
17	RES 12		9	72	72
18	TOTAL RESALE		18	268	268
19	TOTAL SYSTEM		1,330,606	245,494	245,227

Line No.

PPL ELECTRIC UTILITIES CORPORATION

ALLOCATION OF METERING COSTS

METER READING EXPENSE (CW2)

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

METER READING EXPENSE 10,418,001

Line No.	RATE CLASS	PRORATION OF EXPENSE: CUSTOMERS	PRORATED EXPENSE	INDICATED COSTS	CUSTOMERS	AVERAGE METER READING EXPENSE $/CUSTOMER/YEAR
1	RS	1,151,910	9,027,509	9,027,509	1,151,910	7.84
2	RTS	14,342	112,398	112,398	14,342	7.84
3	GS-1,BL	137,064	1,074,171	1,074,171	137,064	7.84
4	GS-3,IS-1	21,352	167,332	167,332	21,352	7.84
5	LP-4	866	6,789	6,789	866	7.84
6	ISP	34	269	269	34	7.84
7	LP-5	95	745	745	95	7.84
8	IST	33	256	256	33	7.84
9	LP-6	4	32	32	4	7.84
10	LPEP	1	8	8	1	7.84
11	ISA	1	8	8	1	7.84
12	GH	3,611	28,298	28,298	3,611	7.84
13	SL/AL	0	0	0	0	0.00
14	L5-S	6	46	46	6	7.84
15	TOTAL PPUC	1,329,318	10,417,860	10,417,860	1,329,318	
	RES 69	9	71	71	9	7.84
	RES 12	9	71	71	9	7.84
	TOTAL RESALE	18	141	141	18	
16	TOTAL SYSTEM	1,329,336	10,418,001	10,418,001	1,329,336	

PPL ELECTRIC UTILITIES CORPORATION

DETERMINATION OF METER READING ALLOCATOR (CW2)

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

Line No.	RATE CLASS	AVERAGE METER READING EXPENSE $/CUST/YEAR	CUSTOMERS	INDICATED METER READING EXPENSE	ALLOCATOR CW2
1	RS	7.84	1,151,910	9,027.51	9,027,502
2	RTS	7.84	14,342	112.40	112,400
3	GS-1,BL	7.84	137,064	1,074.17	1,074,169
4	GS-3,IS-1	7.84	21,352	167.33	167,330
5	LP-4	7.84	866	6.79	6,790
6	IS-P	7.84	34	0.27	270
7	LP-5	7.84	95	0.74	740
8	IS-T	7.84	33	0.26	260
9	LP-6	7.84	4	0.03	30
10	LPEP	7.84	1	0.01	10
11	ISA	7.84	1	0.01	10
12	GH	7.84	3,611	28.30	28,300
13	SL/AL	0.00	0	0	0
14	L5-S	7.84	6	0.05	50
15	TOTAL PPUC		1,329,318	10,418	10,417,861
16	RES 66	7.84	9	0.07	70
17	RES 12	7.84	9	0.07	70
18	TOTAL RESALE		18	0.14	140
19	TOTAL SYSTEM		1,329,336	10,418	10,418,001

Line No.

PPL ELECTRIC UTILITIES CORPORATION

ALLOCATOR CW4 FOR USE WITH LATE PAYMENTS (ACCOUNT 450)

ALLOCATOR CW5 FOR USE WITH UNCOLLECTIBLE ACCOUNTS (ACCOUNT 904)

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004
($000)

	RATE CLASS	LATE PAYMENTS CW4	LATE PAYMENTS PROPOSED LEVEL	ALLOCATOR CW5
1	RS/RTD	3,486	3,834	16,499
2	RTS	32	36	62
3	GS-1,BL	994	1,093	797
4	GS-3,IS-1	1,004	1,105	954
5	LP-4	271	298	210
6	ISP	7	7	162
7	LP-5	83	0	133
8	IST	20	0	223
9	LP-6	9	0	0
10	LPEP	0	0	0
11	ISA	0	0	0
12	GH	52	57	29
13	SL/AL	40	44	256
14	L5-S	0	0	0
15	TOTAL PPUC	5,998	6,474	19,327
16	RES66	0		
17	RES12	2		
18	TOTAL RESALE	2		
19	TOTAL	6,000		

PPL ELECTRIC UTILITIES CORPORATION

CUSTOMER DEPOSITS ALLOCATORS CW6 AND CW6A

CUSTOMER ADVANCES FOR CONSTRUCTION ALLOCATOR CW7

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004
($000)

Line No.	RATE CLASS	TRANSMISSION RELATED CUSTOMER DEPOSITS CW6A (1)		DISTRIBUTION RELATED CUSTOMER DEPOSITS CW6 (1)		CUSTOMER ADVANCES CW7 (2)
1	RS,RTD		0	10,074		0
2	RTS		0	79		0
3	GS-1,BL		0	1,977		137,064
4	GS-3,IS-1		0	2,467		21,352
5	LP-4		0	341		0
6	IS-P		0	0		0
7	LP-5		0	20		0
8	IS-T		0	0		0
9	LP-6		0	0		0
10	LPEP		0	0		0
11	ISA		0	1,000		0
12	GH		0	60		0
13	SL/AL		0	22		0
14	L5-S		0	0		0
15	TOTAL PPUC		0	16,039		158,416
16	RES 66		0	0		0
17	RES 12		0	0		0
18	TOTAL RESALE		0	0		0
19	TOTAL SYSTEM		0	16,039	16,039	158,416
				Increase - Rebuttal	4,424	
				Revised Total - Rebuttal	20,463	

SOURCE: (1) PER STUDY OF ACCOUNT 235 (CUSTOMER DEPOSITS)
(2) BASED ON NUMBER OF CUSTOMERS ON GS-1 AND GS-3

Line No.

PPL ELECTRIC UTILITIES CORPORATION

SECONDARY CUSTOMER COMPONENT STUDY

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

Line No.		BASIC DATA	TOTAL SYSTEM	RS	RTS	GS-1,BL	GS-3,IS-1	GH	SL/AL
1	SINGLE PHASE EQUIVALENT CUSTOMERS		1,280,510	1,143,769	14,068	115,812	3,329	2,262	1,270
2	TWO PHASE EQUIVALENT CUSTOMERS		18,735	15,053	116	3,464	75	27	---
3	THREE PHASE EQUIVALENT CUSTOMERS		42,943	136	-	22,948	18,536	1,323	---
4	TOTAL EQUIVALENT CUSTOMERS		1,342,188	1,158,958	14,184	142,224	21,940	3,612	1,270

CW8 - CUSTOMER COMPONENT ALLOCATOR FOR ACCOUNT 368 (LINE TRANSFORMERS CUSTOMER COMPONENT)

Line No.		WEIGHTING FACTOR							
5	SINGLE PHASE CUSTOMERS	1.00	1,280,483	1,143,769	14,068	115,812	3,329	2,262	1,243
6	TWO PHASE EQUIVALENT CUSTOMERS	1.52	28,477	22,881	176	5,265	114	41	---
7	THREE PHASE CUSTOMERS	2.24	96,192	305	-	51,404	41,521	2,964	---
8	WEIGHTED ALLOCATOR	---	1,405,153	1,166,954	14,244	172,481	44,964	5,267	1,243

CW9 - CUSTOMER COMPONENT ALLOCATOR FOR ACCOUNT 369 (SERVICES CUSTOMER COMPONENT)

Line No.		WEIGHTING FACTOR							
9	SINGLE PHASE (3 WIRES)	1.000	1,279,240	1,143,769	14,068	115,812	3,329	2,262	---
10	TWO PHASE EQUIVALENT CUSTOMERS	1.725	32,318	25,966	200	5,975	129	47	---
11	THREE PHASE (4 WIRES)	1.725	74,077	235	-	39,585	31,975	2,282	---
12	WEIGHTED ALLOCATOR	---	1,385,635	1,169,970	14,268	161,373	35,433	4,591	-

Line No.

PPL ELECTRIC UTILITIES CORPORATION

DETERMINATION OF ENERGY ALLOCATORS

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

Line No.	RATE CLASS	ANNUAL SALES MWH ES15	ANNUALIZATION ADJUSTMENT MWH	ANNUALIZED SALES CUSTOMER LEVEL MWH ES15A	GENERATION LEVEL MWH EG10
1	RS	12,899,883	122,532	13,022,415	14,248,466
2	RTS	399,999	6,663	406,662	444,948
3	GS-1,BL	2,034,025	25,167	2,059,192	2,253,063
4	GS-3,IS-1	8,732,335	84,073	8,816,408	9,646,466
5	LP-4	5,567,372	-174,114	5,393,258	5,731,772
6	ISP	404,108	11,647	415,755	441,850
7	LP-5	3,348,588	-111,337	3,237,251	3,338,846
8	IST	1,944,598	159,333	2,103,931	2,169,959
9	LP-6	511,847	-3,545	508,302	524,254
10	LPEP	72,000	-7,661	64,339	66,358
11	ISA	242,640	-15,201	227,439	234,577
12	GH	413,115	18,440	431,555	472,185
13	SL/AL	111,595	-324	111,271	121,747
14	LS-S	7,024	234	7,258	7,486
15	TOTAL PPUC	36,689,129	115,907	36,805,036	39,701,978

Line No.

PPL ELECTRIC UTILITIES CORPORATION

DEMAND ALLOCATORS - MW
GENERATION LEVEL
FOR COST ALLOCATION PURPOSES
YEAR ENDED DECEMBER 31, 2004

Line No.	RATE CLASS	12-CP DEMANDS TRANSMISSION LEVEL	PRIMARY LEVEL	RATE CLASS MAXIMUM DEMANDS	DEMAND ALLOCATOR AT THE SECONDARY LEVEL
		D10	D20		D30
1	RS	2,320,941	2,819,810	2,819,810	2,819,810
2	RTS	80,283	217,071	217,071	217,071
3	GS-1,BL	377,743	566,500	566,500	566,500
4	GS-3,IS-1	1,465,094	1,760,092	1,760,092	1,760,092
5	LP-4	829,643	939,736	939,736	0
6	ISP	50,183	58,511	58,511	0
7	LP-5	491,779	0	576,230	0
8	IST	219,103	0	292,143	0
9	LP-6	71,650	0	85,908	0
10	LPEP	15,237	0	31,222	0
11	ISA	35,568	0	90,451	0
12	GH	58,982	112,013	112,013	112,013
13	SL/AL	12,782	27,441	27,441	27,441
14	LS-S	625	0	11,836	0
15	TOTAL PPUC	6,029,612	6,501,173	7,588,962	5,502,926
16	RES 66	141,192	0	167,294	
17	RES 12	33,589	38,473	38,473	
18	TOTAL RESALE	174,781	38,473	205,767	
19		6,204,393	6,539,645	7,794,729	

Line No.

PPL ELECTRIC UTILITIES CORPORATION

DEMAND ALLOCATORS - MW

AVERAGE & EXCESS RESPONSIBILITY METHOD

FOR COST ALLOCATION PURPOSES

YEAR ENDED DECEMBER 31, 2004

Line No.	RATE CLASS	ALLOCATOR	(1) GENERATION LEVEL ANNUAL ENERGY MWH	(2) AVERAGE ANNUAL DEMAND	(3) CLASS MAXIMUM DEMANDS(NCD)	(4) CLASS EXCESS (3) - (2)	(5) ADJUSTED CLASS EXCESS 1/.	(6) AVERAGE & EXCESS (2) + (5) D10	(7) PRIMARY LEVEL D20
1	RS,RTD		14,248,466	1,626,537	2,819,810	1,193,273	918,077	2,544,614	2,544,614
2	RTS		444,948	50,793	217,071	166,278	127,930	178,723	178,723
3	GS-1,BL		2,253,063	257,199	566,500	309,301	237,969	495,168	495,168
4	GS-3,IS-1		9,646,466	1,101,195	1,760,092	658,897	506,940	1,608,135	1,608,135
5	LP-4		5,731,772	654,312	939,736	285,424	219,599	873,911	873,911
6	IS-P		441,850	50,440	58,511	8,071	6,209	56,649	56,649
7	LP-5		3,338,846	381,147	576,230	195,083	150,093	531,240	0
8	IS-T		2,169,959	247,712	292,143	44,431	34,184	281,896	0
9	LP-6		524,254	59,846	85,908	26,062	20,051	79,897	0
10	LPEP		66,358	7,575	31,222	23,647	18,194	25,769	0
11	ISA		234,577	26,778	90,451	63,673	48,988	75,766	0
12	GH		472,185	53,902	112,013	58,111	44,709	98,611	98,611
13	SL/AL		121,747	13,898	27,441	13,543	10,420	24,318	24,318
14	LS-S		7,486	855	11,836	10,981	8,449	9,304	0
15	TOTAL PPUC		39,701,978	4,532,189	7,588,962	3,056,773	2,351,811	6,884,001	5,880,129

1/ COLUMN 5 = COLUMN 4 RATIOED TO TOTAL THE DIFFERENCE OF THE ANNUAL PEAK LESS TOTAL AVERAGE ANUUAL DEMAND

2004 VALUES

6,884,000	PEAK MONTH
4,532,189	AVERAGE DEMAND
2,351,811	EXCESS

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00049255

PPL Electric Utilities Corporation

Exhibit JMK-Remand 3

PPL ELECTRIC UTILITIES CORPORATION

Exhibit JMK 1
Cost Allocation Study
Test Year Ended December 31, 2006

Witness: Joseph M. Kleha
Docket No. R-00072155

PPL ELECTRIC UTILITIES CORPORATION
COST ALLOCTION DETAILS - 12 MONTH ENDED 12/31/2006
OPERATING REVENUES AND EXPENSES, RETURN, RATE OF RETURN, AND CLASS RATE % OF TOTAL
$1,000

Line No.		Output	Pa Jurisdict Distribution	RS	RTS	GS-1	GS-3	LP-4	ISP	LP-5
	OPERATING REVENUES AT PRESENT RATE LEVELS									
	SALES OF ELECTRICITY									
1	TRANSMISSION REVENUES		0	0	0	0	0	0	0	0
2	DISTRIBUTION REVENUES		624,995	367,273	3,744	75,825	115,387	31,755	1,825	1,972
3	TOTAL SALE OF ELECTRICITY	RRT	624,995	367,273	3,744	75,825	115,387	31,755	1,825	1,972
4	*LATE PAY CHARGES PRESENT RATES*	*R11*	*10,107*	*6,598*	*52*	*1,339*	*1,288*	*472*	*24*	*187*
5	TOTAL ADJUSTED SALES OF ELECTRICITY	RRTT	635,102	373,871	3,796	77,164	116,675	32,227	1,849	2,159
6	ANNUALIZATION PRESENT REVENUES	ANN	1,163	1,048	(82)	(289)	40	330	(56)	(44)
7	*ADJUSTMENT - RATE REFUND*		*(1,124)*	*(798)*	*(22)*	*(112)*	*(121)*	*(29)*	*(2)*	*(1)*
8	ANNUAL ADJ'D SALE OF ELECT	ARTT	635,141	374,123	3,692	76,763	116,594	32,528	1,791	2,114
9	OTHER OPERATING REVENUES	ROOT	34,831	22,432	659	3,119	5,203	1,274	65	51
10	TOTAL OPERATING REVENUES	ROT	669,972	396,555	4,351	79,882	121,797	33,802	1,856	2,165
	OPERATING EXPENSES									
	OPERATION AND MAINTENENCE EXPENSES									
11	TRANSMISSION	EE20	0	0	0	0	0	0	0	0
12	DISTRIBUTION	EE30	141,811	88,578	2,687	12,196	21,228	6,024	305	248
13	OTHER OPER & MAINT EXPENSES	EEOT	207,094	160,398	2,838	15,799	17,848	3,977	198	206
14	TOTAL OPER & MAINT EXPENSES	EE00	348,905	248,976	5,525	27,995	39,076	10,001	503	454
	DEPRECIATION EXPENSE									
15	TRANSMISSION	ED20	0	0	0	0	0	0	0	0
16	DISTRIBUTION	ED30	84,152	54,372	1,618	7,563	12,158	2,867	142	281
17	OTHER DEPREC EXP	EDOT	11,761	8,299	193	1,106	1,332	317	16	10
18	TOTAL DEPRECIATION AND AMORTIZATION EXPENSE	ED00A	95,913	62,671	1,811	8,669	13,490	3,184	158	291
	TAXES									
19	CAPITAL STOCK PRESENT LEVEL	ET1	2,840	1,849	53	256	421	105	6	5
20	OTHER OTHER TAXES	ET001	9,201	6,290	160	849	1,170	285	15	11
21	DEFERRED INCOME TAXES	TXTA	10,029	6,306	193	858	1,611	399	21	18
22	NET INVESTMENT TAX CREDIT	TX93	(1,713)	(1,109)	(32)	(154)	(250)	(61)	(3)	(3)
23	GROSS RECEIPTS TAX	TXG	37,540	22,120	219	4,536	6,886	1,921	106	125
24	TOTAL PA INCOME TAX	TSIT1	9,032	(100)	(503)	3,002	4,830	1,522	92	108
25	TOTAL FED INC TAX	TFTX	30,742	1,465	(1,512)	9,570	15,372	4,814	288	343
26	TOTAL TAXES	TFIT1	97,671	36,823	(1,422)	18,917	30,040	8,985	525	607
27	TOTAL OPERATING EXPENSES	*TEXP1*	*542,489*	348,470	5,914	55,581	82,606	22,170	1,186	1,352
28	RETURN (LN 10 - 27)	PRERTN	127,483	48,083	(1,563)	24,301	39,191	11,632	670	813
29	TOTAL RATE BASE	*RBX*	*1,924,884*	1,258,062	36,872	170,842	283,667	71,963	3,636	3,248
30	RATE OF RETURN (LN 28 / LN 29)	PRRTR	6.62%	3.82%	-4.24%	14.22%	13.82%	16.16%	18.43%	25.03%
31	CLASS RATE IN % OF TOTAL	PRCLRT	100.00%	57.70%	-64.05%	214.80%	208.76%	244.11%	278.40%	378.10%

PPL ELECTRIC UTILITIES CORPORATION
COST ALLOCTION DETAILS - 12 MONTH ENDED 12/31/2006
OPERATING REVENUES AND EXPENSES, RETURN, RATE OF RETURN, AND CLASS RATE % OF TOTAL
$1,000

Line No.		Output	IST	LP-6	LPEP	ISA	GH	SL/AL	L5-S	Large Power Summary
	OPERATING REVENUES AT PRESENT RATE LEVELS									
	SALES OF ELECTRICITY									
1	TRANSMISSION REVENUES		0	0	0	0	0	0	0	0
2	DISTRIBUTION REVENUES		1,338	177	463	576	7,052	17,559	49	4,575
3	TOTAL SALE OF ELECTRICITY	RRT	1,338	177	463	576	7,052	17,559	49	4,575
4	*LATE PAY CHARGES PRESENT RATES*	R11	*30*	*0*	*0*	*0*	61	*55*	1	*218*
5	TOTAL ADJUSTED SALES OF ELECTRICITY	RRTT	1,368	177	463	576	7,113	17,614	50	4,793
6	ANNUALIZATION PRESENT REVENUES	ANN	438	16	3	49	112	(399)	(2)	460
7	ADJUSTMENT - RATE REFUND		0	0	(1)	0	(9)	(31)	0	(2)
8	ANNUAL ADJ'D SALE OF ELECT	ARTT	1,806	193	465	625	7,216	17,184	48	5,251
9	OTHER OPERATING REVENUES	ROOT	13	5	27	3	373	1,606	1	100
10	TOTAL OPERATING REVENUES	ROT	1,819	198	492	628	7,589	18,790	49	5,351
	OPERATING EXPENSES									
	OPERATION AND MAINTENENCE EXPENSES									
11	TRANSMISSION	EE20	0	0	0	0	0	0	0	0
12	DISTRIBUTION	EE30	66	24	15	15	1,534	8,883	8	376
13	OTHER OPER & MAINT EXPENSES	EEOT	38	14	78	8	1,308	4,380	4	348
14	TOTAL OPER & MAINT EXPENSES	EE00	104	38	93	23	2,842	13,263	12	724
	DEPRECIATION EXPENSE									
15	TRANSMISSION	ED20	0	0	0	0	0	0	0	0
16	DISTRIBUTION	ED30	75	27	47	17	956	4,020	9	456
17	OTHER DEPREC EXP	EDOT	3	1	7	1	98	376	0	22
18	TOTAL DEPRECIATION AND AMORTIZATION EXPENSE	ED00A	78	28	54	18	1,054	4,396	9	478
	TAXES									
19	CAPITAL STOCK PRESENT LEVEL	ET1	1	0	1	0	30	112	0	7
20	OTHER OTHER TAXES	ET001	4	2	5	0	85	324	0	22
21	DEFERRED INCOME TAXES	TXTA	5	1	8	3	115	483	1	36
22	NET INVESTMENT TAX CREDIT	TX93	(1)	0	(1)	0	(18)	(81)	0	(5)
23	GROSS RECEIPTS TAX	TXG	107	11	27	37	426	1,016	3	310
24	TOTAL PA INCOME TAX	TSIT1	147	10	27	54	222	(383)	2	348
25	TOTAL FED INC TAX	TFTX	460	32	86	168	719	(1,071)	6	1,095
26	TOTAL TAXES	TFIT1	723	56	153	262	1,579	400	12	1,813
27	TOTAL OPERATING EXPENSES	TEXP1	905	122	300	303	5,475	18,059	33	3,015
28	RETURN (LN 10 - 27)	PRERTN	914	76	192	325	2,114	731	16	2,336
29	TOTAL RATE BASE	RBX	868	311	842	199	20,723	73,546	102	5,570
30	RATE OF RETURN (LN 28 / LN 29)	PRRTR	105.30%	24.44%	22.80%	163.32%	10.20%	0.99%	15.69%	41.94%
31	CLASS RATE IN % OF TOTAL	PRCLRT	1590.63%	369.18%	344.41%	2467.07%	154.08%	14.95%	237.01%	633.53%

PPL ELECTRIC UTILITIES CORPORATION
COST ALLOCATION DETAILS - 12 MONTHS ENDED 12/31/2006
OPERATING REVENUES AT PROPOSED RATE LEVELS
$1,000

Line No.		Output	Pa Jurisdict Distribution	RS	RTS	GS-1	GS-3	LP-4	ISP	LP-5
	OPERATING REVENUES AT PROPOSED RATE LEVELS									
	SALES OF ELECTRICITY									
1	TRANSMISSION REVENUES		0	0	0	0	0	0	0	0
2	DISTRIBUTION REVENUES		624,995	367,273	3,744	75,825	115,387	31,755	1,825	1,972
3	2007 REVENUE INCREASE		81,735	75,438	886	838	556	(326)	(111)	(127)
4	TOTAL SALE OF ELECTRICITY	RRTP	706,730	442,711	4,630	76,663	115,943	31,429	1,714	1,845
5	LATE PAY CHARGES	R11P	10,107	6,598	52	1,339	1,288	472	24	187
6	TOT ADJUSTED SALE OF ELECTRICITY	RRTTP	716,837	449,309	4,682	78,002	117,231	31,901	1,738	2,032
7	ANNUALIZATION ADJUSTMENT	ANNP	1,164	1,048	(82)	(289)	40	330	(56)	(44)
8	ADJUSTMENT - RATE REFUND		(1,124)	(796)	(22)	(112)	(121)	(29)	(2)	(1)
9	ADJUSTED SALE OF ELECTRICITY	ARTTP	716,877	449,561	4,578	77,601	117,150	32,202	1,680	1,987
10	OTHER OPERATING REVENUES	ROOT	34,831	22,432	659	3,119	5,203	1,274	65	51
11	TOTAL OPERATING REVENUES	ROTP	751,708	471,993	5,237	80,720	122,353	33,476	1,745	2,038
	OPERATING EXPENSES									
	OPERATION AND MAINTENANCE EXPENSES									
12	TRANSMISSION	EE20	0	0	0	0	0	0	0	0
13	DISTRIBUTION	EE30	141,811	88,578	2,687	12,196	21,228	6,024	305	248
14	OTHER OPER & MAINT EXPENSES	EEOT	207,597	160,854	2,841	15,820	17,860	3,978	198	207
15	TOTAL OPER & MAINT EXPENSES	EE00	349,408	249,432	5,528	28,016	39,088	10,002	503	455
	DEPRECIATION EXPENSE									
16	TRANSMISSION	ED20	0	0	0	0	0	0	0	0
17	DISTRIBUTION	ED30	84,152	54,369	1,618	7,563	12,158	2,867	142	281
18	OTHER DEPRECIATION EXPENSE	EDOT	11,761	8,304	193	1,106	1,332	317	16	10
19	TOTAL DEPRECIATION AND AMORTIZATION EXPENSE	ED00	95,913	62,673	1,811	8,669	13,490	3,184	158	291
	TAXES									
20	CAPITAL STOCK PROP LEVEL	ET1P	3,087	2,010	58	278	458	115	6	5
21	OTHER-W/O CAP STOCK	ET001	9,168	6,268	159	847	1,165	283	15	11
22	DEFERRED INCOME TAXES	TXTA	10,029	6,317	193	858	1,611	399	21	18
23	NET INVESTMENT TAX CREDIT	TX93	(1,713)	(1,109)	(32)	(154)	(250)	(61)	(3)	(3)
24	GROSS RECEIPTS TAX	TXG	42,362	26,571	271	4,585	6,919	1,902	99	117
25	TOTAL PA INCOME TAX	TSIT1	16,642	6,933	(421)	3,077	4,878	1,490	81	96
26	TOTAL FED INC TAX	TFTX	54,748	23,647	(1,251)	9,805	15,523	4,715	255	306
27	TOTAL TAXES	TFIT1	134,323	70,637	(1,023)	19,296	30,304	8,843	474	550
28	TOTAL OPERATING EXPENSES	TEXP1	579,644	382,742	6,316	55,981	82,882	22,029	1,135	1,296
29	**RETURN (LN 11 - 28)**	PRERTN	172,064	89,244	(1,079)	24,739	39,471	11,447	610	742
30	**TOTAL RATE BASE**	RBX	1,924,884	1,258,062	36,873	170,842	283,667	71,963	3,636	3,248
31	**RATE OF RETURN (LN 29 / LN 30)**	PRRTR	8.94%	7.09%	-2.93%	14.48%	13.91%	15.91%	16.78%	22.84%
32	**CLASS RATE IN % OF TOTAL**	PRCLRT	100.00%	79.31%	-32.77%	161.97%	155.59%	177.96%	187.70%	255.48%

PPL ELECTRIC UTILITIES CORPORATION
COST ALLOCATION DETAILS - 12 MONTHS ENDED 12/31/2006
OPERATING REVENUES AT PROPOSED RATE LEVELS
$1,000

Line No.		Output	IST	LP-6	LPEP	ISA	GH	SL/AL	L5-S
	OPERATING REVENUES AT PROPOSED RATE LEVEL								
	SALES OF ELECTRICITY								
1	TRANSMISSION REVENUES		0	0	0	0	0	0	0
2	DISTRIBUTION REVENUES		1,338	177	463	576	7,052	17,559	49
3	2007 REVENUE INCREASE		(89)	(7)	0	4	515	4,155	3
4	TOTAL SALE OF ELECTRICITY	RRTP	1,249	170	463	580	7,567	21,714	52
5	LATE PAY CHARGES	R11P	30	0	0	0	61	55	1
6	TOT ADJUSTED SALE OF ELECTRICITY	RRTTP	1,279	170	463	580	7,628	21,769	53
7	ANNUALIZATION ADJUSTMENT	ANNP	438	16	3	49	112	(399)	(2)
8	ADJUSTMENT - RATE REFUND		0	0	(1)	0	(9)	(31)	0
9	ADJUSTED SALE OF ELECTRICITY	ARTTP	1,717	186	465	629	7,731	21,339	51
10	OTHER OPERATING REVENUES	ROOT	13	5	27	3	373	1,606	1
11	TOTAL OPERATING REVENUES	ROTP	1,730	191	492	632	8,104	22,945	52
	OPERATING EXPENSES								
	OPERATION AND MAINTENANCE EXPENSES								
12	TRANSMISSION	EE20	0	0	0	0	0	0	0
13	DISTRIBUTION	EE30	66	24	15	15	1,534	8,883	8
14	OTHER OPER & MAINT EXPENSES	EEOT	38	14	78	8	1,309	4,380	4
15	TOTAL OPER & MAINT EXPENSES	EE00	104	38	93	23	2,843	13,263	12
	DEPRECIATION EXPENSE								
16	TRANSMISSION	ED20	0	0	0	0	0	0	0
17	DISTRIBUTION	ED30	75	27	47	17	956	4,020	9
18	OTHER DEPRECIATION EXPENSE	EDOT	3	1	7	1	98	376	0
19	TOTAL DEPRECIATION AND AMORTIZATION EXPENSE	ED00	78	28	54	18	1,054	4,396	9
	TAXES								
20	CAPITAL STOCK PROP LEVEL	ET1P	1	0	1	0	33	121	0
21	OTHER-W/O CAP STOCK	ET001	4	2	5	0	85	323	0
22	DEFERRED INCOME TAXES	TXTA	5	1	8	3	115	483	1
23	NET INVESTMENT TAX CREDIT	TX93	(1)	0	(1)	0	(18)	(81)	0
24	GROSS RECEIPTS TAX	TXG	101	11	27	37	457	1,261	3
25	TOTAL PA INCOME TAX	TSIT1	139	9	27	54	270	7	2
26	TOTAL FED INC TAX	TFTX	433	30	86	169	870	158	7
27	TOTAL TAXES	TFIT1	682	53	153	263	1,812	2,272	13
28	TOTAL OPERATING EXPENSES	TEXP1	864	119	300	304	5,709	19,931	34
29	**RETURN (LN 11 - 28)**	PRERTN	866	72	192	328	2,395	3,014	18
30	**TOTAL RATE BASE**	RBX	868	311	842	199	20,723	73,546	102
31	**RATE OF RETURN (LN 29 / LN 30)**	PRRTR	99.77%	23.15%	22.80%	164.82%	11.56%	4.10%	17.65%
32	**CLASS RATE IN % OF TOTAL**	PRCLRT	1116.00%	258.95%	255.03%	1843.62%	129.31%	45.86%	197.43%

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00049255

PPL Electric Utilities Corporation

Exhibit JMK-Remand 4

PPL ELECTRIC UTILITIES CORPORATION

Exhibit JMK 2
Cost Allocation Study
Test Year Ending December 31, 2007

Witness: Joseph M. Kleha
Docket No. R-00072155

PPL ELECTRIC UTILITIES CORPORATION
COST ALLOCATION DETAILS - 12 MONTHS ENDED 12/31/2007
PRESENT OPERATING REVENUES AND EXPENSES, RETURN, RATE OF RETURN, AND CLASS RATE % OF TOTAL
$1,000

Line No.		Output	Pa Jurisdict Distribution	RS	RTS	GS-1	GS-3	LP-4	ISP	LP-5
	OPERATING REVENUES AT PRESENT RATE LEVELS									
	SALES OF ELECTRICITY									
1	TRANSMISSION REVENUES		0	0	0	0	0	0	0	0
2	DISTRIBUTION REVENUES		631,715	376,667	3,705	75,559	116,079	30,559	1,818	1,719
3	LATE PAY CHARGES PRESENT RATES	R11	8,923	5,825	46	1,182	1,137	417	21	165
4	SALE OF ELECTRICITY	RRT	640,638	382,492	3,751	76,741	117,216	30,976	1,839	1,884
5	ANNUALIZATION PRESENT REVENUES	ANN	1,724	2,357	(18)	(92)	386	(298)	74	(51)
6	**ANNUAL ADJ'D SALE OF ELECT**		642,362	384,849	3,733	76,649	117,602	30,678	1,913	1,833
7	ADJUSTMENT - RATE REFUND		(1,124)	(796)	(22)	(112)	(121)	(29)	(2)	(1)
8	ADJUSTED ELECTRIC SALES	0	641,238	384,053	3,711	76,537	117,481	30,649	1,911	1,832
9	OTHER OPERATING REVENUES	ROOT	32,379	20,849	614	2,897	4,841	1,187	60	46
10	TOTAL OPERATING REVENUES	ROT	673,617	404,902	4,325	79,434	122,322	31,836	1,971	1,878
	OPERATING EXPENSES									
	OPERATION AND MAINTENENCE EXPENSES									
11	TRANSMISSION	EE20	0	0	0	0	0	0	0	0
12	DISTRIBUTION	EE30	134,943	84,304	2,561	11,604	20,197	5,733	290	238
13	OTHER OPER & MAINT EXPENSES	EEOT	204,612	159,095	2,773	15,605	17,144	3,889	194	198
14	TOTAL OPER & MAINT EXPENSES	EE00	339,555	243,399	5,334	27,209	37,341	9,622	484	436
	DEPRECIATION EXPENSE									
15	TRANSMISSION	ED20	0	0	0	0	0	0	0	0
16	DISTRIBUTION	ED30	88,481	57,271	1,706	7,966	12,764	2,995	148	300
17	OTHER DEPREC EXP	EDOT	23,343	16,256	396	2,178	2,760	656	34	29
18	TOTAL DEPRECIATION AND AMORTIZATION EXPENSE	ED00A	111,824	73,527	2,102	10,144	15,524	3,651	182	329
	TAXES									
19	CAPITAL STOCK PRESENT LEVEL	ET1	2,295	1,495	43	206	340	86	4	4
20	OTHER OTHER TAXES	ET001	9,654	6,586	170	891	1,237	301	15	11
21	DEFERRED INCOME TAXES	TXTA	8,378	5,564	150	715	1,179	284	15	13
22	NET INVESTMENT TAX CREDIT	TX93	(1,673)	(1,083)	(31)	(150)	(244)	(60)	(3)	(2)
23	GROSS RECEIPTS TAX	TXG	37,900	22,706	220	4,522	6,939	1,810	113	108
24	TOTAL PA INCOME TAX	TSIT1	9,599	701	(499)	2,972	4,993	1,365	104	82
25	TOTAL FED INC TAX	TFTX	32,452	4,005	(1,493)	9,462	15,798	4,315	325	260
26	TOTAL TAXES	TFIT1	98,605	39,974	(1,440)	18,618	30,242	8,101	573	476
27	TOTAL OPERATING EXPENSES	TEXP1	549,984	356,900	5,996	55,971	83,107	21,374	1,239	1,241
28	RETURN (LN 10 - 27)	PRERTN	123,633	48,002	(1,671)	23,463	39,215	10,462	732	637
29	TOTAL RATE BASE	RBX	2,022,963	1,321,699	38,737	179,448	298,479	75,648	3,836	3,072
30	RATE OF RETURN (LN 28 / LN 29)	PRRTR	6.11%	3.63%	-4.31%	13.08%	13.14%	13.83%	19.08%	20.74%
31	CLASS RATE IN % OF TOTAL	PRCLRT	100.00%	59.41%	-70.54%	214.08%	215.06%	226.35%	312.27%	339.44%

PPL ELECTRIC UTILITIES CORPORATION
COST ALLOCATION DETAILS - 12 MONTHS ENDED 12/31/2007
PRESENT OPERATING REVENUES AND EXPENSES, RETURN, RATE OF RETURN, AND CLASS RATE % OF TOTAL
$1,000

Line No.		Output	IST	LP-6	LPEP	ISA	GH	SL/AL	L5-S
	OPERATING REVENUES AT PRESENT RATE LEVELS								
	SALES OF ELECTRICITY								
1	TRANSMISSION REVENUES		0	0	0	0	0	0	0
2	DISTRIBUTION REVENUES		739	139	332	538	7,109	16,707	45
3	LATE PAY CHARGES PRESENT RATES	R11	26	0	0	0	54	49	1
4	SALE OF ELECTRICITY	RRT	765	139	332	538	7,163	16,756	46
5	ANNUALIZATION PRESENT REVENUES	ANN	12	16	3	36	(61)	(625)	(13)
6	**ANNUAL ADJ'D SALE OF ELECT**		777	155	335	574	7,102	16,131	33
7	ADJUSTMENT - RATE REFUND		0	0	(1)	0	(9)	(31)	0
8	ADJUSTED ELECTRIC SALES	0	777	155	334	574	7,093	16,100	33
9	OTHER OPERATING REVENUES	ROOT	12	4	24	3	347	1,494	1
10	TOTAL OPERATING REVENUES	ROT	789	159	358	577	7,440	17,594	34
	OPERATING EXPENSES								
	OPERATION AND MAINTENENCE EXPENSES								
11	TRANSMISSION	EE20	0	0	0	0	0	0	0
12	DISTRIBUTION	EE30	64	23	14	14	1,466	8,427	8
13	OTHER OPER & MAINT EXPENSES	EEOT	34	13	74	8	1,265	4,314	4
14	TOTAL OPER & MAINT EXPENSES	EE00	98	36	88	22	2,731	12,741	12
	DEPRECIATION EXPENSE								
15	TRANSMISSION	ED20	0	0	0	0	0	0	0
16	DISTRIBUTION	ED30	80	29	46	19	1,010	4,137	9
17	OTHER DEPREC EXP	EDOT	7	3	12	1	207	804	1
18	TOTAL DEPRECIATION AND AMORTIZATION EXPENSE	ED00A	87	32	58	20	1,217	4,941	10
	TAXES								
19	CAPITAL STOCK PRESENT LEVEL	ET1	1	0	1	0	24	90	0
20	*OTHER OTHER TAXES*	ET001	4	2	5	0	92	343	0
21	DEFERRED INCOME TAXES	TXTA	4	1	7	0	82	364	1
22	*NET INVESTMENT TAX CREDIT*	TX93	(1)	0	(1)	0	(17)	(79)	0
23	GROSS RECEIPTS TAX	TXG	46	9	20	34	419	952	2
24	TOTAL PA INCOME TAX	TSIT1	51	6	16	49	213	(450)	1
25	TOTAL FED INC TAX	TFTX	159	21	50	152	687	(1,284)	2
26	TOTAL TAXES	TFIT1	264	39	98	235	1,500	(64)	6
27	*TOTAL OPERATING EXPENSES*	TEXP1	449	107	244	277	5,448	17,618	28
28	RETURN (LN 10 - 27)	PRERTN	340	52	114	300	1,992	(24)	6
29	TOTAL RATE BASE	RBX	820	294	821	190	21,654	78,174	94
30	RATE OF RETURN (LN 28 / LN 29)	PRRTR	41.46%	17.69%	13.89%	157.89%	9.20%	-0.03%	6.38%
31	CLASS RATE IN % OF TOTAL	PRCLRT	678.56%	289.53%	227.33%	2584.12%	150.57%	-0.49%	104.42%

PPL ELECTRIC UTILITIES CORPORATION
COST ALLOCATION DETAILS - 12 MONTHS ENDED 12/31/2007
PROPOSED REVENUES AND EXPENSES, RETURN, RATE OF RETURN AND CLASS RATE % OF TOTAL
$1,000

Line No.		Output	Pa Jurisdict Distribution	RS	RTS	GS-1	GS-3	LP-4	ISP	LP-5
	OPERATING REVENUES AT PROPOSED RATE LEVELS									
	SALES OF ELECTRICITY									
1	TRANSMISSION REVENUES		0	0	0	0	0	0	0	0
2	DISTRIBUTION REVENUES		631,715	376,667	3,705	75,559	116,079	30,559	1,818	1,719
3	LATE PAYMENT CHARGES	R11P	8,923	5,825	46	1,182	1,137	417	21	165
4	ANNUALIZATION ADJUSTMENT	ANNP	1,726	2,357	(18)	(92)	386	(298)	74	(51)
5	TOTAL SALE OF ELECTRICITY	RRTP	642,364	384,849	3,733	76,649	117,602	30,678	1,913	1,833
6	PROPOSED REVENUE INCREASE		83,521	77,329	944	845	612	(391)	(107)	(135)
7	ANNUAL ADJ'D SALE OF ELECT		725,885	462,178	4,677	77,494	118,214	30,287	1,806	1,698
8	ADJUSTMENT - RATE REFUND		(1,124)	(796)	(22)	(112)	(121)	(29)	(2)	(1)
9	ADJUSTED ELECTRIC SALES & LATE PAYMEN	ARTTP	724,761	461,382	4,655	77,382	118,093	30,258	1,804	1,697
10	OTHER OPERATING REVENUES	ROOT	32,379	20,849	614	2,897	4,841	1,187	60	46
11	TOTAL OPERATING REVENUES	ROTP	757,140	482,231	5,269	80,279	122,934	31,445	1,864	1,743
	OPERATING EXPENSES									
	OPERATION AND MAINTENANCE EXPENSES									
12	TRANSMISSION	EE20	0	0	0	0	0	0	0	0
13	DISTRIBUTION	EE30	134,943	84,304	2,561	11,604	20,197	5,733	290	238
14	OTHER OPER & MAINT EXPENSES	EEOT	205,281	159,714	2,775	15,633	17,160	3,890	194	199
15	TOTAL OPER & MAINT EXPENSES	EE00	340,224	244,018	5,336	27,237	37,357	9,623	484	437
	DEPRECIATION EXPENSE									
16	TRANSMISSION	ED20	0	0	0	0	0	0	0	0
17	DISTRIBUTION	ED30	88,481	57,271	1,706	7,966	12,764	2,995	148	300
18	OTHER DEPRECIATION EXPENSE	EDOT	23,343	16,256	396	2,178	2,760	656	34	29
19	TOTAL DEPRECIATION AND AMORTIZATION EXPENSE	ED00	111,824	73,527	2,102	10,144	15,524	3,651	182	329
	TAXES									
20	CAPITAL STOCK PROP LEVEL	ET1P	2,517	1,640	47	226	373	95	4	4
21	OTHER-W/O CAP STOCK	ET001	9,654	6,583	170	891	1,237	301	15	11
22	DEFERRED INCOME TAXES	TXTA	8,378	5,564	150	715	1,179	284	15	13
23	NET INVESTMENT TAX CREDIT	TX93	(1,673)	(1,083)	(31)	(150)	(244)	(60)	(3)	(2)
24	GROSS RECEIPTS TAX	TXG	42,827	27,269	276	4,572	6,975	1,787	107	100
25	TOTAL PA INCOME TAX	TSIT1	17,362	7,891	(411)	3,046	5,045	1,327	94	69
26	TOTAL FED INC TAX	TFTX	56,934	26,689	(1,215)	9,697	15,964	4,196	293	220
27	TOTAL TAXES	TFIT1	135,999	74,549	(1,014)	18,997	30,529	7,930	525	415
28	TOTAL OPERATING EXPENSES	TEXP1	588,047	392,094	6,424	56,378	83,410	21,204	1,191	1,181
29	**RETURN (LN 11 - 28)**	PRERTN	169,093	90,137	(1,155)	23,901	39,524	10,241	673	562
30	**TOTAL RATE BASE**	RBX	2,022,963	1,321,695	38,737	179,448	298,479	75,648	3,836	3,072
31	**RATE OF RETURN (LN 29 / LN 30)**	PRRTR	8.36%	6.82%	-2.98%	13.32%	13.24%	13.54%	17.54%	18.29%
32	**CLASS RATE IN % OF TOTAL**	PRCLRT	100.00%	81.58%	-35.65%	159.33%	158.37%	161.96%	209.81%	218.78%

PPL ELECTRIC UTILITIES CORPORATION
COST ALLOCATION DETAILS - 12 MONTHS ENDED 12/31/2007
PROPOSED REVENUES AND EXPENSES, RETURN, RATE OF RETURN AND CLASS RATE % OF TOTAL
$1,000

Line No.		Output	IST	LP-6	LPEP	ISA	GH	SL/AL	L5-S
	OPERATING REVENUES AT PROPOSED RATE LEVELS								
	SALES OF ELECTRICITY								
1	TRANSMISSION REVENUES		0	0	0	0	0	0	0
2	DISTRIBUTION REVENUES		739	139	332	538	7,109	16,707	45
3	LATE PAYMENT CHARGES	R11P	26	0	0	0	54	49	1
4	ANNUALIZATION ADJUSTMENT	ANNP	12	16	3	36	(61)	(625)	(13)
5	TOTAL SALE OF ELECTRICITY	RRTP	777	155	335	574	7,102	16,131	33
6	PROPOSED REVENUE INCREASE		(127)	(5)	(1)	6	542	4,007	2
7	ANNUAL ADJ'D SALE OF ELECT		650	150	334	580	7,644	20,138	35
8	ADJUSTMENT - RATE REFUND		0	0	(1)	0	(9)	(31)	0
9	ADJUSTED ELECTRIC SALES & LATE PAYMEN	ARTTP	650	150	333	580	7,635	20,107	35
10	OTHER OPERATING REVENUES	ROOT	12	4	24	3	347	1,494	1
11	TOTAL OPERATING REVENUES	ROTP	662	154	357	583	7,982	21,601	36
	OPERATING EXPENSES								
	OPERATION AND MAINTENANCE EXPENSES								
12	TRANSMISSION	EE20	0	0	0	0	0	0	0
13	DISTRIBUTION	EE30	64	23	14	14	1,466	8,427	8
14	OTHER OPER & MAINT EXPENSES	EEOT	34	13	74	8	1,266	4,314	4
15	TOTAL OPER & MAINT EXPENSES	EE00	98	36	88	22	2,732	12,741	12
	DEPRECIATION EXPENSE								
16	TRANSMISSION	ED20	0	0	0	0	0	0	0
17	DISTRIBUTION	ED30	80	29	46	19	1,010	4,137	9
18	OTHER DEPRECIATION EXPENSE	EDOT	7	3	12	1	207	804	1
19	TOTAL DEPRECIATION AND AMORTIZATION EXPENSE	ED00	87	32	58	20	1,217	4,941	10
	TAXES								
20	CAPITAL STOCK PROP LEVEL	ET1P	1	0	1	0	27	98	0
21	OTHER-W/O CAP STOCK	ET001	4	2	5	0	92	343	0
22	DEFERRED INCOME TAXES	TXTA	4	1	7	0	82	364	1
23	NET INVESTMENT TAX CREDIT	TX93	(1)	0	(1)	0	(17)	(79)	0
24	GROSS RECEIPTS TAX	TXG	38	9	20	34	451	1,188	2
25	TOTAL PA INCOME TAX	TSIT1	39	6	16	50	263	(74)	1
26	TOTAL FED INC TAX	TFTX	121	19	50	154	847	(99)	2
27	TOTAL TAXES	TFIT1	206	37	98	238	1,745	1,741	6
28	TOTAL OPERATING EXPENSES	TEXP1	391	105	244	280	5,694	19,423	28
29	**RETURN (LN 11 - 28)**	PRERTN	271	49	113	303	2,288	2,178	8
30	**TOTAL RATE BASE**	RBX	820	294	821	190	21,654	78,174	94
31	**RATE OF RETURN (LN 29 / LN 30)**	PRRTR	33.05%	16.67%	13.76%	159.47%	10.57%	2.79%	8.51%
32	**CLASS RATE IN % OF TOTAL**	PRCLRT	395.33%	199.40%	164.59%	1907.54%	126.44%	33.37%	101.79%

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00049255

PPL Electric Utilities Corporation

Exhibit JMK-Remand 5

ATTACHMENT 1

Pennsylvania Power & Light Company

Exhibit AJB 3

Cost Allocation Study
Present and Proposed Rate Levels
Future Period - Year Ending July 31, 1983

Docket No. R-822169

Witness: Andrew J. Baldwin

PENNSYLVANIA POWER & LIGHT COMPANY
COST ALLOCATION - YEAR ENDED JULY 31, 1983
SUMMARY OF RESULTS AT PRESENT RATE LEVEL
$1,000

FUTURE TEST YEAR

JURISDICTIONAL COST ALLOCATION
CAPACITY ALLOCATION METHOD-MONTHLY PEAK RESPONSIBILITY

			TOTAL PENNA. JURISDICT	RS	GS-1	GS-3	LP-4
1	ELECTRIC PLANT IN SERVICE	P00	4,338,888	1,808,543	309,571	772,902	503,143
2	RESERVE FOR DEPRECIATION	A00	852,081	381,112	63,135	144,229	88,447
3	NET PLANT IN SERVICE	P01	3,486,807	1,427,431	246,436	628,673	414,696
4	ELECT PLANT HELD FOR FUT USE	PF00	11,819	4,626	825	2,236	1,562
5	POLLUTION CONTROL PROJECTS	PC00	2,572	897	169	498	358
6	ASSOCIATED RETIREMENTS	PCR0	0	0	0	0	0
7	NET ADDITIONS AND DEDUCTIONS	NAD	14,391	5,523	994	2,734	1,920
8	DEPRECIATED ELECTRIC PLANT	TEP	3,501,198	1,432,954	247,430	631,407	416,616
9	CASH WORKING CAPITAL	CWC	26,039	10,465	1,477	4,535	3,284
10	FUEL STOCK AND MATERIALS						
11	AND SUPPLIES	WCD	193,598	74,668	9,661	34,580	25,524
12	TOTAL WORKING CAPITAL	W00	219,637	85,133	11,138	39,115	28,808
13	ACCUM DEFERRED INCOME TAXES	DF99	129,973	51,601	9,848	24,023	15,718
14	CUSTOMER ADVANCES	CA00	163	85	17	48	2
15	CUSTOMER DEPOSITS	DA00	1,841	285	800	543	62
16	TOTAL DEDUCTIONS	PLDED	131,977	51,971	10,665	24,614	15,782
17	MEASURES OF VALUE (RATE BASE)	RBX	3,588,858	1,466,116	247,903	645,908	429,642
18	REV FROM SALES - BASE & ECR	R104	1,159,777	469,891	82,411	218,192	139,637
19	OTHER OPERATING REVENUES	OOR	26,502	8,612	1,123	4,383	1,979
20	TOTAL OPERATING REVENUES	R00	1,186,279	478,503	83,534	222,575	141,616
21	OPERATION & MAINTENANCE EXP	EE00	633,735	273,355	39,354	104,481	74,327
22	DEPRECIATION EXPENSE	ED00	107,731	48,484	7,941	18,139	11,118
23	TAXES OTHER THAN INCOME	OTT	46,243	19,586	3,261	8,225	5,310
24	FEDERAL INCOME TAXES	FTAX1	2,976	-6,625	2,561	8,333	742
25	STATE INCOME TAXES	STAX1	3,362	38	616	1,890	482
26	DEFERRED INCOME TAXES - NET	TXD31	75,107	26,772	5,068	14,449	10,219
27	ITC PROV PRESENT RATES	TXD35	8,544	3,561	609	1,523	991
28	INVEST TAX CREDIT AMORT	TXD38	-3,061	-1,276	-219	-544	-355
29	TOTAL TAXES	TEX1	133,171	42,057	11,895	33,876	17,388
30	AMORTIZATION OF PROPERTY LOSS	TXD21	682	238	45	132	95
31	TOTAL OPERATING EXPENSES	TEXP1	875,319	364,134	59,235	156,628	102,928
32	OPERATING INCOME	PRERTN	310,960	114,369	24,299	65,947	38,688
33	RATE OF RETURN - %	PRRTR	8.66	7.80	9.80	10.21	9.00
34	CLASS RATE IN % OF TOTAL	PRCLRT	100.0	90.0	113.1	117.8	103.9

PENNSYLVANIA POWER & LIGHT COMPANY
COST ALLOCATION - YEAR ENDED JULY 31, 1983
SUMMARY OF RESULTS AT PRESENT RATE LEVEL
$1,000

JURISDICTIONAL COST ALLOCATION
CAPACITY ALLOCATION METHOD-MONTHLY PEAK RESPONSIBILITY

FUTURE TEST YEAR

			LP-5	LP-6	GH	STREET AND AREA LIGHTING
1	ELECTRIC PLANT IN SERVICE	P00	173,653	431,547	284,322	55,207
2	RESERVE FOR DEPRECIATION	A00	29,173	72,336	53,620	20,029
3	NET PLANT IN SERVICE	P01	144,480	359,211	230,702	35,178
4	ELECT PLANT HELD FOR FUT USE	PF00	490	1,223	812	45
5	POLLUTION CONTROL PROJECTS	PC00	135	335	180	0
6	ASSOCIATED RETIREMENTS	PCR0	0	0	0	0
7	NET ADDITIONS AND DEDUCTIONS	NAD	625	1,558	992	45
8	DEPRECIATED ELECTRIC PLANT	TEP	145,105	360,769	231,694	35,223
9	CASH WORKING CAPITAL	CWC	1,165	3,441	1,422	250
10	FUEL STOCK AND MATERIALS					
11	AND SUPPLIES	WC0	9,057	28,026	10,285	1,797
12	TOTAL WORKING CAPITAL	W00	10,222	31,467	11,707	2,047
13	ACCUM DEFERRED INCOME TAXES	DF99	5,625	12,803	9,281	1,074
14	CUSTOMER ADVANCES	CA00	0	7	0	4
15	CUSTOMER DEPOSITS	DA00	54	0	95	2
16	TOTAL DEDUCTIONS	PLDED	5,679	12,810	9,376	1,080
17	MEASURES OF VALUE (RATE BASE)	RBX	149,648	379,426	234,025	36,190
18	REV FROM SALES - BASE & ECR	R104	46,800	127,229	58,419	17,198
19	OTHER OPERATING REVENUES	OOR	254	7,730	1,974	447
20	TOTAL OPERATING REVENUES	R00	47,054	134,959	60,393	17,645
21	OPERATION & MAINTENANCE EXP	EE00	25,931	75,488	33,400	7,399
22	DEPRECIATION EXPENSE	ED00	3,691	9,162	6,746	2,450
23	TAXES OTHER THAN INCOME	OTT	1,791	4,894	2,564	612
24	FEDERAL INCOME TAXES	FTAX1	-851	645	-3,714	1,885
25	STATE INCOME TAXES	STAX1	-9	429	-412	328
26	DEFERRED INCOME TAXES - NET	TXD31	3,823	9,396	5,277	103
27	ITC PROV PRESENT RATES	TXD35	342	850	559	109
28	INVEST TAX CREDIT AMORT	TXD38	-123	-305	-200	-39
29	TOTAL TAXES	TEX1	4,974	15,909	4,072	3,000
30	AMORTIZATION OF PROPERTY LOSS	TXD21	35	89	48	0
31	TOTAL OPERATING EXPENSES	TEXP1	34,631	100,648	44,266	12,849
32	OPERATING INCOME	PRERTN	12,423	34,311	16,127	4,796
33	RATE OF RETURN - %	PRRTR	8.30	9.04	6.89	13.25
34	CLASS RATE IN % OF TOTAL	PRCLRT	95.8	104.4	79.5	153.0

PENNSYLVANIA POWER & LIGHT COMPANY
COST ALLOCATION - YEAR ENDED JULY 31, 1983
SUMMARY OF RESULTS AT PROPOSED RATE LEVEL
$1,000

JURISDICTIONAL COST ALLOCATION
CAPACITY ALLOCATION METHOD-MONTHLY PEAK RESPONSIBILITY

FUTURE TEST YEAR

			TOTAL PENNA. JURISDICT	RS	GS-1	GS-3	LP-4
1	ELECTRIC PLANT IN SERVICE	P00	4,338,888	1,808,543	309,571	772,902	503,143
2	RESERVE FOR DEPRECIATION	A00	852,081	381,112	63,135	144,229	88,447
3	NET PLANT IN SERVICE	P01	3,486,807	1,427,431	246,436	628,673	414,696
4	ELECT PLANT HELD FOR FUT USE	PF00	11,819	4,626	825	2,236	1,562
5	POLLUTION CONTROL PROJECTS	PC00	2,572	897	169	498	358
6	ASSOCIATED RETIREMENTS	PCR0	0	0	0	0	0
7	NET ADDITIONS AND DEDUCTIONS	NAD	14,391	5,523	994	2,734	1,920
8	DEPRECIATED ELECTRIC PLANT	TEP	3,501,198	1,432,954	247,430	631,407	416,616
9	CASH WORKING CAPITAL	CWC	26,039	10,465	1,477	4,535	3,284
10	FUEL STOCK AND MATERIALS						
11	AND SUPPLIES	WCD	193,598	74,668	9,661	34,580	25,524
12	TOTAL WORKING CAPITAL	W00	219,637	85,133	11,138	39,115	28,808
13	ACCUM DEFERRED INCOME TAXES	DF99	129,973	51,601	9,848	24,023	15,718
14	CUSTOMER ADVANCES	CA00	163	85	17	48	2
15	CUSTOMER DEPOSITS	DA00	1,841	285	800	543	62
16	TOTAL DEDUCTIONS	PLDED	131,977	51,971	10,665	24,614	15,782
17	MEASURES OF VALUE (RATE BASE)	RBX	3,588,858	1,466,116	247,903	645,908	429,642
18	REV FROM SALES - BASE & ECR	R104P	1,451,306	586,944	103,466	273,382	174,888
19	OTHER OPERATING REVENUES	OORP	31,041	9,729	1,244	5,151	2,282
20	TOTAL OPERATING REVENUES	R00P	1,482,347	596,673	104,710	278,533	177,170
21	OPERATION & MAINTENANCE EXP	EE00	633,735	273,355	39,354	104,481	74,327
22	DEPRECIATION EXPENSE	ED00	107,731	48,484	7,941	18,139	11,118
23	TAXES OTHER THAN INCOME	OTTP	53,036	22,306	3,746	9,501	6,126
24	FEDERAL INCOME TAXES	FTAX2	21,543	-1,079	3,908	12,990	3,405
25	STATE INCOME TAXES	STAX2	23,545	8,093	2,059	5,706	2,905
26	DEFERRED INCOME TAXES - NET	TXD31	75,107	26,772	5,068	14,449	10,219
27	INVEST TAX CR PROV PROP RATES	ITCP	113,759	47,417	8,115	20,266	13,192
28	INVEST TAX CREDIT AMORT	TXD38	-3,061	-1,276	-219	-544	-355
29	TOTAL TAXES	TEX2	283,929	102,233	22,678	62,366	35,493
30	AMORTIZATION OF PROPERTY LOSS	TXD21	682	238	45	132	95
31	TOTAL OPERATING EXPENSES	TEXP2	1,026,077	424,310	70,018	185,118	121,033
32	OPERATING INCOME	PPRTN	456,270	172,363	34,692	93,415	56,137
33	RATE OF RETURN - %	PPRTR	12.71	11.76	13.99	14.46	13.07
34	CLASS RATE IN % OF TOTAL	PPCLRT	100.0	92.5	110.1	113.8	102.8
35	SAME AT PRESENT RATES	PRCLRT	100.0	90.0	113.1	117.8	103.9

PENNSYLVANIA POWER & LIGHT COMPANY
COST ALLOCATION - YEAR ENDED JULY 31, 1983
SUMMARY OF RESULTS AT PROPOSED RATE LEVEL
$1,000

JURISDICTIONAL COST ALLOCATION
CAPACITY ALLOCATION METHOD-MONTHLY PEAK RESPONSIBILITY

FUTURE TEST YEAR

			LP-5	LP-6	GH	STREET AND AREA LIGHTING
1	ELECTRIC PLANT IN SERVICE	P00	173,653	431,547	284,322	55,207
2	RESERVE FOR DEPRECIATION	A00	29,173	72,336	53,620	20,029
3	NET PLANT IN SERVICE	P01	144,480	359,211	230,702	35,178
4	ELECT PLANT HELD FOR FUT USE	PF00	490	1,223	812	45
5	POLLUTION CONTROL PROJECTS	PC00	135	335	180	0
6	ASSOCIATED RETIREMENTS	PCR0	0	0	0	0
7	NET ADDITIONS AND DEDUCTIONS	NAD	625	1,558	992	45
8	DEPRECIATED ELECTRIC PLANT	TEP	145,105	360,769	231,694	35,223
9	CASH WORKING CAPITAL	CWC	1,165	3,441	1,422	250
10	FUEL STOCK AND MATERIALS					
11	AND SUPPLIES	WC0	9,057	28,026	10,285	1,797
12	TOTAL WORKING CAPITAL	W00	10,222	31,467	11,707	2,047
13	ACCUM DEFERRED INCOME TAXES	DF99	5,625	12,803	9,281	1,074
14	CUSTOMER ADVANCES	CA00	0	7	0	4
15	CUSTOMER DEPOSITS	DA00	54	0	95	2
16	TOTAL DEDUCTIONS	PLDED	5,679	12,810	9,376	1,080
17	MEASURES OF VALUE (RATE BASE)	RBX	149,648	379,426	234,025	36,190
18	REV FROM SALES - BASE & ECR	R104P	58,276	159,364	73,990	20,996
19	OTHER OPERATING REVENUES	OORP	259	9,522	2,344	510
20	TOTAL OPERATING REVENUES	R00P	58,535	168,886	76,334	21,506
21	OPERATION & MAINTENANCE EXP	EE00	25,931	75,488	33,400	7,399
22	DEPRECIATION EXPENSE	ED00	3,691	9,162	6,746	2,450
23	TAXES OTHER THAN INCOME	OTTP	2,057	5,662	2,940	698
24	FEDERAL INCOME TAXES	FTAX2	-263	4,369	-3,949	2,162
25	STATE INCOME TAXES	STAX2	774	2,742	674	592
26	DEFERRED INCOME TAXES - NET	TXD31	3,823	9,396	5,277	103
27	INVEST TAX CR PROV PROP RATES	ITCP	4,553	11,315	7,454	1,447
28	INVEST TAX CREDIT AMORT	TXD38	-123	-305	-200	-39
29	TOTAL TAXES	TEX2	10,820	33,180	12,195	4,964
30	AMORTIZATION OF PROPERTY LOSS	TXD21	35	89	48	0
31	TOTAL OPERATING EXPENSES	TEXP2	40,477	117,919	52,389	14,813
32	OPERATING INCOME	PPRTN	18,058	50,967	23,945	6,693
33	RATE OF RETURN - %	PPRTR	12.07	13.43	10.23	18.49
34	CLASS RATE IN % OF TOTAL	PPCLRT	94.9	105.7	80.5	145.5
35	SAME AT PRESENT RATES	PRCLRT	95.8	104.4	79.5	153.0

ATTACHMENT 2

Pennsylvania Power & Light Company

Exhibit AJB 3

Cost Allocation Study
Present and Proposed Rates
Year Ending March 31, 1985

Docket No. R-842651

Witness: Andrew J. Baldwin

PENNSYLVANIA POWER & LIGHT COMPANY
COST ALLOCATION SUMMARY - YEAR ENDING MARCH 31, 1985 PART 3
COMPONENTS OF OPERATING EXPENSES @ PRESENT RATES
WITH RESULTING RETURN, RATE OF RETURN, AND CLASS RATE % OF TOTAL FUTURE TEST YEAR
JURISDICTIONAL COST ALLOCATION $1,000
CAPACITY ALLOCATION METHOD-MONTHLY PEAK RESPONSIBILITY

		INPUT	ALLOC	OUTPUT	TOTAL PENNA. JURISDICT	RS	GS-1	GS-3	LP-4
1	PRESENT REVENUES								
2	RATE REVENUE	RR			1,360,106	546,370	99,640	260,380	163,617
3	ENERGY COST RATE	ECR			88,200	32,030	4,265	15,924	12,295
4	PENNSYLVANIA TAX SURCHARGE	SCR			0	0	0	0	0
5	JC ADJUSTMENT	JCR			-50,213	-18,235	-2,428	-9,065	-7,000
6	REV FROM SALES - BASE & ECR			R104	1,398,093	560,165	101,477	267,239	168,912
7	ANNUALIZATION @ PRES RATES			ANN	-87	2,197	303	-1,517	-657
8	LATE PAY CHGS @ PRES RATES			LPC	3,592	1,214	936	833	223
9	OTHER OPERATING REVENUES			R21	10,269	5,096	842	1,680	910
10	TOTAL OPERATING REVENUES			R00	1,411,867	568,672	103,558	268,235	169,388
11	OPERATING EXPENSE - PRESENT REVENUES								
12	O&M: PROD-FUEL			EOPF1	587,615	218,114	28,993	107,189	80,671
13	" " -INTERCH & PURCH			EOPI1	-364,599	-136,313	-16,589	-65,965	-50,015
14	" " -OTHER			EOPO1	220,301	79,787	13,704	41,291	30,323
15	" " -TOTAL			EE10T	443,317	161,588	26,108	82,515	60,979
16	" TRANSMISSION			EE20	10,917	3,851	826	2,103	1,507
17	" DISTRIBUTION			EE30	77,228	41,552	7,097	12,063	5,076
18	" OTHER			EOMT1	143,396	79,971	11,744	18,643	11,706
19	" TOTAL			EE00	674,858	286,962	45,775	115,324	79,268
20	DEPREC EXP: PRODUCTION			ED10	66,464	23,445	5,029	12,806	9,173
21	" " TRANSMISSION			ED20	6,742	2,378	511	1,299	930
22	" " DISTRIBUTION			ED30	47,321	26,044	4,182	7,529	2,725
23	" " OTHER			E088	3,015	1,401	246	491	313
24	" " TOTAL			ED00	123,542	53,268	9,968	22,125	13,141
25	MISCELLANEOUS			TXD21	342	121	26	65	48
26	TAXES: DEF INC TAXES-NET			TXD31	101,089	36,356	7,681	19,374	13,685
27	" OTH-CAP STOCK TAX			ET1	12,189	4,751	955	2,286	1,515
28	" OTH-W/O CAP STOCK TAX			ET001	17,254	7,899	1,313	2,835	1,837
29	" GROSS RECEIPTS			GRT	28,032	11,272	2,054	5,331	3,369
30	" NET ITC-PRES RATES			TXD69	29,794	13,421	2,458	5,309	3,005
31	" PA & FED INC TAXES			FSTAX1	11,585	-835	887	10,094	1,803
32	" TOTAL			TEX1	199,943	72,864	15,348	45,229	25,214
33	TOTAL OPERATING EXP-PRES REV			TEXP1	998,685	413,215	71,117	182,743	117,671
34	RETURN (LN 10 - 33) PRES REV			PRERTN	413,182	155,457	32,441	85,492	51,717
35	RATE OF RETURN (LN 34 / RBX)			PRRTR	8.92	8.59	9.06	9.86	8.97
36	CLASS RATE IN % OF TOTAL			PRCLRT	100.0	96.4	101.6	110.6	100.6
37	TOTAL RATE BASE			RBX	4,634,314	1,809,277	358,243	867,335	576,425

PENNSYLVANIA POWER & LIGHT COMPANY
COST ALLOCATION SUMMARY - YEAR ENDING MARCH 31, 1985 PART 3
COMPONENTS OF OPERATING EXPENSES @ PRESENT RATES
WITH RESULTING RETURN, RATE OF RETURN, AND CLASS RATE % OF TOTAL FUTURE TEST YEAR
JURISDICTIONAL COST ALLOCATION $1,000
CAPACITY ALLOCATION METHOD-MONTHLY PEAK RESPONSIBILITY

		INPUT	ALLOC	OUTPUT	LP-5	LP-6	LP-5/LP-6	GH	STREET AND AREA LIGHTING
1	PRESENT REVENUES								
2	RATE REVENUE	RR			60,103	161,159	221,262	51,353	17,484
3	ENERGY COST RATE	ECR			5,152	14,809	19,961	3,255	470
4	PENNSYLVANIA TAX SURCHARGE	SCR			0	0	0	0	0
5	JC ADJUSTMENT	JCR			-2,933	-8,431	-11,364	-1,853	-268
6	REV FROM SALES - BASE & ECR			R104	62,322	167,537	229,859	52,755	17,686
7	ANNUALIZATION @ PRES RATES			ANN	-73	181	108	-539	18
8	LATE PAY CHGS @ PRES RATES			LPC	52	129	181	160	45
9	OTHER OPERATING REVENUES			R21	269	664	933	515	293
10	TOTAL OPERATING REVENUES			R00	62,570	168,511	231,081	52,891	18,042
11	OPERATING EXPENSE - PRESENT REVENUES								
12	O&M: PROD-FUEL			EOPF1	32,900	94,758	127,658	21,794	3,196
13	" " -INTERCH & PURCH			EOPI1	-20,499	-60,493	-80,992	-12,452	-2,273
14	" " -OTHER			EOPO1	12,164	32,084	44,248	10,336	612
15	" " -TOTAL			EE10T	24,565	66,349	90,914	19,678	1,535
16	" TRANSMISSION			EE20	594	1,411	2,005	625	0
17	" DISTRIBUTION			EE30	834	1,813	2,647	4,061	4,732
18	" OTHER			EOMT1	4,178	10,462	14,640	5,300	1,392
19	" TOTAL			EE00	30,171	80,035	110,206	29,664	7,659
20	DEPREC EXP: PRODUCTION			ED10	3,615	8,594	12,209	3,802	0
21	" " TRANSMISSION			ED20	367	872	1,239	385	0
22	" " DISTRIBUTION			ED30	424	966	1,390	2,525	2,926
23	" " OTHER			ED88	112	267	379	150	35
24	" " TOTAL			ED00	4,518	10,699	15,217	6,862	2,961
25	MISCELLANEOUS			TXD21	18	44	62	20	0
26	TAXES: DEF INC TAXES-NET			TXD31	5,338	12,697	18,035	5,763	195
27	" OTH-CAP STOCK TAX			ET1	557	1,325	1,882	692	108
28	" OTH-W/O CAP STOCK TAX			ET001	669	1,678	2,347	811	212
29	" GROSS RECEIPTS			GRT	1,247	3,356	4,603	1,048	355
30	" NET ITC-PRES RATES			TXD69	939	2,220	3,159	1,662	780
31	" PA & FED INC TAXES			FSTAX1	365	6,435	6,800	-8,212	1,048
32	" TOTAL			TEX1	9,115	27,712	36,827	1,763	2,698
33	TOTAL OPERATING EXP-PRES REV			TEXP1	43,822	118,490	162,312	38,309	13,318
34	RETURN (LN 10 - 33) PRES REV			PRERTN	18,748	50,021	68,769	14,582	4,724
35	RATE OF RETURN (LN 34 / RBX)			PRRTR	8.82	9.84	9.54	5.60	11.30
36	CLASS RATE IN % OF TOTAL			PRCLRT	99.0	110.3	107.0	62.9	126.7
37	TOTAL RATE BASE			RBX	212,468	508,560	721,028	260,203	41,803

PENNSYLVANIA POWER & LIGHT COMPANY
COST ALLOCATION SUMMARY - YEAR ENDING MARCH 31, 1985
COMPONENTS OF OPERATING EXPENSES @ PROPOSED RATES
WITH RESULTING RETURN, RATE OF RETURN, AND CLASS RATE % OF TOTAL

PART 3

FUTURE TEST YEAR

JURISDICTIONAL COST ALLOCATION $1,000
CAPACITY ALLOCATION METHOD-MONTHLY PEAK RESPONSIBILITY

		INPUT	ALLOC	OUTPUT	TOTAL PENNA. JURISDICT	RS	GS-1	GS-3	LP-4
1	PROPOSED REVENUES								
2	RATE REVENUE	RRP			1,727,233	701,643	128,267	322,074	210,161
3	ENERGY COST RATE	ECRP			0	0	0	0	0
4	PENNSYLVANIA TAX SURCHARGE	SCRP			0	0	0	0	0
5	REV FROM SALES - BASE & ECR			R104P	1,727,233	701,643	128,267	322,074	210,161
6	ANNUALIZATION @ PROP RATES			ANNP	-74	2,752	383	-1,828	-818
7	LATE PAY CHGS @ PROP RATES			LPCP	4,438	1,500	1,157	1,029	275
8	OTHER OPERATING REVENUES			R21	10,269	5,096	842	1,680	910
9	TOTAL OPERATING REVENUES			R00P	1,741,866	710,991	130,649	322,955	210,528
10	OPERATING EXPENSE - PROPOSED REVENUES								
11	O&M: PROD-FUEL			EOPF1	587,615	218,114	28,993	107,189	80,671
12	" " -INTERCH & PURCH			EOPI1	-364,599	-136,313	-16,589	-65,965	-50,015
13	" " -OTHER			EOPO1	220,301	79,787	13,704	41,291	30,323
14	" " -TOTAL			EE1OT	443,317	161,588	26,108	82,515	60,979
15	" TRANSMISSION			EE20	10,917	3,851	826	2,103	1,507
16	" DISTRIBUTION			EE30	77,228	41,552	7,097	12,063	5,076
17	" OTHER			EOMT1	143,396	79,971	11,744	18,643	11,706
18	" TOTAL			EE00	674,858	286,962	45,775	115,324	79,268
19	DEPREC EXP: PRODUCTION			ED10	66,464	23,445	5,029	12,806	9,173
20	" " TRANSMISSION			ED20	6,742	2,378	511	1,299	930
21	" " DISTRIBUTION			ED30	47,321	26,044	4,182	7,529	2,725
22	" " OTHER			ED88	3,015	1,401	246	491	313
23	" " TOTAL			ED00	123,542	53,268	9,968	22,125	13,141
24	MISCELLANEOUS			TXD21	342	121	26	65	48
25	TAXES: DEF INC TAXES-NET			TXD31	101,089	36,356	7,681	19,374	13,685
26	" OTH-CAP STOCK TAX			ET22	13,180	5,112	1,031	2,475	1,647
27	" OTH-W/O CAP STOCK TAX			ET0022	17,254	7,899	1,313	2,835	1,837
28	" GROSS RECEIPTS			GRTP	34,632	14,118	2,596	6,426	4,192
29	" NET ITC-ADJ PROP RATE			TXD79	143,777	57,109	11,328	26,752	17,413
30	" PA & FED INC TAXES			FSTAX2	54,774	23,449	4,937	14,627	6,980
31	" TOTAL			TEX2	364,706	144,043	28,886	72,488	45,755
32	TOTAL OPERATING EXP-PROP REV			TEXP2	1,163,448	484,394	84,655	210,002	138,212
33	RETURN (LN 9 - 32) PROP REV			PPRTN	578,418	226,597	45,994	112,953	72,316
34	RATE OF RETURN (LN 33 / RBX)			PPRTR	12.48	12.52	12.84	13.02	12.55
35	CLASS RATE IN % OF TOTAL			PPCLRT	100.0	100.3	102.9	104.3	100.5
36	TOTAL RATE BASE			RBX	4,634,314	1,809,277	358,243	867,335	576,425

PENNSYLVANIA POWER & LIGHT COMPANY
COST ALLOCATION SUMMARY - YEAR ENDING MARCH 31, 1985
COMPONENTS OF OPERATING EXPENSES @ PROPOSED RATES
WITH RESULTING RETURN, RATE OF RETURN, AND CLASS RATE % OF TOTAL

PART 3

FUTURE TEST YEAR

JURISDICTIONAL COST ALLOCATION $1,000
CAPACITY ALLOCATION METHOD-MONTHLY PEAK RESPONSIBILITY

		INPUT	ALLOC.	OUTPUT	LP-5	LP-6	LP-5/LP-6	GH	STREET AND AREA LIGHTING
1	PROPOSED REVENUES								
2	RATE REVENUE	RRP			76,544	200,123	276,667	69,414	19,007
3	ENERGY COST RATE	ECRP			0	0	0	0	0
4	PENNSYLVANIA TAX SURCHARGE	SCRP			0	0	0	0	0
5	REV FROM SALES - BASE & ECR			R104P	76,544	200,123	276,667	69,414	19,007
6	ANNUALIZATION @ PROP RATES			ANNP	-90	216	126	-709	20
7	LATE PAY CHGS @ PROP RATES			LPCP	65	158	223	199	55
8	OTHER OPERATING REVENUES			R21	269	664	933	515	293
9	TOTAL OPERATING REVENUES			R00P	76,788	201,161	277,949	69,419	19,375
10	OPERATING EXPENSE - PROPOSED REVENUES								
11	O&M: PROD-FUEL			EOPF1	32,900	94,758	127,658	21,794	3,196
12	" " -INTERCH & PURCH			EOPI1	-20,499	-60,493	-80,992	-12,452	-2,273
13	" " -OTHER			EOPO1	12,164	32,084	44,248	10,336	612
14	" " -TOTAL			EE10T	24,565	66,349	90,914	19,678	1,535
15	" TRANSMISSION			EE20	594	1,411	2,005	625	0
16	" DISTRIBUTION			EE30	834	1,813	2,647	4,061	4,732
17	" OTHER			EOMT1	4,178	10,462	14,640	5,300	1,392
18	" TOTAL			EE00	30,171	80,035	110,206	29,664	7,659
19	DEPREC EXP: PRODUCTION			ED10	3,615	8,594	12,209	3,802	0
20	" " TRANSMISSION			ED20	367	872	1,239	385	0
21	" " DISTRIBUTION			ED30	424	966	1,390	2,525	2,926
22	" " OTHER			ED88	112	267	379	150	35
23	" " TOTAL			ED00	4,518	10,699	15,217	6,862	2,961
24	MISCELLANEOUS			TXD21	18	44	62	20	0
25	TAXES: DEF INC TAXES-NET			TXD31	5,338	12,697	18,035	5,763	195
26	" OTH-CAP STOCK TAX			ET22	609	1,447	2,056	748	111
27	" OTH-W/O CAP STOCK TAX			ET0022	669	1,678	2,347	811	212
28	" GROSS RECEIPTS			GRTP	1,530	4,010	5,540	1,378	382
29	" NET ITC-ADJ PROP RATE			TXD79	6,324	15,006	21,330	8,134	1,711
30	" PA & FED INC TAXES			FSTAX2	1,735	9,145	10,880	-6,837	738
31	" TOTAL			TEX2	16,205	43,983	60,188	9,998	3,348
32	TOTAL OPERATING EXP-PROP REV			TEXP2	50,912	134,761	185,673	46,544	13,968
33	RETURN (LN 9 - 32) PROP REV			PPRTN	25,876	66,400	92,276	22,875	5,407
34	RATE OF RETURN (LN 33 / RBX)			PPRTR	12.18	13.06	12.80	8.79	12.93
35	CLASS RATE IN % OF TOTAL			PPCLRT	97.6	104.6	102.5	70.4	103.6
36	TOTAL RATE BASE			RBX	212,468	508,560	721,028	260,203	41,803

ATTACHMENT 3

PENNSYLVANIA POWER & LIGHT COMPANY

EXHIBIT JMK 1

SUMMARY OF COST ALLOCATION STUDY RESULTS

RATES APPROVED AT Docket No. R-00943271

FUTURE TEST YEAR ENDED SEPTEMBER 30, 1995

The summaries contained in this section present the results of the detailed allocations of Pennsylvania jurisdictional costs at approved rates for the future test period contained in Section III. The summaries consist of an array of customer class income statements and the relationships of class operating incomes (or returns) to the respective allocated measures of value or rate base. The relationship of each class rate of return to the total Pennsylvania jurisdiction rate of return also is shown.

Further details are shown in Section III.

PENNSYLVANIA POWER & LIGHT COMPANY
COST ALLOCATION DETAILS - FUTURE TEST YEAR ENDED 9/30/95
COMPONENTS OF OPERATING EXPENSES AT PRESENT RATE LEVELS
WITH RESULTING RETURN, RATE OF RETURN, AND CLASS RATE % OF TOTAL

PART 3
SUMMARY

PPUC JURISDICTIONAL COST ALLOCATION
$1,000
CAPACITY ALLOCATION METHOD-MONTHLY PEAK DEMAND RESPONSIBILITY

		INPUT ALLOC	OUTPUT	TOTAL PENNA. JURISDICT	RS	RTS	GS-1	GS-3	LP-4
1	OPERATING REVENUES AT PRESENT RATE LEVELS								
2	SALE OF ELECTRICITY								
3	RATE REVENUE	RR		2,263,602	909,213	20,360	165,977	520,355	281,626
4	ENERGY/FUEL COST REVENUE	ECR		-21,487	-7,008	-248	-1,005	-4,491	-3,377
5	STATE TAX ADJ SURCHARGE	STAS		0	0	0	0	0	0
6	SPEC BASE RATE CREDIT ADJ	SBRCA		-38,084	-15,093	-338	-2,755	-8,692	-4,896
7	TOTAL SALE OF ELECTRICITY		RRT	2,204,031	887,112	19,774	162,217	507,172	273,353
8	ANNUALIZATION	ANN		25,615	8,192	367	3,393	5,340	4,745
9	LATE PAY CHARGES		R11	7,074	3,509	27	1,314	1,528	376
10	TOT ADJ'D SALE OF ELECTRIC		RRTT	2,236,720	898,813	20,168	166,924	514,040	278,474
11	OTHER OPERATING REVENUES		ROOT	165,535	63,271	2,358	8,694	35,469	22,223
12	TOTAL OPERATING REVENUES		ROT	2,402,255	962,084	22,526	175,618	549,509	300,697
13	OPERATING EXPENSES								
14	OPERATING AND MAINTENANCE EXPENSES								
15	PRODUCTION								
16	FUEL		EOPF1	431,704	153,338	5,471	21,424	94,562	62,644
17	POWER PURCHASES		EOPP1	252,511	89,959	3,252	12,539	55,412	36,502
18	OTHER PRODUCTION		EOPO1	297,079	110,334	4,707	14,881	66,888	40,610
19	TOTAL PRODUCTION		EE10T	981,294	353,631	13,430	48,844	216,862	139,756
20	TRANSMISSION		EE20	10,487	4,025	192	529	2,411	1,365
21	DISTRIBUTION		EE30	92,936	51,714	2,093	7,737	15,501	5,466
22	OTHER OPER & MAINT EXP		EOMT1	288,210	157,206	4,505	19,181	46,028	24,842
23	TOTAL OPER & MAINT EXPENSES		EE00T	1,372,927	566,576	20,220	76,291	280,802	171,429
24	DEPRECIATION EXPENSE								
25	PRODUCTION		ED10	231,599	88,905	4,233	11,683	53,235	30,159
26	TRANSMISSION		ED20	7,753	2,988	142	393	1,789	1,013
27	DISTRIBUTION		ED30	70,147	41,443	1,514	5,654	10,577	3,280
28	OTHER DEPREC EXP		ED88	11,298	5,602	204	714	2,084	1,083
29	TOTAL DEPRECIATION EXPENSE		EDOST	320,797	138,938	6,093	18,444	67,685	35,535
30	AMORTIZATION EXP (ACCT 406)		ED97T	0	0	0	0	0	0
31	TOTAL DEPRECIATION AND								
32	AMORTIZATION EXPENSE		ED00	320,797	138,938	6,093	18,444	67,685	35,535
33	MISC ALLOWABLE EXPENSES		TX89	-29,674	-11,377	-540	-1,497	-6,815	-3,872
34	TAXES								
35	-OTHER CAPITAL STOCK		ET1	30,553	13,791	602	1,826	6,521	3,289
36	-OTHER M/O CAP STOCK		ET001	57,584	26,654	1,082	3,498	11,741	6,054
37	DEFERRED INCOME TAXES		TXT	-15,424	-3,059	-210	-397	-4,291	-3,030
38	NET INV TAX CR		TX91	-8,625	-3,913	-169	-518	-1,811	-912
39	GROSS RECEIPTS TAX		TXG	98,416	39,548	887	7,345	22,617	12,253
40	PA & FED INCOME TAXES		TSF1	209,079	61,512	-3,108	27,008	67,267	32,147
41	TOTAL TAXES		TEX1	371,583	134,533	-915	38,762	102,044	49,802
42	TOTAL OPERATING EXP		TEXP1	2,035,633	828,670	24,858	132,000	443,716	252,894
43	RETURN (LN 12 - 42)		PRERTN	366,622	133,414	-2,332	43,618	105,793	47,803
44	TOTAL RATE BASE		RBX	5,017,178	2,285,856	98,945	302,661	1,064,881	533,792
45	RATE OF RETURN (LN 43 / RBX)		PRRTR	7.31	5.84	-2.36	14.41	9.93	8.96
46	CLASS RATE IN % OF TOTAL		PRCLRT	100.0	79.9	-32.3	197.2	136.0	122.6

PENNSYLVANIA POWER & LIGHT COMPANY
COST ALLOCATION DETAILS - FUTURE TEST YEAR ENDED 9/30/95
COMPONENTS OF OPERATING EXPENSES AT PRESENT RATE LEVELS
WITH RESULTING RETURN, RATE OF RETURN, AND CLASS RATE % OF TOTAL

PART 3
SUMMARY

PPUC JURISDICTIONAL COST ALLOCATION
CAPACITY ALLOCATION METHOD-MONTHLY PEAK DEMAND RESPONSIBILITY

$1,000

		INPUT	ALLOC	OUTPUT	LP-5	LPEP	ISA	GH	SL/AL	STANDBY
1	OPERATING REVENUES AT PRESENT RATE LEVELS									
2	SALE OF ELECTRICITY									
3	RATE REVENUE	RR			268,654	8,665	21,238	44,746	21,591	1,177
4	ENERGY/FUEL COST REVENUE	ECR			-4,364	-116	-422	-375	-72	-9
5	STATE TAX ADJ SURCHARGE	STAS			0	0	0	0	0	0
6	SPEC BASE RATE CREDIT ADJ	SBRCA			-4,678	-144	-367	-743	-358	-20
7	TOTAL SALE OF ELECTRICITY			RRT	259,612	8,405	20,449	43,628	21,161	1,148
8	ANNUALIZATION	ANN			4,973	0	0	-1,014	-381	0
9	LATE PAY CHARGES			R11	133	0	0	135	52	0
10	TOT ADJ'D SALE OF ELECTRIC			RRTT	264,718	8,405	20,449	42,749	20,832	1,148
11	OTHER OPERATING REVENUES			ROOT	25,996	692	2,423	3,099	1,254	56
12	TOTAL OPERATING REVENUES			ROT	290,714	9,097	22,872	45,848	22,086	1,204
13	OPERATING EXPENSES									
14	OPERATING AND MAINTENANCE EXPENSES									
15	PRODUCTION									
16	FUEL			EOPF1	75,890	1,972	7,158	7,616	1,475	154
17	POWER PURCHASES			EOPP1	44,092	1,153	4,147	4,517	848	90
18	OTHER PRODUCTION			EOPO1	46,918	1,325	4,233	6,316	755	112
19	TOTAL PRODUCTION			EE10T	166,900	4,450	15,538	18,449	3,078	356
20	TRANSMISSION			EE20	1,512	46	131	252	20	4
21	DISTRIBUTION			EE30	2,367	84	218	2,144	5,606	6
22	OTHER OPER & MAINT EXP			EOMT1	26,672	775	2,350	4,744	1,840	67
23	TOTAL OPER & MAINT EXPENSES			EE00T	197,451	5,355	18,237	25,589	10,544	433
24	DEPRECIATION EXPENSE									
25	PRODUCTION			ED10	33,393	1,011	2,882	5,571	435	92
26	TRANSMISSION			ED20	1,122	27	75	187	14	3
27	DISTRIBUTION			ED30	1,414	47	126	1,409	4,679	4
28	OTHER DEPREC EXP			ED88	1,115	34	97	229	133	3
29	TOTAL DEPRECIATION EXPENSE			ED0ST	37,044	1,119	3,180	7,396	5,261	102
30	AMORTIZATION EXP (ACCT 406)			E097T	0	0	0	0	0	0
31	TOTAL DEPRECIATION AND									
32	AMORTIZATION EXPENSE			ED00	37,044	1,119	3,180	7,396	5,261	102
33	MISC ALLOWABLE EXPENSES			TX89	-4,293	-129	-370	-712	-57	-12
34	TAXES									
35	-OTHER CAPITAL STOCK			ET1	3,008	101	200	717	489	9
36	-OTHER M/O CAP STOCK			ET001	5,798	186	428	1,273	854	16
37	DEFERRED INCOME TAXES			TXT	-4,128	-114	-417	-384	616	-10
38	NET INV TAX CR			TX91	-852	-27	-61	-200	-159	-3
39	GROSS RECEIPTS TAX			TXG	11,648	370	900	1,881	916	51
40	PA & FED INCOME TAXES			TSF1	19,364	924	531	3,552	-375	257
41	TOTAL TAXES			TEX1	34,837	1,440	1,581	6,838	2,342	319
42	TOTAL OPERATING EXP			TEXP1	265,039	7,785	22,628	39,111	18,090	842
43	RETURN (LN 12 - 42)			PRERTN	25,675	1,312	244	6,737	3,996	362
44	TOTAL RATE BASE			RBX	480,584	16,216	30,930	117,256	84,586	1,471
45	RATE OF RETURN (LN 43 / RBX)			PRRTR	5.34	8.09	0.79	5.75	4.72	24.58
46	CLASS RATE IN % OF TOTAL			PRCLRT	73.1	110.7	10.8	78.6	64.6	336.4

FUTURE TEST YEAR COST ALLOCATION
COMPANY AND PPUC ADJUSTMENTS FOR COMPLIANCE FILING

PENNSYLVANIA POWER & LIGHT COMPANY
COST ALLOCATION DETAILS - FUTURE TEST YEAR ENDED 9/30/95
COMPONENTS OF OPERATING EXPENSES AT APPROVED RATE LEVELS
WITH RESULTING RETURN, RATE OF RETURN, AND CLASS RATE % OF TOTAL

PART 3
SUMMARY

PPUC JURISDICTIONAL COST ALLOCATION $1,000
CAPACITY ALLOCATION METHOD-MONTHLY PEAK DEMAND RESPONSIBILITY

		INPUT	ALLOC	OUTPUT	TOTAL PENNA. JURISDICT	RS	RTS	GS-1	GS-3	LP-4
1	OPERATING REVENUES AT APPROVED RATE LEVELS									
2	SALE OF ELECTRICITY									
3	RATE REVENUE APPROVED	RRP			2,348,853	953,918	21,492	168,178	531,689	269,460
4	ENERGY REVENUE APPROVED	ECRP			25	1,399	50	115	514	-531
5	STATE TAX ADJ SURCHARGE	STASP			0	0	0	0	0	0
6	SPEC BASE RATE CREDIT ADJ	SBRCAP			-39,498	-15,835	-357	-2,791	-8,880	-4,694
7	TOTAL SALE OF ELECTRICITY			RRTP	2,309,380	939,482	21,185	165,502	523,323	264,235
8	ANNUALIZATION	ANNP			26,556	8,493	380	3,518	5,536	4,919
9	LATE PAY CHARGES	S11P	CM4	R11P	7,341	3,641	28	1,363	1,586	391
10	TOT ADJ'D SALE OF ELECTRIC			RRTTP	2,343,277	951,616	21,593	170,383	530,445	269,545
11	OTHER OPERATING REVENUES			ROOT	165,535	42,811	1,383	6,005	23,217	13,886
12	TOTAL OPERATING REVENUES			ROTP	2,508,812	994,427	22,976	176,388	553,662	283,431
13	OPERATING EXPENSES									
14	OPERATING AND MAINTENANCE EXPENSES									
15	PRODUCTION									
16	FUEL			EOPF1	431,704	153,338	5,471	21,424	94,562	56,935
17	POWER PURCHASES			EOPP1	252,511	89,959	3,252	12,539	55,412	33,177
18	OTHER PRODUCTION			EOPO1	297,079	110,334	4,707	14,881	66,888	36,943
19	TOTAL PRODUCTION			EE10T	981,294	353,631	13,430	48,844	216,862	127,055
20	O & M TRANSMISSION			EE20	10,487	4,025	192	529	2,411	1,243
21	O & M DISTRIBUTION			EE30	92,936	51,714	2,093	7,737	15,501	5,019
22	OTHER OPER & MAINT EXP			EOMT1	224,529	131,620	3,364	15,862	31,831	15,394
23	TOTAL OPER & MAINT EXPENSES			EE00T	1,309,246	540,990	19,079	72,972	266,605	148,711
24	DEPRECIATION EXPENSE									
25	PRODUCTION			ED10	231,599	88,905	4,233	11,683	53,235	27,455
26	TRANSMISSION			ED20	7,753	2,988	142	393	1,789	922
27	DISTRIBUTION			ED30	70,147	41,443	1,514	5,654	10,577	2,998
28	GENERAL			ED88	11,298	5,602	204	714	2,084	986
29	TOTAL DEPRECIATION EXPENSE			EDOST	320,797	138,938	6,093	18,444	67,685	32,361
30	AMORTIZATION EXP (ACCT 406)			ED97T	0	0	0	0	0	0
31	TOTAL DEPRECIATION AND									
32	AMORTIZATION EXPENSE			ED00	305,523	133,074	5,814	17,673	64,175	30,550
33	MISC ALLOWABLE EXPENSES			TX89	-29,674	-11,376	-541	-1,496	-6,816	-3,525
34	TAXES									
35	INCREASE CAPITAL STOCK			ET1I	31,238	13,905	606	1,841	6,550	3,059
36	-OTHER M/O CAP STOCK			ET001	57,584	26,400	1,072	3,464	11,591	5,507
37	DEFERRED INCOME TAXES			TXT	-10,078	-1,179	-121	-149	-3,168	-2,125
38	NET INV TAX CR			TX91	-8,625	-3,876	-167	-513	-1,788	-830
39	GROSS RECEIPTS TAX			TXGRP	103,104	41,872	950	7,497	23,339	11,860
40	STATE INCOME TAX			TSTXP	71,450	21,772	-658	7,425	19,332	9,305
41	FEDERAL INCOME TAX			TFTXP	200,344	60,716	-1,907	20,917	54,350	26,168
42	TOTAL TAXES			TEX1	445,017	159,609	-225	40,482	110,206	52,944
43	TOTAL OPERATING EXP			TEXP1	2,030,112	822,297	24,127	129,631	434,170	228,680
44	RETURN (LN 12 - 42)			PRERTN	478,700	172,130	-1,151	46,757	119,492	54,751
45	TOTAL RATE BASE			RBX	5,017,708	2,251,525	97,298	298,179	1,044,620	485,782
46	RATE OF RETURN (LN 43 / RBX)			PRRTRP	9.54	7.65	-1.18	15.68	11.44	11.27
47	CLASS RATE IN % OF TOTAL			PRCLRT	100.0	80.1	-12.4	164.4	119.9	118.1

PENNSYLVANIA POWER & LIGHT COMPANY
COST ALLOCATION DETAILS - FUTURE TEST YEAR ENDED 9/30/95
COMPONENTS OF OPERATING EXPENSES AT APPROVED RATE LEVELS
WITH RESULTING RETURN, RATE OF RETURN, AND CLASS RATE % OF TOTAL

PART 3
SUMMARY

PPUC JURISDICTIONAL COST ALLOCATION
$1,000
CAPACITY ALLOCATION METHOD-MONTHLY PEAK DEMAND RESPONSIBILITY

		INPUT	ALLOC	OUTPUT	ISP	LP-5,6	IST	LPEP	ISA	STANDBY
1	OPERATING REVENUES AT APPROVED RATE LEVELS									
2	SALE OF ELECTRICITY									
3	RATE REVENUE APPROVED	RRP			21,274	179,975	102,067	8,824	20,991	1,196
4	ENERGY REVENUE APPROVED	ECRP			-54	-770	-579	-36	-131	-3
5	STATE TAX ADJ SURCHARGE	STASP			0	0	0	0	0	0
6	SPEC BASE RATE CREDIT ADJ	SBRCAP			-353	-3,206	-1,694	-146	-363	-20
7	TOTAL SALE OF ELECTRICITY			RRTP	20,867	175,999	99,794	8,642	20,497	1,173
8	ANNUALIZATION	ANNP			0	5,156	0	0	0	0
9	LATE PAY CHARGES	S11P	CM4	R11P	0	138	0	0	0	0
10	TOT ADJ'D SALE OF ELECTRIC			RRTTP	20,867	181,293	99,794	8,642	20,497	1,173
11	OTHER OPERATING REVENUES			ROOT	6,374	10,519	43,960	459	13,915	35
12	TOTAL OPERATING REVENUES			ROTP	27,241	191,812	143,754	9,101	34,412	1,208
13	OPERATING EXPENSES									
14	OPERATING AND MAINTENANCE EXPENSES									
15	PRODUCTION									
16	FUEL			EOPF1	5,709	44,098	31,792	1,972	7,158	154
17	POWER PURCHASES			EOPP1	3,325	25,665	18,427	1,153	4,147	90
18	OTHER PRODUCTION			EOPO1	3,667	28,039	18,879	1,325	4,233	112
19	TOTAL PRODUCTION			EE10T	12,701	97,802	69,098	4,450	15,538	356
20	O & M TRANSMISSION			EE20	122	927	585	46	131	4
21	O & M DISTRIBUTION			EE30	447	1,583	784	84	218	6
22	OTHER OPER & MAINT EXP			EOMT1	1,482	10,700	7,192	511	1,591	43
23	TOTAL OPER & MAINT EXPENSES			EE00T	14,752	111,012	77,659	5,091	17,478	409
24	DEPRECIATION EXPENSE									
25	PRODUCTION			ED10	2,704	20,475	12,918	1,011	2,882	92
26	TRANSMISSION			ED20	91	688	434	27	75	3
27	DISTRIBUTION			ED30	282	909	505	47	126	4
28	GENERAL			ED88	97	685	430	34	97	3
29	TOTAL DEPRECIATION EXPENSE			EDOST	3,174	22,757	14,287	1,119	3,180	102
30	AMORTIZATION EXP (ACCT 406)			ED97T	0	0	0	0	0	0
31	TOTAL DEPRECIATION AND									
32	AMORTIZATION EXPENSE			ED00	2,996	21,406	13,435	1,052	2,990	96
33	MISC ALLOWABLE EXPENSES			TX89	-346	-2,630	-1,664	-130	-370	-11
34	TAXES									
35	INCREASE CAPITAL STOCK			ET1I	300	2,065	1,295	101	288	9
36	-OTHER M/O CAP STOCK			ET001	543	3,764	2,400	184	533	15
37	DEFERRED INCOME TAXES			TXT	-210	-1,880	-1,227	-94	-277	-8
38	NET INV TAX CR			TX91	-82	-557	-350	-28	-77	-2
39	GROSS RECEIPTS TAX			TXGRP	919	7,976	4,391	381	902	51
40	STATE INCOME TAX			TSTXP	862	5,322	5,131	267	1,398	70
41	FEDERAL INCOME TAX			TFTXP	2,423	14,945	14,456	751	3,943	197
42	TOTAL TAXES			TEX1	4,754	31,637	26,095	1,562	6,710	333
43	TOTAL OPERATING EXP			TEXP1	22,156	161,425	115,525	7,575	26,808	827
44	RETURN (LN 12 - 42)			PRERTN	5,085	30,387	28,229	1,526	7,604	381
45	TOTAL RATE BASE			RBX	47,620	325,549	205,020	15,838	45,327	1,434
46	RATE OF RETURN (LN 43 / RBX)			PRRTRP	10.68	9.33	13.77	9.64	16.78	26.57
47	CLASS RATE IN % OF TOTAL			PRCLRT	111.9	97.8	144.3	101.0	175.8	278.5

FUTURE TEST YEAR COST ALLOCATION
COMPANY AND PPUC ADJUSTMENTS FOR COMPLIANCE FILING

PENNSYLVANIA POWER & LIGHT COMPANY
COST ALLOCATION DETAILS - FUTURE TEST YEAR ENDED 9/30/95
COMPONENTS OF OPERATING EXPENSES AT APPROVED RATE LEVELS
WITH RESULTING RETURN, RATE OF RETURN, AND CLASS RATE % OF TOTAL

PART 3
SUMMARY

PPUC JURISDICTIONAL COST ALLOCATION
CAPACITY ALLOCATION METHOD-MONTHLY PEAK DEMAND RESPONSIBILITY

$1,000

		INPUT	ALLOC	OUTPUT	GH	SL/AL
1	OPERATING REVENUES AT APPROVED RATE LEVELS					
2	SALE OF ELECTRICITY					
3	RATE REVENUE APPROVED	RRP			47,083	22,706
4	ENERGY REVENUE APPROVED	ECRP			43	8
5	STATE TAX ADJ SURCHARGE	STASP			0	0
6	SPEC BASE RATE CREDIT ADJ	SBRCAP			-782	-377
7	TOTAL SALE OF ELECTRICITY			RRTP	46,344	22,337
8	ANNUALIZATION	ANNP			-1,051	-395
9	LATE PAY CHARGES	S11P	CM4	R11P	140	54
10	TOT ADJ'D SALE OF ELECTRIC			RRTTP	45,433	21,996
11	OTHER OPERATING REVENUES			ROOT	1,817	1,154
12	TOTAL OPERATING REVENUES			ROTP	47,250	23,150
13	OPERATING EXPENSES					
14	OPERATING AND MAINTENANCE EXPENSES					
15	PRODUCTION					
16	FUEL			EOPF1	7,616	1,475
17	POWER PURCHASES			EOPP1	4,517	848
18	OTHER PRODUCTION			EOPO1	6,316	755
19	TOTAL PRODUCTION			EE1OT	18,449	3,078
20	O & M TRANSMISSION			EE2O	252	20
21	O & M DISTRIBUTION			EE3O	2,144	5,606
22	OTHER OPER & MAINT EXP			EOMT1	3,274	1,665
23	TOTAL OPER & MAINT EXPENSES			EE0OT	24,119	10,369
24	DEPRECIATION EXPENSE					
25	PRODUCTION			ED1O	5,571	435
26	TRANSMISSION			ED2O	187	14
27	DISTRIBUTION			ED3O	1,409	4,679
28	GENERAL			ED88	229	133
29	TOTAL DEPRECIATION EXPENSE			ED0ST	7,396	5,261
30	AMORTIZATION EXP (ACCT 406)			ED97T	0	0
31	TOTAL DEPRECIATION AND					
32	AMORTIZATION EXPENSE			ED0O	7,029	5,233
33	MISC ALLOWABLE EXPENSES			TX89	-712	-57
34	TAXES					
35	INCREASE CAPITAL STOCK			ET1I	721	498
36	-OTHER W/O CAP STOCK			ET001	1,258	853
37	DEFERRED INCOME TAXES			TXT	-266	626
38	NET INV TAX CR			TX91	-197	-158
39	GROSS RECEIPTS TAX			TXGRP	1,999	967
40	STATE INCOME TAX			TSTXP	1,211	13
41	FEDERAL INCOME TAX			TFTXP	3,385	0
42	TOTAL TAXES			TEX1	8,112	2,798
43	TOTAL OPERATING EXP			TEXP1	38,548	18,343
44	RETURN (LN 12 - 42)			PRERTN	8,702	4,807
45	TOTAL RATE BASE			RBX	115,105	84,411
46	RATE OF RETURN (LN 43 / RBX)			PRRTRP	7.56	5.69
47	CLASS RATE IN % OF TOTAL			PRCLRT	79.2	59.7

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00049255

PPL Electric Utilities Corporation

Exhibit JMK-Remand 6

PPL Electric Utilities Corporation
Compliance Cost Allocation Results in
1994 and 2004 Proceedings by Rate Class
($000)

1994

	Total	RS	RTS	GS-1	GS-3	LP-4	IS-P	LP-5, 6	IS-T	LPEP	ISA	Stand-By	GH	SL/AL
Rate of Return	9.54	7.65	-1.18	15.68	11.44	11.27	10.68	9.33	13.77	9.64	16.78	26.57	7.56	5.69
Class Rate in % of Total	100.0	80.1	-12.4	164.4	119.9	118.1	111.9	97.8	144.3	101.0	175.8	278.5	79.2	59.7

2004

	Total	RS	RTS	GS-1	GS-3	LP-4	IS-P	LP-5, 6	IS-T	LPEP	ISA	Stand-By	GH	SL/AL
Rate of Return	3.91	1.60	-3.95	9.28	10.50	10.64	14.46	27.34	87.15	11.15	107.25	5.65	9.76	1.03
Class Rate in % of Total	100.0	40.86	-101.22	237.61	268.65	272.22	370.14	699.23	2,230.45	285.40	2,757.56	144.59	249.79	144.59

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00049255

PPL Electric Utilities Corporation

Exhibit JMK-Remand 7

PPL Electric Utilities Corporation
Hypothetical Example of
Revenue Increase Allocations by Rate Class
($000)

Present Rates

	Total System	Rate Class X	Rate Class Y	Rate Class Z
Revenue	$485	$315	$150	$20
Expense	415	290	110	15
Return	$70	$25	$40	$5
Rate Base	$1,745	$1,230	$450	$65
Rate of Return	4.01%	2.03%	8.89%	7.69%
Rate of Return % of Total System	100.00%	50.62%	221.70%	191.77%

Proposed Rates – 30% Increase to Each Rate Class

Revenue	$631	$410	$195	$26
Expense	481	333	130	18
Return	$150	$77	$65	$8
Rate Base	$1,745	$1,230	$450	$65
Rate of Return	8.60%	6.26%	14.44%	12.31%
Rate of Return % of Total System	100.00%	72.79%	167.91%	143.14%
Change in Revenue	30.10%	30.16%	30.00%	30.00%
Change in Return	214.29%	308.00%	62.50%	60.00%

Proposed Rates – Non Proportional Increase to Each Rate Class

	Total System	Rate Class X	Rate Class Y	Rate Class Z
Revenue	$631	$400	$200	$26
Expense	481	328	132	18
Return	$150	$72	$68	$8
Rate Base	$1,745	$1,230	$450	$65
Rate of Return	8.60%	5.85%	15.11%	12.31%
Rate of Return % of Total System	100.00%	68.02%	175.70%	143.14%
Change in Revenue	30.10%	26.98%	33.33%	30.00%
Change in Return	214.29%	288.00%	70.00%	60.00%

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00049255

PPL Electric Utilities Corporation

Exhibit JMK-Remand 8

PPL Electric Utilities Corporation
Sumary of Alternative Cost Allocation Study Details 12 Months Ended 12/31/2004
($000s)

Comparison of Key Results for Alternative Allocators - Proposed Rates

	Distribution Pa Jurisd	RS	RTS	GS-1	GS-3	LP-4	ISP	LP-5	IST	LP-6	LPEP	ISA	GH	SL/AL	L5-S
Compliance Filing - Excluding Hurricane Isabel Storm Expenses															
AT CLASS % RATE OF RETURN	8.47%	5.48%	-3.33%	15.54%	16.69%	16.48%	16.73%	29.19%	53.66%	58.96%	11.90%	109.85%	15.85%	4.00%	19.28%
TOTAL REVENUE REQUIREMENTS	631,254	362,402	3,920	79,503	119,891	30,880	2,082	1,879	1,301	214	391	668	8,682	19,367	74
DEMAND COMPONENT	260,607	87,648	2,146	30,817	101,793	28,506	1,752	377	216	54	359	28	6,135	775	1
CUSTOMER COMPONENT	370,647	274,754	1,774	48,686	18,098	2,374	330	1,502	1,085	160	32	640	2,547	18,592	73
TOTAL RATE BASE	1,836,964	1,188,218	43,171	177,572	270,794	67,662	4,238	1,973	751	134	975	264	20,754	60,291	166
DEMAND COMPONENT	804,978	377,547	29,067	75,856	235,662	63,340	3,947	0	0	0	900	0	15,001	3,658	0
CUSTOMER COMPONENT	1,031,986	810,671	14,104	101,716	35,132	4,322	291	1,973	751	134	75	264	5,753	56,633	166
50-50 Demand-Customer Allocators															
AT CLASS % RATE OF RETURN	8.47%	6.32%	-3.89%	15.73%	11.91%	15.61%	16.07%	25.30%	37.14%	33.89%	10.91%	84.62%	12.19%	4.09%	17.46%
TOTAL REVENUE REQUIREMENTS	631,127	361,733	3,991	79,833	120,091	30,837	2,078	1,792	1,249	203	388	662	8,707	19,487	76
DEMAND COMPONENT	308,824	121,401	2,469	40,626	106,490	28,226	1,747	(93)	(53)	(14)	358	(6)	6,765	908	0
CUSTOMER COMPONENT	322,303	240,332	1,522	39,207	13,601	2,611	331	1,885	1,302	217	30	668	1,942	18,579	76
TOTAL RATE BASE	1,836,961	1,105,161	49,703	175,411	340,864	72,360	4,499	3,360	1,516	360	1,063	364	24,705	57,408	189
DEMAND COMPONENT	1,034,752	494,126	38,041	99,274	308,426	65,906	4,103	0	0	0	960	0	19,635	4,278	0
CUSTOMER COMPONENT	802,210	611,035	11,662	76,137	32,438	6,454	396	3,360	1,516	360	103	364	5,070	53,130	189
50-50 Demand-Energy Allocators															
AT CLASS % RATE OF RETURN	8.47%	11.97%	-3.84%	20.99%	6.13%	1.64%	0.86%	-8.37%	-8.29%	-8.67%	0.19%	-1.58%	8.67%	4.30%	7.89%
TOTAL REVENUE REQUIREMENTS	631,189	361,625	3,991	79,788	120,027	30,811	2,076	1,782	1,241	200	389	660	8,702	19,822	75
DEMAND COMPONENT	317,811	171,614	2,514	49,879	74,969	11,530	639	6	7	0	151	0	5,565	937	0
ENERGY COMPONENT	159,743	75,364	660	16,743	38,471	18,246	1,205	1,651	962	200	227	613	2,065	3,305	31
CUSTOMER COMPONENT	153,635	114,647	817	13,166	6,587	1,035	232	125	272	0	11	47	1,072	15,580	44
TOTAL RATE BASE	1,836,960	820,359	50,023	145,354	460,319	155,334	10,511	53,329	30,491	7,983	2,133	3,996	29,409	67,440	279
DEMAND COMPONENT	1,034,752	494,130	38,040	99,273	308,429	65,906	4,102	0	0	0	959	0	19,633	4,280	0
ENERGY COMPONENT	584,868	195,470	6,095	30,897	133,692	85,272	6,188	51,300	29,786	7,841	1,102	3,713	6,319	27,085	106
CUSTOMER COMPONENT	217,341	130,759	5,888	15,184	18,198	4,156	221	2,029	705	142	72	283	3,457	36,075	173
1/3 Demand-Customer-Energy															
AT CLASS % RATE OF RETURN	8.47%	8.20%	-3.54%	18.53%	10.47%	5.25%	4.50%	-5.94%	-5.75%	-6.26%	3.10%	3.63%	12.20%	3.58%	9.52%
TOTAL REVENUE REQUIREMENTS	631,215	361,784	3,988	79,829	120,088	30,855	2,081	1,808	1,260	204	389	662	8,709	19,482	76
DEMAND COMPONENT	254,471	112,280	2,270	36,911	80,156	15,702	898	(92)	(52)	(14)	201	(6)	5,501	716	0
CUSTOMER COMPONENT	278,666	210,425	1,382	32,990	11,153	1,521	264	290	338	13	20	104	1,724	18,392	50
ENERGY COMPONENT	98,078	39,079	336	9,928	28,779	13,632	919	1,610	974	205	168	564	1,484	374	26
TOTAL RATE BASE	1,836,955	993,887	44,453	157,680	359,126	124,386	8,296	34,399	19,544	5,095	1,744	2,618	24,339	61,132	252
DEMAND COMPONENT	848,265	398,267	30,659	80,015	248,587	66,293	4,132	0	0	0	973	0	15,822	3,515	0
CUSTOMER COMPONENT	615,733	458,073	9,675	56,358	25,227	4,045	241	1,904	686	131	73	260	4,406	54,475	180
ENERGY COMPONENT	372,959	137,558	4,119	21,306	85,309	54,046	3,923	32,494	18,857	4,964	698	2,358	4,111	3,142	72

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00049255

PPL Electric Utilities Corporation

Exhibit JMK-Remand 9

PPL Electric Utilities Corporation
Transmission Service Charge Components

TSC Related Charge	OATT Attachments	Determinant Basis Description	*Formula Components*	*Units of Rate*
Network Transmission Service Charge (NITS)	H-8	PPL Electric Peak Load Responsibility (PLR)	PLR (MWD) x Rate	$/MWD
Network Transmission Service Charge - Call Option	Power Supply Agreement	PPL Electric Peak Load Responsibility (PLR)	PLR (MWD) x Rate	$/MWD
Seams Elimination Cost Assignment - SECA Charge	Attachment R, X	PPL Electric PLR (PPL Share of Zone PLR)		
Seams Elimination Cost Assignment - SECA Call Option	Power Supply Agreement	PPL Electric PLR (PPL Share of Zone PLR)		
PJM System Control and Dispatch Service	1, 9	Real Time Net POLR Load	kWh Load x Rate	$/kWh
Transmission Owner Scheduling, System Control and Dispatch Se	1A	Real Time Net POLR Load	kWh Load x Rate	$/kWh
Reactive Supply and Voltage Control from Generation Sources Se	2	PPL Electric PLR (PPL Share of Zone PLR)	PLR (MWD) x Revenue Requirement	$/Share of MWD
Black Start Service	6A	PPL Electric PLR (PPL Share of Zone PLR)	PLR (MWD) x Revenue Requirement	$/Share of MWD
Regulation and Frequency Response Service	3	Average Hourly Regulation Obligation	Obligation * Market Clearing Price	$/MWH
Operating Reserve - Supplemental Reserve Service				
Day Ahead	6	Day Ahead Net POLR Load Forecast	Day Ahead kWh Forecast * DA LMP	$/kWh
Real Time (Balancing)	6	Real Time Net POLR Load less Day Ahead Net POLR Load Forecast	Deviation kWh * Real Time LMP	$/kWh
Synchronous Condensing Charge & Spinning Reserve	5	Real Time Net POLR Load	Real Time kWh * RT LMP	$/kWh
MAAC / Reliability First Corp. / NERC	10	Reliability Council Fee	Load (kWh) x Monthly Expenses	$ /Share of kWh
PJM Expansion Cost Recovery Mechanism	13	Average PPL Electric Peak Load Responsibility (PLR)	Demand (MW-month) * Rate	$/MW - Month
TSC Related Credits				
Transmission Losses (Point-to-Point) Credits	7	PPL Electric Peak Load Responsibility (PLR)	Demand (MW) x Loss Charge	$/MWD
Non-Firm Point-to-Point Transmission Service Credits	7	PPL Electric Peak Load Responsibility (PLR)	Demand (MW) x Demand Charge	$/MWD

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00049255

PPL Electric Utilities Corporation

Exhibit JMK-Remand 10

Summary of Revenue Billed Reallocation

	Total Adjustment w/ GRT	Adjustment w/ Interest & GRT Each Year 2008	2009
2005 Reallocation			
Large C & I	$11,495,919	$6,655,481	$7,138,003
Small C & I	$6,352,627	$3,685,026	$3,952,190
Residential	($17,848,545)	($10,340,506)	($11,090,193)
Net Change	$0	$0	$0
2006 Reallocation			
Large C & I	$14,337,334	$7,752,948	$8,315,037
Small C & I	$3,087,904	$1,660,876	$1,781,290
Residential	($17,425,238)	($9,413,824)	($10,096,327)
Net Change	$0	$0	$0
2007 Reallocation (Forecast)			
Large C & I	$11,020,614	$5,550,259	$6,325,880
Small C & I	($3,049,849)	($1,556,615)	($1,774,144)
Residential	($7,970,765)	($3,993,645)	($4,551,736)
Net Change	$0	$0	$0
Total Adjustment (Forecast)			
Large C & I	$36,853,867	$19,958,688	$21,778,920
Small C & I	$6,390,681	$3,789,287	$3,959,336
Residential	($43,244,549)	($23,747,975)	($25,738,256)
Net Change	$0	$0	$0

Summary of Revenue Billed Reallocation

w/o GRT

	January	February	March	April	May	June	July	August	September	October	November	December	Total Adjustment
2005 Reallocation													
Large C & I	$227,108	$595,497	$628,184	$1,020,961	$1,228,744	$1,010,146	$1,142,653	$853,796	$1,069,100	$1,269,635	$1,268,215	$503,621	$10,817,660
Small C & I	$587,203	$210,022	$342,727	$369,170	$572,953	$712,467	$619,666	$442,759	$620,851	$674,722	$461,559	$363,722	$5,977,822
Residential	($814,311)	($805,519)	($970,911)	($1,390,131)	($1,801,697)	($1,722,613)	($1,762,319)	($1,296,554)	($1,689,951)	($1,944,357)	($1,729,773)	($867,343)	($16,795,481)
Net Change	($0)	$0	$0	$0	$0	$0	$0	($0)	($0)	($0)	$0	$0	$0
2006 Reallocation													
Large C & I	$695,118	$774,474	$799,118	$1,056,474	$1,478,743	$1,369,342	$854,574	$1,157,174	$1,414,380	$1,643,111	$1,170,115	$1,078,808	$13,491,431
Small C & I	($173,797)	$15,506	$23,168	$230,131	$398,584	$495,387	$444,058	$218,744	$531,411	$401,851	$277,749	$42,924	$2,905,717
Residential	($521,321)	($789,979)	($822,287)	($1,286,605)	($1,877,327)	($1,864,729)	($1,298,633)	($1,375,919)	($1,945,791)	($2,044,962)	($1,447,865)	($1,121,732)	($16,397,149)
Net Change	($0)	$0	$0	$0	$0	$0	$0	($0)	$0	$0	$0	$0	$0
2007 Reallocation (Forecast)													
Large C & I	$322,609	$525,511	$606,856	$869,839	$1,137,289	$1,154,329	$1,023,669	$970,601	$1,047,002	$1,075,542	$985,044	$652,105	$10,370,398
Small C & I	($622,992)	($571,811)	($480,605)	($264,653)	($17,647)	$10,006	($95,699)	($174,888)	($85,804)	($82,823)	($134,743)	($348,251)	($2,869,908)
Residential	$300,382	$46,300	($126,251)	($605,186)	($1,119,643)	($1,164,335)	($927,970)	($795,714)	($961,198)	($992,720)	($850,301)	($303,855)	($7,500,490)
Net Change	$0	$0	$0	$0	$0	$0	($0)	$0	$0	$0	($0)	($0)	$0

w/ GRT

	January	February	March	April	May	June	July	August	September	October	November	December	Total Adjustment
2005 Reallocation													
Large C & I	$241,348	$632,835	$667,571	$1,084,975	$1,305,786	$1,073,481	$1,214,296	$907,328	$1,136,132	$1,349,240	$1,347,731	$535,197	$11,495,919
Small C & I	$624,020	$223,190	$364,216	$392,317	$608,877	$757,139	$658,518	$470,519	$659,778	$717,027	$490,498	$386,527	$6,352,627
Residential	($865,368)	($856,025)	($1,031,787)	($1,477,292)	($1,914,662)	($1,830,620)	($1,872,815)	($1,377,847)	($1,795,910)	($2,066,267)	($1,838,229)	($921,725)	($17,848,545)
Net Change	($0)	$0	$0	$0	$0	$0	$0	($0)	$0	($0)	$0	$0	$0
2006 Reallocation													
Large C & I	$738,702	$823,032	$849,222	$1,122,714	$1,571,459	$1,455,199	$908,155	$1,229,728	$1,503,061	$1,746,133	$1,243,481	$1,146,448	$14,337,334
Small C & I	($184,694)	$16,478	$24,621	$244,560	$423,575	$526,447	$471,900	$232,460	$564,730	$427,047	$295,164	$45,615	$3,087,904
Residential	($554,008)	($839,511)	($873,843)	($1,367,274)	($1,995,034)	($1,981,646)	($1,380,056)	($1,462,188)	($2,067,791)	($2,173,180)	($1,538,645)	($1,192,063)	($17,425,238)
Net Change	($0)	$0	$0	$0	$0	$0	$0	($0)	$0	$0	$0	$0	$0
2007 Reallocation (Forecast)													
Large C & I	$342,837	$558,460	$644,906	$924,378	$1,208,597	$1,226,704	$1,087,852	$1,031,457	$1,112,648	$1,142,978	$1,046,806	$692,992	$11,020,614
Small C & I	($662,053)	($607,663)	($510,739)	($281,247)	($18,753)	$10,633	($101,699)	($185,853)	($91,184)	($88,016)	($143,191)	($370,086)	($3,049,849)
Residential	$319,216	$49,203	($134,167)	($643,131)	($1,189,844)	($1,237,338)	($986,153)	($845,604)	($1,021,464)	($1,054,962)	($903,614)	($322,906)	($7,970,765)
Net Change	$0	$0	$0	$0	$0	$0	($0)	$0	$0	$0	($0)	($0)	$0

COMMONWEALTH OF PENNSYLVANIA
PUBLIC UTILITY COMMISSION

DATE: June 29, 2007

SUBJECT: Pa PUC et al. v. PPL Electric Utilities Corporation
R-00049255

TO: Wanda Zeiders, Supervisor of Docket Management
Docket Section, Secretary's Bureau

FROM: Susan D. Colwell
Administrative Law Judge

Attached please find two copies of testimony which were accepted into evidence in the above-captioned case.

Please docket these and place them in the yellow exhibit folder.

Please do not hesitate to contact me with any questions you may have, and thank you for your attention to this matter.

Attachments

#529911 09/06

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-00049255**
	)	
PPL Electric Utilities Corporation	)	

REMAND DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

PP&L INDUSTRIAL CUSTOMER ALLIANCE ("PPLICA")

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2007

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-00049255**
	)	
PPL Electric Utilities Corporation	)	

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BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-00049255**
	)	
PPL Electric Utilities Corporation	)	

REMAND DIRECT TESTIMONY OF STEPHEN J. BARON

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by who are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

Q. Please state your educational background.

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of

Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. Please describe your professional experience.

A. I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy

forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My

article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Virginia, West Virginia, Federal Energy Regulatory Commission and in United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Baron Exhibit ____ (SJB-1).

Q. Have your previously presented testimony in PPL rate proceedings?

A. Yes. I previously presented Direct, Rebuttal and Surrebuttal Testimony in this proceeding. I have also participated in five other PPL proceedings before the Pennsylvania PUC since 1984.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the PP&L Industrial Customer Alliance ("PPLICA"), a group of large industrial customers of PPL Electric Utilities Corporation ("PPL") who take service primarily on PPL Rate Schedules LP-4, LP-5, LP-6, IS-P and IS-T. I will refer to customers on these rate schedules generally as Large Commercial and Industrial or "Large C&I" customers.

Q. Would you please briefly describe the members of PPLICA who are participating in this rate proceeding?

A. There are nineteen PPLICA members who are participating in this rate proceeding and on whose behalf I am presenting testimony. These companies consume in excess of 2.2 billion kWhs annually on the PPL system. PPLICA member companies are major employers in the Commonwealth of Pennsylvania and contribute in a substantial manner to the overall economy of the state. This contribution includes not only direct benefits in the form of jobs to Pennsylvanians, but also includes the payment of corporate state income taxes, charitable and community development contributions and other activities which contribute to the overall well being of the citizens of the Commonwealth. Several PPLICA members provided testimony in this proceeding regarding the impact of the Commission's decisions regarding the design and level of transmission and distribution rates. A

summary of this prior testimony prepared by counsel is attached as Baron Exhibit___(SJB-2).

Q. What is the purpose of your testimony?

A. I am responding to the testimony and proposals of PPL witnesses Douglas Krall, Oliver Kasper and Joseph Kleha regarding PPL's proposed modifications to its tariff and refunds that are now before the Commission in this docket as a result of the Commonwealth's Court remand decision ("the remand"). See Lloyd v. Pa. P.U.C., 904 A.2d 1010 (Pa. Commw. Ct. 2006).

Specifically, I will address the Company's proposals for: 1) the appropriate design of the Transmission Service Charge ("TSC") on a cost of service basis; 2) the calculation and implementation of refunds and surcharges resulting from the correction of the cost allocation and rate design flaws in the TSC that was (or will be) applicable for the period 2005 through 2007; and (3) the Company's proposed plan to address the subsidies that currently exist in the distribution rates adopted by the Commission in the original litigation of this case.

Q. Before addressing the specific issues raised by the Company's testimony in this case, would you briefly discuss the some of the recommendations that you made on these issues in your Direct Testimony?

A. In my Direct Testimony in this case, I proposed an alternative cost allocation and rate design to recover transmission revenue requirements from customers who receive Basic Utility Supply Service ("BUSS") from PPL. PPL's TSC tariff proposal, which was ultimately approved by the Commission, simply computed a uniform per kWh transmission rate for each of PPL's rate schedules by dividing the transmission revenue requirement by total test year kWh. The approved TSC did not even recognize voltage loss differentials for different rate schedules, such as Rate Schedule LP-5, whose customers take service at 69,000 volts or higher.

In contrast to the Company's proposal, I proposed a TSC in the original litigation that reflected the manner in which PPL actually incurred transmission expenses pursuant to the PJM Interconnection L.L.C.'s ("PJM") Open Access Transmission Tariff ("OATT"). As I discussed in my 2004 testimony, PPL is charged for PJM transmission service based on both kW demand and kWh energy usage. A reasonable cost-based retail TSC should reflect the nature of the transmission costs that are being recovered under the OATT. This requires a classification of

the BUSS retail transmission revenue requirement into demand and energy components, which should then be allocated to rate schedules based on each schedule's demand and energy share of total retail costs.[1] Despite the fact that PJM bills PPL on the basis of demand and energy, PPL's current TSC ignored this underlying cost differential. The TSC that I proposed in the original litigation reflects the cost-based allocation and rate design contemplated by the Electricity Generation Customer Choice and Competition Act ("Competition Act") and the Commonwealth Court's decision in Lloyd rejecting PPL's TSC.

In addition to addressing the TSC issues, I also addressed the apportionment of the authorized distribution revenue increase. My proposal, as described in my Direct Testimony, apportioned the authorized distribution revenue increase in such a manner as to reduce the current dollar subsidies in PPL's distribution rates by 50%.

Q. Are portions of your testimony from the original litigation relevant to the Commission's decision in this remand proceeding?

[1] Consistent with standard cost of service methodologies, these demand and energy allocation factors should be based on each rate schedule's 5 coincident peak ("CP") demands and MWh energy, adjusted for losses (i.e., "generation level"). For example, energy-related transmission expenses from PJM are billed to PPL based on PPL's MWh on the transmission system, which include losses. These costs should be allocated to rate schedules using each rate schedule's MWh at the same voltage (i.e., "generation level" voltage), not metered MWh.

A. Yes. It is my understanding from counsel that my testimony from the original litigation remains part of the record upon which the Commission can base its decision in this remand proceeding. For convenience, attached as Baron Exhibit___(SJB-3) is a list of the most relevant portions of my prior testimony regarding the subjects of this remand proceeding. Other portions of the record, including the testimony by PPLICA members and cross-examination (including exhibits) conducted during the hearings for the original litigation also may be relied upon by PPLICA in this matter.

Q. Would you summarize your recommendations in this remand proceeding?

A. Yes.

- **PPL's proposed cost of service based TSC, which is designed to replace the current TSC that charges a uniform price on a kWh basis, is generally reasonable and should be adopted by the Commission with <u>three</u> changes. First, the allocation of energy-related transmission costs should be made on the basis of rate group kWh, including losses. PPL has performed this allocation using rate group kWh at the meter, which does not properly reflect cost causation. The second and third adjustments to PPL's TSC are applicable to the Large C&I rate design. The demand portion of the TSC should be recovered from Large C&I customers on the basis of each customer's 5 CP demand, not on a kWh basis as proposed by PPL. This will ensure that the retail rate reflects cost of service and that high load factor Large C&I customers do not unduly overpay for transmission service. Finally, the energy portion of the Large C&I rate should be adjusted to reflect voltage loss differentials among the Large C&I rate group.**

- **PPL's proposed TSC adjustment (refunds and surcharges) for past over or under-charges due to the inappropriate design of the TSC on a uniform kWh basis must be corrected to properly reflect the allocation of 2005 through 2007 energy-related transmission costs on a kWh basis, including losses. With such a correction PPL's proposal is reasonable if customer-specific credits cannot be calculated. The credit/charge can be reflected on a kWh basis for each rate group, following the same rate design as was originally used to collect the TSC from customers. However, the adjustments should be separately reflected on customer bills in a "shopping neutral" charge or credit; not as an adjustment to the TSC as proposed by PPL. This will insure that customer decision making regarding generation supply service from PPL as the Provider of Last Resort ("POLR") or an Electric Generation Supplier ("EGS") will not be influenced by the adjustment.**

- **PPL's proposal in this case to maintain current distribution rates approved by the Commission should be rejected. The current rates do not adequately reflect the application of cost of service principles, as required in the Commonwealth Court's remand order in Lloyd. The Commission authorized revenue increase (less the storm damage expenses rejected by the Court) should be allocated based on PPLICA's proposed "50% dollar subsidy" methodology.**

II. PPL's PROPOSAL TO IMPLEMENT A COST-BASED TRANSMISSION SERVICE CHARGE

Q. Have you reviewed PPL's proposed allocation and design of its TSC to address the Commonwealth's Court decision on remand?

A. Yes. The Company's proposal appears to be generally consistent with the principles that I supported in my Direct Testimony in this case. That is, the allocation of the costs in the TSC rate generally reflects the cost basis on which PPL is billed for transmission service from PJM; however, the allocation of the energy portion of the TSC, which reflects certain ancillary costs that are billed by PJM on a MWh or kWh basis, should be based on a rate group kWh, including distribution and transmission losses. PPL has inappropriately used metered kWh for this allocation. Consistent with standard cost allocation methodologies, energy-related transmission expenses should be allocated on the basis of class (or in this case, rate group) kWh energy at the transmission voltage level, which means that the appropriate allocation factor is metered kWh plus losses for each rate group.

As noted by witness Kasper, "the majority of the Company's transmission costs are incurred based on its 5 coincident peak demand days." The Company has

reasonably reflected this cost causation in its allocation of the demand (i.e., kW billed) transmission costs to rate schedules.

Q. Is the Company proposing to recover allocated transmission costs from each rate schedule, as you recommended in your Direct Testimony?

A. No. The Company is proposing to group individual rate schedules into three rate groups comprised of: 1) residential rates; 2) small commercial and industrial rates; and 3) large commercial and industrial rates. The Large C&I rate group includes Rate Schedules LP-4, LP-5, IS-P, IS-T, LP-6, LPEP, ISA and Standby.

PPL argues that the use of rate groups, instead of individual rate schedules, for TSC rate design is a "reasonable compromise" and reflects the methodology used to recover CTC and ITC costs. In addition, Mr. Kasper states that the Company intends to use this "rate group" approach to calculate POLR rates after the expiration of the rate caps on January 1, 2010.

Q. Do you agree with the Company's proposal to group rate schedules into three rate groups?

A. I do not oppose this proposal, subject to a few modifications that must be made to the Large C&I rate design. First, the Company's proposal to charge the TSC on a per kWh basis to all customers on the Large C&I TSC rate is not reasonable. As noted above, the Company fully recognizes that the majority of TSC costs are demand-related. Specifically, the demand-related transmission costs allocated to the Large C&I rate group are based on the group's 5 CP demand. There is no reason not to charge individual customers in the Large C&I rate group on a 5 CP basis for the demand-related portion of allocated transmission costs.[2] As I discussed in my Direct Testimony, this is the basis (5 CP) on which an EGS would be charged for these same customers, if they were to shop. As a result, using a 5 CP billing basis for the recovery of demand-related transmission costs is both cost-based, and "shopping neutral." The smaller, energy-related portion of the TSC charge should be charged to individual customers in the Large C&I group on a kWh basis, though as I will discuss subsequently, it should be loss adjusted to reflect differences in service voltage among the Large C&I rate schedules.[3]

[2] This proposal to use 5 CP billing is only for the Large C&I rate group customers, who have interval metering. For any customer without interval metering, the Company could use the estimated 5 CP demand for that customer that would be provided to an EGS, in the event that the customer becomes a shopping customer.

[3] This voltage differentiation issue only concerns the Large C&I rate group and is thus a rate design issue; this is in contrast to the cost allocation issue that I previously discussed regarding the allocation of TSC energy related revenue requirements among the three rate groups proposed by PPL.

Q. Why is it unreasonable to use a single kWh charge for all Large C&I customers to recover both the demand and the energy portion of TSC costs?

A. First, there should be no dispute that a "cost-based" rate design to recover demand-related PJM transmission costs is the customer's 5 CP demand. These costs are incurred by PPL on a 5 CP basis and allocated to each "rate group" on a 5 CP basis. PPL has implemented this first step of reflecting cost of service in the TSC (i.e., the interclass allocation) appropriately.

Once the first step is accomplished, the question is whether using a customer's kWh usage as the billing determinant for the retail rate is a reasonable proxy for the correct 5 CP demand that reflects the cost of service for individual rate schedules and customers. Table 1 below shows the "5 CP load factor" for each of the rate schedules (other than Standby load) comprising the Large C&I rate group. As can be seen, there are large differences in these 5 CP load factors.

Table 1
Large C&I Rate Group - 5 CP Load Factors

Rate Schedule	mWh @ Transmission Voltage	NITS 5 CP Load Responsibility	5 CP Load Factor
LP4	6,042,458	1,062.7	64.9%
LP5	3,195,711	481.0	75.8%
LP6	363,650	67.6	61.4%
LPEP	72,000	13.8	59.6%
ISP	354,285	43.8	92.3%
IST	1,977,902	171.6	131.6%
ISM	266,000	33.9	89.6%
Total	12,272,006	1,874.4	74.7%

This means that charging customers on the basis of kWh energy, instead of the customer's 5 CP demand, results in a biased rate design. Large C&I customers with 5 CP load factors greater than 75% will overpay for transmission costs, if these customers are billed on a kWh basis; likewise, customers with load factors less than 75% will underpay. Customers on Rate Schedules LP-5, IS-P, IS-T and ISM, who have 5 CP average load factors in excess of the average for the entire Large C&I rate group, will pay an effective TSC rate that exceeds PPL's cost to provide transmission service to them. The higher a customer's load factor, the greater the "effective" TSC charge.

Q. Please explain why adopting a retail TSC rate design that reflects cost of service principles is appropriate.

A. There are many reasons why the retail rate design for the TSC (and other charges) should reflect cost of service principles.

First, the Commonwealth Court indicated that cost of service should be the "pole star" for the Commission's decisions. Based upon my discussions with PPLICA's counsel, this was not limited to solely the interclass allocation of the transmission costs, but also extends to the de facto intraclass allocation of the costs that occurs when a decision is made regarding retail rate design.

Second, Section 2804(6) of the Competition Act states that any public utility "that owns or operates jurisdictional transmission and distribution facilities shall provide transmission and distribution service to all retail customers in their service territory . . . on rates, terms of access and conditions that are comparable to the utility's own use of its system." 66 Pa. C.S. § 2804(6). Adopting a cost-based retail TSC design including both a demand and an energy component ensures that this mandate is fulfilled.

Third, adopting a retail rate design that departs from cost of service principles can result in rates that are unduly discriminatory for some customers. As I have shown in Table 1, there is significant and material variation in load factors among customers in this broad rate grouping. A customer with a high 5 CP load factor, who is charged for demand-related transmission expenses on an energy basis will effectively pay a higher charge for transmission service than a lower load factor customer in the same (Large C&I) rate group. Thus, even if transmission costs have been reasonably allocated to the Large C&I group as a whole, discrimination can and will occur among Large C&I customers, if the rate design does not reflect a proper relationship to cost.

Fourth, designing retail rates to reflect cost of service provides customers with appropriate signals and incentives regarding their use of the particular utility service. Because transmission facilities are installed and sized to meet the peak demand placed on the system, the customer should receive appropriate signals through retail rates to reduce its contribution to the system peaks. This is accomplished through the inclusion of an appropriate demand component in the retail rate design. Energy usage by the customer occurring outside the five coincident peaks for the zone is irrelevant on a cost of service basis.

Fifth, the TSC is included in the shopping equation when a customer purchases supply from an EGS. Departing from cost of service principles in the TSC rate design could influence the evaluation of competitive offers. This distortion should be avoided when possible.

Q. Was the retail transmission charge developed during PPL's Restructuring Proceeding and applied prior to January 1, 2005, designed as a "cents per kWh charge" similar to the one proposed here by PPL?

A. Not exactly. The unbundled transmission charge applicable prior to January 1, 2005, was a distinct "cents per kWh charge" for each rate schedule that was developed based on a kW demand allocation of transmission costs to each rate schedule that occurred in the cost of service study from the last bundled case prior to restructuring. In other words, Rate Schedules LP-4, LP-5, LP-6, IS-T and IS-P each had its own specific "cents per kWh" transmission charge developed based on the transmission costs allocated to the particular individual rate schedule.

The Company's proposed grouping of Rate Schedules LP-4, LP-5, LP-6, IS-T, IS-P and others to develop a single "cents per kWh" TSC represents a shift away from cost of service principles by removing the rate schedule-by-rate schedule

allocation. Rather than regressing from cost of service principles as PPL proposes, the Company should be progressing towards greater reliance on cost of service principles as indicated in the Lloyd decision by implementing a retail rate design for Large C&I customers that reflects appropriate demand and energy components.

Q. Do you have any further comments on why it is preferable to use a demand and energy retail rate design for the TSC?

A. Yes. The Company attempts to categorize the TSC grouping proposal as consistent with its CTC and ITC process. This is not entirely correct. PPL's tariff includes specific CTC and ITC charges for each rate schedule that are billed on a demand and energy basis. It is my understanding that only the annual reconciliation of over-collections and under-collections is accomplished on a customer grouping basis. PPLICA does not object to grouping LP-4, LP-5, LP-6, IS-T, IS-P and the other Large C&I rate schedules for reconciliation purposes if the retail rates for each are properly designed on a cost of service basis as advocated herein, which should minimize the amount to be reconciled each year.

Q. What is the second modification that must be made to the Company's TSC rate design for the Large C&I rate group?

A. The energy-related portion of Large C&I TSC costs should be recovered on a kWh basis that reflects differences in losses. About 50% of the kWh in the Large C&I rate group take service on Rate Schedules LP-4 and IS-P. These two rates serve customers who take service at primary voltage. All of the other rate schedules in the Large C&I group serve customers who take service at transmission voltage. Customers served at primary voltage must pay for additional losses to traverse the distribution system that are not applicable to customers taking service directly at transmission voltage. The kWh charge should be adjusted by a factor to reflect this cost of service difference.

Q. Have you developed the appropriate kWh charge voltage adjustment factors for the Large C&I rate group?

A. Yes. The Large C&I kWh charge should be adjusted by a factor of 1.01457 for customers on Rate Schedules LP-4 and IS-P and by 0.984601 for customers on Rate Schedules LP-5, IS-P, IS-T, LP-6, LPEP, ISA and Standby. I should also note that, if the Commission adopts the Company's proposal to recover the Large

C&I TSC costs entirely on a kWh basis (instead of using the correct 5 CP billing basis for the demand related portion of costs), these loss adjustment factors should be applied to the single kWh charge.

Q. Have you developed a Large C&I TSC rate reflecting these modifications?

A. Yes. Baron Exhibit__(SJB-4) shows the development of a cost-based Large C&I TSC rate for 2007 to illustrate these rate design proposals. The transmission demand revenue requirements are allocated to rate groups using the same 5 CP method as proposed by PPL. However, as I discussed previously, the energy portion reflects the use of loss adjusted rate group kWh as the allocation factor used to allocate energy-related revenue requirements.

PPL's implicit 2007 TSC rate for all Large C&I customers is $0.004454 per kWh.[4] With a correct energy allocation factor reflecting each rate group's cost responsibility (i.e., kWh energy including losses), the average 2007 TSC energy rate becomes $0.004418 per kWh for the Large C&I rate group.

[4] Based on Mr. Kleha's workpapers provided in response to OSBA Set I, Q 7-rm. The allocated Large C&I TSC revenue requirement of $53,873,442 divided by 12,095,551,004 kWh equals $0.004454 per kWh.

The equivalent PPLICA cost-based TSC rate for these customers is $1.74 per kW (5 CP basis), and $0.00121 per kWh. The kWh charge should then be adjusted up or down by the Large C&I primary or transmission voltage adjustment factor. This methodology should be used to calculate the Company's TSC on a going forward basis.

Q. Mr. Kasper has provided some estimates of the 2008 TSC rates for each rate group in his Exhibit OGK-Remand 3. Have you reviewed this exhibit?

A. Yes. This exhibit simply presents estimates of the 2008 TSC rate under two alternative assumptions regarding the timing of system peaks. The actual 2008 TSC will be calculated in a filing in November of 2007. Notwithstanding that this is only an illustration the analysis does not properly reflect the inclusion of losses in the energy portion of the rate group allocation factors. This should be corrected in the final 2008 TSC rate design, as I discussed previously.

Q. Have you reviewed the Company's plan to refund the prior over-collections and recover the prior under-collections associated with the incorrect "uniform kWh based" TSC rate that was implemented as of January 2005, but is being revised in this remand case?

A. Yes. The Company has calculated the over and under-collections for each rate group for the years 2005 through 2007 (estimated for 2007) and proposes to refund or surcharge these amounts over a two-year period beginning January 2008, by adjusting the applicable TSC charge.

Q. Do you agree with the Company's proposal?

A. No. As I discussed earlier, PPL has allocated the energy portion of TSC expenses based on rate group kWh at the meter and failed to properly reflect losses in the allocation factor. As a result, the Company's calculation of refunds and surcharges ("adjustments") is not correct.

Q. Have you corrected the Company's TSC refund and surcharge calculations for the period 2005 through 2007?

A. Yes. Baron Exhibit __(SJB-5) presents a summary of the revised calculations for the years 2005 through 2007, reflecting the use of rate group kWh at the transmission voltage level to allocate the energy portion of each year's TSC. In all other respects, the calculations are identical to those performed by Mr. Kleha.

Q. Do you have any additional concerns regarding the Company's TSC refund and surcharge proposal?

A. Notwithstanding PPLICA's recommendation (discussed later in my testimony) to implement the new TSC rates and begin the refund/surcharge earlier than January 2008 (if possible), the refunds and surcharges should be made through a separate rider. The reason for this recommendation is that some PPL customers who are entitled to a TSC refund would be denied such refunds if they were to purchase generation supply from an EGS during the two-year refund period. Since shopping customers will no longer pay a TSC (they are charged for transmission service from their EGS), they would lose their refund entitlement, if they were to shop. This is not a reasonable policy and creates a bias against shopping, which should be avoided.

An appropriate "shopping neutral" mechanism, such as a separate rider, should be used to provide the refunds and recover the prior TSC under-collections.

Q. PPL is proposing to calculate and reflect the TSC refunds and surcharges on customer bills on a per kWh basis for each rate group. Do you agree with

this approach to calculating the adjustments for prior years over or under-collections of the TSC?

A. Ideally, PPL would calculate a credit for each Large C&I customer based on the actual amount the customer was overcharged due to the inappropriate rate design. This would minimize intraclass cost shifting and the generational mismatch that may exist due to new customers and/or changes in usage by customers. Recognizing the administrative burden that this proposal may create, however, PPLICA can compromise by accepting the rate grouping proposal, under the circumstances of this remand. The purpose of the refunds and surcharges is to place customers in each rate group in the same approximate economic position that they would have been in had the Company's TSC been properly designed to reflect cost of service beginning in 2005. Since customers have been charged the incorrect TSC rate during the period 2005 through 2007 on a per kWh basis, it is proper that the adjustments (refunds, surcharges) also be made on the same basis.

Q. Is this consistent with your recommendation to use a 5 CP rate design for the Large C&I rate group?

A. Yes. Based on the estimates prepared by Mr. Kleha, the Large C&I rate group will receive a refund of past TSC overcharges. These overcharges were paid by Large C&I customers on a per kWh basis and, therefore, the refund can be made on the same basis. As previously stated, however, PPLICA would also support a more precise calculation for the Large C&I rate schedules.

III. APPORTIONMENT OF THE DISTRIBUTION REVENUE INCREASE TO RATE SCHEDULES

Q. Would you briefly summarize PPLICA's recommendation to apportion the Commission authorized distribution revenue increase, as discussed in your Direct Testimony in this case?

A. Yes. In my Direct Testimony in this case (PPLICA Statement No. 1), I recommended that the authorized distribution revenue increase be allocated to rate schedules in such a manner that the dollar subsidies paid and received by each rate schedule would be reduced by 50% at the new, authorized rates that reflect the Commission approved increase. As I discussed in that testimony, all of the commercial and industrial rate schedules were paying subsidies to residential customers at the then current distribution rates. Based on PPL's cost of service study, residential customers were receiving subsidies in their distribution rates of about $57 million annually.

Q. Did PPL propose to reduce these subsidies in its original rate filing?

A. Not for all rate schedules. Though the Company recognized that residential distribution rates were substantially below cost, PPL actually increased the

subsidies received by residential customers from other rate schedules, due to its self-imposed "10% total increase rule," which considered the impact of the combined transmission and distribution increases, thus ignoring distribution cost of service results in setting the distribution revenue increase. The Commission adopted PPL's approach.

In contrast, the PPLICA recommendation was based on consideration of the distribution cost of service in setting distribution rates and transmission cost of service in setting transmission rates through the TSC.

Q. Did the Commonwealth Court's decision in the Lloyd case reject the PPL methodology adopted by the Commission?

A. That is my understanding of the decision. The Court stated that it was ordering a remand "for the setting of non-discriminatory reasonable rates and rate structure for each service." Thus, it is now appropriate in this remand proceeding to address the subsidies that continue in PPL's distribution rates on a stand alone basis.

Q. Have you prepared an analysis of the subsidies paid by PPL's distribution customers using the Company's compliance cost of service study results, which reflect the Commission's adjustments to the originally filed case?

A. Yes. Baron Exhibit__(SJB-6) calculates the subsidies paid or received by each rate schedule at "present rates", based on the compliance cost of service study. "Present rates" reflect the distribution rates for each rate schedule, before the increases that became effective in January 2005.[5] Also shown in the exhibit are the subsidies paid and received by each rate schedule at current or "compliance" rates, which reflect the Commission's approved increases for each rate schedule, adjusted for the Court ordered removal of storm damage expenses. These "compliance rates" are now back before the Commission for review, in light of the Court's remand decision requiring consideration of distribution (and transmission) rates on a stand alone basis. Table 2 summarizes these subsidies for each rate schedule under present and compliance (current) rates.

[5] Present rates are thus the rates that were in effect prior to the increases authorized by the Commission in this case. In contrast, "Current rates" reflect the increases granted by the Commission and are currently being charged by the Company (adjusted to reflect the removal of storm damage expenses from rate schedules identified in the proposed SBRA).

Table 2
Dollar Subsidies at Present (pre-increase)
and Compliance Rates
($000)

Rate Class	Present Subsidies	Compliance Rate Subsidies*
RS, RTD	(44,423)	(63,939)
RTS	(6,530)	(9,257)
GS-1, BL	17,429	22,629
GS-3, IS-1	24,428	40,200
LP-4 *	6,080	9,788
ISP *	630	632
LP-5 *	838	738
IST *	1,140	614
LP-6	214	123
LPEP	66	60
ISA *	508	486
GH	1,777	2,766
SL/AL	(2,162)	(4,874)
L5-S	5	33
Total	(0)	0

* Reflects rate reduction for Hurricane Isabel costs as proposed by PPL

As can be seen from this table, the subsidies received by residential customers has increased, while the subsidies paid by GS-1, GS-3, LP-4 and GH have also increased. This of course assumes that no changes are made to current rates as a result of this remand proceeding.

Q. Is PPL proposing to change distribution rates in this case, in light of the substantial subsidies that continue to exist?

A. No. As discussed by PPL witnesses, the Company is not proposing any changes to its distribution rates in this remand proceeding. PPL argues that the compliance rates reflect some progress towards cost of service and that further progress will occur in its recently filed 2007 distribution rate case and subsequent cases.

Q. Do you agree with the Company's position of foregoing any adjustments to its current distribution rates to address the subsidy problem, until the 2007 base rate case is complete?

A. No. Table 3 shows the increases approved by the Commission that underlie the current, compliance rates (reflecting the removal of storm damage expenses). As can be seen, the overall distribution increase approved by the Commission in this case was 27%, while the rate schedules GS-1, GS-3 and LP-4 received increases of 29%, 42% and 41% respectively. This was done despite the fact that these rate schedules were paying rates substantially in excess of cost. Residential customers received increases of 23% and 13%. PPL's current rates do not adequately mitigate the subsidies that commercial and industrial customers have been and continue to pay in their distribution rates. The Company's current rates should be adjusted in this remand case, and further adjusted in future cases, to reduce and ultimately eliminate the dollar subsidies paid and received by each rate schedule.

In addition, appropriate credits should be calculated and paid to customers whose distribution rates decrease as a result of the decision on remand from the levels approved in the original litigation.

Table 3
Commission Approved Revenue Increases
Compliance Rates

Rate Class	Revenue Increase*	Percent Increase
RS, RTD	67,870	23.1%
RTS	469	13.4%
GS-1, BL	18,010	29.3%
GS-3, IS-1	35,371	42.0%
LP-4 *	8,833	40.8%
ISP *	311	17.8%
LP-5 *	(7)	-0.4%
IST *	(473)	-32.5%
LP-6	(82)	-28.9%
LPEP	74	23.7%
ISA *	(3)	-0.5%
GH	2,445	39.3%
SL/AL	1,773	10.0%
L5-S	39	108.1%
Total w/o PRS	134,632	27.2%
PRS	-	0.0%
Total w/o PRS	134,632	27.2%

* Excludes revenues from PRS
Reflects rate reduction for Hurricane Isabel costs per PPL

Q. Have you updated your revenue apportionment analysis to reflect the compliance cost of service study, which incorporated the Commission approved adjustments to the PPL rate case filing?

A. Yes. Using the compliance cost of service study, I have updated the PPLICA recommend "50% dollar subsidy reduction" revenue apportionment. Baron Exhibit__(SJB-7) shows this analysis, which apportions the Commission approved $134.6 million revenue increase (adjusted to remove the storm damage expenses). Table 4 summarizes the PPLICA recommended revenue increases for each rate schedule, using the "50% dollar subsidy reduction" methodology.[6]

Table 4
PPLICA Recommended Revenue Increases
"50% Subsidy Reduction Methodology"

Rate Class	Revenue Increase*	Percent Increase
RS, RTD	114,687	39.0%
RTS	1,371	39.0%
GS-1, BL	4,096	6.7%
GS-3, IS-1	7,385	8.8%
LP-4 *	2,085	9.6%
ISP *	(7)	-0.4%
LP-5 *	(326)	-20.3%
IST *	(517)	-35.5%
LP-6	(98)	-34.7%
LPEP	48	15.2%
ISA *	(236)	-36.3%
GH	567	9.1%
SL/AL	5,567	31.4%
L5-S	9	24.9%
Total	134,632	27.2%

*Reflects rate reduction for Hurricane Isabel costs per PPL

[6] Due to the large increase for rate RTS using the 50% dollar subsidy method, the PPLICA proposal is to combine the results for all residential rates (RS, RTD and RTS) to compute an average residential increase.

Q. Do you agree with PPL that further subsidy reductions should be implemented in future distribution rate cases?

A. Yes. However, I continue to support the PPLICA methodology that apportions the approved revenue increases in a manner that reduces the dollar subsidies being paid or received by each rate schedule. PPL has recommended a three case phase-in to fully eliminate its distribution rate subsidies.[7] While I do not object to phasing-in the elimination of subsidies over three cases, it is appropriate to begin in this current case and to explicitly confirm that the adopted plan will be implemented by the Commission in deciding future cases. In future cases, further dollar subsidies must be removed such that by the completion of the third case, distribution rates will be set at full cost of service.

Q. PPL witness Kleha recommends the use of a "relative rate of return index" criterion to move rates towards cost of service. How does this differ from the PPLICA recommendation?

A. Assuming that both the relative rates of return and the dollar subsidies are computed based on the same cost of service study, the two methodologies are

[7] Docket No. R-00049255 is the first of these three cases; the 2007 Distribution rate case (Docket No. R-00072155) is the second and the next distribution rate case would be the third.

directly related. However, it is possible that a rate schedule's relative rate of return could move towards 1.0 (which means that the rates are at cost of service), and have the dollar subsidies actually increase. Therefore, it is more appropriate to use a "dollar subsidy" reduction methodology, such as the PPLICA recommendation. Since customers pay rates based on "dollars," it is reasonable to calculate the amount of those "dollars" that are subsidy payments or receipts and target them for reduction. At the completion of the three-phase process, distribution rates should be identical under either the Company's method or the PPLICA method, since a rate of return index of 1.0 (which I understand to be the Company's goal) implies $0 subsidies.[8] The difference between the PPL approach and the PPLICA approach is the path over which this common ultimate objective will be met and whether the distribution rates move towards cost of service in each rate case. The PPLICA recommended methodology makes definitive progress in each case to reduce the dollars of subsidies paid or received by each rate schedule.

Q. Can you provide any illustration of the problem of using PPL's proposed "relative rate of return index" as the basis to move rates towards cost of service and reduce subsidies in the Company's distribution rates?

[8] This will not occur if the Commission abandons the subsidy reduction plan in future cases.

A. Yes. Baron Exhibit__(SJB-6) shows the rates of return at present distribution rates (the rates prior to the Commission's approved increase in this case in 2004) and at compliance rates (the rates in effect after the Commission approved increase). The rate of return for the residential class is 2.33%, which is a relative rate of return of 0.53. At present rates, the residential class was receiving a subsidy from other rate schedules of $44.4 million.

After the Commission approved increase, the rate of return for the residential class is 5.48% (compliance rate of return), compared to a total retail rate of return of 8.43%. This equates to a relative rate of return for rate RS of 0.65. PPL witness Kleha argues that this shows significant improvement. The problem, however, is that the subsidy received by the residential rate class actually increased to $63.9 million, an increase of 44% in the subsidies that are being funded by almost all of PPL's commercial and industrial customers. This cannot be considered progress towards cost of service, which the Commonwealth Court's Lloyd decision categorizes as the "pole star" to guide the Commission's decision regarding the establishment of just, reasonable and non-discriminatory distribution rates. Rather, similar to the allocation and rate design for the TSC discussed in the previous section of my testimony, this represents a regression away from cost of service for this rate schedule. Similarly, rate schedules such as Rate Schedule

LP-4 cannot be said to be moving towards cost of service when the subsidy in the revenue requirement for this customer class increases from $6.1 million at present rates (before the implementation of the January 1, 2005 change) to $9.8 million in the compliance rates.

Q. The Commission approved a revenue increase for the residential class of 23.1%, compared to an overall increase for all retail customers of 27.2% (see Table 3). Is there any justification to increase residential rates by less than the system average increase, when this rate class is only providing a "relative rate of return" of 0.53?

A. No. Even under the Company's relative rate of return criterion, there is no justification to increase residential rates by less than the system average, while increasing the rates of other schedules by significantly more than the system average, when these other rate schedules are providing relative rates of return far in excess of 1.0. This result, combined with the fact that the dollar subsidies received by the residential class increased by 44% is ample evidence that the Company's methodology is inadequate to produce just and reasonable distribution rates.

Q. Beginning on page 17 and continuing to page 21 of Mr. Kleha's testimony, he discusses alternative methodologies to develop a distribution cost of service analysis. Do you have any comments on Mr. Kleha's testimony on this issue?

A. Yes. As I discussed in my Direct Testimony, I am supporting PPL's distribution cost of service study. Though I would generally support the use of a minimum system analysis for primary distribution costs (which PPL did not incorporate in its analysis), the PPL cost of service methodology is a reasonable basis to assign distribution costs to rate schedules. As noted by Mr. Kleha, the Company has generally followed the cost of service principles described in the NARUC Electric Utility Cost Allocation Manual.

Q. Is there any basis for the use of distribution cost of service studies that classifies all or any portion of the distribution system as "energy"-related?

A. No. There is no basis to classify any distribution cost as energy-related. The two alternative cost of service studies presented by Mr. Kleha that rely on an energy classification of either 50% or 33% of the distribution system are not a reasonable basis to conduct a distribution cost analysis. Distribution plant and expenses are not "driven" by a customer's energy usage; rather these costs are incurred to: 1)

meet customer demands (either diversified or simply the maximum demand that could be imposed by a customer); or 2) simply provide an interconnection for the customer (a "customer-related cost") based on the minimum size equipment being installed to serve any customer. A customer's energy usage does not impact this "cost causation" determination, and it is inappropriate to classify or allocate any distribution costs on this basis.

The underlying (and incorrect) assumption is these energy based-studies is that a customer's energy usage impacts the level of distribution plant and expenses. To easily see why this is incorrect, assume that a modern grocery store decides to change its current 6:00 a.m. to 10:00 p.m. daily store hours to a 24 hour per day schedule. Typical grocery stores have maximum demands of about 500 kW. PPL would have to size its distribution system to meet this existing demand, which is primarily comprised of refrigeration, air conditioning and lighting loads. The distribution investment needed to serve this customer does not change, if the store hours increase to 24 hours per day. The same refrigeration, air conditioning and lighting loads exist. The increase in energy usage has no effect on the level of distribution investment and expenses.

IV. IMPLEMENTATION SCHEDULE

Q. When does PPL propose to implement its revised TSC rate and begin refunding or surcharging the prior over or under-collections from each rate group?

A. The Company is proposing to implement its revised TSC on January 1, 2008. The refunds or surcharges to each rate schedule would also begin on this date. Effectively, the Company is proposing to continue with its non-cost based TSC for the remainder of the year. The refunds and surcharge amount that will be amortized over a two year period beginning on January 1, 2008 including amounts for all of 2007.

Q. Should a revised, cost-based TSC be implemented earlier than January 2007, if the Commission approves the tariff earlier?

A. Yes. There is no reason to continue charging customers under an inappropriate TSC tariff beyond the date that the Commission issues an order in this case. If the parties agree with a revised TSC structure, the revised rate should be implemented as soon as possible.

Q. The Company is also proposing to implement its distribution rate changes and refunds to reflect the removal of storm damage expenses, required by the Court, on January 1, 2008. Should these rate adjustments and refunds be implemented sooner, if the Commission issues an order on these issues prior to this date?

A. Yes. As in the case of the TSC, customers have been paying excessive charges since the rate effective date in this case. Corrections to these rates, if approved by the Commission, should be implemented as soon as practicable. In addition, as I discussed earlier in my testimony, the Commission should adopt the PPLICA proposal in this remand case to reduce dollar subsidies in distribution rates by 50%, based on the Commission authorized revenue increase. PPL's proposal to gradually move rate schedule rates of return towards equality, while moving in the right direction, does not adequately address the very large dollar subsidies being paid by Large C&I rate schedules under the rates that are in effect today. The PPLICA proposed rates, based on the authorized $135 million revenue increase, less the excluded storm damage expenses, should be implemented upon Commission approval in this case.

Q. PPL is proposing to implement a new Special Base Rate Adjustment ("SBRA") beginning January 1, 2008 to provide refunds associated with approximately $4.1 million in Hurricane Isabel (storm expense). Do you agree with the Company's SBRA proposal?

A. Yes, as long as it is "shopping neutral" and applies to both POLR and shopping customers equally. The Company is proposing to use the storm damage refund to further the movement of rate schedules towards cost of service. I agree with this proposal, which applies the refund (in 2008) only to rate schedules that were shown to have been earning in excess of the average retail rate of return. These rate schedules (GS-1, GS-3, LP-4, LP-5, IS-T, LP-6, LPEP, IS-1, BL, SL/SA, GH-1, GH-2 and Standby) have been paying rates in excess of cost of service and should receive the SBRA rate credit to partially mitigate the subsidies that they have been paying to other rate schedules.[9]

Q. Does that complete your testimony?

A. Yes.

[9] This should not be interpreted to mean that the SBRA rate credit will resolve the subsidy problem. It does not. As discussed previously, the subsidies paid by these rate schedules are substantially greater than the impact of the SBRA.

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-00049255
	)	
PPL Electric Utilities Corporation	)	

REMAND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

PP&L INDUSTRIAL CUSTOMER ALLIANCE ("PPLICA")

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-00049255**
	)	
PPL Electric Utilities Corporation	)	

REMAND EXHIBIT__(SJB-1)

OF

STEPHEN J. BARON

ON BEHALF OF

PP&L INDUSTRIAL CUSTOMER ALLIANCE ("PPLICA")

Expert Testimony Appearances
of
Stephen J. Baron
As of May 2007

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.

Expert Testimony Appearances
of
Stephen J. Baron
As of May 2007

Date	Case	Jurisdict.	Party	Utility	Subject
6/85	84-768-E-42T	Clara WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.

Expert Testimony Appearances
of
Stephen J. Baron
As of May 2007

Date	Case	Jurisdict.	Party	Utility	Subject
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.

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Stephen J. Baron
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Date	Case	Jurisdict.	Party	Utility	Subject
10/87	E-015/ GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load forecasting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.

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Date	Case	Jurisdict.	Party	Utility	Subject
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410-EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.

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Date	Case	Jurisdict.	Party	Utility	Subject
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank-ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues
7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocated Stranded Cost Issues)	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate

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Date	Case	Jurisdict.	Party	Utility	Subject
			Millennium Inorganic Chemicals Inc.		unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross-Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.
5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/00	98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER-2854-000 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and the Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZKroger Company	Arizona Public Service Co.	Revenue allocation rate design.	
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

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of
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As of May 2007

Date	Case	Jurisdict.	Party	Utility	Subject
04/04	2003-00433 2003-00434	PA	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
10/04	04S-164E	CO	CF&I Steel Company, Climax Mines	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
07/05	U-28155	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos. 05-0402-E-CN 05-0750-E-PC	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Environmental cost recovery, Securitization, Financing Order
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses. Congestion Cost Recovery Mechanism
03/06	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Transmission Prudence Investigation
06/06	R-00061346 C0001-0005	PA	Duquesne Industrial Intervenors & IECPA	Duquesne Light Co.	Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues
06/06	R-00061366 R-00061367 P-00062213 P-00062214		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.

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Date	Case	Jurisdict.	Party	Utility	Subject
07/06	Case No. 2006-00130 Case No. 2006-00129	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
08/06	Case No. PUE-2006-00065	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Revenue Incr, Off-System Sales margin rate treatment
11/06	Doc. No. 97-01-15RE02	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power United Illuminating	Rate unbundling issues.
01/07	Case No. 06-0960-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Implementation of FERC Decision Jurisdictional & Rate Class Allocation
05/07	Case No. 07-63-EL-UNC	OH	Ohio Energy Group	Ohio Power, Columbus Southern Power	Environmental Surcharge Rate Design

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-00049255**
	)	
PPL Electric Utilities Corporation	)	

REMAND EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

ON BEHALF OF

PP&L INDUSTRIAL CUSTOMER ALLIANCE ("PPLICA")

Exhibit ___ (SJB-2)

Summary of Direct Testimony Submitted by
PP&L Industrial Customer Alliance ("PPLICA") Members

PPLICA Statement No. 2 – Direct Testimony of Jennifer Hunsperger

Ms. Hunsperger offers the perspective of Praxair, Inc., which operates two air separation facilities purchasing service from PPL on Rate Schedule IS-T. This testimony details the competitive impact that high distribution rates have on industrial gas producers and their customers. Ms. Hunsperger supports Stephen Baron's alternative Transmission Service Charge ("TSC") proposal as a favorable approach that will reduce annual transmission charge responsibility and allow large industrial Provider of Last Resort customers to better compare Electric Generation Supplier ("EGS") offers to POLR rates.

PPLICA Statement No. 3 – Direct Testimony of Larry Stalica

Mr. Stalica, on behalf of BOC Gases, similarly details the impact that PPL's proposed distribution rates will have on the narrow profit margins that exist in the air separation industry. BOC Gases is an industrial gas producer that owns and operates an air separation facility on PPL's IS-T rate. The testimony explains the benefits of the cost-based distribution rates that would result if all interclass subsidies are removed, and describes the disparity between these cost-based rates and PPL's proposed rates. Mr. Stalica likewise supports Mr. Baron's alternative phase-down proposal for removing interclass subsidies, and recommends Commission implementation of this plan. Mr. Stalica also addresses PPL's proposed transmission rate increase, and supports Mr. Baron's alternative proposal for calculating the TSC under the same methodology used by EGSs.

PPLICA Statement No. 4 – Direct Testimony of James H. Rooney

Mr. Rooney's Direct Testimony also supports Mr. Baron's three-year gradual movement toward cost of service rates over PPL's proposed distribution rates, and examines the excessive overcharges that will be incurred by Armstrong World Industries, Inc., under PPL's proposed rates. Mr. Rooney specifically requests the immediate phase-in of Mr. Baron's cost of service proposal. Comparing international strategies to PPL's current and proposed methods, Mr. Rooney warns that U.S. industrial customers like Armstrong will not long be able to endure excessive distribution charges in the face of such competitively favorable foreign alternatives. Additionally, Mr. Rooney supports Mr. Baron's alternate per kW-based transmission charge as consistent with the manner in which PPL incurs transmission costs from PJM. Armstrong World Industries, Inc., has two facilities in the PPL service territory that take service on Rate Schedules IS-T and IS-P.

PPLICA Statement No. 5 – Direct Testimony of Aaron P. Croop

Mr. Croop offers the position of Anvil International, Inc. ("Anvil"), which owns a production plant that purchases service from PPL on Rate Schedule LP-5. This testimony details

how PPL's proposed distribution rates will far exceed the cost of serving Anvil, and explains how PPL's proposed transmission rate increase will effectively penalize Anvil regardless of measures implemented to reduce its on-peak usage. Mr. Croop also recommends Mr. Baron's gradual implementation of cost of service rates in order to reduce excessive annual distribution charges and overpayments. With regard to PPL's proposed transmission charge increase, Mr. Croop explains in detail some efforts that Anvil already undertakes to reduce its usage during peak periods and explains how these efforts will be completely nullified under PPL's TSC proposal. Finally, Mr. Croop calculates the potential reduction in transmission costs available under Mr. Baron's proposal and accordingly supports Commission adoption of this alternative per kW approach to the TSC.

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-00049255
	)	
PPL Electric Utilities Corporation	)	

REMAND EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

ON BEHALF OF

PP&L INDUSTRIAL CUSTOMER ALLIANCE ("PPLICA")

Exhibit ___ (SJB-3)

References to Baron Testimony in Original Litigation

PPLICA Statement No. 1, Direct Testimony of Stephen J. Baron

- Pages: 7-9, 11, 13-45, 51-55, and Exhibits SJB-2 through SJB-12

PPLICA Statement No. 1-R, Rebuttal Testimony of Stephen J. Baron

- Pages: 3, 14-16

PPLICA Statement No. 1-S, Surrebuttal Testimony of Stephen J. Baron

- Pages: 3-19

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-00049255**
	)	
PPL Electric Utilities Corporation	)	

REMAND EXHIBIT__(SJB-4)

OF

STEPHEN J. BARON

ON BEHALF OF

PP&L INDUSTRIAL CUSTOMER ALLIANCE ("PPLICA")

PPLICA Corrected Allocation of 2007 TSC Revenue Requirement between Demand and Energy Components

Line No.	Description	Total Year-to-date
1	Network Transmission Service Charge	$135,322,727
2	Network Transmission Service Charge - Call Option	6,272,641
3	Seams Elimination Cost Assignment - SECA Charge	-
4	Seams Elimination Cost Assignment - SECA Call Option	-
5	PJM System Control and Dispatch Service	11,916,681
6	Transmission Owner Scheduling, System Control and Dispatch Servic	2,301,409
7	Reactive Supply and Voltage Control from Generation Sources Servic	13,344,133
8	Black Start Service	87,355
9	Regulation and Frequency Response Service	18,809,840
10	Operating Reserve - Supplemental Reserve Service	-
11	Day Ahead	2,930,627
12	Real Time (Balancing)	1,458,175
13	Synchronous Condensing Charge & Spinning Reserve	8,594,906
15	MAAC	298,208
16	PJM West Transition Charge	-
17	Transmission Losses (Point-to-Point) Credits	(1,200,000)
18	Non-Firm Point-to-Point Transmission Service Credits	(750,000)
19	PJM Membership	-
20	PJM Schedule 13 Expansion Cost Recovery Mechanism	210,341
		0
21	Total	$199,595,245

		Large C&I	Small C&I	Residential
NITS Load Responsibility	7,345.92	1,874.38	2,323.67	3,147.88
Allocation Factors	100.00%	25.52%	31.63%	42.85%
Energy @ Transmission Voltage	39,068,795	12,284,722	11,747,872	15,036,201
Allocation Factors	100.00%	31.44%	30.07%	38.49%
Energy @ Metered Voltage		12,095,551	11,073,912	14,173,593
Revenue Requirement				
Demand Components	$153,076,856	39,058,921	48,421,387	65,596,549
Energy Components	46,518,388	14,627,159	13,987,943	17,903,286
Total	$199,595,245	53,686,079	62,409,330	83,499,835
Costs to be recovered through Energy Charge		14,627,159	62,409,330	83,499,835
TSC Energy Charge		0.00121	0.00564	0.00589
Primary Metered Adjustment Factor		1.01457		
TSC Energy Charge for LP-4, ISP Customers		0.00123		
Transmission Voltage Metered Adjustment Factor		0.98460		
TSC Energy Charge for LP-5, IST,LP-6, LPEP, ISA and Standby		0.00119		
Costs to be recovered through Demand Charge		39,058,921		
TSC Demand Charge - Large C&I		$ 1.74		

Baron Exhibit__(SJB-4)

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-00049255**
	)	
PPL Electric Utilities Corporation	)	

REMAND EXHIBIT__(SJB-5)

OF

STEPHEN J. BARON

ON BEHALF OF

PP&L INDUSTRIAL CUSTOMER ALLIANCE ("PPLICA")

Summary of Revenue Billed Reallocation

	Total Adjustment w/ GRT	Adjustment w/ Interest & GRT Each Year 2008	2009
2005 Reallocation			
Large C & I	$12,016,629	$6,655,481	$7,138,003
Small C & I	$6,125,477	$3,685,026	$3,952,190
Residential	($18,142,107)	($10,340,506)	($11,090,193)
Net Change	$0	$0	$0
2006 Reallocation			
Large C & I	$14,814,747	$7,752,948	$8,315,037
Small C & I	$2,876,101	$1,660,876	$1,781,290
Residential	($17,690,848)	($9,413,824)	($10,096,327)
Net Change	$0	$0	$0
2007 Reallocation (Forecast)			
Large C & I	$11,485,753	$5,550,259	$6,325,880
Small C & I	($3,254,705)	($1,556,615)	($1,774,144)
Residential	($8,231,049)	($3,993,645)	($4,551,736)
Net Change	$0	$0	$0
Total Adjustment (Forecast)			
Large C & I	$38,317,130	$19,958,688	$21,778,920
Small C & I	$5,746,873	$3,789,287	$3,959,336
Residential	($44,064,003)	($23,747,975)	($25,738,256)
Net Change	$0	$0	$0

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-00049255
	)	
PPL Electric Utilities Corporation	)	

REMAND EXHIBIT__(SJB-6)

OF

STEPHEN J. BARON

ON BEHALF OF

PP&L INDUSTRIAL CUSTOMER ALLIANCE ("PPLICA")

PPL Electric Utilities Corporation
Summary of Subsidies - Prior Rate Case
Adjusted Compliance Cost of Service Studies

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Rate Class	Rate Base	Present Return	Present Rate of Return	Present Subsidy	Compliance Return	Compliance Rate of Return	Compliance Subsidy	% Change in Subsidy
1	RS	1,188,218	27,678	2.33%	(44,423)	65,111	5.48%	(63,939)	43.9%
2	RTS	43,171	(1,690)	-3.91%	(6,530)	(1,436)	-3.33%	(9,257)	41.7%
3	GS-1	177,572	17,333	9.76%	17,429	27,377	15.42%	22,629	29.8%
4	GS-3	270,794	25,253	9.33%	24,428	44,870	16.57%	40,200	64.6%
5	LP-4	67,662	6,297	9.31%	6,080	11,071	16.36%	9,788	61.0%
6	ISP	4,238	531	12.53%	630	704	16.61%	632	0.4%
7	LP-5	1,973	546	27.67%	838	571	28.94%	738	-12.0%
8	IST	751	658	87.62%	1,140	400	53.26%	614	-46.1%
9	LP-6	134	123	91.79%	214	79	58.96%	123	-42.2%
10	LPEP	975	79	8.10%	66	115	11.79%	60	-9.6%
11	ISA	264	290	109.85%	508	289	109.47%	486	-4.2%
12	GH	20,754	1,883	9.07%	1,777	3,266	15.74%	2,766	55.7%
13	SL/AL	60,291	1,455	2.41%	(2,162)	2,410	4.00%	(4,874)	125.5%
14	L5-S	166	10	6.02%	5	32	19.28%	33	559.5%
15	Total	1,836,963	80,446	4.38%	(0)	154,859	8.43%	0	

Gross Revenue Conversion Factor (calculated from Exh Future 1, Sch D-13, p.4 of 4 - 164,438/90162) 1.82381

Baron Exhibit__(SJB-6)

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-00049255**
	)	
PPL Electric Utilities Corporation	)	

REMAND EXHIBIT__(SJB-7)

OF

STEPHEN J. BARON

ON BEHALF OF

PP&L INDUSTRIAL CUSTOMER ALLIANCE ("PPLICA")

PPL Electric Utilities Corporation

Summary of Increases required to reduce Present Rate subsidies by 50% at Compliance Rates

Rate Class	Present Distribution Revenues	Proposed Distribution Revenue	Increase	Percent Increase	Difference from Compliance	Remaining Subsidy
RS, RTD	293,920	403,517	109,597	37.3%	41,727	(22,212)
RTS	3,513	9,974	6,461	183.9%	5,991	(3,265)
Average RES	297,433	413,491	116,058	39.0%	47,718	(25,477)
Adjusted RESIDENTIAL:						
RS RTD	293,920	408,607	114,687	39.0%	46,817	(17,122)
RTS	3,513	4,884	1,371	39.0%	902	(8,355)
GS-1	61,460	65,556	4,096	6.7%	(13,914)	8,715
GS-3	84,183	91,568	7,385	8.8%	(27,985)	12,214
LP-4 *	21,644	23,729	2,085	9.6%	(6,748)	3,040
ISP *	1,741	1,735	(7)	-0.4%	(317)	315
LP-5 *	1,607	1,281	(326)	-20.3%	(319)	419
IST *	1,455	938	(517)	-35.5%	(44)	570
LP-6	283	185	(98)	-34.7%	(17)	107
LPEP	313	361	48	15.2%	(27)	33
ISA *	649	414	(236)	-36.3%	(233)	254
GH	6,222	6,789	567	9.1%	(1,877)	888
SL/AL	17,705	23,272	5,567	31.4%	3,793	(1,081)
L5-S	36	46	9	24.9%	(30)	2
Total w/o PRS	1,089,599	1,456,346	366,747	33.7%	95,436	(50,954)
PRS	686	686	-	0.0%	-	-
Total w/o PRS	1,090,284	1,457,032	366,747	33.6%	95,436	(50,954)

Gross Revenue Conversion Factor (calculated from Exh Future 1, Sch D-13, p.4 of 4 - 164,438/90162)

* Excludes revenues from PRS which are included in COSS revenues

Baron Exhibit__(SJB-7)

OSBA STATEMENT NO. 1 (REMAND)

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-00049255
PPL ELECTRIC UTILITIES CORPORATION	:	

Remand Direct Testimony and Exhibits of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Distribution Revenue Allocation

Date Served: May 11, 2007

Date Submitted for the Record: _____

REMAND DIRECT TESTIMONY OF ROBERT D. KNECHT

1 Introduction and Overview

Q. Mr. Knecht, please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. With Mr. Mark D. Ewen of Industrial Economics, Incorporated ("IEc"), I submitted direct, rebuttal and surrebuttal testimony earlier in this proceeding. My qualifications were presented in Exhibit IEc-1 attached to our direct testimony. This testimony is solely my responsibility.

Q. What is the purpose of this testimony?

A. In this proceeding, PPL Electric Utilities Corporation ("PPL" or "the Company") has submitted a proposal for allocating the approved distribution revenue increase among the various rate classes. The distribution revenue increase, as approved by the Commission earlier in this proceeding and reduced on account of the decision by the Commonwealth Court in the *Lloyd* case, is approximately $134.65 million.[1] PPL's proposal for allocating that increase is virtually identical to that presented in its compliance filing earlier in this proceeding, with a minor adjustment to reallocate $1.19 million in Hurricane Isabel credits to those rate classes whose revenues exceed allocated costs.

The Pennsylvania Office of Small Business Advocate ("OSBA") retained me to evaluate whether PPL's proposal is consistent with sound economics and regulatory principles. In particular, OSBA asked me to evaluate whether or not PPL's proposal will result in proposed electric distribution rates for general service customers that are closer to, or farther away from, allocated costs.

Q. Please summarize the conclusions from your analysis.

A. In summary, my conclusions are as follows:

- Regarding distribution revenue allocation, the key question that must be addressed in this phase of the proceeding is whether the "relative rate of return" ("RRoR") metric

[1] See *Lloyd v. Pennsylvania Public Utility Commission*, 904 A.2d 1010 (Pa. Cmwlth. 2006).

can be relied upon as the sole indicator of progress toward cost-based rates. The answer is that it cannot.

- In a base rates proceeding, a utility submits a cost of service study ("COSS"), which has the objective of allocating a utility's revenue requirement among the various rate classes based on each class's causal contribution to incurring those costs. By any performance metric, PPL's COSS indicates that the general service rate classes (Rates GS-1, GS-3, and GH) are providing subsidies to the residential and lighting rate classes (Rates RS, RTS, and SL/AL) at current rates.[2]

- One of the primary objectives for revenue allocation in a utility base rates proceeding is to move class rates more into line with allocated costs. However, despite the fact that its cost allocation study shows that general service customers are providing subsidies to other classes at current rates, PPL inexplicably proposes to assign disproportionately high increases to those rate classes, and lower rate increases to those classes that receive subsidies. Not surprisingly, PPL's proposal therefore results in rates *moving away from* allocated costs, rather than *moving closer to* allocated costs.

- PPL's reliance on the relative rate of return ("RRoR") metric for evaluating progress toward cost-based rates is misplaced. To evaluate alternative revenue allocation proposals, the Commission should consider other metrics, all of which indicate that PPL's proposal will move rates farther away from allocated costs.

- Recognizing that PPL has a longer term plan of moving rates into line with allocated costs, and recognizing that the residential customers will be exposed to transmission

[2] For the purposes of this testimony, I use the term "subsidies" in a manner that is consistent with normal practice for utility cost allocation and rate design in "embedded cost" jurisdictions such as Pennsylvania. That is, a class that provides a subsidy exhibits revenues in excess of allocated embedded costs, and a class that receives a subsidy exhibits revenues below allocated costs. The theoretical economics definition of subsidy is based on incremental and stand-alone cost concepts, which are not particularly relevant in an embedded cost jurisdiction.

For the purposes of this testimony, I use the term "current rates" to mean those rates that were in place prior to the start of this proceeding, and not the rates that ratepayers currently see on their bills that were set in PPL's compliance filing.

rate increases associated with both prospective and retroactive rate changes, I recommend that the Commission adopt a "do no harm" approach to distribution revenue allocation in this proceeding. Specifically, I propose that the Commission apply a distribution rate increase on an "across-the-board" percentage basis for the major distribution rate classes.

- PPL's ratepayers have incurred over- and under-charges in distribution rates between 2005 and 2007 as a result of the flaws and inequities in PPL's compliance tariff. The differences between actual charges and those that would have resulted from an across-the-board rate increase in 2005 should be refunded to, or recovered from, customers using a special base rates adjustment ("SBRA") mechanism that applies to the 2008 to 2010 time period.

Q. How is your testimony organized?

A. Section 2 demonstrates why PPL's proposal is not consistent with moving rates into line with allocated costs. Section 3 explains why I believe that an across-the-board rate increase is justified in this phase of the proceeding.

2 PPL's Revenue Allocation Proposal

Q. Mr. Knecht, you are charged with evaluating whether PPL's distribution revenue allocation proposal is consistent with moving rates into line with allocated costs. What cost basis do you rely upon in your analysis at this stage of the proceeding?

A. In this testimony, I rely on the COSS submitted by PPL as Exhibit JMK-Remand 2. This COSS is PPL's compliance COSS, adjusted to exclude the Hurricane Isabel Storm Expense as mandated by the Commonwealth Court.[3] I rely on this COSS for several reasons.

[3] The "compliance COSS" is a version of PPL's originally filed cost of service study adjusted to the overall revenue requirement approved by the Commission, and corrected for certain programming errors identified by OSBA. Although it is my understanding that PPL prepares a compliance COSS at the end of a base rates proceeding, the Commission does not require that one be filed. In this phase of the proceeding, PPL has presented the results of its compliance COSS, as well as an adjusted compliance COSS reflecting the exclusion of Hurricane Isabel costs and revenues.

In its original filing in this proceeding, PPL submitted a COSS that was based on a cost allocation methodology that PPL had consistently used for many years. Two alternative COSSs were developed and submitted by intervenors. Pennsylvania Office of Consumer Advocate ("OCA") witness Richard Galligan relied on an alternative COSS analysis prepared by PPL that used significantly different cost allocation assumptions. On behalf of OSBA, Mr. Ewen and I presented an alternative COSS that (a) corrected a number of computational errors in PPL's COSS, and (b) relied on modestly different cost allocation assumptions.

For the reasons detailed in the OSBA rebuttal testimony, I disagree with the cost causation principles that underpin the cost allocation methodology used in the OCA COSS. In addition, Administrative Law Judge Allison K. Turner ("the ALJ") rejected the OSBA COSS, and she indicated that she relied primarily upon PPL's COSS in making her recommendation. The Commission did not reject her rationale regarding the choice of a COSS methodology. For that reason, I do not rely on either the OCA or the OSBA COSS.

In this phase of the proceeding, PPL's COSS again relies on the cost allocation methodology that it has used for many years. However, I note that Exhibit JMK-Remand 2 has been corrected for the computational errors that Mr. Ewen and I identified in PPL's original filing in 2004.[4]

Thus, I conclude that the PPL COSS submitted in this proceeding represents the most reasonable cost basis for my evaluation.

Q. Mr. Kleha explains that different cost allocation methodologies can have very different implications for revenue allocation, and that they can therefore only be used as a guide. Do you agree?

A. I certainly agree that different methodologies produce different results. I also agree that other considerations beyond allocated costs may affect revenue allocation decisions. In

[4] See PPL response to OSBA-Remand-1. All referenced interrogatory responses are attached to this testimony as Exhibit IEc-Remand-1.

particular, regulators will generally consider the principle of gradualism or avoidance of rate shock, and regulators will also often consider "value of service" ratemaking in certain competitive situations.

Nevertheless, it is important for a regulator to establish a specific cost basis for setting rates, based on the best understanding of cost causation. As the Commonwealth Court noted in the *Lloyd* decision, allocated cost is the "polestar" criterion for revenue allocation.[5] Thus, while other factors may temper the influence of allocated cost, Mr. Kleha's arguments cannot be used to simply ignore allocated costs, or to develop a revenue allocation proposal that moves rates away from allocated costs.

Unfortunately, that is exactly what PPL has proposed in this phase of the proceeding.

Q. How can a regulator use the results of a COSS as guidance for revenue allocation?

A. An "embedded cost" COSS allocates all of a utility's revenue requirement and its rate base among the various rate classes.[6] By comparing these allocated costs with the tariff revenues that are generated by each rate class, a COSS will show which rate classes are over-recovering allocated costs (i.e., they are providing a subsidy) and which classes are under-recovering allocated costs (i.e., they are receiving a subsidy). Typically, this information is then used to assign above-average rate increases to those classes that receive a subsidy under current rates, and to assign below-average rate increases to those classes that are providing the subsidy under current rates.

Q. What COSS metrics can be used to evaluate whether a class is receiving a subsidy or providing a subsidy?

A. A variety of different metrics are available to analysts and regulators. In general, these metrics fall into two different categories: rate of return metrics and revenue-cost metrics. These metrics can generally be calculated both at "current rates," meaning the rates that

[5] See *Lloyd v. Pennsylvania Public Utility Commission*, 904 A.2d 1010, 1020 (Pa. Cmwlth. 2006).

[6] By way of contrast, marginal cost studies allocate only those costs that vary directly with demand, consumption or other measurable factors. Marginal cost studies therefore require a "true-up" approach for reconciling allocated marginal costs with the utility's revenue requirement.

are in place *going into* a rate proceeding, and at "proposed rates," meaning the rates that are proposed to be in effect *coming out* of a rate proceeding.

Q. Please explain how *rate of return metrics* show whether a class is over- or under-recovering allocated costs, relative to the other rate classes.

A. A COSS can used to calculate the rate of return earned by each rate class. Class rate of return is calculated by taking the revenue produced by each class and subtracting allocated operating costs and taxes to produce class income. Class income is divided by allocated rate base to produce class rate of return. Algebraically, class rate of return for any class "i" is:

$$RoR_i = [Revenue_i - Allocated\ Operating\ Cost_i - Taxes_i] \div Allocated\ Rate\ Base_i$$

To evaluate whether a class is over- or under-recovering allocated costs relative to the other classes, the class rate of return can be compared to the system average rate of return. This comparison can be made in two different ways: the relative (or indexed) rate of return metric ("RRoR") and the differential rate of return ("DRoR") metric.

The RRoR is calculated by taking the *ratio* of the class rate of return to the system average rate of return. For example, if the class average rate of return is 4.5 percent, and the system average rate of return is 6.0 percent, the class RRoR is:

$$Class\ RRoR = 4.5 \div 6.0 = 0.75 = 75\ percent$$

If the class RRoR is less than 100 percent (or 1.0, or "unity"), the class is under-recovering allocated costs; if the class RRoR is greater than 100 percent, the class is over-recovering allocated costs.

The DRoR measure is calculated by taking the *difference* between class rate of return and system average rate of return. For example, if the class average rate of return is 4.5 percent, and the system average rate of return is 6.0 percent, the class DRoR is:

$$Class\ DRoR = 4.5 - 6.0 = -1.5\ percent$$

If the class DRoR is less than zero, the class is under-recovering allocated costs; if the class DRoR is greater than zero, the class is over-recovering allocated costs.

It is important to recognize, however, that these are *relative* metrics, in that they show differences among the rate classes on a relative basis. They are not necessarily *absolute* indicators regarding whether a class should be assigned a rate increase at all. For example, suppose the system average rate of return is 6.0 percent at current rates, and the rate of return for the commercial class is 7.5 percent at current rates. Both the RRoR and the DRoR metrics indicate that the class is over-recovering allocated costs. However, if the regulator determines that the utility should be entitled to an 8.5 percent rate of return overall, it will be necessary to assign *some* rate increase to the commercial class to bring its rate of return up to or above system average. On a relative basis, the metric implies that the relative rate increase for the commercial class should be below the average rate increase for the system as a whole.

Q. Please explain how the *revenue-cost metrics* can be used to show whether a rate class is over- or under-recovering allocated costs.

A. In addition to calculating a class rate of return, a COSS can be used to calculate the total cost allocated to each rate class, including the cost of capital (also called "return on rate base"). The total cost of providing service to each class is calculated as the sum of allocated operating costs, allocated income taxes and allocated capital costs. In this method, because capital costs and income taxes are incurred in proportion to rate base, these costs are allocated in proportion to rate base. Algebraically, the total allocated cost for each class "i" is:

$$\text{Alloc. Cost}_i = \text{Alloc. Operating Cost}_i + \text{Alloc. Taxes}_i + \text{Alloc. Capital Cost}_i$$

By comparing class revenues with class allocated costs, the COSS can be used to evaluate whether a class is over- or under-recovering allocated costs. In my experience, several different metrics can be used to make this comparison.

The first is to simply take the difference between revenues and allocated costs, a metric that can be defined as the revenue-cost differential ("RCD") or dollar subsidy approach.

If a class's RCD is greater than zero, the rate class is providing a subsidy; if the class RCD is less than zero, the rate class is receiving a subsidy.

In making this calculation at current rates, however, most analysts assume that the capital cost at current rates is not the full capital cost -- it is only the return on rate base that is provided at current rates. In that way, the system average RCD is zero, since system revenues are assumed to be equal to system allocated costs.

A second revenue-cost approach is to calculate the *ratio* of revenues to allocated costs, a metric known as the revenue-cost ratio ("RCR"). If the class's RCR exceeds 100 percent (1.0 or "unity"), the class is providing a subsidy; if the class's RCR is below 100 percent, the class is receiving a subsidy.

The third revenue-cost metric is the "normalized revenue-cost ratio" ("NRCR"). This metric is very similar to the RCR metric, but it can produce modestly different values than the RCR when applied at current rates. The NRCR metric recognizes that, at current rates, class revenues are less than allocated costs, because the full cost of capital is not recovered by current rates. The class NRCR is therefore calculated as the ratio of each class's revenues to the class's allocated cost at the full utility revenue requirement, which includes a full cost of capital. However, because that ratio will be below 100 percent on average, each class's ratio is *normalized* in such a way that the system average ratio is 100 percent. As I will show below, this metric has the advantage that it produces results that are most consistent with common sense.

Q. What do all of these metrics tell us about class over- and under-recovery of PPL's distribution costs in this proceeding?

A. In Table IEc-Remand-1 below, I show the results of each metric for PPL's major distribution rate classes. In that table, the cells in bold font represent classes that are receiving a subsidy; and the cells in normal font show a class that is providing a subsidy. (The RCD measure is reported in millions of dollars.)

Table IEc-Remand-1 *Subsidy Metrics for PPL Distribution Costs at Current Rates*					
	RRoR	*DRoR*	*RCD*	*RCR*	*NRCR*
RS	**53%**	**- 2.1%**	**($41.6)**	**88%**	**89%**
RTS	**- 89%**	**- 8.3%**	**($ 6.1)**	**40%**	**38%**
GS-1	223%	5.4%	$16.4	134%	132%
GS-3	213%	5.0%	$23.6	136%	130%
LP-4	213%	4.9%	$6.0	137%	131%
GH	207%	4.7%	$1.7	134%	128%
SL/AL	**55%**	**- 2.0%**	**($3.3)**	**85%**	**89%**
Total	*100%*	*0.0%*	*$0*	*100%*	*100%*

Source: Exhibit IEc-Remand-2, Schedule 2-A.
Note that totals include ISP, LP-5, IST, L-6, LPEP, ISA, and L5-S classes, although these classes have very little impact on distribution costs and revenues.

Table IEc-Remand-1 shows a consistent story from all of the different metrics. Each indicator shows that the RS, RTS and Lighting ("SL/AL") classes are receiving subsidies, and that the GS-1, GS-3, LP-4 and GH classes all provide subsidies.

Q. Is PPL's proposed revenue allocation consistent with reducing the subsidies reported in Table IEc-Remand-1?

A. Based on a common sense interpretation, it most certainly is not. (PPL Witness Krall admits that it is difficult to explain this counter-intuitive proposal to customers.[7]) PPL's distribution revenue allocation proposal in this proceeding is virtually identical to that in its compliance filing. In this stage of the proceeding, PPL has proposed only a modest adjustment to its compliance filing, by assigning the $1.2 million in Hurricane Isabel credits to the classes that provide subsides, namely all rate classes except RS, RTS and Lighting. While this adjustment represents some progress toward cost-based rates relative to the compliance filing, the impact is minimal.

As shown in Table IEc-Remand-2, PPL's proposal is exactly opposite of what common sense would dictate. The rate classes that are receiving subsidies are assigned below system average distribution rate increases (RS, RTS, and SL/AL), while the classes that

[7] PPL Statement No. Remand 1, page 18.

are providing the subsidies are assigned above system average distribution rate increases (GS-1, GS-3, LP-4, and GH).

Table IEc-Remand-2 PPL Proposed Rate Increases (Percent of Rate Revenues)	
	Increase
RS	**23.1%**
RTS	**13.4%**
GS-1	29.3%
GS-3	42.0%
LP-4	40.4%
GH	39.3%
SL/AL	**10.0%**
Total	*27.2%*
Source: Exhibit IEc-Remand-2	

Q. Beyond relying on common sense, can any of the metrics that you discuss above be used to evaluate whether each class's rates are moving closer to, or farther away from, allocated costs?

A. Yes. In fact, all of these metrics can be used to evaluate "progress toward cost-based rates." However, these metrics must be used with some care, since they can provide very different indications of whether or not any progress is being achieved. In the end, I encourage the Commission to consider all of these metrics, combined with a large dollop of judgment and common sense, when it evaluates competing revenue allocation proposals.

Q. How, specifically, can each of these metrics be used to evaluate progress toward cost-based rates?

A. Progress can be assessed by comparing the value of the metric at current rates with the value of the metric at proposed rates. Let me take them one at a time.

For the relative rate of return ("RRoR") metric, progress can be measured by calculating how much closer the metric has moved toward 100 percent between current and proposed rates. For example, if a class's RRoR is 88 percent at current rates and 94 percent at

proposed rates, then it has moved halfway (or 50 percent) toward allocated costs. That is, it would need to move 12 percentage points to get from 88 percent to 100 percent, but it has moved 6 percentage points. This is the approach adopted by PPL in this proceeding. Mr. Kincel, on behalf of the Department of Defense and All Federal Executive Agencies ("DOD/FEA"), also relied on RRoR, but he advocated much greater progress toward cost-based rates than did PPL.[8]

For the differential rate of return ("DRoR"), progress can be measured by calculating how much closer the metric has moved toward zero between current and proposed rates. For example, if a class's DRoR is 2.0 percent at current rates and 1.5 percent at proposed rates, its DRoR progress is 25 percent. That is, the class would need to move 2.0 percentage points to get to a DRoR of zero, but it moved only 0.5 points, or 25 percent of that amount. This is the approach that Mr. Ewen and I used earlier in this proceeding.

Progress as measured using the revenue-cost difference ("RCD") or dollar subsidy approach can be calculated in exactly the same way as the DRoR approach, because the goal is to measure progress toward zero. This approach was used by Mr. Baron on behalf of PPLICA earlier in this proceeding. Mr. Selecky, representing Walmart, also relied on a dollar subsidy approach as part of his "first dollar relief" proposal.

Progress under the revenue-cost ratio approaches (both "RCR" and "NRCR") can be measured in the same manner as for the RRoR, because the goal is to measure how much closer the metric has moved toward unity.

Q. What does each of these metrics reveal about progress toward cost-based rates under PPL's revenue allocation proposal?

A. Table IEc-Remand-3 below shows the amount of progress toward cost-based rates that is implied by each metric, under PPL's revenue allocation proposal. To interpret the results reported in this table, note that a negative value for the progress metric (in bold font in the table) implies that rates are moving away from allocated cost, and a positive

[8] Mr. Kincel also observes that PPL's original distribution revenue allocation proposal was counter-intuitive, using logic identical to that expressed in this testimony, as well as the direct testimony submitted by Mr. Ewen and myself. See Direct Testimony of Kenneth L. Kincel, page 23, lines 8-14.

value (normal font) indicates that rates are moving closer to allocated costs. For example, the RRoR metric implies that PPL's proposed increase for the RS class will move rates 25 percent of the way toward allocated cost. By contrast, the revenue-cost difference ("RCD") methodology implies that PPL's proposal will move rates for the RS class 44 percent farther away from allocated costs than they are under current rates.

Table IEc-Remand-3
Progress Toward Cost-Based Rates
Under PPL's Revenue Allocation Proposal

	RRoR	*DRoR*	*RCD*	*RCR*	*NRCR*
RS	25%	**-44%**	**-44%**	**-16%**	**-26%**
RTS	26%	**-42%**	**-42%**	**-9%**	**-7%**
GS-1	33%	**-30%**	**-30%**	**-2%**	**-7%**
GS-3	15%	**-65%**	**-63%**	**-23%**	**-49%**
LP-4	16%	**-61%**	**-58%**	**-20%**	**-44%**
GH	19%	**-56%**	**-55%**	**-17%**	**-43%**
SL/AL	**-17%**	**-125%**	**-76%**	**-47%**	**-105%**

Source: Exhibit IEc-Remand-2.
Note that totals include ISP, LP-5, IST, L-6, LPEP, ISA, and L5-S classes, although these classes have very little impact on distribution costs and revenues.

Table IEc-Remand-3 indicates that all of the metrics except RRoR show that PPL's proposal will move rates away from allocated costs. (Even the RRoR metric shows that PPL's proposal for street and area lighting classes moves rates away from allocated costs. PPL's Mr. Kasper acknowledges this point in PPL Statement No. Remand-2 at page 10.) Table IEc-Remand-3 also shows that the DRoR and RCD metrics indicate that PPL's proposal will result in greater *"negative progress"* (i.e., more movement away from allocated costs) than that implied by the revenue-cost ratio metrics (RCR and NRCR). In addition, other than for the lighting classes, the DRoR and RCD metrics show about the same amount of negative progress for each rate class.

Q. Why does the RRoR metric produce results that are at variance with both common sense and with all of the other metrics?

A. The fundamental arithmetic problem with the RRoR metric is that it relies on a ratio of ratios. As I explained earlier, rate of return, in and of itself, is already a ratio, namely the

ratio of income to rate base. The RRoR is the ratio of class rate of return to system average rate of return. By taking a ratio of ratios, the underlying revenue and cost components can be badly distorted. The largest distortion arises when the RRoR is used to compare current rates with proposed rates, because the RRoR measure can have a very different system average rate of return as a denominator.

Let's take the very simple example of PPL's GS-3 rate class. At current rates, the class rate of return is 9.33 percent, compared to a system average 4.38 percent return.[9] This yields a current-rates relative rate of return as follows.

$$Current\ GS\text{-}3\ RRoR = \frac{9.33\%}{4.38\%} = 213\%$$

If we assign an across-the-board increase, each class would face the system average increase of 27.6 percent. A 27.6 percent increase to the GS-3 class results in an increase in that class's rate of return of 4.73 percent, from 9.33 percent to 14.06 percent. It also results in an increase in the system average rate of return of 4.05 percent, from 4.38 percent to 8.43 percent.[10] Therefore, even with an across-the-board rate increase (which ought to, by common sense, show no progress toward cost-based rates), the GS-3 relative rate of return at proposed rates goes to:

$$Proposed\ GS\text{-}3\ RRoR = \frac{9.33\% + 4.73\%}{4.38\% + 4.05\%} = \frac{14.06\%}{8.43\%} = 167\%$$

Thus, by adding a similar number to both the numerator and the denominator of the relative rate of return equation, the index automatically moves substantially closer to unity, from 213 percent to 167 percent, even though the rate increase for the GS-3 class is no different from that for any other class.

[9] The details of this analysis are shown in Exhibit IEc-Remand-2, pages 1 and 2.

[10] An across-the-board increase has a slightly larger impact on the GS-3 class rate of return than it does on the system average, because the ratio of current revenues to rate base is higher for GS-3 than it is for the system as a whole. See Exhibit IEc-Remand-3 for the algebraic basis for this effect.

A similar pattern can be observed for the residential class. At current rates, the RS residential class rate of return is 2.33 percent, implying a relative rate of return of 53 percent based on the system average return of 4.38 percent. If the RS class is assigned a system-average 27.6 percent increase, the class rate of return increases by 3.77 percent, thereby having the following effect on its relative rate of return:

$$Proposed\ RS\ RRoR = \frac{2.33\% + 3.77\%}{4.38\% + 4.05\%} = \frac{6.10\%}{8.43\%} = 72\%$$

Again, by adding similar numbers to both the numerator and the denominator of the RRoR equation, the index moves closer to unity, from 53 percent to 72 percent, even though the residential class faces the same increase as every other class.

In Exhibit IEc-Remand-3, I have detailed the arithmetic for the relative rate of return calculation. That analysis demonstrates that, to hold the RRoR constant for a class that is currently over-recovering allocated costs, it is necessary to assign that class an above system average increase. It also demonstrates that, the more a particular class is over-recovering at current rates, the larger is the increase necessary to maintain a constant relative rate of return. In effect, keeping the RRoR at a constant level between current and proposed rates requires that subsidies increase.

Q. Mr. Krall opines that the illogical results exhibited by PPL's RRoR metric occur "because revenue, rate base, and return are not proportional among rate classes, particularly where there is a very significant distortion in rates of return among classes . . ." Is he correct?

A. No he is not. While these factors can contribute to counter-intuitive results, they are not the primary reason that the RRoR produces illogical results. The arithmetic shown in Exhibit IEc-Remand-3 demonstrates mathematically that, under the RRoR metric, an across-the-board rate increase will appear to result in significant progress toward cost-based rates. This result is not specific to PPL in this particular case; it is endemic to the RRoR metric.

Q. Mr. Kleha testifies that the Commission and other Pennsylvania electric, gas, and water utilities have relied upon the RRoR metric for many years. How can the Commission have relied upon a metric that produces results that are at odds with common sense?

A. I can speak only to the Pennsylvania base rate proceedings in which I have been involved. Based on that experience, however, I observe that utilities and the Commission have historically relied upon both the RRoR metric *and* common sense. That is, when they prepared their rate filings, utilities would apply judgment and common sense, and propose to assign above-average rate increases to classes that were providing subsidies, and to assign below-average increases to classes that were receiving subsidies. The utilities would then calculate the RRoR metric, which would indicate that progress was being made toward cost-based rates. While the RRoR may have overstated how much progress was being made, it was not producing counter-intuitive results. That is, the RRoR has not *always* been producing illogical results; however it can produce illogical results if a utility makes an illogical proposal.

For example, in PPL's 1994 base rates case (Docket No. R-00943271), the RRoR for the GS-1 rate class was 197 percent at then-current rates. In its filing, PPL proposed to assign a rate increase to the GS-1 class of 3.9 percent, compared to a system average increase of 11.7 percent. That is, because the GS-1 class was over-recovering allocated costs, PPL logically proposed to assign it a below-average rate increase. PPL's COSS analysis indicated that this proposal would reduce the RRoR for the GS-1 class from 197 percent to 154 percent. The RRoR metric did not produce a counter-intuitive result, because PPL did not make a counter-intuitive proposal.[11]

Unfortunately, I have observed recently that some utilities are abandoning common sense and relying solely on the indexed rate of return metric. As detailed above, PPL's original

[11] These values are derived from OSBA Statement No. 1 at Docket R-00943271, page 5 and Exhibit 4. The "current rates" values are also shown in Exhibit JMK-Remand 5, Attachment 3. In my testimony at the time, I opined: *"Note that movement of the indexed rate of return toward unity does not necessarily imply true progress toward cost-based rates. Using more neutral methods, the GS classes also exhibit progress toward cost-based rates. My citing of the indexed rate of return measure herein should not be construed as acceptance of this metric -- I cite it because of its widespread use in this jurisdiction."*

filing in this proceeding was illogical, although PPL can perhaps be forgiven because its proposal was driven by the arbitrary 10 percent bill impact constraint that it imposed in its original filing (and which was subsequently rejected by the Commonwealth Court).[12] However, PPL's gas distribution affiliate recently offered a similarly illogical proposal, in which its GS-Small rate class was assigned a proposed rate increase that was modestly in excess of system average, despite the fact that it exhibited the highest class rate of return.[13] PPL Gas attempted to justify that proposal on the basis of the RRoR metric. In that matter, the Commission rejected PPL's approach in favor of "first dollar relief" for the GS-Small class, which the Commission found to be consistent with *Lloyd*.[14]

Therefore, in my view, the problem that we observe in this proceeding is not that the Commission has, in the past, relied partly on a poor metric; it is that some utilities have abandoned common sense entirely and are imprudently basing revenue allocation proposals *only* on this one metric. This change *by the utilities* has caused the RRoR to go from a metric that merely overstated progress toward cost-based rates to one that implies that there is progress toward cost-based rates when the reverse is true.

Q. Mr. Kleha offers an example in Exhibit JMK-Remand 7 that purports to justify the RRoR metric. Can you comment on Mr. Kleha's example?

A. Mr. Kleha's example merely demonstrates the obvious, namely that the RRoR produces counter-intuitive results. In my view, the issue is not whether the RRoR metric *can* produce counter-intuitive results; the issue is whether the RRoR metric can be relied upon

[12] In its original filing, PPL set an upper bound of a 10 percent rate increase, on a total bill basis, as one of its constraints for its transmission-plus-distribution revenue allocation. Under its proposal for transmission rates, some rate classes (notably RS, RTS and SL/AL) experienced significant rate increases. When combined with the 10 percent bill constraint, these transmission increases limited PPL's ability to impose reasonable distribution rate increases for those classes. Other classes, including the GS-1 and GS-3 classes, were assigned relatively modest transmission cost increases. This left more room under the cap for distribution increases for those classes. In effect, PPL's original revenue allocation proposal for distribution rates was based more on transmission rate design and the total bill rate cap than on cost of service considerations.

[13] See OSBA Statement No. 1, Docket No. R-00061398, page 25.

[14] Pennsylvania Public Utility Commission, Opinion and Order, Docket No. R-00061398, pages 134-135.

as the sole indicator of progress toward cost-based rates. Mr. Kleha's example demonstrates that the answer to that question is "no."

Mr. Kleha's example shows that an across-the-board rate increase will cause all class RRoR values to move closer to 100 percent. As I demonstrate in Exhibit IEc-Remand-3, that result is almost certain to be true, if allocated costs and rate base are reasonably correlated. Mr. Kleha's example also shows that it is possible to assign above-average rate increases to the classes who are providing subsidies and still see RRoRs moving closer to unity. There is no need for an example to show this -- PPL's actual revenue allocation proposal has the same illogical results. In fact, as Mr. Kleha readily admits, his example can be used to demonstrate just how extremely wrong the RRoR can be. In Mr. Kleha's example, the following results obtain:

Table IEc-Remand-4
Implications of RRoR in Exhibit JMK-Remand 7 Example

	System	*Class X*	*Class Y*	*Class Z*
Rate of Return -- Current Rates	4.01%	2.03%	8.89%	7.69%
RRoR -- Current Rates	100%	51%	222%	192%
Rate Increase	30%	19%	50%	50%
Rate of Return -- Proposed Rates	8.60%	4.80%	18.00%	15.38%
RRoR -- Proposed Rates	100%	56%	209%	179%

Source: OSBA-Remand-3, Exhibit IEc-Remand-4, Schedule 4-B. Note that I have not corrected the conceptual and computational rounding errors in Mr. Kleha's exhibit.

In this example, Rate Class X produces a rate of return at current rates that is 2.0 percent, well below the system average of 4.0 percent. It is therefore receiving the subsidy. Rate Classes Y and Z both exhibit rates of return well above system average, meaning that they provide the subsidy. The example then assumes that the utility has abandoned all common sense, and proposes to impose a massive 50 percent increase on Rate Classes Y and Z, far in excess of the system average increase of 30 percent. With those increases, the Rate Class X increase needs to be only 19 percent, to achieve the system average increase of 30 percent.

Based on such an absurd proposal, one would normally expect the subsidies from Rate Classes Y and Z to Rate Class X to get much larger.[15] However, the RRoR metric implies just the reverse. All RRoR's move closer to 100 percent. No reasonable person would or could credibly believe that such a proposal was consistent with progress toward cost-based rates.

As I show in Exhibit IEc-Remand-4, all of the other metrics imply that this extreme proposal would result in rates that are much farther away from allocated costs. Therefore, Mr. Kleha's example demonstrates the fallacy of relying solely on the RRoR as a measure of progress toward cost-based rates.

Q. **In his rebuttal testimony earlier in this proceeding, Mr. Galligan opined that the RRoR metric can reasonably be used, because if the RRoR keeps moving toward 100 percent from rate proceeding to rate proceeding, PPL will eventually have rates that are based on allocated costs. PPL offers similar arguments with respect to its longer-term plan in this proceeding. Do you agree with this logic?**

A. No. As Mr. Ewen and I demonstrated in surrebuttal testimony, the RRoR *coming out* of this proceeding will not be the same as the RRoR *going into* the next rate proceeding. In all probability, the RRoRs *going into* the next proceeding will be much farther away from unity than the RRoRs *coming out* of this proceeding.

This result can be shown using Mr. Kleha's example, but continuing it into the next proceeding, as shown in Table IEc-Remand-5 below. The values for the current rate case are the same as those shown in Table IEc-Remand-4. That example seems to show that the proposal, in defiance of logic, results in progress toward cost-based rates. However, to see the fallacy of that line of reasoning, consider what happens in the next case.

For the next rate case, I assume that all allocated costs and rate base increase by approximately 30 percent. This rate increase implies that the system average rate of

[15] In fact, as shown in Exhibit IEc-Remand-5, all other metrics indicate that the subsidies are much larger at proposed rates than at current rates.

return *going into* the next rate case is back to the 4.01 percent that it was *going into* the current case.[16]

Table IEc-Remand-5
Implications of RRoR in Exhibit JMK-Remand 7 Example
For the Next Base Rates Case

	System	*Class X*	*Class Y*	*Class Z*
Rate of Return -- Current Rates	4.01%	2.03%	8.89%	7.69%
RRoR -- Current Rates	100%	51%	222%	192%
Rate Increase	30%	19%	50%	50%
Rate of Return -- Proposed Rates	8.60%	4.80%	18.00%	15.38%
RRoR – Proposed Rates	100%	56%	209%	179%
Cost Increase to Next Proceeding	30%	30%	30%	30%
Rate of Return -- Current Rates	4.01%	0.89%	11.71%	9.67%
RRoR -- Current Rates	100%	22%	292%	241%

Source: OSBA-Remand-1, Exhibit IEc-Remand-4, Schedules 4-B and 4-C..

As I explained above, Table IEc-Remand-5 shows that the RRoR appears to be closer to unity *coming out* of the current case than it was *going into* the current case. For example, it shows that the RRoR for Class Y declines from 222 percent at current rates to 209 percent at proposed rates in the current proceeding, despite facing a rate increase far in excess of system average. However, if we continue the example to the next base rates proceeding, the RRoR *going into* the next case will be much farther away from 100 percent than it is *going into* the current case. For example, while Rate Y class exhibits an RRoR of 209 percent *coming out* of the current case, it will show a 292 percent RRoR *going into* the next base rates case, even though its costs have increased proportionately. The net effect, comparing the RRoR *going into* the current case compared to the RRoR *going into* the next case, is an increase in the RRoR from 222 percent to 292 percent.

[16] Due to the treatment of tax adjustments in Mr. Kleha's example, the return *going into* the next rate case is slightly higher at 4.4 percent than the return *going into* the current rate case. The difference is immaterial.

This result is, of course, not surprising, because the example assumes that Rate Y is assigned a disproportionate rate increase in the current proceeding.

Thus, on an "apples-to-apples" basis, Mr. Kleha's example, when followed to its logical conclusion, indicates sensibly that this proposal causes rates to move farther away from allocated costs. For that reason, looking at the change in the RRoR between current and proposed rates *within* a single proceeding will obscure the longer term impact of a rate proposal.

Q. Mr. Knecht, you have expressed numerous concerns regarding sole reliance on the RRoR metric. Do you have similar concerns about the other metrics that you discuss above?

A. I do, albeit to a lesser extent. Exhibit IEc-Remand-3 presents the arithmetic underpinning all of the progress metrics, and it evaluates each of them in an "across-the-board" framework. That is, I ask the question, what kind of progress toward cost-based rates does each metric imply under an across-the-board increase? Common sense suggests that an across-the-board rate increase will result in little progress either toward or away from cost-based rates. The arithmetic in that exhibit supports the following general conclusions:[17]

- The differential rate of return ("DRoR') and revenue-cost difference ("RCD") methods will generally show about the same amount of progress toward or away from cost-based rates (as observed earlier with respect to PPL's proposal).

[17] In some circumstances, the complexities of specific cost allocation studies, such as complicated tax adjustments and non-rate revenue factors, may cause these generalizations to not be exactly correct in all circumstances. Nevertheless, these generalizations are useful for the Commission to consider when reviewing the results of these metrics.

- Under an across-the-board rate increase, the DRoR and RCD methods will tend to show that subsidies are increasing, rather than remaining the same, between current and proposed rates.[18] (As I noted earlier, I recognize that PPLICA Witness Baron relied on the RCD approach earlier in this proceeding, while Mr. Ewen and I relied on the DRoR approach.)

- The normalized revenue-cost ratio ("NRCR") approach is most consistent with the common sense conclusion, in that it exhibits no change between current and proposed rates under an across-the-board rate increase.

Q. In light of these observations, what metrics do you recommend that the Commission consider in base rates proceedings?

A. Because it is most consistent with my view of common sense, and because it is widely used in the various Canadian jurisdictions where I have testified, I prefer the revenue-cost ratio method, particularly the normalized revenue-cost ratio method. Nevertheless, for practical reasons, I recommend that the Commission consider all of these metrics. But more importantly, I think, the Commission should apply a healthy helping of common sense and judgment when evaluating competing revenue allocation proposals.

To move rates into line with allocated costs, rate classes that under-recover allocated costs should face above-average rate increases; rate classes that over-recover costs should face below-average or zero increases (or, in extreme cases, rate decreases). How much progress toward cost-based rates can be effected in any particular proceeding is a matter of judgment, based on rate shock, value of service, and other relevant practical considerations. It is as simple as that.

[18] As detailed in Exhibit IEc-Remand-3, subsidies measured by DRoR and RCD will increase with an across-the-board increase if the revenue to rate base ratio for subsidizing classes is higher than the system average revenue to rate base ratio, and if the revenue to rate base ratio for subsidized classes is lower than the system average revenue to rate base ratio. If allocated costs are closely correlated with allocated rate base, which is typical, these conditions will obtain. However, in some cases they do not, such as PPL's street lighting classes, which exhibit progress toward cost-based rates under an across-the-board increase.

3 IEc Remand Revenue Allocation Proposal

Q. Mr. Knecht, you and Mr. Ewen offered distribution revenue allocation proposals earlier in this proceeding. What considerations have caused you to alter those proposals?

A. Several factors have contributed to my re-thinking of our original proposals, including the following:

- PPL's revenue requirement is now known with certainty; our earlier proposals were based on PPL's proposed revenue requirement as well as a hypothetical scaleback. This knowledge reduces the uncertainty of rate class impacts.

- The Commonwealth Court determined that a total bill basis evaluation was not consistent with the required electric utility industry rate unbundling into generation, transmission and distribution components. However, our original proposals were based on total bill considerations. In particular, our original recommendations would now result in rates for the RTS and SL/AL classes that are farther away from allocated costs, based on all metrics except the RRoR.

- PPL's proposal for transmission rates in this portion of the proceeding will result in material rate increases for the RS and RTS rate classes, both prospectively for future rates and retroactively for recovery of 2005 to 2007 rate changes. While the Commonwealth Court rejected the total bill basis impact as the sole criterion for revenue allocation, I very strongly suspect that the transmission rate impacts will be a consideration for the Commission with respect to *how much* progress toward cost-based *distribution* rates can be effected in this proceeding.

- For the past three years, PPL's distribution rates for residential and lighting customers have been set too low, because PPL's compliance filing had the effect of moving rates away from allocated costs. Any change in that filing will therefore have both a prospective and retroactive effect on residential and lighting distribution rates. The retroactive impact will therefore also have an impact on how much prospective progress toward cost-based rates can be achieved in this proceeding.

- PPL has developed a specific plan to "move its distribution rates for all major rate classes to at or near full cost of service in three rate cases, including the 2004 rate case."[19] In addition, in PPL's current base rates case filing ("the 2007 base rates case"), it proposes a revenue allocation that will, based on my preliminary evaluation, make some progress toward cost-based rates.[20] Thus, it is not unreasonable to consider the proposal in the remand phase of this proceeding as the first step in a longer-term plan. I note also that it will be easier for PPL to achieve its ultimate goal if it does not take a step in the wrong direction in the current proceeding.

Q. What is your proposal for allocating distribution revenues in this remand proceeding?

A. In light of all of these considerations, I recommend that the Commission follow the admonition often given to medical students: *Primum non nocere*, or "First, do no harm." This proceeding represents the first step toward achieving PPL's goal of moving rates into line with allocated costs over three rate proceedings. In that light, it makes no sense to take the first step in the wrong direction. However, in recognition of the factors listed above, I do not believe that it is absolutely necessary to take a large step in the right direction in this phase of this proceeding. I therefore propose that the Commission approve an across-the-board rate increase, by applying the same percentage rate increase to all of the major distribution rate classes. In effect, I propose to get back to revenue-cost neutrality compared to the rates that were in place prior to the beginning of this proceeding.

As a practical matter, I propose some modest departures from a strict across-the-board approach. Specifically, I propose to retain the compliance filing rate increases for several rate classes, namely the ISP, LP-5, IST, LP-6, LPEP, and ISA rate classes. These classes

[19] PPL Statement No. Remand-1, page 11.

[20] *Unfortunately, in that filing, PPL again relies on the RRoR to determine that it has moved halfway toward cost-based rates.* For the reasons detailed above in response to Mr. Galligan's assertion, it is likely that PPL will effectively lose some of the RRoR progress that it thinks that it will achieve *coming out* of its 2007 base rates case by the time it *goes into* the subsequent base rates case. For that reason, PPL's proposal may need to be modified in order to achieve its stated goal.

generally exhibit class rates of return at current rates that are well in excess of system average, and PPL's compliance filing assigned below-average rate increases or rate decreases to those classes. Because the compliance filing for those classes implied rate increases that were consistent with progress toward cost-based rates, and because the overall distribution revenues associated with these classes are small, I see no reason to make any further adjustment to those class's rates at this time.[21]

The upshot of excluding those rate classes from any adjustment is that an "across-the-board" rate increase for the remaining classes requires an increase of 27.6 percent, which is only slightly higher than the system average increase of 27.2 percent.

Q. What are the implications of your proposal for progress toward cost-based rates?

A. My analysis of this proposal is detailed in Exhibit IEc-Remand-2, and summarized in Table IEc-Remand-6 below.

Table IEc-Remand-6
Progress Toward Cost-Based Rates
Under an Across-the-Board Revenue Allocation Proposal

	RRoR	*DRoR*	*RCD*	*RCR*	*NRCR*
RS	41%	**- 14%**	**- 14%**	9%	2%
RTS	31%	**- 34%**	**- 35%**	**- 3%**	**- 1%**
GS-1	36%	**- 23%**	**- 24%**	3%	**- 1%**
GS-3	41%	**- 14%**	**- 14%**	13%	**- 1%**
LP-4	40%	**- 15%**	**- 15%**	12%	**- 2%**
GH	41%	**- 13%**	**- 13%**	14%	**- 2%**
SL/AL	57%	17%	9%	25%	2%

Source: Exhibit IEc-Remand-2, Schedule 2-B.
Note that totals include ISP, LP-5, IST, L-6, LPEP, ISA, and L5-S classes, although these classes have very little impact on distribution costs and revenues.

Table IEc-Remand-6 reports progress toward cost-based rates under each of the five metrics with an across-the-board distribution rate increase. As I noted earlier, a positive

[21] To minimize changes relative to PPL's proposal, I have retained the assignment of a small amount of the Hurricane Isabel credits to these rate classes.

number for progress indicates that rates are moving into line with allocated costs. For example, the RRoR metric suggests that rates for the RS class have moved 41 percent of the way to allocated costs between current rates and proposed rates. In contrast, a negative number indicates that rates are moving farther away from allocated costs. For example, the DRoR metric indicates that RS rates are 14 percent farther away from allocated costs under proposed rates than they are at current rates.

Overall, Table IEc-Remand-6 generally shows a pattern that is consistent with the algebraic analysis presented in Exhibit IEc-Remand-3. That is, the RRoR metric counter-intuitively implies that there is substantial progress toward cost-base rates under this proposal. Conversely, the DRoR and RCD metrics generally suggest that this proposal will modestly move rates *farther away* from allocated costs. And finally, the normalized revenue-cost ratio shows virtually no progress either toward or away from cost-based rates in the context of an across-the-board rate increase. As I mentioned, that metric is therefore most consistent with common sense.

When considered in totality, these metrics suggest that an across-the-board increase will neither move rates significantly closer to allocated costs, nor will it move rates farther away from allocated costs. As such, it will do no serious harm.

Q. If your proposal is accepted, how do you propose to treat the over- and under-charges that have been in place since PPL's compliance filing took effect?

A. I propose to adopt a method that is conceptually similar to the Special Base Rate Adjustment ("SBRA") proposal made by PPL for refunding the Hurricane Isabel overcharges. For convenience, I will refer to this version as the "SBRA-2." In its SBRA proposal, PPL will apply a percentage credit to distribution bills for the eligible rate classes for a one-year period.

In my proposed SBRA-2 approach, PPL would determine the class-specific test year percentage difference between across-the-board revenues and compliance filing distribution revenues. It would then apply those percentage differences to each class's actual distribution revenues in 2005, 2006 and 2007, grossed up for interest. An approximation of the impact of this calculation is shown in Exhibit IEc-Remand-5.

The total over- and under-collection from each rate class would then be refunded or recouped through an SBRA-2 rider, applied as a percentage of base rates revenues. Of course, due to the revenue-neutral nature of the test-year distribution rate adjustments, the SBRA-2 factors would need to be class-specific, and there would need to be surcharges for some classes and credits for others. Specifically, the GS-1, GS-3, LP-4, and GH classes would be entitled to credits, and the RS, RTS and SL/AL classes would be subject to a surcharge.

In addition, because of the magnitude of the adjustment for some of the affected classes, I recommend that the SBRA-2 be amortized over a three-year period, rather than a single year as PPL proposes for the SBRA. While there is nothing magical about a three-year SBRA-2 period, it provides for a three-year period of redress which matches the length of time that PPL's distribution rates have been in effect.

Q. Can you summarize the key points in your remand testimony?

A. My key conclusions are as follows:

- The Commission cannot reasonably rely on the relative rate of return metric as the only indicator of whether proposed rates are better aligned with allocated costs than are current rates.

- PPL's sole reliance on the relative rate of return metric, in defiance of common sense and all other metrics, has caused it to offer a distribution revenue allocation proposal that moves rates farther away from allocated costs.

- In recognition of distribution costs, the need for retroactive adjustments, and transmission rate impacts, I recommend that an across-the-board percentage rate increase be applied to distribution rates for the major distribution rate classes.

- The revenue differences that have arisen between an across-the-board increase and PPL's rates should be reversed through an SBRA mechanism over the next three years.

Q. Does this conclude your remand direct testimony?

A. Yes it does.

EXHIBIT IEc-REMAND-1

REFERENCED INTERROGATORY RESPONSES

(in numerical order)

OSBA-Remand-1

OSBA-Remand-3

PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Small Business Advocate, Set I,
Dated April 19, 2007
Docket No. R-00049255

Q.1. Reference PPL Statement No. Remand-3, page 2, lines 10 to 12

a. Please confirm that OSBA witnesses Knecht and Ewen prepared an alternative cost allocation study that corrected errors made by PPL in its original filing.

b. Please confirm that OSBA witnesses Knecht and Ewen prepared an alternative cost allocation study that corrected errors made by PPL in its original filing and employed a zero-intercept methodology for classifying distribution system costs.

c. Please confirm that the cost allocation studies prepared by Messrs. Knecht and Ewen were available in "live" electronic format to all parties participating in the proceeding.

If you cannot confirm any or all of these statements, please explain your response fully.

A.1. It is acknowledged that Messrs. Knecht and Ewen prepared a cost allocation study, which included the use of a partial zero-intercept analysis based on their assumptions, that identified certain inadvertent programming errors in Exhibits JMK1 and JMK2 in the classification of costs between the demand and customer-related components. It is acknowledged that this cost allocation study was available electronically. Exhibits JMK-Remand 1 and JMK-Remand 2 reflect the correction of those programming errors.

PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Small Business Advocate, Set I,
Dated April 19, 2007
Docket No. R-00049255

Q.3. Reference Exhibit JMK-Remand-7:

a. Please provide an electronic version of this exhibit in MS Excel electronic format with cell formulae intact. If supporting workpapers are required, please provide them in MS Excel electronic format as well, with cell formulae intact.

b. Please explain how, in the non-proportional increase table, the sum of revenues of $400, $200, and $26 equal $631. If this table is incorrect, please provide a corrected version.

c. Please provide a version of the first "proposed rates" table (30 percent increase to each class) as it would appear *going into* the next base rates case, if each class's expenses (excluding income tax) and rate base increased by 30 percent. Please provide this analysis in MS Excel electronic format.

d. Please confirm that the relative rates of return going into the next rate case in your response to part (c) will look almost identical to the relative rates of return going into this rate case, implying that no progress toward cost-based rates has been made. If you cannot confirm, please explain your response.

e. Please provide a version of the second "proposed rates" table (non-proportional increase to each rate class) as it would appear *going into* the next base rate case, if each class's expenses (excluding income tax) and rate base increase by 30 percent. Please provide this analysis in MS Excel electronic format.

f. Please confirm that, in the results from part (e) of this interrogatory, the relative rates of return for each class going into the next rate case are further away from unity than they are going into this rate case, implying that rates have moved away from allocated costs. If you cannot confirm, please explain your response.

g. Please provide a version of the "proposed rates" table assuming rate increases of 50 percent for Rate Classes Y and Z, with Rate Class X being assigned the difference necessary to meet the $631 revenue requirement. Please provide this analysis in MS Excel electronic format.

h. Please confirm that the relative rates of return at proposed rates in your response to part (g) are closer to unity (albeit by a relatively small amount) than they are at present rates. If you cannot confirm, please explain your response.

i. Would PPL contend that assigning 50 percent rate increases to the *subsidizing* Rate Classes Y and Z, while assigning a rate increase of under 20 percent for *subsidized* Rate Class X, would imply that all three classes were making some progress toward cost-based rates? If your answer is in any way affirmative, please explain your response fully.

A.3. a.&b. Exhibit JMK-Remand 7, which was prepared in MS Word format, contained typographical errors that are corrected in Exhibit JMK-Remand 7 (Revised). See Attachment 1 and OSBA, Set I, Question 3 of the enclosed CD for a copy of Exhibit JMK-Remand 7 (Revised) in the MS Excel format.

c. See Attachment 1 and page 5 of OSBA, Set I, Question 3 of the enclosed CD.

d. The relative rates of return produced by the inclusion of OSBA's proposed assumptions regarding increased O&M expenses and rate base in Exhibit JMK-Remand 7 (Revised), which is a simple hypothetical example demonstrating that revenue, return and rate base are not proportional among rate classes, show that all rate classes diverge from the system average rate of return.

The Company would note that the hypothetical presented in this question is not meaningful because it assumes that increases in O&M expenses and rate base are uniform among rate classes, which they are not. Moreover, the fact that relative rates of return may change during the period between base rate cases is not surprising. Indeed, it is precisely for this reason that the Company has proposed to examine the relative rate of return of rate classes over a series of base rate cases, and not just in one base rate case. Moreover, the Company has proposed to move all rate classes to or near the system average rate of return over three base rate cases. If this goal is achieved, the fact that rate classes may change their relative rate of return position between those base rate cases is irrelevant.

e. See Attachment 1 and page 6 of OSBA, Set I, Question 3 of the enclosed CD.

f. The results show that all rate classes diverge from the system average rate of return, on a relative rate of return basis.

g. See Attachment 1 and page 7 of OSBA, Set I, Question 3 of the enclosed CD.

h. The results show that all rate classes move toward the system average rate of return, on a relative rate of return basis.

i. The Company believes that any movement, whether substantial or modest, toward the system average rate of return at proposed rates is a move toward cost-based rates.

ATTACHMENT 1

PPL Electric Utilities Corporation
Exhibit JMK-Remand 7 (Revised)
Hypothetical Example of
Revenue Increase Allocations by Rate Class
($000s)

	Total System	Rate Class X	Rate Class Y	Rate Class Z
Present Rates				
Revenue	485	315	150	20
Expense	415	290	110	15
Return	70	25	40	5
Rate Base	1,745	1,230	450	65
Rate of Return	4.01%	2.03%	8.89%	7.69%
Rate of Return % of Total System	100.00%	50.62%	221.70%	191.77%
Proposed Rates - 30% Increase to Each Rate Class				
Revenue	631	410	195	26
Expense	481	333	130	18
Return	150	77	65	8
Rate Base	1,745	1,230	450	65
Rate of Return	8.60%	6.26%	14.44%	12.31%
Rate of Return % of Total System	100.00%	72.79%	167.91%	143.14%
Change in Revenue	30.10%	30.16%	30.00%	30.00%
Change in Return	114.29%	208.00%	62.50%	60.00%

PPL Electric Utilities Corporation
Exhibit JMK-Remand 7 (Revised)
Hypothetical Example of
Revenue Increase Allocations by Rate Class
($000s)

	Total System	Rate Class X	Rate Class Y	Rate Class Z
Proposed Rates - Non Proportional Increase to Each Rate Class				
Revenue	631	405	200	26
Expense	481	331	132	18
Return	150	74	68	8
Rate Base	1,745	1,230	450	65
Rate of Return	8.60%	6.02%	15.11%	12.31%
Rate of Return % of Total System	100.00%	70.00%	175.70%	143.14%
Change in Revenue	30.10%	28.57%	33.33%	30.00%
Change in Return	114.29%	196.00%	70.00%	60.00%

PPL Electric Utilities Corporation
Exhibit JMK-Remand 7 (Revised)
Hypothetical Example of
Revenue Increase Allocations by Rate Class
($000s)

	Total System	Rate Class X	Rate Class Y	Rate Class Z
Expenses-Income Taxes:				
Present Rates:				
Revenues	485	315	150	20
Expenses				
GRT	29	19	9	1
O&M	290	220	61	9
Tax Adjustments	47	33	12	2
Total	366	272	82	12
Taxable Income	119	43	68	8
Income Taxes	49	18	28	3
Total Expenses	415	290	110	15
Proposed Rates - 30% Increase to Each Rate Class				
Revenues	631	410	195	26
Expenses				
GRT	38	24	12	2
O&M	290	220	61	9
Tax Adjustments	48	34	12	2
Total	376	278	85	13
Taxable Income	255	132	110	13
Income Taxes	106	55	46	5
Total Expenses	481	333	130	18
Proposed Rates - 30% Increase to Each Rate Class				
Revenues	631	405	200	26
Expenses				
GRT	38	24	12	2
O&M	290	220	61	9
Tax Adjustments	48	34	12	2
Total	376	278	85	13
Taxable Income	255	127	115	13
Income Taxes	106	53	48	5
Total Expenses	481	331	132	18
Tax Rates:				
Fed & State Comp Rate		41.4935%	41.4935%	41.4935%
GRT Rate		5.90%	5.90%	5.90%

PPL Electric Utilities Corporation
Exhibit JMK-Remand 7 (Revised), as Adjusted for OSBA, Set I, Question 3
Hypothetical Example of
Revenue Increase Allocations by Rate Class
($000s)

	Total System	Rate Class X	Rate Class Y	Rate Class Z
Going into Next Rate Case **- Present Rates**				
Revenue	485	315	150	20
Expense	466	328	121	17
Return	19	(13)	29	3
Rate Base	2,269	1,599	585	85
Rate of Return	0.84%	-0.81%	4.96%	3.53%
Rate of Return % of Total System	100.00%	-96.43%	590.48%	420.24%
Change in O&M	30.00%	30.00%	29.51%	33.33%
Change in Rate Base	30.03%	30.00%	30.00%	30.77%
Expenses-Income Taxes:				
Revenues	485	315	150	20
Expenses				
GRT	29	19	9	1
O&M	377	286	79	12
Tax Adjustments	47	33	12	2
Total	453	338	100	15
Taxable Income	32	(23)	50	5
Income Taxes	13	(10)	21	2
Total Expenses	466	328	121	17
Tax Rates:				
Fed & State Comp Rate		41.4935%	41.4935%	41.4935%
GRT Rate		5.90%	5.90%	5.90%

PPL Electric Utilities Corporation
Exhibit JMK-Remand 7 (Revised), as Adjusted for OSBA, Set I, Question 3
Hypothetical Example of
Revenue Increase Allocations by Rate Class
($000s)

OSBA, Set I, Q.3.c.

Going into Next Rate Case - Proposed Rates -
30% Increase to Each Rate Class

	Total System	Rate Class X	Rate Class Y	Rate Class Z
Revenue	631	410	195	26
Expense	532	371	141	20
Return	99	39	54	6
Rate Base	2,269	1,599	585	85
Rate of Return	4.36%	2.44%	9.23%	7.06%
Rate of Return % of Total System	100.00%	55.96%	211.70%	161.93%
Change in Revenue	30.10%	30.16%	30.00%	30.00%
Change in Return	421.05%	400.00%	86.21%	100.00%
Expenses-Income Taxes:				
Revenues	631	410	195	26
Expenses				
GRT	38	24	12	2
O&M	377	286	79	12
Tax Adjustments	48	34	12	2
Total	463	344	103	16
Taxable Income	168	66	92	10
Income Taxes	69	27	38	4
Total Expenses	532	371	141	20
Tax Rates:				
Fed & State Comp Rate		41.4935%	41.4935%	41.4935%
GRT Rate		5.90%	5.90%	5.90%

PPL Electric Utilities Corporation
Exhibit JMK-Remand 7 (Revised), as Adjusted for OSBA, Set I, Question 3
Hypothetical Example of
Revenue Increase Allocations by Rate Class
($000s)

OSBA, Set I, Q.3.e.

Going into Next Rate Case - Proposed Rates -
Non Proportional Increase to Each Rate Class

	Total System	Rate Class X	Rate Class Y	Rate Class Z
Revenue	631	405	200	26
Expense	532	369	143	20
Return	99	36	57	6
Rate Base	2,269	1,599	585	85
Rate of Return	4.36%	2.25%	9.74%	7.06%
Rate of Return % of Total System	100.00%	51.61%	223.39%	161.93%
Change in Revenue	30.10%	28.57%	33.33%	30.00%
Change in Return	421.05%	376.92%	96.55%	100.00%
Expenses-Income Taxes:				
Revenues	631	405	200	26
Expenses				
GRT	38	24	12	2
O&M	377	286	79	12
Tax Adjustments	48	34	12	2
Total	463	344	103	16
Taxable Income	168	61	97	10
Income Taxes	69	25	40	4
Total Expenses	532	369	143	20
Tax Rates:				
Fed & State Comp Rate		41.4935%	41.4935%	41.4935%
GRT Rate		5.90%	5.90%	5.90%

PPL Electric Utilities Corporation
Exhibit JMK-Remand 7 (Revised), as Adjusted for OSBA, Set I, Question 3
Hypothetical Example of
Revenue Increase Allocations by Rate Class
($000s)

OSBA, Set I, Q.3.g.

Proposed Rates - 50% Increase to Y & Z Rate Classes
and Increase to Rate Class X to Yield 30% Overall increase

	Total System	Rate Class X	Y	Z
Revenue	631	376	225	30
Expense	481	317	144	20
Return	150	59	81	10
Rate Base	1,745	1,230	450	65
Rate of Return	8.60%	4.80%	18.00%	15.38%
Rate of Return % of Total System	100.00%	55.81%	209.30%	178.84%
Change in Revenue	30.10%	19.37%	50.00%	50.00%
Change in Return	114.29%	136.00%	102.50%	100.00%
Expenses-Income Taxes:				
Revenues	631	376	225	30
Expenses				
GRT	37	22	13	2
O&M	290	220	61	9
Tax Adjustments	48	34	12	2
Total	375	276	86	13
Taxable Income	256	100	139	17
Income Taxes	106	41	58	7
Total Expenses	481	317	144	20
Tax Rates:				
Fed & State Comp Rate		41.4935%	41.4935%	41.4935%
GRT Rate		5.90%	5.90%	5.90%

EXHIBIT IEc-REMAND-2

REVENUE ALLOCATION ANALYSES

		Exhibit IEc-Remand-2: Schedule 2-A						
		PPL Remand Case: PPL Distribution Revenue Allocation Proposal						
	Total	RS	RTS	GS-1	GS-3	LP-4	ISP	LP-5
"Present" Rates								
Rate Revenues	495,418	293,920	3,513	61,460	84,182	21,873	1,757	1,774
Other Revenues	28,865	18,277	463	3,882	4,650	544	72	(100)
Total Revenues	524,283	312,197	3,976	65,342	88,832	22,417	1,829	1,674
O&M Expenses	298,298	209,067	5,421	26,268	32,946	8,606	706	602
Dep'n/Amortization	93,464	60,186	2,017	8,939	12,309	2,809	172	99
Total Taxes	52,075	15,266	(1,772)	12,802	18,324	4,705	420	427
Return	80,446	27,678	(1,690)	17,333	25,253	6,297	531	546
Total Cost	524,283	353,755	10,033	48,903	65,236	16,412	1,218	905
Rate Base	1,836,963	1,188,218	43,171	177,572	270,794	67,662	4,238	1,973
Rate of Return	4.38%	2.33%	-3.91%	9.76%	9.33%	9.31%	12.53%	27.67%
Indexed RoR	100.0%	53.2%	-89.4%	222.9%	212.9%	212.5%	286.1%	631.9%
Revenue/Cost Ratio	100.0%	88.3%	39.6%	133.6%	136.2%	136.6%	150.2%	185.0%
Normalized R/C Ratio	100.0%	89.2%	38.3%	132.0%	129.8%	130.5%	150.4%	201.6%
Differential RoR	0.00%	-2.05%	-8.29%	5.38%	4.95%	4.93%	8.15%	23.29%
Subsidy	-	(41,558)	(6,057)	16,439	23,596	6,005	611	769
Adjusted Compliance Rates								
Percent Rate Incr.	27.2%	23.1%	13.4%	29.3%	42.0%	40.4%	17.7%	10.6%
Rate Increase	134,649	67,870	469	18,010	35,372	8,833	311	11
Rate Revenues	630,067	361,790	3,982	79,470	119,554	30,706	2,068	1,785
Other Revenues	30,523	19,148	469	4,240	5,082	425	76	(64)
Total Revenues	660,590	380,938	4,451	83,710	124,636	31,131	2,144	1,721
O&M Expenses	299,383	209,828	5,441	26,364	33,066	8,637	709	604
Dep'n/Amortization	93,464	60,186	2,017	8,939	12,309	2,809	172	99
Total Taxes	112,884	45,813	(1,571)	21,030	34,391	8,614	559	447
Return	154,859	65,111	(1,436)	27,377	44,870	11,071	704	571
Total Cost	660,590	440,837	13,070	62,378	86,217	21,642	1,532	1,046
Rate Base	1,836,963	1,188,218	43,171	177,572	270,794	67,662	4,238	1,973
Rate of Return	8.43%	5.48%	-3.33%	15.42%	16.57%	16.36%	16.61%	28.94%
Indexed RoR	100.0%	65.0%	-39.5%	182.9%	196.6%	194.1%	197.0%	343.3%
Revenue/Cost Ratio	100.0%	86.4%	34.1%	134.2%	144.6%	143.8%	139.9%	164.5%
Differential RoR	0.00%	-2.95%	-11.76%	6.99%	8.14%	7.93%	8.18%	20.51%
Subsidy	-	(59,899)	(8,619)	21,332	38,419	9,489	612	675
Progress								
Indexed RoR		25%	26%	33%	15%	16%	48%	54%
Revenue/Cost Ratio		-16%	-9%	-2%	-23%	-20%	20%	24%
Normalized R/C Ratio		-26%	-7%	-7%	-49%	-44%	21%	37%
Differential RoR		-44%	-42%	-30%	-65%	-61%	0%	12%
Subsidy		-44%	-42%	-30%	-63%	-58%	0%	12%

Exhibit IEc-Remand-2: Schedule 2-A
PPL Remand Case: PPL Distribution Revenue Allocation Proposal

	Total	IST	LP-6	LPEP	ISA	GH	SL/AL	L5-S
"Present" Rates								
Rate Revenues	495,418	1,717	283	314	662	6,222	17,705	36
Other Revenues	28,865	(6)	(1)	(18)	(39)	445	694	2
Total Revenues	524,283	1,711	282	296	623	6,667	18,399	38
O&M Expenses	298,298	471	50	95	62	2,492	11,495	17
Dep'n/Amortization	93,464	34	6	53	13	959	5,860	8
Total Taxes	52,075	548	103	69	258	1,333	(411)	3
Return	80,446	658	123	79	290	1,883	1,455	10
Total Cost	524,283	646	80	219	126	4,972	21,744	35
Rate Base	1,836,963	751	134	975	264	20,754	60,291	166
Rate of Return	4.38%	87.62%	91.79%	8.10%	109.85%	9.07%	2.41%	6.02%
Indexed RoR	100.0%	2000.7%	2096.0%	185.0%	2508.4%	207.2%	55.1%	137.6%
Revenue/Cost Ratio	100.0%	264.7%	354.7%	135.0%	495.2%	134.1%	84.6%	108.4%
Normalized R/C Ratio	100.0%	320.6%	424.1%	128.7%	548.6%	127.9%	88.9%	96.6%
Differential RoR	0.00%	83.24%	87.41%	3.72%	105.47%	4.69%	-1.97%	1.64%
Subsidy	-	1,065	202	77	497	1,695	(3,345)	3
Adjusted Compliance Rates								
Percent Rate Incr.	27.2%	27.5%	29.0%	23.2%	0.5%	39.3%	10.0%	111.1%
Rate Increase	134,649	(473)	(82)	73	(3)	2,445	1,773	40
Rate Revenues	630,067	1,244	201	387	659	8,667	19,478	76
Other Revenues	30,523	(2)	-	(26)	(39)	524	687	3
Total Revenues	660,590	1,242	201	361	620	9,191	20,165	79
O&M Expenses	299,383	473	50	95	62	2,501	11,536	17
Dep'n/Amortization	93,464	34	6	53	13	959	5,860	8
Total Taxes	112,884	335	66	98	256	2,465	359	22
Return	154,859	400	79	115	289	3,266	2,410	32
Total Cost	660,590	672	84	290	143	6,567	26,063	50
Rate Base	1,836,963	751	134	975	264	20,754	60,291	166
Rate of Return	8.43%	53.26%	58.96%	11.79%	109.47%	15.74%	4.00%	19.28%
Indexed RoR	100.0%	631.8%	699.3%	139.9%	1298.5%	186.7%	47.4%	228.7%
Revenue/Cost Ratio	100.0%	184.7%	239.9%	124.6%	433.3%	140.0%	77.4%	159.4%
Differential RoR	0.00%	44.83%	50.53%	3.36%	101.04%	7.31%	-4.43%	10.85%
Subsidy	-	570	117	71	477	2,624	(5,898)	29
Progress								
Indexed RoR		72%	70%	53%	50%	19%	-17%	-243%
Revenue/Cost Ratio		49%	45%	30%	16%	-17%	-47%	-608%
Normalized R/C Ratio		62%	57%	14%	26%	-43%	-105%	1865%
Differential RoR		46%	42%	10%	4%	-56%	-125%	-559%
Subsidy		46%	42%	7%	4%	-55%	-76%	-900%

Exhibit IEc-Remand-2: Schedule 2-B
PPL Remand Case: "Across-the-Board" Distribution Revenue Allocation

	Total	RS	RTS	GS-1	GS-3	LP-4	ISP	LP-5
"Present" Rates								
Rate Revenues	495,418	293,920	3,513	61,460	84,182	21,873	1,757	1,774
Other Revenues	28,865	18,277	463	3,882	4,650	544	72	(100)
Total Revenues	524,283	312,197	3,976	65,342	88,832	22,417	1,829	1,674
O&M Expenses	298,298	209,067	5,421	26,268	32,946	8,606	706	602
Dep'n/Amortization	93,464	60,186	2,017	8,939	12,309	2,809	172	99
Total Taxes	52,075	15,266	(1,772)	12,802	18,324	4,705	420	427
Return	80,446	27,678	(1,690)	17,333	25,253	6,297	531	546
Total Cost	524,283	353,755	10,033	48,903	65,236	16,412	1,218	905
Rate Base	1,836,963	1,188,218	43,171	177,572	270,794	67,662	4,238	1,973
Rate of Return	4.38%	2.33%	-3.91%	9.76%	9.33%	9.31%	12.53%	27.67%
Indexed RoR	100.0%	53.2%	-89.4%	222.9%	212.9%	212.5%	286.1%	631.9%
Revenue/Cost Ratio	100.0%	88.3%	39.6%	133.6%	136.2%	136.6%	150.2%	185.0%
Normalized R/C Ratio	100.0%	89.1%	38.2%	132.2%	131.0%	131.6%	150.5%	201.7%
Differential RoR	0.00%	-2.05%	-8.29%	5.38%	4.95%	4.93%	8.15%	23.29%
Subsidy	-	(41,558)	(6,057)	16,439	23,596	6,005	611	769
"Across-the-Board" Proposed Rates			27.57%	630,067				
Percent Rate Incr.	27.2%	27.6%	27.6%	27.6%	27.6%	27.6%	17.7%	0.6%
Rate Increase	134,649	81,027	968	16,943	23,207	6,030	311	11
Rate Revenues	630,067	374,947	4,481	78,403	107,389	27,903	2,068	1,785
Other Revenues	30,497	19,296	475	4,214	4,928	462	76	(64)
Total Revenues	660,564	394,243	4,956	82,617	112,317	28,365	2,144	1,721
O&M Expenses	299,383	209,848	5,459	26,342	33,005	8,622	709	604
Dep'n/Amortization	93,464	60,186	2,017	8,939	12,309	2,809	172	99
Total Taxes	112,873	51,712	(1,371)	20,591	28,932	7,391	560	448
Return	154,844	72,496	(1,149)	26,745	38,072	9,543	703	570
Total Cost	660,564	441,632	13,116	62,290	85,424	21,462	1,532	1,046
Rate Base	1,836,963	1,188,218	43,171	177,572	270,794	67,662	4,238	1,973
Rate of Return	8.43%	6.10%	-2.66%	15.06%	14.06%	14.10%	16.59%	28.89%
Indexed RoR	100.0%	72.4%	-31.6%	178.7%	166.8%	167.3%	196.8%	342.8%
Revenue/Cost Ratio	100.0%	89.3%	37.8%	132.6%	131.5%	132.2%	140.0%	164.6%
Differential RoR	0.00%	-2.33%	-11.09%	6.63%	5.63%	5.67%	8.16%	20.46%
Subsidy	-	(47,389)	(8,159)	20,327	26,893	6,903	612	675
Progress								
Indexed RoR		41%	31%	36%	41%	40%	48%	54%
Revenue/Cost Ratio		9%	-3%	3%	13%	12%	20%	24%
Normalized R/C Ratio		2%	-1%	-1%	-1%	-2%	21%	36%
Differential RoR		-14%	-34%	-23%	-14%	-15%	0%	12%
Subsidy		-14%	-35%	-24%	-14%	-15%	0%	12%

Exhibit IEc-Remand-2: Schedule 2-B
PPL Remand Case: "Across-the-Board" Distribution Revenue Allocation

	Total	IST	LP-6	LPEP	ISA	GH	SL/AL	L5-S
"Present" Rates								
Rate Revenues	495,418	1,717	283	314	662	6,222	17,705	36
Other Revenues	28,865	(6)	(1)	(18)	(39)	445	694	2
Total Revenues	524,283	1,711	282	296	623	6,667	18,399	38
O&M Expenses	298,298	471	50	95	62	2,492	11,495	17
Dep'n/Amortization	93,464	34	6	53	13	959	5,860	8
Total Taxes	52,075	548	103	69	258	1,333	(411)	3
Return	80,446	658	123	79	290	1,883	1,455	10
Total Cost	524,283	646	80	219	126	4,972	21,744	35
Rate Base	1,836,963	751	134	975	264	20,754	60,291	166
Rate of Return	4.38%	87.62%	91.79%	8.10%	109.85%	9.07%	2.41%	6.02%
Indexed RoR	100.0%	2000.7%	2096.0%	185.0%	2508.4%	207.2%	55.1%	137.6%
Revenue/Cost Ratio	100.0%	264.7%	354.7%	135.0%	495.2%	134.1%	84.6%	108.4%
Normalized R/C Ratio	100.0%	320.7%	424.3%	128.7%	548.8%	128.9%	88.1%	96.7%
Differential RoR	0.00%	83.24%	87.41%	3.72%	105.47%	4.69%	-1.97%	1.64%
Subsidy	-	1,065	202	77	497	1,695	(3,345)	3
"Across-the-Board" Proposed Rate								
Percent Rate Incr.	27.2%	-27.5%	-29.0%	23.2%	-0.5%	27.6%	27.6%	111.1%
Rate Increase	134,649	(473)	(82)	73	(3)	1,715	4,881	40
Rate Revenues	630,067	1,244	201	387	659	7,937	22,586	76
Other Revenues	30,497	(2)	-	(26)	(39)	500	674	3
Total Revenues	660,564	1,242	201	361	620	8,437	23,260	79
O&M Expenses	299,383	473	50	95	62	2,497	11,601	17
Dep'n/Amortization	93,464	34	6	53	13	959	5,860	8
Total Taxes	112,873	336	66	98	257	2,132	1,698	22
Return	154,844	399	79	115	288	2,849	4,101	32
Total Cost	660,564	672	84	290	143	6,518	26,306	50
Rate Base	1,836,963	751	134	975	264	20,754	60,291	166
Rate of Return	8.43%	53.16%	58.80%	11.78%	109.13%	13.73%	6.80%	19.24%
Indexed RoR	100.0%	630.6%	697.6%	139.8%	1294.7%	162.9%	80.7%	228.3%
Revenue/Cost Ratio	100.0%	184.8%	240.0%	124.6%	433.5%	129.4%	88.4%	159.5%
Differential RoR	0.00%	44.73%	50.38%	3.35%	100.70%	5.30%	-1.63%	10.81%
Subsidy	-	570	117	71	477	1,919	(3,047)	29
Progress								
Indexed RoR		72%	70%	53%	50%	41%	57%	-242%
Revenue/Cost Ratio		49%	45%	30%	16%	14%	25%	-608%
Normalized R/C Ratio		62%	57%	14%	26%	-2%	3%	1878%
Differential RoR		46%	42%	10%	5%	-13%	17%	-557%
Subsidy		46%	42%	7%	4%	-13%	9%	-900%

EXHIBIT IEc-REMAND 3

ARITHMETIC IMPLICATIONS OF

METRICS FOR PROGRESS TOWARD COST-BASED RATES

Indexed Rate of Return

The indexed rate of return is purported to be a measure of progress toward cost-based rates in utility regulation. For each rate class, an indexed rate of return is calculated both at current rates and at proposed rates. If the index for a particular class moves closer to unity at proposed rates than at current rates, it is assumed that the class's revenues are more in line with costs at proposed rates. This section of testimony examines the arithmetic implications of this metric.

The indexed rate of return is defined as the ratio of the class rate of return to the system average rate of return. Algebraically, it is therefore:

(1) $IRR_i = [(R_i-C_i)/RB_i]/[(R_t-C_t)/RB_t]$

where:

IRR = Indexed Rate of Return

R = Revenues

C = Allocated Costs (excluding capital costs)[22]

RB = Rate Base

i = Rate Class indicator

t = System Total indicator

Define the IRR at current (CIRR) and proposed (PIRR) as follows:

(2) $CIRR_i = [(R_i-C_i)/RB_i]/[(R_t-C_t)/RB_t]$

(3) $PIRR_i = [((1+B_i)R_i-C_i)/RB_i]/[((1+B_t)R_t-C_t)/RB_t]$

where:

R = Current Rates Revenues

B = Proposed Revenue Increase Percent

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[22] Note that income taxes are not explicitly modeled in this analysis. However, if the income tax rate is the same for each rate class and system average, it simply drops out of the indexed rates of return calculation shown in equation (1). In more complicated cost allocation studies, such as PPL's, the myriad tax adjustments can affect the specific calculations and produce results that are different than those shown from the algebra. Changes in non-tariff revenues can also have an impact. Nevertheless, this mathematical analysis shows the general patterns that are most likely to obtain from the use of various "progress" metrics.

From a common sense perspective, if a rate class gets the same percentage increase as the system average (i.e., $B_i = B_t$), the indexed rate of return at current and proposed rates should be the same. That is, an across-the-board increase in rates should not imply that any progress is being made toward cost-based rates, nor should it imply that rates are moving further away from costs.

This issue can be analyzed two ways. First, consider the implications of no change occurring between $CIRR_i$ and $PIRR_i$, regarding the relative magnitudes of B_i and B_t. That is, if the indexed rate of return at proposed rates is exactly the same as the indexed rate of return at current rates, what does that imply for the relationship between B_i and B_t.

Algebraically, this goes as:

(4) $CIRR_i = PIRR_i$

substituting

(5) $[(R_i-C_i)/RB_i]/[(R_t-C_t)/RB_t] = [((1+B_i)R_i-C_i)/RB_i]/[((1+B_t)R_t-C_t)/RB_t]$

reducing

(6) $(R_i-C_i)/(R_t-C_t) = ((1+B_i)R_i-C_i)/((1+B_t)R_t-C_t)$

multiplying out

(7) $((1+B_i)R_i-C_i)(R_t-C_t) = ((1+B_t)R_t-C_t)(R_i-C_i)$

(8) $R_iR_t + B_iR_iR_t - R_iC_t - B_iR_iC_t - C_iR_t + C_iC_t = R_tR_i + B_tR_tR_i - R_tC_i - B_tR_tC_i - C_tR_i + C_tC_i$

simplifying

(9) $B_i(R_iR_t-R_iC_t) = B_t(R_iR_t - R_tC_i)$

(10) $B_iR_i(R_t-C_t) = B_tR_t(R_i-C_i)$

(11) $B_i = B_t[(R_i-C_i)/R_i]/[(R_t-C_t)/R_t]$

To interpret this equation, it is useful to think of the (R-C)/R expression as current rates income as a percent of current rates revenues or a margin percentage; call it M%. That is, it is a measure of the relative profitability of each rate class at current rates. In general, rate classes that exhibit higher margin percentages at current rates are those that provide subsidies to other classes, and those that exhibit lower margin percentages are the recipients of the subsidies. The equation can then be simplified to:

(12) $B_i = B_t(M\%_i)/(M\%_t)$

With that simplification, this equation tell us that for the class indexed rate of return to stay the same, the rate increase for the class must be the system average rate increase multiplied by the ratio of the M% for the class to the M% for the system.

Therefore, if a class is already over-recovering its allocated costs, its M% is almost certainly higher than system average. Under those conditions, for the indexed rate of return to remain exactly the same, it will need to be assigned a rate increase above system average. Moreover, the larger the current rates over-recovery, the larger will be the rate increase for the class. Similarly, for those classes that are under-recovering allocated costs (with $M\%_i$ being below $M\%_t$), the rate increase that is necessary to keep the indexed rate of return constant is below the system average increase. And, of course, the lower the current return for the class, the greater the discount necessary to simply break even.

Table 3-A attached to this exhibit shows the implications of this analysis for an example utility's Commercial class. At current rates, the margin percentage for the Commercial class is 43.5 percent, compared to a system average of 22.6, a ratio of about 1.92. At current rates, the Commercial IRR is 223 percent. System-wide, the utility proposes a $100 million increase that translates into an average percentage revenue increase of 30.1 percent. The breakeven analysis indicates that assigning a 57.9 percent increase (the 1.92 times the 30.1 percent) to the Commercial class will keep its indexed rate of return at 223 percent. Any increase below 57.9 percent for the Commercial class will result in a lower indexed rate of return, and will therefore imply progress toward cost-based rates. Thus, the utility's proposed increase for the Commercial class in this example of 47.3 percent causes the IRR metric to drop from 223 percent to 200 percent. Thus, the IRR metric implies that progress is being made toward cost-based rates for the Commercial Class, despite the fact that it is assigned a rate increase much higher than the system average of 30.1 percent.

The other approach to analyzing the IRR metric is to show the implications of an across-the-board rate increase. That is, set $B_i = B_t = B$. Algebraically:

(13) $CIRR_i = [(R_i-C_i)/RB_i]/[(R_t-C_t)/RB_t]$

(14) $PIRR_i = [((1+B)R_i-C_i)/RB_i]/[((1+B)R_t-C_t)/RB_t]$

by inspection

(15) $PIRR_i = CIRR_i[((1+B)R_i-C_i)/(R_i-C_i)]/[((1+B)R_t-C_t)/(R_t-C_t)]$

simplifying and substituting

(16) $PIRR_i = CIRR_i(1+B/M\%_i)/(1+B/M\%_t)$

This equation then shows that an across-the-board rate increase will cause the IRR to change between current and proposed rates. For those rate classes whose margin percentage is above system average ($M\%_i > M\%_t$), the proposed indexed rate of return will be lower than the current IRR, despite the fact that an across-the-board increase has been assigned. Conversely, for rate classes whose margin percentages are below system average, an across-the-board increase will cause the IRR to rise between current and proposed rates. Thus, the IRR metric will tend to move closer to unity for all rate classes using an across-the-board rate increase, despite the fact that common sense suggests that an across-the-board increase should be neutral in terms of cost recovery.

As shown in Table 3-A, this effect can be substantial. For the Commercial class, an across-the-board rate increase of 30.1 percent would cause the class IRR to fall from 223 percent to 162 percent. Not surprisingly, the IRR metric implies that an across-the-board increase would result in "even more" progress toward cost-based rates for the Commercial class than the increase proposed by the utility.

Finally, as explained in the text, the indexed rate of return tends to move toward unity because a similar number is added to both the numerator and denominator of the IRR ratio. The difference between the rate of return effect for a class and for the system as a whole is a function

of the ratio of revenue to rate base. For any class, or even the system as a whole, the increase in rate of return associated with a percentage revenue increase of B is:

(17) Current RoR = (R - C)/RB

(18) Proposed RoR = [(1+B)*R - C]/RB

(19) Change in RoR = B * R/RB

Thus, in the context of an across-the-board percentage increase, the amount of the change in the RoR between current and proposed rates for any class will depend on the ratio of revenues to rate base at current rates. Thus, in the example reported in the text of this testimony, the effect of an across-the-board increase on rate of return is slightly larger for GS-3 than for the system as a whole, because its revenues are somewhat higher in proportion to rate base than the system average. Similarly, for the RS class, the change in RoR is somewhat below the system average, because the class revenue to rate base ratio is below average.

Other Metrics

The tables attached to this exhibit evaluate the following alternative metrics for evaluating progress toward cost-based rates:

- Dollar cross-subsidy (or revenue-cost difference);
- Differential rate of return;
- Revenue-cost ratio;
- Normalized revenue-cost ratio.

All four of these metrics are evaluated using the "breakeven analysis." That is, the arithmetic shows what rate increase for each class will result in no change in the particular metric. For example, for the dollar cross-subsidy metric, a class increase that is equal to the system average increase multiplied by the system revenue to rate base ratio divided by the class

revenue to rate base ratio will produce no change in the dollar cross-subsidy between current and proposed rates. Algebraically, for that metric, the breakeven class increase is:

$$(17) \qquad B_i = B_t(R_t/RB_t)/(R_i/RB_i)$$

The breakeven algebra for the other metrics is reported on the attached tables. Based on that analysis, it is clear that all of the other metrics are far superior to the indexed rate of return for evaluating progress toward cost-based rates.

First, the constant dollar cross-subsidy and the differential rate of return methodology exhibit the identical results from the breakeven analysis. For these metrics, the rate increase necessary to result in no change in the subsidy metric will generally require the rate increase for an over-recovering class to be less than system average. Thus, in the example shown, to maintain a constant dollar cross-subsidy from the commercial class, it is necessary to assign a 25.9 percent increase which is slightly below the system average increase.

Second, for the non-normalized revenue-cost ratio[23] metric, the breakeven analysis indicates that the rate increase necessary to maintain a constant revenue-cost ratio between current and proposed rates will be slightly different from the system average increase, depending on the relationship between costs allocated to the class and rate base allocated to the class. In the special case where a class's allocated costs are the same as the class's share of allocated rate base, a class increase equal to the system average increase will result in no change in the revenue-cost ratio between current and proposed rates.

Finally, the normalized revenue-cost ratio metric is the most credible of all approaches, from a common-sense standpoint. If an across-the-board rate increase is assigned, the normalized revenue-cost ratio remains exactly the same at current and proposed rates. That is, this approach is most consistent with common sense, because an across-the-board rate increase will result in no progress toward cost-based rates, nor will it suggest that rates are moving farther away from cost-based rates.

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[23] The non-normalized or "simple" revenue-cost ratio at current rates is calculated as the ratio of current rate revenues to allocated *current* costs, where the return to capital in current costs includes only the actual return provided. In effect, that metric tends to understate the actual capital-related costs of the utility. The normalized revenue-cost ratio metric for current rates is based on the ratio of current revenues to *proposed* costs, including the utility's proposed return on capital. Because that metric will necessarily be less than unity, the results for all classes are normalized to equal an average of 100 percent. As shown in the attached arithmetic, this approach produces common-sense results. Note also that, at proposed rates, the non-normalized and normalized approaches produce the same values.

Supporting Calculations for Exhibit IEc-Remand-3: Table 3-A
Indexed Rate of Return
$ millions

	Current Rates		*Breakeven Increase*		*Across-the-Board Increase*		*Utility Proposal*	
	Class (i)	*System (t)*	*Class (i)*	*System (t)*	*Class (i)*	*System (t)*	*Class (i)*	*System (t)*
Revenue	52.3	331.7	82.6	431.6	68.1	431.6	77.1	431.6
Cost	29.6	256.6	29.6	256.6	29.6	256.6	29.6	256.6
Return	22.7	75.0	53.0	175.0	38.5	175.0	47.5	175.0
Rate Base	168.7	1,243.6	168.7	1,243.6	168.7	1,243.6	168.7	1,243.6
RoR	13.5%	6.0%	31.4%	14.1%	22.8%	14.1%	28.1%	14.1%
Indexed RoR	223%		223%		162%		200%	
Capital Cost Current	10.2	75.0						
Capital Cost Proposed	23.7	175.0	23.7	175.0	23.7	175.0	23.7	175.0
Subsidy $	12.6	-	29.3	-	14.8	-	23.7	-
Differential RoR	7.4%		17.3%		8.7%		14.1%	
Revenue-Cost Ratio	132%		155%		128%		145%	
Normalized R/C Ratio	128%		155%		128%		145%	
Income % of Revenue	43.5%	22.6%	64.2%	40.5%	56.5%	40.5%	61.6%	40.5%
RoR Increase			17.9%	8.0%	9.3%	8.0%	14.7%	8.0%
Revenue Increase			57.9%	30.1%	30.1%	30.1%	47.3%	30.1%

Breakeven Class Increase = System Average Increase *
Class Income % of Revenue / System Income % of Revenue

Breakeven Algebra:
CIRRi = [(Ri-Ci)/RBi]/[(Rt-Ct)/RBt]
PIRRi = [((1+Bi)Ri-Ci)/RBi]/[((1+Bt)Rt-Ct)/RBt]
Breakeven at CIRRi = PIRRi
With a little algebra, solve for Bi:
Bi = Bt * [(Ri-Ci)/Ri]/[(Rt-Ct)/Rt]

Supporting Calculations for Exhibit IEc-Remand-3: Table 3-B
Dollar Subsidy/Differential RoR
$ millions

	Current Rates		*Breakeven Increase*	
	Class (i)	*System (t)*	*Class (i)*	*System (t)*
Revenue	52.3	331.7	65.9	431.6
Cost	29.6	256.6	29.6	256.6
Return	22.7	75.0	36.3	175.0
Rate Base	168.7	1,243.6	168.7	1,243.6
RoR	13.5%	6.0%	21.5%	14.1%
Indexed RoR	223.3%		152.9%	
Capital Cost Current	10.2	75.0		
Capital Cost Proposed	23.7	175.0	23.7	175.0
Subsidy $	12.6	-	12.6	-
Differential RoR	7.4%		7.4%	
Revenue-Cost Ratio	132%		124%	
Normalized R/C Ratio	128%		124%	
Income % of Revenue	43.5%	22.6%		
RoR Increase			8.0%	8.0%
Revenue Increase			25.9%	30.1%

Breakeven Class Increase = System Present Revenue to Rate Base/
Class Revenue to Rate Base

Breakeven Algebra:
CSUBi = Ri - Ci - rRBi
PSUBi = (1+Bi)Ri - Ci - (r+d)RBi
Note d = Bt*Rt/RBt
PSUBi = (1+Bi)Ri - Ci - (r+BtRt/RBt)RBi
Breakeven at PSUBi = CSUBi
PSUBi - CSUBi = BiRi - BtRt/RBtRBi = 0
Bi = Bt(Rt/RBt)/(Ri/RBi)

Similarly, for Differential RoR
CDRRi = (Ri - Ci)/RBi - (Rt - Ct)/RBt
PDRRi = ((1+Bi)Ri - Ci)/RBi - ((1+Bt)Rt - Ct)/RBt
PDRRi - CDRRi = BiRi/RBi - BtRt/RBt = 0
Bi = Bt(Rt/RBt)/(Ri/RBi)

Supporting Calculations for Exhibit IEc-Remand-3: Table 3-C
Non-Normalized R/C Ratio Example
$ millions

	Current Rates		*Breakeven Increase*	
	Class (i)	*System (t)*	*Class (i)*	*System (t)*
Revenue	52.3	331.7	70.2	431.6
Cost	29.6	256.6	29.6	256.6
Return	22.7	75.0	40.6	175.0
Rate Base	168.7	1,243.6	168.7	1,243.6
RoR	13.5%	6.0%	24.0%	14.1%
Indexed RoR	223.3%		170.9%	
Capital Cost Current	10.2	75.0		
Capital Cost Proposed	23.7	175.0	23.7	175.0
Subsidy $	12.6	-	16.8	-
Differential RoR	7.4%		10.0%	
Revenue-Cost Ratio	132%		132%	
Normalized R/C Ratio	128%		132%	
Income % of Revenue	43.5%	22.6%		
RoR Increase			10.6%	8.0%
Revenue Increase			34.1%	30.1%

Breakeven Algebra:
CRCi = Ri/(Ci+rRBi)
PRCi = (1+Bi)Ri/(Ci + (r+d)RBi)
Note d = Bt*Rt/RBt
Set CRCi = PRCi
With a little algebra, solve for Bi:
Bi = Bt*(RBi/RBt)/((Ci+rRBi)/Rt)

Note if RBi/RBt = Ci/Ct
Bi = B

Supporting Calculations for Exhibit IEc-Remand-3: Table 3-D
Normalized R/C Ratio Example
$ millions

	Current Rates		*Breakeven Increase*	
	Class (i)	*System (t)*	*Class (i)*	*System (t)*
Revenue	52.3	331.7	68.1	431.6
Cost	29.6	256.6	29.6	256.6
Return	22.7	75.0	38.5	175.0
Rate Base	168.7	1,243.6	168.7	1,243.6
RoR	13.5%	6.0%	22.8%	14.1%
Indexed RoR	223.3%		162.2%	
Capital Cost Current	10.2	75.0		
Capital Cost Proposed	23.7	175.0	23.7	175.0
Subsidy $	12.6	-	14.8	-
Differential RoR	7.4%		8.7%	
Revenue-Cost Ratio	132%		128%	
Normalized R/C Ratio	128%		128%	
Income % of Revenue	43.5%	22.6%		
RoR Increase			9.3%	8.0%
Revenue Increase			30.1%	30.1%

Breakeven Class Increase = System Increase

Breakeven Algebra:

$CNRCi = (Ri/(Ci + (r+d)RBi))/(Rt/(Ct+(r+d)RBt))$

$PNRCi = ((1+Bi)Ri/(Ci + (r+d)RBi))/((1+Bt)Rt/(Ct+(r+d)RBt))$

$PNRCi = (1+Bi)/(1+Bt)CNRCi$

Set $PNRCi = CNRCi$

$Bi = Bt$

EXHIBIT IEc-REMAND-4

IMPLICATIONS OF

PPL'S RELATIVE RATE OF RETURN EXAMPLES

Exhibit IEc-Remand-4: Schedule 4-A
Implications of Various Progress Metrics in JM Kleha Example
Across-the-Board Increase

	Total	*Class X*	*Class Y*	*Class Z*
Current Rates				
Revenues	**485**	**315**	**150**	**20**
Total Expenses	**415**	**290**	**110**	**15**
Return	**70**	**25**	**40**	**5**
Rate Base	1,745	1,230	450	65
Rate of Return	4.01%	2.03%	8.89%	7.69%
Total Cost	**485**	**356**	**113**	**16**
Indexed Rate of Return	100.0%	50.6%	221.7%	191.8%
Differential Rate of Return	0.00%	-1.98%	4.88%	3.68%
Dollar Subsidy	-	(41)	37	4
Revenue-Cost Ratio	100.0%	88.5%	133.1%	121.7%
Normalized R-C Ratio	100.0%	89.4%	129.2%	115.5%
Proposed Rates with 30% Across-the-Board Increase				
Revenues	**631**	**410**	**195**	**26**
Percent Increase	*30.1%*	*30.2%*	*30.0%*	*30.0%*
Total Expenses	**481**	**333**	**130**	**18**
Return	**150**	**77**	**65**	**8**
Rate Base	1,745	1,230	450	65
Rate of Return	8.60%	6.26%	14.44%	12.31%
Total Cost	**631**	**458**	**151**	**23**
Indexed Rate of Return	100.0%	72.8%	168.0%	143.2%
Differential Rate of Return	0.00%	-2.34%	5.85%	3.71%
Dollar Subsidy	-	(48)	44	3
Revenue-Cost Ratio	100.0%	89.4%	129.1%	115.4%
Normalized R-C Ratio	100.0%	89.4%	129.1%	115.4%
Progress Toward Cost-Based Rates				
Indexed Rate of Return		45%	44%	53%
Differential Rate of Return		-18%	-20%	-1%
Dollar Subsidy		-19%	-18%	3%
Revenue-Cost Ratio		8%	12%	29%
Normalized R-C Ratio		0%	0%	1%
GRT Rate	5.9000%			
Income Tax Rate	41.4935%			

Source: OSBA-Remand-3

Notes: This exhibit does not correct for rounding errors in Exhibit JMK-7 (Revised).

Like Exhibit JMK-7 (Revised), this exhibit incorrectly includes the tax adjustment as an expense.

Exhibit IEc-Remand-4: Schedule 4-B
Implications of Various Progress Metrics in JM Kleha Example
Extreme Increase for Classes Y and Z

	Total	*Class X*	*Class Y*	*Class Z*
Current Rates				
Revenues	**485**	**315**	**150**	**20**
Total Expenses	**415**	**290**	**110**	**15**
Return	**70**	**25**	**40**	**5**
Rate Base	1,745	1,230	450	65
Rate of Return	4.01%	2.03%	8.89%	7.69%
Total Cost	**485**	**356**	**113**	**16**
Indexed Rate of Return	100.0%	50.6%	221.7%	191.8%
Differential Rate of Return	0.00%	-1.98%	4.88%	3.68%
Dollar Subsidy	-	(41)	37	4
Revenue-Cost Ratio	100.0%	88.5%	133.1%	121.7%
Normalized R-C Ratio	100.0%	89.8%	128.4%	115.5%
Proposed Rates with Extreme Differential Increase				
Revenues	**631**	**376**	**225**	**30**
Percent Increase	*30.1%*	*19.4%*	*50.0%*	*50.0%*
Total Expenses	**481**	**317**	**144**	**20**
Return	**150**	**59**	**81**	**10**
Rate Base	1,745	1,230	450	65
Rate of Return	8.60%	4.80%	18.00%	15.38%
Total Cost	**631**	**456**	**152**	**23**
Indexed Rate of Return	100.0%	55.8%	209.3%	178.8%
Differential Rate of Return	0.00%	-3.80%	9.40%	6.78%
Dollar Subsidy	-	(80)	73	7
Revenue-Cost Ratio	100.0%	82.4%	148.0%	133.1%
Normalized R-C Ratio	100.0%	82.4%	148.0%	133.1%
Progress Toward Cost-Based Rates				
Indexed Rate of Return		11%	10%	14%
Differential Rate of Return		-92%	-93%	-84%
Dollar Subsidy		-97%	-96%	-109%
Revenue-Cost Ratio		-53%	-45%	-53%
Normalized R-C Ratio		-73%	-69%	-114%
GRT Rate	5.9000%			
Income Tax Rate	41.4935%			

Source: OSBA-Remand-3, IEc calculations.

Notes: This exhibit does not correct for rounding errors in Exhibit JMK-7 (Revised), as presented in OSBA-Remar
Like Exhibit JMK-7 (Revised), this exhibit incorrectly includes the tax adjustment as an expense.

Exhibit IEc-Remand-4: Schedule 4-C
Implications of Various Progress Metrics in JM Kleha Example
Extreme Increase for Classes Y and Z: Implications for Next Case

	Total	*Class X*	*Class Y*	*Class Z*
Metrics Coming Out of Current Case				
Revenues	**631**	**376**	**225**	**30**
Total Expenses	**481**	**317**	**144**	**20**
Return	**150**	**59**	**81**	**10**
Rate Base	1,745	1,230	450	65
Rate of Return	8.60%	4.80%	18.00%	15.38%
Total Cost	**631**	**456**	**152**	**23**
Indexed Rate of Return	100.0%	55.8%	209.4%	179.0%
Differential Rate of Return	0.00%	-3.80%	9.40%	6.79%
Dollar Subsidy	-	(80)	73	7
Revenue-Cost Ratio	100.0%	82.4%	148.0%	133.1%
Normalized R-C Ratio	100.0%	82.4%	148.0%	133.1%
Metrics Going Into the Next Case with 30 Percent Cost Increase				
Revenues	**631**	**376**	**225**	**30**
Percent Increase	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Total Expenses	**540**	**362**	**157**	**22**
Return	**91**	**14**	**68**	**8**
Rate Base	2,269	1,599	585	85
Rate of Return	4.01%	0.89%	11.71%	9.67%
Total Cost	**631**	**461**	**148**	**22**
Indexed Rate of Return	100.0%	22.3%	292.1%	241.2%
Differential Rate of Return	0.00%	-3.12%	7.70%	5.66%
Dollar Subsidy	-	(85)	77	8
Revenue-Cost Ratio	100.0%	81.5%	152.0%	137.5%
Normalized R-C Ratio	100.0%	82.4%	147.8%	134.5%
Progress Toward Cost-Based Rates Compared to Going Into Last Case				
Indexed Rate of Return		-57%	-58%	-54%
Differential Rate of Return		-57%	-58%	-54%
Dollar Subsidy		-108%	-106%	-129%
Revenue-Cost Ratio		-61%	-57%	-73%
Normalized R-C Ratio		-73%	-68%	-123%
GRT Rate	5.9000%			
Income Tax Rate	41.4935%			

Source: OSBA-Remand-3; IEc Calculations

Notes: This exhibit does not correct for rounding errors in Exhibit JMK-7 (Revised), reported in OSBA-Remand-3.
Like Exhibit JMK-7 (Revised), this exhibit incorrectly includes the tax adjustment as an expense.

EXHIBIT IEc-REMAND-5

ESTIMATED CLASS IMPACT OF RETROACTIVE

ACROSS-THE-BOARD DISTRIBUTION RATE INCREASE

Exhibit IEc-Remand-5

Estimated Impact of SBRA-2 Adjustment

	Rate Increase Difference	*2005 Billed Distribution Revenues*		*2006 Billed Distribution Revenues*		*2007 Forecast Distribution Revenues*		*Total 2008 Adjustment Incl Interest*
		Total $mm	*Adjustment*	*Total $mm*	*Adjustment*	*Total $mm*	*Adjustment*	
RS/RTD	3.64%	380.03	13.82	377.08	13.71	375.69	13.66	47.56
RTS	12.54%	3.74	0.47	3.74	0.47	3.68	0.46	1.62
GS-1	-1.34%	75.90	(1.02)	75.59	(1.01)	75.38	(1.01)	(3.52)
GS-3	-10.18%	113.78	(11.58)	115.65	(11.77)	115.62	(11.76)	(40.51)
LP-4	-9.13%	30.78	(2.81)	31.76	(2.90)	30.25	(2.76)	(9.78)
GH	-8.42%	8.79	(0.74)	8.39	(0.71)	7.10	(0.60)	(2.37)
SL/AL	15.96%	19.29	3.08	17.56	2.80	16.67	2.66	9.89
Sub-Total		***632.31***	***1.22***	***629.76***	***0.60***	***624.38***	***0.65***	***2.89***
PPL Interest Rate		7.09%		7.36%		7.43%		

Source: Exhibit OGK-Remand-5, Exhibit IEc-Remand-2, IEc calculations

OCA Statement No. 1-Remand

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
v.	)	DOCKET NO. R-00049255
PPL ELECTRIC UTILITIES CORPORATION	)	

REMAND DIRECT TESTIMONY

OF

RICHARD A. GALLIGAN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

MAY 11, 2007

EXETER
ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
v.	)	DOCKET NO. R-00049255
PPL ELECTRIC UTILITIES CORPORATION	)	

REMAND DIRECT TESTIMONY OF RICHARD A. GALLIGAN

Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Richard A. Galligan. I am a principal with Exeter Associates, Inc., a firm of consulting economists specializing in utility economics. My business address is 5565 Sterrett Place, Suite 310, Columbia, Maryland, 21044.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have two degrees from the University of Wisconsin, including a Master's degree in economics and, in addition, I completed two years of graduate study at the University of Minnesota, where I fulfilled all of the course work requirements for the Ph.D. degree.

Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE?

A. I have taught economics at the University of Minnesota, the University of Wisconsin, Mankato State University, and Webster College. In these positions, I taught a wide range of courses covering all aspects of economics.

In January 1975, I joined the staff of the Minnesota Public Service Commission at the commencement of that Commission's responsibility over gas and electric utility

operations in the State of Minnesota. From 1976 to 1984, I was an economic consultant specializing in public utility rate regulation of gas, electric and telephone utilities.

From 1984 until 1987, I was Director of Utilities Division at the Iowa State Commerce Commission and Executive Director of the Texas Public Utility Commission. At Iowa, my responsibilities included the management and administration of all Utilities Division activities regarding the regulation of gas, electric and telephone utilities operating in the State of Iowa under Iowa State Commerce Commission jurisdiction. At the Texas Public Utility Commission, I was responsible for the management and day-to-day administration of that Commission's regulatory activities regarding all aspects of its jurisdictional responsibilities. I also served briefly as General Manager of Rates & Regulatory Affairs at Gas Company of New Mexico before assuming my present position at Exeter Associates, Inc. in October 1987.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS ON UTILITY RATES?

A. Yes. I have previously presented testimony on more than 100 occasions before the Federal Energy Regulatory Commission ("FERC") and the public utility commissions of Alabama, California, Connecticut, Delaware, the District of Columbia, Florida, Georgia, Idaho, Illinois, Kansas, Louisiana, Maryland, Michigan, Minnesota, Missouri, Montana, Nevada, New Hampshire, New Jersey, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Utah, and Vermont.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Exeter Associates, Inc. was retained by the Pennsylvania Office of Consumer Advocate ("OCA") to review the class cost of service studies, and the proposed revenue allocation reflected in PPL Electric Utilities Corporation's ("PPL's" or "the Company's") Remand Direct Testimony. My testimony addresses the use of various record cost allocation studies for use as guides to the setting of rates, and PPL's proposed allocation of its

Commission-authorized total Distribution cost of service, or Distribution revenue requirement.

Q. ARE YOU FAMILIAR WITH THE ISSUES WHICH ARE THE SUBJECT OF THIS REMAND PROCEEDING?

A. Yes. I participated in the original proceeding before the Commission regarding PPL's Application for a general rate increase. I am familiar with PPL's testimony, exhibits and data responses in this current remand proceeding.

Q. IN GENERAL, WHAT CONCLUSIONS HAVE YOU REACHED REGARDING PPL'S PROPOSALS IN THIS REMAND PROCEEDING?

A. Based on my analysis of PPL's proposals, I conclude that:

- PPL's proposed allocation of the revenue requirement associated with its total Distribution costs of service is reasonable and consistent with its proposal to move all major customers classes to cost of service rates over a period of three rate cases;
- The adoption of the results of only the one cost of service study variant proposed by PPL as the standard which must be applied to achieve cost-based rates is unreasonable;
- PPL's allocation of its transmission revenue requirement is consistent with how costs are currently billed under PJM's Open Access Transmission Tariff ("OATT");
- Because PPL's transmission costs are about 70 percent related to its peak demands and those peak demands may occur in either summer or winter, an annual determination of PPL's Transmission Service Charge ("TSC") violates the stability standard of utility ratemaking; and

- PPL's proposal to return Hurricane Isabel-related revenues only to customers taking service under rate schedules which were providing an above system average rate of return under PPL's cost study violates the matching principle, is an example of "fortuitous" ratemaking, and is unreasonable.

Q. PLEASE SUMMARIZE PPL'S PROPOSALS IN THIS REMAND PROCEEDING.

A. PPL is proposing Distribution revenue responsibilities that move its distribution rates for all major rate classes to at or near full cost of service rates in three rate cases. PPL relies on its own proposed class cost of service study as the standard against which the adequacy of class revenues is to be determined. Table 1-R below shows the movement by major classes toward cost-based rates proposed by PPL in this current remand proceeding based on the results of several cost of service studies performed in this proceeding. Lines (1) - (4) show the results under PPL's proposed cost allocations. Lines (5) - (7) show the results under alternative cost study variants.

Table Remand-1

PPL Remand Cost Study Results[1]
Class Rates of Return
Major Classes

	Rate of Return	RS	GS-1	GS-3	LP-4	Total
	PPL Proposed Study					
(1)	Present Rates	2.33%	9.76%	9.33%	9.31%	4.38%
(2)	Index	53%	223%	213%	212%	100%
(3)	Proposed Rates	5.48%	15.42%	16.57%	16.36%	8.47%
(4)	Index	65%	183%	197%	194%	100%
(5)	Peak & Average Study[2]	11.97%	20.99%	6.13%	1.64%	8.47%
(6)	1/3 Demand-Customer Energy Study	8.20%	18.53%	10.47%	5.25%	8.47%
(7)	50/50 Demand-Customer Study	6.32%	15.73%	11.91%	15.61%	8.47%
(8)	Demand/Energy Secondary Distribution Study[3]	6.99%	19.91%	8.63%	14.09%	8.43%

[1] Compliance costs with Hurricane Isabel-related costs removed.
[2] PPL refers to this Peak and Average study in its Exhibit JMK-Remand 8 as a 50-50 Demand-Energy study.
[3] These study results reflect PPL's re-run of a study I requested in the original proceeding, but as explained on page 5, PPL limited cost reallocations to plant allocators only.

For example, in this current remand proceeding and using PPL's cost of service study results, regular residential customers would move 25 percent toward fully cost-based rates under PPL's remand proposal.[1]

Transmission costs would be allocated to classes on a demand/energy basis consistent with how PPL incurs transmission costs under PJM's OATT. Revenues that were included in rates and related to amortized Hurricane Isabel costs would be refunded, but only to customers taking service under rate schedules providing an above system average rate of return -- again, using PPL's proposed cost of service study.

[1] In its 2007 Application for general rate relief, PPL proposes regular residential rates that recover 80 percent of fully allocated costs.

Q. YOU MENTIONED IN FOOTNOTE 3 TO TABLE REMAND-1 THAT THE STUDY PPL RAN AT YOUR DIRECTION APPARENTLY DID NOT REFLECT ALL THE NECESSARY CHANGES IN ASSUMPTIONS. COULD YOU EXPLAIN?

A. The results shown on line (8), the Demand-Energy results, comport with the cost of service study that PPL ran in response to my data request as part of the review of PPL's original Application for a general rate increase before the Commission, Docket No. R-00049255. In PPL's response to a data request in this Remand proceeding, OSBA Set I-Q.2, it became apparent that PPL did not fully reflect the related changes that were implicit in my request in the original proceeding. In performing the requested Peak & Average cost study, PPL did the re-run limiting cost reallocations to plant allocators only, rather than following that through to expenses. The results shown on Table Remand-1 (and PPL's Exhibit JMK-Remand 8) show the Peak and Average cost study results when expenses, as well as plant, are allowed to be reallocated consistent with the Peak & Average cost methodology.

Q. IS PPL'S PROPOSED SPREAD OF ITS COMMISSION-AUTHORIZED RATE INCREASE REASONABLE AND CONSISTENT WITH BASIS IN COST?

A. Yes. PPL's TSC is based entirely on allocated cost of service results. PPL's Distribution rates make substantial movement toward basis in cost as indicated in Table 1-R above. Moreover, whereas PPL's fully allocated cost study results show regular residential customers paying rates that recover all expenses plus a rate of return that is 65 percent of system average, Exhibit JMK-Remand 8 shows that under a different cost of service study method, the Peak & Average method, regular residential customers are paying rates that provide a rate of return that is 141 percent of fully distributed costs.

Q. ARE AVERAGE, EMBEDDED, ALLOCATED, CLASS COST OF SERVICE STUDIES CAPABLE OF YIELDING RESULTS THAT ARE SO PRECISE THAT THEIR RESULTS SHOULD BE DEEMED DEFINITE?

A. No. The bulk of PPL's costs are fixed costs. The allocation of fixed costs is controversial, largely because in the short-run, these costs may not change with the provision of a little more or less service. Regarding the allocation of fixed customer costs, Bonbright puts it this way:

> The really controversial aspect of customer-cost computation arises because of the cost analyst's frequent practice of including, not just the costs than can be definitely earmarked as incurred for the benefit of specific customers, but also a substantial fraction of the annual maintenance and capital costs of the secondary (low-voltage) distribution system - a fraction equal to the estimated annual costs of a hypothetical system of minimum capacity. [Bonbright, James C., et. al, Principles of Public Utility Rates, Public Utility Reports, Inc., Arlington, Virginia, Second Edition, 1988, p.491, emphasis added.]

Also, regarding capacity related costs, the NARUC Manual, at page 23 states:

Dr. James Bonbright, whose Principles of Public Utility Rates is the classic examination of regulation and ratemaking, wrote:

> "Of all of the many problems of rate making that are bedeviled by unresolved disputes about issues of fairness, the one that deserves first rank for frustration is that concerned with the apportionment among different classes of consumers of the demand costs or capacity costs....Here, notions of 'fair apportionment' are almost sure to conflict with economists' convictions as to the relevant cost allocations. But these notions are themselves, neither stable nor uniform, although they reveal a general tendency in favor of a fairly wide spreading out of costs, as butter would be spread over bread in a well-made sandwich. Awareness of these unresolved conflicts about 'fair' cost apportionment has lead the British economist Professor W. Arthur Lewis to exclaim that, in rate determination, 'equity' is the mother of confusion,'''

Dr. Bonbright also includes the following regarding the allocation of capacity, or demand related costs:

> We come now to that category of costs, capacity, ready to serve, or demand costs, the treatment of which has made a nightmare of utility cost analysis (for two masterly theoretical treatments see Boiteux, 1960, and Crew

> and Kleindorfer, 1986). As the FERC *Handbook* (1983, p. 139) states: "For the problem which it presents is that of imputing joint costs to joint products or byproducts, and not merely that of distributing those common, but nonjoint, costs (See Chapter 2) which vary more or less continuously with number of consumers or with rates of output....
>
> Here, as with the other two categories of cost, there is no general agreement as to what items or portions of total costs should be included among the demand-related costs, perhaps because cost functions are far too complex to be reflected by the arbitrary, three-way classification of customer, energy, and demand....
>
> In attempting to assess these relative responsibilities, the analyst is offered a wide variety of alternative formulas of apportionment, each of which has received support from some rate experts. Testifying before the ICC in Illinois (1953) in a rate case, Corey noted the existence of twenty-nine such formulae; in their textbook Garfield and Lovejoy (1964, p. 159) mention "20 or more allocation methods"; and Grainger (1972), 1976) discusses several methods of allocating the ready-to-serve costs. Most of them have no claim whatever to validity from the standpoint of cost determination and only a dubious claim to acceptance as compromise measures of reasonable rates. A harsher critic might use the metaphor of Bentham that these claims are "nonsense upon stilts". [Ibid., pp. 494-495]

I conclude that allocated cost of service study results based on often controversial cost allocations are themselves controversial. Allocated costs of service are one component of information available for the Commission as it considers its affirmative responsibility to set just and reasonable rates. The controversial aspect of fixed cost allocations reinforces the general regulatory principle that cost of service results are often used as a guide to the setting of rates.

Q. IS IT APPROPRIATE TO REQUIRE THAT CLASS REVENUE RESPONSIBILITIES MUST BE SET EXACTLY EQUAL TO THE RESULTS OF A SINGLE, ALLOCATED, EMBEDDED, HISTORIC, ACCOUNTING COST OF SERVICE STUDY?

A. No. While such a prescription would lead to index rates of return equal to 100 percent, revenue-to-allocated cost ratios of 1.0, and revenue minus allocated cost differences of zero, in my opinion, this prescription is neither necessary nor desirable. First, this

revenue allocation prescription would produce a slavish, mechanistic basis for the setting of rates to the exclusion of all other cost and non-cost considerations. This conflicts with the long-standing Commission policy of using allocated cost study results as a guide to the setting of rates. Second, this prescription implies a precision and a lack of allocated cost controversy that simply does not exist. I discuss above the existence of many different allocated cost studies and the controversies that attend such studies. The very existence of numerous cost study variants and the controversial nature of various cost allocations reinforces the use of cost studies as guides to the setting of rates.

Third, the wide range of allocated cost study results reported in Exhibit JMK-Remand 8 supports a skepticism regarding precise study results. Variations in results imply that as class revenues approach variously stated allocated costs, further precision in class revenue prescriptions may not be warranted. For example, it would not be unreasonable to find that very little confidence attends the exercise of fine-tuning class revenue adjustments when cost study results suggest that class revenues are in substantial agreement with costs. Regular residential customers would pay a rate of return of 141 percent of the PPL system average rate of return at PPL's proposed Distribution rates, when costs are allocated in accord with the peak and average methodology, and regular residential customers would yield a rate of return essentially equal to the system average rate of return (i.e., 97 percent of the system average rate of return) when costs are allocated one-third each on demand, customer and energy. These cost study results are consistent with a finding that residential customers are paying cost-based rates that essentially recover, or more than recover, their allocated costs of service.

Q. YOU HAVE EARLIER CITED PROFESSOR BONBRIGHT'S COMMENTS REGARDING THE DIFFICULTIES ATTENDANT TO THE ALLOCATION OF FIXED COSTS, THE MANY AND VARIED METHODOLOGIES THAT ARE USED TO ALLOCATE FIXED COSTS, AND THE CONTROVERSIAL

NATURE OF FIXED COST ALLOCATIONS. WHAT DOES PROFESSOR BONBRIGHT SAY ABOUT THE EXTENT TO WHICH FULLY ALLOCATED, AVERAGE, EMBEDDED, HISTORIC ACCOUNTING COSTS OF SERVICE SHOULD BE USED AS A STANDARD AGAINST WHICH CLASS REVENUES MAY BE DETERMINED?

A. When addressing capacity related embedded cost allocations, Professor Bonbright states, "Should the capacity costs be assigned to the different ratepayers on the basis of system peak responsibility, of coincident class demand, or any one of the other thirty-odd proposed bases of assignment to be found in the literature of rate theory? Here, notions of fair apportionment are almost sure to conflict with economists' convictions as to the relevant cost allocations. But these notions are themselves neither stable nor uniform, *although they reveal a general tendency in favor of a fairly wide spreading out of the* costs, as butter would be spread over bread in a gourmet's sandwich." (Bonbright, James C., Principles of Public Utility Rates, Public Utilities Reports, Inc., Arlington, VA, second edition, 1988, p. 184) A standard that is best described as the wide spreading of costs as butter would be spread over bread in a gourmet's sandwich hardly supports a finding that class revenue responsibilities should be set entirely on the basis of and consistent with costs allocated in accord with the standard. Unfortunately, such is the nature of allocated, fully distributed cost of service findings.

Q. DOES YOUR FINDING THAT A PRESCRIPTION TO SET CLASS REVENUES AT RESULTING ALLOCATED COSTS IS NOT WARRANTED MEAN THAT CLASS COST RESULTS MAY NOT BE CONSIDERED IN THE RATE SETTING PROCESS?

A. No. In this present case, for example, the fully complete Peak and Average study, shows that PPL's cost of service study over-allocates costs to residential customers; the one-third demand, customer, energy study shows that residential customers are paying

essentially cost-based rates; and PPL's own study shows that its proposed rates are consistent with substantial movement toward rates based on allocated costs. These cost studies show that class revenues are sufficient to cover all allocated expenses and provide a return on invested capital. At PPL's proposed rates for regular residential customers, for example, when class return is related to the investment which gives rise to the return (i.e., the traditional measure of the adequacy of rates), the regular residential rates provide a 5.48 percent rate of return (PPL Study). This represents a substantial, twenty-five percent movement toward rates based on allocated costs. A greater movement toward costs is indicated under the Peak and Average study, since PPL's proposed rates provide an 11.97 percent rate of return for regular residential customers. Both of these rates of return compare to an 8.47 percent system rate of return shown on Exhibit JMK-Remand 8.

Q. YOU MENTIONED THAT PPL'S PROPOSAL TO REFUND HURRICANE ISABEL-RELATED REVENUES TO CUSTOMERS PAYING ABOVE AVERAGE RATES OF RETURN UNDER PPL'S PROPOSED COST STUDY WOULD VIOLATE THE MATCHING PRINCIPLE. PLEASE EXPLAIN.

A. The matching principle requires that refunds be given to those customers responsible for the payment of subject revenues in the first place. The source of the overpaid dollars should not be viewed as a fortuitous pot of dollars, convenient for utilization for other purposes. On a going-forward basis, no class of customers will be either allocated Hurricane Isabel-related costs, nor pay Hurricane Isabel-related revenues. That is, neither the costs nor revenues will be recognized for ratemaking purposes. Consistency and the matching principle require similar treatment of the Hurricane Isabel refunds.

Q. YOU MENTIONED EARLIER THAT AN ANNUAL DETERMINATION OF PPL'S TSC WOULD VIOLATE THE RATEMAKING STABILITY STANDARD. WHAT DO YOU RECOMMEND?

A. Seventy percent of PPL's transmission related costs incurred under PJM's OATT are based on peak demands. PJM's peak demands can occur in the summer or winter. Because class contributions to a summer or winter system peak vary among the classes, PPL's TSC applicable to the classes would accordingly change annually. This rate instability could be mitigated by considering both winter and summer class demands in the allocation of transmission costs. For example, a five-year rolling average of class demands, or an average of class summer and winter demands could be utilized to allocate transmission costs and stabilize rates.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

*93955

BEFORE THE
PENNSYLVANIA PUBLIC SERVICE COMMISSION

In the Matter of:	
Pennsylvania Public Utility Commission et al.	**Remand of Docket No. R-00049255 Docket No. R-00049255C0001 throughR-00049255C0020**
vs.	
PPL Electric Utilities Corporation	

Remand Direct Testimony of Kenneth L. Kincel

Q. PLEASE STATE YOUR NAME, TITLE AND OCCUPATION.

A. My name is Kenneth L. Kincel. I am President of Decision Analysis Corporation of Virginia, an energy consulting firm located at 8009 Snowpine Way, Suite 100, McLean, Virginia. Decision Analysis Corporation of Virginia was founded in 1980 and performs energy modeling and forecasting, and utility market and rate analysis services for government, industry associations, utility commissions and private energy firms. In this capacity, I am currently providing independent expert witness services to the U.S. Department of Defense in utility rate and restructuring cases at federal and state regulatory commissions.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE

A. Details of my education and experience are described in Remand Exhibit KLK-1 which is attached to my testimony. An updated listing of my recent submissions and testimony to various government utility regulatory agencies is shown in Remand Exhibit KLK-2.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am presenting testimony on behalf of the consumer interests of the U.S. Department of Defense and all other Federal Executive Agencies, hereinafter collectively referred to as "DOD/FEA." As noted in my direct testimony in the 2004 proceeding under this docket, DOD/FEA has large military installations and several federal civilian agencies which purchase electricity from PPL Electric Utilities Corporation ("PPL" or the "Company). Because of the diversity of the electricity applications associated with these facilities, DOD/FEA is taking electric service off of many of the rate schedules of PPL. Therefore, it is important to DOD/FEA that all customer class rates of PPL are just and reasonable.

The three largest military installations served by PPL are Carlisle Barracks, Tobyhanna Army Depot and the US Navy Support Activity at Mechanicsburg. Carlisle Barracks and Tobyhanna Army Depot are taking service from the Company under Rate LP-5. The US Navy Support Activity at Mechanicsburg is taking service under Rate LP-6. These three military installations alone currently account for approximately $9.0 million annually in total electric revenues to PPL.

Q. HAVE YOU TESTIFIED BEFORE IN THIS PROCEEDING?

A. Yes, as I mentioned earlier, I provided direct testimony under Pennsylvania Public Utility Commission ("PPUC" or the "Commission") Docket No. R-00049255 dated June 28, 2004. My testimony here will reference my 2004 direct testimony in several instances. In fact, this testimony should be considered an updated supplement to, rather than a substitute for, my 2004 direct testimony, except where I specifically alter my recommendations to the Commission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS REMAND PROCEEDING?

A. The purpose of my testimony is to again address under this docket, on behalf of DOD/FEA, transmission and distribution customer class cost allocation and rate design issues for rates placed into effect on January 1, 2005.

Q. WHY IS THIS REMAND PROCEEDING NECESSARY?

a. The Commonwealth Court of Pennsylvania (the "Court"), in the "Lloyd vs. PPL" appeal case, issued a decision on August 4, 2006 which vacated both the transmission and distribution rates approved by the PPUC as a result of the original 2004 proceeding under this docket. The Court also rejected inclusion within distribution rates the cost recovery of expenses association with Hurricane Isabel. Furthermore, the Court rejected the Commission's use of customer class impacts on a "total bill basis" in order to avoid "rate shock" and required that both distribution rates and transmission rates be designed based on separate customer class cost-of-service studies. The Court further stated that the principle of "gradualism" could not "trump" all other ratemaking concerns, especially the "polestar," which is the cost of providing service. More specifically, the Court noted that rates and rate structures must be set for each service primarily based on a cost-of-service study.

In response to the Court's decision, on February 8, 2007, the PPUC remanded the case to the Office of Administrative Law Judge. In response to a "Scheduling Order on Remand," issued by the Commission on March 9, 2007, the Company prepared a "Remand Proposal," dated April 13, 2007. The PPL proposal is intended to satisfy the

Court's concerns through the design of new transmission and distribution rates that can be deemed just and reasonable.

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL.

A. The PPL proposal sets forth new transmission rates for three large groupings of customer classes (residential, small commercial and industrial, and large commercial and industrial) based on actual cost-of-service to these customer groupings. Surcharges and refunds are calculated for bills during 2008 and 2009 in order to account for the differences between the customer class revenues that would have been collected under these new transmission rates if they had been placed in effect on January 1, 2005, and those transmission revenues that will actually be collected over the 2005-2007 period based on the Commission's Order following the 2004 proceeding. PPL proposes that the new transmission rates go into effect on or before the end of 2007.

PPL proposes to re-establish the distribution rates approved by the Commission resulting from the 2004 proceeding, but with a downward adjustment to eliminate Hurricane Isabel storm expense. In order to be compliant with the Court's decision, PPL offers to refund the component of distribution rate revenues collected over the 2005-2007 period that was intended to recover costs associated with Hurricane Isabel. Such refunds are proposed only for customer classes paying above system average returns. The refunds are to be implemented by applying a fixed Special Base Rate Adjustment (i.e., a percentage reduction) of approximately 1.77% of class distribution charges on monthly bills over calendar year 2008. (See Company Witness Oliver G. Kasper Remand Direct Testimony, p. 8.)

PPL justifies re-establishment of current distribution rates (with slight adjustment for storm expense) because they moved each major rate schedule closer to cost-of-service. In addition, PPL plans to move each major rate schedule to or near cost of service in three base rate cases, namely, the 2004 proceeding, the pending 2007 base rate case and one thereafter. (See Company Witness O. G. Kasper, page 10.)

Q. PLEASE SUMMARIZE YOUR RESPONSE TO THE COMPANY'S PROPOSAL.

A. I generally support the transmission cost allocation rate design offer by the Company, but recommend that the Large Commercial and Industrial Group ("Large C&I") be further divided into two smaller groups, one for Large C&I transmission voltage customers and one for Large C&I primary voltage customers. This will provide more precision in the matching of costs incurred in serving these customers and the revenues from transmission rates, and thereby facilitate shopping.

Regarding distribution class cost allocation, as in my 2004 testimony, I generally support the distribution cost-of-service study performed by the Company for the same reasons that I set forth in my 2004 direct testimony. But I reiterate the need for a significant change in the Company's customer class allocation of Commission-approved increases in total revenue requirements. The Company's proposal in this "Remand Proceeding," like in the original 2004 proceeding, does not adequately redress significant cross subsidies among distribution customer classes that were occurring before the 2004 rate case and have now endured over the 2005-2007 timeframe. I will demonstrate (with the data supplied by the Company's Adjusted Compliance Filing) the distribution revenue requirement allocation methodology that I proposed in my 2004 direct testimony, with an adjustment to eliminate "rate shock," and reiterate its benefits. I recommend that this

allocation methodology be approved by the Commission in order to establish distribution rates retroactive to January 1, 2005, and that refunds/surcharges be imposed to rectify class distribution revenues collected over this period. In addition, I recommend (as I did in the 2004 proceeding) that the same methodology be applied (but with successively lower maximum acceptable class relative rates of return) over the next two rate cases (including in the pending 2007 rate case) in order to bring all class distribution returns on a percentage basis to or very near jurisdictional system average returns.

Q. PLEASE DESCRIBE YOUR SUPPORT FOR THE COMPANY'S PROPOSAL FOR TRANSMISSION RATES.

A. In my 2004 direct testimony, I recommended establishing transmission rates by individual rate class based on class cost causation, and rejected the Company's proposal for a single average kWh rate to be applied to all classes. Based on the data that the Company provided at that time, I demonstrated within Exhibit KLK -12 of my 2004 direct testimony how that could be accomplished by using annual cost and consumption data by rate class. The simple formula that I used was to allocate total annual transmission revenue requirements by the 5-day peak load coincident peak load contribution for each rate class. Recognizing that allocation shares changed significantly by individual rate class depending upon whether or not the 5 system peak days were experienced during the summer or during the winter of the previous year, I averaged the most recent contribution to the system peak for each class that was experienced during the summer with the class contribution experienced during the most recent winter peak, in order to foster some rate stability through the years.

The Company's methodology for deriving class cost-based transmission rates as presented in its Remand Proposal is superior to mine because it more precisely aligns transmission rates with cost causation for each year (see Remand Direct Testimony of Oliver G. Kasper, p. 2-8 and the CD associated with the Response by PPL to Interrogatories of the Small Business Advocate, Set 1, Question 7, dated April 19, 2007). The Company divides total transmission costs for each month into the portion that is demand-related and the portion that is energy-related. The demand-related portion of transmission costs is allocated to three large groupings of customer rate classes based on the actual 5-day peak contribution experienced by each group during the previous calendar year. Allocation of monthly energy-related transmission costs is based on energy consumed by each class grouping during each month. Rate stability is gained by the grouping of individual customer rate schedule classes into three large aggregate classes, namely, Residential (RS, RTS and RTD), Small C&I (GS-1, GS-3, BL, IS-1, GH-1, GH-2 and all Street and Area Lighting Schedules, or SL/AL), and Large C&I (LP-4, LP-5, IST, ISP, LP-6, LPEP, ISA and Standby or L5-S).

The Company offers several reasons for this grouping: (1) it is the same grouping that is used for CTC and ITC rates; (2) it reflects cost causation while limiting the number of transmission rate calculations; (3) it is consistent with how the Company proposes to calculate POLR rates after its generation rate caps expire on January 1, 2010, thereby making it easier for both customers and energy generation suppliers ("EGS") to make informed decisions regarding retail competition, i.e., it facilitates shopping (see Remand Direct Testimony of Oliver Kasper, page 3-4.)

Q. WHAT MODIFICATION TO YOU PROPOSE TO THE COMPANY'S TRANSMISSION RATE METHODOLOGY?

A. I propose to divide the Large C&I customer group into two separate, smaller groups when transmission rates are calculated, and later when calculating POLR rates after the generation rates expire. The two smaller groups would be for the rate schedule classes served at transmission voltage, that is, "Large C&I-T" and for the rate schedule classes served at primary voltage, "Large C&I-P." Large C&I-P would consist of rate schedule classes LP-4 and ISP. Large C&I-T would consist of LP-5, LP-6, IST, ISA, LPEP and Standby (L5-S). Note that this split is consistent with the functional breakdown of costs that is used by Company Witness Joseph M. Kleha when performing distribution class cost-of-service studies.

There is no reason to continue to define customer class groupings to correspond to those used for the CTC and ITC, because those charges will expire. The complexity of transmission cost calculations will be increased slightly due to the addition of one more customer class group. But this certainly can be handled quite easily using the Microsoft EXCEL spreadsheet software that the Company is now employing.

More importantly, shopping for third party generation providers will be better facilitated by the greater precision in customer group transmission costs that will be achieved by separating primary voltage and transmission voltage customer classes. It is more important to have greater precision in matching cost causation with transmission revenue when designing transmission rates for Large C&I customers than it is for Small C&I and Residential customers. Large C&I customers are more likely to be searching alone for a competitive EGS. In addition, EGS's are more likely to offer rates to Large C&I

customers which take into account the specific load profile of each customer. For smaller customers, EGS's will more likely use a typical load profile when designing rates that is representative of an entire class of customers, like residential, or small commercial.

Moreover, transmission voltage customers generally experience higher annual load factors (i.e., ratio of average to peak day load) than primary voltage customers, and therefore can be expected to enjoy lower average transmission rates when using a kWh rate design. This is evidenced by observing the transmission rates for the various individual rate classes that I calculated within Exhibit KLK-12 of my 2004 direct testimony. Therefore, the effect of not distinguishing primary voltage from transmission voltage large customer transmission rates, as the Company proposes, will be to push transmission voltage customers to third party EGS's during shopping, and retain primary voltage customers for POLR service, when generation caps expire. This is a non-competitive result that should and can be avoided by calculating separate transmission rates for large primary voltage and transmission voltage customers.

In sum, I propose that the Commission direct the Company to recalculate transmission rates and associated refunds/surcharges for four customer groups rather than three, namely, the Residential, Small C&I, Large C&I-P and Large C&I-T groups.

Q. WHY DO YOU GENERALLY SUPPORT THE DISTRIBUTION COST OF SERVICE METHODOLOGY EMPLOYED BY THE COMPANY?

A. I addressed this question in my 2004 direct testimony, but will reiterate my answer here because of the importance of this issue. The Company uses the class maximum demand method, which is based on the highest annual non-coincident peak (NCP) demand

imposed by each rate class on its distribution system, to allocate its demand-related distribution costs. Distribution facilities are separated between primary and secondary voltages, and secondary investment is further classified as customer-related and demand-related using the "minimum size system" method. Costs considered customer-related are then allocated on the basis of the numbers of customers in each class.

Within its Remand Proposal, the Company also provides for comparison cost of service studies based on the distribution system costs allocated on a 50%/50% demand/customer-related basis, 50%/50% demand/energy-related basis and 1/3 each demand/customer/energy-related basis (see Exhibit Remand JMK-8). The class results for the 50%/50% demand-customer related basis closely match those using the Company's cost-of-service methodology, while the other two methodologies shift costs markedly from the small to the large customers. In its 2004 application, the Company also presented for comparison the class allocation of distribution costs based on the average and excess allocation method.

The Company justifies its methodology (the maximum non-coincident peak demand method) as the most appropriate method for the allocation of distribution costs for two reasons: (1) because the Commission has traditionally accepted this method in all of its previous base cases; and (2) because the NARUC Electric Cost Allocation Manual deems it to be the most appropriate method when distribution-related facilities are generally sized to meet the maximum load requirements of customers. I agree with and support both of these reasons. The NARUC Manual elaborates further (p. 97):

> There are several factors to consider when allocating the demand components of distribution plant. Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads. Distribution substations are designed to meet the maximum load from the distribution feeders

> emanating from the substation. Similarly, when designing primary and secondary distribution feeders, the distribution engineer ensures that sufficient conductor and transformer capacity is available to meet the customer's loads at the primary- and secondary-distribution service levels. Local area loads are the major factors in sizing distribution equipment. Consequently, customer-class non-coincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities.

I believe that the most important criterion to be considered in selecting an appropriate methodology is that the methodology should be consistent with the utility's planning process. The factors which primarily influence the utility's capacity expansion plan should also serve as the basis for developing allocation factors. Otherwise costs will not be assigned to the classes in the same manner in which the costs are incurred. In a distribution utility, the most significant factor influencing the Company's expansion plan is the level of peak demand projected for the system. The use of NCP demands as a basis for allocating demand-related distribution plant, as the Company proposes, is consistent with this principle.

In contrast, the use of the average and excess allocation method (or any method which allocates distribution facility costs based partly on energy use) allocates a greater portion of demand-related costs to customer groups with higher load factors. The average and excess methodology rests on the assumption that while system peak demands establish the level of capacity, providing continuous service creates additional incentive for such capacity costs. This is not the case with distribution plant. The provision of continuous service, that is, more throughput at a given peak demand level, does not cause a need for additional capacity. The sole determination of the need for additional distribution capacity is greater peak load requirements on the system. Thus, to burden higher load factor customers with higher costs of distribution plant would be grossly inequitable. So, in my view, there is no uncertainty as to which is the more correct cost-of-service

methodology to apply – it is the Company's methodology. There is no "movement" of the "polestar" that should be used to measure class cost of service in this case.

I also support the Company's proposal to use the minimum-size system method for determining the demand and customer components of secondary distribution facilities. The minimum-size system method requires less data to employ and is easier to understand and apply. It is also less prone than the alternative method, the minimum-intercept method, to produce anomalies caused by statistically unreliable results.

Q. WHY DO YOU OBJECT TO THE COMPANY'S PROPOSAL FOR THE ALLOCATION OF INCREASED REVENUE REQUIREMENTS BY CUSTOMER CLASS?

A. The Company's Remand Proposal is simply the 2004 Compliance Filing as adjusted for the elimination of storm damage expense from Hurricane Isabel (see Remand Exhibit JMK-2). I object to the allocation of revenue requirements contained therein for the same reasons as given in my 2004 direct testimony.

Within its Remand Proposal, the Company proposes only one criterion for allocating increased revenue requirements: that the relative rate of return for each rate schedule moves closer (about half-way on a percentage basis for most rate classes) to 1.0, which is parity with the system average rate of return. As shown in Remand Exhibit KLK-3, column 4, enormous customer class subsidies existed prior to the 2004 proceeding. For example, the Company was earning six times its average system return from customers taking service under LP-5 and over 20 times the system average return from customers

taking service under LP-6. Meanwhile, the Company was earning only 53% of its system average return from residential customers.

Under the Company's Remand Proposal, the residential customer will be paying only 65% of the system average return (see column 7 of Remand Exhibit KLK-3). In contrast, the LP-5 customer will still be required to pay about 3.4 times the system average return and the LP-6 customer about 7 times the system average return. Moreover, the residential customer is asked to pay an increase of only 23.1% in its distribution revenue requirement, which is less than the average rate increase, 27.2%. The Company simply does not go far enough in redressing the egregious gross inequities that now exist in distribution rates. I explained within my 2004 direct testimony why such large required customer class cross subsidies are inequitable, result in non-economic behavior of both the donors and recipients of these subsidies, and decrease the general economic welfare of the society. These arguments still apply here, but will not be repeated.

Within my 2004 direct testimony, I proposed that the Commission adopt the following criteria for allocating any increased distribution revenue requirement that is found in this proceeding. First, set rates for all customer classes that are now unfairly burdened by paying the Company more than 150% of the system average return, so that the return paid by these customers falls to 150% of the newly approved system average return from this proceeding. Secondly, adjust rates to all other customer classes such that they pay an equal percentage of the distribution system average return.

The result of applying this revenue requirement allocation methodology using the Adjusted Compliance Filing offered by the Company is shown is shown in columns 10

through 12 of Remand Exhibit KLK-3. The Company's system average rate of return with the revenue requirement approved by the Commission (after adjustment to eliminate storm damage expense from Hurricane Isabel) is 8.43%. All but four customer classes will pay a return of 12.64%, and the remaining four will incur rate increases such that they will pay the Company 79% of the system average return. (The Interruptible Supply Agreement or "ISA" rate class is not affected by these allocations because the rates are set by contract agreement.) Under these criteria, as expected if the existing gross inequities are to be mitigated, the residential customers will receive an increase in distribution billings that is greater than the system average increase, 31.5% versus 27.2%, as shown in column 12. Many of the customer classes now paying significant cross subsidies will receive reductions in revenue requirements. However, no customer class will be forced to pay the Company more than 150% of the system average return.

I incurred two criticisms of my proposed revenue requirement allocation methodology during the 2004 proceeding – that the increase for the RTS class was too high and caused "rate shock," and that the methodology was self-serving, i.e., it helped the LP-5 and LP-6 customer classes.

In response to the first criticism, I offer the incorporation of an additional criterion within my proposed revenue requirement methodology, the limitation of any one class increase to 40% (which is less than 150% of the system average increase). The results are shown in Remand Exhibit KLK-4. The increase for the RTS class is limited to 40%, while increases for the other three customer class paying less than system average returns are very slightly higher. The increases for customer classes paying higher than system average returns are unaffected.

In response to the second criticism, that my proposed methodology is self-serving, I point out that DOD/FEA receives service off of nearly all of the PPL rate schedules for electricity delivered on a firm requirements basis due to the diversity of its facility types. Furthermore, other rate classes, such as the GS-1 rate class are more beneficially affected by my allocation methodology than the LP-5 and LP-6 rate classes. Under the Company's proposal, the GS-1 class incurs a 29.3% increase, which is higher than the system average increase of 27.2%, despite the fact that this class is providing 223% of the system average return before the rate increase. This is absurdly inequitable. Under my proposed allocation methodology, the GS-1 rate class will incur only a 15.1% increase. I recommend that the Commission adopt my revenue requirement allocation methodology, and require the Company to compute refunds and surcharges to rectify class revenues received during the 2005-2007 period.

As I stated in my 2004 testimony, this should be considered only the first of three steps in the "gradual" process of moving all customer classes to unitized class returns. Within the pending 2007 general rate case of PPL, I recommend that the maximum acceptable relative rate of return, set at 150% of the system average return in this proceeding, be reduced to 125% of the system average return. And finally, in the subsequent general rate case for PPL, all customer classes (except perhaps the RTS class) should be near or to the system average return. I recommend that the Commission explicitly establish this multi-step process within its final order in this Remand Proceeding.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED ALLOCATION OF THE REDUCTION IN RATES ASSOCIATED WITH THE HURRICAN ISABEL EXPENSE?

A. Yes, I do. The Company is proposing to allocate the reduction in revenue requirements associated with the Court's elimination of Hurricane Isabel expense only to customer classes (other than the ISA class) that are paying higher than system average returns. This methodology serves to reduce the inequities inherent in existing distribution rates which result from required customer class cross-subsidies and therefore should be adopted by the Commission. Consistent with this position, I employed Remand Exhibit JMK-2 rather than Remand Exhibit JMK-1 as a basis for the implementation of my proposed revenue requirement allocation methodology as shown within Remand Exhibits KLK-3 and KLK-4.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY IN THIS REMAND PROCEEDING?

A. Yes it does.

Commonwealth of Virginia

County of Fairfax

Before me, the undersigned Notary Public, personally appeared Kenneth L. Kincel, who being duly sworn on oath deposes and says that the foregoing prepared direct testimony and statement of facts contained therein are true and correct to the best of his knowledge, information and belief.

_____

Kenneth L. Kincel

President, Decision Analysis Corporation of Virginia

Subscribed to and sworn before me on this 11th day of May 2007.

_____

Notary Public

My Commission Expires: _____

Exhibit KLK-1
Education and Qualifications of Kenneth L. Kincel

PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

My name is Kenneth L. Kincel. My business mailing address is Decision Analysis Corporation of Virginia, 8009 Snowpine Way, Suite 100, McLean, Virginia 22102.

WHAT IS YOUR OCCUPATION?

I am an energy consultant in the field of energy modeling, forecasting and economic analysis, and I perform these services as President and Chief Executive Officer of Decision Analysis Corporation of Virginia, an energy and environmental analysis consulting firm.

PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

I was awarded a Bachelor of Science Degree in Engineering by Rensselaer Polytechnic Institute (RPI) in 1967, and a Master of Science in Business Management in 1968, also from RPI. Subsequently, I served as Project Manager at Computer Sciences Corporation where I performed management consulting services until the summer of 1972. From July 1972 through June 1974, I served in several capacities performing industry economic analysis for the Cost of Living Council of the Federal Government during the period of wage and price controls. Following the oil embargo of 1973 -1974, I joined the Federal Energy Administration in the capacity of Director, Office of Energy Demand Policy and Special Projects, and was later promoted to Director, Office of Conservation and Resource Development Policy.

During this period, I testified in several natural gas import cases before the Federal Energy Regulatory Commission as to the economic benefits to the nation of limiting liquefied natural gas imports. I also appeared before several committees of the U.S. Senate and the U.S. House of Representatives on issues such as the availability of winter fuels, the domestic supply and price of natural gas and horizontal oil company divestiture. I headed the Interagency Natural Gas Emergency Task Force, the Synthetic Natural Gas Task Force and the Interagency Liquefied Natural Gas Task Force for FEA. When the Department of Energy (DOE) was formed in 1977, I joined the Energy Information Administration of DOE, and ultimately became the Deputy Assistant Administrator for Energy Applied Analysis (Modeling and Forecasting). In this capacity, I managed over 200 professional economists, energy analysts and computer scientists in the conduct of energy modeling and forecasting services to produce the *Short Term Energy Outlook, the Annual Energy Outlook* and the *International Energy Outlook,* the major energy forecasting publications of the Federal Government.

In August 1980 I left the Federal Government and founded Decision Analysis Corporation of Virginia (DAC). DAC performs energy and environmental modeling, forecasting and analysis services for utilities, industry associations, utility commissions, private firms and several agencies of the Federal Government, including DOD, Commerce and Energy. Since 1980, DAC has performed over 600 projects involving analysis of energy issues, and I have served as Project Manager for most of these projects.

Since 1994 and to the present, DAC has assisted DOE in the development of the National Energy Modeling System. Since the mid-1980's and to the present, DAC has also provided energy analysis and expert witness services to DOD on utility rate cases and cases involving the restructuring of the natural gas or electric utility industry for competition. I, myself, have

testified on cost of capital, revenue requirements, deregulation/industry restructuring policy and/or rate design issues before the Georgia Public Service Commission (natural gas and electricity), the New York State Public Service Commission (electricity), the Federal Energy Regulatory Commission (natural gas), the Kentucky Public Service Commission (electricity), the Public Utility Commission of Texas (electricity), the North Carolina Utilities Commission (natural gas), the New Jersey Office of Administrative Law (electricity) and the Public Service Commission of Maryland (gas and electricity), as listed in Exhibit KLK-2. I have testified before the Pennsylvania Public Utility Commission within the initial 2004 proceeding under this docket.

Recent Testimony and Regulatory Submissions of Kenneth L. Kincel

Regulatory Commission	Date	On Behalf Of	Submission Type	Docket No.	Utility	Issues	Topics Covered
Georgia Public Service Commission	October 18, 1996	US Dept. of Defense/FEA	Direct Testimony	6691-U	United Cities Gas Company	Natural gas rate increase	Revenue requirements, ROE
Federal Energy Regulatory Commission	December 13, 1996	US Dept. of Defense/FEA	Direct Testimony	RP96-190-00	Colorado Interstate Gas Co.	Interstate gas transportation rates	Cost allocation, rate design
New York Public Service Commission	January 7, 1997	US Dept. of Defense/FEA	Direct Testimony	96-E-0134	Niagara Mohawk Power Co.	Electric rate increase	Revenue requirements
Georgia Public Service Commission	October 23, 1997	US Dept. of Defense/FEA	Direct Testimony	8044-U	GPSC NOPR	Implementation of gas retail dereg.	Comments on marketers' certification
Georgia Public Service Commission	October 23, 1997	US Dept. of Defense/FEA	Direct Testimony	8053-U	GPSC NOPR	Implementation of gas retail dereg.	Comments on random assignment of customers
Georgia Public Service Commission	January 23, 1998	US Dept. of Defense/FEA	Formal Comments	8346-U	GPSC NOPR	Implementation of gas retail dereg.	Formal recommendations on unbundling methods
Maryland Public Service Commission	February 12, 1998	US Dept. of Defense/FEA	Direct Testimony	8780	Baltimore Gas & Electric Co.	Gas base rate increase	ROE, rate design
Georgia Public Service Commission	March 31, 1998	US Dept. of Defense/FEA	Direct Testimony	8390-U	Atlanta Gas Light Co.	Unbundling, Restructuring	ROE, rate design, performance rates
Georgia Public Service Commission	October 1, 1998	US Dept. of Defense/FEA	Direct Testimony	9355-U	Georgia Power Company	Base rate increase, earnings sharing	ROE, earnings sharing mechanism
Maryland Public Service Commission	December 18, 1998	US Dept. of Defense/FEA	Direct Testimony	8794	Baltimore Gas & Electric Co.	Electric restructuring	Stranded costs, cost unbundling, rate design
Maryland Public Service Commission	February 3, 1999	US Dept. of Defense/FEA	Direct Testimony	8804	Baltimore Gas & Electric Co.	Electric base rates, rate design	ROE, rate design
Kentucky Public Service Commission	March 18, 1999	US Army	Direct Testimony	98-474	Kentucky Utilities	Electric performance based rates	Performance based rates, earnings sharing mechanism
Kentucky Public Service Commission	March 18, 1999	US Army	Direct Testimony	98-426	Louisville Gas & Electric Co.	Electric performance based rates	Performance based rates, earnings sharing mechanism
Texas Public Utility Commission	September 15, 2000	US Army	Affidavit	23040	TXU Electric Company	Wholesale electric purchaser status	Information in support of petition for Fort Hood
Texas Public Utility Commission	February 2, 2001	US Army	Direct Testimony	22350	TXU Electric Company	Unbundling, Restructuring	Rate design
Georgia Public Service Commission	October 12, 2001	US Dept. of Defense/FEA	Direct Testimony	14000-U	Georgia Power Company	Base rate increase, earnings sharing	ROE, earnings sharing mechanism
North Carolina Utilities Commission	August 23, 2002	US Dept. of Defense/FEA	Direct Testimony	G21 Sub 431	North Carolina Natural Gas Corp.	Base rate rebalancing and increase	Rate design
New Jersey Office of Administrative Law	December 20, 2002	US Dept. of Defense/FEA	Direct Testimony	ER02080506-7 PUC7983,4-02	Jersey Central Power & Light Co.	Base rate increase, surcharges	ROE, ROI, rate design
Kansas State Corporation Commission	July 10, 2003	US Dept. of Defense/FEA	Direct Testimony	03-KGSG-602-RTS	Kansas Gas Division, ONEOK, Inc.	NG base rate increase, rate design	ROE, rate design
North Carolina Utilities Commission	August 12, 2003	US Dept. of Defense/FEA	Direct Testimony	G21 Sub 442	North Carolina Natural Gas Corp.	NG base rate increase, rate design	ROE, rev. reqts., rate design, terms
Kentucky Public Service Commission	March 19, 2004	US Dept. of Defense/FEA	Direct Testimony	2003-00433	Louisville Gas & Electric Company	NG and electric base rate increases	ROE, cost allocation, rate design, terms and conditions
Pennsylvania Public Utility Commission	June 28, 2004	US Dept. of Defense/FEA	Direct Testimony	R-00049255	PPL Electric Utilities Corporation	Electric base rate increases	ROE, cost allocation, rate design, terms and conditions
Georgia Public Service Commission	October 6, 2004	US Dept. of Defense/FEA	Direct Testimony	18300-U	Georgia Power Company	Electric base rate increases	ROE, cost allocation, rate design, terms and conditions
North Carolina Utilities Commission	August 26, 2005	US Dept. of Defense/FEA	Direct Testimony	G-9 Sub 499; G-21 Sub 461; G-44 Sub 15	Piedmont NG Company/NCNG	NG base rate increase, rate integratior	ROE, rev. reqts., rate design, terms & conditions
Wisconsin Public Service Commission	October 12, 2005	US Dept. of Defense/FEA	Direct Testimony	4220-UR-114	Excel Energy/Northern States Power	Electricity and NG base rate increases	ROE, rev. reqts., cost allocation, rate design
New York Public Service Commission	December 19, 2005	US Dept. of Defense/FEA	Direct Testimony	05-G-0935 and 05-E-0934	Central Hudson Gas & Electric Co.	NG Base Rate Increase and Gas Balancing	Cost of service, cost allocation, rate design
Kansas State Corporation Commission	September 27, 2006	US Dept. of Defense/FEA	Direct Testimony	06-KGSG-1209-RTS	Kansas Gas Division, ONEOK, Inc.	NG Bsae Rate Increase	ROE, cost allocation, rate design

Remand Exhibit KLK-3
PPL Electric Utilities Corporation
PPUC Docket No. R-00049255
Direct Testimony of K. L. Kincel for DOD/FEA
May 11, 2007

DOD/FEA Allocation of PPL's Adjusted Compliance 2004 Total Distribution Revenue Requirements Increase By Customer Class Using Original Methodology

$ (Thousands)

(1)	(2)	(3)	(4)			(5)	(6)		(7)			(8)	(9)	(10)		(11)	(12)	(1)
Rate Class	Rate Base $	RR at Present Rates $	Class Return at Present Rates $	%	RROR	RR at PPL's Proposed Rates $	PPL's % Increase in RR at Proposed Rates $	%	Class Return at PPL's Proposed Rates $	%	RROR	Gross-Up Factor	DOD/FEA Proposed RROR at PPL's Proposed RR	DOD/FEA Proposed Return $	%	DOD/FEA RR Increase Allocation $	DOD/FEA Class RR Percent Increase %	Rate Class
RS	1,188,218	293,920	27,678	2.33%	0.53	361,790	67,870	23.1%	65,111	5.48%	0.65		0.79	78,791	6.63%	92,491	31.5%	RS
RTS	43,171	3,513	-1,690	-3.91%	-0.89	3,982	469	13.4%	-1,436	-3.33%	-0.39		0.79	2,863	6.63%	8,238	234.5%	RTS
GS-1	177,572	61,460	17,333	9.76%	2.23	79,470	18,010	29.3%	27,377	15.42%	1.83		1.50	22,452	12.64%	9,264	15.1%	GS-1
GS-3	270,794	84,182	25,253	9.33%	2.13	119,554	35,372	42.0%	44,870	16.57%	1.97		1.50	34,240	12.64%	16,261	19.3%	GS-3
LP-4	67,662	21,873	6,297	9.31%	2.13	30,706	8,833	40.4%	11,071	16.36%	1.94		1.50	8,555	12.64%	4,086	18.7%	LP-4
ISP	4,238	1,757	531	12.53%	2.86	2,068	311	17.7%	704	16.61%	1.97		1.50	536	12.64%	9	0.5%	ISP
LP-5	1,973	1,774	548	27.87%	6.32	1,785	11	0.6%	571	28.94%	3.43		1.50	249	12.64%	-537	-30.2%	LP-5
IST	751	1,717	658	87.62%	20.01	1,244	-473	-27.5%	400	53.26%	6.32		1.50	95	12.64%	-1,019	-59.3%	IST
LP-6	134	283	123	91.79%	20.96	201	-82	-29.0%	79	58.96%	6.99		1.50	17	12.64%	-192	-67.8%	LP-6
LPEP	975	314	79	8.10%	1.85	387	73	23.2%	115	11.79%	1.40		1.50	123	12.64%	80	25.5%	LPEP
ISA	264	662	290	109.85%	25.09	659	-3	-0.5%	289	109.47%	12.99		12.99	290	109.85%	0	0.0%	ISA
GH	20,754	6,222	1,883	9.07%	2.07	8,667	2,445	39.3%	3,266	15.74%	1.87		1.50	2,624	12.64%	1,341	21.6%	GH
SL/AL	60,291	17,705	1,455	2.41%	0.55	19,478	1,773	10.0%	2,410	4.00%	0.47		0.79	3,998	6.63%	4,602	26.0%	SL/AL
LS-S	166	36	10	6.02%	1.38	76	40	111.1%	32	19.28%	2.29		0.79	11	6.63%	2	5.1%	LS-S
Total*	1,836,958	495,418	80,434	4.38%	1.00	630,067	134,649	27.2%	154,845	8.43%	1.00	1.81	1.00	154,845	8.43%	134,627	27.2%	Total*

Sources: Remand Exhibit JMK-2 is PPL's Cost Allocation Study Adjusted for Compliance Filing and Further Adjusted to Exclude Hurricane Isabel Storm Expense
Columns 2 through 7 were taken from Remand Exhibit JMK-2; values in the remaining columns are derived.
Column 9: The UROR is set at 1.50 for all classes (except for ISA) having a ROR of greater than 1.50 at present rates; for all other classes, the revenue requirement that will produce an equal UROR for each class having a present UROR of less than 1.50 is derived.
Class ISA revenues are set by a Special Agreement and are unaffected by the revenue allocations.
RR = Revenue Requirements; UROR = unitized or relative rate of return, i.e, the class return percentage divided by the system average return percentage.
* Slight differences occur in totals when compared to corresponding columns on Remand Exhibit JMK-2 due to rounding or errors in Remand Exhibit JMK-2.

Remand Exhibit KLK-4
PPL Electric Utilities Corporation
PPUC Docket No. R-00049255
Direct Testimony of K. L. Kincel for DOD/FEA
May 11, 2007

DOD/FEA Allocation of PPL's Adjusted Compliance 2004 Total Distribution Revenue Requirements Increase By Customer Class With Reduced Rate Shock

$ (Thousands)

(1)	(2)	(3)	(4)			(5)	(6)		(7)			(8)	(9)	(10)		(11)	(12)	(1)
Rate Class	Rate Base $	RR at Present Rates $	Class Return at Present Rates $	%	RROR	RR at PPL's Proposed Rates $	PPL's % Increase in RR at Proposed Rates $	%	Class Return at PPL's Proposed Rates $	%	RROR	Gross-Up Factor	DOD/FEA Proposed RROR at PPL's Proposed RR	DOD/FEA Proposed Return $	%	DOD/FEA RR Increase Allocation $	DOD/FEA Class RR Percent Increase %	Rate Class
RS	1,188,218	293,920	27,678	2.33%	0.53	361,790	67,870	23.1%	65,111	5.48%	0.65		0.82	82,385	6.93%	98,993	33.7%	RS
RTS	43,171	3,513	-1,690	-3.91%	-0.89	3,982	469	13.4%	-1,436	-3.33%	-0.39		-0.25	-913	-2.12%	1,405	40.0%	RTS
GS-1	177,572	61,460	17,333	9.76%	2.23	79,470	18,010	29.3%	27,377	15.42%	1.83		1.50	22,452	12.64%	9,264	15.1%	GS-1
GS-3	270,794	84,182	25,253	9.33%	2.13	119,554	35,372	42.0%	44,870	16.57%	1.97		1.50	34,240	12.64%	16,261	19.3%	GS-3
LP-4	67,662	21,873	6,297	9.31%	2.13	30,706	8,833	40.4%	11,071	16.36%	1.94		1.50	8,555	12.64%	4,086	18.7%	LP-4
ISP	4,238	1,757	531	12.53%	2.86	2,068	311	17.7%	704	16.61%	1.97		1.50	536	12.64%	9	0.5%	ISP
LP-5	1,973	1,774	546	27.67%	6.32	1,785	11	0.6%	571	28.94%	3.43		1.50	249	12.64%	-537	-30.2%	LP-5
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SL/AL	60,291	17,705	1,455	2.41%	0.55	19,478	1,773	10.0%	2,410	4.00%	0.47		0.82	4,180	6.93%	4,931	27.9%	SL/AL
LS-S	166	36	10	6.02%	1.38	76	40	111.1%	32	19.28%	2.29		0.82	12	6.93%	3	7.8%	LS-S
Total*	1,836,958	495,418	80,434	4.38%	1.00	630,067	134,649	27.2%	154,845	8.43%	1.00	1.81	1.00	154,845	8.43%	134,627	27.2%	Total*

Sources: Remand Exhibit JMK-2 is PPL's Cost Allocation Study Adjusted for Compliance Filing and Further Adjusted to Exclude Hurricane Isabel Storm Expense
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Column 9: The UROR is set at 1.50 for all classes (except for ISA) having a ROR of greater than 1.50 at present rates; for all other classes, the revenue requirement that will produce an equal UROR for each class having a present UROR of less than 1.
Class ISA revenues are set by a Special Agreement and are unaffected by the revenue allocations.
Column 12: The increase to the RTS Class is held to 40% to avoid "rate shock."
RR = Revenue Requirements; UROR = unitized or relative rate of return, i.e, the class return percentage divided by the system average return percentage.
* Slight differences occur in totals when compared to corresponding columns on Remand Exhibit JMK-2 due to rounding or small errors in Remand Exhibit JMK-2.