OCA EXHIBIT 24
R-850152

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Q.IR-OCA-1-2. Provide a comparison of budgeted versus actual Electric Plant in Service by primary accounts including common plant as of December 31, 1984, March 31, 1985, June 30, 1985 and September 30, 1985.

A.IR-OCA-1-2. Attachment IR-OCA-1-2 provides a comparison of budgeted versus actual Electric Plant in Service by primary accounts including common plant as of December 31, 1984, March 31, 1985, June 30, 1985 and September 30, 1985.

Responsible Witness: T.P.Hill,Jr.,Asst. Manager-Rate Division
W.H.Smith, Manager - Plant Accounting

Philadelphia Electric Company - Electric Operations

ELECTRIC PLANT

(Thousand $)

		December 31, 1974 Budget	December 31, 1974 Actual
Electric Plant In Service			
Intangible Plant			
302.	Franchises and Consents	$163	$163
Production Plant			
Steam Production Plant			
310.	Land and Land Rights	$7,598	7,598
311.	Structures and Improvements	232,003	220,906
312.	Boiler Plant Equipment	625,176	583,462
314.	Turbogenerator Units	179,834	179,760
315.	Accessory Electric Equipment	116,879	108,432
316.	Miscellaneous Power Plant Equipment	12,560	12,904
	Total Steam Production Plant	1,174,050	1,113,062
Nuclear Production			
320.	Land and Land Rights	400	357
321.	Structures and Improvements	303,147	301,686
322.	Reactor Plant Equipment	592,234	590,935
323.	Turbogenerator Units	220,789	201,112
324.	Accessory Electric Equipment	174,590	174,806
325.	Miscellaneous Power Plant Equipment	43,940	38,136
	Total Nuclear Production Plant	1,335,100	1,307,032
Hydraulic Production			
330.	Land and Land Rights	1,421	1,421
331.	Structures and Improvements	14,484	14,483
332.	Reservoirs, Dams and Waterways	34,311	34,292
333.	Water Wheels, Turbines and Generators	21,971	21,971
334.	Accessory Electric Equipment	8,645	8,650
335.	Miscellaneous Power Plant Equipment	2,039	2,047
336.	Roads, Railroads and Bridges	998	998
	Total Hydraulic Production Plant	83,869	83,862
Other Production Plant			
340.	Land and Land Rights	849	850
341.	Structures and Improvements	4,406	4406
342.	Fuel Holders, Producers and Accessories	22,448	22,448
343.	Prime Movers		
344.	Generators	90,903	90,903
345.	Accessory Electric Equipment	13,064	13,064
346.	Miscellaneous Power Plant Equipment	2,277	2,277
	Total Other Production Plant	133,947	133,948
Total Production Plant		2,726,966	2,637,904

Philadelphia Electric Company -

ELECTRIC PLANT

(Thousand $)

December 31, 19[illegible]

Electric Plant In Service (Continued)

		Budget	Actual
Transmission Plant			
350.	Land and Land Rights	47,381	47,404
352.	Structures and Improvements	15,057	15,057
353.	Station Equipment	219,184	218,835
354.	Towers and Fixtures	183,473	183,142
355.	Poles and Fixtures	445	445
356.	Overhead Conductors and Devices	81,611	81,997
357.	Underground Conduit	2,521	2,521
358.	Underground Conductors and Devices	33,825	33,825
359.	Roads and Trails	1,730	1,730
	Total Transmission Plant	585,227	584,956
Distribution Plant			
360.	Land and Land Rights	20,483	20,535
361.	Structures and Improvements	37,087	35,015
362.	Station Equipment	280,924	279,953
364.	Poles, Towers and Fixtures	126,151	127,295
365.	Overhead Conductors and Devices	195,690	192,909
366.	Underground Conduit	138,374	138,752
367.	Underground Conductors and Devices	245,782	243,816
368.	Line Transformers	146,851	147,998
369.	Services	92,451	94,490
370.	Meters	86,112	86,667
371.	Installations on Customers' Premises	276	277
373.	Street Lighting and Signal Systems	25,520	25,693
	Total Distribution Plant	1,395,701	1,393,400
General Plant			
389.	Land and Land Rights	1,716	1,805
390.	Structures and Improvements	14,934	16,494
391.	Office Furniture & Equipment	1,045	2,820
393.	Stores Equipment	406	406
394.	Tools, Shop and Garage Equipment	4712	4879
395.	Laboratory Equipment	6,897	6773
397.	Communication Equipment	1,639	1750
398.	Miscellaneous Equipment	926	958
	Sub-Total	32,275	35,885
399.	Other Tangible Property — Anti-trust Price Adjustment	(2,995)	(3106)
	Total General Plant	29,280	32,779
	Total Electric Plant In Service [redacted]	4,737,337	4,649,202

Philadelphia Electric Company

COMMON UTILITY PLANT

(Thousand $)

		December 31, 1984 Budget	December 31, 1984 Actual
Intangible Plant			
301.	Organization	$677	$677
General Plant			
389.	Land and Land Rights	2380	$2,371
390.	Structures and Improvements	84,292	83,732
391.	Office Furniture and Equipment	19,183	18,863
392.	Transportation Equipment	9,853	9600
393.	Stores Equipment	1,816	1757
394.	Tools, Shop and Garage Equipment	6576	6638
396.	Power Operated Equipment	1564	1499
397.	Communication Equipment	1850	1861
398.	Miscellaneous Equipment	2181	2263
	Total - General Plant	129,695	128,584
Total Common Utility Plant in Service		130,372	129,261

Philadelphia Electric Company -

ELECTRIC PLANT

(Thousand $)

March 31, 1985

	Budget	Actual
Electric Plant In Service		
Intangible Plant		
302. Franchises and Consents	163	163
Production Plant		
Steam Production Plant		
310. Land and Land Rights	7,598	7,598
311. Structures and Improvements	221,324	221,482
312. Boiler Plant Equipment	586,756	587,138
314. Turbogenerator Units	179,920	179,802
315. Accessory Electric Equipment	108,593	105,225
316. Miscellaneous Power Plant Equipment	13,058	12,899
Total Steam Production Plant	1,117,249	1,114,144
Nuclear Production		
320. Land and Land Rights	357	357
321. Structures and Improvements	302,705	305,906
322. Reactor Plant Equipment	617,240	579,134
323. Turbogenerator Units	207,456	217,487
324. Accessory Electric Equipment	175,916	180,809
325. Miscellaneous Power Plant Equipment	38,624	38,721
Total Nuclear Production Plant	1,342,298	1,322,414
Hydraulic Production		
330. Land and Land Rights	1,421	1,421
331. Structures and Improvements	14,484	14,483
332. Reservoirs, Dams and Waterways	34,292	34,292
333. Water Wheels, Turbines and Generators	21,970	21,971
334. Accessory Electric Equipment	8,650	8,651
335. Miscellaneous Power Plant Equipment	2,047	2,048
336. Roads, Railroads and Bridges	998	998
Total Hydraulic Production Plant	83,862	83,864
Other Production Plant		
340. Land and Land Rights	849	849
341. Structures and Improvements	4406	4406
342. Fuel Holders, Producers and Accessories	22448	22449
343. Prime Movers	–	
344. Generators		
345. Accessory Electric Equipment	90,903	90,905
346. Miscellaneous Power Plant Equipment	2,277	2,275
Total Other Production Plant	133,947	133,948
Total Production Plant	2,677,356	2,654,370

Philadelphia Electric Company

ELECTRIC PLANT

(Thousand $)

March 31, 1975

Electric Plant In Service (Continued)

		Budget	Actual
Transmission Plant			
350.	Land and Land Rights	47,434	47,709
352.	Structures and Improvements	15,472	14,984
353.	Station Equipment	219,914	218,703
354.	Towers and Fixtures	185,649	181,931
355.	Poles and Fixtures	450	445
356.	Overhead Conductors and Devices	82,446	82,916
357.	Underground Conduit	2,521	2,521
358.	Underground Conductors and Devices	33,825	33,878
359.	Roads and Trails	1,730	1,730
	Total Transmission Plant	589,441	584,817
Distribution Plant			
360.	Land and Land Rights	20,608	21,253
361.	Structures and Improvements	35,056	35,002
362.	Station Equipment	280,536	279,912
364.	Poles, Towers and Fixtures	128,383	129,912
365.	Overhead Conductors and Devices	195,685	194,725
366.	Underground Conduit	141,255	139,258
367.	Underground Conductors and Devices	249,117	246,282
368.	Line Transformers	149,921	150,788
369.	Services	95,928	96,662
370.	Meters	87,844	88,632
371.	Installations on Customers' Premises	277	277
373.	Street Lighting and Signal Systems	26,099	25,861
	Total Distribution Plant	1,410,709	1,408,564
General Plant			
389.	Land and Land Rights	1,805	1838
390.	Structures and Improvements	16,607	16,870
391.	Office Furniture & Equipment	2,922	3047
393.	Stores Equipment	406	406
394.	Tools, Shop and Garage Equipment	4,879	4916
395.	Laboratory Equipment	6,794	6969
397.	Communication Equipment	1,751	1780
398.	Miscellaneous Equipment	958	960
	Sub-Total	36,122	36,786
399.	Other Tangible Property Anti-trust Price Adjustment	(2,946)	(2945)
	Total General Plant	33,176	33,841
Total Electric Plant In Service		4,710,865	4,681,755

Philadelphia Electric Company

COMMON UTILITY PLANT

(Thousand $)

		March 31, 1985 Budget	Actual
Intangible Plant			
301.	Organization	$677	$677
General Plant			
389.	Land and Land Rights	$2692	$2407
390.	Structures and Improvements	84.040	84,319
391.	Office Furniture and Equipment	19,141	19,130
392.	Transportation Equipment	9,271	9,281
393.	Stores Equipment	1,797	1,752
394.	Tools, Shop and Garage Equipment	6,641	6,783
396.	Power Operated Equipment	1,499	1,437
397.	Communication Equipment	1,860	1,851
398.	Miscellaneous Equipment	2,304	2,307
	Total - General Plant	$129,245	$129,279
Total Common Utility Plant in Service		$129,922	$129,956

Philadelphia Electric Company

ELECTRIC PLANT

June 30, 1985

(Thousand $)

	Budget	Actual
Electric Plant In Service		
Intangible Plant		
302. Franchises and Consents	163	163
Production Plant		
Steam Production Plant		
310. Land and Land Rights	7,481	7598
311. Structures and Improvements	207,224	222,007
312. Boiler Plant Equipment	579,357	588,162
314. Turbogenerator Units	173,123	180,054
315. Accessory Electric Equipment	105,705	106,034
316. Miscellaneous Power Plant Equipment	12,631	12,895
Total Steam Production Plant	1,085,521	1,116,750
Nuclear Production		
320. Land and Land Rights	357	357
321. Structures and Improvements	303,710	307,048
322. Reactor Plant Equipment	621,709	614,150
323. Turbogenerator Units	209,121	224,960
324. Accessory Electric Equipment	176,230	181,741
325. Miscellaneous Power Plant Equipment	39,018	43,747
Total Nuclear Production Plant	1,350,145	1,372,003
Hydraulic Production		
330. Land and Land Rights	1,420	1421
331. Structures and Improvements	14,484	14 4[illegible]4
332. Reservoirs, Dams and Waterways	34,320	[illegible]
333. Water Wheels, Turbines and Generators	21,971	21 [illegible]
334. Accessory Electric Equipment	8,650	8662
335. Miscellaneous Power Plant Equipment	2,047	2039
336. Roads, Railroads and Bridges	998	[illegible]
Total Hydraulic Production Plant	83,890	83,867
Other Production Plant		
340. Land and Land Rights	849	849
341. Structures and Improvements	4326	[illegible]406
342. Fuel Holders, Producers and Accessories	22,204	22,44[illegible]
343. Prime Movers	-	-
344. Generators	88,417	[illegible]
345. Accessory Electric Equipment	12,867	13,064
346. Miscellaneous Power Plant Equipment	2277	2,282
Total Other Production Plant	13[illegible] [illegible]40	133,955
Total Production Plant	2,650,496	2,706,575

Philadelphia Electric Company

ELECTRIC PLANT

June 30, 1985

(Thousand $)

Electric Plant In Service (Continued)

		Budget	Actual
Transmission Plant			
350.	Land and Land Rights	47,464	47,850
352.	Structures and Improvements	15,887	14,934
353.	Station Equipment	220,740	219,022
354.	Towers and Fixtures	185,671	183,834
355.	Poles and Fixtures	455	444
356.	Overhead Conductors and Devices	82,885	83,864
357.	Underground Conduit	2,521	2521
358.	Underground Conductors and Devices	33,825	33,914
359.	Roads and Trails	1,730	1,730
	Total Transmission Plant	591,178	588,113
Distribution Plant			
360.	Land and Land Rights	20,681	21,195
361.	Structures and Improvements	35,097	35,022
362.	Station Equipment	283,991	280,305
364.	Poles, Towers and Fixtures	129,417	131,562
365.	Overhead Conductors and Devices	198,339	197,119
366.	Underground Conduit	144,040	140,481
367.	Underground Conductors and Devices	253,578	248,347
368.	Line Transformers	151,825	152,904
369.	Services	97,353	100,516
370.	Meters	88,945	90,918
371.	Installations on Customers' Premises	277	278
373.	Street Lighting and Signal Systems	26,503	26,378
	Total Distribution Plant	1,430,046	1,425,025
General Plant			
389.	Land and Land Rights	1,805	1967
390.	Structures and Improvements	17,053	17,219
391.	Office Furniture & Equipment	2,945	3160
393.	Stores Equipment	406	404
394.	Tools, Shop and Garage Equipment	4,881	4974
395.	Laboratory Equipment	6,812	7382
397.	Communication Equipment	1,751	1830
398.	Miscellaneous Equipment	958	961
	Sub-Total	36,611	37,897
399.	Other Tangible Property Anti-trust Price Adjustment	(2,786)	(2783)
	Total General Plant	33,825	35,114
Total Electric Plant In Service		4,705,708	4,754,990

Philadelphia Electric Company

COMMON UTILITY PLANT

(Thousand $)

		June 30, 1985 Budget	June 30, 1985 Actual
Intangible Plant			
301.	Organization	$ 677	$ 677
General Plant			
389.	Land and Land Rights	$ 2,692	$ 2393
390.	Structures and Improvements	85,015	84,710
391.	Office Furniture and Equipment	20,553	20,191
392.	Transportation Equipment	8,755	8,809
393.	Stores Equipment	1,837	1830
394.	Tools, Shop and Garage Equipment	6,644	6952
396.	Power Operated Equipment	1,499	1422
397.	Communication Equipment	1,861	1866
398.	Miscellaneous Equipment	2,345	2335
	Total - General Plant	$ 131,201	$ 130,508
Total Common Utility Plant in Service		$ 131,878	$ 131,185

Philadelphia Electric Company

ELECTRIC PLANT

(Thousand $)

September 30, 1985

	Budget	Actual
Electric Plant In Service		
Intangible Plant		
302. Franchises and Consents	163	163
Production Plant		
Steam Production Plant		
310. Land and Land Rights	7598	7598
311. Structures and Improvements	228,072	227,082
312. Boiler Plant Equipment	589,180	593,878
314. Turbogenerator Units	180,554	180,307
315. Accessory Electric Equipment	106,169	105,108
316. Miscellaneous Power Plant Equipment	13,086	13,440
Total Steam Production Plant	1,124,659	1,127,413
Nuclear Production		
320. Land and Land Rights	357	357
321. Structures and Improvements	308 556	308,058
322. Reactor Plant Equipment	620,512	630,742
323. Turbogenerator Units	227,747	225,315
324. Accessory Electric Equipment	182,086	183,310
325. Miscellaneous Power Plant Equipment	43,922	45,800
Total Nuclear Production Plant	1,383,180	1,393,582
Hydraulic Production		
330. Land and Land Rights	1,421	1,421
331. Structures and Improvements	14,483	14,483
332. Reservoirs, Dams and Waterways	34,309	34,292
333. Water Wheels, Turbines and Generators	21,971	21,971
334. Accessory Electric Equipment	8,662	8,662
335. Miscellaneous Power Plant Equipment	2,039	2,042
336. Roads, Railroads and Bridges	998	998
Total Hydraulic Production Plant	83,883	83,869
Other Production Plant		
340. Land and Land Rights	849	849
341. Structures and Improvements	4,406	4,406
342. Fuel Holders, Producers and Accessories	22,449	22,449
343. Prime Movers	–	–
344. Generators	90,905	90,905
345. Accessory Electric Equipment	13,064	13,064
346. Miscellaneous Power Plant Equipment	2,282	2,287
Total Other Production Plant	133,955	133,960
Total Production Plant	2,725,677	2,738,824

Philadelphia Electric Company

ELECTRIC PLANT

(Thousand $)

September 30, 1985

Electric Plant In Service (Continued)

	Budget	Actual
Transmission Plant		
350. Land and Land Rights	47,880	47,910
352. Structures and Improvements	15,349	15,031
353. Station Equipment	219,892	219,051
354. Towers and Fixtures	183,930	184,062
355. Poles and Fixtures	450	414
356. Overhead Conductors and Devices	84303	83,975
357. Underground Conduit	2,521	2,521
358. Underground Conductors and Devices	33,914	33,998
359. Roads and Trails	1,730	1,730
Total Transmission Plant	589,969	588,692

	Budget	Actual
Distribution Plant		
360. Land and Land Rights	21,267	21,260
361. Structures and Improvements	35,063	35,422
362. Station Equipment	280,789	287,209
364. Poles, Towers and Fixtures	132,595	133,538
365. Overhead Conductors and Devices	199,773	199,639
366. Underground Conduit	142,984	141,676
367. Underground Conductors and Devices	252,677	251,957
368. Line Transformers	154,307	157,736
369. Services	101,945	103,298
370. Meters	92,019	92,605
371. Installations on Customers' Premises	278	278
373. Street Lighting and Signal Systems	26,780	26,983
Total Distribution Plant	1,440,977	1,451,601

	Budget	Actual
General Plant		
389. Land and Land Rights	1,966	1,966
390. Structures and Improvements	17,557	17,371
391. Office Furniture & Equipment	3,183	3,239
393. Stores Equipment	404	404
394. Tools, Shop and Garage Equipment	4,975	5,046
395. Laboratory Equipment	7,400	7,637
397. Communication Equipment	1830	1,830
398. Miscellaneous Equipment	960	964
Sub-Total	38,275	38,457
399. Other Tangible Property Anti-trust Price Adjustment	(2,621)	(2621)
Total General Plant	35,654	35,836
Total Electric Plant In Service	4,792,440	4,815,116

Philadelphia Electric Company

COMMON UTILITY PLANT

(Thousand $)

		September 30, 1975	
		Budget	Actual
Intangible Plant			
301.	Organization	677	677
General Plant			
389.	Land and Land Rights	2,393	2,393
390.	Structures and Improvements	85,583	84 909
391.	Office Furniture and Equipment	20,988	20,533
392.	Transportation Equipment	8,293	8,388
393.	Stores Equipment	1,870	1,863
394.	Tools, Shop and Garage Equipment	6,955	7101
396.	Power Operated Equipment	1,422	1,392
397.	Communication Equipment	1866	1,868
398.	Miscellaneous Equipment	2,375	2,294
	Total - General Plant	131,745	130,741
Total Common Utility Plant in Service		132,422	131,418

OCA EXHIBIT 25
R-850152

12-13-85
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Public Utility Commission

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DEC 23 1985

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Q.IR-OCA-1-3. Similar to OCA Interrogatory Set I No. 6 in the prior case, provide an explanation of the quarterly variations in the "original cost of plant for ratemaking" for the quarters in No. 2 above.

A.IR-OCA-1-3. Attachment IR-OCA-1-3 provides an explanation of the quarterly variations in IR-OCA-1-2.

Responsible Witness: T.P.Hill,Jr.,Asst. Manager-Rate Division
W.H.Smith, Manager - Plant Accounting

PREPARED		
CHECKED		
TYPED		
COMPARED AND FOOTED		

Philadelphia Electric Company
Electric Plant in Service
Comparison of Budgeted Plant vs Actual Plant
at December 31, 1984

($1,000)	Actual Plant	Budget Plant	Actual over (under) Budget
M60 Plants (Allied & Essex)	2501	58907	(56406)
Peach Bottom Unit 2 Purchase and Install 2 Low Pressure Turbine Rotors Budgeted 12/84 actual 4/85	-	13999	(13999)
Peach Bottom Torus attached Piping Modification MOD 842	-	7571	(7571)
Peach Bottom Refueling platform replacement on Unit 2	-	810	(810)
Salem Environment Qualification of Equipment on Unit 1	-	500	(500)
Eddystone units 1 & 2 install coal pile runoff system	-	1136	(1136)
Cromby Unit 1 - new comb, feedwater & system Temp controls Budgeted 12/84 Actual 6/85	-	1732	(1732)
Pulaski substation - Wister Area 4KV to 13KV conversion	-	1079	(1079)
Sun Pipe Line Co - Install 34KV service	-	1030	(1030)
Salem Units 1 & 2 upgrade station security	-	2436	(2436)
Peach Botton fire protection budgeted 3/85 Actual 12/84	9128	-	9128
8 miscellaneous steam production works	732	5436	(4704)
Other miscellaneous jobs			(5860)
			(88135)

Attachment IR-OCA-1-3

PREPARED	
CHECKED	
TYPED	
COMPARED AND FOOTED	

Philadelphia Electric Company
Electric Plant in Service
Comparison of Budgeted Plant vs Actual Plant at March 31, 1985

($1,000)	Actual Plant	Budget Plant	Actual over (under) Budget
Eddystone station completion work on particulate and SO2 removal	$435	$900	($465)
Peach Bottom fire protection Mod 1110 penetration seal upgrade budgeted for 3/85 actual in service 12/84	–	9 128	(9 128)
Peach Bottom replace recirculation system (Loops A & B), RHR shut down cooling system 20" suction & 24" RHR return on Loops A & B and RHR head spray line 6" Mod 1278 Unit 2. Budgeted for 1/85 actual 5/85	–	13 820	(13 820)
Upgrade Whitpain-Warrington 230 KV lines and establish new lines. Budgeted for 1/85 actual 5/85	–	2 436	(2 436)
Plymouth meeting Substation tansfer 24 MVA of load from 69-13KV sub. to 230-13KV sub. Budgeted for 1/85 actual 5/85	–	375	(375)
Miscellaneous jobs			(2 866)
Total			($29 090)

PREPARED	
CHECKED	
TYPED	
COMPARED AND FOOTED	

Attachment IR-OCA-1-3

Philadelphia Electric Company
Electric Plant in Service
Comparison of Budgeted Plant vs Actual Plant at September 30, 1985

$1,000	Actual Plant	Budget Plant	Actual over (Under) Budget
Eddystone Units 1 & 2 feedwater, PP and HPB FB control Budgeted June 1985 Actual July 1985	$2224	–	$2224
Keystone Unit 2 Economizer replacement Budgeted May 1985 Actual July 1985	1047	–	1047
Eddystone Station construct maintenance store room and personnel facilities Budgeted Sept 1985 Actual 8/85	4083	5506	(1423)
Delaware Station Unit 8 water induction protection	585	–	585
Peach Bottom Units 2 & 3 Construction of Radwaste storage facility Budgeted for Dec, 1985 Actual Aug 1985	6087	–	6087
Salem Unit 1 feedwater containment isolation valving Budgeted Feb 1986 Actual July 1985	541	–	541
Salem Unit 1 Fan coil leak detection and isolation Budgeted Dec 1986 Actual July 1985	406	–	406
Salem Units 1 and 2 upgrade station security Budgeted Dec 1984 Actual Aug 1985	2436	–	2436
Sun Pipe Line Co. - Install 34KV service Budgeted Dec 1984 Actual July 1985	925	–	925
System Reinforcements - Eastern Division	538	–	538
Heaton Substation additional 13 KV capacity Budgeted May 1986 Actual July 1985	8183	–	8183
Miscellaneous jobs			1077
Total			$22676

Attachment IR-OCA-1-3

PREPARED	
CHECKED	
TYPED	
COMPARED AND FOOTED	

Philadelphia Electric Company
Electric Plant in Service
Comparison of Budgeted Plant vs Actual Plant at June 30, 1985

	Actual Plant	Budget Plant	Actual over (Under) Budget
Peach Bottom replace recirculation system (Loops A & B), RHR shut down cooling system 20" suction & 24" RHR return on Loops A & B and RHR head spray line 6" MOD 1278 Unit 2 Budgeted for 2/85 actual 1/85	$33804	$13820	$19984
Retirement of Richmond Station	–	(40808)	40808
Pulaski substation - Winter Area 4KV to 13KV conversion Budgeted for 12/84 actual 4/85			
	1019	–	1019
Peach Bottom Unit 2 Purchase and install 2 Low Pressure Turbine Rotors Budget 12/84 actual 4/85	–		
	13992	36	13956
Upgrade Whitpain-Warrington 230KV lines and establish new lines. Budgeted 1/85 actual 5/85			
	2813	2131	682
Plymouth Meeting Substation Transfer 24MVA of load from 69-13KV sub to 230-13KV sub Budgeted 1/85; Actual 5/85			
	404	375	29
Cromby Unit 1 new comb, feedwater & system Temperature control Budgeted 12/84, Actual 6/85			
10 miscellaneous Steam Production work orders	2108	–	2108
7 miscellaneous Nuclear Production work orders		(9782)	(9782)
Miscellaneous Transmission & Distribution	621	16904	(16284)
		3238	(3238)
Total			$49282

OCA EXHIBIT 26
R-850152

12-13-85
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Q. IR-OCA-1-52. Provide the appropriate value and workpapers for the "Salem Unit #1 Rate Base Adjustment" (ordered at R-822291, page 10) at June 30, 1986. Please state why the Company has not included such an adjustment in this case.

A. IR-OCA-1-52. The net plant of the "Salem Unit #1 Rate Base Adjustment" at June 30, 1986 is $4,379,899. The claimed rate base did not reflect this adjustment because the Company continues to believe that such an adjustment is inappropriate.

Responsible Witness: T.P. Hill, Jr., Asst. Manager-Rate Division

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R-850152
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Q. IR-OCA-1-26. Provide a copy of the latest Financial Analyst's Forecast Information.

A. IR-OCA-1-26. Attachment IR-OCA-1-26 provides the requested data.

Responsible Witness: J.F. Paquette, Jr.- Vice President

Attachment [illegible]

PHILADELPHIA ELECTRIC COMPANY

PHILADELPHIA SERVICE ELECTRIC COMPANY

FINANCIAL ANALYSTS FORECAST INFORMATION

Direct inquiries to:
Joseph F. Paquette, Jr., Vice President
2301 Market Street
Philadelphia, Pa. 19101
Telephone: 215-841-5800

May 31, 1985

NOTES:

1. Forecast information has been set forth in anticipation that revenues in the forecast years will be sufficient to support the projected construction expenditures, internal sources of cash flow and financing. This forecast reflects Limerick No. 1 commercial operation in the fourth quarter of 1985 at a total cost of $3.1 billion including 50% of Common Plant.

2. Peak load, which occurs during the summer months, is actual for 1984 (excluding the sale of Salem No. 2 output - see Note 3) and is estimated for 1985-1989 on the basis of weather conditions which have a 50% probability of occurrence. In 1984 the weather adjusted summer peak was 6100 MW.

3. The indicated generating capability for the years 1984 to 1989 includes the Company's share (471 MW) of the Salem No. 2 nuclear unit and the Limerick No. 1 nuclear unit (1055 MW) which is expected to go into service in 1985.

   For 1985, electric output is expected to be generated as follows: 44% nuclear, 21% coal including minemouth, 8% oil including internal combustion and 27% other, primarily interchange purchases. In 1986 nuclear generation will increase to approximately 55% and net interchange will decrease to about 11%. By 1989, nuclear generation is expected to climb to 58%.

4. The indicated expenditures reflect a suspension of construction on Limerick No. 2 until October 1985 with resumption of construction at that time based on a completion schedule of 1990.

5. The indicated outside financing requirements will increase total capitalization by about 6% per year from 1984 to 1989. The objective of the Company's financing plan is to maintain maximum financial flexibility and to assure ready access to required capital at reasonable cost. Short term debt is used primarily as a source of interim funds between financings, the amount outstanding generally being less than $150 million, well below existing bank lines of $238 million.

   In 1984 the Company sold and leased back its Allied MgO facility for $56 million. A like arrangement is planned in 1986 concerning the Company's Limerick Nuclear Fuel Investment.

6. Allowance for Funds Used During Construction (AFUDC) is included in Construction Expenditures and in Other Internal Sources. The rate used for capitalizing AFUDC, which ranges from 9.5% in 1985 to 9.9% in 1989, is applied to the Construction Work in Progress (CWIP) base including prior AFUDC which is compounded semi-annually.

   The rate is a "net after-tax rate" in conformance with an Order of the Pennsylvania Public Utility Commission whereby the current income tax reductions arising from interest charges associated with debt used to finance construction are allocated to nonutility operations.

7. Federal income tax reductions for investment tax credits are deferred and amortized by credits to income over the estimated useful life of the plant. Approximately $162 million of investment tax credits available in 1984, of which $11 million represents 1 1/2% employee stock ownership plan credit from 1982 and 1983, were not realized due to taxable income limitations. These credits have been carried forward and are reflected in the Budget and Forecast. The years 1984 through 1989 reflect a 10% investment tax credit rate to the extent it may be utilized.

PHILADELPHIA ELECTRIC COMPANY

FINANCIAL ANALYSTS FORECAST INFORMATION

These estimates are subject to significant change - Note 1

	Actual 1984	Estimate 1985	Forecast 1986	Forecast 1987	Forecast 1988	Forecast 1989	Compound Growth Rates 1984-89
SALES AND LOAD DATA							
Electric:							
Sales - Billion KWH							
Ultimate Consumers	28.0	28.3	28.2	28.1	28.4	28.7	0.5%
Sale of Salem No. 2 Output - Note 3	1.4	—	—	—	—	—	
Total	29.4	28.3	28.2	28.1	28.4	28.7	
Peak Load - Net MW - Note 2							
Ultimate Consumers	5,925	6,140	6,160	6,180	6,200	6,220	1.0
Sale of Salem No. 2 Capacity	471	—	—	—	—	—	
Total	6,396	6,140	6,160	6,180	6,200	6,220	
Generating Capability - Net MW (at time of peak) - Note 3	7,765	7,599	7,858	7,858	7,858	7,593	(0.4)
Gas Sales - Billion Cubic Feet	69.8	62.3	63.6	64.4	65.4	66.5	(1.0)
Steam Sales - Billion Pounds	4.7	4.4	4.2	3.4	3.3	3.2	(7.5)

	Actual 1984	Estimate 1985	Forecast 1986	Forecast 1987	Forecast 1988	Forecast 1989	5 Years 1985-89
CAPITAL REQUIREMENTS ($ Millions)							
Construction Expenditures: Note 6							
Limerick Unit 1	$ 431	$ 285	$ 20	$ —	$ —	$ —	$ 305
Limerick Unit 2 - Note 4	132	160	419	531	575	502	2,187
Limerick Common Plant	245	173	66	68	75	83	465
Other Electric	206	278	304	305	282	278	1,447
Gas	31	31	33	35	34	36	169
Nuclear Fuel	15	19	9	9	8	7	52
Other - Note 6	4	16	13	14	11	15	69
Total Construction Expenditures	$1,064	$ 962	$ 864	$ 962	$ 985	$ 921	$4,694
Long-Term Debt and Preferred Stock Refundings - Oth. than Limerick Revolver	11	69	106	82	87	98	442
- Limerick Revolver	—	—	—	69	137	137	343
Total Capital Requirements	$1,075	$1,031	$ 970	$1,113	$1,209	$1,156	$5,479
SOURCES OF CAPITAL ($ Millions)							
Internal Sources:							
Depreciation	$ 175	$ 177	$ 243	$ 272	$ 281	$ 289	$1,262
Other	42	231	83	246	371	345	1,276
Total Internal Sources	$ 217	$ 408	$ 326	$ 518	$ 652	$ 634	$2,538
As a Percent of Construction Expenditures	20%	42%	38%	54%	66%	69%	54%
Outside Financing - Note 5							
Long-Term Debt - Limerick Revolver	$ 400	$ 150	$ —	$ —	$ —	$ —	$ 150
- Other- Net	299	100	200	500	400	400	1,600
Preferred Stock	100	50	50	50	75	50	275
Common Stock	250	211	168	115	118	120	732
Other	56	—	200	—	—	—	200
Short-Term Debt - Incr. (Decr.)	(247)	112	26	(70)	(36)	(48)	(16)
Total Outside Financing	$ 858	$ 623	$ 644	$ 595	$ 557	$ 522	$2,941
Total Sources of Capital	$1,075	$1,031	$ 970	$1,113	$1,209	$1,156	$5,479
SIGNIFICANT INCOME ITEMS ($ Millions)							
Allowance for Funds Used During Construction - Note 6	$ 355	$ 433	$ 217	$ 244	$ 301	$ 359	
Income Tax Reductions Allocated to Construction - Note 6	113	138	69	77	95	113	
Deferred Federal Income Taxes from Liberalized Depreciation	27	107	115	117	101	116	
Investment Tax Credits - Note 7:							
Utilized	58	80	90	102	163	103	
Amortized	(8)	(11)	(14)	(14)	(23)	(27)	
Net Deferred	$ 50	$ 69	$ 76	$ 88	$ 140	$ 76	

OCA EXHIBIT 28
R-850152

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Q. IR-OCA-3-7. Please provide, for each month from January 1984 through December 1984, the following information for each customer class:

a. Sales as projected in the last base rate case at R-842590;
b. Actual sales;
c. Weather adjusted actual sales

A. IR-OCA-3-7. a. Attachment IR-OCA-3-7a provides the requested data.

b, c. Attachment IR-OCA-3-7b provides the requested data.

Responsible Witness: T.P. Hill, Jr., Asst. Manager - Rate Division
W.C. Hoch, Manager - Marketing Department

P.E. COMPANY
1984 BUDGET

	#	J	F	M	A	M	J	J	A	S	O	N	D	YR.
D. RESIDENTIAL R	1	232 000	198 000	216 000	165 100	177 000	192 000	270 000	285 000	225 000	190 000	180 000	201 400	2 523 000
RS	2	334 900	301 100	302 100	248 500	250 900	269 800	350 200	367 200	311 900	276 300	260 800	294 600	3 570 300
RM	3	5 200	4 800	4 500	4 300	3 800	4 000	5 000	5 200	4 200	4 300	4 400	4 600	54 400
WH	4	40 000	38 000	37 000	34 000	31 000	30 000	35 000	33 000	32 000	26 000	31 000	35 000	[illegible]
HWE	5	1 500	1 400	1 400	1 400	1 300	1 400	1 300	1 000	1 200	1 300	1 400	1 500	16[illegible]
TOTAL	6	614 600	544 200	556 000	455 200	464 600	497 200	654 500	676 600	569 300	500 900	477 600	538 900	6 [illegible]
	7													
HTG. HSE. HTG. RH	8	190 000	183 500	153 800	109 400	72 000	57 600	65 600	67 400	62 800	60 900	89 400	142 900	1 256 000
	9													
SMALL GS	10	201 500	206 100	215 700	188 500	194 500	212 500	244 100	252 000	228 000	211 400	189 600	202 400	2 553 500
GS EH	11	54 100	76 000	68 600	46 700	41 600	44 000	49 800	47 700	45 200	42 800	45 400	62 400	651 300
POL	12	800	600	800	800	800	800	800	100	800	800	800	800	9 600
TOTAL	13	291 400	282 800	285 100	236 300	237 100	257 300	294 700	300 200	274 800	254 500	235 800	265 600	3 142 200
	14													
L. LARGE PD	15	187 000	180 000	183 000	167 000	169 000	170 000	192 000	195 000	184 000	172 000	165 000	176 000	2 152 000
HT EXCL. BIG 8	16	834 600	822 200	842 700	710 100	752 600	838 900	822 200	911 400	858 000	816 500	753 200	805 500	9 828 700
	17													
	18	56 000	40	49	51	56	47	54	49	47	55	51	49 000	607 000
Large	19	34 000	36	37	30	33	29	34	31	29	33	30	36 000	374 000
	20	41 000	37	37	37	36	31	39	36	34	40	37	36 000	444 000
8	21	36 000	22	33	34	33	22	25	23	22	26	24	23 000	283 000
	22	35 000	32	32	31	33	28	35	32	30	35	31	31 000	381 000
Custs.	23	22 000	20	20	20	19	18	26	19	18	21	20	19 000	237 000
	24	14 000	12	12	13	12	12	13	12	12	14	13	12 000	151 000
	25	11 000	10	10	10	9	9	10	9	9	10	10	9 000	116 000
TOTAL BIG 8	26	259 000	213 000	214 000	216 000	213 000	199 000	231 000	211 000	201 000	234 000	216 000	209 000	2 596 000
	27													
TOTAL	28	1 060 600	1 215 200	1 239 700	1 052 100	1 139 600	1 212 400	1 300 200	1 312 400	1 243 400	1 232 500	1 132 700	1 190 600	14 581 200
	29													
L. LTG. SCP	30	9 311	8 111	8 211	5 511	6 811	5 011	5 410	7 310	6 610	8 410	7 710	7 810	86 226
SCPA	31	100	100	700	600	600	500	500	500	600	200	800	200	6 100
SCS	32	5 100	5 100	5 100	5 100	5 100	5 100	5 100	5 100	5 100	5 100	5 100	5 100	61 200
TL	33	3 700	3 100	3 700	3 700	3 700	3 700	3 100	3 100	3 700	3 700	3 700	3 700	33 400
TOTAL	34	18 011	16 711	16 711	13 911	15 211	13 311	13 710	15 610	15 610	16 910	16 310	16 510	1879[illegible]
	35													
RR AMTRAK	36	34 700	33 400	36 400	31 000	33 300	33 300	31 500	35 300	29 400	34 300	37 300	35 300	405 [illegible]
SEPTA	37	15 900	15 200	14 200	12 500	12 500	13 100	11 100	12 800	10 500	13 000	14 600	14 300	160 300
RWYS. READING	38	7 000	6 700	6 500	6 500	6 400	5 600	5 400	6 100	5 600	5 500	6 200	6 600	73 300
TOTAL	39	57 600	54 500	57 100	50 100	52 500	52 [illegible]	48 500	54 100	45 300	52 800	58 800	56 200	639 900
	40													
RESALE LANSDALE	41	9 791	8 790	8 991	8 294	8 395	8 896	10 292	9 592	8 294	9 596	8 593	9 388	108 822
CENTURY	42	40 300	32 900	37 500	28 000	31 500	32 400	41 100	38 200	29 600	36 200	31 800	41 200	421 600
PPL + MET. ED	43	7	7	2	4	1	3	2	2	5	3	6	10	62
TOTAL	44	50 098	41 697	46 498	36 298	39 899	41 299	51 498	47 799	38 099	46 299	40 499	50 598	530 452
	45													
INTERDEPT	46	6 400	5 000	5 200	4 600	4 600	4 500	4 700	4 800	4 200	4 600	4 100	5 100	58 300
	47													
TOTAL P.E. COMPANY	48	2 492 409	2 344 208	2 360 109	1 992 909	2 425 910	2 140 910	2 433 509	2 484 509	2 252 209	2 169 109	2 059 409	2 266 608	27 022 108
	49													
OP. SE. TOCP.	50	9 600	8 000	8 000	6 200	6 200	6 400	7 600	6 900	5 200	7 000	7 200	8 800	87 600
	51													
ELIMINATIONS)	52	(40 202)	(32 901)	(32 501)	(28 000)	(31 501)	(53 401)	(41 101)	(58 301)	(29 301)	(36 200)	(31 901)	(41 201)	(421 611)
	53													

✓ = (CHK TO 345.)

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OCA EXHIBIT 29
R-850152

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Q. IR-OCA-3-7. Please provide, for each month from January 1984 through December 1984, the following information for each customer class:

a. Sales as projected in the last base rate case at R-842590;
b. Actual sales;
c. Weather adjusted actual sales

A. IR-OCA-3-7. a. Original Attachment IR-OCA-3-7a provided the requested data.

b, c.
Revised Attachment IR-OCA-3-7b provides the requested data.

Responsible Witness: T.P. Hill, Jr., Asst. Manager - Rate Division
W.C. Hoch, Manager - Marketing Department

RJS. 11/6/85

P.E. COMPANY ONLY
MWH MWH

	J	F	M	A	M	J	J	A	S	O	N	D	YR
RESIDENTIAL ACTUAL	647318	554160	541550	458162	423632	525161	203221	222527	573613	500930	485262	526217	6837636
WEATHER CORRECTED	627700	553200	541600	490360	477500	558600	717700	25200	613200	517600	492200	560800	6909400
HSE. HTG. ACTUAL	230720	186486	167409	131436	86042	22446	52607	85023	70864	72963	89696	153183	1435436
W.C.	216500	185600	167400	127700	86000	22500	83700	87000	72000	73000	91600	153200	1421200
SM. C&I ACTUAL	315524	294138	286365	260571	248193	277311	326629	320368	292761	275726	264126	282543	3446560
W.C.	305900	243700	286400	258600	249200	272500	324600	329700	285000	284600	265100	282500	3461600
LG. C&I ACTUAL	1246449	1234198	1215652	1130016	1152205	1239343	1329109	1338133	1212920	1234365	1160344	1160632	14705540
W.C.	1273700	1224200	1215700	1124100	1152200	1224500	1392000	1364900	1257600	1249200	1163400	1160600	14602100
ST. LTG. ACTUAL	18225	16820	16747	15332	14751	14101	14486	15240	15963	17192	17713	18405	1[illegible]1025
RR & RWYS - ACTUAL	63547	52510	64047	54652	56585	55556	52016	59116	47338	54326	62319	57846	665541
RESALE - ACTUAL*	52469	45655	39422	50394	46226	44763	46117	51602	38525	43646	46362	46611	545842
INTERDEPARTMENTAL - ACTUAL	5836	5835	5352	4641	5340	5262	5438	5361	5119	5041	4556	5665	61600
TOTAL ACTUAL	2632168	2384672	2336648	2142269	2077337	2259263	2603714	2557844	2256025	2268205	2135018	2290669	27954015
W.C.	2563200	2382100	2336600	2125200	2089200	2253102	2636100	2664800	2354300	2244600	2143830	2290700	28024500

* Includes PECo sales to Conowingo

Revised
Attachment 1
I12-CCA-3 76

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R-850152

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Q. IR-OCA-3-8. Please provide, for each month from January 1985 through the present, the following information for each customer class:

a. Sales as projected in the Company's budget;
b. Actual sales;
c. Weather-adjusted actual sales.

A. IR-OCA-3-8. a,b,c.

Revised Attachment IR-OCA-3-8 provides the requested data.

Responsible Witnesses: T.P. Hill, Jr., Asst. Manager-Rate Division
W.C. Hoch, Manager - Marketing Department

PREPARED	RJS
CHECKED	[illegible]
TYPED	11/19/85
COMPARED AND POSTED	

P.E. COMPANY ONLY
1985 MWH

	J	F	M	A	M	J	J	A	S		9 MOS. TOTALS
RESIDENTIAL											
BUDGET	631 216	524 400	524 400	516 200	467 200	538 100	724 400	734 300	657 900		5 312 600
ACTUAL	619 150	523 133	516 961	501 849	467 896	505 425	660 367	666 728	612 532		5 122 282
WEATHER CORRECTED	630 900	559 500	523 200	583 600	466 900	512 200	700 200	712 200	642 900		5 257 300
HSE HTG.											
BUDGET	224 300	195 500	173 100	147 100	91 100	73 000	82 400	80 300	69 600		1 137 400
ACTUAL	201 529	230 495	157 889	125 442	80 629	71 539	82 260	82 888	88 261		1 125 285
W. C.	210 000	221 200	166 400	127 700	82 500	71 500	86 700	88 900	82 300		1 141 500
SM. C&I											
BUDGET	311 300	301 330	281 900	263 100	244 900	265 000	306 100	314 000	259 600		2 591 160
ACTUAL	306 793	331 570	297 768	222 696	277 107	265 806	313 551	323 768	333 944		2 744 048
W. C.	314 200	324 200	303 600	223 100	277 100	288 700	342 700	330 600	328 100		2 763 300
LG. C&I											
BUDGET	1 242 300	1 235 000	1 190 200	1 211 000	1 152 500	1 223 900	1 342 600	1 339 300	1 381 700		11 250 600
ACTUAL	1 196 333	1 257 812	1 186 239	1 167 886	1 181 553	1 215 393	1 301 672	1 312 848	1 315 100		11 129 975
W. C.	1 210 200	1 241 000	1 201 100	1 170 400	1 181 600	1 225 300	1 325 800	1 329 700	1 297 200		11 232 600
ST. LTG											
BUDGET	18 414	16 514	16 614	15 514	14 914	14 314	14 714	15 214	16 014		142 426
ACTUAL	18 479	16 548	16 525	15 334	14 339	14 233	14 555	15 335	12 355		142 421
RR & RWYS.											
BUDGET	63 000	60 200	63 300	54 600	58 100	56 700	53 200	59 300	48 200		517 300
ACTUAL	64 357	57 172	66 091	55 312	61 259	49 729	58 462	62 166	52 409		532 993
RESALE											
BUDGET *	54 548	45 092	47 098	43 298	41 655	43 155	46 607	39 602	31 205		386 403
ACTUAL *	54 278	46 371	45 005	40 825	41 164	39 521	38 182	32 343	29 995		374 262
INTERDEPARTMENTAL											
BUDGET	6 100	5 100	5 600	5 600	5 000	4 900	5 200	5 200	5 100		45 300
ACTUAL	5 102	6 035	5 090	5 276	4 264	5 564	5 350	5 451	5 462		45 768
TOTAL											
BUDGET	2 601 212	2 418 011	2 411 212	2 311 712	[illegible] 413	2 212 813	2 554 421	[illegible]	2 412 315		21 423 079
ACTUAL	2 468 220	2 523 [illegible]	2 329 515	2 166 646	[illegible]	2 162 [illegible]	2 413 414	[illegible]	2 385 042		21 [illegible] 613
WEATHER CORRECTED	2 528 700	2 425 200	2 321 500	2 194 500	2 139 200	2 211 200	2 622 100	2 583 600	2 460 500		21 512 700

* Includes REG. Sales & Cogeneration

Revised

Attachment LIB-CCA-3-E

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R-850152
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Q. IR-OCA-13-13. Re: Statement 18A; Keystone Alliance discussion. Please provide a comparable breakdown for the Company's future test year claims in the following base rate proceedings: R-822291 and R-842590.

A. IR-OCA-13-13. The following data provides an estimate of the requested data for R-822291 and R-842590 comparable to Company Statement 18A.

	12 Months Ending	
	Dec. '84 R-842590	Oct. '83 R-822291
Paragraph 1	$767,600	$960,650
Paragraph 2	6,300	5,800
Paragraph 3	9,900	7,200
Paragraph 4	Note 1	Note 1
Paragraph 5	20,400	17,800
Paragraph 6	1,000,000	-
Paragraph 7	53,000	5,000
Paragraph 8	-	-
Paragraph 9	-	-
Paragraph 10	Note 2	Note 2
Paragraph 11	-	-
Paragraph 12	-	-
Paragraph 13	Note 3	Note 3

Note 1 - Attachment IR-OCA-13-13a provides the requested information.
Note 2 - Attachment IR-OCA-13-13b provides the requested information.
Note 3 - Attachment IR-OCA-13-13c provides the requested information.

Reponsible Witness: T.P.Hill,Jr.,Asst. Manager-Rate Division

Estimated Speaker's Bureau Expenses

	R-842590 12 Months Ended Dec. 1984	R-822291 12 Months Ended Oct. 1983
Payroll	$404,759,000	$361,224,000
Pensions & Benefits	92,002,000	78,230,000
Disallowance	(15,801,000)	(6,553,000)
Total Allowed Labor Expense	$480,960,000	$432,901,000
Budget Employees	10,798	10,631
Avg./Employee	44,542	40,721
Factor	1.19	1.19
Cost to Electric	$53,005	$48,458
Nuclear Related	30.2%	30.2%
Total	$16,008	$14,634

Philadelphia Electric Company
ESTIMATED CORPORATE COMMUNICATIONS EXPENSE
12 Months Ending December 1984
R-842590

1978 Corporate Communications Expense (Excluding Muddy Run) = $3,482,841

Wage Increases

1978 = 2.9% (7.0% x 5/12)	1982 = 8.8%
1979 = 7.2%	1983 = 6.75%
1980 = 9.5%	1984 = 6.0%
1981 = 9.75%	

Cumulative Wage Adjustment Factor =
(1.029)(1.072)(1.095)(1.0975)(1.088)(1.0675)(1.06)=1.63

Inflation Adjusted 1978 Corporate Communications Expense =
$3,482,841 x 1.63 = $5,677,031

	W/O Inflation	W/Inflation
Dec. 31, 1984 Test Year Corporate Communications =	$7,416,786	$7,416,786
Less: 1978 Corporate Communications =	3,482,841	5,677,031
Excess of Test Year Expenses Over the 1978 Level =	$3,933,945	$1,739,755
Less: TMI Cleanup	1,000,000	1,000,000
EEAC Expenses	767,600	767,600
Utility Nuclear Waste Management Group	20,400	20,400
Life Jobs	53,000	53,000
American Nuclear Society	-	-
Expenses in Excess of 1978 Level	$2,092,945	($101,245)
Adjustment to Reflect Increase in Staff	870,710 (a)	1,419,258 (a)
Expenses in Excess of the 1978 Level Adjusted for wage inflation and required staffing increases	$1,222,235	($1,520,503)

(a) Adjustment for 25% increase in staff.

	W/O Inflation	W/Inflation
1978 Expense	$3,482,841	$5,677,031
Adjustment @ 25%	870,710	1,419,258

Philadelphia Electric Company
ESTIMATED CORPORATE COMMUNICATIONS EXPENSE
12 Months Ending October 1983
R-822291

1978 Corporate Communications Expense (Excluding Muddy Run) = $3,482,841

Wage Increases

1978 = 2.9% (7.0% x 5/12)
1979 = 7.2%
1980 = 9.5%
1981 = 9.75%
1982 = 8.8%
1983 = 5.63% (10/12 x 6.75%)

Cumulative Wage Adjustment Factor =
(1.029)(1.072)(1.095)(1.0975)(1.088)(1.0563)=1.52

Inflation Adjusted 1978 Corporate Communications Expense =
$3,482,841 x 1.52 = $5,293,918

	W/O Inflation	W/Inflation
Oct. 31, 1983 Test Year Corporate Communications =	$5,302,548	$5,302,548
Less: 1978 Corporate Communications =	3,482,841	5,293,918
Excess of Test Year Expenses Over the 1978 Level =	$1,819,707	$8,630
Less: TMI Cleanup	-	-
EEAC Expenses	960,650	960,650
Utility Nuclear Waste Management Group	17,800	17,800
Life Jobs	5,000	5,000
American Nuclear Society	-	-
Expenses in Excess of 1978 Level	$836,257	($974,820)
Adjustment to Reflect Increase in Staff	870,710 (a)	1,323,480 (a)
Expenses in Excess of the 1978 Level Adjusted for wage inflation and required staffing increases	($34,453)	($2,298,300)

(a) Adjustment for 25% increase in staff.

	W/O Inflation	W/Inflation
1978 Expense	$3,482,841	$5,293,918
Adjustment @ 25%	870,710	1,323,480

Attachment IR-OCA-13-13c

Philadelphia Electric Company

ESTIMATED ASSOCIATION DUES

	R-842590 12 Months Ending Dec. 1984	R-822291 12 Months Ending Oct. 1983
American Nuclear Energy Council	20,250	20,250
Atomic Industrial Forum	53,000	61,200
Edison Electric Institute	530,000	512,000
Electrical Association of Philadelphia	106,480	101,600
Pennsylvania Electric Association	300,000	250,000
Total	$1,009,730	$945,050

OCA Exhibit No. 32

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IR-OCA-3-19. Please describe all actions taken by PECo to deal with the theft of electric services.

IR-OCA-3-19. In the third quarter of 1984, PECo took the first steps in the reorganization of the Meter Irregularities Section. Investigators that had formally worked out of the Main Office were permanently assigned to each Division's Service Building, thereby, creating an ever present force and better contact between the investigators and their prime source of leads, the meter reader. Additional benefits realized included reduced travel time, increased job completion, familiarity with the territory and a closer working relationship with other company personnel.

Coinciding with decentralization was the development of a computer operated system for the inputting and tracking of leads. Another offshoot is the program developed to help identify potential theft of service incidences by scanning customer usage history.

In May, 1985 a program was started to train senior personnel in each Division on basic skills needed to detect the existence of a theft of service situation. In order to complete this task, a detailed manual was prepared and used in conjunction with an intensive training seminar, utilizing both classroom and field location. The creation of the "back-up program" lets the fully qualified field investigator continue to work on cases requiring his special skills but still allows all the incoming leads to be attended to in a timely fashion.

Besides the above mentioned changes, PECo attempts to dissuade energy theft through more conventional means. These methods are outlined below:

1. Increased use of plastic seals. These plastic seals more readily show tampering than lead seals, are easier to install and are serialized for recordkeeping.

2. Increased use of meter locking devices (barrel locks) in areas where sealing has been ineffective.

3. Increased use of "sweeps" to inspect all meter locations in areas of high seal breakage.

4. Testing of new detection devices such as Sangamo's Tamperscam Meters and Extron's plastic disconnect devices. Both products readily identify any illegal use of service or attempted entry to our equipment.

5. Networking with established organizations such as PEA and the Northeastern Utilities Theft of Service Group to keep abreast of the changing trends of theft in the geographical area.

6. Increasing the number of cases referred to the Legal Department for prosecution.

Along with these methods, PECo is attempting to publicize the cost of energy theft through increased awareness programs. Meter Readers are given classroom instruction and are shown films dealing with tampering as part of their regular training programs with refresher courses scheduled twice a year in each Division. Customers are advised via a bill stuffer on energy theft and area newspapers give a fair amount of coverage to arrests and trial for the theft of our services.

sponsible Witness: T. P. Hill, Jr., Asst. Manager - Rate Division

Q.IR-Staff-REO-1. Provide a description of PECo's current theft of service prevention program. Include where the responsibility falls within the Company, the number of incidents over the past two years, number of prosecutions initiated, number of successful prosecutions, amount recovered through detection and prosecution, cost of the program and estimated volume of kwh's lost to theft over the past two years.

A.IR-Staff-REO-1. Reference interrogatory responses IR-OCA-3-19 and IR-OCA-3-20 for information pertinent to PECo's current theft of service program. In addition to the information contained in those interrogatories, the following data is presented below:

1. No. of known incidences: 550/year
2. No. of prosecutions: 15 to 20/year

Note: Prosecutions are instituted upon determination of aggravated circumstances and with approval of jurisdictional District Attorney. Most incidences are rectified and restitutions made after PECo confrontations with Customer.

3. Recovery of Revenue: Approximately $600,000 to $650,000/year

4. Cost of Program: Approximately $440,000/year. The expenses associated with this program cover both investigatory and educational functions.

Responsible Witness: T.P. Hill, Jr., Asst. Manager-Rate Division

Q. IR-OCA-3-20. Please provide PECo's best estimate of the lost revenues associated with the theft of electric services.

A. IR-OCA-3-20. The Company does not have a formula for determining the dollar amount of the extent of theft of service. One industry organization, The Public Utilities Group, estimates revenues lost by theft of service to be approximately one-half of one percent of total revenues.

Responsible Witness: T.P. Hill, Jr., Asst. Manager - Rate Division

OCA Exhibit No. 33

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Q. IR-OCA-20-10. Regarding Schedule 8, D-24 (Sequoyah and Lee Mine):

a. provide workpapers and explain how "revenue recovered from customers" was determined.

b. if the above revenue was calculated utilizing earned return, provide a calculation utilizing allowed return.

A. IR-OCA-20-10. a. Attachment IR-OCA-20-10a provides the requested workpaper. The revenue recovered from customers was determined by multiplying the actual pre-tax earned return for the period 5/21/82 to 11/23/83 (R-811626 rate effective period) by the amount allowed in rate base, at Docket R-811626.

b. The revenue recovered from customers when utilizing allowed return is $1.425 million for the Sequoyah project and $361,000 for Lee Mine. Attachment IR-OCA-20-10b provides the workpaper for the above revenue recoveries.

Responsible Witness: T.P. Hill, Asst. Manager-Rate Division

D-24 BACK-UP

REVENUE RECOVERY

1982 RETURN

	CAP. RATIO	COST RATE	WTD. COST	TAX FACTOR	PRE-TAX COST
DEBT	51.2%	10.30%	5.27%	—	5.27
PREFERRED	11.1	8.80	0.98	.50232	1.95
COMMON	37.7	12.25	4.62	.50232	9.20
					16.42%

1983 RETURN

DEBT	50.4%	10.50%	5.29%	—	5.29%
PREFERRED	12.0	9.60	1.05	.50232	2.09
COMMON	37.6	15.61	5.87	.50232	11.69
					19.07%

LOCKET REG. (5/21/82 - 11/23/83)

LEE MINE CLAIM = $1,158

SALEM NUCLEAR FUEL COMM = 5291

RETURN

7 MOS. @ 16.42% = 16.42 × 7/12 = 9.6%

11 MOS. @ 19.07% = 19.07 × 11/12 = 17.5%

27.1%

LEE MINE: $1158 × .271 = $315

SALEM NUCL. FUEL COMM. = $5291 × .271 = $1434

ALLOCATED TO SEQUOYAH (1434 × .864) = $1239

$$.864 = \frac{\text{OPEN PIT + BILL SMITH + AFUDC}}{\text{TOTAL SALEM NUC. FUEL (10/31/82)}} = \frac{1750 + 4480 + 2230}{9,807}$$

Return Allowed at R-811626

	Cap. Ratio (1)	Cost (2)	Wtd. Cost (3)=(1)x(2)	Tax Factor (4)	Pre-Tax Cost (5)=(3)x(4)
Debt	51.1%	11.07%	5.65%	1	5.65%
Preferred	12.4	9.01	1.12	1.99	2.23
Common	36.5	17.75	6.48	1.99	12.90
					20.78%

eturn for period from 5/21/82 to 11/23/83
20.78 x 18/12 - 31.17%

Revenue Recovered

Lee Mine = $361 = $1,158 x 31.17%
Sequoyah = $1,425*

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*Salem Nuclear Fuel Commitments = $5,291
Return Rate = 31.17%
Revenue Received = $1,649
Allocated to Sequoyah @ 86.4% = $1,425

R-850152

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PHILADELPHIA ELECTRIC COMPANY
ELECTRIC STATEMENT OF OPERATIONS (THOUSANDS OF DOLLARS)

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
OPERATING REVENUE										
ELECTRIC SALES REVENUE										
FUEL ADJ REVENUE	85464	-254548	-342336	-282288	-287455	-245562	-284404	-287434	-341715	-185171
STATE TAX ADJ REVENUE	93617	117198	152070	150308	152115	156294	176374	221647	220316	224931
OPERATING REVENUE	2006281	2778137	3122719	3102226	3144644	3218215	3753763	4374475	4394731	4449409
TOTAL ELEC. SALES REV	2185363	2640787	2932453	2970245	3009304	3128947	3645733	4308688	4273331	4489170
OTHER ELECTRIC REVENUE	97337	32501	33341	34477	36895	44686	46393	47978	48816	51224
TOTAL OPERATING REVENUE	2282700	2673288	2965794	3004722	3046199	3173633	3692126	4356666	4322147	4540394
OPERATING EXPENSES										
STM PWR GEN-FUEL	340759	262492	237512	240828	246287	244101	271590	278786	320002	386788
-OPER+MAINT	170080	177290	166990	178220	183690	172910	178060	179650	189780	198690
SUBTOTAL	510839	439782	404502	419048	429977	417011	449650	458436	509782	585478
NUCLEAR GEN-FUEL	47649	116907	133408	123120	145965	156260	215580	239156	273967	272014
-OPER+MAINT	139911	212374	252100	255588	268949	293408	335013	378861	401880	421970
SUBTOTAL	187560	329281	385508	378708	414914	449668	550593	618017	675847	693984
PURCHASES FROM SECO	12204	13180	14234	15373	16603	17931	19366	20915	22588	24395
INTERCHANGE	505976	185392	103545	168784	145520	188572	70230	46858	-74397	29357
OTHER	-55481	190123	101720	25570	29960	31300	32670	34340	36480	38780
SUBTOTAL	1161098	1157759	1009509	1007483	1036975	1104482	1122508	1178567	1170300	1371995
TRANSMISSION	26214	28242	30529	32985	35627	38467	41512	44787	48306	52085
DISTRIBUTION	98307	106344	115769	125946	137037	149102	162203	176410	191699	208349
SUBTOTAL	124521	134586	146298	158931	172664	187569	203715	221197	240005	260434
CUSTOMER EXPENSES	79680	86559	94459	103003	112246	122238	133034	144694	157281	170865
ADMINISTRATIVE+GENERAL	131547	143889	158122	173552	190278	208396	228005	249217	272150	296934
TOTAL OPER + MAINT	1496846	1522793	1408388	1442969	1512163	1622685	1687262	1793675	1839736	2100228
BALANCE AFTER OPER+MAINT	785854	1150495	1557406	1561753	1534037	1550949	2004863	2562992	2482411	2440166
DEPRECIATION + AMORT	147390	183167	233561	237901	244177	251798	311009	369150	375958	383924
PROVISION FOR TAXES										
FEDERAL INCOME	63562	85077	167529	208188	184774	194503	299693	402920	384141	383768
STATE + LOCAL INCOME	16570	60514	61242	59529	56458	54585	77044	96033	93506	93479
INVEST.TAX CREDIT ADJ	-7117	167733	84444	35030	44407	25833	16174	-6645	572	218
DEFERRED INC TAXES	78391	-23284	94566	111515	91752	91681	121346	208344	187608	163796
INCOME TAXES	151406	290040	407782	414261	377391	366602	514258	700652	665827	641262
CAPITAL STOCK	24182	25855	27424	28664	30434	32374	32840	33583	32829	32397
GROSS RECEIPTS	97358	117647	130641	132324	134865	139395	162417	191952	190377	199993
UNEMP.+AGE+TEL.	15392	16708	18244	19923	21710	23650	25801	28142	30656	33384
STATE REAL ESTATE	22348	23382	38463	39018	39872	41082	42259	62838	63718	65046
OTHER	2080	2246	2426	2620	2830	3056	3301	3565	3850	4158
NON-INCOME TAXES	161361	185837	217197	222549	228911	239556	266618	320081	321430	334977
TOTAL TAXES	312767	475878	624979	636811	606302	606158	780876	1020732	987257	976238
TOTAL OPERATING EXPENSES	1957003	2181837	2266928	2317680	2362642	2480640	2779147	3183557	3202951	3460390
OPERATING INCOME(PECO)	325697	491451	698866	687042	683558	692993	912978	1173110	1119196	1080004
OPERATING INCOME(SUBSID)	8217	8710	9233	9787	10375	10998	11658	12358	13100	13886
OTHER INCOME										
AFUDC-OTHER FUNDS	161135	137731	78318	100761	126196	149174	0	0	0	0
INCOME TAX CREDITS	104024	81802	51995	68997	87978	105937	57738	2648	2740	2588
OTHER INC OR DED - NET	4840	5547	5996	6480	7005	7570	8173	8808	9485	10213
INCOME DEDUCTIONS										
LONG-TERM DEBT CHARGES	348376	414570	418229	456236	505774	555651	572465	560448	537886	518693
OTHER INTEREST	4927	6059	6893	7475	7317	6319	6406	6819	6641	6384
AFUDC-BORROWED FUNDS	-192828	-200751	-113758	-149481	-193968	-231594	-251405	-25790	-29688	-28768
NET INCOME	443438	505362	533045	558837	595989	636296	663082	655447	629683	610382

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PHILADELPHIA ELECTRIC COMPANY
CONSOLIDATED STATEMENT OF SOURCE AND APPLICATION OF FUNDS

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
OURCE OF FUNDS										
ET INCOME	483382	527282	557465	584033	622295	663950	692119	685782	661139	643268
HARGES(CRED.) TO INCOME NOT AFFECTING FUNDS										
DEPRECIATION	162059	198641	249869	255244	262598	271313	331662	390988	399065	408405
AMORT OF NUCLEAR FUEL	-9118	31635	46420	28797	32964	46495	102172	113784	141257	128919
INV.TAX CRED. ADJ-NET	559	169856	86849	37596	46934	28284	18776	-3928	3464	3301
DEFERRED INCOME TAXES	68831	-14868	111083	116654	97409	97413	127438	214907	194709	171527
FUNDS FROM OPERATIONS	222331	385264	494221	438291	439906	443505	580047	715751	738495	712152
ALE OF:										
LONG-TERM DEBT	150000	0	200000	400000	525000	350000	650000	0	0	0
PREFERRED STOCK	75000	25000	25000	50000	75000	50000	0	0	0	0
COMMON STOCK	199005	105087	38286	21003	121676	53459	0	0	0	0
NCREASE(DECREASE) IN NOTES PAYABLE	9196	2050	9254	10868	-6870	-5664	15661	0	0	0
THER	51000	0	0	0	0	0	0	0	0	0
TOTAL	1189914	1044683	1324225	1504195	1777006	1555250	1937827	1401533	1399634	1355420

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
PPLICATION OF FUNDS										
DDITIONS TO UTILITY PLT	1045396	733429	726249	886323	922121	818121	500098	245189	332248	337398
UCLEAR FUEL	31631	18439	54356	61886	229864	118669	121296	181368	138721	213180
IVIDENDS ON COMMON STK	329426	351883	361465	365125	384972	409623	429172	566310	544225	527724
IVIDENDS ON PREF STOCK	82961	90486	94286	99911	108998	117786	121211	119472	116914	115543
ETIREMENT LONG-TRM DEBT	200500	50446	87869	90950	131050	91050	766050	16050	141050	76845
THER	-500000	-200000	0	-0	0	0	0	273144	126475	84729
TOTAL	1189914	1044683	1324225	1504195	1777006	1555250	1937827	1401533	1399634	1355420

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PECO STATEMENT NO. 16

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PENNSYLVANIA PUBLIC UTILITY
COMMISSION v. PHILADELPHIA ELECTRIC
COMPANY, Docket No. R-850152

DIRECT TESTIMONY OF
DAVID J. FARLING
COOPERS & LYBRAND

ACCOUNTING ISSUES RELATED
TO PHASE-IN PROPOSAL

DOCKETED

DEC 23 1985

September 27, 1985

Testimony of David J. Farling

Q. Please state your name, business address and occupation.

A. David J. Farling, 1900 Mellon Bank Center, Philadelphia, Pennsylvania 19102. I am a Certified Public Accountant, Partner and Chairman of the Electric and Gas Utilities Industry Specialization Program of Coopers & Lybrand.

Q. What is the business of Coopers & Lybrand?

A. Coopers & Lybrand is an international public accounting firm engaged in the business of providing accounting, tax and consulting services.

Q. What are your responsibilities at Coopers & Lybrand?

A. I am responsible for the direction of the Firm's electric and gas utilities industry program which includes advising other professionals and partners on accounting and auditing for public utilities, managing our regulatory and advisory services practice, and speaking on current topical accounting and auditing issues concerning the industry. I serve as the engagement partner or concurring partner for recurring audit examinations and for regulatory and advisory work.

Q. Please describe your educational background.

A. I graduated with honors from Lebanon Valley College with a Bachelor of Science degree, majoring in economics. I also hold a Master of Science degree in Business Administration from the Pennsylvania State University. While at the Pennsylvania State University, I was elected a member of Beta Gamma Sigma, a national honorary society in business administration.

Q. Please describe your professional experience.

A. I joined Coopers & Lybrand in 1958 upon completion of my college education. I became a partner in 1969. I have been actively involved in the Firm's services to electric and gas utility clients since 1971. My experience includes responsibility for the examination of financial statements of electric and gas utilities, representation of clients in accounting and compliance matters before the Federal Energy Regulatory Commission, and presentation of testimony on accounting matters in regulatory proceedings before state and federal jurisdictions. I became co-chairman of the electric and gas industry program for Coopers & Lybrand in 1975 and chairman in 1980.

I served as a member of the American Institute of Certified Public Accountants, Public Utilities Subcommittee from 1979 through 1983, and was Subcommittee Chairman for 1981-83. The objectives of this subcommittee are to review and prepare comments on accounting and auditing pronouncements and proposals of the Federal Energy Regulatory Commission and legislative proposals of the Congress, to issue publications, as needed, on the application of accounting and auditing standards to public utilities, and to communicate with regulatory and industry officials on matters of mutual interest. The exposure draft of Statement of Financial Accounting Standards, No. 71, "Accounting for the Effects of Certain Types of Regulation," was discussed and critiqued during my tenure as chairman of this subcommittee.

I have made presentations on accounting topics before various committees and conferences of the Edison Electric Institute, the American Gas Association, the National Association of Regulatory Utility Commissioners Staff Subcommittee on Accounts, the Pennsylvania Electric Association, and the Electric Council of New England. I am a member of the American Institute of Certified Public Accountants, the Pennsylvania Institute of Certified Public Accountants, and the American Accounting Association.

Q. What have been your responsibilities for services performed by Coopers & Lybrand for the Philadelphia Electric Company (the "Company")?

A. I was the assigned engagement partner for the Firm's services to the Company during the period 1971 to 1979. I presently serve as the concurring partner in our services to the Company.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the principal accounting issues arising out of the Company's proposal to phase-in the rate increase requested in this proceeding.

Q. Please briefly describe the Company's phase-in proposal.

A. The proposed increase in electric rates will be phased-in over a three-year period, with approximately one-third of the increase in year 1, two-thirds in year 2, and the full amount in year 3. The unrecovered revenues from years 1 and 2 will be recovered over a three-year period beginning in year 4, without recovery of any carrying charges on the unrecovered revenue.

Q. Please briefly describe the accounting procedures which will be employed to reflect the phase-in on the Company's financial statements.

A. In general, the Company will continue to recognize revenue and costs in accordance with the Uniform System of Accounts of the Federal Energy Regulatory Commission, prescribed by the Pennsylvania PUC for use by Pennsylvania electric utilities. The revenue unrecovered under the phase-in proposal during years 1 and 2 of the phase-in will be recorded as operating revenue and as a noncurrent asset in Account 186. When this revenue is billed (i.e., years 4, 5, and 6 of the phase-in), the Company will record an accounts receivable in Account 142, in the amount of the billing and reduce Account 186 by a like amount.

Q. What are the principal accounting issues arising from the Company's phase-in proposal?

A. I believe there are two principal accounting issues associated with the Company's phase-in proposal:

1. Future realization of the unrecovered revenue recorded as a noncurrent asset.

2. Measurement of the economic effect of unrecovered revenue being recovered over an extended period where no return is received on the unrecovered amount.

Q. What accounting standards and principles are relevant to a resolution of these two issues?

A. Resolution of these issues will be governed by application of "generally accepted accounting principles" ("GAAP") for the preparation of financial statements. GAAP refers to the rules and conventions of practice supported or promulgated by an authoritative body of the accounting profession. Presently, the Financial Accounting Standards Board ("FASB") is the authoritative source of accounting principles, having been so designated by the Council of the American Institute of Certified Public Accountants.

The economic effects of regulation can create circumstances that require different accounting for public utilities as compared to unregulated business. Statement of Financial Accounting Standards No. 71 ("Statement 71"), "Accounting For The Effects of Certain Types of Regulation," issued by the FASB in December 1982, presently provides the accounting guidance for the preparation of financial statements for public utilities. Statement 71 establishes the principles to be applied in reporting the effects of various types of rate actions in a utility's financial statements.

Q. What is the current status of Statement 71?

A. As set forth above, Statement 71 was issued in December 1982. In 1984, the FASB requested its staff to examine the application of Statement 71 to certain major events in the electric utility industry, including rate moderation ("phase-in") plans of electric utility companies. In October 1984, the American Institute of Certified Public Accountants Public Utilities Subcommittee completed an Issues Paper, "Application of Concepts in FASB Statement No. 71 To Emerging Issues in the Public Utility Industry," which was made available to the FASB. The issues in this Issues Paper are presently being discussed at a series of meetings of the FASB with the express intention of preparing an amendment to Statement 71. Presently, an exposure draft of the amendment is expected to be issued in the second half of 1985. It is too early to predict whether a final amendment date will be adopted in time to affect financial statements for the year ending December 31, 1985.

Q. Does the Company's phase-in plan meet the requirements of Statement 71 as it is now effective?

A. Yes, for the reasons set forth subsequently, I believe the Company's phase-in plan, as filed, meets the present requirements of Statement 71.

Q. Why is it important that the Company's phase-in plan meet the requirements of GAAP?

A. The Company's financial statements must be prepared in accordance with generally accepted accounting principles. The annual financial statements of the Company are examined and reported upon by Coopers & Lybrand, the Company's outside auditors. In our report, we must express our opinion that these statements fairly present the financial position and the results of operations of the Company in conformity with generally accepted accounting principles consistently applied. If the Company's financial statements were not prepared in accordance with GAAP, they would not be accepted for filing with the Securities and Exchange Commission.

The significance of this requirement to the phase-in plan is of importance. If the Company's phase-in plan is in accordance with GAAP, unrecovered revenue will be reflected in the financial statements, thereby significantly improving earnings and coverage ratios during the phase-in period. Conversely, if the phase-in plan is not in accordance with GAAP, the Company will not be able to recognize an equivalent amount of unrecovered revenue in its financial statements. This would decrease the Company's earnings and coverage ratios during the phase-in.

ACCOUNTING ISSUE I: FUTURE REALIZATION OF UNRECOVERED REVENUE

Q. Turning first to the issue of future realization of unrecovered revenue, please explain the application of Statement 71 to this issue.

A. Statement 71, as presently written, does not specifically address the accounting for rate phase-in plans. However, certain general premises underlying the accounting standards cited in Statement 71 create some uncertainty as to the validity of phase-in programs. Specifically, Paragraph 5b of Statement 71 indicates that Statement 71 is based on the premise that "the regulated rates are designed to recover the specific enterprise's costs of providing the regulated services or products." Further, Paragraph 5c states that, "in view of the demand for the regulated services or products and the level of competition direct or indirect it is reasonable to assume that rates set at levels that will recover the enterprise's costs can be charged to and collected from customers."

An inherent assumption in the above-cited language of Statement 71 is that a utility's costs, such as those for Limerick 1 would be allocated over time for ratemaking purposes consistent with the provisions of the then applicable uniform system of accounts for such costs under ordinary circumstances. It was further assumed that rates so determined could be collected from customers. Billing of such costs in a subsequent accounting period and collection from customers at that time was not specifically contemplated in formulating accounting standards underlying Statement 71.

However, there is other general guidance which supports the Company's specific proposal. Statement of Financial Accounting Concepts No. 3, issued by the FASB in December 1980, defines assets as probable future economic benefits obtained or controlled by a particular entity as a result of past transactions or events. And, paragraph 9 of Statement 71 states that "rate actions of a regulator can provide reasonable assurance of the existence of an asset." Thus, if future recovery of unrecovered revenue is assured and if the deferral of billing is over a reasonably short time period, then "reasonable assurance" of the asset would be provided and the phase-in plan would be acceptable.

For example, in numerous instances, regulatory commissions have deferred recovery of certain non-recurring costs by billing such costs over a period of years. Examples of this practice include storm damage expense, rate case expense, and computer leasing expenses.

Q. Please describe those provisions of a rate phase-in plan which are required for a favorable assessment of the probability of future recovery of the currently unrecovered revenue.

A. First, it is paramount that the rate order contain indisputable language assuring the Company of recovery from the customers of all costs recognized as unrecovered revenue under the rate phase-in plan. Any future condition or requirement on recovery of this revenue would seriously jeopardize the "reasonable assurance of the existence of an asset" and could require removal of the unrecovered revenue from the income statement. Second, the plan of recovery should not require additional regulatory action in a subsequent period. Third, in the determination of the period of recovery for this revenue, consideration should be given to the fact that the longer the period of recovery the greater becomes the risk that the Company may not be able to recover its ongoing current costs plus the unrecovered revenue of a prior period. In my opinion, the Company's plan, if adopted by the Commission, as filed, meets these requirements.

Q. How might the expected amendment to Statement 71 affect the present wording of Paragraph 9 concerning acceptable regulatory action for recovery of unrecovered revenue?

A. The comments of the FASB and its staff at the aforementioned meetings concerning realization of unrecovered revenue in phase-in situations indicate that revised Statement 71 will require that future recovery of currently unrecovered revenue or costs must be contingent solely on the passage of time. Any dependency of total realization on future conditions would, therefore, not be acceptable for unrecovered revenue to be recognized as an asset. In addition, it appears likely that the Statement 71, as amended, will establish a time limit on the length of the deferral period.

Q. Why would the FASB place emphasis on the time period for recovery?

A. As previously stated, in Paragraph 5c of Statement 71, a fundamental premise underlying the accounting standards for regulated companies is that rates set at levels which will recover the enterprise's costs can be charged to and collected from customers. A phase-in plan for the cost of new utility plant is an indication that this underlying premise of Statement 71 may not be valid. In such situations, the rates ultimately billed customers are not the result of the utility's plant costs but the result of market or political forces. As indicated earlier, the longer the period of recovery, the greater becomes the risk that because of these forces, the utility may never be able to fully recover the revenue of a prior period.

ACCOUNTING ISSUE II: MEASUREMENT OF THE ECONOMIC EFFECT OF UNRECOVERED REVENUE WITHOUT A RETURN ON THE UNRECOVERED AMOUNT

Q. Please explain the commentary in Statement 71 applicable to the measurement of the economic effect of currently unrecovered revenue being recovered over an extended period without a return on the unrecovered amount.

A. Paragraph 92 of Statement 71 states that "generally accepted accounting principles do not necessarily require the carrying amount of an intangible asset to be its discounted present value, nor do they necessarily require an enterprise to consider a return on investment when evaluating possible impairment of an intangible or depreciable asset. Accordingly, the Board concluded that it should not impose such a requirement on regulated enterprises."

Q. Why then is the absence of a return on the unrecovered revenue in the Company's proposal a principal accounting issue?

A. Because the FASB staff, as part of the process to amend Statement 71, has proposed to the FASB that the economic effect of not recovering a return on a long-term asset be reflected in the financial statements of the entity in the accounting period that such determination is made in the ratemaking process. This recognition of the time value of money is called discounting.

Q. What are the implications of a discounting requirement to the Company's financial statements?

A. The income statement of the Company in the year of recognition of unrecovered revenue would reflect an amount reducing net income by the difference between the present value and the gross amount of the unrecovered revenue. The longer the time period for billing the unrecovered revenue to the customer the greater the amount of the discount and the larger the amount of the charge on the Company's income statement.

Q. Since the proceedings covering the amendment to Statement 71 will be of concern to the Pennsylvania Public Utility Commission, can you provide an update of the subsequent deliberations of the FASB and your testimony at a later date.

A. Yes, I will be informed on the developments concerning this subject in connection with my position as Chairman of the

Electric and Gas Utilities Industry practice of Coopers & Lybrand.

Q. Does this conclude your testimony at this time?

A. Yes, it does.

Statement No. 17

JAT 12-13-85 Hbg

R-850152

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

RATE PHASE-IN PROPOSAL

CLASS REVENUE ALLOCATION

RATE DESIGN

DIRECT TESTIMONY OF

RAYMOND C. WILLIAMS

SEPTEMBER 1985

Direct Testimony Of Raymond C. Williams

Q. Please state your name and business address for the record.

A. Raymond C. Williams, 2301 Market Street, Philadelphia, Pennsylvania.

Q. By whom are you employed, Mr. Williams, and in what capacity?

A. I am Manager of the Rate Division of Philadelphia Electric Company.

Q. What is your educational background?

A. I received a Bachelor's Degree in Electrical Engineering from Penn State University in 1950. In 1970, I attended the Cornell University Executive Program in Business Administration which covered a broad curriculum including business management, cost control, economics, finance and accounting. I am a Registered Engineer in Pennsylvania.

Q. Please describe your work experience with Philadelphia Electric Company.

A. Immediately upon graduation from Penn State, I was employed by Philadelphia Electric Company as a junior engineer in the Transmission and Operating Department. I progressed through various job responsibilities and was appointed Electric Superintendent of Western Division (Operations) in 1963. My responsibilities in this position included administering the construction and maintenance of distribution substations and lines, as well as the maintenance of service to all customers in the Division on a twenty-four hour a day basis.

In 1967, I was appointed Assistant Manager of the Rate Division in the Finance and Accounting Department and in

1975 was appointed Manager of that Division. The Rate Division is responsible for the preparation of all rate case filing material and testimony, the administration of rate tariffs, fuel adjustment calculations and filings as well as various cost and economic studies including load testing.

Q. Please describe in greater detail your responsibilities in the Rate Division?

A. As Assistant Manger of the Rate Division, I participated in the preparation and development of data for all of the Company's rate filings since 1968. As Manager, I report to the Vice-President of Finance and Accounting and administer under his direction the various functions of the Rate Division as described above.

Q. Have you been active in any professional organizations?

A. Since 1969, I have been a member of the Load Research Committee of the Association of Edison Illuminating Companies (AEIC). In 1975, I became a member of the Rate Research Committee of the Edison Electric Institute (EEI) and I was a member of Task Force Five of the EPRI/NARUC Utility Rate Design Study.

The purpose of the AEIC Load Research Committee is to review currently available load research data, discussing its implications for electric rate design as well as the problems of obtaining accurate load data. The EEI Rate Research Committee reviews current developments in electric utility ratemaking. Task Force Five was one of ten task forces created to investigate and report on various aspects of the EPRI/NARUC study into alternative electric rate structures. Task Force Five's particular function was to analyze the theoretical and practical aspects of the various rate forms under study as a means of achieving defined ratemaking objectives.

Q. Mr. Williams, have you testified in any previous regulatory proceedings?

A. Yes. I have presented testimony before this Commission in its generic investigation into alternative electric rate structures at Proposed Rule Making Docket No. 7 (1976). My testimony included a statement of the Company's position on the several alternative rate structures and costing methodologies at issue in that proceeding. I presented testimony in the Company's last six Electric Rate Cases at Dockets R.I.D.438, R-79060865, R-80061225, R-811626, R-822291 and R-842590, in support of revenue allocation and rate design. I have also testified before this Commission in the Company's most recent Gas Rate Increase at Docket R-832410 and a prior Steam Rate Increase at Docket R-79040785, in proceedings under Section 1307(e) of the Public Utility Code regarding fuel clause over-or-under collections for electric, gas and steam utilities, and before the Maryland Public Service Commission in support of the Company's request at Case Nos. 7225, 7403, and 7589 for increases in retail electric rates.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the Company's phase-in proposal, the allocation of the increase to the various rate classifications and the rate design.

Q. Please describe the Company's phase-in proposal.

A. As part of this filing, the Company is voluntarily proposing to "phase-in" the requested increase over a three-year period by delaying the billing and collection of a portion of the requested rate increase. It is important to emphasize, however, that as a matter of tariff filing and customer notice, the Company is requesting the legal authority to charge customers the full amount of the requested increase, and that under the tariffs filed by the Company, ratepayers have a legal obligation to pay the full amount of the requested increase. However, for purposes of billing and collection only, the Company is voluntarily proposing to delay billing and collecting a portion of the increase through the application of an Unrecovered Revenue Collection Rider as set forth in Schedule 1 to my testimony. These schedules, of course, are based upon the full amount of the requested increase, and would be revised as part of the Company's compliance tariff filing to reflect any disallowances made in the Commission's final rate order.

Q. Why is the Company proposing to phase-in this rate increase?

A. The Company recognizes that this is a significant rate increase and presents this phase-in proposal in an effort to reduce the impact of this increase on ratepayers and the economy of the Company's service territory.

Q. Please explain the specifics of the Company's phase-in proposal.

A. As part of this filing, the Company proposes to voluntarily phase-in the rate increase in three steps. Assuming approval of the entire increase, each step would be an increase of 9.4% or $223.6 million so that the total increase of 28.2% or $670.7 million would be billed beginning with the third year after the rate increase is granted. The amount of revenue not billed during the first two years would be collected over three years beginning with the fourth year and continuing through the fifth and sixth years. The Company is not seeking to recover any carrying charges associated with this revenue not yet recovered. For a 500 kWh residential customer the proposed base rate billing excluding STAC and ECR for years one through seven would be as follows:

Rate R Phase-In

Present Rate	$56.25
Year 1	61.78
Year 2	67.32
Year 3	72.85
Year 4	78.38
Year 5	78.38
Year 6	78.38
Year 7	72.85

If the overall rate increase granted by the Commission is less than that originally requested in this filing, any amount disallowed by the Commission would be deducted first from the third year increase and then from the second year increase. Thus, if the total increase granted is less than the full amount requested but more than 18.8%, the first and second year increases would be 9.4% and the remainder would be billed in year three. Similarly, if the total increase is 18.8% or less and more than 9.4%, the increase would be phased-in over two years -- 9.4% in year one and the remainder in year two. If the total increase is 9.4% or less, no phase-in would be implemented.

Similarly, the revenue recovery period would vary with the amount of the increase granted by the Commission. Specifically, if the phase-in occurs over two years rather than three years, then recovery of the revenue not billed in year one would be recovered over a two-year period in years three and four.

Q. How will the phase-in be implemented?

A. Upon completion of the rate case the total rates as allowed would be filed with the Commission together with adjustment factors for each rate block of each rate to reflect the phase-in. Assuming approval of the full amount requested, these adjustment factors would be used to compute the customer bills during the first two years of the phase-in. The full rate increase would be billed during the third year.

The Company also will compute each month for each rate schedule, the difference between the amount the customer would have been billed under the approved tariff rate and the amount actually billed by application of the rate adjustment factor. During the first two years that the new rates are in effect this difference will be recorded as unrecovered revenue. This unrecovered revenue will be carried on the Balance Sheet in Account #186 as a Deferred Debit and there will be a separate subdivision established for each rate classification so that the appropriate amount of unrecovered revenue will be collected from each rate classification. The collection of this revenue will begin in the fourth year with a specific unrecovered revenue factor applicable for each rate block. The collection of unrecovered revenue will continue for a rate class until all of the revenue in Account #186 for that class has been collected.

Collection of the unrecovered revenue will be in a manner similar to the initial delay of the revenue collection. Specifically, adjustment factors designed to recover the revenue over a three-year period will be applied to each block of each rate schedule for each rate class. The Company will precisely track the recovery of revenue from each rate class and cease application of the factor when recovery is complete. Due to sales differences and other factors, the precise recovery time will vary from class to class and may occur in more or less than exactly three years. In addition, the Company would propose to review the recovery factors after the first year of the recovery period and adjust the factors, if necessary, to permit recovery over a three-year period.

The detailed procedures which the Company will employ in applying the phase-in proposal are set forth in Schedule 2 to my testimony. As set forth therein, the Company will calculate the difference between present and proposed rates for each rate block. One-third of that differential will be billed in year one, and two-thirds will not be billed. In year two, two-thirds of the difference will be billed, and one-third not be billed. In year three, the full tariff rate will be billed. In years four through six, one-third of this differential will be added to the tariff prices to recover the revenue not billed in years one and two. I would note that the Company's phase-in proposal is identical in concept to that recently proposed by Pennsylvania Power & Light Company, except that the Company's proposal more precisely tracks revenue billing and recovery by applying billing factors to each component of each rate.

Q. Will you please explain how the rate increase was spread among the various classes of customers.

A. Yes, With Supplement #15, as with all rate design efforts, several factors were considered in developing the distribution of the rate increase to the various classes of customers.

Because of the size of this increase we were concerned that it should be spread as equally as possible to all rate classifications. We were also concerned that the difference between the index of individual class rates of return to the average system rate of return should not be increased. For those classes whose index of return to system average before the rate increase was above 140%, the net increase was limited to zero, that is, the increase was exactly equal to the fuel saving allocated to that class. The remaining base rate increase was then spread to all other classes to produce equal net percentage increases to each class. This application of the rate increase resulted in most classes moving toward the average rate of return with the exception of the RH class. The increase to the RH class was therefore limited to a value which would maintain the 116% index of relative return to the class average.

A summary of the ratio of the rates of return for the various classes is shown below:

	Percent of System Average Rate of Return	
Rate	Before Increase	After Increase
R	96%	96%
RH	116%	116%
OP	343%	244%
GS	126%	116%
PD	97%	98%
HT	84%	96%
SLP	174%	97%
SLS	206%	108%

A review of the return indexes for the major rate classifications relative to the system average return after the rate increase shows a range of 96% to 116%. All of the major rate classes are within 20% of the average rate of return and move toward the system average return with the exception of Rates R and RH which remain constant.

Q. Turning now to the rate structure area, Mr. Williams, please describe the Company's electric service rate structure, referring to the rate classifications listed on page A-5 of Exhibit TPH-2.

A. Residential service is supplied under a combination of three rates. Our basic residential rate is Rate R under which we will supply approximately 77% of our service to residential customers during the future test year.

We also have a separately metered rate (Rate OP - Off-Peak) which offers service on a controlled basis for water heating or other 240 Volt appliances, either with 7-day interruption by time clock or for a small additional charge, 5-day interruption by radio control. Rate OP is used primarily for water heating and accounts for approximately 5% of total residential usage. Residential homes with electric space heating are served under rate RH which is identical to Rate R except that usage above 500 kilowatt-hours per month during the eight winter months is priced approximately 4.4¢ below the comparable price of Rate R, in recognition of the seasonally off-peak nature of the electric heating load on our system. Rate RH will account for approximately 18% of our total residential usage during the future test year.

Our commercial and industrial customers are separated into three categories depending on service voltage. Those customers supplied at secondary voltage, 120 or 240 Volts, are supplied under Rate GS which is a General Service rate available for offices, professional, commercial or industrial establishments, and other applications outside the scope of the residential rates, and is available both with and without demand measurement.

Our second category of commercial and industrial customers are those served at Primary Voltage (4,160 Volts) under Rate PD. We have over 2600 customers served under this rate who have demands ranging from about 25 to 1,000 kilowatts, with the average about 175 kilowatts.

The final class of commercial and industrial customer is Rate HT for service supplied at High Tension voltage of 13.2 kV or above. We have approximately 2300 customers served under this rate and their energy usage accounts for about 50% of the Company's total sales during the future test year. Customers served on this rate include our largest customers, some of which have demands in excess of 100,000 kilowatts.

In addition to the above-described major rate classifications, we have two major street lighting rates: Rate SLP for sevice in the City of Philadelphia where the lighting fixtures are not provided by the Company, and Rate SLS for service in the suburbs where the Company does provide the fixtures. In addition, Rate POL is available for private outdoor lighting throughout the system.

Rate TL is available to Municipalities for service to traffic signal light installed and owned by the Municipalities throughout the territory. Rate BLI is available for service to adjacent utilities where Philadelphia Electric's facilities are more accessible to their customers because of geographical locations.

Q. Mr. Williams, is the Company proposing any changes in rate structure within the various rates in Supplement No. 15?

A. Yes. In both Rates R and RH we propose to increase the customer charge from $4.50 to $4.75. This increase is less than the average increase proposed for these rate classifications and is cost justified using the same approach proposed by the Commission Staff in previous rate cases. The $4.50 customer charge is about 25% of the fully allocated customer cost of $18.50 as developed in the Company's cost allocation at page 43.

Q. What other rate structure changes are being proposed as a part of this filing?

A. We are proposing to increase the differential between the single-phase and three-phase customer charges to the cost difference between these two types of service. Three-phase service requires additional costs for metering, transformer installations and services. Even at $20.50 the three-phase customer charge is only about 55% of the fully cost justified customer charge of $37.05. The present and proposed customer charges are as shown:

	Single-Phase	Three-Phase	Difference
Present	$5.50	$15.20	$9.70
Proposed	$6.00	$20.50	$14.50

Q. Are there any proposed changes within Rate GS?

A. Yes. Rate GS presently consists of two parts: a rate for those customers without demand measurement and a rate for those customers with demand measurement. The rate for customers without demand measurement is constructed so that the customer's bill is the same as it would be if the customer made 220 hours use of registered demand -- in other words, the demand is created for the customer by dividing the monthly kilowatt-hours registered by 220.

Our load studies have shown that the hours use of demand for this group of non-demand measured customers is about 125 hours per month rather than the 220 hours as presently built into the rate. We propose as a part of this filing to revise the hours use of demand used to compute bills for non-demand measured customers from the present 220 hours to 175 hours. This represents a move of about 50% of the distance from the present hours use, which is too high, toward the appropriate 125 hours use level.

In order to simplify the rate, we also propose to eliminate the "without demand measurement" portion of Rate GS and retain the "with demand measurement" portion only. For those customers without demand measurement, the monthly kilowatt-hours will be divided by 175 to create a demand for billing purposes which will be used to calculate the customer's bill. In addition, we have revised the billing demand definition to assure that the billing demand for both measured and non-measured customers using 1100 kWh or less per month will never represent less than 175 hours use.

The increase in pricing for Rate GS has been constructed so that the end block of the rate (greater than 400 hours' use) does not receive any increase and in fact is decreased as a result of the fuel roll-out from base rates. This treatment is consistent with the relationship of revenue to cost within the rate. The revenue and cost curves shown on pages 55 to 58 of Exhibit WFS-1 show that at high hours of use of demand the GS revenue is above the GS cost to serve curve whereas for lower hours of use the revenue is below the cost to serve curve. In order to further improve the relationship between cost and revenue the first block of the rate is revised from 65 to 80 hours use of the billing demand.

Q. Are there other rate structure changes being proposed?

A. Yes. Although the suburban street lighting schedule Rate SLS receives a net zero increase, that is, the rate increase for the class is completely offset by the fuel savings allocated to the class, the rate increase has been assigned to those lamps (generally the smaller sizes of lamps) that are now below the cost to provide service to them. The fuel savings, of course, go to each lamp based upon the kWh use of that lamp. The effect of this treatment is to continue the closure between revenue and the cost to serve for each of the lamp sizes within the Rate SLS classification. The net effect on any one Municipality is a small increase or decrease depending on the mix of lamp sizes in service.

Q. Mr. Williams as a part of the Order in the last rate case, Philadelphia Electric was directed to prepare and submit to the Commission studies indicating the cost of providing service to SEPTA and AMTRAK. Have those studies been completed?

A. Yes. We have made a careful study of the cost to serve SEPTA and AMTRAK. As set forth in Mr. Sundermeir's Testimony, a complete analysis has been made of the distribution facilities to reach the numerous points of service for each of these two customers and the cost to serve each customer has been calculated. A customer demand and energy rate has been developed for each customer to provide the system average return. The energy charge of each rate is the same as the end block of Rate HT and time of use credits and surcharges applicable to Rate HT would also be applicable to the rates for SEPTA AND AMTRAK.

These two new rates have been designated EP-S (Electric Propulsion - SEPTA) and EP-A (Electric Propulsion - AMTRAK). The revenue data for these two rates is set forth separately on Exhibit TPH-2, page A-5. The Company recommends Commission approval of these two new rates.

Q. Mr. Williams would you please explain the footnote regarding AMTRAK revenue as shown on page A-5 of Exhibit TPH-2.

A. The budgeted revenue for AMTRAK was based upon the demands historically billed with demand simultaneously measured at the frequency converter input supply points and the railroad interchange points at Perryville (Baltimore Gas and Electric) and Thorndale (Pennsylvania Power & Light). Subsequent to the preparation of the budget the Company finalized a new contractual agreement with AMTRAK which eliminated the railroad interchange points of Perryville and Thorndale from the demand calculation. The percent of revenue increase shown in column 11 on page A-5 is the actual percentage increase that will result under the new contractual demand calculation. The actual revenue increase proposed is $3,746,516 as calculated in the Company's response to 52 Pa. Code Section 53.53(IC C-1).

Q. Are there any other rate revisions in the filing?

A. Yes. We have revised Rate OP to more clearly set forth the two types of service offered. The service that is interrupted everyday has now been designated OP-1 and the service that is interrupted only five days a week and is not interrupted on Saturdays, Sundays or Holidays has been designated OP-2. There are now approximately 3,400 customers on Rate OP-2 and this restatement of the rate will provide greater flexibility to relate the off-peak times to high cost operating periods.

Q. Does that conclude your testimony at this time?

A. Yes.

STANDARD RIDERS–Continued

Applicable to rates as indicated in Applicability Index of Riders

UNRECOVERED REVENUE COLLECTION RIDER

APPLICABILITY. This rider provides for the delay of the billing of part of the revenue otherwise due through application of Rates R, R-H, GS, PD, HT, EP-A, EP-S and BLI and the Transformer Rental Rider, and the subsequent recovery of this revenue. (C)

TERMS. In accordance with the provisions of this rider, revenue collection will be partially delayed during the two years after the effective date of this rider. The base rate revenue to be billed to customers on this rider during each year after the effective date of the increase approved at Docket No. R-850152 shall be computed by use of the factors shown herein. The unrecovered revenues are the differences between the revenues due through application of the base rates and the billed base rate revenues. This revenue shall be recovered in a three-year period beginning with the end of the third year that this rider is in effect; however, this rider shall remain in effect until the unrecovered revenue account balances are zero for all applicable rates. The Unrecovered Revenue Collection Rider applies only to the timing of the billing of the rates as filed in this tariff supplement, and does not in any way affect the Company's right to recover and the Customer's obligation to pay the full amount of the rates as set forth in this tariff supplement.

OTHER PROVISIONS. In the event base rates are changed by action of the Pennsylvania Public Utility Commission from those reflected in the tariff supplement of which this rider was first a part, appropriate changes shall be made to this rider so that the effects on Customer billing will be substantially the same as those contemplated in the original rider.

UNRECOVERED REVENUE FACTORS. Unrecovered revenue factors are applied to each block of each rate schedule. The unrecovered revenue factors to be applied to each rate schedule for each of the six years are as follows:

RATE	Year 1	Year 2	Year 3	Years 4, 5 & 6
R				
Customer Charge	0.96421	0.98316	1.00000	1.01684
Energy Charge				
Summer				
Block 1	0.83994	0.91997	1.00000	1.08003
Block 2	0.83589	0.91762	1.00000	1.08237
Winter	0.83994	0.91997	1.00000	1.08003
R-H				
Customer Charge	0.96421	0.98316	1.00000	1.01684
Energy Charge				
Summer				
Block 1	0.83994	0.91997	1.00000	1.08003
Block 2	0.83589	0.91762	1.00000	1.08237
Winter				
Block 1	0.83994	0.91997	1.00000	1.08003
Block 2	0.89362	0.94752	1.00000	1.05248
GS				
Without Demand Measurement				
Customer Charge				
Single-Phase	0.94500	0.97167	1.00000	1.02833
Polyphase	0.82780	0.91366	1.00000	1.08634
Energy Charge				
Block 1				
65 Hours' Use	0.83326	0.91642	1.00000	1.08358
15 Hours' Use	0.61578	0.80810	1.00000	1.19190
Block 2				
65 Hours' Use	0.93303	0.96652	1.00000	1.03348
15 Hours' Use	0.75023	0.87511	1.00000	1.12489
Block 3	0.90773	0.95386	1.00000	1.04614
Block 4	1.22957	1.11479	1.00000	0.88521

(C) Indicates change.

(Continued)

Philadelphia Electric Company

STANDARD RIDERS-Continued

Applicable to rates as indicated in Applicability Index of Riders

UNRECOVERED REVENUE COLLECTION RIDER-Continued (C)

RATE	Year 1	Year 2	Year 3	Years 4, 5 & 6
GS				
With Demand Measurement				
Customer Charge				
Single-Phase	0.94500	0.97167	1.00000	1.02833
Polyphase	0.82780	0.91366	1.00000	1.08634
Energy Charge				
Block 1				
65 Hours' Use	0.83326	0.91642	1.00000	1.08358
15 Hours' Use	0.61578	0.80810	1.00000	1.19190
Block 2				
65 Hours' Use	0.93303	0.96652	1.00000	1.03348
15 Hours' Use	0.75023	0.87511	1.00000	1.12489
Block 3	0.90773	0.95386	1.00000	1.04614
Block 4	1.14591	1.04864	1.00000	0.95136
Heating Block	0.89362	0.94752	1.00000	1.05248
PD				
Customer Charge	0.98308	0.99152	1.00000	1.00848
Capacity Charge	0.67554	0.83826	1.00000	1.16174
Energy Charge				
Block 1	0.88229	0.94166	1.00000	1.05834
Block 2	0.92330	0.96165	1.00000	1.03835
Block 3	1.02611	1.01305	1.00000	0.98695
HT				
Customer Charge	0.88972	0.94484	1.00000	1.05516
Capacity Charge	0.71292	0.85593	1.00000	1.14407
Energy Charge				
Block 1	0.84440	0.92220	1.00000	1.07780
Block 2	0.88772	0.94461	1.00000	1.05539
Block 3	1.00267	1.00000	1.00000	1.00000
BL1				
Energy Charge	0.85140	0.92606	1.00000	1.07394
EP-A				
Service Charge	0.35013	0.67506	1.00000	1.32493
Capacity Charge	0.56020	0.78010	1.00000	1.21990
Energy Charge				
Block 1	1.64800	1.32267	1.00000	0.67733
Block 2	1.32267	1.16000	1.00000	0.84000
Block 3	1.00000	1.00000	1.00000	1.00000
EP-S				
Service Charge	0.33675	0.66838	1.00000	1.33162
Capacity Charge	0.54492	0.77246	1.00000	1.22754
Energy Charge				
Block 1	1.64800	1.32267	1.00000	0.67733
Block 2	1.32267	1.16000	1.00000	0.84000
Block 3	1.00000	1.00000	1.00000	1.00000
Transformer Rental Rider				
Fixed Charge				
Block 1	0.85426	0.92704	1.00000	1.07296
Block 2	0.85569	0.92477	1.00000	1.07523
Operating Charge	0.84431	0.92216	1.00000	1.07784

(C) Indicates change.

PROCEDURES FOR DETERMINING RATE PRICING FOR PHASE-IN OF RATE INCREASE

A phase-in ratio will be computed for each rate block price for year 1 and for year 2 in accordance with the following procedure.

First Year

1. Determine the difference between the presently effective rate and the compliance filing rate by rate blocks. This difference will be the basis for the calculation of phase-in and phase-out ratios during the entire period that the Unrecovered Revenue Collection Rider is in effect.
2. Subtract 2/3's of the difference by rate blocks as calculated in step #1 to obtain the first year rate pricing.
3. Divide this first year rate pricing by the compliance filing rate pricing to obtain ratios for each rate block.
4. Calculate the base revenue portion of the customers bill using the full compliance filing rate.
5. Apply the ratios for each rate block calculated in step #3 to the bill calculation in step #4 to determine the base rate revenue to be billed to the customer.
6. Subtract the base rate revenue calculated in step #5 from the revenue calculated in step #4 to determine the amount to be placed in the Unrecovered revenue account.

Second Year

1. Subtract 1/3 of the difference by rate blocks as calculated in step #1 to obtain the second year rate pricing.
2. Divide this second year rate pricing by the compliance filing rate pricing to obtain ratios for each rate block.

3. Calculate the base revenue portion of the customers bill using the full compliance filing rate.
4. Apply the ratios for each rate block calculated in step #2 to the bill calculation in step #3 to determine the base rate revenue to be billed to the customer.
5. Subtract the base rate revenue calculated in step #4 from the revenue calculated in step #3 to determine the amount to be placed in the unrecovered revenue account.

<u>Third Year</u>

1. The full compliance filing rate increase will be put into effect therefore, the ratio will be 1.000 and there will be no revenue placed in the uncovered revenue account.

<u>Fourth Year</u>

1. Add 1/3 of the difference calculated in first year - step #1 to the compliance filing rate by rate blocks to obtain the fourth year rate pricing.
2. Divide this fourth year rate price by the compliance filing rate price to obtain a ratio for each rate block.
3. Calculate the base revenue portion of the customers bill using the compliance filing rate.
4. Apply the ratios for each rate block obtained in step #2 to the bill calculation in step #3 to determine the base rate revenue to be billed to the customer.
5. Subtract the base rate revenue calculated in step #3 from the revenue calculated in step #4 to determine the amount to be credited to the unrecovered revenue account.

At the end of the fourth year, the rate of revenue recovery will be adjusted if necessary to spread the remaining revenue to be recovered over the fifth and sixth years.

Fifth and Sixth Years

1. Same procedure as the fourth year unless adjustment is required as described above.

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Q. IR-City-1-17. Did the Company consider any other period or method of phase-in methodology; for example, a 10-year phase-in or a longer period for amortizing the deferred revenue? If so, list all such alternative time periods and methods reviewed; provide all work papers and calculations associated with such reviews; and provide any model runs associated with such reviews.

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A. IR-City-1-17. In discussion, the Company considered various lengths of time for the phase-in. It was concluded that the time frame proposed by the Company would be appropriate. This phase-in was determined to be less risky financially than longer phase-ins and also allowed for annual rate increases consistent with the average over the past ten years. Another fact considered was that the Company's phase-in plan was consistent with the proposed revisions to FASB No. 71 which would limit accounting recognition of phase-ins. Discussion of FASB No. 71 is contained in Company Statement No. 16, the Direct Testimony of David J. Farling. Two of the points in this discussion having significant impact on the Company's decision to implement a three-year phase-in were 1) longer phase-in plans are considered more risky as utility rates can be subject to both market and political forces and the longer the period the greater the risk of recovery due to these forces, and 2) it is possible that FASB No. 71, as amended, will require discounting of deferred revenue, thus penalizing earnings during the phase-in.

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Responsible Witness: R. C. Williams, Manager, Rate Division
D. Farling - Coopers and Lybrand

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SUMMARY OF BASE REVENUES ALLOWED
AND COLLECTED OVER PHASE-IN PERIOD

Phase-In Year (1)	Proposed Revenue Increase (2) $	Proposed Revenue Collections (3) $	Amount (Deferred) and Collected Through Surcharge (4) $
1	670.7	223.6	(447.1)
2	670.7	447.2	(223.5)
3	670.7	670.7	---
4	670.7	894.2	223.5
5	670.7	894.2	223.5
6	670.7	894.2	223.5
7	670.7	670.7	---

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Note: (a) Assumes Commission approval of entire requested increase.

(b) Does not include ECR revenues.

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RESPONSE OF PHILADELPHIA ELECTRIC COMPANY
TO SEPTEMBER 14, 1984 INQUIRY OF
REPRESENTATIVE JAMES GALLAGHER RELATING TO
COMPETITION BETWEEN ELECTRIC SUPPLIERS

During the September 14, 1984 hearing before the House of Representatives Select Committee to Investigate Limerick Unit II, the Philadelphia Electric Company was asked to respond to Representative Gallagher's inquiry regarding the impact of opening the franchise territories of electric utilities to competition. This memorandum constitutes that response.

The question of competition between electric suppliers has been considered by the Pennsylvania Public Utility Commission (Commission) and the courts on many occasions. In each instance, both the Commission and the courts have concluded that between suppliers of electric power, competition for existing customers is deleterious to the public interest because of its tendency to encourage the waste of valuable resources and increase consumer costs.

I. PUC DECISION

Most recently the question of whether a customer should be permitted to transfer suppliers of electric energy to obtain a lower cost source of electric power was reviewed by the Commission in the Lukens Steel case*. Specifically, Lukens, a large industrial customer of PECO, sought Commission approval to purchase property from Pennsylvania Power & Light (PP&L) and to construct a private transmission line from the Lukens plant into the service territory of PP&L for the purpose of transferring electric suppliers. Lukens contended that due to the cheaper power supply of PP&L, it could reduce

*Petition of Lukens Steel Company, a Division of Lukens, Inc., for an order declaring the acquisition of certain property of Pennsylvania Power & Light Company for the purpose of taking Pennsylvania Power & Light service to be in the public interest, P-810310, PA PUC decision entered January 17, 1984 (hereinafter referred to as Opinion).

production costs and thereby save several hundred jobs in Pennsylvania.

The PUC, after nearly two years of discovery and hearings and extensive economic analysis by all the participants, concluded that despite the fact that PP&L could currently supply power at a price that was lower than PECO, the transfer of electric suppliers by Lukens should be denied as contrary to the public interest. The Commission concluded that competition among suppliers of electric service only increased the cost to serve all electric consumers by decreasing the efficient utilization of utility resources; encouraging investment in redundant facilities; and requiring higher rates of return in recognition of the higher risk which would result from a decision to permit load transfer as proposed by Lukens.

II. CONSUMER BURDEN

The Commission Order stated in relevant part:

> "Keeping in mind that the primary purpose of public utility regulation is to serve the public interest by insuring to the public adequate and reasonable service at reasonable and non-discriminatory rates, we cannot ignore the fact that Lukens' eventual goal, which it here seeks the Commission to facilitate by approval of the transfer from PP&L to Lukens of the transmission line corridor, is to transfer its existing electric energy requirements from PECO to PP&L. In accordance with the duty imposed upon PECO as a certified public utility, it has invested capital and incurred expenses in the rendition of electric service to Lukens' plant facilities. There has been no evidence presented that would indicate that Lukens has received less than adequate and reliable service. Lukens has been benefited by the provision of utility service by PECO in the production of Lukens' steel products. Lukens' sole concern, and certainly a vital concern, is the present and projected future rate differential between PECO electric service and PP&L electric service." (Opinion p. 27)
>
> "We consider the arguments raised in opposition to the encouragement of competition among fixed energy utilities to be important. Competition among electric suppliers does encourage redundant capital construction which may adversely impact the environment and which may increase the cost of serving all electric customers. Encouragement of competition among electric suppliers would in all likelihood increase the cost of capital to all electric utilities since the thrust of a loss of customers would

increase the business and financial risk to which such utilities would be exposed. Furthermore, a loss of any significant number of industrial customers could result in increased rates to residential and commercial customers and industrial customers unable to switch to a utility having lower industrial rates." (Opinion p. 29)

"'The undesirable competition between two utilities, as would occur in this instance if an extension of service were permitted by one utility to an established customer of the other utility, would place an unreasonable burden on customers of both utilities and would not be in the public interest.'" (Opinion p. 29 quoting Koppers Company, Inc. v. North Penn Gas Company, 42 Pa. PUC 730 (1966)).*

III. Efficient Service

The extensive economic regulation of the utility industry imposed by state and federal governments since the early 1900's reflects the effort to substitute regulatory controls for economic discipline otherwise imposed by competitive forces in the free market situation. In Pennsylvania and elsewhere, the continued policy, after review of all the facts pro and con competition, has been that the lowest cost and most reliable level of service is provided by a single regulated supplier obligated to serve all customers within a given market or territorial franchise.

A utility's service obligation includes four recognized elements: (1) the obligation to serve all customers within its service area who desire service,

*Both the OCA and the PUC Trial Staff argued against the Lukens transfer stating that the transfer of suppliers on the basis of the price of electricity was not in the public interest and would only result in price increases for all electric consumers, in particular, those unable to transfer suppliers. Under the facts of record in the Lukens case the customer impact of the Lukens transfer for a large customer using 500 GWH per year was estimated to be $1,000,000 and for an industrial customer using 1,300 GWH per year the rate increase as a result of the Lukens transfer was estimated to be $5,200,000. (Opinion p. 19, PECO stmt. No. 15, p. 9). Generally, PECO estimated that the Lukens transfer would produce a 0.376% increase in the rates of remaining Pennsylvania industrial customers which would result in the loss of 1,127 jobs in Pennsylvania.

(2) with adequate facilities, (3) at reasonable rates, and (4) without undue discrimination. These responsibilities, the capital intensive nature and extremely long-lead-times associated with the construction of new power facilities dictate the need to impose a corresponding obligation on customers to purchase the output of facilities built on their behalf.

The real losers from any decision that would allow customers to purchase power outside their designated service area would be the remaining utility customers who would be obligated to cover the fixed charges on capacity initially designed to serve those large customers who would now purchase off-system. The resultant rates would encourage increasingly greater numbers of remaining industrial and commercial customers to seek lower cost off-system purchases. The long-term effects of a spiraling number of off-system purchases and a corresponding reallocation of fixed costs over fewer customers would be that only those "captive" customers (primarily residential and small commercial) would be left on the system and they would be obligated to pay inordinately high rates for electric service.

The adverse financial impacts of such "off-system" purchases are exacerbated by the utility's continuing obligation to serve any customers located within its territorial franchise. Thus, while the customer has been given the flexibility to select suppliers based on short-term price differentials, the utility is nevertheless obligated to maintain sufficient reserve capacity to serve that customers's future needs (should that customer subsequently desire to revert back to its original supplier once any short-term rate advantages which initially prompted off-system purchases have dissolved). The utility is also required to maintain sufficient backup capacity to deal with a variety of contingencies again placing the cost burden on the utility's remaining customers.

In addition, competition among utilities would make it difficult and considerably more costly for any utility to build new baseload generating facilities because of the substantial risk that those new facilities would never be fully utilized. Under the regulatory system now in effect, utility investors are not permitted to earn a return sufficient to compensate them for risks associated with a "competitive" market. Rather, most utility rates are based upon the assumption that investments in electric power production carry far less risk than investments made by non-regulated companies. This assumes, however, that the utility's territorial franchise will assure a predictable and stable revenue flow sufficient to amortize any <u>prudent</u> investment in plant and equipment.

In summary, public utilities must commit large sums for new facilities, pursuant to service obligations, to meet their customers' future load requirements over a period of many years. Allowing customers to shift from one utility to another because of short-term rate savings would introduce major uncertainty in long-term projections of new capacity requirements. The outcome would be either tremendous waste and inefficiency from unused capacity, or conversely, a substantial risk of future electric power shortages because the risk of investing in new generation would be unacceptably high. Only one thing is certain, the cost of supplying electric power to all customers in Pennsylvania would be greater.

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Statement on Behalf of the Philadelphia Electric Company
Sponsored by William B. Morlok, Vice President of
Commercial Operations, James R. Rodisch, Supervisor,
Alternative Energy Section; William F. Sundermeir,
Supervisor, Cost and Load Analysis Section

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PECO wishes to thank the Mines and Energy Committee for the opportunity to present its views on this very important legislation. I am William B. Morlok, Vice President of Commercial Operations. I have with me today Messrs. Rodisch and Sundermeir who are co-sponsors of this statement as well as technical support persons who will be available to respond to your questions.

At the outset I should state that Philadelphia Electric Company shares the views expressed by Mr. Butler on behalf of the Pennsylvania Electric Association. In short, PECO recognizes that lower energy costs are in everyone's best interests and fully supports the objectives reflected in PURPA, the Public Utility Regulatory Policies Act of 1978. However, PECO also must recognize and protect the interests of all its customers and make every effort to insure that its customers are not required to pay excessive costs for electric energy produced by cogenerators, such as Scott Paper Company, which will happen if PECO is required to pay more than PECO's avoided costs - the costs for PECO to generate such electric energy or purchase it from another source.

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Since Mr. Butler has already outlined the legal objections to the proposed legislation, the principal purpose of this statement is to quantify the significant economic impact on other PECO customers of House Bill 2095.

The legislation as proposed will substantially increase the rates for electricity paid by other electric customers including, I note for special emphasis, PECO's other industrial customers.

First, considering specifically the 55 MW cogeneration plant proposed by Scott Paper, other PECO customers will be forced to provide a minimum subsidy to Scott of $7,700,000 in the first year of the contract under the proposed legislation. This subsidy increases during the term of a contract with a 10-year life and will total at least $108,000,000 for the ten years.

This analysis is based on PECO's policy of paying cogenerators a rate for their energy which equals the rate PECO pays for purchases of energy from other utilities through the Pennsylvania-New Jersey-Maryland Interconnection (PJM). Approximately one-third of PECO's energy is purchased from other utilities on the PJM because PECO can do so at a rate cheaper than it can generate itself.

Quite simply the purchases from the cogenerator and small power producer (cumulatively known as qualifying facilities) become a substitute for purchases on the PJM. Therefore, the value of the qualifying facility power to PECO is no greater than the price PECO would have paid to other PJM utilities had the qualifying facility power not been made available.

The average cost of power purchased by PECO on the PJM (PJM billing rate) in 1983 was 4.2¢ per kilowatt hour. In sharp contrast the average rate for customers on rate HT (High Tension Power) under the PECO tariff currently on file and approved by the PUC is 6.9¢ per kilowatt hour. House Bill 2099 establishes a minimum payment the cogenerator may demand at 90% of the average sale price per kWh at rate HT. Ninety percent of the average HT rate is 6.2¢ per kilowatt hour. Thus, if this legislation were adopted, PECO and ultimately its customers would be required to pay 2.0¢ per kilowatt hour <u>more</u> for the energy purchased from Scott than for energy purchased from other PJM utilities. This is 48% higher than the cost of energy that could have been purchased through the PJM Interconnection which in fact is PECO's avoided cost. Thus, this overpayment of 2¢ per kWh is nothing more than a direct subsidy to Scott.

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The inequity of the proposed legislation to other customers becomes even more apparent when one realizes that Scott currently pays only 6¢ per kilowatt hour for its energy because of its high load factor. House Bill 2099, however, would require PECO to purchase the same energy from Scott at 6.2¢ per kilowatt hour. Under this scenario, Scott would sell all of its cogenerated energy to PECO for 6.2¢ per kWh and purchase its requirements from PECO at 6.0¢ per kWh. Therefore, PECO would have to pay .2¢ per kilowatt hour more to purchase energy from Scott than PECO could sell such energy to Scott. In effect, PECO would be paying Scott .2¢ per kilowatt hour to use PECO electricity and Scott would contribute nothing toward the fixed costs for generation, transmission and distribution facilities even though they obviously make use of the equipment. Thus, the legislation provides Scott and other cogenerators with an opportunity to make an unearned and unwarranted profit at the expense of PECO's other customers.

However, House Bill 2099 does not apply just to Scott, but to all cogenerators and small power producers.

The minimum economic potential for cogeneration and small power production in the PECO service area has been previously estimated to be 378 MW (1 MW is equal to 1000 kW). This potential is a conservative estimate based on a Governor's Energy Council Forecast for cogeneration and estimates of small power production potential by the PA PUC, Army Corps of Engineers, developers, and PECO experience. Under current rates, this would mean a $53,000,000 subsidy in the first year by PECO customers and a $937,000,000 subsidy over the life of a ten (10) year contract if the proposed legislation is enacted.

If ratepayers were forced to subsidize such facilities as Scott proposes, PECO could reasonably expect 720 MW of cogeneration and small power production to develop. The potential impact, again, assuming current PECO rates, would be $100,000,000 in the first year and $1,414,000,000 over the life of a 10-year contract.

The impact of the subsidy on the electric rates of PECO's other industrial customers would be especially adverse and must not be ignored. For example, the potential impact of the proposed Act on a large industrial customer using 500,000,000 kilowatt hours per year would be $1,890,000 in the first year and $26,724,000 over the life of a ten-year contract. This is detailed in case 3 of the PECO back-up materials. Subsidies such as this would surely erode Pennsylvania's ability to retain and attract industry and jobs. Further, they would negate efforts made by utilities and the PUC to design rates that foster the industrial development of Pennsylvania. For instance, PECO has recently proposed and the PUC has approved a revision to the Night Service Rider and a special Employment and Economic Recovery Rider to lower the electric rates paid by energy intensive industry and to attract new industry to the PECO service area. The subsidy proposed by this legislation would nullify benefits bestowed by these rate changes.

Nor would the legislation proposed by Scott produce new jobs in the coal industry. Only a small portion of the total potential cogenerators and small power producers would use coal as a fuel source. Yet the power supplied by Scott and others would replace coal fired generation purchased from other PJM companies. Consequently, there could be a decrease in the total amount of coal purchased by utilities which could foreseeably result in a decrease in the total number of jobs in the coal industry.

Similarly, the Scott legislation provides for the sale of back-up, maintenance and supplementary power to the cogenerator at a kilowatt hour rate which ignores minimum charges designed to recover fixed costs. Section 210 PURPA requires that utilities provide such service to qualifying facilities at a rate which does not discriminate against the qualifying facility in comparison to rates to other customers served by the utility. In compliance with federal and state regulations, PECO has filed its Auxiliary Service Rider. The Auxiliary Service Rider, as most recently amended and approved by the PUC, specifically requires PECO to supply qualifying facilities with back-up, maintenance or supplementary power at the same rate as any other customer with similar load characteristics. Therefore, Scott is treated the same as any other HT customer when it takes power.

The PUC as recently as July 1983 examined PECO's Auxiliary Service Rider and found the rate established for back-up, maintenance and supplementary power to be just and reasonable. Scott did not challenge that Rider either before the PUC or in the courts. In fact, there was no objection by anyone to the approval of the revised Auxiliary Service Rider. Scott is now merely attempting to circumvent the appellate process.

If the provisions of the Auxiliary Service Rider are changed to conform with the provisions of the proposed Act, there could be an annual revenue loss, based on PECO's present rates, of $14,500,000. This revenue shortfall would also have to be borne by other industrial and residential ratepayers. Ratemaking has traditionally been delegated to the PUC and it should remain there where the true impact of a rate change can be ascertained.

In summary, the policy of Philadelphia Electric Company is to pay all qualifying facilities a rate for each kilowatt hour generated that is equivalent to what is paid to our utility suppliers through the PJM interconnection for purchase power. This is PECO's true avoided cost, and any amount paid over this is a subsidy which must be contributed by all non-generating customers, including other industrials.

In order to achieve a bail-out, Scott proposes that PECO, along with all other utilities in the state, be asked to make a payment equal to at least 90% of the utility's retail rate to high voltage customers for each unit of electricity purchased from a qualifying facility. In the case of PECO, this requires a 48% overpayment for purchase power which, pursuant to the proposed Act, will be passed on to PECO's other non-generating electric customers. Surely all PECO ratepayers would like a similar subsidy.

State-wide, Scott would encourage the legislature to pass on billions of dollars to ratepayers in the coming years. These increased utility costs for the benefit of a select group of customers could have a disastrous effect on economic development plans in the Commonwealth.

I want to emphasize that PECO has always been willing, and stands ready today, to negotiate in good faith with Scott and any other cogenerator for the purchase of electric energy within the parameters mandated by PURPA. It cannot, however, agree to require its ratepayers to pay more for such energy than it would cost PECO to acquire such energy from other sources. That is why PECO must oppose this legislation and urge that it not be enacted.

Lastly, PECO would bring to your attention the Alabama experience. In May, 1983, Scott Paper arranged for a similar legislative proposal in Alabama.* We have discussed this experience with our counterparts at Alabama

*Known as HB #675 and titled "Alabama Energy and Job Developments Act of 1983".

Power Company. The same rush to a vote was organized. But legislators there realized there were pitfalls to avoid, slowed down the process, carefully reviewed the consequences, and rejected the proposed legislation. Substitute legislation with which all parties could live and which did not unfairly impact other customers was enacted.