Pennsylvania Power & Light Company

Rebuttal Testimony

Volume 2

Docket No. R-00973954

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H&G

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 8-R

Rebuttal Testimony of Joseph R. Schadt

Q. Please state your name and place of employment.

A. My name is Joseph R. Schadt and I am employed by the Pennsylvania Power & Light Company ("PP&L" or the "Company"), Two North Ninth Street, Allentown, Pennsylvania 18101.

Q. Have you provided direct testimony in this restructuring proceeding?

A. Yes. My direct testimony in this proceeding was admitted as PP&L Statement No. 8. The primary focus of my direct testimony was to describe the Company's calculation of stranded costs.

Q. What issues will you be addressing in your rebuttal testimony?

A. I will be responding to the following issues related to stranded costs raised by the witness indicated for each:

Issue	Witness
Stranded Methodology	Mr. Stephen J. Baron
	Mr. Richard La Capra
Pension Costs	Mr. Lane Kollen
Taxes Other Than Income	Mr. Stephen M. Reed
	Mr. Richard La Capra
	Mr. Randall J. Falkenberg
General Plant Allocation	Mr. Randall J. Falkenberg

Rate Case Expense	Mr. Thomas Catlin
	Mr. Stephen M. Reed
Postretirement Benefits Other Than Pensions	Mr. Lane Kollen
A&G Costs	Mr. Richard La Capra
	Mr. Randall J. Falkenberg
	Mr. Stephen M. Reed
Deferred Susquehanna Refueling Costs	Mr. Lane Kollen
	Mr. Stephen M. Reed
	Mr. Thomas Catlin
Employee Transition Costs	Mr. Lane Kollen
	Mr. Thomas Catlin
Depreciation Change	Mr. Richard La Capra
	Mr. Thomas J. Prisco
	Mr. David Schoengold
O&M Reduction	Mr. Richard La Capra

<u>Stranded Methodology</u>

Q. Please describe the stranded methodologies proposed by Mr. Baron, on behalf of the PP&L Industrial Customer Alliance (PPLICA), and Mr. La Capra, on behalf of the Office of Consumer Advocate (OCA).

A. PP&L has used one methodology (the regulatory, or revenue requirements, method) to calculate its stranded costs, and PECO

Energy (PECO) used another methodology (the asset value method). Mr. Baron and Mr. La Capra favor the PECO method for calculating stranded costs associated with generation and the PP&L method for calculating stranded costs associated with regulatory assets. Both methods use the same methodology to calculate the stranded costs associated with above-market power purchases from non-utility generators. The asset value method yields lower estimates for stranded costs associated with generation, and the regulatory method yields lower estimates for stranded costs associated with regulatory assets. However, if applied consistently, both methods would yield essentially the same results for total stranded costs.

Q. So you don't agree with the methodologies used by Mr. Baron or Mr. La Capra?

A. I do not agree with their methodologies. The Company reviewed three approaches to calculate stranded costs. Not surprisingly, if properly used, all three models calculate similar estimates of stranded costs. Mr. Baron and Mr. La Capra, however, conveniently and erroneously mix the methodologies to calculate much lower, and inaccurate, estimates of stranded costs.

Q. Which approach did PP&L use to calculate stranded costs, and why?

A. Of the three approaches that the Company reviewed, two are economic models and one is an accounting model. One of the economic models -- the "regulatory model" -- calculates stranded costs by comparing, on a present value basis, revenues from generation that could be received under traditional regulation and revenues from generation that could be received in a market environment. The other economic model -- the "asset value" or "PECO approach" model -- compares the present value of revenues that could be earned in a market environment from generation, less related cash expenses, with the current book value of the generating assets and regulatory assets. Finally, the accounting model shows revenues and expenses using generally accepted accounting principles, but it doesn't incorporate present value techniques; it can be used to test and verify the economic models.

The Company used the regulatory model to calculate its stranded costs because it recognized that ***only*** the regulatory model calculated stranded costs in accordance with The Electricity Generation Customer Choice and Competition Act (Act). In addition, the regulatory model allows the PUC to use the extensive experience it has developed in implementing concepts previously developed under the regulatory framework. Due to this wealth of experience, use of the regulatory model requires only an agreement on the underlying assumptions, such as the future cost to operate a plant, in order to accurately calculate stranded costs. Answers to most conceptual questions can be addressed through a review of existing regulatory precedents. These existing procedures and methods already incorporate the linkage between rate base, depreciation, return and income taxes that are necessary for a consistent, accurate economic model.

Q. Can you describe more fully the three models that were considered by the Company and their interrelationships?

A. As I stated earlier, the regulatory model compares the generation-related revenue stream that a utility could have received under traditional regulation with the revenue stream the utility could receive in the competitive market. The differences are discounted to the effective date of customer choice, January 1, 1999, for recovery through the Competitive Transition Charge (CTC).

The regulatory model has several characteristics that make it the natural choice for the analysis of stranded costs. First, the model is easy to use and understand. All revenues and costs are displayed in whatever time period they are expected to occur. In essence, the model is a series of future test years, consistent with the test year concept used under traditional regulation. Second, the answers to certain conceptual questions, such as the treatment of income taxes, already have been decided through the historic ratemaking process. I reiterate that one need only apply these existing rules and agree upon assumptions in order to accurately calculate stranded costs. Accordingly, with this model, the Commission's time need not be wasted developing complex alternative procedures that, in the end, will yield the same result. Third, the language of the Act suggests that this model is the correct model for calculation of stranded costs. The Act defines stranded costs as "an electric utility's known and measurable net electric generation-related costs, determined on a net present value basis over the life of the asset or liability as part of its restructuring plan, which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive generation market and which the commission determines will remain following mitigation by the electric utility." This definition specifically states that a comparison of revenue requirements under regulation with revenues resulting from the competitive marketplace is the correct approach to calculate stranded costs. Finally, because the regulatory model specifically calculates the revenues a utility would have received under cost-based regulation and compares this to the revenues obtainable from the marketplace, the regulated model provides assurance to the Commission that a utility will not unfairly benefit by the transition to customer choice.

The asset based model calculates the present value of the market-based revenues less cash expenses from generation and compares this with the sum of the book value of generation assets and regulatory assets (investments and costs that already have been incurred). Cash expenses include any above-market costs of power purchased under contracts with non-utility generators that will be incurred. The asset-based model can be used to calculate stranded costs accurately and is the economic model used by PECO. It also is, with some flawed adjustments, the model used by Messrs. Baron and La Capra. The most serious limitation to this model is that it has never been used in the Pennsylvania regulatory environment and, therefore, has no historical support or precedent. Accordingly, to effectively use this model, one must first develop the necessary logic to ensure that items such as income taxes are properly handled, as I'll show below. The point is, without consistent application of proper logic, results of this and any model can yield erroneous results.

The third model reviewed by the Company is the accounting model. The attractions to this model are twofold. First, the rules of accounting have been developed and confirmed by the financial community, and they are not subject to vague interpretations. Second, due to the general lack of discounting cash flows, the accounting model is the simplest of the three models and the easiest to understand. However, this lack of discounting cash flows also is the accounting model's greatest limitation, because the time value of money is not reflected.

For the above reasons, the Company believes that the regulatory model is the best method available for calculating stranded costs. Ultimately, model selection is not the real issue. Properly applied, all models should yield the same result. Mr. Baron's and Mr. La Capra's criticism of the regulatory method is a smokescreen designed to obscure the true issues in this case.

Q. Regarding the Company's estimate of generation-related stranded costs, Mr. La Capra states, "My review of the Company's estimate confirms that the $3.45 billion estimate is a substantial overstatement of the Company's generation-related stranded costs. The Company's estimate is based on an inappropriate methodology for computing stranded costs and has a number of problems with inputs and assumptions." (See direct testimony of Richard La Capra, page 12, lines 19 through 23.) Does the Company's methodology overstate stranded costs?

A. No, it does not. This can be proven, first, through an examination of the underlying economic theory supporting the regulatory model and, second, through an illustration.

As justification for his claim that the regulatory model is flawed, Mr. La Capra states, "it builds in return on investment over the entire forecast period, ignoring that the CTC period will be a much shorter (7 years) period for recovery of stranded costs authorized by the Commission." (See direct testimony of Richard La Capra, page 13, lines 12 through 15.) Mr. La Capra has seemingly forgotten a basic premise of present value theory. The fact is, the impact of discounting exactly offsets the impact of calculating a return on investment, because the Company used its cost of capital rate as the discount rate. Accordingly, for purposes of calculating the return on investment, it doesn't matter if the forecast period is 3 years, 30 years or 300 years -- the return on investment will be offset by discounting. For example, if you grow $100 at 10% and subsequently discount at 10%, you will always get back to $100, regardless of the duration of the forecast period.

The only exception to that rule is the calculation and payment of income taxes. Income taxes within both the regulatory model and the asset value model present complex issues that require additional discussion. The regulatory model calculates an income tax gross-up on the equity portion of return on investment, essentially determining a "revenue requirements" number. Mr. La Capra correctly points out that because the regulatory model calculates a return on investment over the life of the related asset, income taxes also are calculated over that period. Accordingly, in total dollars (***not*** present valued), the regulatory model results in a higher amount of income taxes than would be calculated under the asset value model. However, Mr. La Capra neglects to mention that the higher income taxes calculated in the regulatory model are spread over an extended period of time and are offset by the longer period of discounting. In other words, the regulatory model calculates higher nominal income taxes that are significantly reduced through the discount factor to their present value. Conversely, the asset value model calculates a lower amount of nominal income taxes, but they are incurred over the first seven-year period (between 1999-2005), when discounting has a much smaller impact. For example, $110 next year is worth $100 today, using a 10% discount factor, but $260 ten years from now also is worth $100 today. In summary, when properly applied, the methods provide similar results.

A simple example will provide evidence that the regulatory method of calculating stranded costs results in exactly the cost recovery necessary, and no more. Assume that a generating plant has a $150 book and tax basis with 3 years of depreciable life remaining. Further, assume PP&L's tax rate of 41.4935% and capital structure, as shown:

	Cost of Capital	Ratio	Weighted Cost of Capital	After-tax weighted Cost of Capital
Debt	7.89%	47.0%	3.71%	2.17%
Preferred equity	7.10%	7.8%	0.55%	0.55%
Common equity	11.50%	45.2%	5.20%	5.20%
		100.0%		7.92%

For simplicity of this example, assume the plant has annual market revenues of $60 and annual operation and maintenance (O&M) costs of $10, debt and equity costs are based on rate base at the beginning of the year, and all returns are calculated and all streams are discounted as of the first of the year.

The Company's regulatory method calculates stranded costs under the traditional ratemaking methodology as follows:

	Year 1	Year 2	Year 3	Total
Revenue requirements				
Depreciation	$ 50.00	$ 50.00	$ 50.00	$ 150.00
O&M	10.00	10.00	10.00	30.00
Common equity return	7.80	5.20	2.60	15.60
Preferred equity return	0.83	0.55	0.28	1.65
Debt return	5.57	3.71	1.86	11.13
Income taxes				
on equity return	6.12	4.08	2.04	12.23
Total revenue requirements	$ 80.31	$ 73.54	$ 66.77	$ 220.61
Market revenues	60.00	60.00	60.00	180.00
Stranded costs	$ 20.31	$ 13.54	$ 6.77	$ 40.61
Present value - stranded costs	$ 20.31	$12.54	$ 5.81	$ 38.66

The Company's methodology identifies the need to collect $38.66 as stranded costs. If this is correct, the sum of the $38.66 stranded cost amount collected in the first year and the market revenues should be sufficient for the utility to meet its obligations over the three-year period and have $0 left over. The following calculations support this result:

	Year 1	Year 2	Year 3	Total
Stranded Recovery	$ 38.66			$ 38.66
Market Revenues	60.00	$ 60.00	$ 60.00	180.00
Less: Depreciation *	50.00	50.00	50.00	150.00
Less: O&M	10.00	10.00	10.00	30.00
Less: Interest Expense	5.57	3.31	1.72	10.60
Less: Income Taxes #	13.73	(1.37)	(0.71)	11.65
Net Income	$ 19.36	$ (1.94)	$ (1.01)	$ 16.42
Required Return - Preferred Stock	(0.75)	(0.45)	(0.23)	(1.43)
Required Return - Common Stock	(7.88)	(4.69)	(2.43)	(14.99)
Remainder *	$ 10.74	$ (7.07)	$ (3.67)	$ (0.00)
Beginning investment	$ 150.00	$ 89.26	$ 46.33	
Available to pay investors -sum of *	60.74	42.93	46.33	
Ending investment	$ 89.26	$ 46.33	$ 0.00	

For example, income taxes in Year 2 equal 41.4935% x (60.00-50.00-10.00-3.31)

As this example illustrates, the Company's method calculates exactly the amount of stranded cost recovery necessary to meet its ongoing obligation and does not overstate the net present value of stranded costs by a single cent.

Q. You mentioned that consistent application of logic is necessary in order to accurately calculate stranded costs under any of the models. Can you give an example of an item that requires different logic for the different models discussed?

A. The regulatory asset associated with taxes recoverable through future rates (taxes recoverable) provides a good illustration of how the different models require different logic.

Taxes recoverable generally result from depreciating assets more quickly for tax purposes than for book purposes. This accelerated depreciation results in lower income tax payments in the current period, and higher income tax payments in the future.

The correct calculation of stranded costs relating to taxes recoverable is an easy calculation within the regulatory model, because the governing rules and logic previously have been developed by regulatory procedures. A comparison of future book depreciation with future tax depreciation identifies exactly the future period in which the taxes will become payable. This also is the period in which taxes recoverable should be collected from ratepayers, under traditional ratemaking. Note that this is true because the proper linkage exists between rate base, deferred taxes and taxes recoverable. As rate base is depreciated over time, deferred taxes become payable to the government and taxes recoverable become due from ratepayers. By applying this method, the regulatory method calculates a present value of $219 million of stranded costs associated with taxes recoverable (net of the associated regulatory liability for investment tax credits), and this is the amount requested by the Company in this filing.

The correct calculation of taxes recoverable within the accounting model also is straightforward. Taxes recoverable (net of the associated regulatory liability for investment tax credits) applicable to generation and to PUC customers amount to approximately $626 million as of January 1, 1999, stated in nominal dollars. Existing accounting rules will require the Company to amortize the $626 million to expense during the transition period, regardless of what method is selected for calculating the associated rate recovery. Accordingly, stranded costs for taxes recoverable simply amount to $626 million in the accounting model. At this point, it is worth noting that the present value of $626 million over 7 years is $479 million, using the Company's discount rate. However, the Company requested rate recovery amounting to only the present value of $219 million, not $479 million, for this item. This occurs because the Company consistently applied the concepts of discounting within its calculation of stranded costs.

Unlike the rules which already exist within the regulatory and accounting models for computing the stranded costs associated with taxes recoverable, there are no historic rules to fall back upon within the asset value model. It is interesting to note that Mr. La Capra overcomes this dilemma by recommending the regulatory method for quantifying stranded costs related to taxes recoverable. However, the PP&L method of calculating stranded costs associated with taxes recoverable is **only** valid if used consistently within the regulatory model - that is, book depreciation drives deferred taxes which drive taxes recoverable. If book depreciation is eliminated from the calculation of stranded generation costs, as it is in the asset value model, there is absolutely no theoretical justification for amortizing taxes recoverable on the basis of book depreciation, and alternative amortization logic must be developed, as follows.

On page 13 of his testimony, Mr. La Capra actually identified the correct logic that should be used to calculate stranded costs for taxes recoverable within the asset value model, but elected not to use it. As previously noted above, regarding the Company's regulatory model, Mr. La Capra states, "For example, it builds in return on investment over the entire forecast period, ignoring that the CTC period will be a much shorter (7 year) period for recovery of stranded costs authorized by the Commission." Because stranded generation plant is recovered over seven years, the related unfunded deferred taxes also will reverse over the same seven year period, requiring the reversal of taxes recoverable over the same seven years. As such, the stranded cost for taxes recoverable using the asset value method is the present value of PP&L's $626 million of taxes recoverable discounted over seven years, or $479 million.

The point of this example is to *illustrate that*, although it is not difficult to select advantageous portions of the regulatory model and the asset value model in order to calculate a lower (or higher) amount of stranded costs, such a mixture is logically flawed and flagrantly incorrect. This point also is presented by PECO in its proceeding; PECO is strenuously objecting to the OCA's recommendation to mix the regulatory method of calculating stranded costs associated with taxes recoverable with the asset value method of calculating stranded generation costs. Finally, on page 13 of Mr. Kollen's direct testimony, which Mr. Baron relied on in his testimony, Mr. Kollen asserts that consistency is important in the valuation of regulatory assets, liabilities, and generation stranded costs. On that point, I agree with him.

In summary, the above discussion highlights the fact that the methodology employed by the Company to calculate stranded costs utilizes traditional ratemaking techniques that have withstood the test of time. The regulatory method complies with the requirements of the Act, handles technical issues in a manner familiar to Pennsylvania regulators, accurately calculates stranded costs and is applied consistently by the Company. Additionally, to date, the method has been utilized by PP&L, Metropolitan Edison, Penelec, and West Penn in recent restructuring filings. Intervenors, except for the OCA and PPLICA, have accepted the regulatory method. For these reasons, I believe the Company's proposed method of calculating stranded costs should be accepted in this proceeding.

Q. The stranded cost estimates submitted in this case cover a wide range of values. Is there any way to evaluate the reasonableness of the estimates?

A. Yes. Following are the stranded cost estimates submitted in this case:

PP&L	$4.6 billion
Office of Small Business Advocate	3.9 billion
Office of Trial Staff (OTS)	3.2 billion
American Association of Retired Persons	3.0 billion
PPLICA	0.7 billion
OCA	0.4 billion

The estimates submitted by the Office of Small Business Advocate, the OTS and the American Association of Retired Persons differ from the Company's estimates primarily due to differences in assumptions and misunderstandings regarding the proper discount rate. As the Commission reviews and obtains closure on these issues, the differences in the above estimates and the Company's estimate quickly will be reconciled. However, the estimates provided by the PPLICA and the OCA differ so radically from all of the other estimates presented that there seems to be no reasonable link between the traditional regulatory method and the hybrid method used by PPLICA and the OCA.

Because the Act states that stranded costs must be calculated on a net present value basis, an economic model must be used to calculate the estimate. However, the accounting model provides an important tool with which to evaluate the results calculated by the economic models. In order to determine whether any of the above estimates pass the reasonableness test, I reviewed the results of the estimates provided by the Company and the OCA within the accounting model, using the most positive scenario reasonably possible during the transition period.

This analysis requires an income statement which is representative of 1999 activity as a starting point. For simplicity, I used the Company's 1996 results of operations that were applicable only to PUC jurisdiction as a proxy for 1999. This is appropriate because the Company previously submitted these results of operations for calendar year 1996 with its filing, and the

Company's 1996 results have been audited by Price Waterhouse LLP. Between 1996 and 1999, evidence indicates that there will be downward pressure on earnings, due to bulk power capacity and energy returning from expiring contractual arrangements being resold at lower prices and projected energy costs being higher than the energy costs that were rolled into base rates on January 1, 1997. However, for simplicity, this downward earnings pressure will be ignored, and the 1996 results will be used as the starting point for analyzing 1999 results under the Company's and the OCA's proposals. The 1996 results and calculations that build upon those results are detailed in Exhibit JRS2.

As the generation portion of the electric utility industry becomes deregulated, accounting rules will require all deregulated generators to expense all generation-related regulatory assets and to accrue all above-market non-utility generator obligations by the end of the transition period, at a minimum. (These rules are documented in Statement of Financial Accounting Standards (SFAS) 5, *Accounting for Contingencies*; SFAS 71, *Accounting for the Effects of Certain Types of Regulation*; and SFAS 101, *Regulated Enterprises--Accounting for the Discontinuation of Application of FASB Statement No. 71*, as well as in minutes of the Financial Accounting Standards Board's (FASB) Emerging Issues Task Force meetings regarding Issue 97-4, *Deregulation of the*

Pricing of Electricity - Issues Related to the Application of FASB Statements No. 71, Accounting for the Effects of Certain Types of Regulation, and No. 101, Regulated Enterprises Accounting for the Discontinuation of Application of FASB Statement No. 71.) The rules will require the Company, during the period 1999-2005, to accelerate the amortization of regulatory assets and to accrue for above-market power purchases from non-utility generators by the amount of the amortizations and above-market payments that would have occurred after 2005. This will result in increased expenses of $935 million over the transition period. Partially offsetting the increased expense is the scheduled reduction of Susquehanna's depreciation by about $70 million annually as a result of switching from the modified sinking fund method to the straight-line method of depreciation. In other words, PP&L will recognize and expense all the stranded costs associated with regulatory assets and purchases from non-utility generators during the transition period to satisfy accounting rules, but would not recognize during the transition period any incremental expense to accelerate the recovery of the $3.6 billion of stranded costs associated with generation assets. This provides the <u>most positive scenario reasonably possible during the transition period.</u>

Q. Applying these assumptions, what are the financial results under the Company's proposal?

A. The recognition of this increased expense for regulatory assets and purchases from non-utility generators, coupled with a rate cap and the reduction in Susquehanna's depreciation expense, will result in an annual after-tax decline of about $20 million in earnings, as shown below. This reduction is representative of the impact throughout the transition period.

	Actual 12 months ended 12/31/96	Accelerated Amort. - Reg. Assets/NUGs & Deprec. Reduc.	1999 Pro forma
	Thousands of dollars		
Operating revenues	$2,563,242		$2,563,242
Operating expenses			
Operation & maintenance	1,362,047	$26,054	1,388,101
Annual depreciation	316,035	(70,180)	245,855
Taxes-other than income	189,960		189,960
Income taxes	218,772		218,772
Deferred income taxes/ITC	(793)	64,573	63,780
Total operating expenses	2,086,021	20,447	2,106,468
Income available for return	$477,221	($20,447)	$456,774
Rate of return-overall	9.42%		9.02%
Rate of return-debt	7.89%		7.89%
Rate of return-pref. equity	7.09%		7.09%
Rate of return-com. equity	11.42%		10.52%

The decline in return shown above is not surprising because the Company is unable to recover all of its stranded costs during the transition period, due to the rate cap. Further, this illustrates that under the Company's proposal, investors in the Company's common stock incur a portion of stranded costs immediately when customer choice begins.

Q. Applying the same assumptions, what are the financial results under the OCA's proposal?

A. The OCA, because it calculated stranded costs of only $0.4 billion, proposes a 32% rate reduction for PP&L, which would result in minimal CTC revenues. The impact of such a rate reduction, even using the most positive scenario reasonably possible, is devastating, as shown below. (For simplicity, the rate decrease is shown as applicable to all customers on January 1, 1999.)

Thousands of dollars

	1999 Pro forma	OCA-proposed 32% base rate reduction	OCA - 1999 Pro forma
Operating revenues	$2,563,242	($797,132)	$1,766,110
Operating expenses			
Operation & maintenance	1,388,101		1,388,101
Annual depreciation	245,855		245,855
Taxes-other than income	189,960	(35,074)	154,886
Income taxes	218,772	(300,253)	(81,481)
Deferred income taxes/ITC	63,780		63,780
Total operating expenses	2,106,468	(335,327)	1,771,141
Income available for return	$456,774	($461,805)	($5,031)
Rate of return-overall	9.02%		-0.10%
Rate of return-debt	7.89%		7.89%
Rate of return-pref. equity	7.09%		7.09%
Rate of return-com. equity	10.52%		-9.65%

Q. What do these results show?

A. Under the OCA's proposal, the Company's overall return and common equity return from PUC-jurisdictional operations would be negative, and would remain negative throughout the transition period. Moreover, on a total Company basis, the Company would experience severe and sustained operating losses, in 1999 and in every year of the transition period. In 1996, PP&L's operating income, from both PUC and FERC jurisdictions, was $556 million. Using 1996 data as a proxy for 1999, the OCA's proposed adjustments would cause operating income to fall by $482.2 million ($20.4 million + $461.8 million). Income available for debt and equity holders would equal about $74 million, which is far less than interest and preferred dividends ($242 million) and would yield a net loss of $168 million.

The Company does not believe that the OCA's proposal results in a fair sharing in the burden of stranded costs, nor does the Company believe that this result was intended by the Act. Should this scenario be permitted to occur, the Company will be unable to pay interest on outstanding debt and dividends on outstanding common and preferred stock. The inability to meet interest requirements and to pay dividends would create a default that could result in bankruptcy.

Moreover, it is important to note that investors in utility stocks have not benefited from the growth in stock prices over the last several years. In fact, PP&L's stock price currently stands at essentially the same level its was at 10 years ago. This performance is similar to the performance of other electric utility stocks. Investors in electric utility stocks have relied on dividends for their return on investment. The position of the OCA and PPLICA would result in a further deterioration of the Company's stock price at the same time as the dividend is jeopardized, sapping all financial strength from the Company.

I believe that the transition period was designed to enable utilities to have the opportunity to prepare for competition. Indeed, under the Company's proposal, much cost cutting and other mitigation efforts will be required in order for the Company to remain a viable player in the competitive marketplace. The Company recognizes this and is confident in its ability to succeed in the competitive marketplace, given an opportunity. However, the proposals made by the OCA and the PPLICA effectively eliminate any possibility of prosperity for PP&L, should they be adopted. Not only would the generation portion of the business fail, but the impact would be so great as to endanger the ability of the transmission and distribution portion of the business to maintain financial stability and it also could compromise the Company's ability to be the supplier of last resort, to obtain credit, to maintain adequate system reliability, and to do so in an acceptably safe manner.

Q. The scenario you described was "the most positive scenario reasonably possible during the transition period." Are there any other financial statement impacts that you would expect to occur if Mr. La Capra's recommendations were accepted?

A. Yes, the impacts of the minimal CTC revenue proposed by Mr. La Capra are somewhat predictable. The following table compares Mr. La Capra's and PP&L's estimates of stranded costs, in millions of dollars:

	Mr. La Capra	PP&L
Regulatory assets	$259	$384
Non-utility generation	551	657
Generation plant (incl. decommissioning)	(427)	3,570
	$383	$4,611

It is important to remember that the above numbers are an economic calculation and were prepared on a present value basis. To understand how the Commission's decision on stranded cost recovery will impact the Company's financial statements, it is necessary to compare proposed CTC revenues with known expenses during the transition period.

As of January 1, 1999, the Company will have approximately $867 million (not present valued) of generation-related regulatory assets and approximately $924 million (not present valued) of above-market non-utility generation purchased power obligations which must be amortized/accrued through the transition period. If the Company receives only the $383 million of CTC revenue proposed by Mr. La Capra and dedicates all of it to recovery of regulatory assets, the Company would underrecover approximately $484 million of regulatory assets on an accounting basis. Accordingly, accounting rules would require the Company to immediately write off the $484 million underrecovery of regulatory assets and the $924 million of above-market non-utility generation purchased power obligations.

Finally, Mr. La Capra calculates a net present value for the Company's Susquehanna nuclear plant of $826 million as of January 1, 1999. A comparison of this market value with the $2.8 billion book value on that date indicates that the Company would likely be required to record a substantial impairment write-off for Susquehanna. The sum of the three write-offs will exceed the Company's entire balance of retained earnings, which amounted to about $1.1 billion at the end of 1996. Again, this impact on shareowners reiterates that the OCA's proposal does not result in a reasonable sharing of stranded costs

<u>Pension Costs</u>

Q. Please describe the adjustment for pension costs proposed by Mr. Kollen, representing PPLICA.

A. Mr. Kollen contends that the Company has "excess" pension fund assets and that the Company failed to reflect these "excess" pension fund assets as a regulatory liability in its restructuring filing. Mr. Kollen then proposes to reduce the Company's claimed regulatory assets by what he determines to be the "excess" pension funding applicable to the generation part of the Company.

Q. Do you consider Mr. Kollen's adjustment appropriate?

A. No, I do not. The "excess" pension fund assets referred to by Mr. Kollen relate to the Company's funded noncontributory defined benefit pension plan (qualified retirement plan) covering substantially all employees. To fully understand this issue, it is necessary to determine how these "excess" pension fund assets came about and the best manner to reflect these "excess" pension fund assets within the stranded cost model.

The PUC has previously ruled that the appropriate basis for reflecting pension costs in rates is the Company's pension expense under SFAS 87, *Employers' Accounting for Pensions*, the standard for U.S. pension accounting. The SFAS 87 calculation of annual pension expense reflects a long-term view of pension accounting by levelizing unusual fluctuations in the value of pension assets over a long period of time. SFAS 87 requires the establishment of an assumed long-term rate of return on plan assets, and reduces annual pension expense by the product of plan assets times the assumed long-term rate of return. In any given year, the difference between the actual return on plan assets and the assumed return (unrecognized net gain) is deferred and amortized over the remaining expected service years of employees.

Over the past few years, the strong performance of the stock market has resulted in higher returns for the assets within the pension plan than the 8% assumed long-term rate of return. In accordance with SFAS 87, the Company has deferred this unrecognized net gain and is amortizing it annually, resulting in lower annual pension expense.

The value of future service benefits earned by all participants during the current year approximates $32 million per year for 1997. This amount is known as the Service Cost and is shown at the top of page SI-3 in the Actuarial Report for 1997. (See Attachment 1 to Question 2 of Interrogatories of the Office of Consumer Advocate, Set I, Dated April 14, 1997. Also, see Exhibit JRS3 attached to this testimony for a copy of page SI-3.) However, due primarily to the amortization of the unrecognized net gain, the amount included in expense and used to project future expenses is only $5.7 million for 1997. Accordingly, the excellent performance of pension assets over the past few years has dramatically reduced the projections of annual pension costs included in the stranded cost model. Any additional offset of the plan's funded status to reflect the "excess" plan assets as a regulatory liability is inappropriate, unless the full $32 million of the annual value of benefits earned is allowed as a basis for charges to ratepayers. Otherwise the funded status of the pension plan would be double counted.

Mr. Kollen states that the supposed overfunding "can be utilized by the Company to either offset future pension expense or to withdraw in some manner, albeit with certain limitations and penalties." (See direct testimony of Mr. Lane Kollen, pages 14 through 16). The fact is, the full amount of the plan's assets and obligations are already and appropriately being used to lower the amounts currently charged to ratepayers and to offset future pension expense, which lowers the Company's estimate of stranded costs.

Mr. Kollen's conclusion that past rate relief "will never inure to the benefit of the ratepayers" is simply not true. The plan's funding already is significantly reducing the cost of benefits on an annual basis to an accrual amount appropriate for rate relief; therefore, as a result of the rate cap, the benefits of the overfunding already are "locked in" for ratepayers.

Q. How much was included in this stranded cost filing for the qualified retirement plan costs?

A. As discussed in my direct testimony, the stranded cost filing was based on the 1997 budget, then escalated at 2.5% annually. The pension cost used for the 1997 budget included $5.7 million attributable to the qualified retirement plan

Q. What is your conclusion concerning Mr. Kollen's pension fund adjustment?

A. Mr. Kollen's pension fund adjustment amounts to trying to pay two bills with one check. Mr. Kollen would not change the pension expense reflected in the filing, the amount of which is reduced substantially by actuarial calculations that take into account, on an ongoing basis, the total value of current plan assets and projected earnings on those assets. He then, having taken advantage of the projected long-term value of those assets to reduce pension costs already reflected in the filing, recommends that the same assets be used over again to reduce regulatory assets.

Q. What is your suggestion as to an adjustment?

A. No adjustment is necessary. The Company agree with the PUC's decision to accept SFAS 87 as the basis for accounting for pension costs for regulatory purposes. SFAS 87 is structured to spread the cost of pensions fairly over time in a uniform and predictable pattern. The Company is following both the dictates of the FASB and the PUC. If Mr. Kollen's adjustment to regulatory assets is accepted, in order to avoid double counting, the stranded cost filing should be increased substantially to reflect the annual $32 million normal cost of the plan. However, if Mr. Kollen's adjustment is made, that effectively removes SFAS 87 as the basis for accounting for pension costs for regulatory purposes.

<u>Taxes Other Than Income</u>

Q. What witnesses proposed adjustments to Taxes Other Than Income?

A. Three witnesses proposed adjustments: Mr. La Capra, representing the OCA; Mr. Falkenberg, representing PPLICA; and Mr. Reed, representing the OTS.

Q. What adjustments do these witnesses propose?

A. Mr. La Capra, in his recalculation of stranded costs, holds Taxes Other Than Income constant over the life of nuclear and fossil generation facilities. (See direct testimony of Richard La Capra, page 16, lines 18 through 20.) Mr. Falkenberg criticizes PP&L's assumption regarding Taxes Other Than Income and observes the PECO "assumed such costs would remain constant." He then proposes to hold Taxes Other Than Income applicable to nuclear and fossil production facilities constant over the life of these facilities (direct testimony of Randell J. Falkenberg, page 51, lines 1 through 9).

Mr. Reed, on the other hand, held the capital stock component of Taxes Other Than Income constant over the life of each generation facility. For the Public Utility Realty Tax (PURTA), Mr. Reed proposes a declining PURTA tax relative to the decline in the net plant balance (direct testimony of Stephen M. Reed, pages 16 through 23).

Q. What was the Company's proposal in the restructuring filing?

A. The Company determined the actual amount of capital stock and PURTA taxes in 1996 applicable to fossil and nuclear generation facilities and escalated the 1996 taxes at the rate of inflation throughout the life of each generating facility (see Exhibit JRS1, pages 4-5).

Q. Do you agree with the adjustments made by either Mr. La Capra, Mr. Falkenberg or Mr. Reed?

A. No, I do not.

Q. Please explain.

A. Section 2810 of the Act specifies that tax revenues expected to be collected by the Commonwealth are to remain "neutral." The

Company interprets this section of the Act to mean that the Commonwealth would receive the same level of revenues, plus some increase for inflation, through application of the capital stock and PURTA tax in a restructured utility environment as it would receive in a continued regulated environment.

The question then becomes what taxes would the Commonwealth collect in a regulated environment. It was assumed by the Company that the cost of services provided by the Commonwealth would correspondingly increase with inflation similar to the Company's costs. It was further assumed that the various components of tax revenue collected by the Commonwealth would increase proportionally to fund the higher cost of goods and services.

There are a number of ways that the Commonwealth has used historically to increase various components of its taxing structure. One method is to increase the tax rate. Exhibit JRS4 shows the tax rate changes since 1984. Since 1984 the capital stock tax rate was increased from 10 mills to 12.75 mills. The PURTA tax rate has increased from 30 mills to 42 mills. Another method used by the Commonwealth is an additional assessment. Section 101-268 of Article XI-A applicable to the Public Utility Realty Tax specifies that a utility can be assessed an additional amount of PURTA tax to make up any shortfall. In 1994, 1995, and

1996, the Company was assessed an additional amount of PURTA tax.

Q. What is your conclusion relative to Taxes Other Than Income?

A. Although it is very difficult to predict future tax revenues, common sense would dictate that as the cost of services provided by the Commonwealth increase, tax revenues must keep pace. A reasonable assumption is that all tax components would increase proportionally. As the tax base decreases, the Commonwealth could, and most likely would, increase the tax rate. It is difficult to believe that the capital stock and PURTA taxes would remain at the 1996 level over the next 20 to 30 years, let alone decrease during this period

General Plant Allocation

Q. Please describe the adjustment for general plant allocation proposed by Mr. Falkenberg, representing PPLICA.

A. Mr. Falkenberg contends that it is inappropriate to allocate a portion of general plant to generation costs. He believes that general plant applies to such assets as PP&L's office buildings, and that there is no evidence that the office buildings are worth less than the amount on the Company's books. In addition, Mr. Falkenberg states that other competitors would be required to have office buildings and other types of overheads to enter the electricity markets, and that there is no reason to assume that PP&L would be at a competitive disadvantage with regards to this type of cost.

Q. Do you agree with Mr. Falkenberg's adjustment of the General Plant allocation in the Company's calculation of stranded costs?

A. No, I do not. General Plant includes the costs for such components as: Structures and Improvements, Office Furniture and Equipment, Transportation Equipment, Stores Equipment, Tools, Shop and Garage Equipment, Laboratory Equipment, Communication Equipment and Miscellaneous Equipment. These items are used in supporting generation operations but their costs are not specifically provided for or includable in the functional plant accounts in accordance with the Uniform System of Accounts as prescribed by the "Code of Federal Regulations". This concept is very similar to that used to allocate A&G costs to the generation function. The portion of general plant applicable to generation is 66.1% as derived from Exhibit JMK1. Mr. Falkenberg's assertion that "there is absolutely no evidence that PP&L's office building is worth less than the amount on the Company's books" simply is not relevant to the issue. The Act defines stranded costs as the difference between the utility's known and measurable net electric generation-related costs under regulation compared to revenues collected under the competitive environment. General plant is a generally accepted cost under regulation, and general plant associated with the generation function should be included in the stranded cost calculation.

Regulatory Assets - Rate Case Expense

Q. What are the positions taken by Mr. Catlin, representing the OCA, and Mr. Reed, representing the OTS?

A. Mr. Catlin states it is the PUC's practice to normalize rate case expenses over four years in determining revenue requirements rather than approve the deferral and amortization of those costs. Mr. Catlin asserts that the PUC approved the normalization of rate case expenses for PP&L at Docket No. R-00943271, but it did not authorize PP&L to defer and amortize rate case expenses; therefore, the Company's unamortized rate case expenses do not qualify as a regulatory asset. Mr. Reed also asserts that rate case expenses are normalized.

Q. Please summarize your reasoning for including the balance of unamortized rate case expenses as a regulatory asset.

A. Mr. Catlin correctly notes that the PUC, in its Final Order at Docket No. R-00943271, normalized rate case expense recovery over four years. For accounting purposes, SFAS 71 permits a regulated entity to match incurred costs with the associated revenues through the use of regulatory assets. The amounts recorded in the regulatory asset are to be charged, concurrently with the recovery of the amounts in rates, to the same account that would have been charged if included in income when incurred. Based on the PUC's ruling, PP&L properly established a regulatory asset in September 1995 for the 1994 Rate Case Expenses to be amortized over a four-year period. PP&L included in its calculation of stranded costs, in accordance with the Act, the present value of the post-1998 recovery of these deferred costs that are applicable to the generation function.

Postretirement Benefits Other Than Pensions

Q. Please describe the adjustment for postretirement benefits other than pensions proposed by Mr. Kollen.

A. Mr. Kollen believes that the PUC should recognize a regulatory liability for interest earned by external trust funds set up by PP&L to fund postretirement benefits other than pensions.

Q. Do you agree with the adjustment recommended by Mr. Kollen to the regulatory asset associated with postretirement benefits other than pensions?

A. No, I do not. The interest identified by Mr. Kollen is used already to reduce the projected cost of postretirement benefits other than pensions. Costs associated with postretirement benefits other than pensions, which consist primarily of medical and life insurance, are accounted for in accordance with SFAS 106, *Postretirement*

Benefits Other Than Pensions. A basic premise within SFAS 106 is that a liability associated with postretirements benefits, like a pension liability, is recorded at its **present value**. Most other generally accepted accounting principles require transactions to be recorded using nominal dollars. This difference can cause confusion.

Prior to SFAS 106, companies recognized the costs of postretirement benefits on a pay-as-you-go, or cash, basis when benefits costs were paid to retirees and did not recognize or disclose any future liability associated with postretirement benefits. SFAS 106 requires companies to accrue the cost of postretirement benefits as deferred compensation and disclose the nature of future obligations for postretirement benefits.

PP&L adopted SFAS 106 in January 1993. In December 1993, PP&L established external trust funds for postretirement benefits and, after making initial contributions, deferred additional funding of the trusts pending resolution of PP&L's ability to recover the costs of the plans in rates. As a result of the final order issued by the PUC on September 27, 1995, pertaining to PP&L's base rate case filed in December 1994 (PUC Decision), PP&L is currently collecting in rates the full SFAS 106 costs applicable to PUC-jurisdictional customers. Rates include about $11 million more than the current cash payment requirements for postretirement benefits claims, primarily to recover the transition obligation. The transition obligation represents the accrued liability for postretirement benefits that existed as of January 1, 1993, when SFAS 106 was adopted; it is being amortized over 20 years. The PUC required PP&L to place the additional amounts in external trust funds, and PP&L has set aside funds to contribute to the trust funds, but continued funding of these trusts is subject to the resolution of the OCA's appeal of the PUC Decision.

PP&L could have included the transition obligation within the regulatory asset category of its stranded cost calculation to highlight that it represents deferred expenses that are being collected through rates in accordance with PUC approval; instead, PP&L included ***all*** of its postretirement benefits expenses, calculated in accordance with SFAS 106, in its projections of O&M expenses as a component of wages and benefits. As such, the projected postretirement expenses include the present value of the current year's service costs, the amortization of the transition obligation, the interest cost necessary to "grow" the liability to represent the fact that the estimated future retirement benefits are now one year closer, ***less*** the interest earned on trust assets. To carve out the interest earned on trust assets as a regulatory liability, as suggested by Mr. Kollen, would simply result in higher projected O&M expenses. As a result, the estimated stranded costs for generation would increase by the same amount as the decline in net regulatory assets/liabilities.

Therefore, the return earned by trust funds for postretirement benefits has already been included in, and results in a decrease in, the Company's estimate of stranded costs.

<u>Administrative and General (A&G) Costs</u>

Q. Do you agree with Mr. La Capra's testimony that the Company incorrectly reallocated some of the Company's A&G costs to other plants in the future as plants retire, rather than reducing the A&G expense associated with the retiring plants.

A. No. The Company did reduce the A&G costs as major plants retired and were decommissioned. His testimony incorrectly states that the Company reallocated its A&G costs to other plants in the future as major plants retire rather than discontinuing the A&G expense associated with retiring plants. For example, the Company reduced $25,997,000 in 2013 to reflect the retirement and end of decommissioning of Martins Creek 3 & 4 and a $75,832,000 reduction in 2019 to reflect the retirement and end of decommissioning of Brunner Island, Martins Creek 1 & 2 and Montour. Because these plants are all retiring around the same time, 2019 was chosen as the average year of retirement and decommissioning for these plants.

Q. Describe how the Company has eliminated A&G expenses associated with the retirement of major plants.

A. The stranded value for fossil facilities is $718,219,000 as shown on Page 1 of 117 of Exhibit JRS1. This value is based on the Fossil Summary Sheet (Page 5 of 117 of Exhibit JRS1), which is derived on the Fossil Rollup Sheet (Page 20 of 117 of Exhibit JRS1).

On the Fossil Rollup Sheet, the O&M amounts shown are the sum of projected plant O&M and A&G costs. A&G costs are included in the electronic model of Exhibit JRS1 on the spreadsheet tab named "A&G". A&G amounts utilized in the calculations come from Line 19 of this spreadsheet. Line 19 is entitled "A&G Adjusted for Major Retirements". A copy of this spreadsheet is attached as Exhibit JRS5.

"A&G Adjusted for Major Retirements" is based on the original projections of A&G costs allocated to fossil and nuclear generation and adjusted to reflect reductions in A&G due to major plant retirements. A&G amounts are reduced for the fourth year after a plant's retirement instead of the actual retirement year to reflect A&G expenditures during plant decommissioning. A&G was not reduced for the retirements of minor plants (i.e. Sunbury, Holtwood) because administrative and general costs associated with generation generally would remain the same.

Major plant retirements and their respective dates recognized in the calculations include:

Plant	Retirement Year	End of Decommissioning
Martins Creek 3 & 4	2010	2013
Brunner Island	2014	2017
Martins Creek 1 & 2	2015	2018
Montour	2017	2020

By 2020, only $3,745,000 of A&G is being allocated to existing fossil generation. Mr. La Capra's contention is simply wrong.

Deferred Susquehanna Refueling Costs

Q. What are the recommendations made by Mr. Kollen, Mr. Reed, and Mr. Catlin related to the regulatory asset for deferred Susquehanna refueling costs?

A. Mr. Kollen states that the Company's request is premised on a change of accounting and that "the Company simply has assumed that it can defer the accounting recognition of those changes into the 'subsequent to 1999' period, although it had no accounting order from the Commission that authorized such a deferral." (See direct testimony of Lane Kollen, pages 36 and 37.) Mr. Reed and Mr. Catlin believe that deferred refueling costs are not regulatory assets, but are recoverable at a normalized level, similar to rate case expenses.

Q. Do you agree with Mr. Kollen's, Mr. Reed's, and Mr. Catlin's recommendations related to the regulatory asset of the deferred Susquehanna refueling outage costs?

A. No, I do not.

Q. Could you please describe the origination of the deferred Susquehanna refueling outage regulatory asset?

A. The Company did not make a claim for the first refueling outage of SSES Unit 1 in the Susquehanna Unit 1 rate filing with the PUC in 1983. PP&L did, however, request permission to defer refueling costs over and above the normal operating costs, and amortize this amount over the period of time from the date of restart after the outage through the date of restart after the next outage.

Because PP&L proposed to recover these costs in a period after they were incurred, it was necessary to accumulate and defer the actual costs of the first refueling outage on the Company books and amortize this amount over the period it was to be recovered in rates.

The Administrative Law Judge (ALJ) approved PP&L's request to defer these costs on the Company books and amortize them for book purposes. The Commission, at Docket No. R-822169, agreed with the ALJ and approved the Company's request to defer refueling outages on the Company's books of account.

The Company has been utilizing this deferral method for both SSES units since 1983.

Q. Could you also provide additional data for why the Company included deferred Susquehanna refueling outage costs as a stranded cost?

A. Yes. As I indicated, the Company did not make a claim for the first refueling outage of Unit 1, but instead chose to accumulate the costs and recover them over the subsequent fuel cycle; <u>therefore, the Company has always been one cycle behind in recovering outage costs.</u>

Both Susquehanna units have been on an 18-month fuel cycle since going into operation in the mid-1980's. Based on the long range refueling schedule, both units were refueled in the same year every third year. This necessitated that the Company approximate and include one and one-third normal outages in rates since Unit 2 came on line and was included in rates. The Company amortized deferred refueling outage costs over the 18-month fuel cycle.

Starting in 1997 with the eighth reload of Unit 2 (U2R8), the unit will begin operating on a 24-month refueling cycle. Because refueling costs associated with the last Unit 1 refueling cycle are still being expensed in 1997, the Company chose to continue its present refueling deferral methodology by deferring U2R8 refueling costs and amortizing them over the 24-month fuel cycle.

In 1998, the tenth reload of Unit 1 (U1R10) will put Unit 1 on a 24-month cycle. As previously noted in the response to Question 11a of Interrogatories of PPLICA, Set II, Dated April 30, 1997, 1999 will be the first year SSES will have both units on a 24-month refueling cycle. This change will allow the Company to schedule one outage per year rather than four outages over three years as previously done. Once completing this transition for both units, the Company immediately will begin expensing the costs associated with the inspections/outages at SSES.

Q. Is the Company's request to include as a regulatory asset the deferred Susquehanna refueling outage costs as a stranded cost premised upon a change in accounting?

A. No. The Company assumed an accounting change in 1999 from the deferral to immediate expense of refueling costs because, upon completing the transition to customer choice for generation in 1999, accounting rules will require utilities to eliminate the deferral of costs associated with the unregulated businesses.

Regardless of the fuel cycle length or the subsequent accounting of the deferred outage costs, the Company will still have unrecovered deferred refueling outage costs at January 1,

1999. Because the Company has always been one cycle behind in recovering outage costs, there will still be prior deferred refueling outage costs remaining after both units make the transition to the 24-month cycle. See Exhibit JRS6. Under the existing regulatory accounting methodologies, these unrecovered prior outage costs would have remained a regulatory asset until they could be included in rates. In other words, they represent costs that would have been recovered in an ongoing regulatory environment; therefore, they are appropriately classified as a regulatory asset. If the Company expensed current outage costs as well as continued to amortize the prior outage costs, the Company would experience double outage costs without the benefit of matching revenues. The filing reflects the expensing of these outage costs on a levelized basis, with the unamortized amount of outage costs at the time of customer choice being classified as "stranded costs".

<u>Employee Transition Costs</u>

Q. Please describe the adjustments for employee transition costs proposed by Mr. Kollen and Mr. Catlin.

A. Mr. Kollen asserts that the amounts included for employee transition costs are highly speculative, that PP&L failed to incorporate normal employee attrition into its computations, and that, if the regulatory asset is conceptually adopted by the PUC, it should be valued at the net present value of future cash outlays by the Company, which should include cash payments for postretirement benefits and pension contributions. Mr. Catlin states that the costs incurred for employee transition costs incurred in 1997 and 1998 should be excluded. In addition, he proposes excluding incremental pension benefits incurred, because, due to the overfunded position of the pension plan, he believes that the incremental pension benefits will not result in any additional out-of-pocket costs to the Company.

Q. Do you agree with Mr. Kollen's and Mr. Catlin's adjustments for the Company's employee transition cost claim?

A. No, I do not. The additional severance and incremental pension costs expected to be incurred is a result of the Company's projected decline in the number of employees as the Company prepares for a competitive market and is not considered an ongoing cost.

The cost savings associated with the projected employee reductions are reflected in A&G expenses related to the generation function which are included in operation and maintenance expenses. Instead of escalating these costs at 2.5% between 1997 and 2001 to reflect inflation, these A&G expenses are projected to decline as the Company re-engineers its processes in preparation for competition. (See electronic Exhibit JRS1, worksheet A&G)

Q. Why is it appropriate to include the portion of the Company's claimed regulatory asset related to the incremental pension benefits in the employee transition costs?

A. It is appropriate to include employee transition costs as a regulatory asset for the same reasons that I indicated regarding pension costs.

Q. Please explain how the Company incorporated normal employee attrition into its computations.

A. The projected rate of attrition provided by PP&L reflects a conservative estimate of the impact of normal turnover over the period from 1997 through 2001. The actual historical rate of attrition has been much lower than the 5% projected for this future period, averaging about 2.5%. Because of the large number of employees who have already left the Company under its restructuring initiatives, the rate of "normal" attrition over the next five years is expected to be even lower than the historical rate. Therefore, it could be asserted that all employees who leave the Company over the next five years will do so as a direct result of continued restructuring related to deregulation. However, PP&L chose to present a more conservative forecast and included the assumption that as many as 5% of the 381 projected employee reductions would be the result of "normal" attrition. This results in reducing the amount requested for employee transition costs.

<u>Depreciation Change</u>

Q. Please enumerate the reasons why Mr. La Capra, representing the OCA, Mr. Prisco, representing the Department of Defense and Mr. Schoengold, representing Environmentalists, have proposed adjustments to the transfer of depreciation reserves.

A. They have expounded three reasons for their rejection of this transfer. They are:

1) The transfer will cause cost shifting between rate classes at the retail jurisdictional level and cost shifting between different jurisdictions.

2) The transfer will lead to greater load growth, with concomitant environmental impacts.

3) The transfer is unfair because it will reduce shareholder exposure while increasing regulated transmission and distribution costs. It will result in regulated transmission and distribution customers paying again costs which they have already paid.

Q. Please address the first reason, that the transfer will result in cost shifting between classes and between jurisdictions.

A. Mr. Kleha discusses in his rebuttal testimony (Statement No. 3-R) why PP&L's functional unbundling of its revenue requirements does not result in cost shifting between classes. The Company does not agree with the assertion that the proposed transfer will result in cost shifting between jurisdictions. The Company believes that the proper way to account for this transfer of depreciation reserve is to create a regulatory asset applicable to the T&D functions which is equal to the allocated depreciation reserve that was transferred. That is, if the Nuclear Production function will be credited with $165 million, which represents the retail jurisdictional amount of the $205 million transfer, then the T&D functions will be debited with a regulatory asset of $165 million which will be amortized over the remaining lives of the T&D property.

Q. Please address the second assertion that the depreciation transfer will lead to greater load growth with concomitant environmental impacts.

A. It is the Company's opinion that this highly speculative assertion, even if true, will produce an insignificant differential in retail rates versus no depreciation transfer. It is difficult to believe that a modest depreciation transfer will affect usage patterns, even with differing price elasticities between customer classes.

Q. Please address the third assertion that this depreciation reserve transfer will reduce shareholder exposure and result in retail customers paying again for these costs.

A. It is the Company's belief that this type of mitigation effort is expressly addressed in and recommended by Section 2808 of the Act.

In addition, even after including the effect of this transfer, the Company's shareowners are still sharing a substantial portion of stranded costs. As previously detailed, under the Company's proposal, shareowners will be paying $600 million of stranded costs on a present value basis. Accordingly, the assertion that retail customers are paying twice for any costs is simply incorrect.

O&M Reductions

Q. Do you agree with Mr. La Capra's adjustment related to a productivity factor of 0.2% in the Company's O&M costs?

A. No, I do not. Instead of factoring a 0.2% reduction as suggested by Mr. La Capra, the Company has utilized an alternative methodology. As reflected in its stranded model, (see electronic model of Exhibit JRS1 on spreadsheet Tab named "A&G"), instead of increasing A&G costs, a component of O&M, by 2.5% per year based on 1997 levels for all years, the Company's budget for A&G costs has been reduced by an average 2% each year after 1997, through 2001. This methodology provides a net 4.5% reduction of A&G costs each of these first four years after 1997. After 2001, A&G costs are escalated by 2.5% annually. The early year reductions carry through for the remaining years of the model and provide a permanent cost reduction benefit to the customer. These reductions reflect the Company's estimate of the effects of competition as it relates to O&M.

Q. What is the effect of PP&L's methodology as compared to the OCA methodology?

A. PP&L's methodology provides more benefits to the customer than the methodology suggested by the OCA. Attached is Exhibit JRS7, which is a spreadsheet that compares the savings associated with PP&L's methodology to the OCA proposal for a sample of years for fossil generation. The Company believes that an additional 0.2% reduction in O&M expenses to reflect the effects of competition, as suggested by the OCA, would be double-counting the same benefit.

<u>Adjustments to Stranded Costs Calculation</u>

Q. Have you made any changes to the originally filed stranded cost calculation?

A. Yes. See Exhibit JRS8. In summary, I made three calculation adjustments to the stranded cost calculation that in total increases

PP&L's estimate of stranded costs from $4,611 million to $4,641 million.

First, the calculation of generation rate base was adjusted. In the original calculation, rate base was reduced by the transfer of depreciation reserves; however, the associated deferred taxes were not transferred. Because the deferred taxes that reduce rate base were overstated, rate base was understated and taxes recoverable were overstated. This adjustment increased stranded costs associated with generation by $39 million and decreased stranded costs associated with taxes recoverable in regulatory assets by $30 million.

In addition, the calculation did not include energy revenues and the O&M costs associated with Safe Harbor. The revenues associated with Safe Harbor's capacity inadvertently were included with Holtwood's revenues for hydroelectric capacity. The impact of including the remaining revenues from Safe Harbor (for energy) and all of its O&M costs increased the Company's stranded costs by $38 million.

Finally, the original calculation included the costs associated with the Department of Energy's (DOE) assessment on all utilities with nuclear power operations to provide funds for the decontamination and decommissioning of DOE's uranium enrichment facilities--as a component of fuel and as a regulatory asset. I eliminated the cost from the fuel calculation, and this had the impact of reducing stranded costs by $17 million.

Exhibit JRS 1A is an updated printout of the Company's stranded cost calculation, which was originally filed as Exhibit JRS1 in my direct testimony.

Q. Have these changes been reflected in your testimony?

A. No, they have not. The revised estimate is less than 1% different from the original estimate; therefore, I believe it is unnecessary and potentially confusing to restate and explain these changes in this rebuttal testimony.

Q. Does this conclude your rebuttal testimony?

A. Yes it does.

EXHIBIT JRS 2

Pennsylvania Power & Light Company
PUC Results of Operations
As of December 31, 1996 and Pro forma

Thousands of dollars

	Actual 12 months ended 12/31/96	Accelerated Amort. - Reg. Assets/NUGs & Deprec. Reduc.	1999 Pro forma	OCA-proposed 32% base rate reduction	OCA - 1999 Pro forma
Operating revenues	$2,563,242		$2,563,242	($797,132)	$1,766,110
Operating expenses					
Operation & maintenance	1,362,047	$26,054	1,388,101		1,388,101
Annual depreciation	316,035	(70,180)	245,855		245,855
Taxes-other than income	189,960		189,960	(35,074)	154,886
Income taxes	218,772		218,772	(300,253)	(81,481)
Deferred income taxes/ITC*	(793)	64,573	63,780		63,780
Total operating expenses	2,086,021	20,447	2,106,468	(335,327)	1,771,141
Income available for return	$477,221	($20,447)	$456,774	($461,805)	($5,031)
Rate of return-overall	9.42%		9.02%		-0.10%
Rate of return-debt	7.89%		7.89%		7.89%
Rate of return-preferred equity	7.09%		7.09%		7.09%
Rate of return-common equity	11.42%		10.52%		-9.65%
Rate base	$5,064,121				

*** Includes amortization of taxes recoverable and investment tax credits**

Exhibit JRS 2

EXHIBIT JRS 3

Pension Cost

	January 1, 1997	January 1, 1996
Pension Cost		
Service cost	$ 31,710,830	$ 31,583,584
Interest cost	62,868,211	59,414,176
Expected return on assets	(77,061,242)	(70,927,901)*
Net amortization	(11,828,354)	(7,778,934)*
Pension cost	$ 5,689,445	$ 12,290,925
Percent of pay	1.5%	3.4%
Per active participant	$ 857	$ 1,801

Change in Pension Cost	
Pension cost for fiscal 1996	$ 12,290,925
Change from fiscal 1996 to fiscal 1997:	
▸ Normal operation of plan	3,002,708
▸ Actuarial loss (gain) from liabilities	(3,923,847)
▸ Actuarial loss (gain) from assets	(6,601,419)
▸ Change in assumptions	921,078
▸ Change in plan	0
Pension cost for fiscal 1997	$ 5,689,445

* For disclosure in the Company's financial statements for 1996, the expected return on assets has been replaced with the actual return on assets for the year. The net amortization has been adjusted by a corresponding amount so that the pension cost remains the same.

EXHIBIT JRS 4

Pennsylvania Power & Light Company

Pa Corporate Tax Rates

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
CNI	0.1050	0.0950	0.0950	0 0850	0.0850	0.0850	0 0850	0.1225	0.1225	0.1225	0.1199	0.0999	0.0999
Capital Stock	0.0100	0.0100	0.0100	0.0090	0.0095	0.0095	0.0095	0.0130	0.01275	0.01275	0.01275	0.01275	0.01275
Gross Receipts	0.0450	0.0450	0.0450	0.0450	0.0440	0.0440	0.0440	0.0440	0.0440	0.0440	0.0440	0.0440	0.0440
PURTA	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300	0.0420	0.0420	0.0420	0.0420	0.0420	0.0420
Premiums	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300

Exhibit JRS 4

EXHIBIT JRS 5

STRANDED EVALUATION
A&G

	A	B	C	D	E	F	G	H	I	J
1	**Initial Projections**					2.50%	Escalation from 2002 on			
2		**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**
3	Service Groups	160.9	156.9	154.4	151.5	149.7	153.4	157.2	161.1	165.1
4										
5	Generation %'s									
6	Fossil	34.07	34.07	34.07	34.07	34.07	34.07	34.07	34.07	34.07
7	Nuclear	32.03	32.03	32.03	32.03	32.03	32.03	32.03	32.03	32.03
8	Total	66.10	66.10	66.10	66.10	66.10	66.10	66.10	66.10	66.10
9										
10	Total $ Allocation to Generation	106,355	103,711	102,058	100,142	98,952	101,397	103,909	106,487	109,131
11										
12	Portion Allocated to Fossil	54,819	53,456	52,604	51,616	51,003	52,263	53,558	54,887	56,250
13	Portion Allocated to Nuclear	51,536	50,255	49,454	48,526	47,949	49,134	50,351	51,600	52,881
14										
15										
16										
17	**A&G Adjusted For Major Retirements**									
18										
19	Fossil	54,819	53,456	52,604	51,616	51,003	52,263	53,558	54,887	56,250
20	Nuclear	51,536	50,255	49,454	48,526	47,949	49,134	50,351	51,600	52,881

Exhibit JRS 5

STRANDED EVALUATION
A&G

	A	K	L	M	N	O	P	Q	R	S
1	**Initial Projections**									
2		**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
3	Service Groups	169.2	173.4	177.7	182.1	186.7	191.4	196.2	201.1	206.1
4										
5	Generation %'s									
6	Fossil	34.07	34.07	34.07	34.07	34.07	34.07	34.07	34.07	34.07
7	Nuclear	32.03	32.03	32.03	32.03	32.03	32.03	32.03	32.03	32.03
8	Total	66.10	66.10	66.10	66.10	66.10	66.10	66.10	66.10	66.10
9										
10	Total $ Allocation to Generation	111,841	114,617	117,460	120,368	123,409	126,515	129,688	132,927	136,232
11										
12	Portion Allocated to Fossil	57,646	59,077	60,543	62,041	63,609	65,210	66,845	68,515	70,218
13	Portion Allocated to Nuclear	54,195	55,540	56,917	58,327	59,800	61,305	62,843	64,412	66,014
14										
15										
16										
17	**A&G Adjusted For Major Retirement**									
18										
19	Fossil	57,646	59,077	60,543	62,041	63,609	65,210	66,845	42,518	43,581
20	Nuclear	54,195	55,540	56,917	58,327	59,800	61,305	62,843	64,412	66,014

STRANDED EVALUATION
A&G

	A	T	U	V	W	X	Y	Z	AA	AB
1	**Initial Projections**									
2		**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
3	Service Groups	211.3	216.6	222	227.6	233.3	239.1	245.1	251.2	257.5
4										
5	Generation %'s									
6	Fossil	34.07	34.07	34.07	34.07	34.07	34.07	34.07	34.07	34.07
7	Nuclear	32.03	32.03	32.03	32.03	32.03	32.03	32.03	32.03	32.03
8	Total	66.10	66.10	66.10	66.10	66.10	66.10	66.10	66.10	66.10
9										
10	Total $ Allocation to Generation	139,669	143,173	146,742	150,444	154,211	158,045	162,011	166,043	170,208
11										
12	Portion Allocated to Fossil	71,990	73,796	75,635	77,544	79,485	81,461	83,506	85,584	87,731
13	Portion Allocated to Nuclear	67,679	69,377	71,107	72,900	74,726	76,584	78,505	62,170	41,240
14										
15										
16										
17	**A&G Adjusted For Major Retirement**									
18										
19	Fossil	44,671	45,788	46,932	48,106	3,653	3,745	3,838	3,934	4,033
20	Nuclear	67,679	69,377	71,107	72,900	74,726	76,584	78,505	62,170	41,240

STRANDED EVALUATION
A&G

	A	AC	AD	AE	AF	AG	AH	AI	AJ	AK
1	**Initial Projections**									
2		**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
3	Service Groups	263.9								
4										
5	Generation %'s									
6	Fossil	34.07								
7	Nuclear	32.03								
8	Total	66.10								
9										
10	Total $ Allocation to Generation	174,438								
11										
12	Portion Allocated to Fossil	69,911								
13	Portion Allocated to Nuclear	9,612								
14										
15										
16										
17	**A&G Adjusted For Major Retirement**									
18										
19	Fossil	4,133	4,237	4,343	4,451	4,563	4,677	4,794	4,913	5,036
20	Nuclear	9,612								

STRANDED EVALUATION
A&G

	A	AL	AM	AN	AO	AP	AQ	AR	AS	AT
1	**Initial Projections**									
2		2033	2034	2035	2036	2037	2038	2039	2040	2041
3	Service Groups									
4										
5	Generation %'s									
6	Fossil									
7	Nuclear									
8	Total									
9										
10	Total $ Allocation to Generation									
11										
12	Portion Allocated to Fossil									
13	Portion Allocated to Nuclear									
14										
15										
16										
17	**A&G Adjusted For Major Retirement**									
18										
19	Fossil	5,162	5,291	5,423	5,559	5,698	5,840	5,986	6,136	6,290
20	Nuclear									

STRANDED EVALUATION
A&G

	A	AU	AV	AW	AX	AY
1	**Initial Projections**					
2		**2042**	**2043**	**2044**	**2045**	
3	Service Groups					
4						
5	Generation %'s					
6	Fossil					
7	Nuclear					
8	Total					
9						
10	Total $ Allocation to Generation					
11						
12	Portion Allocated to Fossil					
13	Portion Allocated to Nuclear					
14						
15						
16						
17	**A&G Adjusted For Major Retirement**					
18						
19	Fossil	6,447	6,608	6,773	0	
20	Nuclear					

EXHIBIT JRS 6

Projected Refueling Outage Activity
1996-1998

	1996 (actual)	1997 (budget)	1998
Regulatory Asset-Beg of Yr			
U1 R8	9,268		
U2 R7	10,306	2,412	
U1 R9		11,738	2,410
U2 R8			7,166
U1 R10			
future outages			
	19,574	14,150	9,576
Outage Deferral			
U1 R9	(13,444)		
U2 R8		(13,300)	
U1 R10			(13,699)
future @ 3% escalation			
	(13,444)	(13,300)	(13,699)
Outage Amortization			
U1 R8	9,268		
U2 R7	7,894	2,412	
U1 R9	1,706	9,328	2,410
U2 R8		6,134	6,747
U1 R10			4,566
future			
	18,868	17,874	13,723
Regulatory Asset-End of Yr			
U2 R7	2,412	0	0
U1 R9	11,738	2,410	0
U2 R8		7,166	419
U1 R10			9,133
future outages			
	14,150	9,576	9,552

G:|exchange\Restruct Outproj.xls mdw 7/16/97

Exhibit JRS 6

EXHIBIT JRS 7

CB O&M.xls — Fossil O&M Reductions Due To Competition

	A	B	C	D	E	F	G	H
1	**Fossil**							
2		1997	1998	1999	2000	2001	2002	2003
3	Total Service Group A&G ($millions)	160.9	156.9	154.4	151.5	149.7	153.4	157.2
4								
5								
6		1997	1998	1999	2000	2001	2002	2003
7	Fossil O&M	170,175	175,094	174,026	178,292	180,689	180,290	176,894
8	A&G allocated to Fossil (34.07% of Line 3)	54,819	53,456	52,604	51,616	51,003	52,263	53,558
9								
10	Total Fossil O&M ($000)	224,994	228,550	226,630	229,908	231,692	232,553	230,452
11								
12								
13								
14	**If PP&L would have used 1997 A&G amount and escalated it at 2.5% after 1997**							
15		1997	1998	1999	2000	2001	2002	2003
16	Total Revised Service Group A&G	160.9	164.9	169.0	173.3	177.6	182.0	186.6
17	Revised A&G allocated to Fossil (34.07%)	54,819	56,189	57,594	59,034	60,510	62,022	63,573
18								
19		1997	1998	1999	2000	2001	2002	2003
20	Fossil O&M (same as above Line 7)	170,175	175,094	174,026	178,292	180,689	180,290	176,894
21	Revised A&G allocated to Fossil (Line 17)	54,819	56,189	57,594	59,034	60,510	62,022	63,573
22								
23	Total Revised Fossil O&M ($000)	224,994	231,283	231,620	237,326	241,199	242,312	240,467
24								
25								
26								
27	**Customer Savings associated with PP&L method**							
28		1997	1998	1999	2000	2001	2002	2003
29	Total Revised O&M (Line 23)	224,994	231,283	231,620	237,326	241,199	242,312	240,467
30	Total O&M As Filed (Line 10)	224,994	228,550	226,630	229,908	231,692	232,553	230,452
31	Customer Savings using PP&L "as-filed" method	0	2,733	4,990	7,418	9,507	9,759	10,015
32								
33								
34								
35	**Customer Savings associated w/ OCA 0.2% O&M reduction assuming Revised Fossil Total O&M Dollars**							
36		1997	1998	1999	2000	2001	2002	2003
37	Total Revised Fossil O&M ($000)	224,994	231,283	231,620	237,326	241,199	242,312	240,467
38	Reduction of 0.2% of O&M	224,994	228,508	228,840	234,478	238,304	239,405	237,581
39		0	2,775	2,779	2,848	2,894	2,908	2,886
40								
41								
42								
43	**Customer Savings associated w/ OCA 0.2% O&M reduction assuming As-Filed Fossil Total O&M Dollars**							
44		1997	1998	1999	2000	2001	2002	2003
45	Total Fossil O&M ($000)	224,994	228,550	226,630	229,908	231,692	232,553	230,452
46	Reduction of 0.2% of O&M	224,994	225,807	223,910	227,149	228,912	229,762	227,687
47		0	2,743	2,720	2,759	2,780	2,791	2,765
48								
49								
50								
51	**Net Savings to Customers Using PP&L's Methodology vs. OCA Methodology (Best Case)**							
52		1997	1998	1999	2000	2001	2002	2003
53	PP&L Methodology Savings (Line 31)	0	2,733	4,990	7,418	9,507	9,759	10,015
54	OCA Methodology Savings (Line 38)	0	2,775	2,779	2,848	2,894	2,908	2,886
55	Net Customer Benefit w/ PP&L Method	0	(42)	2,210	4,570	6,612	6,851	7,129

EXHIBIT JRS 8

STRANDED EVALUATION
PUC Summary

NPV (thousands of $)

	1/1/99	Adjustment to Exclude Deferred Taxes Associated With Depreciation Transfer	Adjustment to Include Safe Harbor Energy Revenues and Expenses	Adjustment to Exclude DOE Assessment from Fuel	Revised 1/1/99
NUCLEAR	(2,851,961)	(38,567)		17,487	(2,873,041)
FOSSIL	(718,219)		(38,283)		(756,502)
NUG's	(656,870)				(656,870)
REGULATORY ASSETS	(383,911)	29,585			(354,326)
NPV TOTAL	(4,610,961)	(8,982)	(38,283)	17,487	(4,640,739)

Exhibit JRS 8

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 9-R

Rebuttal Testimony of Susan F. Tierney, Ph.D.

I INTRODUCTION

Q: Please state your name and business address.

A: My name is Susan F. Tierney. My business address is One Mifflin Place, Cambridge, Massachusetts, 02138.

Q: By whom are you employed and in what capacity?

A: I am employed by The Economics Resource Group, Inc. I am a Principal in the firm.

Q: Have you provided testimony previously in this proceeding?

A: Yes. I provided written direct testimony on behalf of Pennsylvania Power & Light Company (PP&L or the Company) in the statement designated as "Pennsylvania Power & Light Statement No. 9." The primary focus of my direct testimony was to provide the economic and policy basis for the Company's proposed unbundling approach and its rate design.

Q: Please describe the purpose of your rebuttal testimony.

A: I will address several issues raised by other parties ("intervenors") regarding PP&L's proposed unbundling approach and its rate design.

Also, because of my past experience as a utility regulator and energy policy maker, and my familiarity with restructuring activities on a national level, I will also address some of the issues raised by intervenors regarding PP&L's universal service program, its customer education program, and its proposed methods to phase in customer choice. Specifically, I will rebut the direct testimony of Stephen M. Reed of the Office of Trial Staff (OTS); Richard La Capra, Lee Smith, Nancy Brockway and Barbara Alexander on behalf of the Office of Consumer Advocate (OCA); Paul D. Reising, Raymond W. Bowen, Jr., and Malcolm W. Jacobson on behalf of Enron Power Marketing Inc.; Stephen J. Baron on behalf of PP&L Industrial Customer Alliance (PPLICA); Robert D. Knecht on behalf of the Office of the Small Business Advocate (OSBA); David Schoengold on behalf of the Environmentalists; Mark N. Cooper on behalf of the American Association of Retired Persons (AARP); Donald E. Johnstone on behalf of the Mid-Atlantic Power Supply Association (MAPSA); David M. Boonin of New Energy Ventures (NEV); and Geoffrey Crandall on behalf of the Commission on Economic Opportunity (CEO).

Q: Please summarize the conclusions of your testimony.

A: My overall conclusions are as follows:

- **Unbundling of Rate Elements Consistent with the Act.** Although they are correct in pointing out that the Company should unbundle Delivery charges into Transmission and Distribution charges on customers' bills, the intervenors err in concluding that further unbundling of charges on the bill is required at this time in light of the objective of the Act in introducing competition into the supply and marketing of generation services.
- **Competitive Transition Charges: Appropriate Structure and Allocation.** The intervenors' proposals to modify the Company's method for developing the CTC as the residual in an unbundled rate are inappropriate and inconsistent with the Act. The Commission should retain the Company's proposal, because it is a competitively neutral approach to CTC collection during the Transition Period envisioned by the Act which is applied consistently across all customers within customer classes, regardless of who supplies them with their power. The intervenors' concerns about the Company enjoying a competitive advantage in the generation market are ill-founded and based on a misunderstanding of the Company's proposal.
- **Appropriate Rate Design in the Transition Period.** By taking an end-result-oriented approach to individual rate design issues, the

intervenors offer inappropriate proposals which disrupt the careful balance of rate design elements that PP&L put into its overall rate design package in order to meet the multiple rate design objectives of consistency with law, efficiency, fairness, rate and revenue sufficiency and predictability, simplicity, continuity, gradualism, understandability, public acceptability, and non-discriminatory treatment of customers regardless of who supplies them with service. The Commission should either (a) reject the intervenors' adjustments and accept the Company's rate design proposal as proposed, or (b) not allow the Customized Rate option at all.

- **Competitively Neutral Program Design.** In their attempts to make various programs (such as universal service, customer education, and the phase-in of choice) competitively neutral, the intervenors draw the wrong conclusions regarding modifications that are necessary to PP&L's proposed programs. The Company agrees with the intervenors' desire to make these programs competitively neutral, and makes appropriate suggestions for accomplishing this objective.

II UNBUNDLING OF THE RATE ELEMENTS IN A MANNER CONSISTENT WITH THE ACT

II.A Unbundling Delivery Charges

Q: Do you agree with several intervenors' comments that PP&L has not sufficiently unbundled its rate elements at this time?

A: I agree with some of their points and not others. First of all, MAPSA,[1] PPLICA[2] and Enron[3] are right in pointing out that the Company's Delivery charges should be further unbundled into two parts: Transmission and Distribution. This is an important change to enable retail customers to see proper price signals for taking power at different transmission voltages and under alternative supply arrangements. PP&L's witness Mr. William Whitehead also concurs with this position in his rebuttal testimony,[4] and PP&L's witness Mr. Joseph Kleha[5] provides the basis for separating Transmission and Distribution charges.

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1 Testimony of Mr. Donald Johnstone, p. 24, line 5.
2 Testimony of Mr. Stephen Baron, pp. 33 (line 3) through 34 (line 13).
3 Testimony of Mr. Paul Reising, p. 2, line 10 to p. 5, line 21.
4 Testimony of Mr. Whitehead, PP&L Statement No. 12-R.
5 Testimony of Mr. Kleha, Exhibit JFK 2.

II.B Unbundling Other Charges

Q: Is further unbundling of the bill appropriate at this time?

A: No. For several reasons, the Commission should approve PP&L's proposal to unbundle the following bill elements during the Transition Period: Transmission; Distribution; Competitive Transition Charges ("CTC"); and generation supply charges (whether for generation supply service provided by PP&L or by another supplier when billed on PP&L's bill, or to indicate to a consumer through a message on the bill that such supply is being provided and billed by another supplier where this is the case).

Several intervenors, including OCA[6] and OTS,[7] recommend that customer bills have a separate line item for universal service charges. In light of the extremely small per-customer size of the universal service charge, along with its non-bypassable nature as part of the responsibility of the electricity distribution company, it is appropriate for PP&L to include this charge as part of distribution service and to indicate its inclusion through a message on the bill, rather than as a separate item in this tariff.[8] This treatment is consistent with sections

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[6] Testimony of Ms. Nancy Brockway, p. 45, lines 6-7.

[7] Testimony of Mr. Stephen Reed, p. 7.

[8] *See the testimonies of Mr. Douglas Krall, PP&L Statement No. 10, p. 7, lines 1-3, and* Mr. Oliver Kasper, Statement No. 11, Exhibit OGK 2.

2802(17) and 2804(8) of the Electricity Generation Customer Choice and Competition Act (Act).

Given the Act's basic structure and purposes of introducing competition into the supply and marketing of electric power service, and in light of the testimonies of Professor Joseph Kalt and Mr. Bernard Bujnowski that it is not appropriate at the present time for the Commission to unbundle distribution services into the various unbundled billing, metering and other revenue cycle services recommended by Enron's and NEV's witnesses,[9] PP&L's proposal to unbundle specific charges on the customer bill includes the following elements: Transmission, Distribution, CTC, and Generation. This reflects a modification of the Company's original position that Transmission and Distribution charges would be combined in a single Delivery charge on customer bills.

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[9] See the testimonies of Prof. Kalt and Mr. Bujnowski, PP&L Statements No. 1-R and 15-R, respectively, rebutting the testimonies of Dr. Mayo, Mr. Dirmeier, and Mr. Shapiro of Enron, and Ms. Day from NEV.

III COMPETITIVE TRANSITION CHARGE: APPROPRIATE STRUCTURE AND ALLOCATION

III.A Methodology for Calculating and Allocating CTC

Q: What is your view regarding various intervenors' criticisms of PP&L's methodology for determining the CTC as part of customers' unbundled bills?

A: Several intervenors (i.e., OCA,[10] PPLICA,[11] and OSBA[12]) agree that PP&L's overall "bottoms up" method is the appropriate way to determine the CTC for each class. This method involves calculating CTC as the residual in a customer class' rate, after first subtracting transmission and distribution and market-priced generation from the total bundled rate.

Nonetheless, there are several witnesses who recommend that the Commission adopt an alternative method for determining the CTC

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[10] See Testimony of Ms. Lee Smith, pp. 2-4, where she states that "this approach is an appropriate method for unbundling rates. It will ensure that the unbundling is accomplished without shifting costs between the current class allocations, or between customers in the same class. This approach will force competition in generation, since the optional avoidable component of the rate is set as the market price of power" (p. 4, lines 10-14).

[11] See Testimony of Mr. Baron: "the appropriate basis for unbundling PP&L's rates is to utilize expected market rates for each year of the seven year Transition Period, while computing the CTC as the residual in the analysis. This is PP&L's proposed rate design methodology." (p. 8, lines 20-23).

[12] See Testimony of Mr. Knecht, p. 7: "I believe that the PP&L approach is reasonable. Because the CTC is determined as the residual, the method puts all classes on an equal basis with regard to the attractiveness of purchasing generation services from non-PP&L suppliers...[and] eliminates the need to develop a cost-allocation method for stranded costs, since they are the residual."

in rates. For example, AARP proposes that the Commission require PP&L to recover a larger share of CTC from non-residential customers.[13] The Environmentalists similarly argue that it is appropriate to "step back and determine an independent, reasonable basis for allocation" of the CTC.[14]

The Commission should reject these alternative methods as inappropriate and inconsistent with the unbundling instructions in the Act, which require that CTC be allocated to customer classes in a manner that does not cause inter-class or intra-class cost shifts and maintains consistency with the allocation methodology for utility production plant accepted by the Commission in the electric utility's most recent base rate proceeding (Section 2808(A) of the Act). As so many of the other intervenors recognize, PP&L's approach to determining the CTC is precisely consistent with the Act and should be adopted by the Commission in this restructuring case.

III.B Fixed Schedule of CTC Charges

Q: What is your view of the intervenors' position that the PUC should not fix a schedule for PP&L's CTC charges for each year of the Transition

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[13] Testimony of Mr. Cooper, pp. 28-29.
[14] Testimony of Mr. Schoengold, p. 26.

Period at the time rates are unbundled, but should rather allow CTC to vary in real time over the course of the Transition Period?

A: The Commission should reject the implication made by NEV that CTC should not be fixed in advance in a schedule of charges in the tariff for each year of the Transition Period, but should vary in real time from hour to hour in inverse relationship to the market-clearing price for energy, which varies from hour to hour across the year.[15]

There are sound public policy reasons for the Commission to set a schedule for PP&L's CTC charges at the time rates are unbundled, as described in the direct and rebuttal statements of Mr. Kleha and my own testimony. PPLICA agrees.[16]

Fixing in advance the CTC schedule for each customer class for each year is important for providing a platform for competition and choice in generation markets. A published schedule for CTC charges for an upcoming period will provide adequate information to consumers to enable them to make decisions regarding supply choices during the Transition Period.

The type of approach suggested by NEV, with a CTC that tracked inversely with market prices on an hourly basis, is

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[15] See Testimony of Mr. Boonin, p. 3 (lines 15-26), p. 4 (lines 4-10), p. 7 (lines 24-26), and p. 9 (lines 1-6).

[16] Testimony of Mr. Baron, p. 23 (lines 15-17), p. 28 (line 20), and p. 37 (lines 14-19).

inappropriate because it would prevent customers from ever having a fixed target in their rates to help them evaluate their supply options. Without a "bogie" of known, predictable and non-bypassable *Transmission, Distribution and CTC during the Transition Period*, customers would not be able to know whether they could beat the capped rate available under PP&L's last resort service (with a published generation price) by going to another supplier for generation service.

PP&L's proposed approach of calculating and charging a CTC on a fixed schedule provides benefits to consumers by enabling them to decide when and under what circumstances they want to buy another supplier's offering. Under the framework established in the Act during the Transition Period, all customers on similar rates would pay the same non-bypassable Transmission and Distribution and CTC charges, regardless of which company supplies them with power, and all customers on last resort service would enjoy capped rate on generation-related services, including CTC and market prices. The generation-related cap, along with the fixed CTC schedule, provide a benchmark against which the consumer can decide whether to buy from another supplier, or stick with or return to PP&L's last resort service.

Additionally, the fixed schedule does not increase PP&L's revenues, nor does it provide a competitive advantage to PP&L's Generation Supply group, as I will explain further below.

III.C Periodic Adjustment of CTC

Q: *The intervenors[17] also criticize PP&L's proposal for charging a fixed schedule of CTC in light of changes in prevailing market prices over time during the Transition Period. Do you agree with them?*

A: No. The intervenors' concerns reflect a basic misunderstanding of how the Company's proposal will work. Mr. Kleha has provided further explanation of the proposal in his rebuttal testimony.[18] There are several key elements of the Company's proposal, as illustrated graphically in Exhibit SFT 13, which shows the following facts about the Company's proposal:

- First, all customers pay the same CTC regardless of whether PP&L or some other supplier provides them with generation service.
- Customers who do not yet have choice under the phase-in period will be served by PP&L's Generation Supply group, as

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[17] See, for example, the Testimonies of Mr. Johnstone of MAPSA, p. 2, lines 11-14; and Mr. Schoengold, p. 8, lines 10-18.

[18] Testimony of Mr. Kleha, PP&L Statement No. 3, p. 17, line 1 through p. 19, line 4, and Statement No. 3-R.

they are today, and will pay capped rates that include all unbundled rate elements in the tariff.

- Customers with choice who choose to be supplied by another entity besides PP&L's "last resort service" will pay the CTC charge and the supplier's competitive supply price. Depending upon how the customer and the supplier structured the price terms of their transaction, prices might rise and fall with changes in prevailing market prices, or they might be fixed for some period under these contractual arrangements. In any event, these customers will pay the supplier's price for generation along with PP&L's CTC charge, with no generation rate cap protection. This situation would apply to all customers who have the opportunity to and do choose to be supplied by any other supplier (including PP&L's Retail Energy Supply Group – PP&L's PUC-licensed retail alternative supplier) other than PP&L's "last resort service" provided by the Electric Delivery group.[19]
- Customers who have the option to choose and take service from PP&L under "last resort service" are in an inherently

[19] "Last resort service" consists of customers "choosing not to choose" once they have the option to choose, or customers choosing to return to capped rates -- all of which are served by PP&L's Electric Delivery group.

different situation under the Act, although they too will pay the same CTC as they would if they were served by another supplier. For these customers, the generation-related rate cap is in effect. If prevailing market prices decline over time, these reductions will flow through to customers via a periodic (annual) downward adjustment to the generation supply component of their tariff. If, on the other hand, market prices increase, the *supply component of their bill will be adjusted upward. In this* latter instance, if there is room under the generation-related cap to accommodate the sum of this upwardly-adjusted supply rate and the CTC (as might occur if market prices initially dropped relative to PP&L's original estimate of market prices, and then subsequently went back up), then the customer's bill will indicate these charges and that's that. If there is no room under the generation-related cap, then these last resort customers' bill will still indicate the new prevailing market price along with the CTC, but would also show an additional line item adjustment to the bottom line of the bill, crediting the total bill for any difference between the generation-related rate cap versus the sum of prevailing market prices and the CTC. This credit mechanism would ensure that customers see the same CTC as other customers, see the prevailing market price for generation supply and pay no more than the rate cap allows.[20]

Q: Is the Company's proposal for the CTC consistent with the Act's goals of establishing a competitively neutral rate design for the non-bypassable portions of the tariff, for providing last-resort service consumers with rate cap protections, for ensuring a competitive generation market, and for ensuring that the electric distribution utility has a reasonable opportunity to collect stranded costs during the Transition Period?

A: Yes. The Company's proposed approach meets these goals in several ways, by:

- relying on a method for determining the CTC as the residual under each customer class' capped rate;
- charging the same CTC regardless of whether a customer buys supply from another supplier, from PP&L's Generation Supply group, or from PP&L's last resort service provided by the Electric Delivery group; and
- charging customers on last resort service both the CTC and the prevailing market price for generation, with a credit on the tariff

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[20] See Testimony of Mr. Kleha, PP&L Statement No. 3-R.

when the combination of the two exceeds the generation-related rate cap.

Consumers buying PP&L's last resort service thus have no upside market price risk (as a result of the rate cap), and they can take advantage of downside market price changes by either going to another supplier or staying with PP&L's last resort service -- which PP&L must provide to any and all customers who want it. Thus it meets the goals of a competitively neutral rate design for the non-bypassable CTC portion of the tariff and provides rate cap protections to customers on last-resort service.

This proposal also ensures a competitive generation market, in the following respects:

- PP&L and its supply competitors are in the same position in marketing competitive generation service to PP&L customers who have the opportunity to choose, since all of these customers will pay the same CTC charges regardless of who supplies them with their power supplies;
- PP&L's competitive generation service has no competitive advantage as a result of PP&L's collection of CTC, since customers pay the same CTC regardless of who supplies them with power, and both PP&L's and other suppliers' competitive

generation services have opportunity to compete for customers based on offerings with competitive terms and conditions.

- The PP&L Electric Delivery group is not a competitor to either PP&L's Retail Energy Supply group or any other market competitor, since the Company's provision of generation services to customers on last resort service must be provided at prevailing market rates -- as a pass through, without a mark-up. Essentially, the Electric Delivery group must obtain supplies from the market at prevailing market rates, and pass this cost through to consumers.[21]
- To the extent that the sum of prevailing market prices for generation and the CTC exceeds the generation-related rate cap, then PP&L must provide a bottom-line credit on the bill for customers on last resort service.

Further, the proposal provides PP&L with a reasonable opportunity to collect its stranded costs, because:

- The fixed schedule of CTC will be charged on a comparable basis to all customers throughout the Transition Period, unless greater-than-expected sales (relative to the level of electricity sales assumed at the time rates are unbundled) causes CTC

[21] This is described in the Testimony of Mr. Kleha, PP&L Statement No. 3-R.

revenues to recover all allowed stranded costs before the end of the Transition Period, in which case the CTC would be ended early.

- PP&L will collect CTC revenues faster or slower than expected at the time rates are unbundled, as a result of greater- or less-than-expected sales of electricity.

Q: Why do you say that last resort service consumers have no upside market price risk and get the benefit of downside price changes?

A: It's clear under the Act that this is the intended outcome of the customer choice/rate cap framework: Once the fixed schedule of CTC payments is established[22] at the time rates are unbundled, all customers in a similar customer class will pay CTC as scheduled, regardless of who they buy their power from. For customers on "last resort" service" – who enjoy rate cap protection, customers enjoy downside price benefits and upside price protection by virtue of the bottom-line adjustment to the tariff when CTC and market prices exceed the generation-related cap. In this way, the total rate for last

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[22] These payments are based on the Commission's determination of stranded costs and the amount of CTC that may be collected as the "residual" under the cap, once transmission and distribution and the expected market price for electricity have been subtracted from the capped rate.

resort service will decline when market prices fall below the original market price forecast, but it can never go above the rate cap even if market prices rise above the original price forecast.

Therefore, consumers get the benefit of a drop in prices relative to PP&L's market price forecast; if actual market prices rise relative to the original forecast, then consumers pay a price lower than the sum of CTC and market prices, so that the total of supply service and CTC never exceeds the cap on generation-related services. This approach advantages consumers, not PP&L. Furthermore, this approach is competitively neutral, since all of PP&L's retail customers in a similar rate class pay the same CTC, regardless of whether PP&L or some other company provides them with their supply service.[23]

III.D CTC Extension

Q: Do you agree with the intervenors that, in the event that decreased sales prevent PP&L from recovering the allowed amount of CTC revenues, PP&L should be required to go back to the PUC in 2005 to request an extension in order to collect CTC revenues beyond the Transition Period?

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[23] The proposed modifications to PP&L's CTC proposal render moot the testimony of NEV's witness Mr. Boonin, regarding his proposal to vary the CTC in real time to conform with continually varying changes in market prices (Testimony of Mr. Boonin, pp. 10-14).

A: No. Several intervenors, including OSBA,[24] PPLICA,[25] and OCA[26] have stated that they do not object to PP&L's position that it be allowed to extend CTC collection beyond the end of the Transition Period for the purposes of reconciling for changes in electricity sales, as long as CTC revenues are tracked, the rate cap is extended, and PP&L goes before the PUC near the end of the Transition Period to decide whether to allow an extension. OSBA, in particular, has suggested that it would be appropriate toward the end of the Transition Period to reopen the issue of whether stranded costs end up being higher or lower than originally projected.

Although I agree that it would be appropriate to extend the rate cap if the period for CTC collection is extended, I strongly disagree with these intervenors that the issue of transition cost recovery could or should be reopened towards the end of the Transition Period. The time to decide whether to allow an extension of CTC collection for the purpose of reconciling undercollection of CTC due to reduced sales is now, not towards the end of the Transition Period.

The issue of reconciling CTC collections against allowed CTC revenues should be a ministerial act, which does not require a new

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[24] Testimony of Mr. Knecht, p. 36, lines 14-20.
[25] Testimony of Mr. Baron, p. 6, lines 17-21.
[26] Testimony of Ms. Lee Smith, p. 17, lines 3-5.

proceeding in the future. Presuming the PUC approves a mechanism for tracking CTC collections over the Transition Period and reconciling them with the amount of CTC revenues approved at the time rates are unbundled, as proposed in the testimony of Mr. Kleha, and presuming that PP&L files data that are subject to a technical review by the PUC staff, there is no additional information that the PUC would need at a later date for the purpose of deciding whether an extension is appropriate. A new hearing towards the end of the Transition Period would create opportunities for parties to introduce information irrelevant to the question of whether the approved amount of CTC had been collected due to changes in electricity sales.

Furthermore, tying collection of approved CTC revenues to another administrative hearing several years from now creates additional risk to the Company and shareholders, and will raise its cost of capital.

The Act anticipates that the PUC settle the stranded cost and cost recovery issues now, at the beginning of the process. Hence, Mr. Knecht's recommendation of reopening the stranded cost issue toward the end of the Transition Period is not only inconsistent with the Act's provisions, but it would also be poor public policy to relitigate this issue once decided in a manner envisioned by the Act.

I recommend that the PUC decide this issue now, based on the record before it in the current proceeding.

III.E CTC Design

Q: Do you agree with the recommendation of the intervenors about how to structure the CTC component of PP&L's rates in the event that the PUC establishes a stranded cost amount that is below the maximum amount of CTC revenues that could be collected through a CTC under the rate cap?

A: No. I disagree with the recommendations of OCA[27] and OSBA[28] that in this circumstance, the PUC should require that CTC charges be levelized over the Transition Period. In this circumstance, PP&L should be allowed to set its schedule for CTC charges using the "residual" under the cap, with a termination of CTC whenever such stranded costs are fully collected. OSBA states that this other approach would also be reasonable: to end the CTC earlier, since it would eliminate the distortions caused by CTC earlier.[29]

The PUC should reject the other intervenors' arguments. The intervenors' recommended levelization of CTC below the cap is unfair

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[27] Testimony of Ms. L. Smith, pp. 9-14.
[28] Testimony of Mr. Knecht, p. 12, lines 1-3.
[29] Testimony of Mr. Knecht, p. 12, lines 10-12.

and inappropriate: First, there is less justification for an immediate rate decrease for PP&L's rates than for other companies in the Commonwealth, because PP&L's are below the statewide average and are just barely above the national average.[30] PP&L's rates have dropped by 25 percent in real terms over the past decade. Even if PP&L were allowed to collect CTC up its capped rates, these rates would represent a decrease of about 2.5 percent a year in real terms.

Secondly, if CTC were allowed to be collected as fully as possible under the cap, then distribution customers in PP&L's service territory would see a rate reduction when the CTC finished or at the end of the Transition Period, whichever came earlier, and in any event customers would enjoy rate cap protection and the benefits of decline in market prices during the Transition Period.

Third, if the PUC set stranded cost at a level lower than the Company's proposed amount, in a way that involved any of the "cost sharing" approaches recommended by intervenors (such as OCA[31] and PPLICA[32]), then PP&L shareholders would already be absorbing substantial costs -- on top of which the OCA wants to pass along

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30 See Testimony of Dr. Susan Tierney, PP&L Statement No. 9, pp. 16-19.

31 *Testimony of Mr. La Capra, p. 29, line 22, to p. 32, line 13.*

32 Testimony of Mr. Baron, p. 15-17.

further near-term rate reductions to consumers through a levelized CTC.

Additionally, a levelized CTC increases the risk to the Company of not recovering its allowed transition costs if market prices rise in later years such that the combination of the CTC and market prices exceeds the rate cap. PP&L's proposal, which allows the Company to use the room under the cap to collect CTC, reduces this risk.

Finally, because PP&L has proposed to not charge interest on the unamortized balance of CTC during the Transition Period, [33] it should be allowed to collect its authorized level of stranded costs as soon as possible consistent with the rate cap established in the Act.

Presuming the PUC adopts a stranded cost amount that exceeds the maximum amount that can be collected under the rate cap, then the intervenors' arguments are moot, since there would be no room under the cap for a near term rate reduction. In the event that the PUC approves a stranded cost amount lower than the maximum amount of CTC revenues that could be collected CTC charges under the rate cap, then the PUC should reject the intervenors' proposals for reducing CTC levels in the near term as

[33] See Testimony of Mr. Kleha, PP&L Statement No. 3.

unfair to PP&L's shareholders.[34] The Commission should allow PP&L to fully collect CTC as soon as possible by setting the CTC equivalent to the residual under the rate cap, and then by terminating the CTC as soon as stranded costs are collected.

IV APPROPRIATE RATE DESIGN IN THE TRANSITION PERIOD

IV.A Optional v. Mandatory Customized Rate Option

Q: Do you agree with the intervenors' views that all customers be allowed to have the option of taking service under Customized or Traditional Rates, instead of just giving residential customers this option, as PP&L has proposed?

A: No. I disagree with the testimony of PPLICA[35] and OSBA[36] that the Company should not require commercial and industrial customers to take service under the Customized Rate Option because, in their view, this rate unfairly affects customers with declining electricity use and acts as a "take or pay" situation with regard to CTC collection. I disagree also with their view that PP&L should give *all* customers the

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[34] See Testimony of Professor Alfred Kahn, PP&L Statement No. 18-R.
[35] Testimony of Mr. Baron, pp. 41-43.
[36] Testimony of Mr. Knecht, pp. 3-4.

option of electing to take service under either Traditional or Customized Rates. As I will describe further below, the intervenors are disingenuous in failing to recognize the full set of goals that are being served by PP&L's rate design package. They also fail to mention the adverse financial impacts on the Company's CTC collection that will occur as a result of the self-interested rate selection choices that will be made by rational commercial and industrial customers if the Customized Rate is made optional for everyone.

Q: Please explain your views about why OSBA and PPLICA have inappropriately focused on certain rate design goals to the exclusion of others.

A: OSBA suggests incorrectly that the only goal the Company had in mind when it was developing the Customized Rate Design was the goal of economic efficiency.[37] In fact, as I stated in my direct testimony,[38] PP&L was attempting to satisfying multiple goals when it designed its rate proposals -- one of which was economic efficiency, and others of which were rate and revenue sufficiency and predictability, fairness, simplicity, continuity, gradualism, convenience

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[37] Testimony of Mr. Knecht, p. 37.

[38] Testimony of Dr. Tierney, PP&L Statement No. 9, pp. 13-14 and 20-22.

of payment, economy in collection, understandability, public acceptability, feasibility of application, non-discriminatory treatment of customers regardless of who supplies them with service, and avoidance of abusive gaming. PP&L tried to balance all of these goals in designing its rates, and determined that while there were economic efficiency advantages of moving all customers to the mandatory Customized Rate design, the goals of simplicity, understandability and acceptability prevented this approach. Similarly, PP&L considered but rejected the idea of giving all customers the option of selecting from among the Customized versus Traditional Rate options, because of concerns that this approach would be an invitation to self-interested selection of rate options by commercial and industrial customers, with unacceptably adverse financial consequences for the Company. PP&L therefore chose a fair compromise, by giving residential customers the option and making Customized Rates mandatory for all other customers.

This is a balanced, appropriate approach.

Q: Please explain the trade-offs of requiring all customers to take service under Customized Rates, versus allowing all customers to choose between the two rate design options.

A: The Company took into account many considerations as it explored how to prepare a rate design package that would meet all of the Company's rate design goals. The Customized Rate is more efficient, which encouraged leaning towards adopting it for all customers -- but especially for customers who are price sensitive and who are used to buying services under complex pricing structure arrangements, as are commercial and industrial customers. The rate administration needed to be as simple as possible, thus supporting a conclusion that everyone should be on the same rate approach. The goals of fairness and non-discriminatory treatment pushed for all customers in a particular class to be treated similarly -- either by allowing all to have the option, or by requiring all customers to be placed on the Customized Rate. The goals of simplicity and continuity encouraged the Company to keep rates as simple as possible at a time when so much change was occurring, and to give residential customers the option of electing Customized Rates or Traditional Rates. The goal of revenue stability discouraged the Company from giving all customers the option to self-select among Customized and Traditional Rates that would lead to revenue uncertainty for the Company.

In weighing these trade-offs, the Company recognized that if all customers had the option to choose between Customized Rates or Traditional Rates, all else being equal, it would be rational for customers expecting to have growing usage to choose the Customized Rate option, and for customers expecting to have declining usage to choose the Traditional Rate. Giving all customers the flexibility to choose between Traditional and Customized Rates would add significant uncertainty and risk regarding CTC revenue collection; in fact, giving everyone the option to elect their rate design option increased to an unacceptable level the uncertainty about the Company's ability to collect the CTC revenues allowed by the Commission.

Indeed, the Company wanted to choose a rate design approach with symmetrical risk in terms of CTC collection: From the Company's point of view, the expected revenue collection for a given level of total sales is equivalent under an approach that required all to be on Traditional Rates or all to be service under Customized Rates. In terms of protecting the Company and its customers against better-than-expected or worse-than-expected sales levels, an approach that requires all customers to go on to Customized Rates would provide the appropriate symmetry in revenue collection risk -- a portion of CTC revenues would be less risky, when collected on a per-customer fixed charge, and a portion of CTC revenues would be tied to usage, with all customers (those with growing and reducing use) having half of their CTC collected in usage-based charges. But the Company recognized that there were other rate design goals that mitigated against this approach for residential customers. So the Company concluded at the time, and continues to believe now, that the approach that provides the best balance across all of these goals is the Company's proposal to require Customized Rates for all commercial and industrial customers, and to allow residential customers to choose between customized versus Traditional Rates.

Q: Please explain PP&L's concerns regarding the adverse financial implications that would occur from self-interested selection of rate options, if all customers were allowed to have the option to select from among a Customized versus a Traditional Rate option.

A: The prospect of this self-interested selection of rate options is unfair to the Company because of the adverse effect on predicting and collecting revenues. OSBA, for example, doesn't mention the likely effect of self-interested selection of rate options by commercial customers on the Company's overall CTC collections when it urges that GS-1 and GS-3 customers, like residential customers, have the option of choosing a rate that has a more efficient rate design.[39] Nor does OCA when it recommends allowing customers to move back and forth between Customized and Traditional Rate designs at will.[40]

The Company's position remains that the best rate design is its original proposal to offer residential the customers option of choosing between Customized and Traditional Rates, and to require commercial and industrial customers to take service under the Customized Rate design.

The PUC should reject the recommendation of the intervenors that all customers (both commercial and industrial, as well as residential) should have the option to choose Traditional or Customized Rates. This would yield insufficient revenues, as shown in Exhibit SFT-14, below, which shows that revenues are equivalent for the two cases where all customers take service either under Traditional Rates or under Customized Rates, but which also shows the adverse effect on Company collection of CTC revenues when all

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39 Testimony of Mr. Knecht, p. 38, lines 20-22.

40 Testimony of Ms. Alexander, p. 47.

customers have the choice.[41] This could happen not only where customers choose the least-cost option for themselves in light of their expectations to either increase or decrease use in the future; but also where individual customers jumped back and forth between the two rate design options across different months of the year, depending upon whether they expected their usage that month to be higher or lower than the average across all months of the year. The Company's tariff provision that requires customers who return to PP&L's last resort service to remain on the tariff for a year would guard against this kind of gaming. But this only solves one of the problems; it does not remedy the clear problem of CTC revenue erosion that arises from self-interested selection of rate options that would occur if all customers were given the option of choosing from among Customized or Traditional Rates.

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[41] Exhibit SFT-14 shows what happens to the Company's CTC collection when all customers have the option of Customized or Traditional Rates. For three GS-3 customers, all of whom start in the base year with the same amount of monthly usage (i.e., 9000 kWh/month and 18 kW of demand), the three customers have the same CTC under Customized and Traditional rates. If one of the customers stays at 9000 kWh and 18 kW, another customer reduces his usage by 3000 kWh and 6 kW, and the other customer increases her usage by 3000 kWh and 6 kW, then the total CTC collection for all three customers is equivalent where all three are all on Customized Rates or all three are on Traditional Rates (amounting to a total of $550.74 for all three customers). If, on the other hand, customers have the option to choose between Customized versus Traditional rates and customers are presumed to choose the rate option that minimizes their total bill, the total CTC collection for all three customers would go down to $520.74, for a $30 revenue gap for the Company.

Thus, if the PUC decides not to adopt the Company's proposal, then the PUC should make Traditional Rates mandatory for all customers, giving no one (including residential customers) the option to take service under Customized Rates, since the substantial revenue uncertainty associated with OSBA's and PPLICA's proposed alternative (giving everyone an option) would leave PP&L in the position of under-collecting total CTC revenues because customers will game the selection of Customized versus Traditional rates in order to bypass CTC collection -- without PP&L having the opportunity to make up for this type of undercollection.

IV.B Efficiency of Customized Rate Design

Q: Do you agree with the intervenors that there is no basis in the record for the Company's position that its proposed Customized Rate is more efficient?

A: No. I disagree with the conclusion of OCA[42] and PPLICA[43] that because there is no marginal cost study in the record, there is no basis for the PUC to determine whether the proposed Customized Rate design is more or less efficient that the Traditional Rate.

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[42] Testimony of Ms. Smith, p. 15, lines 9-17.
[43] Testimony of Mr. Baron, p. 41.

The intervenors offer no evidence that the Company's proposal is not efficient. Even without a marginal cost study, it is possible to conclude that the total non-bypassable usage charges (including Transmission, Distribution and CTC) exceed the Company's marginal costs. It is well known that most of the variable costs of energy use are attributable to the production function. Similarly, it is well known that embedded transmission and distribution costs are largely fixed costs which do not vary with energy use. Indeed, Mr. Kleha offers testimony to support this situation for PP&L's transmission and distribution costs.[44] Because these mainly fixed transmission and distribution costs exceed the amount of the revenues collected through fixed charges, there is also a residual amount of transmission and distribution costs collected through usage-based charges. The residual amounts of transmission and distribution and CTC are collected through usage charges in the Traditional Rate design for all customers.

Based on these circumstances, it is reasonable to conclude that the Customized Rate design is more efficient (i.e., closer to marginal-cost-based rates) than today's Traditional Rate design. OSBA agrees that "If I begin with the assumption that a CTC is

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44 Testimony of Mr. Kleha, Statement No. 3-R.

necessary, an optional CRD [Customized Rate design] is more economically efficient that a CTC that is based solely on energy/demand charges .... customers will see marginal energy/demand charges that are closer to marginal energy/demand costs, and will make more efficient decisions *about incremental demand*".[45]

IV.C Unbundling the Declining Block Rate Structure

Q: Do you agree with the intervenors' suggestion that each and every unbundled rate element retain the declining block structure that appears in today's bundled rate design?

A: No. Several intervenors, including OSBA and the Environmentalists, ignore the goal of rate simplicity when they inappropriately suggest that each and every unbundled rate element retain the declining block structure that appears in today's bundled rate design.[46]

The very act of unbundling rates adds a new level of complexity to customer bills that is unprecedented, at least in recent times, for customers of electric service in Pennsylvania. If each rate element (i.e., Distribution and Transmission and CTC) had a declining block --

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45 Testimony of Mr. Knecht, p. 38, lines 16-20.

46 Testimony of Mr. Knecht, p. 45, lines 14-15, p. 46, lines 13-14, and p. 47, line 16; and Testimony of Mr. Schoengold, p. 4, lines 9-13.

as opposed to the Company's proposal to keep the declining block only in the CTC portion of the rate -- the overall customer bill would be even more complex at a time when so much change is occurring.

PP&L appropriately concluded that the goal of simplicity tilted the decision towards keeping the declining block in its CTC charge, rather than in all charges.

Note that in PP&L's unbundling method, CTC is the residual after transmission and distribution and market prices for energy and capacity are subtracted from today's rates. PP&L has maintained this same concept for CTC as a residual by having CTC be the residual in each block of the rate.

IV.D Risk Shifting Issues in Rate Design

Q: Do you agree with the intervenors' conclusions that PP&L's Customized Rate option shifts risks to consumers?

A: No. I disagree with the conclusion of OCA[47] that the Company's rate shifts CTC responsibility to small customers; with OSBA[48] that mandatory Customized Rates shift CTC risks to low-use customers; and with AARP and the Environmentalists that low-income and

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47 Testimony of Ms. Smith, p. 15, lines 19-20.
48 Testimony of Mr. Knecht, p. 42, lines 8-14.

residential customers bear greater CTC risk.[49] PP&L's approach maintains the current cost allocation, so there is no shifting of risk among customers.

PP&L's approach explicitly tries to balance the risk of CTC collection. First, all residential customers can elect whether to keep the current Traditional Rate or switch to the Customized Rate. Secondly, in the Customized Rate, half of the CTC shifts to a per-customer fixed charge. This is consistent with the spirit and letter of the Act that states that CTC shall be collected through a non-bypassable charge. The ultimate non-bypassable type of rate element is a per-customer fixed charge collected from all retail distribution customers. This placement of CTC collection in a fixed charge is counterbalanced by the fact that the other half of CTC revenue collection and payment varies with a customer's use, and this approach reduces the dependence of CTC payment upon usage. Not only does the half of CTC payment that remains in energy charges vary with weather, but it can also vary as a result of other customer-specific factors that affect usage from a benchmark year. In the event of worse-than-normal weather conditions when customers' usage

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[49] Testimony of Mr. Cooper, pp. 18-19, and Testimony of Mr. Schoengold, pp. 3, 17-18 and 28.

tends to rise, they will be at less risk of increased CTC payment. The inverse is true in the event of better-than-normal weather.

The Company's approach appropriately balances variability of use and non-bypassability in CTC payment by ratepayers and CTC revenue collection by the Company

PP&L's approach is reasonable and appropriate for the Transition Period. Therefore, the PUC should approve the Company's proposal.

If, however, the PUC concludes that OSBA is right about shifting to consumers with declining use, then the PUC should reject PP&L's Customized Rate option proposal in its entirety, and require all customers in all classes to be charged on the basis of the Company's Traditional Rate Design.

IV.E Universal Service Charge Rate Design

Q: Do you agree with the intervenors' recommendation that universal service costs be collected on a cents/kilowatt-hour basis, rather than the cents/customer basis recommended by the Company?

A: No. Currently, these universal service program costs are collected on a cents/customer basis, consistent with the most recently approved rate allocations. In light of the Act's requirement that the Company's rate design adhere to the most recently approved cost of service and cost allocation study approved by the PUC, the Commission should reject the recommendations of OCA and AARP that it would be more equitable to charge a higher portion of the program costs for the universal service program to large customers by charging it on a cents/kWh basis. The Company's proposal to retain this same allocation method for universal service program cost recovery is consistent with the Act and should therefore be approved.

V COMPETITIVELY NEUTRAL PROGRAMS FOR UNIVERSAL SERVICE, CUSTOMER EDUCATION AND PHASE IN OF CUSTOMER CHOICE

V.A Universal Service

Q: Please comment on whether you agree with the conclusions the intervenors draw from their arguments that universal service is designed improperly.

A: No. Although the intervenors make a number of positive statements regarding PP&L's programs, they conclude that large changes are needed. I disagree.

As many intervenors, including OCA[50] and CEO,[51] have themselves pointed out in testimony, PP&L's program is *important to* the low-income community and incorporates most of the necessary elements of a successful universal service program. While it is necessary to make the existing program function in a non-discriminatory way in the new competitive generation market -- a point *made by Enron*[52] *with which the Company*[53] *and I agree -- it is not* necessary to make significant changes in the Program to accomplish this *important objective*. The Company's revised proposal is responsive to these issues, and is described in the rebuttal testimony of Mr. Timothy Dahl.[54] In my opinion, these proposed modifications improve an already well-designed program so that the program will work better in a competitive electric industry during the Transition Period.

As Mr. Dahl states in his Rebuttal Testimony, PP&L has proposed to retain the basic program design and increase the proposed funding level, through a non-bypassable universal service charge supported by all distribution customers of PP&L. These

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50 Testimony of Ms. Brockway, pp. 11-12
51 Testimony of Mr. Crandall, p. 1.
52 Testimony of Mr. Bowen, pp. 31-33.
53 See the Rebuttal Testimony of Mr. Timothy Dahl, PP&L Statement No. 16-R.
54 Testimony of Mr. Dahl, PP&L Statement No. 16-R.

program funds will support the program's financial assistance with respect to all rate elements for low-income customers on last-resort service, and the non-bypassable charges on the bills of low-income program participants who take generation service in the competitive market. The suppliers of competitive power to this latter set of customers will be required to provide comparable levels of financial assistance for the generation supply portion of the low-income participants' bills; the provision of such support will be required by the Commission as a condition of participation in the Pennsylvania retail electricity market. All suppliers of competitive power supplies, including PP&L, will provide the level of financial assistance deemed appropriate for individual low-income program participants by the program administrator.

In my opinion, PP&L has improved its Universal Service Program in ways that modify its current program design to make it work better in a competitive generation market. Eligible customers will have access to program assistance, regardless of who supplies them with their generation. Participating customers and PP&L will benefit from the features of the program's administration that allow participating customers to get the personal financial and repayment plan assistance that enables them to begin to pay their own way over time.[55] The program is expected to grow in terms of numbers of eligible customers served over time. As an ancillary benefit of the program modification that requires *all* suppliers to provide assistance with regard to the generation-related portion of participating customers' bills, more customers will be served by the Company's filed Universal Service Program Budget supported out of the non-bypassable charge. The program is fair in requiring all competitive suppliers to contribute to the program -- with non-bypassable charges on all customers' distribution bills, and with each supplier underwriting its customers' participation in the program as part of its cost of doing business in Pennsylvania.

PP&L's program is competitively neutral. It offers a flexible approach to determining the customer's copayment amount based on what's affordable to the customer. It relies on low-income community based organizations to deliver services to customers. It provides incentives for customers to maintain their copayment obligations. It is targeted to a growing number of eligible customers. It involves program evaluation with regard to the program's effectiveness and

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[55] The program administrators would still establish the appropriate subsidy level for each eligible customer, reflecting the delivery subsidies supported out of delivery charges and the supply subsidy provided by the supplier (including PP&L as supplier). Rebuttal Testimony of Mr. Dahl, PP&L Statement No. 16-R.

quality and the manner in which other suppliers besides PP&L's last resort service is providing service to these customers. These and other features are program elements that the OCA has stated are necessary to successfully promote the goal of universal service.[56]

For these reasons, the PUC should reject the intervenors' conclusions. The PUC should adopt the Company's proposed program and funding level.

Q: Do you agree with the intervenors' recommendation that the ISO collect universal service charges?

A: No. AARP's[57] recommendation that the ISO collect funds from all customers to support the universal service program should be rejected by the PUC for lack of jurisdiction and appropriateness. The universal service program arises out of the PUC's jurisdiction to set rates and the terms and conditions of retail service in the state. The PUC does not have authority over the ISO, which is under federal jurisdiction. Furthermore, the ISO covers other states besides Pennsylvania, so it would be inappropriate for the ISO to collect funds from all customers

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56 Testimony of Ms. Brockway, pp. 11-13.
57 Testimony of Mr. Cooper, pp. 26-28.

for Pennsylvania's program. The PUC should adopt the Company's funding and program proposal, as modified above.

V.B Customer Education

Q: Do you agree with the conclusions the intervenors draw from their position that customer education programs should be competitively neutral?

A: No. While I agree that *customer* education should be competitively neutral, I do not agree with Enron[58] that, because marketing and customer education should be separate and distinct from one another, all market participants (including the electric distribution company) must be prohibited from distributing customer education materials, and in particular ones that bear the Company's logo.

As a former regulator and policy maker, I agree that credible, sound customer education materials are needed at the start of this critical Transition Period. Clearly, the Commission will be playing a critical role in coordinating and providing statewide customer education. The PUC should make the most of this important opportunity to get critical messages out to various publics, with the input from various stakeholders to shape an informative set of

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[58] Testimony of Mr. Bowen, pp. 28-29.

messages and communication approaches. This is evident from the work that is already underway under the sponsorship of the Commission to develop a statewide program. Like the OCA,[59] I agree that this effort is critical, and is appropriately being done in a way that coordinates the statewide program with the customer education efforts of others.

In addition, individual market participants should supplement this statewide effort with their own customer education activities. The OCA concurs.[60] It is not only appropriate to allow and encourage the various market participants to play a role in informing consumers, but it is also not realistic to bar PP&L -- or others -- from distributing information to their existing and potential customers. There is some advantage of allowing many parties to communicate with the public, in part because no entity has a corner on knowing how best to educate the public about the changes underway. All market participants should play a role in informing the public.

Additionally, I understand that there are free speech restrictions on prohibiting a utility company -- or other institutions -- from communicating with their customers and the public. Even if the PUC

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[59] Testimony of Ms. Alexander, p. 3.
[60] Testimony of Ms. Alexander, p. 17.

were able successfully to prohibit PP&L from communicating customer education information to its customers, it would be hard to police communications from other suppliers, leaving PP&L at a disadvantage. Customers are used to dealing with their utility companies, and I think it would surprise them if they didn't hear from them in addition to others.

PP&L has offered to make the proposed text of its customer education materials available to the Commission for review, to help ensure that they are presenting customer education information in a competitively neutral way.[61]

The benefits of PP&L's participation outweigh the risks. The PUC should reject the intervenors' argument that PP&L be prohibited from providing consumer education information to its customers.

Q: Do you agree with Intervenors' criticisms of the Company's consumer education plan as being inadequate?

A: No. The OCA's criticisms[62] of PP&L's customer education programs are misplaced, in light of the timing of the restructuring process in the state. Given the fact that the Act was passed at the end of 1996, and

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[61] See Testimony of Ms. Lennon, Statement No. 17-R.
[62] Testimony of Ms. Alexander, p. 5, lines 6-18.

the Company's restructuring plan was filed just a few months later in April of 1997, with the planning underway to commence retail choice at the start of 1999, it is understandable, reasonable and appropriate that the Company's customer education plan and program is a work in progress.

OCA's criticisms of PP&L's customer education program are premature. As described in the Rebuttal Testimony of Ms. Dawn Lennon, PP&L has already *done* many of the activities that OCA states are important features of a quality customer education program. These include customer surveys, coordination with a statewide customer education program, use of multi-media communications techniques, time lines and interim goals, and a budget.[63] These have begun to take more concrete shape during the time between PP&L's filing of its direct testimony in April and today, and will continue to become more fleshed out in the upcoming months.

For example, at the time OCA was criticizing the Company for its failure to conduct a customer survey to gauge what customers know and want to know about electric industry restructuring and supply choice, the Company already had plans underway to conduct this survey; as Ms. Lennon describes in her rebuttal testimony, the first

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[63] Testimony of Ms. Alexander, pp. 4-9.

phase of this data collection and analysis has taken place, and the second phase is underway. The results have already influenced the Company's planning for its customer education efforts.

Similarly, PP&L has been actively involved in the PUC-sponsored efforts to develop a statewide program; it has plans to use a variety of multi-media communications techniques; it has developed time lines and interim goals, along with a budget. The Company plans to convene an advisory group in the next few months. PP&L plans to update its Customer Education Handbook to reflect not only the results of the customer surveys, but also information gathered through the Company's experience with the pilot program and other stakeholder meetings as well.

In light of these extensive activities, along with the recognition that the Company's customer education program is appropriately a work in progress in anticipation of educating the public in advance of customer choice, which begins a little less than a year and a half from now, the Commission should disregard the criticisms of OCA and AARP as moot.

V.C Phase-In of Customer Choice

Q: Do you agree with the intervenors' proposals for modifying the Company's proposed plan for phasing in customer choice over the 1/1/99 to 1/1/2001 time frame?

A: No. I think that Enron's[64] and PPLICA's[65] proposed changes to the Company's phase-in of choice are unworkable and confusing. According to their proposals, if a commercial or industrial customer class is oversubscribed in each period of the phase-in, then PP&L should allow all customers in those classes who are interested in selecting alternative suppliers to have a portion of their load served by another supplier.[66] Under Enron's proposal, "Enron would be willing to accept the "first through the meter" approach, where Enron would supply the first portion of the customer's electricity received in a given hour and the EDC would supply the remainder. Enron would therefore also be willing to "follow the customer's load" and provide a fixed percentage of its customers' load throughout the day."[67]

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[64] Testimony of Mr. Bowen, p. 19-20.

[65] Testimony of Mr. Baron, pp. 58-59.

[66] Their proposals are to have a portion of their load be served by another supplier, based upon the ratio of (a) the total amount of load in a customer class that is allowed to have choice, to (b) the total loads of all of the customer in that class who are interested in choosing a supplier during that particular period of the phase-in process. For example, if the requesting customers' load was 120% of the load amount allowed to proceed to competition, then each customer would be allowed to have 100%/120% (83%) of its load subject to choice of supplier.

[67] Testimony of Mr. Bowen, p. 20.

As a former regulator, I cannot imagine a phase-in proposal that would create more confusion among the public and more administrative difficulty for PP&L and the suppliers. This proposal presumes, without evidence, that all customer would rather be assigned to two suppliers than wait for choice. It complicates each customers' billing, balancing, and other service issues. Based on my experience in implementing and observing the implementation of policy proposals that test citizens' and consumers' patience, I believe that Enron's and PPLICA's proposal is incurably complex and convoluted from a practical point of view because it makes customers adapt to rules that appear counter to common sense and that are difficult to explain.

Based on my experience, this proposal risks making consumers feel unnecessarily and unacceptably inconvenienced in the end. Adoption of this approach would likely lead to the kind of unintended backlash that leads consumers to complain politically that they think that choice is not worth the problems it introduces.

I cannot imagine a more confusing and politically problematic approach. I urge the PUC to adopt a more simple system for dealing with the possible event of oversubscribed requests to participate in choice in the early phases of the program. The Company's proposal is one such approach.

VI CONCLUSION

Q: Does this conclude your testimony?

A: Yes.

EXHIBIT SFT 13

COMMON AND DIFFERENT RATE ELEMENTS FOR EACH CATEGORY OF PP&L CUSTOMERS DURING THE TRANSITION

Start of Choice

<table>
<tr><td colspan="3"></td><td colspan="4">NEW TARIFF</td></tr>
<tr><td></td><td colspan="2">........12/31/98</td><td>1-1-99</td><td>1-1-00</td><td>1-1-01</td><td>1-1-02........</td></tr>
<tr><td rowspan="2">1</td><td colspan="2" rowspan="2">Customers Who Do Not Yet Have the Opportunity to Choose</td><td>at least 67% of peak load of each customer class</td><td>at least 34% of peak load of each customer class</td><td colspan="2" rowspan="2">no customers (all have choice)</td></tr>
<tr><td colspan="2">They pay the following items in the tariff (under capped rates):
• transmission
• distribution
• CTC
• generation (generation supply provided by Generation Supply Group)</td></tr>
<tr><td rowspan="9">2</td><td colspan="2">Customers With Opportunity to Choose</td><td>no more than 33% of peak load of each customer class</td><td>no more than 66% of peak load of each customer class</td><td colspan="2">all customers</td></tr>
<tr><td rowspan="2"></td><td rowspan="2">A. Customers who choose a supplier offering competitive</td><td colspan="4">Customers pay the following items in the tariff:
• transmission
• distribution
• CTC</td></tr>
<tr><td colspan="4">Generation supply at competitive prices (supplied by customer's supplier of choice)</td></tr>
<tr><td rowspan="6"></td><td rowspan="6">B. Customers who stay with or return to PP&L EDC for "last resort service"</td><td colspan="4">Customers pay the following items in the tariff:
• transmission
• distribution
• CTC</td></tr>
<tr><td colspan="4">Generation supply at prevailing market prices (supplied through the PP&L's Electric Delivery Group):</td></tr>
<tr><td>Yr 1 = tariff</td><td>Yr 2 = revised market price, if appropriate</td><td>Yr 3 = revised market price, if appropriate</td><td>Yr 4 = revised market price, if appropriate</td></tr>
<tr><td colspan="4">Adjustment to Stay Under Rate Cap**</td></tr>
<tr><td>Yr 1= none</td><td>Yr 2 = **</td><td>Yr 3 = **</td><td>Yr 4 =**.........</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td colspan="7">** For each customer class: Adjustment to Stay Under Rate Cap = [(CTC + Prevailing Market Price) - (Gen-related Cap)], where adjustment occurs only when the amount is a positive number.</td></tr>
</table>

EXHIBIT SFT 14

Effect on Company Revenues of Allowing All Customers to Take Service Under Their Choice of Customized or Traditional Rates

	Monthly CTC Revenues ($) (based on Rate Schedule GS-3 Customized in Exhibit DAK 1)*								
monthly usage for each customer	All Customers Take Service Under Traditional Rates			All Customers Take Service Under Customized Rates			All Customers have the Option of Taking Service Under Customized or Traditional Rates		
	fixed	variable	***total***	fixed	variable	***total***	fixed	variable	***total***
flat usage at 9,000 kWh, 18 kW demand	0.00	183.58	***183.58***	91.79	91.79	***183.58***	0.00	183.58	***183.58***
decreased usage at 6,000 kWh, 12 kW demand	0.00	123.58	***123.58***	91.79	61.79	***153.58***	0.00	123.58	***123.58***
increased usage at 12,000 kWh, 24 kW demand	0.00	243.58	***243.58***	91.79	121.79	***213.58***	91.79	121.79	***213.58***
Total 3 customer usage at 27,000 kWh, 54 kW demand	0.00	550.74	***550.74***	275.37	275.37	***550.74***	91.79	428.95	***520.74***
Difference in the Company's revenues =								- ***$30.00***	

* The CTC schedule for the customized schedule is: Fixed, customized $91.79 per month; Demand, 2.51 $/kW; Energy, first 200 kWh = 1.295 c/kWh; next 200 kWh = 0.596 c/kWh; and additional kWh = 0.498 c/kWh. Example assumes that this customer's Customized Rate is based on 18 kW demand, 9,000 kWh energy.

The corresponding CTC schedule for Traditional is: No Fixed, Demand, 5.02 $/kW; Energy, first 200 kWh = 2.590 c/kWh; next 200 kWh = 1.192 c/kWh; and additional kWh = 0.996 c/kWh.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 10-R

Rebuttal Testimony of Douglas A. Krall

Q. Please state your name and business address.

A. My name is Douglas A. Krall. My business address is Two North Ninth Street, Allentown, PA, 18101.

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

A. I am employed by Pennsylvania Power & Light Company ("PP&L" or the "Company") as Manager-Resource Planning and Pricing.

Q. Have you provided testimony previously in this proceeding?

A. Yes, I have. I provided written direct testimony which was designated as Statement No. 10. I also provided Exhibit DAK1. The primary focus of my direct testimony was to describe the development of PP&L's proposed "Progressive Rate Design".

Q. Please describe the purpose of your rebuttal testimony.

A. The purpose of my rebuttal testimony is to address issues raised by other parties regarding the design and application of PP&L's proposed Customized Rate Design, the level of rate unbundling PP&L has proposed, environmental disclosure, continued regulation of transmission and distribution, and PP&L's proposals regarding its obligation as "supplier of last resort". Specifically, I will address issues raised by OCA witnesseses Lee Smith, Barbara Alexander, Nancy Brockway, and Richard La Capra, PPLICA witness Stephen Baron, Environmentalists witnesseses David Schoengold and Bruce Biewald, MAPSA witness Donald Johnstone and OSBA witness Robert Knecht.

Also, because the Resource Planning group which I supervise was responsible for a number of the underlying assumptions in the stranded cost analysis described in the direct testimony of Mr. Schadt (Statement No. 8) and the market clearing price analysis described in the direct testimony of Dr. Jones (Statement No. 7), I also will be addressing issues related to PP&L's continued need for capacity in a regulated environment, deactivation dates for existing generating units, and the performance of non-utility generators (NUGs). Specifically, I will be addressing issues raised by OCA witnesseses La Capra and Lee Smith, Environmentalists witness Schoengold, and PPLICA witnesseses Lane Kollen and Randall Falkenberg.

I would also like to correct a mathematical error that appeared in my direct testimony (Statement No. 10).

Q. Could you please describe that error?

A. Certainly. The forecast of market value of energy used to develop the proposed rates in Tariff No. 201 did not match the final forecast of the market value used to calculate the Company's stranded cost. As a consequence of the unbundling process, the CTC values tabulated for each year for the various rates were slightly in error. Also, the energy usage used to calculate the CTC revenues for the years 1999 to 2005 did not match the final forecast used to determine the forecast market value of energy and capacity. These two items affect, slightly, the total amount of stranded costs that the Company will recover under the rate cap. Reflecting the correction of these items along with a recalculation of the amount of stranded nuclear decommissioning costs that the Company will collect under its proposed CTC produces a stranded cost recovery of $4.001 billion. This compares to the total stranded cost recovery of $4.210 billion cited in the Statement of Reasons (page 10), Mr. Hill's direct testimony (Statement No. 2, page 18) and my direct testimony (Statement No. 10, page 10).

Q. Please summarize the conclusions of your testimony.

A. The following summarizes my conclusions for each of the areas I listed above:

- PP&L's proposal under which the rates of non-residential customers reflect a transfer of 50% of their use-based CTC obligation to a fixed charge ("Customized Rate Design") and the residential customers can elect either a Customized Rate or a rate which reflects traditional fixed and use-based components ("Traditional Rate Design") should be accepted by the Commission as proposed. Proposals by other parties that extend the option of a Traditional Rate Design to additional classes will introduce inappropriate and unacceptable risk to the recovery of stranded costs. Furthermore, such proposals do not provide appropriate economic development incentives consistent with the intent of the Electricity Generation Customer Choice and Competition Act ("Act").

- Proposals to adjust capped rates to reflect a reduction in the Susquehanna depreciation forecast to occur on January 1, 1999 fail to recognize that circumstances have changed since the Company's last retail base rate proceeding, are unfair, inappropriate, inconsistent with the Act, inconsistent with the assumptions underlying the Commission's Final Order at Docket No. R-00943271, and, accordingly, should be rejected.
- PP&L proposes to revise its proposed tariff to reflect actual charges to primary and subtransmission customers for Universal Service Programs rather than rounding these small amounts to zero.
- Proposals by others which are termed environmental disclosure of sources of generation, fuel mix, or environmental impacts fail to consider the complexity of the integrated electric system, the

role of the spot market, and the fact that these issues will lead to "data" which are not reliable, credible, or timely. These proposals go well beyond the disclosure requirements of the Commission's Interim Requirements for Customer Information issued on July 10, 1997 (Docket No. M-00960890F0008).

- Proposals to integrate generation supply and use options with transmission and distribution planning, while appropriate in a vertically integrated, cost-based environment, may be inconsistent and unworkable with the deregulation of generation. It would be premature to establish any such requirements in the context of this proceeding.
- PP&L's proposals regarding the discharge of its obligation as "supplier of last resort" under the Act are consistent with the requirements of the Act and are not anti-competitive in any way.
- The Act specifies that stranded generation costs are to be calculated as the difference between revenues that would be available under continued traditional regulation and revenues that would be available in a market environment. Under continued regulation, PP&L would be required to acquire additional generation resources to meet its obligation to serve its franchised customers. PP&L planned to meet this obligation through the return of portions of generation which had been sold for fixed periods of time in the wholesale market.

Accordingly, PP&L's stranded cost calculation reflects the return of that generation consistent with the Commission's finding in PP&L's most recent base rate proceeding that that generation represents cost effective generation from prudently constructed plant. Counter proposals suggesting that PP&L's jurisdictional allocators not be adjusted to reflect this returning generation should be rejected.

- The deactivation dates which PP&L has proposed for its generating plants are consistent with the dates accepted in PP&L's most recent base rate proceeding and are consistent with the depreciation schedules which are reflected in PP&L's rates at January 1, 1997. PP&L's projection of stranded costs includes investments necessary to continue operating its generating plants to those dates. The investments include investments to comply with existing and anticipated environmental requirements. PP&L's proposal is internally consistent and consistent with the requirements of the Act. PP&L's schedule of deactivation dates and investments should be accepted as proposed without modification.
- The values that PP&L has used for performance of NUGs in its calculation of stranded investment represent a reasonable forecast of future NUG production. Assertions that projected output levels should be reduced by 10-15% or more should be

rejected. There is no reason to believe that the recent operating levels of NUGs on PP&L's system, which are the basis for PP&L's estimate of future NUG operation, cannot be sustained, particularly in view of the strong incentive for a high level of electricity generation provided by power purchase agreements that base payment on kWh output.

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CUSTOMIZED RATE DESIGN

Q. Please briefly describe PP&L's proposed Progressive Rate Design.

A. PP&L's proposed Progressive Rate Design is described in detail in both the direct testimony of Dr. Tierney (Statement No. 9) and in my own direct testimony. PP&L's proposal begins with a basic unbundling of the individual fixed and usage-based blocks of existing rates. Delivery charges were isolated first in accordance with the Company's most recent base rate proceeding. Where the base rate proceeding did not establish a specific basis for rate design, the Company elected to use a flat cents/kWh charge for delivery across all use blocks. The selection of a flat delivery charge was driven by the desire to introduce simplicity. Next, the Company estimated the charge for market-based generation which would be included in each block for each class. The charge for market-based generation used in rate design reflects the same forecast of market generation prices which was used to estimate

PP&L's stranded costs. Finally, the Competitive Transition Charge ("CTC") was calculated as the residual between the rate cap established by the Act and the sum of the delivery charge and the generation charge. The result is an unbundling of existing rates and their structures into components with the assurance that there is no inter- or intra-class cost shifting. PP&L's proposal refers to rates unbundled in this manner as a "Traditional" unbundling and the option of a Traditional Rate Design is available to residential customers.

PP&L's proposal goes one additional step and develops a Customized Rate Design by reducing each use-based CTC step by 50% and substituting for those charges a fixed monthly charge reflective of 50% of each particular customer's CTC based upon that customer's historic use. Historic use is defined as calendar year 1996. Thus, if a customer's use is the same as it was in 1996, that customer will pay exactly the same amount, although 50% less will have been collected through use-based charges and the difference will have been collected through fixed charges. PP&L believes that its Customized Rate Design is an appropriate transition to the fully market-based rates that customers will see at the end of the transition period and that, by promoting economically efficient energy purchases, is consistent with the economic development objectives of the Act. Accordingly, PP&L would like to see all of its customers taking service under the Customized design. However, recognizing that residential customers may not be comfortable with redesigned rates, PP&L's proposal offers residential customers the option of Traditional or Customized rates while moving all commercial and industrial customers to the Customized design.

Q. What criticisms have other parties raised regarding PP&L's proposal?

A. Several witnesses representing different parties have criticized PP&L's proposal. However, each appears to arrive at a different conclusion depending upon their particular self-interest. PPLICA witness Stephen Baron characterizes the proposed shifting of a portion of CTC collection from a usage-based mechanism to a fixed mechanism as an inappropriate shifting of risk and a violation of the Act's prohibition against cost-shifting on a risk adjusted basis (Baron page 42 lines 1 -20). Mr. Baron's proposed remedy is to make the Customized design available to large customers on an optional basis (Baron page 43 lines 1-8). The rebuttal testimony of Dr. Tierney responds to Mr. Baron's assertions.

OCA witness Lee Smith argues that the Customized design is not economically efficient and that it shifts stranded cost responsibility from customers who increase their usage (Smith page 15 line 8 through page 16 line 14). Ms. Smith offers a tabulation of bills for customers whose use increases or decreases over time to demonstrate that the Customized and Traditional options produce different total bills. Ms. Smith offers this tabulation as evidence that "the proposed design shifts stranded cost responsibility from customers who increase their usage" (page 15 lines 19 and 20). Ms. Smith feels there is a situation which needs to be remedied, however her proposed remedy is completely different than that proposed by Mr. Baron. Whereas Mr. Baron proposes to extend the choice of a Traditional or Customized design to other classes, Ms. Smith proposes to eliminate the option for residential customers and require that all classes be charged using the Traditional design (Smith page 16 line 16 - 18).

OSBA witness Knecht, like Ms. Smith, criticizes the characterization of the Customized design as being efficient and contends that it is unfair to customers whose usage decreases (Knecht page 37 line 5 through page 39 line 9). Mr. Knecht also raises an issue that the proposed CTC's are unfairly allocated among classes. Mr. Knecht's proposed remedy is to make the Customized design available to Rate Schedule GS-1 and GS-3 customers on an optional basis (Knecht page 42 lines 15-17).

Environmentalists witness Schoengold also criticizes the Customized Rate Design on the grounds that it is an incentive for customers to "buy more electricity wastefully" and a "disincentive for energy efficiency" (page 27 line 19), and that it will lead to "increases in costs for low-usage and many low-income customers".

Q. How does PP&L respond to Ms. Smith's assertion that the Customized Rate Design shifts stranded cost responsibility to customers who increase their usage?

A. Ms. Smith's assertion that there is a shift in stranded cost responsibility is wrong. Regardless of which rate design a residential customer picks, that customer's contribution to stranded costs will go up or down as actual usage goes up or down. Furthermore, the schedule of CTC charges in PP&L's proposed tariff (Exhibit OGK 2) establishes what a customer's stranded cost contribution will be and that contribution will be unaffected by the choices made by other customers; thus there is no cost shifting.

Q. How does PP&L respond to Mr. Knecht's assertion that the proposed CTC's are unfairly allocated among classes?

A. Mr. Knecht's criticism ignores the limitations that the Act places on the unbundling process. PP&L's unbundling is consistent with the requirements of the Act in that it functionally unbundles rates in place as of January 1, 1997 without shifting costs among rate classes. To support his assertion, Mr. Knecht offers a table on page 41 of his testimony which tabulates "Average 1999 CTC Rates" on a cents per kWh basis for each major class. What Mr. Knecht appears to have done is take the total 1999 CTC revenues for each class supplied by PP&L in response to Question 39 of Interrogatories of the Office of Consumer Advocate, Set III, Dated April 17, 1997 and divide those amounts by the 1999 kWh consumption also supplied by PP&L in response to the same interrogatory. Mr. Knecht asserts that the differences in the amounts calculated in this way for different classes are indicative of unfair allocations; however, these differences are simply differences that exist in the January 1, 1997 bundled rates which are now made visible through unbundling.

Furthermore, Mr. Knecht's use of a cents/kWh comparison suggests that it is his belief that CTC collection in the commercial classes is too high on a cents/kWh basis. Although Mr. Knecht's calculation is stated in a cents/kWh figure, it is based on the total CTC collection (fixed and usage-based) and not just the usage-based collection. Ironically, counter to Mr. Knecht's apparent concern for high usage-based CTC collection, his proposed remedy to make the option of the Traditional design available to commercial customers would actually result in *higher* use-based CTC charges for those customers electing the Traditional Design.

Q. How does PP&L respond to Environmentalists witness Schoengold's assertions that the proposed rate design incents increased consumption and increases costs to low-usage customers?

A. Mr. Schoengold's assertions are wrong. With regard to the first criticism, this is simply not true. Customers will continue to have an incentive to conserve energy which is equal to the variable cost of that energy. With regard to shifting of costs to low-usage or low-income customers, the issues are the same as outlined above; i.e., the rate design does not shift costs, customers can retain a traditional rate design and, thereby, insure that they will have no different usage-related impact, and the schedule of CTC charges in the tariff assures what a customer's stranded contribution will be as a function of his actual use -- unaffected by the use patterns of others.

Q. Could you please summarize PP&L's position regarding its proposals for a Customized Rate Design?

A. The Company stands by its original proposal. As described by Dr. Tierney in both her direct and rebuttal testimony, the Customized rate option is a more economically-efficient structure than PP&L's existing rate structure. PP&L believes that, within the limitations that the Act sets on unbundling and cost shifting, this proposal represents an appropriate balance of competing interests. Paramount in the Company's thinking regarding the design of this proposal is that it should contribute to the transition from regulation to deregulation. When CTC collection has ended, customers will be paying for generation service at prices that reflect marginal costs. PP&L's Customized rate provides a transition for customers from the existing structure under regulation to the new structure of unregulated pricing. Customers benefit from this transition in terms of education (customers will actually see how their energy buying decisions may be different in the future) and in terms of the savings that they may be able to achieve on incremental energy purchases. The opportunity to achieve such savings serves as an incentive for customers to expand their operations and to bring economic development benefits to Pennsylvania consistent with the objectives outlined in Section 2802 of the Act.

In addition, the Company stands by its proposal that the Customized Option be the only rate design available to commercial and industrial customers in order to maximize the economic development potential of the Act. All business owners, large or small, should be well equipped to understand how the proposed structure is different from the existing structure and how those differences can be used to their advantage. Business owners, large or small, continuously must make profitability decisions in the course of running their businesses. In addition, these decisions must be made in light of and with an understanding of complex tax laws and regulations, licensing requirements, employment law issues, liability issues, and business accounting issues. It is because residential customers may not possess this level of sophistication that PP&L has proposed that those customers have the Customized rate available to them as an option, but that they may retain a Traditional rate design if that increases their level of comfort. Moreover, PP&L believes that the proposed Customized Rate Design is consistent to the Act's endorsement of flexible pricing and flexible rates (Section 2806(H)).

PP&L objects to any proposal to extend the option of retaining a Traditional design to other classes for two reasons. First, extending the option of a Traditional design to commercial and industrial customers will dilute the economic development potential of the Act. Second, as described by Dr. Tierney in her rebuttal testimony, offering the option to other classes will result in customers making selections which will put the Company's collection of Commission-approved CTC level at risk. The Company recognizes that its own proposal puts residential CTC collection at some risk. However, the interest of consumer education and protection for that particular group of customers alone warrant accepting that risk. The rebuttal testimony of Dr. Tierney includes an example of this risk as it relates to CTC collections from customers in the RS class. Exhibit DAK2 shows two typical industrial customers served on Rate Schedule LP-5 who may be changing their operations. One may be going from a 2-shift operation to a 1-shift operation; the other may be going from 2-shifts to 3-shifts. The ability of these customers to choose between the Customized Design and the Traditional Design would cost PP&L $6,475 (or 5%) in CTC recovery. Accordingly, if the Commission does not accept PP&L's proposal, the Company's alternative proposal would be to accept the OCA position wherein all rates are unbundled on a traditional basis only.

Q. On page 33 of his testimony, OCA witness La Capra discusses a Company proposal at the time of its last retail base rate proceeding to reduce customer rates on January 1, 1999 to reflect a reduction in Susquehanna SES depreciation charges that was projected to occur on that date. Mr. La Capra states, at lines 6 through 13 of his testimony, that if the Commission supports a higher stranded cost collection in 1999 than he has recommended, "it should at the same time reduce the Company's rates by the amount that reflects the reduction in depreciation expense and rates that was promised to customers." What is the Company's response to this proposal?

A. The Company reiterates the statement made in my direct testimony: the Company's filing uses the additional revenue available from this change in depreciation to offset increased capital and operating costs under the rate cap and does not propose to reduce rates below the rate cap to reflect this change. The Company's reason for adopting this position is the same as before; that is, the proposal was to reduce rates existing at January 1, 1999, not to reduce rates from a level capped as of January 1, 1997. Under a continuation of traditional rate regulation, PP&L would have been able to file for a base rate increase during 1997, 1998, or thereafter to recover increased costs of providing service, including general inflation and other factors. Because of the rate caps in the Act, this is no longer possible. Indeed, based on current inflation estimates, as a result of the rate cap, PP&L's rates, in real terms, will be lower at January 1, 1999 than they were at January 1, 1996 by more than twice the reduction contemplated as a result of the change in Susquehanna depreciation. PP&L continues to believe that to require a rate reduction to reduce the rate cap under these circumstances would be unfair, inappropriate, inconsistent with the

Act, and inconsistent with the assumptions underlying the Commission's Final Order at Docket No. R-00943271.

COMPONENTS OF UNBUNDLED RATES

Q. On pages 42 through 45 of her testimony, OCA witness Brockway discusses PP&L's proposal for recovering costs for Universal Service Programs. Do you concur with her criticisms?

A. PP&L does not agree with her criticism regarding the method of allocation. This issue is addressed in the rebuttal testimony of Dr. Tierney and Mr. Kleha. PP&L does, however, concur with her recommendation that, although the universal service program charges may be billed under the more general category of distribution charges, the tariff should spell out the charge as a separate item. Consistent with that recommendation, PP&L will revise its proposed tariff page Original Page No. 13B (Tariff No. 201 -- Exhibit OGK2) to reflect the actual charge for primary and subtransmission customers and not simply a rounding of this small charge to zero. Accordingly, the primary customers will see a charge in the amount of 0.001 cents/kWh and subtransmission customers will see a charge of 0.000009 cents/kWh.

ENVIRONMENTAL DISCLOSURE OF SOURCES OF GENERATION

Q. On page 29 line 15 through page 30 line 6 of her testimony, OCA witness Barbara Alexander asserts that the Company should *support disclosure of suppliers' fuel mix and show such information* on its bill. Could you please explain the Company's position regarding this matter?

A. Certainly. What Ms. Alexander and Environmentalists witness Bruce Biewald (page 9 line 1 through page 19 line 8) are proposing is a system of environmental reporting with the end result being *that customer bills would include a summary of environmental* impacts corresponding to the mix of generating sources used to serve each customer. As Mr. Alexander notes (at page 29 line 20), PP&L's concerns are rooted in the "integrated and instantaneous nature of the electric generation and delivery system." Specifically:

- Because individual generators cannot respond directly and instantaneously to individual loads, it is likely that all load servers (and even individual end-users buying directly from suppliers on their own behalf) will take a significant portion of their supply from the spot market. Although it may be possible to track the average fuel mix of the spot market, this information will probably not cause any change in buying habits because, *among other reasons, (1) load servers will access this market* as a default and not based on a planned decision, and (2) the spot market fuel mix will vary hourly and such variations will not be apparent in data that is aggregated monthly or quarterly.

- As a provider of generation to "last resort customers", distribution utilities are obligated to provide generation service at "prevailing market prices". To the extent that it is unclear exactly how this obligation will be met (a fact acknowledged by Ms. Alexander on page 45 lines 17 through 19), the Company is uncertain as to how specific plants and their fuel mixes can be segregated to the accounts of individual customers.

These issues make accurate and reliable reporting extremely difficult. Accordingly, PP&L believes that a more workable system which satisfies the needs of responsible disclosure is embodied in the Commission's Interim Requirements for Customer Information issued on July 10, 1997 (Docket No. M-00960890F0008). These interim requirements place the burden on suppliers claiming to provide environmentally-benign or beneficial energy to provide a plain-language description of the supply source so that consumers may judge for themselves at the time they are making a purchase decision. The interim requirements also put the burden on the suppliers making such claims to account for their energy supply in a way that matches its representations to customers.

REGULATION OF TRANSMISSION AND DISTRIBUTION

Q. On pages 31 through 33 of his testimony, Environmentalists witness David Schoengold proposes an approach to transmission and distribution planning. Do you concur with his recommendation?

A. No, I do not.

Q. Could you explain your concerns?

A. Yes. Mr. Schoengold proposes that distribution utilities undertake an integrated approach to planning which includes localized generation, demand-side management, and renewable resources as alternatives to transmission and distribution construction. Although the goal of "finding the least expensive solution to T&D problems" (page 31 lines 17 and 18) is laudable, the three alternatives listed are all matters of generation use. With the deregulation of generation, it is difficult to understand how these should be valued from the perspective of a distribution utility when it is performing a least-cost analysis and, also, how costs incurred will be collected by the distribution utility if any of those alternatives are implemented. Although there may be merit in Mr. Schoengold's proposal, PP&L believes that it would be premature to establish such a program in the context of this proceeding. Furthermore, the type of analysis proposed by Mr. Schoengold, because it addresses transmission issues as well as distribution issues, could not be carried out without the involvement of the Independent System Operator and the Federal Energy Regulatory Commission.

A similar concern arises with OCA witness Nancy Brockway's recommendation that PP&L undertake a renewables pilot within its universal service program (page 34 line 3 through page 38 line 2). As in the case of Mr. Schoengold's proposal, Mr. Brockway seems to be proposing the imposition of a program on the distribution utility which really relates to generation service. Again, PP&L believes it would be premature to establish such a program absent a broader assessment of how distribution utilities will be regulated.

<u>OBLIGATIONS AS "SUPPLIER OF LAST RESORT"</u>

Q. On pages 45 through 48 of her testimony, OCA witness Barbara Alexander discusses several issues regarding PP&L's proposal with regard to its obligation as provider of last resort. Do you concur with her comments?

A. I concur with her observation that the Act is not very specific in this area and that the Commission has not yet issued any policy guidance. PP&L looks forward to working with the Commission and other parties to further define the duties of distribution utilities in this regard. Ms. Alexander does point out several areas of concern which I feel have been adequately addressed in PP&L's unbundling proposal and in the Company's proposed code of conduct.

Q. Please identify those concerns to which you take exception.

A. Certainly. First, on page 46 lines 13 through 16, Ms. Alexander asserts that the pricing structure for customers who take "last-resort" generation service from PP&L, as a result of their chosen alternative supplier failing to supply, should be the same as that for customers who elect not to shop. Indeed, PP&L's pricing structure relative to those two types of customers will be the same. However, PP&L (or PJM on behalf of PP&L) will penalize alternative generation suppliers who fail to meet their scheduled obligation and it is possible that some of this penalty will be passed on to the alternative supplier's customers by the alternative supplier. If there were no penalty, there would likely be significant gaming and a burden which ultimately would be placed unfairly on non-shopping customers. Without penalties, customers will be incented to enter into purchases from alternative suppliers for the least expensive portion of their energy needs and to obtain that supply from the distribution utility during high-cost periods. That is, during high-cost periods, the customer will simply turn to the provider of last resort. If there is no penalty, then the round-the-clock customers will end up subsidizing these "leaners".

Q. Do you have other concerns regarding Ms. Alexander's testimony?

A Yes. On page 46 line 17 through page 47 line 2, Ms. Alexander comments that the disposition of customers who do not qualify for participation in a given phase of direct access causes her concern. Ms. Alexander appears to misinterpret an interrogatory response to *mean that customers who do not qualify for choice will become customers* of PP&L's Generation Supply Group. This is not PP&L's intent. As stated in the response referenced by Ms. Alexander, "A Delivery Group customer who does not qualify for participation in a given phase of direct access will continue to receive generation supply from the Generation Supply Group." The intent of this statement, and, specifically the use of the word "continue", is that all PP&L customers currently receive cost-based generation services from PP&L's generating plants and, those customers who are not selected for participation in a particular phase of direct access will continue to receive cost-based service from those plants. Customers who do have choice, but who do not elect an *alternative generation supplier, will have generation services* arranged for them by the Delivery Group at prevailing market prices.

Q. Are there other matters to which you take exception?

A. Yes, one final area is Ms. Alexander's assertion (page 47 line 10 through page 48 line 5) that returning customers (that is those who have selected an alternative supplier, but then return to Basic Utility Supply Service) should have access to any programs which they enjoyed prior to shopping, even if those programs are closed to new applicants. Although Ms. Alexander does not identify any specific programs, it is presumed that she is considering programs such as economic and industrial development incentives, interruptible service rates, time-of-day rates, demand-free day provisions, and price response service. As the Company has stated, these riders, provisions, and rate schedules are fundamentally related to generation supply. To the extent that the Act deregulates generation, PP&L, the distribution utility, should not and cannot be in the business of offering competitive generation services. PP&L's proposal to continue these programs for customers who currently are served under these programs and would continue to be served under them is based on the belief that to do otherwise could be a violation of the rate cap provisions of the Act. Because they represent generation services, the programs are only available if the customer continues to take Basic Utility Supply Service from PP&L. To allow customers to return to these programs after shopping gives these programs the standing of competitive options and wrongly keeps PP&L's distribution utility in the competitive generation business.

Q. Do other witnesses raise concerns regarding the "last resort" obligation?

A. Yes, and most of these are addressed by Dr. Tierney in her rebuttal testimony. However, I do want to address an observation made by MAPSA witness Donald Johnstone which is totally inaccurate and misleading. Mr. Johnstone concludes on page 16 lines 11 through 13 of this testimony that PP&L's unbundling procedures and forecast market price are such that PP&L will have a distinct price advantage and easily could result in most customers being served by PP&L as their default supplier. Dr. Tierney has addressed the flaws in Mr. Johnstone's testimony that bring him to this conclusion. However, Mr. Johnstone then goes on to observe (page 16 lines 13 and 14) that, "If PP&L is the default supplier, the stranded costs would be zero instead of the amount claimed; virtually no load would be lost." Clearly, there is no linkage in the Act between the amount of load served as a default supplier and stranded costs. Stranded costs are derived from a separate calculation which compares the revenues which would be collected under traditional ratemaking and those which would be collected in a market-based environment. The determination of stranded costs does not require a determination of how many customers a utility will continue to serve under its last resort obligation. Furthermore, because the obligation on the provider of last resort is to provide generation service at prevailing market prices and because the Competitive Transition Charge is a non-bypassable delivery charge, the Act creates a situation in which the last resort provider is indifferent to serving end-users or selling any resources available to him into the wholesale market.

<u>RETURN OF CAPACITY TO SERVE RETAIL CUSTOMERS</u>

Q. How do you respond to assertions by OCA witness La Capra, that capacity returning from expiring wholesale contracts should not be automatically included into PUC-jurisdictional rate base (used to establish allocators associated with the calculation of PUC-jurisdictional stranded costs) because it is not consistent with past practice of the Commission and it is speculative to assume that costs associated with this capacity would have been recovered under traditional regulation (La Capra, page 9, lines 17-22). Lee Smith, also testifying on behalf of the OCA, adopts La Capra's arguments at page 3, lines 6-9. Environmentalists witness Schoengold also observes that jurisdictional allocators should not change (page 17). Mr. Schoengold, without explanation, recommends the use of an 80% allocation.

A. Mr. La Capra has assumed a very narrow interpretation of the Act's language regarding costs "which traditionally would be recoverable under a regulated environment" -- one which focuses only on test-year ratemaking. In fact, under Commission regulations, electric utilities are required annually to demonstrate that they have sufficient generating resources to meet the needs of their franchise customers over a ten-year horizon. If a utility is unable to make this demonstration, it is required to undertake a competitive solicitation to obtain such resources -- either in the form of a new generating plant or a power purchase agreement. Also, a utility unable to demonstrate sufficient resources would be required to include a capacity value in its avoided cost rates which are available to Qualifying Facilities under PURPA.

PP&L's resource plans, filed each year with the Commission, have shown the capacity needs of franchised customers being met through the return of the capacity from these sales. Exhibits DAK2 and DAK3, which are attached to this testimony, demonstrate that if this capacity did not to return, PP&L would have to solicit for additional resources and would have to file avoided cost rates which include not just energy, but also capacity. In summary, to simply remove the effect of the returning capacity and associated energy from the allocation factors used to determine the PUC-jurisdictional portion of stranded costs fails to recognize that they, or some combination of new power plants, power purchases, or additional Qualifying Facilities would be there instead and would increase overall stranded cost levels.

Q. Could you please describe PP&L's need for capacity and plans to meet that need?

A. The Commission determined in Docket R - 00943271 that a capacity reserve of 22% represents a reasonable reserve margin for ratemaking purposes. In reaching this conclusion, the Commission acknowledged that, owing to the difficulty of forecasting needs precisely 10 years into the future and the fact that power plants are most economically constructed in certain sizes, there is a certain amount of "lumpiness" that must be acknowledged to exist and, therefore, "reasonable" reserves may actually occur in a range of 16% to 22%. Exhibit DAK2 is an analysis of PP&L's loads and capacity through the Winter of 2007-2008. The capacity plans in this exhibit assume no return of capacity and associated energy from the expiring wholesale contracts and no other actions to meet increasing loads. As can be seen, even if NUG capacity and interruptible loads are included as resources, reserve levels never reach even the low end of the range -- reserves would range from a high of only 13.8% in 1997 to a low of 0.8% in 2007. Clearly, some action would be required under traditional Commission practice to address this deficiency, regardless of whether the appropriate reserve margin is the 16% to

22% typical of a regulated environment or 18% as might be expected in a competitive environment.

Q. You specifically mention the inclusion of NUG purchases and interruptible loads in your analysis. Is there a rationale for excluding these from the calculation of available capacity?

A. Yes, there is. Because the NUG generation was added (under the mandate of federal law and the regulations of this Commission) after PP&L's last unit was completed, it is inappropriate to consider such capacity in an assessment of reasonable reserve levels for ratemaking purposes. Also, Act 94, which was passed in 1996, amended Section 527 of Title 66 of the Pennsylvania Statutes to encourage the buy-out, buy-down, and restructuring of above-market power purchase agreements; thereby, establishing that the continued availability of any particular NUG as a resource is uncertain. Furthermore, because interruptible load resources are not wholly under PP&L's control, their availability is subject to uncertainty that differs from the constraints of power plant availability. Although PJM procedures treat interruptible load as having firm capacity value, it is nevertheless appropriate to note the extent of reliance on such resources.

Q. What would be the effect of excluding NUG purchases and interruptible loads from your analysis of capacity reserves?

A. Clearly, if PP&L is deficient when NUG purchases and interruptible loads are included as capacity resources, the problem becomes even greater without them. As shown in Exhibit DAK2, reserves would range from a high of only 4.1% in 1997 to a low of negative 7.8% in 2007 if both NUG purchases and interruptible loads are removed from the analysis.

Q. Does the returning capacity address this deficiency?

A. Yes, it does. Exhibit DAK3 demonstrates that the capacity returning from expiring wholesale contracts would be needed to maintain adequate reserves for reliability. Although, even under the assumption that both NUG purchases and interruptible loads are included as PP&L capacity resources, the resulting reserve levels fall to the low end of the Commission's range toward the end of the ten-year period. If the reserves forecast from the period 97/98 through 07/08 are averaged, the resultant average reserve level is 22.2% -- almost exactly equal to the Commission's figure. Furthermore, without the NUG capacity, reserves in each year of the period 1997 through 2007 are below 22% (except for 2001 with reserves of 22.5%), and fall as low as 11.9% in 2007. If interruptible loads also are excluded as a resource, then projected reserves in the period 1997 through 2007 range from a high of only 17.8% to a low of 7.6%.

Based on the preceding analysis, PP&L believes it is just and reasonable to include the capacity and associated energy returning from expiring wholesale contracts in the calculation of the PUC-jurisdictional portion of PP&L's overall level of stranded costs. To exclude this capacity and associated energy from the calculation of PUC-jurisdictional allocation ratios would, in effect, be ignoring the historic importance of reserves in maintaining system reliability and the Commission's regulations which require that adequate reserves be maintained -- not just in the context of a test year, but in the future.

DEACTIVATION DATES FOR EXISTING POWER PLANTS

Q. Please summarize the basis for the deactivation dates proposed by PP&L in its stranded cost claim.

A. The deactivation dates which PP&L has proposed for its generating plants are the dates approved by the Commission in PP&L's most recent base rate proceeding at Docket No. R-00943271 and are consistent with the depreciation schedules which are reflected in PP&L's retail customer rates at January 1, 1997.

Q. Could these dates be characterized as representative of extended lives?

A. Life extension is a relative term and one must be clear whether one is talking about extending the original design life of a plant or extending the current life which, itself, already may reflect some amount of extension. For example, the oldest units at PP&L's Sunbury station date to 1949 and are, therefore, 48 years old. Considering the fact that planners and engineers in the 1940's probably made design decisions and equipment selections in anticipation that those units would last 30 to 40 years, it can be said that PP&L already has extended their lives. PP&L's projection of stranded costs includes investments necessary to continue operating its plants to the proposed retirement dates. In the case of Sunbury, the date is 2010 which equates to a life of 61 years and is representative of additional life extension. PP&L's stranded cost calculation includes investments necessary to achieve those dates, but not investments to extend the lines beyond those dates.

Q. Why does PP&L's filing not include additional life extensions?

A. The Act begins its definition of "Transition or Stranded Costs" as follows: "An electric utility's known and measurable net electric generation-related costs, determined on a net present value basis over the life of the asset or liability as part of its restructuring plan, which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market and which the Commission determines will remain following mitigation by the electric utility." (Section 2803). Clearly, there is uncertainty regarding what the retirement date of any generating plant will be and, therefore, the "life" to be used in performing the stranded calculation also reflects some uncertainty. Just as clearly, lives are not extended without cost, and investments will have to be made to replace worn-out components and to comply with new regulations in order to continue to operate any generating plant. Although Mr. La Capra characterizes PP&L's deactivation dates as conservative (page 16 line 26), it is PP&L's view that they are consistent with the requirements of the Act.

Q. How do you address the recommendations of Mr. La Capra (page 16 lines 22-24), PPLICA witness Kollen (page 31 line 8 through page 32 line 5), and PPLICA witness Falkenberg (page 51 lines 11-12) that the lives of Keystone and Conemaugh be extended?

A. The Keystone units were placed in service in 1967 and 1968. The deactivation date approved by the Commission in PP&L's last retail base rate proceeding Docket No. R-00943271 was 2007 -- the same date that PP&L has used in its stranded costs calculation and representative of 40 and 39 year lives for the two units. The

Conemaugh units were placed in service in 1971 and 1972. The deactivation date approved by the Commission in PP&L's last retail base rate proceeding was 2010 -- the same date that PP&L has used in its stranded costs calculation and representative of 39 and 38 year lives for the two units. Lives of 35 to 40 years are appropriate for 1970-vintage 800 MW-class once-through super-critical pressure generating units. This class of units "stretched the envelope" on certain mechanical designs and materials selections and have, in fact, seen certain stress-related problems occurring at 15 to 20 years of age which would normally not occur in lower temperature and pressure units until 30 to 40 years of age. The current lives assigned by PP&L, and approved by the Commission, reflect these issues and also are consistent with commitments made to comply with the requirements of the 1990 Clean Air Act Amendments. Any extension of these lives is speculation.

Q. How do you address the observation by these witnesses that PP&L's dates are not consistent with and shorter than the dates used by PECO for its share of these plants?

A. It has not been unusual for the various owners of Keystone and Conemaugh to reflect different deactivation dates in their rates. In fact, I have been involved with establishing deactivation dates for PP&L plants since 1977 and I cannot recollect an occasion when all owners used the same dates. All of these different dates have been reviewed and approved by the Commission.

Mr. Kollen asserts, at page 31 line 16 of his testimony, that these units are operated by PECO Energy and seems to conclude from this observation that the longer PECO dates are, therefore, correct. In fact, PECO is an owner like PP&L and not the operator -- the operator is GPU with oversight from the Keystone-Conemaugh Projects Office which reports to the Keystone and Conemaugh Owners Committee. Furthermore, no one owner can unilaterally cause investments to be made at these plants that would extend their lives. Investment decisions require the approval of 75% of the ownership shares. Finally, the PUC lacks jurisdiction over five of the owning companies whose combined ownership exceeds 25% and, therefore, would be unable to impose life extension requirements on those owners.

Q. Environmentalists Witness Schoengold asserts on page 36 lines 13-16 that PP&L's plans do not include any significant improvement of environmental performance of existing plants. Is this true?

A. No, it is not true. The capital expenditures for PP&L's fossil generation are shown in Tab H of Exhibit JRS1. As I stated above, the capital costs included are those that will be necessary to reach the Company's current by approved deactivation dates. Of the costs projected for the five years 1997 through 2001, 48% is for environmental compliance, including the 1990 Clean Air Act Amendments (CAAA). The capital costs after 2001 are based on individual projects identified as likely to be required at each station. A significant portion of these costs are to comply with provisions of the CAAA. These costs include Selective Catalytic Reduction and Selective Non-Catalytic Reduction systems for NOx reductions beyond those already achieved with the installation of Reasonably Available Control Technology in order to comply with the likely requirements of Title I of the CCAAA. Other costs include scrubbers to remove air toxics and fine particulates to comply with Title III of CAAA. For the years 2003, 2004, and 2005, 54% of the $429 million of capital identified, or $230 million, will be for compliance with the CAAA, alone.

Q. Mr. Schoengold asserts that PP&L's plants (and existing generating plants in general) can compete unfairly because builders of new plants must meet more stringent environmental requirements and the plans of utilities such as PP&L do not bring their plants "up to current environmental standards." How do you respond?

A. As I have discussed above, PP&L's plans include significant expenditures to bring its plants into compliance with current and anticipated environmental requirements. If Mr. Schoengold is referring to the fact that new plants must meet New Source Performance Standards which generally are more strict than the standards for existing plants, then I would disagree with his characterization of this situation as unfair, but simply as a fact of law.

Furthermore, it is not at all clear that existing plants enjoy any competitive advantage and, if they do, that it can be sustained. Since the passage of the Clean Air Act, environmental regulations have placed increasing burdens on existing plants and those burdens have accelerated with the passage of the CAAA. During its most recent base rate proceeding, PP&L requested that the Commission approve shorter lives for certain of its older, less efficient generating plants in large part because the Company believed (and continues to believe) that there is significant uncertainty as to whether it will be cost-effective to retrofit these plants to meet the new requirements. It is because of the likelihood that compliance standards for existing plants will continue to be raised and the likelihood, as discussed in the rebuttal testimony of Dr. Jones, *that replacement plants will operate with greater* efficiency, that PP&L believes that its proposed deactivation dates are the appropriate measure to use in this filing.

AVAILABILITY OF NON-UTILITY GENERATORS

Q. How do you respond to assertions of OCA witness La Capra, that the Company has based its future cost of purchases from non-utility generators on an unreasonably high forecast of future NUG production? (La Capra, page 10, lines 18 to 20.)

A. The future output levels of NUGs on PP&L's system reflected in this filing are based on the average of the last three years (1994-1996) of actual experience. Operation in this time frame reflects what PP&L believes is near "steady-state" performance levels. Because most of the NUG capacity began operation in the late 1980's or early 1990's, early problems of start-up have been resolved, and operation levels that recently have been realized will be the norm for well into the future. Because of the strong incentive for a high level of output which results from power purchase agreements that pay on the basis of kWh output, it is reasonable to expect that the NUG units will be well maintained, and that future production levels will equal or exceed those of the recent past.

Q. Mr. La Capra points out (page 11, lines 21 to 25) that PP&L's projected purchases from the Gilberton NUG were only achieved one year in the past, and uses this circumstance as at least partial justification for reducing the future performance of each NUG to an 80% annual average capacity factor (page 12, lines 3 to 5) -- a 15 percentage point reduction for Gilberton. Is this appropriate?

A. Information presented by Mr. La Capra does not provide the entire story relative to the Gilberton NUG, and certainly provides no basis for a general conclusion about overall production levels of other NUGs. Mr. La Capra notes that the 3-year average output for Gilberton was 659,688 MWH. He does not note, however, that production levels were 648,720 MWH in 1994, 651,456 MWH in 1995, and 678,886 MWH in 1996. These levels are all significantly above the level that would result with an 80% capacity factor level, i.e. 553,632 MWH. Furthermore, Mr. La Capra fails to note that even in the early years of Gilberton's operation, high production levels were achieved. For example, in 1991 output was 647,438 MWH; in 1992 output was 655,329 MWH, and in 1993 output was 614,376 MWH. Additionally, Mr. La Capra ignores those situations where output levels in the years before 1994 for a number of NUGs exceeded the 3-year averages used by PP&L (for example, Foster Wheeler, Wheelabrator Frackville, and Viking).

Q. Mr. La Capra notes that because of a FERC proceeding now underway involving Schulykill Energy Resources (SER), the price and/or volume of purchases the Company is required to make could be reduced (page 11, lines 27 and 28 and page 12, lines 1 and 2). Should this possibility be reflected in PP&L's claim for stranded?

A. No, it should not. First, the current FERC proceeding only addresses issues related to price, not volume. PP&L is continuing to pay SER a rate that reflects its status as a cogenerator, i.e., a rate that is higher than would be paid if this status is revoked. Second, PP&L has no way of knowing when or how FERC will resolve this matter. For these reasons, no adjustment is appropriate at this time.

Q. Are there other issues regarding non-utility generators raised by intervenors?

A. Yes. Mr. La Capra asserts that PP&L must pursue any reasonable avenue to reduce the costs of what are now high-cost NUG contracts (La Capra, page 25, lines 22 to 24) and set aggressive goals for cost reduction in this area.

Q. Do you agree that this is appropriate?

A. No. In the last year, PP&L has completed the buyout of approximately 25% of its NUG capacity. It will continue to pursue opportunities to buy-out, buy-down, or otherwise restructure existing NUG contracts. It is noted, however, that in those situations where the NUG's operating costs (excluding capital-related charges) are below PP&L's replacement energy costs, a buyout is unlikely. This is the case because the NUG's "margin" (revenue above variable cost) under the existing NUG contract will likely be more than the utility could pay for a buy-out (on an overall present-worth of contract life basis) because the practical limit on utility buy-out payments is the difference between its replacement energy cost and the costs under its contract. PP&L does not have access to NUG financial data, but recognizes that the operating cost of many of its NUG units may be relatively low because of the type of fuel burned. As noted above, in these cases, NUG contract restructuring can be difficult to achieve.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Exhibit DAK2

Monthly Usage	All Customers Take Service Under Traditional Rates			All Customers Take Service Under Customized Rates			All Customers have the Option of Taking Service Under Customized or Traditional		
	Fixed	Variable	Total	Fixed	Variable	Total	Fixed	Variable	Total
Base Case (2 Shift Operation)	0	67,540	67,540	33,770	33,770	67,540	33,770	33,770	67,540
2 customers (or 2 locations)									
5,000 KW each							67,540	67,540	135,080
2,000,000 KWH									
Increase Case (add 3rd Shift)	0	74,470	74,470	33,770	37,235	71,005	33,770	37,235	71,005
5,000 KW									
2,500,000 KWH									
Decrease Case (Reduce to 1 Shift)	0	57,600	57,600	33,770	28,800	62,570	0	57,600	57,600
5,000 KW									
1,500,000 KWH									128,605
									6,475

5% decline

Exhibit DAK3

PENNSYLVANIA POWER & LIGHT COMPANY

LOAD AND CAPACITY FORECAST 1997-2007

Winter Capacity & Loads

Without Any Firm Capacity Sales Returning

Winter Peak Load Period	Winter Peak Load	PP&L Owned or Leased Capacity	Capacity Additions and Reductions		Firm Capacity Sales to Other Utilities (MW)			Net Resources At Time Of Peak	Reserves At The Time Of the Peak		Interruptible Load Adjustment	Reserves At The Time Of the Peak		NUG	Reserves At The Time Of the Peak		Capacity Credit Sales to Other PJM Utilities (MW)		Reserves At The Time Of the Peak	
			Location	Inservice	AE	BG&E	JCP&L	w/o NUG, IL, & CC Sales				w/ IL			w/ IL & NUG		GPU	AE	w/ IL, NUG, & CC Sales	
	(MW)	(MW) (1)	(MW)	Date	(MW) (2)	(MW) (3)	(MW) (4)	(MW)	(MW)	(%)	(MW) (5)	(MW)	(%)	(MW)	(MW)	(%)	(MW)	(MW)	(MW)	(%)
97/98	6910	8396			-129	-132	-945	7190	280	4.1%	335	615	8.9%	338	953	13.8%	-250	-25	678	9.8%
98/99	6935	8396			-129	-132	-945	7190	255	3.7%	335	590	8.5%	350	940	13.6%	-475		465	6.7%
99/00	7030	8396	No Capacity Additions or Reductions		-129	-132	-945	7190	160	2.3%	335	495	7.0%	350	845	12.0%	-300		545	7.8%
00/01	7120	8396	scheduled.		-129	-132	-945	7190	70	1.0%	335	405	5.7%	350	755	10.6%	-300		455	6.4%
01/02	7130	8396			-129	-132	-945	7190	60	0.8%	335	395	5.5%	350	745	10.4%	-300		445	6.2%
02/03	7250	8396			-129	-132	-945	7190	-60	-0.8%	335	275	3.8%	350	625	8.6%	-300		325	4.5%
03/04	7350	8396			-129	-132	-945	7190	-160	-2.2%	335	175	2.4%	350	525	7.1%	-300		225	3.1%
04/05	7470	8396			-129	-132	-945	7190	-280	-3.7%	335	55	0.7%	338	393	5.3%			393	5.3%
05/06	7580	8396			-129	-132	-945	7190	-390	-5.1%	335	-55	-0.7%	338	283	3.7%			283	3.7%
06/07	7690	8396			-129	-132	-945	7190	-500	-6.5%	335	-165	-2.1%	338	173	2.2%			173	2.2%
07/08	7800	8396			-129	-132	-945	7190	-610	-7.8%	335	-275	-3.5%	338	63	0.8%			63	0.8%

Notes:

(1) Winter capacity of PP&L's wholly owned, and share of joint owned units as of December 1st of the Winter Period.

(2) Reflects agreements for Atlantic Electric Co. (AE) to purchase 125MW (Summer Capacity) of PP&L's wholly owned coal fired capacity and energy from 10/1/91 to 3/20/98.

(3) Reflects agreements for Baltimore Gas & Electric Co. (BG&E) to purchase 6.6% of PP&L's share of Susquehanna capacity and energy from 10/1/91 to 5/31/01.

(4) Reflects agreements for Jersey Central Power & Light Co. (JCP&L) to purchase 945 MW (Winter Capacity) of PP&L's average system capacity and energy.
This purchase is proportionately reduced beginning in 1/1/96 and terminated in 1/1/00.

(5) The value of PP&L's Interruptible Load is based on PP&L's estimate of the average availability of the interruptible load at the time of each of PP&L's 13 summer weekly peaks.
The value is currently estimated to be 290 MW. This value is converted into an equivalent capacity value based on the procedures outlined in the PJM Active Load Management Report.
The values shown above are PP&L's estimate of the capacity value of this interruptible load.

Exhibit DAK4

PENNSYLVANIA POWER & LIGHT COMPANY

LOAD AND CAPACITY FORECAST 1997-2007

Winter Capacity & Loads

With Firm Capacity Sales Returning

Winter Peak Load Period	Winter Peak Load	PP&L Owned or Leased Capacity	Capacity Additions and Reductions		Firm Capacity Sales to Other Utilities (MW)			Net Resources At Time Of Peak	Reserves At The Time Of the Peak		Interruptible Load Adjustment	Reserves At The Time Of the Peak		NUG	Reserves At The Time Of the Peak		Capacity Credit Sales to Other PJM Utilities (MW)		Reserves At The Time Of the Peak	
			Location	Inservice	AE	BG&E	JCP&L	w/o NUG, IL, & CC Sales				w/ IL			w/ IL & NUG		GPU	AE	w/ IL, NUG, & CC Sales	
	(MW)	(MW) (1)	(MW)	Date	(MW) (2)	(MW) (3)	(MW) (4)	(MW)	(MW)	(%)	(MW) (5)	(MW)	(%)	(MW)	(MW)	(%)	(MW)	(MW)	(MW)	(%)
97/98	6910	8396			-129	-132	-567	7568	658	9.5%	335	993	14.4%	338	1331	19.3%	-250	-25	1056	15.3%
98/99	6935	8396				-132	-378	7886	951	13.7%	335	1286	18.5%	350	1636	23.6%	-475		1161	16.7%
99/00	7030	8396	No Capacity Additions or Reductions			-132	-189	8075	1045	14.9%	335	1380	19.6%	350	1730	24.6%	-300		1430	20.3%
00/01	7120	8396	scheduled.			-132		8264	1144	16.1%	335	1479	20.8%	350	1829	25.7%	-300		1529	21.5%
01/02	7130	8396						8396	1266	17.8%	335	1601	22.5%	350	1951	27.4%	-300		1651	23.2%
02/03	7250	8396						8396	1146	15.8%	335	1481	20.4%	350	1831	25.3%	-300		1531	21.1%
03/04	7350	8396						8396	1046	14.2%	335	1381	18.8%	350	1731	23.6%	-300		1431	19.5%
04/05	7470	8396						8396	926	12.4%	335	1261	16.9%	338	1599	21.4%			1599	21.4%
05/06	7580	8396						8396	816	10.8%	335	1151	15.2%	338	1489	19.6%			1489	19.6%
06/07	7690	8396						8396	706	9.2%	335	1041	13.5%	338	1379	17.9%			1379	17.9%
07/08	7800	8396						8396	596	7.6%	335	931	11.9%	338	1269	16.3%			1269	16.3%

Notes:

(1) Winter capacity of PP&L's wholly owned, and share of joint owned units as of December 1st of the Winter Period.

(2) Reflects agreements for Atlantic Electric Co. (AE) to purchase 125MW (Summer Capacity) of PP&L's wholly owned coal fired capacity and energy from 10/1/91 to 3/20/98.

(3) Reflects agreements for Baltimore Gas & Electric Co. (BG&E) to purchase 6.6% of PP&L's share of Susquehanna capacity and energy from 10/1/91 to 5/31/01.

(4) Reflects agreements for Jersey Central Power & Light Co. (JCP&L) to purchase 945 MW (Winter Capacity) of PP&L's average system capacity and energy.
This purchase is proportionately reduced beginning in 1/1/96 and terminated in 1/1/00.

(5) The value of PP&L's Interruptible Load is based on PP&L's estimate of the average availability of the interruptible load at the time of each of PP&L's 13 summer weekly peaks.
The value is currently estimated to be 290 MW. This value is converted into an equivalent capacity value based on the procedures outlined in the PJM Active Load Management Report.
The values shown above are PP&L's estimate of the capacity value of this interruptible load.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 11-R

Rebuttal Testimony of Oliver G. Kasper

Q. Please state your full name and business address.

A. My name is Oliver G. Kasper. My business address is Two North Ninth Street, Allentown, Pennsylvania, 18101.

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

A. I am employed by Pennsyvlania Power & Light Company (PP&L or the Company) as Manager-Pricing and Contract Administration.

Q. Did you previously submit direct testimony on behalf of PP&L?

A. Yes. I submitted my direct testimony (Statement No. 11) on April 1, 1997.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the assertions of witnesses on behalf of various intervenors on the following topics:

1. Application of the Interruptible service rate provision of proposed Tariff 201.
2. Treatment of customers utilizing EDI/IDI, Demand Free Days, Time of Day, and Price Response Service proposed in Tariff 201.
3. General rate structure for small, general service customers.
4. Application of the Competitive Rate Rider to new and existing customers.

5. Application of Rate Schedule RTS to existing locations.

6. Utilization of standard tariffs throughout the State of Pennsylvania.

<u>Interruptible Rates</u>

Q. Several witnesses have commented on the treatment of interruptible service customers. Would you please comment on the nature of interruptible load?

A. Interruptible load is a capacity or generation-equivalent resource. It is an offer by the utility to purchase that resource at a price equal to the discount from the price for firm service provided under the applicable interruptible service rate schedule. In exchange for this discounted price, the customer agrees to interrupt service when requested by the Company, under specified terms and conditions.

Q. What was the primary purpose of PP&L's interruptible service rates and other economic development programs?

A. The interruptible service rates, and the other economic development programs implemented by the Company in the 1980's and early 1990's, primarily were intended to increase the utilization of PP&L-owned generation resources and to promote economic development (creating new jobs in its service territory). By increasing the utilization of PP&L's existing generation resources, generation costs would be spread over a larger kWh base, thereby benefiting all customers. An additional purpose of the interruptible service rates was to develop a generation resource of active load management.

Q. How does this change if a customer purchases energy and capacity from an alternative supplier?

A. The customer is no longer purchasing capacity and energy from PP&L's existing generation facilities and is providing none of the benefits of distributing the cost of generation over a larger kWh base or providing active load management to PP&L. The economic development benefits may still be present, if the customer is able to receive an equivalent or better price from the alternative supplier.

Q. Does an interruptible service customer who chooses an alternative generation supplier continue to qualify for the interruptible service rate?

A. No, he does not. As stated in my direct testimony on page 15, lines 2-4 and as stated above, interruptible service is generation-related. The interruptible service rate schedules state that the customer must have 1,000 KW of year-round interruptible load. An interruptible service customer who chooses an alternative supplier for its generation needs is not providing PP&L with generation-related interruptible load. Therefore, that customer no longer can meet the requirements of the interruptible service rate schedule and does not then qualify for that rate schedule.

Q. Why should interruptible service customers that choose an alternative supplier be charged the same CTC as if they were firm service Rate Schedule LP-4 or LP-5 customers?

A. Because they no longer qualify for interruptible service and they are no longer providing the above-referenced benefits of interruptible generation to the Company and its customers.

Q. Will, as PPLICA's witness Baron suggests, an existing interruptible service customer be forced to forego competitive options and remain a captive customer of PP&L's interruptible service rates as a result of PP&L's proposal?

A. PP&L's proposal to offer to continue interruptible service for existing interruptible service customers who do not choose an alternative supplier assures that these customers will receive rate cap protection. If, however, they do choose an alternative supplier, the treatment of those customers will be consistent with the requirements of the Act. Although PP&L's proposal to change shopping interruptible service customers to a Rate Schedule LP-4 or LP-5 CTC may limit the potential gain from choosing alternative suppliers, these customers already receive a significant rate advantage because they currently pay highly discounted rates.

In PP&L's most recent retail base rate proceeding at Docket No. R-00943271, the Company established that the customer's credit for interruptible power is far in excess of the market value of the capacity. In that proceeding, the Company was not allowed to correct for the difference between the cost to serve these customers and the revenues produced by the rate structure. Hence, all other rate classes currently are subsidizing the interruptible service customers. Because of this subsidy, the interruptible service customers are enjoying a rate level which is so low that it may in fact be difficult for them to find as low a rate under actual market conditions. Essentially, these customers are requesting a continuance of this regulated subsidy from other customer classes, which is evident through a reduced CTC to these customers, and the ability to obtain additional savings in the market. This is completely unfair and inappropriate. Exhibit OGK 6 provides an example, for an interruptible service customer, of the size of this credit as compared to PP&L's projected market value of the interruptible capacity in 1999.

It is important to note that PP&L's proposal does not preclude the market-place from setting an appropriate price for these customers. It is entirely possible that alternative suppliers will determine that these customers are sufficiently inexpensive to serve that they will offer inducements which will result in prices equal to or even less than those available under PP&L's existing interruptible service rates.

Q. Does, as Mr. Baron claims, PP&L's proposal violate the prohibition against inter-class cost-shifting in the Act?

A. PP&L's proposal is not intended to produce intra- or inter-class cost-shifting, as suggested by Mr. Baron. The CTC in each of PP&L's proposed rate schedules is a function of the unbundling mandated by the Act. Nothing in the Act grandfathers a customer's CTC obligation based on that customer's rate class on January 1, 1997. Any customer moving between rate schedules for any reason will see a change in CTC charges from the former to the latter. As stated earlier, an interruptible service customer who chooses an alternative supplier no longer qualifies for service under an interruptible service rate schedule. That customer will thereafter be billed under the most advantageous rate schedule for which the customer qualifies.

Moreover, PP&L's proposal should not result in over-collections and a termination of the CTC earlier than would otherwise be the case. It is true that CTC collections will vary depending on the load of customers leaving or connecting to the system or changing rate classes, but these variations will be subject to the CTC true-up. Accordingly, they will not affect total CTC collections.

Q. Has PP&L ever requested interruptible service customers to reduce load to their Firm Level as a result of local transmission or distribution emergencies?

A. In the history of the various interruptible service rates offered by PP&L, the Company has never requested interruptible service customers to interrupt load as a result of local transmission or distribution (T&D) emergencies. To date, requests to customers to interrupt load have always been the result of either generation emergencies on the Pennsylvania-New Jersey- Maryland Interconnection, an emergency test of interruptible service customers, or for economic generation reasons. The purpose of the interruptible service rates was to allow for interruption for generation-related purposes and the rates were developed on that basis. Interruptible service rates for T&D would be designed much differently, both in terms of the discount provided (much less of a discount) and the number of interruptions (many more interruptions).

<u>EDI/IDI Demand Free Days, Time of Day, PR-1, PR-2</u>

Q. Please explain the underlying purpose of PP&L's economic development initiatives.

A. PP&L's economic development initiatives were implemented in the 1980's and early 1990's. They were intended to increase the utilization of PP&L-owned generation resources and to promote economic development (creating new jobs in the service territory). Before the Act, by increasing the utilization of PP&L's existing generation resources, the generation costs would be spread over a larger kWh base, thereby benefiting all customers.

Q. How does this change if a customer purchases electricity (energy and capacity) from an alternative supplier?

A. The customer is no longer purchasing electricity from PP&L's existing generation facilities and is providing none of the benefits of distributing the cost of generation over a larger kWh base. The economic development benefits may still be present, however, if the customer is able to receive an equivalent or better price from an alternative supplier.

Q. As suggested by New Energy Ventures witness Boonin, can the EDI/IDI Riders, the Demand-Free Day provision of Rate Schedules LP-5 and LP-6, the Time-of-Day provision of PP&L's various rate schedules and Rate Schedules PR-1 and PR-2 be unbundled?

A. Mr. Boonin uses the term "unbundled" in his testimony to mean the application of the riders, provisions and rate schedules to customers, regardless of the supplier of energy. PP&L uses the term to mean the separation of prices into their components as explained in my direct testimony (Statement No. 11) on pages 3 and 4. The credits in the EDI/IDI riders already are unbundled into an energy credit and a capacity credit. As stated in my response to Question 45 of Interrogatories of the Office of Consumer Advocate, Set II, dated April 16, 1997, these credits will be applied to the energy and capacity components of the unbundled rates.

The Demand-Free Day provision of Rate Schedules LP-5 and LP-6 does not contain a schedule of charges, but is a statement of how a participating customer's billing will be determined. This provision, therefore, cannot be unbundled into pricing components.

Similarly, the Time-of-Day provision in PP&L's various rate schedules contains no pricing, but is a statement of how participating a customer's billing demand will be determined. This provision cannot be unbundled into pricing components.

Proposed Rate Schedules PR-1 and PR-2 include pricing for the base period under an unbundled rate schedule with incremental use charged at marginal energy and capacity prices. As such, Rate Schedules PR-1 and PR-2 are unbundled.

Q. Mr. Baron, Mr. Boonin and Office of Small Business Advocate witness Knecht all state that the denial of the EDI/IDI Riders, the Demand -Free Day provision of Rate Schedules LP-5 and LP-6, the Time-of-Day provision of PP&L's various rate schedules and

Rate Schedules PR-1 and PR-2 to an existing customer who chooses an alternative supplier will limit the customer's competitive options. Do you agree with their statements?

A. As stated in my direct testimony on page 7, PP&L's proposal to continue to apply these riders, provisions and rate schedules to existing customers who do not choose an alternative supplier assures that these customers will receive rate cap protection consistent with the Act. Moreover, the fact that these witnesses make the claims that they do speaks to the economic advantage that customers already have as a result of these riders, provisions and rate schedules and not to any attempt by PP&L to limit their competitive options. This situation is analogous to that with interruptible service customers.

Q. Why did PP&L propose the continuation of these riders and provisions for customers who continue to receive Basic Utility Supply Service?

A. PP&L's proposal to grandfather these riders, provisions and rate schedules is set forth in my direct testimony (Statement No. 11) on pages 7 to 14. Basically, these riders, provisions and rate schedules are all generation related. Once a customer chooses an alternative supplier, that customer is no longer buying Basic Utility Supply Service, including PP&L's generation supply resources.

The continuation of these riders, provisions and rate schedules is not logical in this situation, and is not fair to other customers who receive service under these rate schedules as their circumstances change. However, PP&L believed that the continuation of these programs to current subscribers was required by the rate caps in the Act. If the Commission disagrees, PP&L is willing to phase out these riders and provisions and eliminate the Time-of-Day options on the schedules provided for in its current tariff.

Rate Structure

Q. Mr. Knecht suggests the Delivery charge should be a blocked rate for Rate Schedules GS-1 and GS-3 instead of a flat rate. Do you agree?

A. No. PP&L determined that a flat charge was much more straightforward. By moving the blocked charges to the CTC, which is a temporary charge, PP&L is moving toward a much simpler and easier to understand pricing approach.

Q. With respect to Rate Schedule GS-1, Mr. Knecht believes that customers who are not demand-metered, or who have billing demand of less than 5 KW, will be effected adversely by including 5 KW of demand in the delivery charge, especially as the market price of capacity increases over time. Do you agree with Mr. Knecht?

A. No. The first 5 KW of demand for Rate Schedule GS-1 customers who are not demand-metered is part of the delivery charge. The delivery charge for Rate Schedule GS-1 customers is composed of a monthly customer charge of $7.48 and a flat per KWH delivery charge. These delivery service rates were designed to recover the delivery service revenue requirements reflected in PP&L's retail customer rates filed in compliance with the Commission's Final Order at Docket No. R-00943271.

For customers who are not demand-metered, the first 5 KW of demand is the minimum demand level used in determining the hours of use in the first energy block. If a customer's energy use reaches a specified level, a demand meter is installed and the customer will be billed based on the metered demand.

Q. Mr. Schoengold suggests that PP&L allocated the CTC to different customer classes based on capacity and energy. It is Mr. Schoengold's belief that the CTC comes mostly from stranded capital investments and represents economic losses, not real capacity (page 26, lines 1-3). Therefore, Mr. Schoengold recommends allocating the CTC on an energy basis. Do you agree with Mr. Schoengold?

A. No. PP&L did not allocate the CTC to different classes based on capacity and energy. The CTC for each rate class was calculated as the remainder after determining the delivery charge and the market value of capacity and energy. This was done in order to ensure that each rate class bore its appropriate share of transition costs, i.e., there was no intra-class or inter-class cost shifting. The approach PP&L used is in full compliance with the Act.

<u>CRR</u>

Q. Using the Competitive Rate Rider (CRR), is it appropriate to allow the Company to acquire or retain generation service customers by discounting the CTC as proposed in the Direct Testimony of Lee Smith, representing the Office of Consumer Advocate, page 8, lines 8-17?

A. Customers acquired or retained by applying this rider will benefit all other PP&L customers by contributing, or continuing to contribute, to the Competitive Transition Charge (CTC). The Company has been, and intends to continue to be, very selective in applying this rider. As of June 30, 1997, only three (3) customers had signed CRR contracts.

Only one of these CRR contracts extends past January 1, 1999, without a competitive cancellation clause. The Company would be willing to re-negotiate this contract and allow the customer to enter competition if the customer is interested in pursuing such an option.

RTS Locations

Q. Please explain the underlying purpose of the Rate Schedule RTS rate structure.

A. The Rate Schedule RTS was implemented by the Company in the 1980's and was intended to increase off-peak utilization of PP&L-owned generation resources. By increasing the utilization of PP&L's existing generation resources, the generation costs would be spread over a larger kWh base, thereby benefiting all customers.

Q. Will these benefits continue if a Rate Schedule RTS customer chooses an alternative supplier?

A. Obviously not. The customer would be buying generation from a third party. This would not improve the utilization of PP&L's generation resources.

Q. Will customers served under Rate Schedule RTS lose their eligibility for this rate schedule if they choose an alternative generation supplier and then seek to return to Basic Utility Supply Service as stated in the direct testimony of Barbara Alexander, representing the Office of Consumer Advocate, page 48, lines 6-21, and page 49, lines 1-8?

A. PP&L's tariff requires that Rate Schedule RTS stay with the current location that it is applied to. The intent of the proposed change in the Rate Schedule RTS is that existing customers will no longer be eligible for the rate schedule if they: a) change their heating system to other than thermal storage units, b) choose an alternative generation supplier, or c) are no longer supplied all of the their electricity (capacity and energy) from the Company on and after January 1, 1999. A new customer who purchases a home with an existing thermal storage unit will be ineligible for Rate Schedule RTS only if the previous owner took any action that caused a loss of eligibility.

This is analogous to the applications of all other rate provisions, riders, and rate options: an existing location taking basic utility service continuously will be given the benefit of the rate schedule. If the location leaves the rate schedule for competition and returns, it is treated as a new customer and given the currently-available most advantageous rate schedule.

Standardized Tariffs

Q. Are standardized distribution service tariffs throughout the state and between states as proposed in the direct testimony of Paul D. Reising, Enron Power Marketing Inc., page 33, lines 3-4, practical?

A. Electric utilities throughout the state and in other states have different cost structures and different work practices which justify differences in rates and terms and conditions for service. Therefore, it would be impractical in this proceeding to try to standardize distribution service tariffs in Pennsylvania and other jurisdictions.

Q. Will consistent distribution service tariffs enhance the benefits of full competition?

A. Differences in rates and terms and conditions between electric utilities will not deny end-use customers the benefits of full competition, if the delivery service rates and conditions of service are applied in a uniform and non-discriminatory manner.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT OGK 6

EXHIBIT OGK 6

CALCULATION OF INTERRUPTIBLE RATE CREDIT COMPARED TO MARKET VALUE OF CAPACITY

Billing Under LP-5:	$642,768/month	21,932 KW
Billing Under IST:	$483,785/month	10,180 KW
Difference:	$158,983/month	11,752 KW
Annual KW credit provided by the IST rate:		$162.33/KW-yr.
Annual KW market value in 1999:		$22.00/KW-yr.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 12-R

Rebuttal Testimony of William H. Whitehead

Q. Please state your full name and business address.

A. My name is William H. Whitehead. My business address is Two North Ninth Street, Allentown, Pennsylvania, 18101.

Q. Have you previously submitted direct testimony on behalf of Pennsylvania Power and Light Company?

A. Yes. I submitted my direct testimony (Statement No. 12) on April 1, 1997.

Q. Has your position in the Company changed since you submitted this testimony on April 1, 1997?

A. Yes. Effective July 30, 1997 I was promoted to the position of Manager - Transmission and Distribution Operations.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the assertions of witnesses on behalf of various intervenors on the following topics:

1. The allocation of the capability of interties that connect PJM with adjoining control areas. (Responding to Enron witness Dr. Tabors).
2. The provision of point-to-point transmission service for retail access customers. (Responding to Enron witness Mr. Coles).

3. The unbundling of the transmission, distribution, and ancillary services components of the customer's bill. (Responding to Enron witness Mr. Reising and PPLICA witness Mr. Baron).

4. The provisions for maintaining reliability through reserve planning. (Responding to Enron witness Mr. Coles).

<u>Current Status of PJM</u>

Q. Mr. Whitehead, what is the current status of the PJM restructuring?

A. On June 2, 1997, the Supporting Companies filed a comprehensive restructuring plan with the Federal Energy Regulatory Commission (FERC). This filing included a revised and updated PJM Limited Liability Corporation (PJM LLC) Operating Agreement, a revised PJM Open Access Transmission Tariff, a Transmission Owners Agreement, and a Reliability Assurance Agreement. Subsequently, both PECO Energy and the Coalition for a Competitive Electricity Market (CCEM) filed separate, competing restructuring plans. The FERC has not yet acted on any of these filings. These filings are available for review on the PJM Webpage at www.pjm.com.

Q. What is the current membership of PJM?

A. There are currently over 40 members of PJM.

Allocation of Intertie Capability

Q. Have you read Dr. Tabors testimony regarding the allocation of intertie capability?

A. Yes, I have.

Q. Why is Dr. Tabors concerned about the allocation of the intertie capability with adjacent control areas?

A. Dr. Tabors believes that the intertie capability will be assigned only to the current load-serving, transmission-owning utilities in PJM. He does not believe that new retail load-serving entities will be assigned any intertie capability.

Q. Is this your understanding of how the intertie capability will be assigned?

A. No.

Q. What is your understanding of how the intertie capability will be assigned?

A. Section 30.8 of the PJM Open Access Transmission Tariff provides that: "There is no limitation upon a Network Customer's use of the

Transmission Provider's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of the Transmission Provider's total interface capacity with other transmission systems may not exceed the Network Customer's Load." The current tariff specifies the Network Customer's Load Ratio Share. However, this section was revised in a FERC filing made by the PJM Office of Interconnection on July 14, 1997, to comply with changes to FERC's pro-forma tariff as a result of Order 888A.

Q. How is a Network Customer defined in the PJM Open Access Transmission Tariff?

A. A Network Customer is defined as "An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff."

Q. Does this provision limit the use of the intertie capability to only the current load-serving, transmission owning utilities?

A. No. A Network Customer is defined as any entity taking service under the PJM Open Access Transmission Tariff. Any Network Customer, including retail customers taking service under the PJM Open Access

Transmission Tariff, or an alternate supplier acting as agent for a retail customer, can use intertie capability to deliver designated resources to loads.

Q. Is there any reason for a retail customer to be concerned about inadequate intertie capability for delivering designated resources to loads?

A. No, not if adequate Network Transmission Service has been obtained from PJM.

<u>Provision of Point-to-Point Transmission Service</u>

Q. Have you read Mr. Coles' testimony regarding the availability of point-to-point transmission service for retail access customers?

A. Yes, I have.

Q. Why is Mr. Coles concerned about the availability of point-to-point transmission service for retail access customers?

A. Mr. Coles believes that point-to-point transmission service will not be available to a retail access customer.

Q. Is this your understanding of how point-to-point transmission service will be provided?

A. No, it is not.

Q. What is your understanding of how point-to-point transmission service will be provided after retail access is available?

A. As proposed in the Supporting Companies' June 2, 1997 filing with the FERC, retail customers have the option of acquiring point-to-point transmission service to deliver resources to loads.

Q. Is this a change in approach since your direct testimony was filed?

A. Yes, it is. The restructuring proposal was revised based on input provided during a lengthy stakeholder review process. This process was not complete when my direct testimony was filed on April 1, 1997.

Unbundling of Transmission, Distribution, and Ancillary Services

Q. Have you read Messrs. Reising and Baron's testimony regarding the further unbundling of PP&L's transmission, distribution, and ancillary services charges?

A. Yes, I have.

Q. Do you agree that further unbundling of these components is necessary?

A. Yes.

Q. Please explain.

A. Transmission service customers, including retail access customers, will take transmission service from PJM under the PJM Open Access Transmission Tariff (Tariff). These customers will pay unbundled charges both for transmission service and for ancillary services as specified in the Tariff. With few exceptions, retail access customers within the PP&L franchised territory will take delivery of generation at a given point on PP&L's distribution system, from either 138 kV or 69 kV transmission, and pay a separate distribution service charge in addition to the transmission service and ancillary services charges under the PJM Tariff. If PJM is not in a position to provide the required transmission service and ancillary services to all retail access customers by January 1, 1999, then the temporary provisions adopted for PP&L's retail access Pilot Program will be extended. PJM has committed to being in a position to provide these services to all retail customers, and I have every confidence that PJM will work diligently to complete the required work by January 1, 1999. PP&L will provide whatever assistance is required to help PJM meet this commitment.

Reserve Planning/Sharing

Q. Have you read Mr. Coles' testimony regarding reserve sharing and reserve planning?

A. Yes, I have.

Q. Why is Mr. Coles concerned about reserve planning in a retail access environment?

A. I believe Mr. Coles is correct in stating that the traditional method of reserve planning is being replaced by a more market-driven process. However, Mr. Coles also is correct in assuming that the replacement of the traditional method of reserve planning cannot occur overnight, it must be phased-in over some period of time. Not all states that are served by the PJM ISO will have retail access simultaneously, and not all customers in states that do have retail access will be given access at the same time. Therefore, it is appropriate to transition from reserve planning to some form of market-based reserves with appropriate penalties. The PJM restructuring filing submitted to the FERC on June 2, 1997, proposes such a transition. The PJM Planning and

Engineering Committee is currently evaluating the most appropriate method to facilitate this transition.

Q. Does the Electric Generation Customer Choice and Competition Act (Act) discuss the issue of continued reliability after retail access is implemented?

A. Yes. Section 2809 (E) of the Act clearly states that: "In regulating the service of electric generation suppliers, the Commission shall impose requirements necessary to ensure that the present quality of service provided by *electric utilities does not deteriorate*, including assuring that adequate reserve margins of electric supply are maintained ..."

Q. Mr. Coles also has stated that the NERC and MAAC standards should be enforced by those organizations, and not by the PJM ISO. Does PP&L believe this approach will be effective?

A. Although NERC and MAAC are the reliability standard-setting entities, their ability to deal with the day-to-day implementation and enforcement of these standards is limited. It would appear more likely that the PJM ISO, the entity operating the transmission system on a day-to-day basis, will be in a far better position to enforce these standards. PP&L believes that these standards are the key element to assuring continued reliable service under retail access.

Q. Does this conclude your rebuttal testimony?

A. Yes.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 13-R

Rebuttal Testimony of Robert M. Geneczko

Q. Please state your full name and business address.

A. My name is Robert M. Geneczko. My business address is Two North Ninth Street, Allentown, Pennsylvania, 18101.

Q. Have you previously submitted direct testimony on behalf of Pennsylvania Power & Light Company?

A. Yes. I submitted my direct testimony (Statement No. 13) on April 1, 1997.

Q. Your previous testimony indicated that your title was Vice President - Electrical Systems. Is this your current title?

A. No. My title has been changed to Vice President - Power Delivery.

Q. Please describe the reason for your change of title and any associated changes in your direct responsibility.

A. The Electrical Systems department has been renamed Power Delivery to be more descriptive of the department's responsibilities for planning, engineering and operation of the transmission and distribution system. My title has been changed to reflect the clarification of departmental roles.

Q. What is the purpose of your rebuttal testimony?

A. I will:

1. Restate PP&L's intent and commitment to a meaningful Code of Conduct that enables a fair and competitive electric generation market.
2. Address many of the theoretical assertions of the intervening parties by discussing the reality of the situation facing PP&L and the Commission.
3. Offer amendments to the previously filed Code of Conduct to clarify PP&L's intent.
4. Address specific assertions raised in the testimonies of Ms. Alexander, Mr. Johnstone, Dr. Mayo and Mr. Dirmeier.

Q. Would you state PP&L's intent with regard to its codes of conduct?

A. First and foremost, PP&L will conduct its business in a fair and honest manner. PP&L will conform to the letter, intent and spirit of the Code of Conduct. We believe our dealings with customers, shareholders, regulators, legislators, communities, other utilities and suppliers all attest to a history of highly ethical behavior. PP&L requires nothing less from its employees and our constituents should expect nothing less from PP&L. This is our commitment and we will deliver on that commitment. I hope I have made this perfectly clear. The PP&L Code of Conduct is certainly no "empty vessel" as Mr. Dirmeier attempts to conclude.

Q. Is there anything else that you would like to add about PP&L's intent?

A. Yes. PP&L has been a leader in promoting electric competition and customer choice within Pennsylvania and has strongly supported Federal efforts as well. We were an important early supporter of Pennsylvania's fast track legislation to provide for a rapid transition to customer choice and we were a participant in the crafting of the legislation. In doing so, we recognized that a competitive market would require the development of certain "rules of the road", with the Code of Conduct being among them. Consistent with that recognition, we have been working under the assumption that the Code of Conduct has been in effect since the date of this filing.

Q. You mentioned theoretical assertions and suggest that they contradict reality. Would you explain those remarks?

A. Certainly. Several witnesses, Dr. Mayo and Mr. Dirmeier in particular, attempt to spin a tale that would lead one to believe that there is some great economic force that compels PP&L's departments and employees to act exclusively on a profit motivation. And with PP&L's Code of Conduct, the so-called "empty vessel," PP&L would somehow be free to shed its history and its culture and to behave in unethical ways. While these arguments are interesting, they are inappropriate as explained elsewhere *in Dr. Kalt's testimony. But even by a stretch if were* somehow possible to instantly change PP&L's culture, there are some realties that cannot be overlooked:

1. PP&L has declared its intent to market competitively in both the wholesale and retail markets. We realize that we will be under regulatory scrutiny. PP&L and its marketing group simply cannot afford to allow inappropriate behavior to jeopardize its freedom to do so. PP&L's other departments could face other sanctions as well.
2. The Electric Delivery group will remain a monopoly function directly under the regulation of both the PAPUC and FERC.

Both agencies have broad powers at their disposal for general audit, targeted investigations and have the ability to act upon inappropriate behavior including Code of Conduct violations.

3. PP&L is one of the first utilities to file a Restructuring Plan and recognized that its Code of Conduct could become the model for comparison in subsequent filings. Thus, this code must be one which would be acceptable in developing an overall competitive framework.

4. There is no profit motive for the Electric Delivery group to retain energy customers. Customers who choose the Electric Delivery group will be supplied by its own purchasing group and that would be done consistent with the Act, that is, without a profit adder. In fact, the Electric Delivery group must procure energy "at market" with a pass through of those costs. Similarly, "channeling" and "tying" are not permitted under the PP&L Code -- this will be discussed later in my testimony.

5. PP&L cannot use its monopoly wires business as a way to limit access to new suppliers. First, PP&L must coordinate operation of its transmission facilities with the PJM ISO

which handles all transmission requests. PP&L also has an obligation to reinforce its transmission under the PJM agreement. At the distribution level, PP&L retains an "obligation to transport" which means that we have the *obligation to add facilities to accommodate new service* requests. Adding to that obligation is another economic reality. The distribution business makes its money by transporting energy. Refusal to accommodate new customers or suppliers means lower profits.

Q. Do you have any other general concerns resulting from the testimony of the intervenors?

A. Yes. I understand that the Act is intended to develop a competitive market in the supply and marketing of electric power. The PP&L Code of Conduct is intended to support that development. On the other hand, the intervenors have suggested changes to the code that go well beyond the Act. In effect, they are introducing new measures and concepts that go well beyond the Act and are characterizing them as necessary elements of the Code of Conduct.

Q. Can you provide an example of this?

A. Yes, Mr. Dirmeier would demand that PP&L allow competitive service providers to act as an agent for the customer to arrange service. In this way, he asserts PP&L's customer service representatives would not have the opportunity to influence customers on their choice of suppliers. The fact of the matter is that new customer hookup is executed through a process that requires dialog. For instance, it requires customers to understand the placement of the meter, timing of service, contractor coordination, local permits and inspections. It requires negotiating *appointments based on joint availability. Ultimately, the Electric* Delivery group is responsible for providing the service in an effective manner, which is not likely to be accomplished through a third party, nor can PP&L rely on a third party. It would not be unlike sending an automobile in for service and depending upon the third party to explain the engine performance, squeaks and rattles. Ultimately, a competent mechanic would call the customer directly for the proper explanation. The third party agent introduces inefficiency and cost into the regulated business which is certainly not the intent of the Act.

Q. Based on your review of the intervenor testimony and their recommendations for changes, are you proposing any changes in the Retail Access Code of Conduct?

A. Yes. We believe that the Code of Conduct can be further strengthened by minor clarifications in the areas of channeling and joint marketing. A revised Code of Conduct is included as Exhibit RMG 4. I will describe the changes in detail later in my testimony.

Retail Access Code of Conduct

Q. Please describe the specific areas of the Code of Conduct which Ms. Alexander, Mr. Johnstone, Dr. Mayo and Mr. Dirmeier raise in their testimony as areas of concern.

A. The intervenor testimony raises general concerns regarding the overall approach utilized by PP&L in the development of a code of conduct and specific concerns regarding PP&L's Code of Conduct in the areas of information protection, information sharing, applicability of the code to employees, cross subsidies, employee sharing and transfers, channeling and tying arrangements, bill access, joint marketing, functional separation and compliance monitoring.

Q. Have you reviewed Dr. Mayo's testimony regarding methodologies to deal with the potential abuse of monopoly power under deregulation?

A. Yes.

Q. Do you agree with Dr. Mayo's assertion that a rules based system will not be successful in ensuring a robust competitive market and that that a vertically integrated utility like PP&L will "devise mechanisms to enable it to circumvent the rules and thereby exploit and/or extend its monopoly power"?

A. No. Dr. Mayo's assertion is based on the premise that the overriding goal of the utility is the continuation of all aspects of the existing vertically integrated monopoly supply model motivated solely by profit without regard to its ethical or legal obligations as a good corporate citizen. PP&L has taken the position, based on a history of operation as a regulated utility for more than seventy-five years and recent experience in the area of open transmission access under FERC Order 888/889, that a simple, principle-based code of conduct, utilized by ethical professionals will provide adequate protection for the consumer, and all competitors. PP&L

has worked in good faith to develop a Code of Conduct for retail access which is built upon this history of honesty and integrity.

Q. Please describe the activities which PP&L has supported under FERC Order 888/889.

A. As a transmission provider under FERC Order 888, PP&L provided open access transmission service to more than thirty-one transmission customers from July 1996 through April 1997. In the period from July 1996 through January 1997, this process was managed without the benefit of the PJM Open Access Same time Information System (OASIS) which was still under development. From January 1997 to date, the process was facilitated by the use of the PJM OASIS system. During this period, PP&L personnel were governed by the provisions of the FERC Order 889 Code of Conduct. The Order 889 Code of Conduct contains provisions similar to the proposed Retail Access Code of Conduct with regard to information safeguards, non-discriminatory administration of tariffs and employee sharing.

Q. How would complaints regarding violations of the FERC Order 889 code of conduct be handled within PP&L?

A. Any complaints filed with the FERC regarding potential violations of the FERC Order 889 Code of Conduct would be directed to my department as the group responsible for the Code of Conduct.

Q. Have there been any complaints regarding the action of PP&L employees under the provisions of the FERC Order 889 Code of Conduct?

A. No, not to my knowledge.

Q. Please describe the concerns raised in the testimony regarding information protection.

A. Mr. Johnstone raises the concern that favoritism as to access, information or other aspects of delivery service would inhibit the development of a competitive market. Mr. Dirmeier recommends that additional competitive safeguards are required to prevent inappropriate information sharing between the Electric Delivery group and PP&L's supply affiliate.

Q. Do you agree that safeguards are appropriate to ensure against anti-competitive behavior with regard to information sharing and information protection?

A. Yes.

Q. Has PP&L proposed such safeguards?

A. Yes. The Retail Access Code of Conduct clearly states PP&L's belief that customer information and supplier information must be treated as confidential to the customer or supplier. This requirement will preclude the disclosure of such information to other customers or suppliers except as authorized by the customer or supplier. This requirement extends not only to disclosure to PP&L affiliates but to disclosure to all other suppliers or customers.

Q. Are you familiar with Mr. Dirmeier's assertion that PP&L may be establishing a loophole to provide information to its supply affiliate while not supplying information to all suppliers?

A. Yes. Mr. Dirmeier testimony cites a response from PP&L to an interrogatory regarding the sharing of information on transmission and distribution facilities from my initial testimony and erroneously infers that this response would establish a mechanism for the

Electric Delivery group to provide preferential information sharing with PP&L's affiliate supplier.

Q. Why is this assertion incorrect?

A. The Company's response refers to the sharing of information regarding transmission and distribution facilities. Under FERC Order 889, transmission providers are prohibited from sharing with merchant personnel any information which would provide an unfair advantage over other merchant entities. The FERC clearly places the burden for the determination of information to which this provision is applicable upon the transmission provider. Mr. Dirmeier has indicated that this prohibition would allow PP&L to disclose information to its retail sales affiliate while failing to disclose information to other suppliers. However, his interpretation of the Company's response simply is incorrect. The prohibition from disclosure indicated in the response to the Enron question applies to all suppliers, including PP&L affiliates.

Q. Would you restate PP&L's policies on information sharing as provided in its codes of conduct?

A. PP&L agrees that safeguards are necessary to prevent improper sharing of all competitive information, however, the limitations on information sharing should be much more focused and specific than those proposed by Mr. Dirmeier. PP&L does not and cannot agree that all information available to the Electric Delivery group should be shared simultaneously for reasons as follows.

There are three types of competitive information.

1) Status and future expansion of the electrical T&D system;

2) Customer information; and

3) Supplier information.

Regarding electrical system information, PP&L is committed to supplying all such information through the OASIS. That is, the Company will disclose this information to all parties promptly and at the same time. No special channels and no 'heads up' will be issued to the Generation Supply group from the Electric Delivery group.

Customer specific data will be shared with the supplier only upon the written request of that customer. No supplier other than that designated by the customer will receive such information.

PP&L's Generation Supply group is included in the definition of supplier and will not receive this information unless designated by the customer.

Supplier specific data will not be shared with the PP&L Generation Group nor with any supplier other than the supplier to which it pertains.

In short, the codes of conduct prohibit dissemination of any of the competitive data noted above with any party other than by the terms noted.

Q. You used the term "all competitive information". Why not include all information shared with the Generation Supply group?

A. PP&L intends to apply the concept of competitive information broadly. Nonetheless, Mr. Dirmeier suggests the need for an internet bulletin board to document all information shared. I disagree. Company personnel necessarily will meet from time to time to discuss matters of a corporate nature, or dealing with specific personnel or even with matters concerning joint work outside of the Electric Delivery group's service territory. Much of the information discussed in these meetings is confidential in nature, and not necessary to achieve competitive access to all retail customers. I would note too that this type of sharing would be necessary regardless of the corporate structure.

Even more to the point, the Electric Delivery group will maintain certain work relationships that require information sharing and that is not necessary to share or even note to others.

Q. Could you expand on what you mean by work relationships?

A. Yes. An example might be work done at the switchyard of a power plant. The Electric Delivery group provides certain maintenance functions. The costs for such services of course would be charged to the power plants at their fully located value. And while this service might be deemed appropriate to offer to other power plant operators, it should not be necessary to do so as long as the Generation Supply group obtains no unfair competitive advantage. Dr. Mayo states that this is a benefit of integration and we agree. Furthermore, the Electric Delivery group does not have a monopoly on this service and so it is not a service provided by the Electric Delivery group that is necessary to create a competitive generation market. Moreover, information concerning that transaction need not be publicized except if the Electric Delivery group chooses to do so.

Q. Please describe concerns raised in the testimony regarding applicability of the code to employees and the sharing or transfer of employees.

A. Ms. Alexander and Mr. Dirmeier indicate that the sharing of employees or the transfer of employees between the Generation Supply group and the Electric Delivery group can be utilized as a means of providing information in a manner which could circumvent the safeguards against information transfer. As discussed below, I disagree.

Q. Were similar issues raised regarding employee sharing and transfers raised with regard to open transmission access under FERC Order 888?

A. Yes.

Q. How were these issues addressed by the FERC?

A. FERC Order 889 provides specific requirements which prohibit the transfer of employees to circumvent the requirements for the separation of merchant and transmission provider activities. PP&L

is required to use the OASIS to post and track such transfers which makes each employee transfer visible by all.

Q. Has PP&L provided similar protection in the Retail Access Code of *Conduct?*

A. Yes. The Retail Access Code of Conduct specifically indicates that employees involved in activities which permit their access to sensitive information in the Electric Delivery group or the Generation Supply group will not have shared responsibilities.

Q. Does PP&L intend to prohibit the transfer of employees between the Generation Supply group and the Electric Delivery group?

A. No. PP&L reserves the right to make such employee transfers when the transfer provides benefits to the Company. PP&L's Code of Conduct will not permit a "revolving door policy" which would create inappropriate information transfers between the regulated and unregulated business groups. Transfers between the Generation Supply group and Electric Delivery group would also typically be subject to reporting on the OASIS and would therefore be visible to public review. Ms. Alexander suggests that any employee transfers should be tracked and reported annually to the

PUC. We believe that the level of reporting required under the FERC Order 889 Code of Conduct using the OASIS should be adequate to meet the overall needs for monitoring transfers.

Q. Please describe concerns raised in the testimony regarding cross subsidies.

A. Ms. Alexander suggests that transactions between groups and transactions between either the Generation Supply group or the Electric Delivery group and corporate services groups be conducted in a manner which precludes cross subsidy.

Q. What specific mechanisms are recommended by Ms. Alexander?

A. The testimony recommends limitations on transactions to those which are specifically tariffed for or for which full compensation is made to the regulated portion of the company.

Q. Are you in agreement with this approach regards the provision of tariffed products and services?

A. Yes. Where the Electric Delivery group provides tariffed services to any alternate supplier, the Retail Access Code of Conduct requires that these services be provided at the same (tariffed) rates for all suppliers, including the PP&L Generation Supply group.

Q. Are there non-tariffed services which the Electric Delivery group might provide to the Generation Supply group or other alternate suppliers?

A. Yes. The Electric Delivery group possesses the technical expertise and experience to perform a wide range of consulting and support services to others. The example noted earlier, switchyard maintenance, falls into this category.

Q. How will the Electric Delivery group charge for these non-tariffed services provided to the Generation Supply group?

A. Any services provided by the Electric Delivery group will be changed at fees in full compliance with Commission rules and guidelines regarding recovery of costs associated with providing the service. These charges will be uniformly applied to any user, whether it be PP&L's operations, or others.

Q. Are you familiar with Mr. Dirmeier's assertion that PP&L's handling of cost allocations between various PP&L groups will not be done according to reasonable rules and standards?

A. Yes. Mr. Dirmeier cites a response by PP&L to a specific interrogatory dealing with the provision of services by Pennsylvania Power and Light Company and other PP&L Resources entities as indicating that the Electric Delivery group will allocate costs between units on a "case by case" basis. The notion that the Electric Delivery group intends to determine the cost for all services performed for the Generation Supply group on a "case by case" basis is a completely misleading interpretation of a response taken out of context. The question posed in Enron Interrogatory III-7 was:

> "With reference to PP&L's response to Enron Capital and Trade Resources, Set I, Question 1, Attachment 3 §B.1.c., please identify and explain in detail the method the Company will use to reasonably approximate the costs attributable to each party?"

The referenced attachment is the Services Agreement between PP&L Resources (including all subsidiaries and affiliates other than PP&L) and PP&L (approved by the Commission in its final order entered February 10, 1995 at Docket No. A-110500F.0206). The subsection of the agreement cited deals with costs and accounting and clearly states that services to be provided are to be charged to the recipient "at their full cost to the provider." This section goes on to indicate that both direct and indirect costs are to be charged and finally in the sub-section cited in the Enron question indicates that charges not directly assigned to one party will be "allocated based on a reasonable approximation of the costs attributable to each party." It is this allocation based on a reasonable approximation of the costs attributed to each party which will be handled on "a case by case basis", not the overall costs of services provided to others.

Q. Please describe concerns raised in the testimony regarding channeling and tying arrangements.

A. Mr. Mayo and Mr. Dirmeier both raise concerns regarding arrangements where the Electric Delivery group could either act as an agent for the Generation Supply group to "point" potential customers exclusively to the Generation Supply group or could create situations which bundle or tie electric delivery services in a discriminatory fashion to services of PP&L's affiliate energy supplier.

Q. Are there safeguards in the Retail Access Code of Conduct which prohibit this type of behavior?

A. Yes, the section of the Code of Conduct describing comparability requirements specifically prohibits bundling arrangements, tying arrangements and discriminatory application of services. An additional provision has been provided in the revised Code of Conduct in Exhibit RMG 4 which prohibits channeling or pointing of customers to the Generation Supply group.

Q. Has PP&L made any decision regarding the ability of generation suppliers to utilize the PP&L billing process for customer advertising, solicitation or other customer contact?

A. PP&L does not expect to allow alternate suppliers to utilize the Electric Delivery group billing process as an avenue to communicate with customers or potential customers.

Q. Mr. Dirmeier and Ms. Alexander indicated that joint marketing by the Electric Delivery group and PP&L's affiliate supplier could result in customer confusion and unfair advantage. Will the Electric Delivery group participate in joint marketing activities with the Generation Supply group?

A. The Electric Delivery group may engage in joint marketing of energy supply products with PP&L's Generation Supply group but will only do so as long as comparable opportunities are available to other suppliers and the purpose of the joint effort is economic development. The Electric Delivery group still has an interest and community responsibility to facilitate economic development. We will act indifferent, however, as to which alternate suppliers provide the energy part of the package. A revision to the Code of Conduct reflecting this intent is included in Exhibit RMG 4.

Q. Will the Electric Delivery group participate with suppliers, including PP&L Generation Supply group, in other forms of joint marketing?

A. Yes. It is important that the Electric Delivery group be afforded the opportunity to participate with any and all alternate suppliers to foster economic development within the franchise service territory, to promote the use of electrotechnologies by Electric Delivery customers and to promote increased utilization of Electric Delivery facilities.

Q. Will the electric Delivery group continue to promote competitive products such as electronic thermostats, Power Watch (tm) devices and Heat Comfort (tm) controls?

A. The Electric Delivery group may market such products to customers within the franchise territory as a means of provide customer oriented services closely associated with safe, reliable energy utilization. This type of marketing has been a long standing practice for Pennsylvania utilities.

Q. Please describe concerns raised in the testimony regarding functional separation.

A. Dr. Mayo and Mr. Dirmeier contend that PP&L's proposed organizational structure and the Retail Access Code of Conduct do not provide adequate functional separation to ensure that the potential for anti-competitive behavior is minimized.

Q. Do you agree with this assertion?

A. No, We believe that the functional separation embodied in the Restructuring Plan filing coupled with the Retail Access Code of Conduct provide adequate safeguards to ensure a fair and comparable treatment for all participants in the competitive marketplace.

Q. Do you believe that the Retail Access Code of Conduct provides sufficient specificity, and adequate safeguards to avoid being "an empty vessel" as described by Mr. Dirmeier?

A. Yes. As I indicated in my opening remarks, PP&L intends to act within both the intent and spirit of the codes of conduct to promote customer choice and a fair competitive market.

Q. What levels of oversight and compliance monitoring are provided to ensure PP&L's compliance with the provisions of the Code of Conduct?

A. There are a number of mechanisms currently in place which can be utilized to ensure compliance with the Code of Conduct. First, PP&L's corporate auditing division will provide internal auditing on all aspects of Code of Conduct compliance from employee education to the actual assurance of code practice. Second, the Pennsylvania Public Utility Commission has the ability to conduct periodic audits of company policy enforcement and activities within the regulated portion of the corporation. In addition, public *information related to certain aspects is available on the OASIS for* review by any interested party. Finally, the FERC compliance reporting hotline provide additional mechanism for raising concerns regarding compliance.

Q. Mr. Dirmeier suggests that the books and records of both the Electric Delivery group and the Generation Supply group should be open for review to ensure appropriate accounting and cost allocations. Do you agree with this requirement?

A. No. The books and records of the Electric Delivery group will be made available to the Commission as required to ensure that the Company is in compliance with the Public Utility Code. The records of the Generation Supply group should be made available only to the extend required for any other non-regulated corporation.

Q. What are the potential consequences for PP&L if the company fails to abide by the provisions of the Code of Conduct?

A. The consequence to the corporation are noted in my opening remarks. In addition, employees who violate the provisions of the Code are subject to discipline under the company's Responsible Behavior Program. This program is an integral part of the Company's Standards of Integrity which govern the actions of all employees and provides for progressive sanctions against the employee up to an including dismissal for violation of company policies.

Q. Does that conclude your rebuttal testimony?

A. Yes.

EXHIBIT RMG 4

Code of Conduct

The relationship of the Generation Supply group, Electric Delivery group, supporting organizations and alternative energy suppliers will be governed by the following code of conduct which is intended to control dissemination of confidential customer information, restrict access to competitive information, prevent cross-subsidies between regulated and unregulated departments, and prevent discriminatory practices.

Segregation of and Restricted Access to Information

1. The following information shall be considered confidential and access to this information shall be limited to only those employees involved in the administration of energy supply by alternative suppliers for the purpose of customer billing, supply scheduling and reconciliation, supplier payments, and customer assistance.

- Supplier pricing and billing information;
- Supplier customer lists;
- Individual customer consumption;
- Identity of the supplier of a participating customer.

2. The Electric Delivery group will release information to a supplier concerning individual customer account history and individual customer consumption only after written approval from the customer.

Assignment of Responsibilities

1. Employees in the Generation Supply group directly involved in marketing energy to customers choosing competitive generation service will not be assigned any responsibilities within the Electric Delivery group and vice versa.

Accounting and Cost Allocations

1. Costs associated with the Generation Supply and Electric Delivery groups will be kept separate.

2. Charges for services between the Generation Supply group, Electric Delivery group and other internal service organizations will be provided at fair and non-discriminatory prices.

Joint Marketing

1. The Electric Delivery group will not favor the Generation Supply group in any marketing of energy supply products.

Comparability

1. The Electric Delivery group will not condition any discount to a customer or condition any deviation from standard terms of service to a customer on the purchase of energy from the Generation Supply group.

2. The Electric Delivery group will make meter reading, billing and other customer assistance services available to all generation suppliers at non-discriminatory rates, terms and conditions.

3. The Electric Delivery group will process requests for access by all generation suppliers in a non-discriminatory manner.

4. The Electric Delivery group will apply tariff provisions in a non-discriminatory manner.

5. The Electric Delivery group will not "point" or "channel" customers to the Generation Supply group.

Communications to Employees and Enforcement

1. The code or conduct will be commercial throughout the Electric Delivery and Generation Supply groups, and other internal service organizations.

2. The code of conduct will be incorporated into the Company's Standards of Integrity.

3. Periodic audits of the code of conduct will be conducted to ensure compliance.

4. Violations of the code of conduct will be treated as a violation of the Company's Standards of Integrity and disciplinary action will be administered in accordance with the Company's Responsible Behavior policy.

5. As deemed appropriate, employees involved in the administration of energy supply by alternative suppliers and having access to competitive information will sign a confidentiality agreement prohibiting improper disclosure of competitive information.

Dispute Resolution Process

1. The Electric Delivery group will establish a procedure for receiving, recording and resolving complaints concerning this code of conduct.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 14-R

Rebuttal Testimony of Henry W. Baumann

Q. Please state your full name and business address.

A. My name is Henry W. Baumann. My business address is Two North Ninth Street, Allentown, Pennsylvania, 18101.

Q. Have you previously submitted direct testimony on behalf of Pennsylvania Power & Light Company?

A. Yes. I submitted my direct testimony (Statement No. 14) on April 1, 1997.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the assertions of witnesses on behalf of various intervenors on the following topics:

1. The proposed method for selecting customers for retail access during the first two transition years, 1999 and 2000 (responding to Messrs. Bowen, Baron and Knecht);
2. The methodology of verifying supplier selection by customers who have direct access (responding to Mr. Bowen);
3. Treatment of customers who return to Basic Utility Supply Service (responding to Ms. Alexander).

Q. Have you reviewed Mr. Bowen's proposed methodology for selecting customers to have direct access?

A. Yes.

Q. What methodology does Mr. Bowen propose to use?

A. Mr. Bowen proposes a first-come, first-served methodology for residential customers but believes that this methodology is not appropriate for commercial and industrial customers due to the possibility of competitive distortions. He recommends the selection process advocated by many commercial and industrial customers, which permits those customers to identify a pro rata share of their load for competition.

Q. Do you agree with Mr. Bowen's proposed methodology for residential customers?

A. No, I do not.

Q. Please explain.

A. I believe that open enrollment followed by random selection if a rate class is over-subscribed, as described in my direct testimony

(Statement 14), is more equitable for residential customers than the first-come, first-served proposal by Mr. Bowen.

Q. What is the basis for your opinion?

A. I believe that PP&L's proposed approach is preferable to Mr. Bowen's proposed approach for three reasons. First, PP&L's proposal is more fair and equitable to all residential customers because all customers will have an equal opportunity to participate in retail choice. Under Mr. Bowen's approach, customers who are more knowledgeable about competition issues or who have been encouraged by alternative suppliers to participate would enroll first. Customers who are just becoming familiar with competition issues or who have not been pursued by alternative suppliers would sign up later and could be excluded from participation if a class is over-subscribed. Second, Mr. Bowen's approach would require customers to make hasty decisions regarding participation in the market place because of the importance of signing up early. PP&L's approach would allow customers to take more time to make a decision because the order of enrollment is not a relevant consideration. Third, and finally, implementation of a first-come, first-served mechanism could be administratively difficult and could lead to a series of disputes regarding the order in which customers signed up for competition.

Q. What is the chronology of events under PP&L's proposal?

A. PP&L is proposing a 90-day sign-up period during which all customers interested in participating in competition can notify the Company. After that initial enrollment period has closed, there will be a 30-day period during which PP&L will determine if any rate classes are over-subscribed. During this period, if any rate classes are over-subscribed, the Company will conduct a random selection among customers seeking to participate. Finally, at the end of this selection period, the Company will release the names, addresses and telephone numbers of all participating customers to alternative suppliers, unless the customer has indicated that his or her information should not be released.

Q. Must a customer choose an alternative supplier before enrolling to participate in the competitive market?

A. No. As I indicated previously, PP&L is proposing a three-step process. Customers are not required to choose an alternative supplier until the sign-up, selection and notification steps have been concluded.

Q. Are you familiar with the selection process advocated by many commercial and industrial customers?

A. The only methodology I'm familiar with is the one proposed by Mr. Baron on behalf of the PP&L Industrial Customer Alliance.

Q. What methodology does Mr. Baron propose to use?

A. Mr. Baron proposes first-come, first-served with the customer designating a desired level of load for participation. If there is an over-subscription of load, Mr. Baron proposes a pro-rata reduction to each subscriber's nominated load. For example, in the first phase, if all customers in a class volunteer and nominate 100% of their load, 33% of each customer's load would be eligible for competition.

Q. Do you agree with Mr. Baron's methodology?

A. No, I do not.

Q. Please explain.

A. I have the same concerns about a first-come, first-served approach for commercial and industrial customers as I previously explained for residential customers.

Q. Mr. Baron contends that his methodology is designed to resolve competitive distortion concerns. Do you agree?

A. No. In my opinion, the process proposed by the Company is the best way to resolve any competitive distortion problems. This type of problem would seriously affect only those customers for whom electricity is a large portion of their operating costs. Moreover, any problem will exist for a maximum of two years and since customers only are allowed to shop for generation service, it will not affect the majority of the total bill. I stated in my direct testimony that the Company would attempt to resolve any competitive distortions to the satisfaction of the affected customers on a case-by-case basis. None of the intervenors has produced any evidence that shows there will be significant problems and the Company has stated a willingness to address any concerns raised by customers.

Q. Has PP&L limited the number of suppliers serving a customer or the amount of load customers can purchase from a single supplier?

A. No. PP&L is not proposing any restrictions. Customers will be able to purchase energy from multiple suppliers and can elect to return to the EDC if they are dissatisfied with a supplier. Purchases from the Company's EDC will be at market rates. In fact, a customer may elect to satisfy his or her total load requirements by purchasing a portion from one or more suppliers and a portion from the Company's EDC at market rates.

Q. Do your comments apply to Mr. Knecht's concerns about phase-in issues for small businesses (Knecht at 51)?

A. Yes, they do.

Q. Have you reviewed the testimony of Mr. Bowen regarding the protections to preclude slamming?

A. Yes, I have.

Q. What methodology does Mr. Bowen propose?

A. Mr. Bowen proposes that evidence from the supplier would satisfy the requirement for written notification. He also proposes verification by an independent third party (Bowen at 24). If further evidence is required, Mr. Bowen proposes allowing written evidence from the entity conducting the third-party verification.

Q. Do you agree with Mr. Bowen's methodology?

A. No, I do not.

Q. Please explain.

A. Mr. Bowen's methodology is flawed because it removes customer input from the switching process. The Company developed its methodology (Baumann, at 6) to insure the customer was aware that a switch of suppliers was taking place. I think it's important for the electric distribution company to communicate directly with the customer under these circumstances. Also, I don't agree that third-party notification is necessary. In fact, such an approach could lead to significant customer confusion. Mr. Bowen's observation that greater protection will be achieved through third-party verification is wrong. Direct communication with the customer will provide the greatest protection.

Q. Have you reviewed the testimony of Ms. Barbara Alexander concerning the return to Basic Utility Supply Service (BUSS)?
A. Yes, I have.

Q. What concerns does Ms. Alexander have?
A. Ms. Alexander has several concerns with PP&L's approach. First, she states that customers may move into and out of the competitive system for a variety of reasons so it is not appropriate for PP&L to require them to sign a one-year contract. Second, Ms. Alexander believes that concerns about gaming can be avoided with the use of a market-based price. Third, she suggests that a modest fee would be appropriate for a customer who switches more than twice in any twelve-month period. Ms. Alexander also does not agree that these customers should be treated as "new" when they return to BUSS.

Q. Do you agree with Ms. Alexander's concerns and recommendations?
A. No, I do not.

Q. Please explain.
A. Ms. Alexander has stated that customers could return to BUSS for a variety of reasons and that PP&L would not know the reason. This is

correct, and that is why the Company has provided a six-month grace period for customers to switch back to BUSS after their initial decision to purchase electricity from an alternative supplier. This six-month grace period should eliminate any concerns regarding the one-year contract period.

Q. Please explain why the Company is proposing that contract period?

A. PP&L's proposal is designed to minimize the amount of gaming which some customers could engage in to achieve the lowest total price for electricity. This is of particular concern when customers return to BUSS during very high-cost periods of the year, such as the summer. A certain amount of planning is required by PP&L in order to procure the correct amount of electricity for its customers. This is especially true because, under the Act, PP&L must be the supplier of last resort.

Q. Please respond to Ms. Alexander's concerns regarding a return to the EDC.

A. These concerns are unfounded. Customers who leave a competitive generation supplier and return to the PP&L electric distribution company (EDC) will not return to regulated service as stated by Ms.

Alexander (Alexander at 48). They will be provided energy at prevailing market prices. If customers are allowed to freely switch between PP&L and other competitive suppliers, particularly during high cost periods, the Company may have a difficult time procuring the correct amount of electricity for its customers at a reasonable price. Ms. Alexander also suggests charging a "modest fee" to customers who may switch more frequently, but she does not define what a modest fee would be. Some companies do charge a fee for switching, such as in the telecommunications and cable TV industries. Fees that I am aware of could be as high as $25. I wouldn't consider this to be a modest fee for customers who are on a limited income.

Q. Please respond to Ms. Alexander's statement that customers should not be treated as "new" when they return to the EDC (Alexander at 48).

A. I disagree with her conclusion. Section 2807 of the Act specifically provides that

> "if a customer that chooses an alternative supplier and subsequently desires to return to the local distribution company for generation service, the local distribution company shall treat that customer exactly as it would any new applicant for energy service."

The Company's proposal is totally consistent with this provision.

Q. Does this conclude your testimony?

A. Yes.