BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION	]	
OF DELMARVA POWER AND LIGHT COMPANY	]	PSC Docket No. 10-237
FOR AN INCREASE IN RATES FOR NATURAL	]	
GAS SERVICE (FILED JULY 2, 2010)	]	

DIRECT TESTIMONY OF

ANDREA C. CRANE

ON BEHALF OF

THE DIVISION OF THE PUBLIC ADVOCATE

OCTOBER 25, 2010

TABLE OF CONTENTS

I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Andrea C. Crane and my business address is PO Box 810, Georgetown, Connecticut 06829. (Mailing Address: 199 Ethan Allen Highway, Ridgefield, CT 06810).

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

A. I am President of The Columbia Group, Inc., a financial consulting firm that specializes in utility regulation. In this capacity, I analyze rate filings, prepare expert testimony, and undertake various studies relating to utility rates and regulatory policy. I have held several positions of increasing responsibility since I joined The Columbia Group, Inc. in January 1989. I became President of the firm in 2008.

Q. Please summarize your professional experience in the utility industry.

A. Prior to my association with The Columbia Group, Inc., I held the position of Economic Policy and Analysis Staff Manager for GTE Service Corporation, from December 1987 to January 1989. From June 1982 to September 1987, I was employed by various Bell Atlantic (now Verizon) subsidiaries. While at Bell Atlantic, I held assignments in the Product Management, Treasury, and Regulatory Departments.

Q. Have you previously testified in regulatory proceedings?

A. Yes, since joining The Columbia Group, Inc., I have testified in approximately 325 regulatory proceedings in the states of Arizona, Arkansas, Connecticut, Delaware, Hawaii, Kansas, Kentucky, Maryland, New Jersey, New Mexico, New York, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Vermont, West Virginia and the District of Columbia. These proceedings involved gas, electric, water, wastewater, telephone, solid waste, cable television, and navigation utilities. A list of dockets in which I have filed testimony is included in Appendix A.

Q. What is your educational background?

A. I received a Master of Business Administration degree, with a concentration in Finance, from Temple University in Philadelphia, Pennsylvania. My undergraduate degree is a B.A. in Chemistry from Temple University.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. On July 2, 2010, Delmarva Power and Light Company ("DPL" or "Company") filed an Application with the State of Delaware, Public Service Commission ("PSC" or "Commission") seeking an increase in its base rates for natural gas service. In its initial filing, the Company requested a base rate increase of $11,915,381, or an increase of approximately 17.4% on base delivery revenues. The Company's initial request would have resulted in an increase of approximately 6.3% on total sales revenue.

The Company's filing was based on a test period ending June 30, 2010. As filed, the Company's test period reflected six months of actual results and six months of projections. On September 10, 2010, DPL updated its filing to reflect actual results for the twelve months of the test period. The Company's update claimed a revenue deficiency of $11,555,638, or approximately 17.2% of gas delivery revenues and 6.2% of total sales revenues. On October 11, 2010, DPL again updated its claim to reflect a delay in the implementation of its Advanced Metering Infrastructure ("AMI") Program. This update resulted in a rate increase request of $10,203,825, or approximately 15.2% of gas delivery revenues and 5.4% of total sales revenues.

The Columbia Group was engaged by the Division of the Public Advocate ("DPA") to review the Company's filing and to provide recommendations to the Commission on revenue requirement, cost of capital, rate design, and certain regulatory policy issues.

Q. Is there a unifying theme to the Company's proposals that you are addressing in your testimony?

A. Yes. Similar to the theme of the Company's recent electric base rate case, the Company's proposals are designed to minimize shareholder risk by shifting much of that risk onto the Company's ratepayers, without a commensurate reduction to the return on equity risk premium. With deregulation, the risk associated with the majority of the Company's revenue requirement was shifted to ratepayers. As noted, the Company's proposal results in a rate increase of 15.2% on base delivery revenue but only 5.4% on total revenues.

Approximately 63% of the Company's test period revenues related to fuel recovery, which is a direct pass-through to customers. Thus, the Company bears no risk of under-recovery for the overwhelming portion of its costs.

With this filing, DPL attempts to provide shareholders with the same risk reduction for the remaining 37% of DPL's cost of service, i.e., the gas delivery component. The Company's filing includes a new modified fixed variable rate design, which essentially guarantees that DPL will achieve its targeted level of revenue, regardless of variations in usage due to weather, conservation, economic conditions, or other factors. In addition, the Company is proposing that it be permitted to recover from ratepayers higher than anticipated pension benefit costs incurred in 2009. The Company is also proposing a tracker mechanism that would provide guaranteed recovery of its pension, other post-employment benefit ("OPEB") costs, and uncollectible costs. Finally, the Company is proposing a Utility Facility Relocation Charge ("UFRC") rider, to provide for immediate recovery of costs associated with relocations of distribution facilities that are mandated by the Delaware Department of Transportation ("DOT") or other state agencies.

In spite of these proposals, the Company is only proposing a 25 basis point reduction its return on equity. The Company attributes this reduction to the impact of its modified fixed variable rate design. No return on equity reduction is being proposed for the other mechanisms that will reduce shareholder risk. This 25 basis point reduction is wholly inadequate to compensate ratepayers for the increased risk that they would bear if the Company's rate design proposal is adopted. Even more egregious is the Company's claim that its proxy group of companies used to determine its cost of equity have comparable risk mitigation measures in place. Therefore, unlike the recent electric case, where DPL argued that a 25 basis point reduction to cost of equity would be appropriate if its proposed rate design was adopted, here the Company argues that its cost of equity should be increased by 25 basis points if its proposed rate design is rejected.

In evaluating DPL's proposals, the PSC should be mindful of the fact that regulation is a substitute for competition, and that there are no guarantees in the competitive world. To the extent that any of these risk-reducing proposals are accepted by the PSC, due to legislature mandates for example, then the PSC should ensure that there is a commensurate reduction to the Company's return on equity award.

III. SUMMARY OF CONCLUSIONS

Q. What are your conclusions concerning the Company's revenue requirement and its need for rate relief?

A. Based on my analysis of the Company's filing and other documentation in this case, my conclusions are as follows:

1. The twelve months ending June 30, 2010 is an acceptable test period to use in this case to evaluate the reasonableness of the Company's claim.

2. I recommend that the Commission adopt a pro forma capital structure for DPL that consists of 48.28% common equity and 51.72% long-term debt (see Schedule ACC-

2).[1]. This is the capital structure proposed by DPL.

3. If the modified fixed variable rate design is adopted by the PSC, then the Company has a pro forma cost of common equity of 7.17%. If the modified fixed variable rate design is not adopted by the PSC, then the Company should be awarded a return on common equity of 9.07%. (see Schedule ACC-2)

4. Based on my recommended capital structure and capital cost rates, I recommend that the Commission adopt an overall cost of capital of 6.19% for DPL if the modified fixed variable rate design is adopted. If the modified fixed variable rate design is not adopted, then I recommend an overall cost of capital of 7.11%. (see Schedule ACC-2)

5. My recommendations regarding cost of equity and the Company's overall cost of capital should be reduced further if the PSC accepts other proposals by DPL to shift risk from shareholders to ratepayers.

6. DPL has test period, pro forma rate base of $202,551,635 (see Schedule ACC-9).

7. The Company has test period, pro forma operating income at present rates of $15,335,955 (see Schedule ACC-18).

8. DPL has a test period, pro forma revenue surplus of $4,715,102 (see Schedule ACC-1). This is in contrast to the Company's claimed deficiency of $10,203,825.

9. The parties to this proceeding, including DPA, have entered into a Settlement

1 Schedules ACC-1, ACC-38, and ACC-39 are summary schedules, ACC-2 to ACC-8 are cost of capital schedules, ACC-9 to ACC-17 are rate base schedules, and ACC-18 to ACC-37 are operating income schedules.

Agreement in support of the modified fixed variable rate design proposed by DPL.

10. DPL's proposal to require ratepayers to compensate shareholders for higher than anticipated 2009 pension costs should be rejected.

11. DPL's proposal to implement a tracking mechanism to track pension, OBEP, and uncollectible costs and to recover these costs on guaranteed basis from ratepayers should be rejected.

12. I understand that the legislature has approved the implementation of a UFRC. Therefore, DPA is not opposed to the implementation of a UFRC that is consistent with the legislation, provided that there are appropriate ratepayer safeguards in place prior to implementation.

IV. COST OF CAPITAL AND CAPITAL STRUCTURE

Q. What is the cost of capital and capital structure that the Company is requesting in this case?

A. The Company has utilized the following capital structure and cost of capital:

	Percent	Cost	Weighted Cost
Long Term Debt	51.72%	5.28%	2.73%
Common Equity	48.28%	11.00%	5.31%
Overall Cost of Capital			8.04%

In its Application, DPL claims that its proposed cost of equity already reflects reduced risk - assuming that its proposed modified fixed rate design is accepted. The Company claims that its proxy group consists of entities that have rate designs or other risk mitigation measures in place that are comparable to DPL's proposed rate design. If the Company's proposed rate design is not adopted, then the Company states that its return on equity should be increased to 11.25%, which would increase DPL's revenue requirement (and therefore its rate increase request) by approximately $490,000.

A. Capital Structure

Q. How did the Company determine its capital structure claim in this case?

A. DPL's capital structure, as updated on July 2, 2010, is based on the actual amounts of long-term debt and common equity as of June 30, 2010, the end of the test period.

Q. **Are you recommending any adjustment to the capital structure proposed by DPL?**

A. No, I am not recommending any adjustment to the capital structure proposed by DPL.

Q. Why aren't you recommending that the Commission include short-term debt in DPL's capital structure for ratemaking purposes, as you have recommended in some other cases?

A. Short-term debt is an appropriate component of a utility's capital structure if it is regularly and consistently utilized for financing. Most utilities do utilize significant amounts of short-term debt, and I often testify that this debt should be included in a utility's capital structure. In a prior litigated Artesian Water Company base rate case, the Hearing Examiner and the Commission rejected my recommendation to include short-term in that company's capital structure. In his Recommended Decision, the Hearing Examiner recommended that "the Commission again remove the short-term debt in this case in order to maintain an appropriate matching between the capitalization supported by the ratepayers and the capitalization used for setting rates... ."[2] Thus, the Hearing Examiner reached the conclusion that short-term debt was primarily associated with temporary financing of capital projects. Moreover, since Artesian Water Company was not requesting the inclusion of construction work in progress ("CWIP") in rate base, the Hearing Examiner apparently felt that it would be inappropriate to include short-term debt in the capital structure. The

2 Recommended Decision, Docket No. 04-42, paragraph 132.

Commission adopted the Hearing Examiner's recommendation in that case.

As I stated in that case, there are other components of rate base, in addition to CWIP, that are routinely financed by short-term debt, such as materials and suppliers and insurance prepayments. Thus, while I continue to believe that short-term debt should be included in a utility's capital structure, I have decided not to include short-term debt in my recommendation in this case since this issue has been addressed by the Commission.

Q. Is there one distinction between this case and the Artesian rate case that should be considered?

A. Yes, there is. In this case, DPL is requesting the inclusion of CWIP in rate base. I am recommending that CWIP be excluded from rate base. However, if the Commission accepts DPL's proposal to include CWIP in rate base, then it would certainly be appropriate to include short-term debt in the Company's capital structure. If short-term debt was included in the Company's capital structure, the impact would be a further reduction to the overall costs of capital that I have reflected in my testimony.

Q. Is DPL requesting recovery of costs associated with the PHI credit facility, which provides short-term debt to the Company?

A. Yes, it is. DPL has included in its claim a rate base adjustment of $57,989 and an operating expense adjustment of $48,000 relating to a short-term credit facility operated by Pepco Holdings, Inc. ("PHI"). As discussed later in this testimony, there is no rationale for including these costs in utility rates if ratepayers are not receiving any of the benefit of this short-term credit facility. Moreover, the only way that ratepayers would receive benefit from this credit facility is if the Company's capital structure included the average balance of short-term debt and the weighted average short-term debt cost. The Company is attempting to make ratepayers pay for a credit facility without providing ratepayers with any resulting benefit. The Company cannot have it both ways, i.e., exclude short-term debt from the capital structure but include the costs of the credit facility in its revenue requirement. Accordingly, I am recommending that the PSC reject the Company's claims with regard to the credit facility. However, if the Commission permits DPL to recover any of these credit facility costs from ratepayers, then the Company's capital structure should be amended to reflect the inclusion of short-term debt.

B. Cost of Equity

Q. What is the cost of equity that the Company is requesting in this case?

A. DPL is requesting a cost of equity of 11.00%. As noted above, if the Company's proposed modified fixed variable rate structure is rejected, then the Company is requesting a cost of equity of 11.25%.

Q. Do you believe that a 25 basis point differential in cost of equity is appropriate if the Company's proposed modified fixed variable rate structure is accepted?

A. No, the Company's proposed 25 basis point differential is wholly inadequate. As noted earlier, the Company's filing is predicated on shifting as much risk as possible from shareholders to ratepayers. The Company's proposed rate structure will eliminate virtually all revenue risk. As designed by DPL, and as discussed in more detail below, the Company's proposal will result in flat rate customer and demand charges for virtually all customers. Thus, DPL will receive the same amount of natural gas delivery revenue regardless of variations in usage. Moreover, the Company will be protected from revenue fluctuations for any reason, i.e., weather, conservation, economic conditions, more efficient appliances, etc. This results in a tremendous benefit to shareholders, one that is worth considerably more than the 25 basis point differential proposed by DPL.

Q. How did you quantify the impact of the proposed modified fixed variable rate structure on the Company's risk?

A. The Company currently faces two kinds of risks. First, it faces the risk of reduced revenues due to multiple factors, including the factors discussed above. Second, it faces the risk of increased costs. In order to compensate shareholders for taking on this risk, shareholders are rewarded with a return on equity risk premium. This risk premium is intended to compensate shareholders for the increase in risk that they bear relative to bondholders. Returns to bondholders are fixed by the parameters of the various bonds that they purchase. Returns to shareholders are not fixed, but instead vary depending upon the Company's earnings. Moreover, the Company's earnings are impacted by both its revenues and its costs. The proposed rate design eliminates one of these two sources of risk, i.e., revenue risk, from shareholders. It is important to recognize, however, that this risk is not entirely eliminated; it is simply transferred from shareholders, who currently bear this risk, to ratepayers. Therefore, if the Company's proposed rate design is approved, ratepayers will be bearing significantly higher risks while shareholders will receive a significant risk reduction.

If the Company's proposed rate design is accepted, I recommend that the Commission reduce DPL's return on equity premium by 50% to reflect the fact that one of the two risk parameters (revenues and costs) will be eliminated. As discussed below, I first calculated DPL's cost of equity assuming that shareholders will continue to bear the risk of revenue fluctuations. That analysis resulted in a cost of equity of 9.07%. Since the Company's cost of debt is 5.28%, the resulting risk premium is 379 basis points. I then reduced this risk premium by 50% to 189 basis points. Therefore, I am recommending a cost of equity for DPL of 7.17% (5.28% cost of debt + 1.89% equity risk premium). This recommendation provides a better valuation of the differential in risk that results from the proposed rate structure than the 25 basis point differential proposed by the Company. The Company's 25 basis point reduction is wholly inadequate and should be rejected outright by the Commission.

Q. How did you develop your cost of equity recommendation, prior to the risk adjustment discussed above?

A. As noted, I first developed a recommended cost of equity based on traditional methodologies, and assuming a traditional rate structure. Accordingly, I utilized both the Discounted Cash

Flow ("DCF") methodology as well as the Capital Asset Pricing Model ("CAPM"). It is my understanding that the Commission has traditionally relied upon the DCF methodology for determining cost of equity for a regulated utility and therefore I have given greater weight to my DCF result.

Q. Please describe the DCF methodology.

A. The DCF methodology is the most frequently used method to determine an appropriate return on equity for a regulated utility. The DCF methodology equates a utility's return on equity to the expected dividend yield plus expected future growth for comparable investments. Specifically, this methodology is based on the following formula:

$$\text{Return on Equity} = \frac{D_1}{P_0} + g$$

where "D_1" is the expected dividend, "P_0" is the current stock price, and "g" is the expected growth in dividends.

In order to ensure that the return on equity determined for a particular utility is representative of returns for comparable investments of similar risk, the DCF methodology examines returns for similar companies through the use of a "comparable" or "proxy" group.

Q. How did you determine the proxy group to use in your analysis?

A. DPL Witness Frank Hanley utilized two comparable groups, one consisting of natural gas companies and one consisting of combination electric and gas companies. I utilized the same comparable groups as those utilized by Witness Hanley.

To determine an appropriate dividend yield for these comparable companies, i.e. the expected dividend divided by the current price, I calculated the dividend yield for each of the comparable companies under two scenarios. First, I calculated the dividend yield using the average of the stock prices for each company over the past two months. This is similar to the method used by Mr. Hanley. The use of a dividend yield using a two-month average price mitigates the effect of stock price volatility for any given day. Based on the average stock prices over the past two months, and the current dividend for each company, I determined an average dividend yield for the natural gas comparable group of 3.73% and for the combination electric and gas comparable group of 4.60%, as shown in Schedule ACC-5. I also calculated the current dividend yield at September 21, 2010, which showed an average dividend yield for the natural gas comparable group of 3.67% and for the combination group of 4.59%, also shown in Schedule ACC-5. Finally, I examined the average dividend yields as reported in the October 2010 AUS Utility Reports, which showed an average dividend yield for natural gas companies of 3.2% and an average yield for combination electric and gas companies of 4.4%. Based on all of this data, I recommend that a dividend yield of 4.00% be used in the DCF calculation. This recommendation gives greater weight to the dividend yields of the natural gas companies, since it is the Company's natural gas operations for which we are establishing rates in this case. My recommended dividend yield should be increased by one-half of my recommended growth rate, as determined below, to reflect the fact that the DCF model is prospective and dividend yields may grow over the next year. Increasing the dividend yield by one-half of the prospective growth rate is commonly referred to as the "half-year convention."

Q. Did Mr. Hanley also increase his dividend yields by one-half of his recommended growth rate?

A. Yes, he did. Unlike the Company's witness in the recent electric case, who increased his dividend yields by 100% of his recommended growth rates, Mr. Hanley used the half-year convention. The reason for using the half-year convention is that companies do not all change their dividends at the same time, nor do they increase their dividends consistently each quarter. The half-year convention recognizes the variation in dividend changes among companies and is therefore a reasonable and realistic approach to reflecting future growth.

Q. How did you determine an appropriate growth rate to use in the DCF calculation?

A. The actual growth rate used in the DCF analysis is the dividend growth rate. In spite of the fact that the model is based on dividend growth, it is not uncommon for analysts to examine several growth factors, including growth in earnings, dividends, and book value.

As shown on Schedule ACC-6 and as summarized below, average five-year historic growth rates have ranged from 3.6% to 8.8% for the natural gas companies, and from 3.1% to 7.4% for the combination electric and gas companies. Average historic growth rates over the past 10 years have ranged from 2.6% to 6.6% for the natural gas companies, and from 0.4%

to 3.5% for the combination electric and gas companies. Projected growth rates in earnings, dividends, and book value for the natural gas companies range from 4.3% to 4.9%. The Value Line projected growth rates for the combination electric and gas companies range from 4.0% for book value to 5.5% for earnings.

	Natural Gas	Combination Electric/Gas
Earnings – 5 Year Growth	8.8%	7.4%
Dividends – 5 Year Growth	3.6%	3.1%
Book Value – 5 Year Growth	6.6%	5.1%
Earnings – 10 Year Growth	6.6%	2.5%
Dividends – 10 Year Growth	2.6%	0.4%
Book Value – 10 Year Growth	5.5%	3.5%
Value Line Projections – Earnings	4.9%	5.5%
Value Line Projections – Dividends	4.4%	4.2%
Value Line Projections - Book Value	4.3%	4.0%

Based on my review of both historic and projected growth rates, I recommend that a growth rate of 5.5% be utilized. This growth rate is equal to or higher than the projected growth rates in earnings, dividend, or book value for both the natural gas companies and for the combination electric and gas companies. However, I believe a 5.5% growth rate is reasonable in light of the actual five and ten-year historic growth rates shown above.

Q. What are the results of your analysis?

A. My analysis indicates a cost of equity using the DCF methodology of 9.61%, as shown below:

Dividend Yield	4.00%
Growth in Dividend Yield (1/2 X 5.5% X 4.0%)	0.11%
Expected Growth	5.50%
Total	9.61%

Q. How does your DCF recommendation compare with the DCF analysis presented by Mr. Hanley?

A. My recommendation is very close to Mr. Hanley's results for his natural gas comparable group. As shown on Schedule FJH-9, Mr. Hanley's analysis produced a DCF result for the natural gas group of 9.67%, which was the median for the group. If Mr. Hanley had used the mean instead of the median, his result would have been even lower at 9.13%.

Mr. Hanley's combination electric and gas comparable group resulted in a higher cost of equity, with a median of 11.10% and a mean of 11.05%. I believe that there are two reasons for this unrealistically high result. First, it appears that the dividend yields for the comparable group are inflated, which I suspect is due to the fact that prices for at least some of these stocks have increased since Mr. Hanley prepared his analysis. These higher stock prices would result in lower dividend yields, and therefore a lower cost of equity (all other things being. equal). In addition, the growth rates used by Mr. Hanley are simply too high. The average growth rate for the combination electric and gas combination group is 5.98 % vs. 5.10% for his stand-alone natural gas group. Moreover, his results are being influenced by the inclusion of Empire District Electric Company, with a projected growth rate of 7.0% and an indicated cost of equity of 14.21%. In Empire's recent base rate case in Kansas, the Company agreed to a settlement reflecting an overall cost of capital of 8.4%, significantly below the 14.21% assumed by Mr. Hanley in his analysis.[3]

There are other flaws in Mr. Hanley's analysis of the combination electric and gas companies comparable group. For example, he generally utilized three earnings projections (by Value Line, Reuters, and Zack's) to determine his pro forma growth rates. For ALLETE, Inc., the three projections were (0.50)%, 8.0%, and 3.7%. Mr. Hanley discarded any negative projections so therefore he utilized a projected growth rate for ALLETE, Inc. of 5.85%, which was considerably higher than two of his three sources. Moreover, Mr. Hanley's analysis is fatally flawed by his failure to consider historic growth projections in his analysis.

Q. Did you also calculate a cost of equity based on the CAPM methodology?

A. Yes, I did.

Q. Please provide a brief description of the CAPM methodology.

A. The CAPM methodology is based on the following formula:

Cost of Equity = Risk Free Rate + Beta (Risk Premium)

3 KCC Docket No. 10-EDPE-314-RTS, Stipulation and Agreement, paragraph 13.

or

$$\text{Cost of Equity} = R_f + B(R_m - R_f)$$

The CAPM methodology assumes that the cost of equity is equal to a risk-free rate plus some market-adjusted risk premium. The risk premium is adjusted by Beta, which is a measure of the extent to which an investor can diversify his market risk. The ability to diversify market risk is a measure of the extent to which a particular stock's price changes relative to changes in the overall stock market. Thus, a Beta of 1.00 means that changes in the price of a particular stock can be fully explained by changes in the overall market. A stock with a Beta of 0.60 will exhibit price changes that are only 60% as great as the price changes experienced by the overall market. Utility stocks have traditionally been less volatile than the overall market, i.e., their stock prices do not fluctuate as significantly as the market as a whole, and therefore their Betas have generally been less than 1.0.

Q. How did you calculate the cost of equity using the CAPM?

A. My CAPM analysis is shown in Schedule ACC-7. First, I used a risk-free rate of 3.73% for the yield on long-term U.S. Government bonds, which was the rate for thirty-year bonds at September 23, 2010, per the Statistical Release by the Federal Reserve Board. Over the past year, this rate has ranged from 3.52% to 4.85%. In addition, I used the average Beta for the proxy groups. As shown in Schedule ACC-8, the average beta for the natural gas companies is 0.64, while the average beta for the combination electric and gas companies is 0.68. Given the fact that these are relatively close, I have reflected a beta of 0.68 in my CAPM analysis. Finally, since I am using a long-term U.S. Government bond rate as the risk-free rate, the risk premium that should be used is the historic risk premium of stocks over the rates for long-term government bonds. According to the Ibbotson Associates' publication, *2010 Classic Yearbook: Market Results for Stocks, Bonds, Bills, and Inflation, 1926-2009,* the risk premium of stocks relative to long-term risk-free rates using geometric mean returns is 5.45%.

Q. What is the difference between a geometric and an arithmetic mean return?

A. An arithmetic mean is a simple average of each year's percentage return. A geometric mean takes compounding into effect. As a result, the arithmetic mean overstates the historic return to investors. For example, suppose an investor starts with $100. In year 1, he makes 100% or $100. He now has $200. In year 2, he loses 50%, or $100. He is now back to $100.

The arithmetic mean of these transactions is 100% - 50% or 50%/ 2 = 25% per year. The geometric mean of these transactions is 0%. In this simple example, it is clear that the geometric mean more appropriately reflects the real return to the investor, who started with $100 and who still has $100 two years later. The use of the arithmetic mean would suggest that the investor should have $156.25 after two years ($100 X 1.25 X 1.25), when in fact the investor actually has considerably less. Therefore, a geometric mean return is a more appropriate measure of the real return to an investor, if it is used as I am using it here, i.e., to develop an historic relationship between long-term risk free rates and market risk premiums. Some utility companies have argued in the past that an arithmetic, rather than geometric mean return should be used, since the arithmetic mean return is more predictive of future results. However, in my case, I am not using the mean to develop an expected outcome, I am simply using the mean returns to develop an historic relationship. Therefore, the geometric mean is the appropriate measure, as illustrated in the above example.

Q. What is the Company's cost of equity using a CAPM approach?

A. Given a long-term risk-free rate of 3.73%, a Beta of 0.68, and a risk premium of 5.45%, the CAPM methodology produces a cost of equity of 7.44%, as shown on Schedule ACC-7.

Risk Free Rate + Beta (Risk Premium) = Cost of Equity

3.73% + (0.68 X 5.45%) = 7.44%

Mr. Hanley presented two versions of the CAPM analysis, resulting in recommendations of 9.94% and 10.63%. Each of Mr. Hanley's analyses is flawed. Perhaps the most serious flaw is in the risk-free rate used by Mr. Hanley. Both of his analyses utilize a risk-free rate of 4.78%, which was the projected 30-year Treasury Rate for the six quarters from January 2010 to June 2011 at the time that Mr. Hanley prepared his testimony. Mr. Hanley's projections, which are shown on Schedule FJH-16, page 3, assumed increasing 30-year Treasury Rates each quarter. In fact, his projected rate for the third quarter of 2010 was 4.70%, which is almost 100 basis points higher than the actual rate at September 21, 2010 that I used in my analysis. Thus, the projections used by Mr. Hanley are unsupportable. In addition, Mr. Hanley used a market risk premium of 7.94%, which is almost 250 basis points above the 5.45% that I reflect in my CAPM analysis. Mr. Hanley's risk premium reflects the average of a long-term historic arithmetic risk premium of 6.60%, and a Value Line projected risk premium of 9.28%. The latter is based on the totally unrealistic projection of a 3-5 year annual market return of 14.06%, while the former is based on the arithmetic mean instead of the geometric mean. Hence, both Mr. Hanley's risk-free rate and his market risk premium are widely overstated.

Q. Does Mr. Hanley also utilize a risk premium model to develop his cost of equity recommendation?

A. Yes, in addition to his DCF and CAPM analyses, Mr. Hanley also relied upon a risk premium model. To my knowledge, the risk premium model has not been utilized in prior cases by the PSC. In addition, the risk premium model is similarly flawed by the use of speculative forecasts of utility bond rates and by the use of arithmetic mean returns.

Q. In addition to the flaws in Mr. Hanley's analyses that you have identified above, do you have any other concerns with his cost of equity recommendation?

A. Yes, I do. Mr. Hanley also calculated what he called "market-based common equity cost rates" for two proxy groups of non-regulated companies. Mr. Hanley's analyses include companies such as McDonalds Corp., Wal-Mart Stores, Colgate-Palmolive, and Tootsie

Roll, companies that are in no way comparable to DPL. Accordingly, I have completely discounted this analysis. I am unaware of any case in which the PSC has considered returns for non-utility companies such as those used by Mr. Hanley when establishing a cost of equity for a regulated natural gas company. Hence, Mr. Hanley's analysis of the non-utility companies should be rejected.

In addition, Mr. Hanley also adjusted his cost of equity results to include flotation costs. This Commission has consistently excluded flotation costs when determining cost of equity. Finally, Mr. Hanley has included a small company premium, which similarly has been rejected in the past by the PSC.

Q. Based on your analysis of the DCF and CAPM results, what cost of equity are you recommending in this case?

A. The DCF methodology and the CAPM methodologies suggest that a return on equity of 7.44% to 9.61% would be appropriate. Since I recognize that the Commission has generally relied primarily upon the DCF, I have weighted my results with a 75% weighting for the DCF methodology and a 25% weighting for the CAPM methodology. This results in a cost of equity of 9.07%, as shown below:

DCF Result	9.61% X 75% =	7.21%
CAPM	7.44% X 25% =	1.86%
Total		9.07%

Q. What is the overall cost of capital that you are recommending for DPL?

A. Based on a 75% DCF /25% CAPM weighting of the cost of equity, under a traditional ratemaking approach DPL would have a cost of equity of 9.07%, as shown in Schedule ACC-3. However, as discussed above, I am recommending that the Company's equity risk premium be reduced by 50%, due to the significant reduction in risk that will result if the Commission accepts the proposed new modified fixed variable rate design. The Company has a cost of debt of 5.28%. Therefore, the equity risk premium is 379 basis points. 50% of this risk premium, or 189 basis points, should be added to the cost of debt to determine an appropriate cost of equity, assuming that the new rate structure is adopted. Therefore, if the new modified fixed variable rate structure is adopted, I recommend a cost of equity for DPL of 7.17%.

Q. Doesn't Mr. Hanley claim that his comparable groups also include companies that have decoupling mechanisms in place?

A. Yes, he does. However, I strongly disagree with Mr. Hanley's analysis, for several reasons. First, all of the natural gas companies in Mr. Hanley's comparable group were included in the comparable group proposed in DPL's last gas base rate case. There was no indication in that case that there were any significant differences in risk profile between DPL and the companies in the comparable group, due to the comparable companies having a less risky rate structure than DPL.

Similarly, nine of the eleven companies in the electric and gas combination group were included in the proxy group used in the Company's recent electric case. In that case, the Company contended that a return on equity reduction was necessary if the new rate structure was approved. Now, just a few months later, DPL is taking the position that no downward adjustment is required, but instead that an upward adjustment is required if the new rate structure is not approved. Clearly, between filing its electric case and its gas case, the Company has had second thoughts about the best way to insulate its shareholders from risk, i.e., adopt the new rate design but do not reflect any reduction to return on equity!

Moreover, the natural gas comparable group includes two companies with which I am very familiar, South Jersey Industries, Inc. and New Jersey Natural Resources. Neither of these companies has the straight fixed variable rate design being proposed in this case. While these two companies do have Conservation Incentive Plans ("CIP") in place, any additional revenues collected from ratepayers as a result of those plans must be matched with a corresponding savings to ratepayers through reduced capacity costs or other measures. Thus, ratepayers are held harmless from any net increase resulting from the CIP.

The PSC should see beyond DPL's new strategy to minimize risk while maximizing shareholder return. Changing the Company's rate of return witness does not change the underlying fundamentals of the companies in the Company's comparable groups. Accordingly, the PSC should reject Mr. Hanley's argument that the comparable groups already reflect risk mitigation measures that are comparable to the Company's proposed modified straight fixed variable rate design.

C. Overall Cost of Capital

Q. What is the overall cost of capital that you are recommending?

A. Assuming that the Company's proposed modified straight fixed variable rate design is adopted by the PSC, then I am recommending an overall cost of capital for DPL of 6.19%, based on the following capital structure and cost rates:

	Percentage	Cost	Weighted Cost
Long Term Debt	51.72%	5.28%	2.73%
Common Equity	48.28%	7.17%	3.46%
Total	100.00%		6.19%

If the Commission grants DPL's request to include CWIP in rate base or its request to recover certain costs associated with the PHI credit facility, then the overall cost of capital should be reduced further to reflect the inclusion of short-term debt in the Company's capital structure.

V. RATE BASE ISSUES

Q. What test year and test period did the Company utilize to develop its rate base claim in this proceeding?

A. The test year in this case is the twelve-month period ending December 31, 2009. As its test period, DPL chose to utilize the twelve-months ending June 30, 2010. The Company's filing is generally based on average balances during the test period.

Q. Are you recommending any adjustments to the Company's rate base claim?

A. Yes, I am recommending adjustments to the Company's claims for "reliability" plant, construction work in progress, cash working capital, miscellaneous rate base items, unamortized regulatory costs, deferred AMI costs, unamortized credit facility costs, and unrecovered 2009 pension costs.

A. Reliability Plant

Q. Please describe the Company's claims associated with reliability plant adjustments.

A. In its filing, DPL included an adjustment to add almost $9.6 million to its rate base claim relating to utility plant-in-service, along with associated adjustments to accumulated depreciation and deferred income taxes, that is has identified as "Reliability Plant". The Company's claim includes three components. First, DPL has included a net rate base adjustment of $4,599,135 related to reliability plant that the Company claims was added during the test period. Second, the Company included a net rate base adjustment of

$2,111,658, related to projects that were completed between July 1, 2010 and August 30, 2010. Third, the Company included a net rate base adjustment of $2,867,364 related to budgeted projects for the period September 1, 2010 through October 30, 2010.

Q. Did the Company provide any support for these adjustments in its testimony?

A. No, it did not. Mr. Von Steuben, the sponsor of these adjustments (Adjustments 16, 17A, and 17B) provides no explanation for why inclusion of this post-test period plant should be included in rate base. On page 15 of his testimony, Mr. Von Steuben states that this plant should be included in rate base "to properly recognize the value that customers are currently realizing and will realize during the rate effective period." However, Mr. Von Steuben does not define what constitutes a "reliability plant" project nor does he explain why these projects should be provided with extraordinary ratemaking treatment. Mr. Von Steuben does state that these adjustments are similar to adjustments permitted in Docket No. 05-304. However, in that case, it appears that no party took issue with the specific projects included in the Company's claim. In this case, no specific information on proposed projects was included in either the Company's initial testimony or in its 12+0 Update.

Q. Didn't Mr. Phillips provide testimony on the reliability projects included in the Company's 2010 budget?

A. Mr. Phillips provided a one paragraph description of the Company's $16 million 2010 budget for reliability projects. However, there was no attempt by Mr. Phillips to tie these projects into the Company's claims for post-test year plant additions. The Company's workpapers contain no additional information on these projects or why they should be afforded extraordinary ratemaking treatment in this case. Moreover, Mr. Phillips did not update his testimony for the 12+0 actual results, even though the rate base impact of these three adjustments was revised by Mr. Von Steuben as part of that update. Therefore, at this time we do not know how the Company defines "reliability", what specific projects are included in its claim, and when those projects were completed. We do know, however, that none of these projects had been booked to utility plant-in-service at June 30, 2010, the end of the test period in this case.

Q. Didn't the Company claim in response to a data request that at least some of this plant was booked to utility plant-in-service at June 30, 2010?

A. Yes, in response to DPA-122, Mr. Von Steuben indicated that Adjustment No. 16 "reflects projects that were completed, placed in service during the test year and booked to Utility Plant in Service at June 20, 2010." However, if these projects were already placed into service during the test year, then they should already be included in the average test period utility plant-in-service balances. Moreover, inclusion of these plant balances distorts the average rate base on which the Company's claim is based.

Q. Didn't the Hearing Examiner in the Company's current electric case recommend that the Commission accept a reliability plant adjustment proposed by DPL?

A. Yes, she did. However, in her Recommended Decision, the Hearing Examiner indicated that the Company's "testimony describes at length the nature of these projects and why they are needed to support the integrity of the distribution system."[4] Moreover, the Hearing Examiner stated that she found these "descriptions of the need for this construction work...compelling...".[5] Given the lack of any testimony in this case with regard to the specific projects included in this adjustment, it is difficult to see how a similar argument can be made here.

Q. Is it normal and customary for a utility to continually add plant?

A. Yes, it is. As noted in Mr. Wathen's testimony at page 6, over the past three years the Company has added approximately $70 million in gas distribution plant. However, it is interesting to note that the Company's rate base claim in this case is only $1.07 million more than its claim in its last base rate case (PSC Docket No. 06-284). This fact illustrates the danger of regulatory commissions adopting post-test period adjustments, particularly those that are based on single-issues such as reliability plant. While the Company proposes to reflect these plant additions in rate base, its rate base claim is, for the most part, based on <u>average</u> balances during the test period. As demonstrated above, when the Company's entire rate base is reviewed, it is clear that rate base, which is the driver behind the Company's return claim, grows much more slowly than does utility plant in service. In fact, the Company's claim for a net rate base adjustment of $9.6 million relating to reliability plant

4 Hearing Examiner's Report, Docket No. 09-414, paragraph 196.

additions is more than 8 times as large as the total claimed increase in rate base since the Company's last base rate case. Thus, including post-test period plant additions, without making corresponding adjustments for rate base components such as additions to the depreciation reserve and deferred income tax reserve, will overstate rate base and result in excessive utility rates.[6]

In addition, the Company's adjustment ignores other changes that have occurred since the midpoint of the test period, such as growth in customers. Because utilities are continually adding utility plant, regulatory commissions use a test year or test period concept to determine a utility's rate base at a point in time. In this case, the Company's claim is based on a rate base at the midpoint of the test period, and its revenue claim reflects customers at December 31, 2009. The PSC should uphold the test period concept and reject the Company's selective reliability plant adjustments, especially since DPL has failed to provide any "compelling" rationale in this case for the inclusion of this plant in rate base.

Q Why is it important to determine a Company's rate base using the test period concept?

A. It is important to utilize a test period concept because a utility's revenue requirement components are continually changing. As shown above, not only do utilities continually add utility plant, but also there are constantly other changes to the components that comprise a utility's revenue requirement. For example, while plant-in-service generally increases over

5 Id.

6 While the Company did make small adjustments to its depreciation reserve and deferred tax reserve to reflect depreciation associated specifically with the reliability projects, it did not make adjustments to reflect additions to the reserves associated with the balance of its utility plant in service.

time, a utility's accumulated reserve for depreciation, which is a rate base deduction, also tends to increase over time. Generally, utilities are continually adding new customers, providing an additional revenue source for the utility. Operating expenses may increase or decrease over time, and from year-to-year. For all these reasons, regulatory commissions establish utility rates based on a test year concept, in order to match all the components of the regulatory triad. The Company's selective adjustment to reflect one post-test period change in rate base violates the regulatory triad and the test period concept. Accordingly, I have made an adjustment at Schedule ACC-10 to eliminate the Company's $9.6 million Reliability Plant adjustments from utility plant-in-service.

Q. Why are you eliminating that portion of the Company's adjustment that relates to plant completed within the test period (Company Adjustment No. 16), as well as the plant completed after the end of the test period (Adjustment No. 17A and No. 17B)?

A. As noted, utilities are continually adding utility plant. Once a project is completed and placed into service, the burden should be on utilities to transfer this plant to utility plant-in-service in a timely manner. While the Company contends that the plant included in Adjustment No. 16 was booked to utility plant-in-service by June 30, 2010, it did not explain why then an additional adjustment is necessary. The utility plant-in-service account is the most appropriate source to quantify the plant that is actually serving the utility's customers. Moreover, in this case, the Company has elected to utilize an average rate base. The burden should not be on the Commission, or Staff, or DPA to review individual project reports to determine whether or not a project is in-service. Thus, the Commission should limit utility plant included in rate base to plant that is actually booked to utility plant in service during the test period. Moreover, since the Company chose to utilize an average rate base, the test period average balances for utility plant-in-service should be the amounts included in rate base. Therefore, I recommend that the PSC reject Adjustment No. 16, as well as Adjustment Nos. 17A and 17B, relating to reliability plant.

Q. How did you quantify your adjustment?

A. I have shown the net rate base impact of the reliability plant adjustments in Schedule ACC-10, and have carried this net rate base adjustment over to my summary schedule at Schedule ACC-9. While this adjustment is denoted as a utility plant-in-service adjustment, it should be noted that it includes all rate base components of the reliability plant adjustment, including the impact on the Company's depreciation reserve and deferred tax reserve. This is consistent with the methodology used by the Company whereby it determined a net rate base impact, including any impacts on the depreciation and deferred tax reserves, for each rate base adjustment included in Mr. Von Steuben's schedules, as shown on Schedule WMV-2, page 1.

B. Construction Work in Progress ("CWIP")

Q. What is CWIP?

A. CWIP is plant that is being constructed but which has not yet been completed and placed into service. Once the plant is completed and serving customers, then the plant is booked to utility plant-in-service and the utility begins to take depreciation expense on the plant. Inclusion of CWIP in rate base creates a mismatch among the components of the test period, since it represents plant that was not actually serving customers during the test period. Thus, including CWIP in rate base overstates the plant necessary to provide service to those customers who were present during the test period and on whom the Company's revenue claim is based.

Q. What CWIP has the Company included in its rate base claim?

A. DPL included its average test period CWIP balance of $4,697,990 in rate base. This claim does reflect adjustments to the actual average CWIP balance relating to the transfer of certain amounts to other rate base components, such as CWIP relating to reliability plant additions.

Q. Should CWIP be included in rate base?

A. No, I do not believe that CWIP is an appropriate rate base element. CWIP does not represent facilities that are used or useful in the provision of utility service. In addition, including this plant in rate base violates the regulatory principle of intergenerational equity by requiring current ratepayers to pay a return on plant that is not providing them with utility service and which may never provide current ratepayers with utility service.

One of the basic principles of utility ratemaking is that shareholders are entitled to a return on, and to a return of, plant that is used and useful in the provision of safe and adequate utility service. By its definition, CWIP does not meet this criteria. The Company should accrue an allowance for funds used during construction ("AFUDC") on projects until such time as the project is completed and placed into service. Since the Company is compensated for its costs in this manner, there is no need to make an exception to good ratemaking principles by allowing CWIP to be included in rate base.

The AFUDC methodology has two distinct advantages over permitting CWIP in rate base. First, it properly matches the benefits provided to ratepayers with the costs paid by those ratepayers, while allowing CWIP in rate base forces today's ratepayers to pay for plant that may never provide them with any benefit. Second, allowing CWIP in rate base transfers the risk during project construction from shareholders, where it properly belongs, to ratepayers. The shareholders will be compensated for that risk once the plant enters utility service and the AFUDC is appropriately included in rate base.

Q. What do you recommend?

A. I recommend that the Commission reject DPL's claim for the inclusion of CWIP in rate base. My adjustment to eliminate CWIP is shown in Schedule ACC-11.

Q. Has the PSC excluded CWIP from rate base in past cases?

A. Yes, it has. In its decision in PSC Docket No. 05-304, the Commission stated "...our position is, and has been for some time, that we retain the discretion to include or exclude CWIP from rate base based on the facts presented in each individual case."[7] The Commission went on to state "[I]n this docket, because the AFUDC allowance is so low, including CWIP in rate base has a considerable adverse impact on Delmarva's revenue requirement."[8] Similarly, in her recent Report in the current electric rate case, the Hearing Examiner concluded that CWIP should continue to be excluded from rate base.

Q. Is the Commission faced with a similar situation in this case?

A. Yes, it is. In this case, the Company has included approximately $4.7 million of CWIP in rate base. This CWIP increases the Company's revenue requirement claim by approximately $400,000, assuming DPA's recommended cost of capital, while the offsetting entry to AFUDC proposed by DPL reduces the Company's revenue requirement by approximately $22,850. Thus, the Company's proposal to include CWIP in rate base results in a substantial net increase to ratepayers. The situation presented to the Commission in this case is very similar to the situation in PSC Docket 05-304. The Commission denied the Company's claim for CWIP in that case and I recommend that it make a similar finding in this proceeding.

7 Final Findings, Opinion, and Order No. 6930, Docket No. 05-304, paragraph 47.
8 Id., paragraph 48.

C. Cash Working Capital

Q. What is cash working capital?

A. Cash working capital is the amount of cash that is required by a utility in order to cover cash outflows between the time that revenues are received from customers and the time that expenses must be paid. For example, assume that a utility bills its customers monthly and that it receives monthly revenues approximately 30 days after the midpoint of the date that service is provided. If the Company pays its employees weekly, it will have a need for cash prior to receiving the monthly revenue stream. If, on the other hand, the Company pays its interest expense quarterly, it will receive these revenues well in advance of needing the funds to pay interest expense.

Q. Do companies always have a positive cash working capital requirement?

A. No, they do not. The actual amount and timing of cash flows dictate whether or not a utility requires a cash working capital allowance. Therefore, one should examine actual cash flows through a lead/lag study in order to accurately measure a utility's need for cash working capital.

Q. Did the Company provide a lead/lag study in this case to support its cash working capital claim?

A. Yes, it did. Based on this study, DPL is requesting a cash working capital allowance of $12,554,204. Approximately 72% of this amount, or $8,989,230, relates to purchased fuel costs.

Q. Are you recommending any adjustments to the Company's cash working capital claim?

A. Yes, I am recommending one adjustment. Specifically, I am recommending the elimination of purchased fuel costs from the study's lead/lag study. The Company's lead/lag study assumes that each month customers are paying for gas purchased to serve them in the month being billed. The Company has included an expense lag for gas costs of 40.59 days in its study, which reflects a service lag of approximately 15.2 days and a payment lag of approximately 25.39 days. DPL is also reflecting a revenue lag of 60.08 days. Therefore, the Company is assuming that the revenues received, on average, 60.08 days after the midpoint of the service period is intended to compensate them for expenses paid, on average, 40.59 days after the associated fuel was procured. However, DPL has a gas cost rate ("GCR") adjustment clause that is based on two factors: estimated gas costs for a twelve-month period and an actual cost adjustment true-up factor. Therefore, in any given month, there is likely to be either an under-recovery or over-recovery of gas costs. The Company's lead/lag study incorrectly assumes a matching of monthly revenues and expenses with a 19.49 day net lag (60.08 day revenue lag - 40.59 day expense lag). However, in any particular month, the revenue received by the Company may be paying for gas purchased in the past, or it may be paying for gas that is still to be purchased in the future.

Because of the special nature of purchased gas adjustment clauses, gas costs are frequently excluded from the cash working capital calculation. This is because it is very difficult at any point in time to determine if the Company is being compensated for prior costs, current costs, or future costs.

Q. Does the Company collect carrying costs on its deferred purchased gas account?

A. Yes, it does. DPL is permitted to charge interest to ratepayers on under-recoveries in its GCR account. The fact that the Company already collects a carrying cost on this balance is another reason why DPL's cash working capital study should be adjusted to eliminate gas costs.

Q. What do you recommend?

A. I recommend that the Commission exclude from rate base the Company's claim for cash working capital associated with purchased gas costs. The Company has not demonstrated that there is any cash working capital requirement associated with these costs. In fact, due to the nature in which the GCR operates, there may be no cash working capital requirement generated by these costs.

Q. What is the total cash working capital requirement that you used in the development of your pro forma rate base?

A. As shown in Schedule ACC-12, I have reduced the Company's claim by $8,989,230. Thus, my cash working capital adjustment results in a total cash working capital allowance for DPL of $3,564,974. It should be noted that this amount does not reflect the impact of the expense adjustments recommended in this testimony. The Company's cash working capital claim should be further updated to reflect the level of pro forma costs ultimately adopted by the Commission.

D. Miscellaneous Rate Base Items

Q. What did the Company include in its claim for Miscellaneous Rate Base Items?

A. DPL's claim includes three components: Prepaid Pension Costs of $11,570,304, Accrued OPEB Liability of ($1,818,869), and Prepaid Insurance of $3,941.

Q. Are you recommending any adjustments to the Company's claim?

A. Yes, I am recommending that the Company's claim for Prepaid Pension Costs and for Accrued OPEB Liability be eliminated from rate base. The Company first argued that Prepaid Pension Costs should be included in rate base in PSC Docket No. 05-304. In that case, the Company argued that it should be permitted to include an adjustment to rate base to compensate shareholders for the fact that the revenue requirement included a negative pension expense. Since the adoption of Financial Accounting Standards Board No. 87 and No. 106, pension and OPEB expense have been determined on an actuarial basis. This methodology seeks to recover the cost of pension and OPEB benefits over the working lives of the employees who receive such benefits, based on assumptions about salary levels, earnings on fund balances, mortality rates, and other factors. There is a separate calculation that determines funding requirements. This Commission has adopted the actuarial methodology for determining pension and OBEP costs. In any given year, the actuarial valuation may be negative or positive. If the Company's assumptions were always 100% accurate, there would be a positive pension and OBEP expense each year. Moreover, an employee's benefits would be recognized over their working life. However, assumptions are never 100% accurate. Thus, in some years, pension (and OPEB) costs can be negative, based on the fact that assumptions in prior years resulting in higher than necessary costs. For example, if one assumes a 5% return on investment, and actual returns are 7%, a negative expense may be booked in a subsequent year.

In PSC Docket No. 05-304, DPL included a negative pension expense in its revenue requirement. However, the Company argued that it was entitled to include an offsetting regulatory asset in rate base, in order to provide a return to investors who were providing the working capital associated with the negative expense. The PSC agreed, noting "...we believe that the pre-paid pension asset is appropriately included in rate base because it is caused by a negative pension expense, which reduces base rates, resulting in rates that are lower than they otherwise might be, and at the same time creates a cash working capital requirement."[9]

Q. Is the Company proposing to include a negative pension expense in its revenue requirement in this case?

9 Order No. 6930, PSC Docket No. 05-304, page 27.

A. No, it is not. The Company no longer has a negative pension expense included in its revenue requirement. Thus, the basis for the inclusion of the pension asset in rate base is no longer valid. Accordingly, I am recommending that the regulatory asset associated with Prepaid Pension Costs be excluded from rate base. My adjustment is shown in Schedule ACC-13.

Moreover, I am also recommending that the Accrued OPEB Liability be excluded from rate base, even though in this case the Company's adjustment reduces its rate base claim. As fully discussed in my testimony in PSC Docket No. 05-304, if the PSC is using actuarial values in a utility's revenue requirement, then I do not believe that it is appropriate to include any rate base components relating to true-ups of accrued vs. funded liabilities. The accrual methodology already takes into account funding status. Moreover, over time the amount funded to the Company's pension and OPEB funds will equal its calculated accrual costs. While there will be timing differences due to variations in assumptions from year-to-year, and due to actual vs. projected results, these variations will all be accounted for in subsequent actuarial studies. In my opinion, including rate base adjustments relating to pension and OPEB costs inappropriately combines the accrual methodology used in the actuarial studies, and which has been adopted by this Commission for ratemaking purposes, with the cash funding approach used by some other regulatory commissions. Accordingly, at Schedule ACC-13, I have also made an adjustment to eliminate the rate base credit of ($1,818,869) included by DPL relating to its OPEB liability.

E. Unamortized Regulatory Costs

Q. Please explain the Company's rate base claim for unamortized regulatory costs.

A. In its filing, DPL included a regulatory commission expense claim consisting of two parts: a) costs for the current rate case of $674,000, amortized over three years, and b) normalized non-rate case costs based on a three year normalization. The Company also included a rate base adjustment of $333,321 consisting of unamortized rate case costs associated with the current case. This claim was calculated based on the average balance during the first year of the amortization, net of deferred taxes.

Q. Are you recommending any adjustment to the Company's claim?

A. Yes, I am recommending that the Company's claim be denied. The Delaware PSC has a policy of normalizing, not amortizing, regulatory commission expenses including rate case costs. If costs are normalized, there is no "unamortized balance". Normalization provides for the recovery of a prospective cost in prospective rates while amortization provides for the recovery of a previously incurred cost in prospective rates. Amortization is, by definition, retroactive ratemaking. Accordingly, normalization is the appropriate ratemaking treatment for a cost that occurs periodically although not necessarily annually, such as rate case costs. The PSC has utilized normalization, rather than amortization, for rate case costs for many years, at least since its decision in PSC Docket No. 90-10. Given the Commission's policy to normalize rate case costs, there is no rationale for including an unamortized balance in rate base. Therefore, at Schedule ACC-14, I have made an adjustment to eliminate the

Company's claim for unamortized regulatory costs in rate base.

Q. Did the Company include unamortized rate case costs in its rate base claim in the recent electric case?

A. No, it did not. DPL did not make an adjustment to include an unamortized balance of rate case costs in its recent electric case. In that case, the Company appropriately reflected the normalization methodology. The Company's proposed adjustment in this case is even more puzzling when one considers the fact that DPL proposed to normalize, and not amortize, its other regulatory commission costs in this case. The Company's rate base adjustment in this case is contrary to long-standing Commission policy, contrary to the Company's testimony in the electric case, and contrary to the Company's proposed treatment for non-rate case related regulatory costs. Accordingly, I recommend that it be rejected by the Commission.

F. Deferred Advanced Metering Infrastructure ("AMI") Costs

Q. What are AMI projects?

A As stated on page 5 of Mr. Pott's testimony, AMI projects involve upgrading the Company's metering technology and processes to provide automated meter reading of the gas meters. In addition, Delmarva will provide customers with their daily and hourly gas usage data on the "My Account" area of its Web site.

Q. Please summarize the rate base adjustments that DPL included in its claim relating to

AMI projects.

A. DPL originally included three rate base adjustments in its claim. First, it included an adjustment of $11,617,306 related to net plant associated with AMI projects. This included AMI plant additions projected for 2010 and 2011, the removal of associated test period CWIP and the associated deferred tax impact. Second, it included a rate base adjustment of ($109,759), to reflect the difference between the retirement of the remote gas indexes, which were being removed from rate base, and the inclusion of an associated stranded cost associated with these indexes. Third, DPL included a rate base adjustment of $1,064,630 relating to the unamortized balance of deferred AMI costs.

Q. How has the Commission directed that AMI costs be treated for ratemaking purposes?

A. In Order No. 7420, issued in PSC Docket No. 07-28 on September 16, 2008, the PSC stated that:

> The Commission approves the diffusion of the advanced metering technology into the electric and natural gas distribution system networks and the Commission permits Delmarva to establish a regulatory asset to cover recovery of and on the appropriate operating costs associated with the deployment of Advanced Metering Infrastructure and demand response equipment. The Commission, Staff, and other parties remain free to challenge the level or any other aspects of the asset's recovery in rates when Delmarva seeks recovery of the regulatory asset in base rates. For ratemaking purposes, the Commission may wish to consider an appropriately valued regulatory asset for advanced metering infrastructure investment consistent with the matching principle giving consideration to both costs and savings in the context of its next base rate case proceeding.

Q. Has the DPA generally been supportive of the Company's AMI projects for its electric and gas services?

A. Yes, it has. Although I have not been personally involved in all of the discussions regarding the AMI project, it is my understanding that DPA is generally supportive of the AMI projects. The DPA recognizes, however, that AMI technology is likely to have a greater impact on electric usage and electric costs than on gas usage and gas costs. This is because peak supplies of electricity at the wholesale level are generally priced on a real-time basis while peak supplies of natural gas are generally priced on a day-ahead basis. Therefore, intraday variations in usage have less of an impact on natural gas service than on electric service. Nevertheless, DPA supports the Company's initiatives with regard to AMI projects for both natural gas and electric service, provided that the associated ratemaking treatment appropriately matches costs and savings as noted in Order No. 7420.

Q. What is the status of the Company's AMI deployment?

A. According to the testimony of Company Witness Potts, DPL expected to complete the deployment and activation of the AMI system in New Castle County in the first quarter of 2011. However, on October 11, 2010, DPL filed Supplemental Testimony informing the parties that its deployment was behind schedule, and modifying its claim in this case.

Q. What revisions did DPL make to its AMI claim in its Supplemental Testimony?

A. In its Supplemental Testimony, DPL eliminated two of its three rate base adjustments associated with the AMI deployment. At the present time, the Company is seeking to recover $1,057,530 in deferred costs over a period of 15 years. In addition, DPL is seeking to include the average unamortized balance of $606,671 in rate base.

Q. Are you recommending any adjustment to the Company's rate base claim?

A. Yes, I am recommending that the Company's rate base claim be denied. While I have generally accepted the Company's proposal to recover actual AMI start-up costs over a period of 15 years, I do not believe that ratepayers should be paying a return on these deferred costs. At this time, ratepayers are not getting any benefit from this deployment. Moreover, the Company has not included any cost savings relating to reductions in meter reading costs or other costs in its Supplemental Testimony. In addition, as noted previously, the eventual benefits to ratepayers are limited by the fact that real time reductions in gas usage will not significantly impact procurement of natural gas during peak periods. Permitting recovery of any of these deferred costs in current rates constitutes extraordinary ratemaking treatment, given that these costs are non-recurring and that the AMI program is not yet implemented. Nevertheless, DPA is willing to begin to permit the Company to recover these costs, given the State's policies with regard to energy efficiency and demand response programs. However, ratepayers should not be required to bear further costs by providing shareholders with a return on the unamortized balance. Given the 15 year amortization period, and the delay in deployment, ratepayers could be required to provide shareholders with significant returns if these amounts are included in rate base. Accordingly, at Schedule ACC-15, I have made an adjustment to eliminate deferred AMI costs from the Company's rate base claim.

G. Credit Facility Costs

Q. Please explain your recommended adjustment relating to the Company’s rate base claim for credit facility costs.

A. DPL included a rate base adjustment of $57,989 and an operating expense adjustment of $48,000 relating to a short-term credit facility operated by PHI. The Company’s claim includes annual recurring costs associated with the facility, as well as amortization of start-up costs. In addition, DPL is requesting that the average balance of unamortized costs be included in rate base and that shareholders be permitted to earn a return on this balance at the Company’s overall cost of capital.

Q. Are you recommending any adjustment to the Company’s claim?

A. Yes, I am recommending that these costs be eliminated from the Company’s revenue requirement. The credit facility is a source of short-term debt for DPL. According to the response to DPA-115, "[t]he Company's credit facility is the primary means of providing short-term liquidity that funds the Company's working capital needs on a daily basis. The credit facility acts as support for the Company's commercial paper program, which is the lowest cost short-term financing available, and allows for borrowing on the rare occasion when commercial paper cannot be issued." However, while the Company recognizes that short-term debt is less expensive than other sources of financing, it has failed to give ratepayers any benefit from this low cost financing. Neither commercial paper nor short-term debt from the PHI credit facility are included in the Company's capital structure. Therefore, there so is no way for ratepayers to benefit from this short-term debt through the ratemaking process. If ratepayers are not benefitting from this credit facility, then it is unreasonable to require them to pay the associated credit facility costs.

In addition, ratepayers are already paying for the "working capital" needs that the Company claims are being funded by the credit facility. The Company's working capital requirements, including cash working capital, materials and supplies, and prepaid insurance, are all rate base components. Ratepayers will be paying for this working capital through rates. Thus, the Company is asking ratepayers to fund its working capital needs, and it is asking ratepayers to fund the credit facility, without providing ratepayers with any benefit from the lower cost financing associated with the credit facility. As explained earlier in my testimony, I have not proposed an adjustment to add short-term debt to the capital structure in this case. Therefore, fairness dictates that Company’s request to recover costs associated with this credit facility should be denied.

If the Company wants to exclude short-term debt from the capital structure, then it should either a) exclude all credit facility costs from its revenue requirement or b) exclude all working capital components from rate base. It should not be permitted to recover credit facility costs while at the same time excluding this low cost financing from the capital structure and charging ratepayers for its working capital requirements. Accordingly, at Schedule ACC-16, I have made an adjustment to eliminate the unamortized PHI credit facility costs from the Company’s rate base. If the Commission permits DPL to recover any of these credit facility costs from ratepayers, then the Company's capital structure should be amended to reflect the inclusion of short-term debt.

H. 2009 Pension Costs

Q. Please provide a brief history of the deferred pension issue from PSC Docket No. 09-182 that has now been consolidated with this base rate case.

A. On May 1, 2009, DPL filed a Petition (Docket No. 09-182) with the PSC requesting authorization to defer, for regulatory accounting purposes, certain costs incurred with respect to its 2009 pension costs. The Company stated in its Petition that DPL's pension costs would increase significantly in 2009 from earlier years, due to the turndown in the economy during 2008. As stated in the Petition, "As a direct result of this downturn in the U.S. economy, the Pension Plan experienced a significant decline in the fair value of its assets, which will result in a significant increase in the annual pension expense in 2009."[10] The Company noted that "[t]he Delaware electric distribution operations of Delmarva are expected to incur an O&M pension expense of approximately $7.249 million for the year ended December 31, 2009, and its gas operations are expected to incur an O&M expense of approximately $1.67 million for the twelve months ending December 31, 2009. These anticipated 2009 O&M expense levels represent increases over the amounts reflected in current rates of approximately $8.2 million in the electric distribution business and approximately $1.8 million for the gas business."[11]

10 Petition of May 1, 2009, paragraph 6.
11 Id, paragraph 7.

On January 7, 2010, the PSC issued Order No. 7727. In its Order, the PSC found that "the recovery, if any, of the difference between the Company's level of O&M pension expense attributable to the Company's Delaware gas customers currently included in base gas rates and the level of O&M pension expense for 2009 that the Company is required to record under generally accepted accounting standards shall be considered and addressed in the Company's next general gas base rate case."

In its filing in this case, DPL is claiming recovery of deferred costs of $4,089,722. Company Witness Ziminsky states in his testimony that $4,089,722 represents the difference between the amount of pension expense included in currently effective rates and the Company's actual 2009 expense. The Company's claim is based on 2009 pension expenses of $3,912,379, and on the assumption that current rates reflect a pension credit of $177,343. DPL is proposing to recover these deferred costs over five years, for an annual expense adjustment of $817,944. In addition, the Company is requesting carrying costs on the unamortized balance at the Company's overall weighted average cost of capital. DPL has included a rate base adjustment of $2,184,341 relating to this deferral.

Q. Before addressing the merits of Mr. Ziminsky's position, do you agree that current rates reflect a pension credit of $177,343?

A. No, I do not. The Company's calculation does not include the revenue requirement impact of the pension asset included in rate base in the last base rate case. It is important to recognize that this pension asset was not related to a cost deferral, as is being requested here. Rather, the pension asset was related to the Company's claim that it should be made whole for pension amounts credited to ratepayers due to an actuarially determined negative pension expense. The Company's current rates include a pension asset of $10.32 million. As shown in the response to DPA-82, this pension asset results in an additional amount of $1.35 million being collected from current ratepayers relating to pension costs. Therefore, even if the PSC accepts the Company's proposal to defer 2009 pension costs for future recovery, the Company's claim is overstated by $1.35 million.

Q. Turning to the basic issue, should the PSC approve recovery of these 2009 pension costs?

A. No, it should not. The Company's request for future recovery of these past costs, along with carrying costs on the unamortized balance, is another attempt to shift risk from shareholders to ratepayers. While pension costs may have increased in 2009 relative to levels in earlier years, DPL's shareholders were awarded a 10.25% return on equity as a result of the Settlement Agreement in the Company's last base rate case. The reason that shareholders received this premium it because they were expected to take risks, including the risk of expense increases. Now that one of those risks has actually resulted in a negative outcome, it is unreasonable for shareholders to expect ratepayers to reimburse DPL for these cost increases. DPL's position is a bit like having ratepayers buy insurance against a negative event, and then when the event happens, having the insurance company refusing to pay.

Q. Did ratepayers also experience a significant downturn in the economy in late 2008 and early 2009?

A. Yes, they did. While shareholders faced higher than expected pension costs due to declines in the market value of the pension fund, ratepayers were also impacted by the downturn in the economy. In addition to suffering the same market declines that impacted DPL's pension costs, ratepayers also suffered record job losses, sharp declines in home values, unprecedented foreclosure rates, and other economic impacts. On top of all of this, ratepayers are now being asked to a) pay higher utility rates, b) pay utility rates that can no longer be controlled by controlling usage, and c) pay for past cost increases experienced by DPL. Something is wrong with this scenario.

Q. Do you believe that there are ever circumstances that could warrant requiring ratepayers to pay for higher than expected previously-incurred costs, as is being requested here?

A. Yes, I do. I believe that it may be reasonable to ask ratepayers to reimburse shareholders for higher than expected past costs if the financial integrity of a utility is jeopardized to the point where the utility may no longer be able to provide service. In that case, it may be appropriate to ask ratepayers to ignore the regulatory compact that gives shareholders a premium return in exchange for taking on increased risk. However that is certainly not the case here.

While DPL's 2009 electric earnings were impacted by higher pension costs, Delmarva still paid its parent company dividends of $28.5 million during 2009. In this same period, PHI paid $238 million in dividends to its shareholders. Moreover, PHI's dividend payment to its public shareholders is well above the industry average. Pepco Holdings, Inc.'s dividend is currently 5.6%, significantly higher than the average dividend of 4.4% paid by combination gas and electric companies, according to the October 2010 AUS Utility Reports. Thus, there is no indication that higher 2009 pension costs have jeopardized the financial integrity of either DPL or PHI, or that DPL is in any danger of not being able to provide safe and reliable service to Delaware ratepayers. Both DPL and PHI continue to maintain investment grade credit ratings. While credit rating agencies and security analysts always prefer higher corporate earnings over lower earnings, there is no indication that either DPL or PHI will suffer serious credit problems if the recovery of these past costs is denied.

Q. Have the Company's pension costs declined since 2009?

A. Yes, DPL acknowledges that its pension costs have declined since 2009 and the Company is proposing a downward adjustments for pro forma pension costs relative to the test period. These lower costs are likely the result, at least in part, of a rebound in the Company's pension fund investments.

Q. Has DPL deferred these costs for financial reporting purposes?

A. No. Although the Company is seeking to retroactively recover these costs from ratepayers, these costs have already been expensed, or written off, for financial purposes. Thus, there is no deferral on the Company's financial books and records of account.

Q. Did DPL request recovery of 2009 pension costs in other recent base rate cases?

A. Yes, DPL made a similar request to the Maryland Public Service Commission. On August 13, 2009, the Secretary of the Maryland PSC issued a letter stating that "the Commission rejects Delmarva's Application. The Commission suggests Delmarva pursue the recovery of these pension costs as part of its pending base rate case." In that rate case, the PSC later rejected DPL's claim for recovery of past 2009 costs, finding, "[w]e found before that tracker mechanisms, like the surcharge and amortization proposals in this case, represent an extraordinary form of ratemaking that we reserve for very large, non-recurring expense items that have the potential to seriously impair a utility's financial well-being and that do not contribute to the Company's rate base."[12] The Maryland PSC also rejected a similar request for a regulatory asset deferral filed by Pepco. In a recent case filed in New Jersey by DPL's affiliate, Atlantic City Electric Company ("ACE"), ACE made a similar request for deferral of these costs. However, recovery of these costs was not included in the Settlement Agreement in that case and the Company's request was withdrawn. I understand that a similar request by Pepco that was filed in the District of Columbia was also denied. Finally, the Hearing Examiner recommended that a request for recovery of these deferred costs be rejected in the recent DPL electric base rate case.

Q. What do you recommend?

12 Order in Maryland PSC Case No. 9192, page 15.

A. For the reasons stated above, I recommend that the Commission deny DPL's request to recover past 2009 pension costs from ratepayers. Shareholders were awarded a premium return for accepting the risk of expense increases between base rate cases. Neither the financial integrity of DPL nor of PHI will be jeopardized if the Company's request is denied. Finally, it is simply unreasonable to demand that ratepayers, who did not have such a great year in 2009 themselves, should be responsible for these costs while DPL continues to pay healthy dividends to PHI and while PHI continues to pay healthy dividends to its shareholders. The Delaware PSC should follow the lead of regulatory commissions in Maryland, New Jersey, and the District of Columbia, as well as the recommendation of the Hearing Examiner in PSC Docket No. 09-414, and deny the Company's request for recovery of these past costs. Accordingly, at Schedule ACC-17, I have made an adjustment to eliminate the proposed regulatory asset relating to 2009 pension costs from rate base.

I. <u>Summary of Rate Base Issues</u>

Q. What is the impact of all of your rate base adjustments?

A. My recommended adjustments reduce the Company's rate base claim from $238,750,769, as reflected in its filing, to $202,551,635, as summarized on Schedule ACC-9.

VI. OPERATING INCOME ISSUES

A. Salary and Wage Expense

Q. How did the Company determine its salary and wage claim in this case?

A. The Company's claim is based on projected payroll costs for the twelve months from February 2011 through January 2012. As shown in the response to DPA-96, DPL began with its test period costs for each month of the test period, separately identifying union and non-union employee costs. For Local 1238 employees, the Company reflected a 2% payroll increase effective February 1, 2011. For Local 1307 employees, the Company reflected a 2.0% payroll increase effective July 1, 2011. For non-union employees, the Company annualized a payroll increase of 3.09%, that was effective during the test period. In addition, DPL reflected an additional non-union increase of 3.0%, effective March 1, 2011. These adjustments resulted in an increase of $3,961,829 to the Company's test period expense, 19% of which is allocated to gas operations. In its Supplemental Testimony of October 11, 2010, the Company revised its adjustment to $4,670,585, due to fewer payroll costs being deferred to the AMI program.

In addition to these payroll increases, DPL also included an expense adjustment of $34,028 in its salary and wage claim. This reflects a three-year amortization of the gas utility's allocated share of a signing bonus awarded to union employees as a result of the recent contract negotiations. The Company has also included a separate adjustment (Adjustment No. 13) relating to 13 new positions for "Energy Experts". This adjustment is discussed later in my testimony.

Q. Are you recommending any adjustment to the Company's claim for salaries and wages?

A. Yes, I am recommending that only test period salary and wage increases be included in the Company's revenue requirement. I recommend that these increases be annualized, to reflect what the Company's costs would have been had these increases been in effect for a full twelve months. I recommend that the Commission exclude all post-test period increases from the Company's revenue requirement.

It should be noted that it was the Company that selected the test year and test period in this case. Most of the salary and wage increases reflected in the Company's claim reach too far beyond the end of the test period in this case, especially when one considers that the Company's claim is based on customers at December 31, 2009, the midpoint of the test period in this case. The Company has including post-test period increases that reflect salary and wage levels through February 2012, or more than 18 months beyond the end of the test period. These adjustments reach too far beyond the test period and distort the regulatory triad of synchronizing rate base, revenues, and expenses. Therefore, I recommend that the Commission limit salary and wage increases to the increases that occurred during the test period, annualized to reflect a full year of costs. I have reflected my adjustment at Schedule ACC-19. I have not made any adjustment to the Company's proposal to recover costs associated with the signing bonus recently negotiated with the unions.

Q. Is the Company planning to eliminate some employee positions at the end of 2010?

A. Yes, it is my understanding that the Company plans to cut its personnel at the end of 2010, as discussed in the response to PSC-LA-49. According to that response, PHI hopes to cut total costs by $20 million as a result of its company-wide restructuring efforts. Given the fact that the Company has used a test period ending June 30, 2010 in this case, I have not included any savings relating to these restructuring efforts in my revenue requirement recommendation. However, the PSC should be aware that at least some salary reductions are likely for the gas utility, lending further support for the reasonableness of my recommended adjustment.

B. Incentive Compensation Expense

Q. Please describe the Company's incentive compensation program.

A. The Company has included $935,046 of non-officer incentive compensation costs in its revenue requirement claim, as shown on Schedule WMV-7, Update for 12+0, Adjustment Nos. 5 and 6. According to the response to DPA-19, these costs relate to the Company's Annual Incentive Plan ("AIP"). This plan is available to all PHI management employees that do not participate in any other incentive plan.

A copy of the AIP was provided in response to DPA-19. The plan has an earnings threshold, i.e., no payments are made unless earnings meet certain targeted levels. According to that response, "[f]or Utility Operations employees, the Utility Operations' earnings must reach a 93% threshold to qualify for any potential payout. Potential payout for Corporate

Services employees is based on an overall corporate earnings threshold of 90%. Corporate Services employees are eligible to receive a payout only to the extent that Power Delivery and/or Non-Regulated earnings meet or exceed threshold levels and such awards shall not exceed 50% of target if PHI corporate earnings do not exceed threshold levels." Thus, the program requires that financial goals be reached prior to any awards being made.

If the earnings threshold is met, an individual's award is then based on a combination of business unit goals and individual goals. Virtually no information about these respective goals was included in the AIP description provided by the Company. However, the plan does indicate that award percentages increase as pay scales rise. Thus, the highest paid employees are eligible for a proportionately greater incentive award. For example, while the target award for pay grades 1-4 is 5% of base pay, employees in pay grades 15-16 are eligible for awards of up to 15% of base pay. Thus, not only do more highly paid employees receive larger nominal awards, but they receive larger proportional awards as well.

Q. Do you believe that the incentive compensation program is an appropriate cost to pass through to ratepayers?

A. No, I do not. I have several concerns about these types of programs, especially as designed and implemented by DPL. The Company's incentive plan is heavily weighted toward financial objectives, no payout being made unless certain financial goals are met. Providing employees with a direct financial interest in the profitability of the Company is an objective that would benefit shareholders, but it does not benefit ratepayers.

Incentive compensation awards that are based largely on earnings criteria may violate the principle that a utility should provide safe and reliable utility service at the lowest possible cost. This is because these plans require ratepayers to pay higher compensation costs as a consequence of high corporate earrings, a spiral that does not directly benefit ratepayers, but does benefit shareholders and the management to whom such awards are granted.

Incentive compensation plans tied to corporate performance result in greater enrichment of company personnel as a company's earnings reach or exceed targets that are predetermined by management. It should be noted that it is the job of regulators, not the shareholders or company management, to determine what constitutes a just and reasonable rate of return award to shareholders in a regulated environment. Regulators make such a determination by establishing a reasonable rate of return award on rate base in a base rate case proceeding.

Allowing a utility to charge for additional return that is then distributed to employees as part of some plan to divide extraordinary profits violates all sense of fairness to the ratepayers of the regulated entity. It is certain to result in burdensome and unwarranted rates to its ratepayers, and it also violates the principles of sound utility regulation, particularly with regard to the requirement for "just and reasonable" utility rates.

Q. What would be the appropriate response by the Commission if the earnings of DPL were in excess of its authorized rate of return?

A. If the Commission determined that these excess earnings were expected to continue, the appropriate response would be to initiate a rate investigation, and, if appropriate, to reduce the utility's rates.

Q. Has the Commission addressed the issue of incentive compensation payments?

A. Yes, it did. In his Recommended Decision in PSC Docket No. 05-304, the Hearing Examiner found that incentive programs that are not triggered primarily by safety-related goals should be excluded from customer rates. The Commission concurred, finding that "the shareholders should bear that expense."[13] In the Company's recent electric case, the Hearing Examiner also recommended that the Commission exclude incentive compensation payments from the Company's revenue requirement.

Q. Are DPL employees being well compensated separate and apart from these employee incentive plans?

A. Yes, they are. Although salaried employees did not receive an increase in 2009, these employees did receive an increase of 3.1% in March 2010. Moreover, in the past, salaried employees have consistently been awarded annual payroll increases in the 3.5% to 3.7% range. Thus, there is no indication that the employees of DPL are underpaid or that the Company would have difficulty attracting qualified employees in the absence of these programs.

13 Recommended Decision, PSC Docket No. 05-304, paragraph 98.

Q. What do you recommend?

A. Since a significant portion of the Company's incentive compensation plan costs is based on financial performance objectives, I recommend that the costs of incentive compensation awards granted under these plans be borne by shareholders. This recommendation will require the Board of Directors to establish incentive compensation plans that shareholders are willing to finance. My adjustment is shown in Schedule ACC-20.

Q. Does your recommendation apply to both the safety-related component of the Company's claim as well as to the non-safety-related component?

A. Yes, it does. In quantifying its claim, DPL identified a portion of its incentive compensation costs that it claimed was "safety" related. This was apparently an attempt by the Company to persuade the Commission that at least a portion of these costs provided direct benefit to ratepayers, and therefore should be included in utility rates. However, DPL provided no supporting documentation for the incentive compensation costs identified as "safety" related. Moreover, the AIP earnings threshold does not distinguish between safety and non-safety related goals, but applies to all incentive compensation payments made pursuant to the plan. Finally, ratepayers have the right to expect that the utility will be operated in a safe manner. There is no rationale for providing employees with additional compensation for meeting certain safety goals. Instead, safety should be an integral part of every employee's job description and base salaries should reflect management's expectations with regard to safety issues.

Q. Did the Company exclude incentive compensation costs related to executives from its revenue requirement claim in this case?

A. Yes, it did. With regard to incentives for officers and executives, the Company claimed that is excluded "executive incentives" from its revenue requirement claim, "in light of the current economic environment".[14] The Company did not explain how it defined "executive incentives". DPL included an adjustment to remove $283,911 related to executive compensation costs allocated to gas operations. It is clear from a review of the PHI Proxy Statement that officers and executives received considerable compensation in 2009. This included stock awards, dividends, club dues, spousal travel, and other perquisites. In addition, it is interesting to note that while the Company incurred costs for sporting and entertainment events for officers in 2009, these amounts were not included in the compensation reported in the Proxy Statement. As noted on page 37 of that statement,

> In addition, in 2009, Company-leased entertainment venues and Company-purchased tickets to sporting and cultural events were made available to employees, including the executive officers listed in the Summary Compensation Table, for personal use when not being used by the Company for business purposes. There was no incremental cost to the Company for providing these benefits.

The Company's 2009 officer compensation also included significant severance costs, including a severance payment of $828,000 for Mr. Barry, formerly Senior Vice President

14 Original Testimony of Mr. Von Steuben, page 11.

and Chief Financial Officer of PHI.

Q. In addition to prior rulings in Delaware, has the New Jersey Board of Public Utilities ("BPU") previously addressed the issue of incentive compensation?

A. Yes. The New Jersey BPU has a policy of disallowing incentive compensation costs when the performance triggers and benchmarks are tied to financial performance objectives. In the 2000 Middlesex Water Company base rate case, Board Staff argued in its Initial Brief that,

> Staff is persuaded by the arguments of the RPA that, at this time, the incentive compensation expenses should be not be recovered from ratepayers. According to the record, incentive compensation expenses have tripled since 1995. In addition, the record also indicated that the bonuses are significantly impacted by the Company achieving financial performance goals. These facts lend strength to the RPA's position that it is inappropriate for the Company to request recovery of bonuses in rates at this time.[15]

The Administrative Law Judge ("ALJ") in that case initially recommended that Middlesex be permitted to recover 50% of its incentive compensation costs in rates. However, the BPU rejected the ALJ's recommendation and instead ordered that 100% of these costs be disallowed.[16]

In an earlier decision, the BPU found that including employee incentives in utility rates is especially troublesome during difficult economic times, finding that,

15 I/M/O the Petition of Middlesex Water Company for Approval of an Increase in Its Rates for Water Service and Other Tariff Charges, BPU Docket No. WR00060362, Staff Initial Brief, page 37.

16 I/M/O the Petition of Middlesex Water Company for Approval of an Increase in Its Rates for Water Service and Other Tariff Charges, BPU Docket No. WR00060362, Order Adopting in Part/Modifying in Part/Rejecting in Part Initial Decision at 25-26 (June 6, 2001).

> We are persuaded by the arguments of Staff and Rate Counsel that, at this time, the incentive compensation or "bonus" expenses should not be recovered from ratepayers. The current economic condition has impacted ratepayers' financial situation in numerous ways, and it is evident that many ratepayers, homeowners and businesses alike, are having difficulty paying their utility bills and otherwise remaining profitable. These circumstances, as well as the fact that the bonuses are significantly impacted by the Company achieving financial performance goals, render it inappropriate for the Company to request recovery of such bonuses in rates at this time. Especially in the current economic climate, ratepayers should not be paying additional costs to reward a select group of Company employees for performing the job they were arguably hired to perform in the first place.[17]

Q. Are ratepayers in Delaware currently facing economic hardship?

A. Yes, they are. It is indisputable that ratepayers are facing very difficult economic conditions, with increasing costs, widespread housing foreclosures, and a general economic downturn. Thus, the PSC's finding in PSC Docket No. 05-304 is perhaps even more appropriate today than it was in 2006. In many respects, the economic hardship being faced by ratepayers is unprecedented, lending further support for my recommended adjustment. Accordingly, the PSC should continue the policy initiated in PSC Docket No. 05-304, and continue to require shareholders to fund the costs of the Company's incentive compensation programs.

C. Payroll Tax Expense

Q. What adjustment have you made to the Company's payroll tax expense claim?

A. Since I am recommending a reduction to the Company's claims for salaries and wages and incentive compensation costs, it is necessary to make a corresponding adjustment to

17 I/M/O the Petition of Jersey Central Power & Light Company for Approval of Increased Base Tariff Rates and Charges for Electric Service and Other Tariff Revisions, BRC Docket No. ER91121820J, Final Decision and Order Accepting in Part and Modifying in Part the Initial Decision at 4 (June 15, 1993).

eliminate certain payroll taxes from the Company's revenue requirement claim. At Schedule ACC-21, I have eliminated payroll taxes associated with my recommended salary and wage and incentive compensation adjustments. To quantify my adjustment, I used the composite rate of 5.32%, which I derived from the Company's payroll tax adjustment shown in Schedule WMV-5, AMI Supplemental, Adjustment No. 3.[18]

D. <u>Energy Experts Payroll Expense</u>

Q. Please describe the Company's claim for costs associated with incremental "Energy Experts."

A. As described beginning on page 12 of Mr. Von Steuben's testimony, DPL is claiming costs for 13 incremental employees "to coach and educate our customers on energy use and to help our customers reduce their bills." The Company's claim includes an adjustment of $1,551,466, which reflects total costs of $1,807,000 less the costs for these positions that the Company estimates were incurred in the test period. All of these employees were hired by the end of the test period in this case. Ten of the employees were hired for "Energy Advisor" activities in March 2010. The remaining three employees are designated as "Energy Specialists". The Energy Specialists were hired in June 2010.

Q. How did the Company determine its costs associated with these incremental positions?

18 To quantify my adjustment, I assumed that the Company's payroll tax adjustment of $253,900, shown in Schedule WMV-5, AMI Supplemental, Adjustment No. 3, applied to both the salary and wage adjustment and the signing bonus adjustment, both of which are shown on this schedule.

A. Unfortunately, DPL did not provide any supporting documentation in its claim relating to these costs. However, in response to PSC-LA-97, the Company indicated that its claim was based on a request, originally made in its recent electric case, for 23 Energy Experts at a total cost of $3,197,000. In that response, DPL stated that it developed its claim in this case based on the average cost per expert originally claimed in the electric gas ($3,197,000 / 23, or $139,000) times the 13 positions that have now been filled.

Q. Subsequent to the electric case, did the Company provide actual salary and wage information for the 13 positions that have been filled?

A. Yes, it did. In response to DPA-101 in this case, the Company provided the actual starting dates and current annual salaries for the 13 new positions.

Q. How do the actual salary and wage costs compare with the average used by DPL in its claim?

A. The Company's claim appears excessive relative to the actual salaries for these employees. The 13 employees have total annualized salaries of $782,459, which is less than 50% of the total annualized costs of $1,807,000 shown in Adjustment No. 13. While I assume that the Company's claim includes costs in addition to direct payroll costs, the Company's proposed adjustment would result in a salary gross-up of more than 130% - well above averages that are seen in most cases.

Q. What do you recommend?

A. I recommend that costs of the 13 Energy Experts hired by the end of the test period be included in the revenue requirement approved by the Commission in this case. However, the Commission should utilize the actual salaries for these employees instead of using the average costs reflected in the Company's filing. According to the response to DPA-101, total annual salary costs for these employees is $782,459. Based on these actual salaries and the start dates provided in response to DPA-101, I calculate that the test period already reflects $192,972 relating to these positions. Thus, an adjustment of $589,487 to salary expense would be appropriate, assuming that 100% of these costs are expensed. I have increased this adjustment by 35%, to reflect additional costs such as payroll taxes, benefits, and other direct payroll costs. The 35% factor is based on my experience in other cases. My adjustment to the Company's Energy Experts claim is shown in Schedule ACC-22.

E. Supplemental Executive Retirement Program ("SERP") Costs

Q. What are SERP costs?

A. These costs relate to supplemental retirement benefits for key executives that are in addition to the normal retirement programs provided by the Company. These programs generally exceed various limits imposed on retirement programs by the IRS and therefore are referred to as "non-qualified" plans. The IRS generally limits the amount of an employee's compensation that can be considered for purposes of determining qualified pension plan benefits. In 2009 and 2010, only the first $245,000 in annual compensation could be considered when determining pension benefits applicable to qualified plans. The SERP benefits have the effect of eliminating this cap. In addition, the Company's SERP provides for additional years of service credit for certain key employees.

Q. What are the test period SERP costs that the Company has included in its claim?

A. As shown in the response to DPA-23, the Company incurred total SERP costs of $190,184 in the test year. This includes costs of $77,232 incurred directly by DPL's gas operations and costs of $112,952 allocated to DPL's gas operations by the Service Company.

Q. Do you believe that these costs should be included in utility rates?

A. No, I do not. As noted above, the officers of the Company are already well compensated. In 2010, Mr. Rigby's base salary is $880,000, which represents an increase of 7.3% over his 2009 salary. Increases for the other four Named Executive Officers ("NEOs") ranged from 3.23% to 10%. In 2010, salaries for the remaining four NEOs range from $352,000 to $484,000. Moreover, employees that receive SERP benefits are also included in the normal retirement plans of the Company, so ratepayers are already paying retirement costs for these employees. If DPL wants to provide further retirement benefits to select officers and executives then shareholders, not ratepayers, should fund these excess benefits. Therefore, I recommend that the Company's claim for SERP costs be disallowed. My adjustment is shown in Schedule ACC-23.

F. Deferred 2009 Pension Expense

Q. Please explain your expense adjustment relating to deferred 2009 pension costs.

A. As noted earlier, the Company is requesting recovery of 2009 pension costs that it claims are in excess of the pension costs included in current rates. The Company is requesting recovery of these costs over a five-year period, and is requesting that the unamortized balance be included in rate base. For the reasons discussed in the Rate Base section of this testimony, I recommend that the Company's claim be denied. In Schedule ACC-24, I have made an adjustment to eliminate the annual amortization expense that the Company included in its filing relating to these deferred 2009 pension costs.[19]

G. Medical Benefits Expense

Q. How did the Company determine its medical benefits expense claim in this case?

A. DPL's claim is based on a projected 8.0% increase in medical benefit costs and on a 5% increase in dental and vision insurance costs. The Company's projections were based on a study performed by Lake Consulting, its benefit plan consultant. That study was provided in response to DPA-98.

19 As noted earlier, these pension costs were not deferred for financial reporting purposes and have already been written off by the Company on its financial books and records of account.

Unfortunately, the referenced study provides no data that is specific to DPL or PHI. Instead, the study is based on trends in medical premiums by several major insurance companies. Moreover, the study is based on trends in Virginia, Maryland, and the District of Columbia. Thus, there is no information about trends in medical premium costs in Delaware. However, even if the Commission found that cost trends in this state are similar to those in the areas included in the study, the Lake Study still fails to support a post-test period adjustment for DPL's gas operations. The use of general cost trends does not rise to the level of a known and measurable change.

In addition, according to the response to DPA-99, since January 1, 2010, DPL has been self-insured for medical, dental and vision expenses. Thus, actual benefit costs will depend on the cost of the underlying services received, the volume of such services required by employees and their families, and the severity of problems experienced by the insured base. This makes the use of insurance cost trends even less applicable to DPL. Moreover, according to the response to PSC-LA-146, the Company has implemented further changes that will impact future costs, such as increasing co-pays and employee contributions and requiring mandatory mail order for prescription drug coverage.

Q. What do you recommend?

A. Based on the lack of any supporting documentation from DPL, and on the fact that the Company's adjustment does not reflect a known and measurable change to the test period, I am recommending that the PSC deny DPL's pro forma adjustment relating to medical benefit costs. My adjustment is shown in Schedule ACC-25. My adjustment is consistent with the recommendation of the Hearing Examiner in the Company's recent electric base rate case.

H. Gas Decoupling Customer Education Expense

Q. Please describe the Company's claim for recovery of Gas Decoupling Customer Education costs.

A. DPL has included an adjustment of $106,500 relating to efforts to educate customers about the Company's proposed modified straight fixed variable rate design. As shown in the response to DPA-103, DPL's claim includes $45,000 in newspaper advertising and $61,500 for direct mailing of educational material. The Company is proposing a one-year recovery of these costs.

Q. Are you recommending any adjustment to the Company's claim?

A. Ordinarily, I would recommend that such costs be disallowed, since these costs were not incurred during the test period. In addition, these costs are not entirely known nor measurable at this time, as acknowledged by DPL in the response to DPA-103. However, given the extraordinary nature of the Company's conversion to a radically different new rate structure, I am not opposed to permitting the Company to begin recovery of these costs. Moreover, I am not recommending any adjustment to the amount of customer education costs included in the Company's claim.

However, I am recommending that these costs be recovered over a three-year period, without carrying costs. Permitting the Company to recover these costs over one year would result in an over-recovery, unless the Company filed a new rate case next year. Moreover, the one year recovery period is inconsistent with the period of time over which these costs will benefit ratepayers, since these customer education costs will provide ratepayers with benefits as long as the new rate design is in place. Accordingly, a multi-year recovery period is appropriate. My adjustment is shown in Schedule ACC-26.

I. Deferred AMI Expense

Q. Please explain your expense adjustment relating to amortization of deferred AMI costs.

A. As noted earlier, the Company is seeking recovery of deferred AMI costs over a period of 15 years. As shown in the response to DPA-123, the Company is seeking recovery of total costs of $1,057,530, which includes actual costs of $1,017,169 and deferred carrying costs of $40,360. The $40,360 in carrying costs is based on a net-of-tax return of 6.54%, which has been applied to costs that were incurred as early as December 2007, even well before the PSC issued its order permitting deferral of these costs. Moreover, as noted earlier, I am recommending that the Company's claim for all carrying costs be denied. Thus, at Schedule ACC-28, I have made an adjustment to eliminate the annual amortization associated with the $40,360 of carrying costs being claimed by DPL.

J. Credit Facility Expense

Q. Please explain your expense adjustment relating to credit facility costs.

A. As noted earlier, the Company is requesting recovery of costs associated with a PHI credit facility. The Company is requesting recovery of annual operating costs, as well as an amortization of deferred costs relating to start-up of the facility. In Schedule JCZ-13, Update for 12+0, Adjustment No. 26, DPL reflected an expense adjustment of $48,000. This includes the gas utility's allocation of the annual costs of maintaining the credit facility, as well as its allocation of amortization expense associated with start-of the credit facility.

For the reasons outlined earlier in the Rate Base section of this testimony, I recommend that the Company's claim be denied. Therefore, at Schedule ACC-28, I have made an adjustment to eliminate the Company's $48,000 expense adjustment.

K. Regulatory Commission Expense

Q. How did the Company develop its claim for regulatory commission expense?

A. DPL's regulatory commission expense claim is based on several components. First, the Company included a three-year average of non-rate case related expense. Second, the Company included costs relating to the current case of $674,000, amortized over three years.[20] Finally, the Company included an additional $50,000 "related to DPA charging non-base activities."

20 As discussed earlier, the Company is requesting rate base treatment for the uamortized balance of rate case costs. This request should be denied, since the Delaware PSC has a policy of normalizing, not amortizing, rate case costs.

Q. Are you recommending any expense adjustments to the Company's claim?

A. Yes, I am recommending two expense adjustments. First, I believe that the Company's claim relating to this current rate case is excessive. In DPA-44, we asked the Company to provide information about the actual costs incurred in each of the last three rate case proceedings. For the last two completed cases, one of which was settled and one of which was litigated, DPL incurred costs of $290,000 and $400,000 respectively. DPL is estimating costs for the recent electric case of $640,000.

Q. What level of rate case costs do you recommend be included in the Company's revenue requirement?

A. I am recommending an allowance of $435,000 for rate case costs. This recommendation is based on an increase of 50% over the actual costs incurred in the last gas case. That case, like this case, was filed shortly after a fully-litigated electric base rate case. Thus, many of the issues raised in this case are similar to those presented in the electric case. Therefore, this case should be relatively less expensive than the recent electric case. I believe that an increase of 50% over actual costs incurred in the last gas case is reasonable. Accordingly, at Schedule ACC-29, I have included a cost of $435,000, normalized over three years. The last gas case resulted in an effective date for new rates of April 1, 2007. The procedural schedule in this case anticipates new rates in approximately April 2011. Thus, I believe that a three-year normalization period is reasonable, and may be generous. This normalization period is also consistent with the period of time over which I recommended DPL be permitted to recover its Gas Decoupling Customer Education costs.

Q. What is your second adjustment?

A. In addition to my recommendation with regard to rate case costs, I am also recommending that the PSC reject the Company's request to recover an additional $50,000 related to DPA charging the Company for non-base activities. No such costs were incurred in the test period in this case. Moreover, it is my understanding that DPA has not charged DPL any such costs to date, nor does DPA have immediate plans to charge DPL for such activities. Therefore, the Company's claim does not represent a known and measurable change to the test period. At Schedule ACC-29, I have also made an adjustment to eliminate $50,000 from the Company's regulatory expense claim relating to these DPA charges.

L. <u>Directors and Officers Insurance Expense</u>

Q. Are you recommending any adjustments to the Company's claim for Directors and Officers Insurance?

A. Yes, I am recommending that the costs included in the Company's revenue requirement relating to Directors and Officers Insurance be denied. These costs should be absorbed by shareholders instead of ratepayers. While I acknowledge that Directors and Officers Insurance is a necessary cost of doing business in today's environment, it is the shareholders, and not the ratepayers, that are responsible for electing the Directors of the Company.

Moreover, it is ultimately these Directors who are responsible for appointing the officers of the Company. Therefore, it is the shareholders of the Company who should be bearing the costs of choosing Directors and Officers whose decisions and actions may be the subject of an insurance claim. Ratepayers should not be burdened with these costs, since they have no input into the selection process for Directors and Officers. Accordingly, at Schedule ACC-30, I have made an adjustment to eliminate costs for Directors and Officers Insurance from the Company's revenue requirement claim.

M. Membership Dues Expense

Q. Are you recommending any adjustment to the Company's claim for membership dues expenses?

A. Yes, I am recommending two adjustments, relating to dues paid to the American Gas Association ("AGA"), and dues paid to the Energy Association of Pennsylvania. First, in its filing, DPL included $111,052 of dues to the American Gas Association ("AGA"). A review of the AGA website clearly demonstrates that this organization has an active lobbying program. A list of 2010 advocacy priorities includes support for "innovative rate approaches", favorable dividend tax treatment, arranging meetings between State Public Utility Commissioners and Wall Street analysts, and other advocacy programs. Moreover, in 2010 to date, AGA has lobbied Congress on 40 bills. Clearly, AGA does undertake significant lobbying and advocacy activities on behalf of its members, as do other trade associations such as the Edison Electric Institute ("EEI") and the National Association of

Water Company ("NAWC"). In addition to explicit lobbying costs, most of these organizations also engage in other activities that should not be charged to ratepayers, such as public affairs, media relations, and other advocacy initiatives.

Q. Are lobbying costs an appropriate expense to include in a regulated utility's cost of service?

A. No, they are not. Lobbying costs are not necessary for the provision of safe and adequate utility service. Moreover, the lobbying activities of a regulated utility may be focused on policies and positions that enhance shareholders but may not benefit, and may even harm, ratepayers. Regulatory agencies generally disallow costs involved with lobbying, since most of these efforts are directed toward promoting the interests of the utilities' shareholders rather than its ratepayers. Ratepayers have the ability to lobby on their own through the legislative process. Moreover, lobbying activities have no functional relationship to the provision of safe and adequate gas service. If the Company were to immediately cease contributing to these types of efforts, utility service would in no way be disrupted. Clearly, these costs should not be borne by ratepayers.

Q. What do you recommend?

A. I recommend that 25% of the Company's claim for AGA dues be disallowed, on the basis that a portion of these dues constitute lobbying. My adjustment is shown in Schedule ACC-31.

Q. Are you recommending any disallowances associated with any of the other dues included in the Company's claim?

A. Yes. In response to PSC-LA-68, the Company stated that 10% of the costs paid to the Energy Association of Pennsylvania constitute lobbying, and should have been excluded from the Company's claim. Given the relatively small payment to this organization, I am accepting the Company's statement that only 10% of the annual dues constitute lobbying. Therefore, at Schedule ACC-31, I have also made an adjustment to eliminate 10% of the dues paid to the Energy Association of Pennsylvania from the Company's revenue requirement claim.

N. <u>Meals and Entertainment Expense</u>

Q. Are you recommending any adjustment to the Company's meals and entertainment expense claim?

A. Yes, I am. According to the response to DPA-53, the Company has included in its filing approximately $16,196 of meals and entertainment expenses that are not deductible on the Company's income tax return. These are costs that the IRS has determined are not appropriate deductions for federal tax purposes. If these costs are not deemed to be reasonable business expenses by the IRS, it seems appropriate to conclude that they are not reasonable business expenses to include in a regulated utility's cost of service. Accordingly, at Schedule ACC-32 , I have made an adjustment to eliminate these costs from the Company's revenue requirement.

Q. Did the Company provide any additional information about these costs?

A. No, it did not. However, as noted earlier in my testimony, in its most recent Proxy Statement, PHI acknowledged that the Company incurred costs for a variety of sporting and entertainment events. Moreover, it stated that such perquisites were made available to employees when not needed for "business purposes." I find it difficult to conceive of a business purpose that would support ratepayers paying for tickets to entertainment or sporting events. Clearly, these are costs that should be borne by the Company's shareholders, and not its ratepayers. While there may be costs for certain meals included in this category that should be borne by ratepayers, there are also clearly costs which should be entirely excluded from the Company's revenue requirement. Therefore, my recommendation to use the 50% IRS criteria provides a reasonable balance between shareholders and ratepayers and should be adopted by the BPU. My adjustment is shown in Schedule ACC-32.

O. Depreciation Expense

Q. Are you recommending any adjustment to the Company's claim for depreciation expense?

A. Yes, I am recommending one adjustment. As discussed in the Rate Base section of my testimony, the Company has included post-test period additions to utility plant in service that it claims relates to "reliability plant". The Company made a rate base adjustment to utility plant-in-service to reflect these plant additions. In addition, it included incremental depreciation expense adjustments associated with the post-test period reliability plant additions. Since I am recommending that DPL's post-test period claim for reliability plant be denied, for the reasons discussed earlier, it is necessary to make a corresponding adjustment to eliminate the associated depreciation expense. My adjustment is shown in Schedule ACC-33.

P. <u>Allowance for Funds Used During Construction</u>

Q. How did the Company reflect AFUDC in its revenue requirement claim?

A. DPL reflected AFUDC above-the-line. This is consistent with the Company's request to include CWIP in rate base. If ratepayers are required to pay a return on CWIP, then ratepayers should receive the benefit of AFUDC as an above-the-line offset to cost of service. However, as discussed earlier, one of the concerns expressed by the Commission in PSC Docket No. 05-304 was that the revenue requirement associated with including CWIP in rate base was significantly greater than the offsetting AFUDC benefit to ratepayers. In that case, the Commission decided that CWIP should be excluded from rate base, and that the associated AFUDC should be moved below-the-line. I am recommending that the Commission adopt the same position in this case. Thus, at Schedule ACC-34, I have made an adjustment to remove the AFUDC credit from the Company's revenue requirement.

Q. Interest Synchronization and Taxes

Q. Have you adjusted the pro forma interest expense for income tax purposes?

A. Yes, I have made this adjustment at Schedule ACC-35. It is consistent (synchronized) with my recommended rate base, capital structure, and cost of capital recommendations. I am recommending a lower rate base than the rate base included in the Company's filing. My recommendations result in a lower pro forma interest expense for the Company. This lower interest expense, which is an income tax deduction for state and federal tax purposes, will result in an increase to the Company's income tax liability under my recommendations. Therefore, my recommendations result in an interest synchronization adjustment that reflects a higher income tax burden for the Company, and a decrease to pro forma income at present rates.

Q. What income tax factors have you used to quantify your adjustments?

A. As shown on Schedule ACC-36, I have used a composite income tax factor of 40.66%, which includes a state income tax rate of 8.7% and a federal income tax rate of 35.0%. These are the state and federal income tax rates contained in the Company's filing.

Q. What revenue multiplier have you used in determining your revenue requirement?

A. As shown in Schedule ACC-37, I have used a revenue multiplier of 1.6901. In addition to the statutory tax rates discussed above, this revenue multiplier includes a PSC assessment of 0.3%. My revenue multiplier is identical to the revenue multiplier used by DPL in its filing.

VII. REVENUE REQUIREMENT SUMMARY

Q. What is the result of the recommendations contained in this testimony?

A. My adjustments result in a revenue surplus at present rates of $4,715,102 as summarized on Schedule ACC-1. This recommendation reflects revenue requirement adjustments of $14,918,928 to the Company's requested revenue increase of $10,203,825.

Q. Have you developed a pro forma income statement?

A. Yes, Schedule ACC-38 contains a pro forma income statement, showing utility operating income under several scenarios, including the Company's claimed operating income at present rates, my recommended operating income at present rates, and operating income under my proposed rate decrease. My recommendations will result in an overall return on rate base of 6.19%.

Q. Have you quantified the revenue requirement impact of each of your recommendations?

A. Yes, at Schedule ACC-39, I have quantified the revenue requirement impact of the rate of return, rate base, and expense recommendations contained in this testimony.

VIII. OTHER ISSUES

A. Modified Fixed Variable Rate Design

Q. Please provide a brief history of the decoupling issue.

A. In its last natural gas base rate case, PSC Docket No. 06-284, DPL proposed a Bill Stabilization Adjustment ("BSA"), a decoupling mechanism that would have severed the relationship between gas revenues and gas sales. In that case, the Company proposed a monthly adjustment mechanism that would have compared the actual revenues collected each month with the revenues determined in its most recent base rate case, adjusted for changes in the number of customers. DPL proposed that any difference between the actual and baseline revenues would then be converted to a rate per CCF and added to, or subtracted from, customers' bills in a subsequent month. The Company proposed that the BSA be subject to an adjustment cap of +/- 10%. It also proposed that adjustments exceeding this cap would be deferred to later months. DPL proposed this surcharge mechanism in order to compensate the Company between base rate cases for changes in consumption due to the Company's conservation efforts. The Company argued the most of its distribution costs are fixed costs, and therefore the Company's utility operating income declines when DPL is successful in promoting conservation.

In the Stipulation in that case, the parties agreed to "participate in any generic statewide proceeding initiated by the Commission for the purpose of investigating Bill Stabilization Adjustments or decoupling mechanisms for electric and gas distribution utilities."[21] The PSC subsequently initiated Regulation Docket No. 59 on March 27, 2007 to address whether to implement a revenue decoupling mechanism for the electric and natural gas utilities subject to the PSC's jurisdiction.

Regulation Docket No. 59 was conducted as a series of workshops. The parties simultaneously conducted workshops in PSC Docket No. 07-28, which addressed the "Blueprint for the Future Application and Plan" that had been filed by DPL on February 6, 2007. PSC Docket No. 07-28 addressed the Company's proposals with regard to demand-side management (DSM"), advanced metering, revenue decoupling, and energy efficiency plans. In PSC Docket Regulation 59, the Company proposed a revenue decoupling surcharge mechanism, similar to the BSA that it had proposed in its prior rate case.

DPA fully participated in the workshops for Regulation Docket No. 59, including making presentations and the filing of written comments. DPA opposed the decoupling surcharge mechanism proposed by the Company, on several grounds. DPA opposed a decoupling mechanism that would compensate a utility for a revenue deficiency caused by factors other than measurable load reduction resulting from conservation efforts. DPA argued that the surcharge mechanism sent the wrong price signals to customers. DPA also argued that customer growth could offset the revenue impact of a decline in per customer energy usage. DPA expressed concerns about the impact of a decoupling mechanism on certain customers segments. DPA also noted that the proposed mechanism would lower the

21 Stipulation in PSC Docket No. 06-284, page 4.

Company's cost of capital, a fact that had not been fully taken into account by the Company in its proposal.

In PSC Docket Regulation 59, Staff rejected the use of surcharges, but recommended that the PSC consider a Modified Fixed Variable Method ("MFVM) rate design as a possible mechanism to remove disincentives to conservation efforts and to more appropriately align fixed costs with the manner in which those costs are recovered.

On June 27, 2008, Hearing Examiner Ruth Ann Price issued the Findings and Recommendations of the Hearing Examiner in PSC Docket Regulation 59 and Docket 07-28. Her recommendations with regard to the decoupling issue were as follows:

(a) The Commission should determine that implementation of surcharges for energy efficiency programs and revenue deficiencies related to conservation efforts are not the preferred approach, but that the Commission not preclude the potential use of surcharges in the future under appropriate conditions;

(b) The Commission should investigate the potential implementation of a revenue decoupling mechanism for each utility in the context of the respective company's next base rate proceeding.[22]

The PSC primarily adopted the Hearing Examiner's Findings and Recommendations. However, the PSC refined certain portions of those Findings and Recommendations, and

22 Findings and Recommendations of the Hearing Examiner, PSC Docket Regulation 59, June 27, 2008, paragraph 44(a) and (b).

addressed Staff's recommendation with regard to the use of the MFVM rate design, as follows:

> The Commission approves the adoption of Staff's recommendations regarding the potential adoption of a modified fixed variable rate design for Delaware distribution utilities in the context of a rate case proceeding; however, the Commission maintains the flexibility to address these rate design changes outside of a base rate case if the situation is warranted. [23]

Q. Did the Delaware General Assembly subsequently address this issue?

A. Yes, in late June 2009, the Delaware General Assembly adopted Senate Bill 106 and an accompanying amendment, which required utilities to implement decoupling mechanisms by December 2010. Specifically the legislation required that:

> Decoupled rate design mechanisms will be implemented by no later than December 2010 for regulated natural gas and electric utilities such that delivery rate structures provide for an appropriate, cost-based level of revenue recovery which will remove disincentives to investment in demand response programs and conservation and improved efficiency of energy use.

This legislation was signed into law by Governor Jack Markell on July 29, 2009.

Q. What was the Company's response to the Commission Order in PSC Docket Regulation No. 59 and to the legislation that required decoupled rate design mechanisms to be implemented by December 2010?

A. On June 25, 2009, even prior to the final passage of Senate Bill 106, DPL filed an Application proposing to implement a modified fixed variable rate design for its gas utility. I filed testimony in that case (PSC Docket No. 09-277T) on November 19, 2009. On January

28, 2010, the Commission approved a motion to stay the procedural schedule in that case pending settlement discussions among the parties. A Settlement Agreement was executed among the parties in July 2010.[24]

Pursuant to that Settlement Agreement, the parties agreed that DPL would eliminate all volumetric billing for its gas delivery revenue requirement. Instead of billing customers based on their usage, the parties agreed that DPL would implement a new two-part rate structure consisting of a monthly customer-related charge and an annual demand-related charge. Demand costs would be recovered through a new billing determinant, called the Delivery Demand Contribution "(DDC") Factor.

The Settlement provides for delivery costs to be allocated between customer charges and demand-related charges based on the results of the functional allocations in its cost of service study. The customer charges would then be allocated over the number of customers in each rate class. The Settlement provides for a premise-specific DDC Factor to be determined for each customer based on a combination of historic heating and non-heating demand. The sum of these individual DDC Factors would then be aggregated and compared with the overall aggregate demand for the class. A reconciliation process would be used to ensure that the sum of the individual demands equaled the aggregated demand. Once established, the DDC factor for each premise would remain fixed until the Company's next base rate case.

23 Order in PSC Docket Regulation 59, September 16, 2008, page 5.

24 At approximately the same time that the Settlement was executed, the Delaware legislature revised Section 1500 of Title 26. The requirement to implement a decoupling mechanism was deleted and replaced with the provision that "Delivery rate structures for regulated natural gas and electric utilities shall be designed to avoid unnecessary

The Settlement Agreement also addresses situations where insufficient historic information exists to determine the DDC Factor for a particular premise. In addition, the Settlement Agreement states that, if necessary, DPL will implement a mechanism to mitigate the impact of the new rate design on existing residential and general gas service customers on the extreme high or low end of the impact frequency distribution.

Q. Has the proposed Settlement Agreement been approved by the Commission?

A. No, it is my understanding that the Settlement Agreement has not yet been approved by the PSC.

Q. Assuming that the PSC adopts a new rate structure for the Company, what impact will the new rate design have on DPL's costs?

A. The primary impact will be a significant reduction in the Company's cost of capital. This proposal will greatly reduce shareholder risk, which has already been largely eliminated by the adoption of recovery clauses and other mechanisms that guarantee the utility dollar-for-dollar recovery. The only portion of its revenue requirement that is still at risk is the delivery revenue that is currently collected on a volumetric basis. This is only a portion of the total delivery revenues currently being collected, i.e., the delivery charges that are currently being collected through a volumetric rate element. All customer charges and demand charges for some rate classes are already recovered on a fixed basis. If a modified fixed variable rate

impediments to the Energy Efficiency Resource Standards under this Chapter."

structure is adopted, the Company and its shareholders will be even more insulated from business risk, a factor that must be considered when establishing a reasonable cost of equity for DPL. As previously discussed, if the modified fixed variable rate design is approved, it must be implemented along with a significant reduction to the Company's cost of equity to reflect this reduced risk to shareholders.

Q. Does DPA support the proposed modified fixed variable rate structure?

A. Yes, DPA is a signatory to the Settlement Agreement supporting the new rate design. DPA has been working with the Company and other parties on implementation plans for the new rate design, including the design of customer education programs. Accordingly, I recommend that the PSC approve the proposed rate design, subject to the cost of equity recommendations addressed earlier in my testimony.

Q. Do you have any other recommendations with regard to the new rate structure?

A. Yes, I am recommending that the parties to this proceeding review the results of the new rate structure after it is in place for a reasonable period of time, to ensure that the rate structure as designed is working as intended. Assuming that the PSC approves the new rate structure, I recommend that the PSC require DPL to provide a report to the parties one year after implementation. This report should compare forecast revenues with actual revenues, and should also compare the forecasted impact on DPL's customers with actual customer impacts. While the parties have worked well together to design implementation plans, the new rate structure represent a radical departure from the way that customers are charged currently. If there are significant problems or unintended consequences with the new structure, the parties should reconvene to determine if any prospective modifications would be appropriate.

Q. Are you recommending a true-up of actual revenues to projected revenues under the new rate design?

A. No, I am not. The new rate structure does not include a true-up mechanism and I would oppose any attempt to implement a true-up mechanism as part of the new rate structure. If there are problems with the new rate structure, any changes should be implemented on a prospective basis. I am not recommending any retroactive adjustments relating to the rate design. I am simply recommending that the parties examine the results of the new structure after one year in order to identify any significant issues well before the Company files its next base rate case.

B. Volatility Mitigation Rider Tracking Mechanism

Q. Is the Company requesting a tracking mechanism to track, and true-up, variations in certain costs between base rate cases?

A. Yes, it is. In addition to seeking a new rate design that eliminates its revenue risk, the Company is also seeking a Volatility Mitigation ("VM") Rider to recover the costs of pension, OPEBs, and uncollectibles. The Company is proposing that the VM rider rate be reset annually, based on a three-year rolling average of these costs. The difference between the actual costs incurred by the Company each year and the amounts recovered under the VM rider would be subject to deferred accounting and would be subject to true-up as part of the annual rate adjustment. The Company is proposing to accrue carrying costs on the unamortized balance at its overall cost of capital. The tracker would initially be set to recover $7,238,395 per year, based on average costs from 2008-2010. In addition, the Company's revenue requirement would be adjusted to eliminate $7,364,848 for the pension, OPEB, and uncollectible costs included in the Company's revenue requirement claim.

Q. Should the PSC approve the VM rider as requested by DPL?

A. No, it should not. The VM rider results in single-issue ratemaking and should be rejected by the PSC. The current regulatory framework provides for utility rates to be established based on a test period selected by the Company and on an appropriate return on investment to shareholders and bondholders. Moreover, during that test period, the Company's revenues, expenses, and investment are matched. Shareholders are awarded a return on equity premium for accepting the risk that revenues and costs, including capital costs, can change between base rate cases.

The Company's surcharge proposal isolates a select group of three expenses for reimbursement ratemaking treatment. Pension, OBEP, and uncollectible costs are costs that are integral to the utility business. There is no rationale for treating these costs differently from other elements of the cost of service, such as salaries and wages, Service Company costs, insurance costs, or outside services costs. The Company's proposal suggests a slippery slope down the path to reimbursement ratemaking. Accordingly, it should be rejected.

Q. Why shouldn't the Commission adopt reimbursement ratemaking for a regulated utility?

A. Reimbursement ratemaking violates the basic premise that regulation is a substitute for competition. In a competitive world, companies do not receive dollar-for-dollar recovery of all costs. In some years, a competitive company may earn more than its costs and in some years it may earn less. By turning utility ratemaking into a reimbursement system, the regulator becomes nothing more than an auditor reviewing a utility's books. Perhaps more importantly, reimbursement ratemaking removes important incentives for the utility to control costs.

Q. How does reimbursement ratemaking eliminate these incentives?

A. Reimbursement ratemaking eliminates these incentives because the utility is essentially guaranteed recovery of any costs that it can demonstrate it actually spent. While I understand that most surcharge mechanisms are subject to after-the-fact review by regulatory agencies, the fact is that there are very, very few disallowances by regulators of amounts that have actually been spent. Moreover, while I am not an attorney, I understand that in Delaware there is no need to even show that an expense was prudent, a standard that does exist in many other jurisdictions.

Under the current regulatory framework, rates are established in a base rate case. To the extent that a utility can cut costs, shareholders benefit from increased earnings until rates are reset in the next base rate case. Moreover, if cost increases in any one area are greater than offsetting cost decreases, then the utility has a tremendous incentive to find ways to cut costs in order to maintain an acceptable level of return for its investors. The proposed VM rider would eliminate this incentive for pension, OPEB, and uncollectible costs, and provide the Company with essentially guaranteed dollar-for-dollar recovery of these costs.

Q. Has the Company adjusted its cost of equity to reflect the reduced risk that would result if the VM rider is approved?

A. No, it has not. DPL has not proposed any adjustment to its cost of equity relating to a reduction in risk if the VM rider is adopted. It should be noted that the VM rider, like the new proposed rate design, does not reduce overall risk, it simply transfers that risk from shareholders to ratepayers. Thus, the VM rider would result in ratepayers accepting higher risk without a commensurate reduction to the equity premium being paid to shareholders.

Q. What do you propose?

A. I propose that the VM rider be rejected by the PSC. This mechanism would constitute single issue ratemaking, would eliminate DPL's incentives to control these costs, and would shift risk from shareholders to ratepayers without any commensurate reduction in the return on equity premium. Accordingly, it should be denied. As a result of this proceeding, the

Company will experience a tremendous reduction in risk due to the adoption of a new rate modified fixed variable rate design. The PSC should not exacerbate this shift by adopting reimbursement ratemaking for costs that are integral to the Company's distribution business, such as benefit costs and uncollectibles. Instead, the PSC should be mindful of the fact that regulation is intended to be a substitute for competition, and should expect the Company and its shareholders to assume the risk of expense variations between base rate cases. If, in spite of my recommendation, the PSC does approve a VM rider for DPL, then it should also make a further reduction in DPL's cost of equity.

Q. Was a similar proposal rejected by the Maryland Public Service Commission in DPL's recent rate case in that state?

A. Yes, it was. In its Decision in PSC Case No. 9192, the Maryland PSC stated:

> We rejected similar proposals in Delmarva's last rate case because surcharges guarantee dollar-for-dollar recovery of specific costs, diminish the Company's incentive to control those costs, and exclude classic, ongoing utility expenses from the standard, contextual ratemaking analysis….Pension and OPEB expenses….even in a bad year - they are classic, ongoing costs of running a utility company, and cannot, in our view, qualify for specialized rate treatment. We find again, as we did in 2007, that a pension and OPEB surcharge breaches the historical ratemaking bargain, and the economic challenges of the last two years offer no reason for us to jettison these long-settled principles.[25]

The District of Columbia PSC also rejected a similar proposal by Pepco, finding "[t]he Commission rejects the Company's surcharge proposal and directs Pepco to continue

25 Order in PSC Case No. 9192, pages 15-16.

recovering these expenses through rates."[26] In addition, DPL's affiliate, ACE, requested a similar tracking mechanism in its recent New Jersey base rate case filing. The Settlement Agreement in that case does not include the tracking mechanism. Finally, in the recent electric base rate case in Delaware, the Hearing Examiner recommended that the Delaware PSC reject the Company's proposal for a VM rider surcharge for its electric operations.

For the reasons discussed earlier in my testimony, and consistent with decisions and recommendations in Maryland, New Jersey, the District of Columbia, and Delaware, the Company's request for a tracking mechanism should be denied.

C. <u>Utility Facility Relocation Charge ("UFRC") Rider</u>

Q. Please describe the UFRC rider being requested by DPL.

A. As described on pages 16-17 of Mr. Janocha's initial testimony, the Company is requesting that the Commission approve a new rider "to provide a mechanism to implement the recovery of costs related to relocation of the Company's delivery facilities as required to accommodate projects sponsored by the Delaware Department of Transportation, or other state agencies, as allowed under Section 315 of Title 26 of the Delaware Code."

Q. Did the Company make a similar request in its recent electric base rate case?

A. Yes, it did. As noted in my testimony in that case, it appears that the Company is permitted to implement a UFRC under Delaware law, and therefore DPA did not oppose the

26 Case No. 1076-E-234, Order No. 15710, page 58.

Company's request. However, in her Recommended Decision in that case, the Hearing Examiner recommended that the PSC decline to authorize the UFRC until "it has investigated whether administrative rules and regulations are necessary to assist in the administration of this rider."[27] Since there could be disputes regarding the types of costs that are appropriate to recover through the rider or other issues, I recommend that the Hearing Examiner make a similar finding in this case. The UFRC should not be implemented until the PSC is satisfied that appropriate rules and a process for dispute resolution are in place.

Q. Does this conclude your testimony?

A. Yes, it does.

27 Recommended Decision, PSC Docket No. 09-414, paragraph 156.