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OTS Statement No. 1
Witness: E. V. Jeschke
Date: November 7, 1997

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PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

DUQUESNE LIGHT COMPANY

Docket No. R-00974104

Direct Testimony

of

Eric Van Jeschke

Office of Trial Staff

Concerning:

Fair Rate of Return

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Q. PLEASE PROVIDE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Eric Van Jeschke. My business address is P. O. Box 3265, Harrisburg, Pa. 17105-3265.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am currently employed by the Pennsylvania Public Utility Commission as a Fixed Utility Financial Analyst. I am assigned to the Office of Trial Staff as an expert witness.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I have provided this information in Appendix A supplementing my direct testimony.

I. <u>SUBJECT OF TESTIMONY</u>

Q. DEFINE THE ISSUES THAT ARE ADDRESSED IN THIS TESTIMONY?

A. The issues addressed in my direst testimony are recommendations concerning the discount rate, the reasonable rate of return, including

capital structure, the embedded cost of debt, the embedded cost of preferred stock, the cost of common equity and the overall fair rate of return for Duquesne Light Company (Duquesne or Company).

Q. DOES YOUR DIRECT TESTIMONY INCLUDE AN EXHIBIT THAT SUPPORTS YOUR RECOMMENDED RATE OF RETURN AND DISCOUNT RATE?

A. Yes. OTS Exhibit No. 1 includes schedules which summarize my recommended rate of return/discount rate and present the financial data and economic factors employed in my analysis.

II. BACKGROUND DISCUSSION

Q. WHAT CONSTITUTES A FAIR AND REASONABLE OVERALL RATE OF RETURN?

A. A fair and reasonable overall rate of return is one which will allow the utility the opportunity to recover those costs prudently incurred by all classes of capital used to finance the rate base during the prospective period its rates will be in effect.

The Bluefield Water Works and Hope Natural Gas cases of 1923 and 1944, respectively, set forth the following principles that are generally accepted by regulators as the proper criteria for measuring a fair rate of return:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

Bluefield Water Works & Improvements Co. v. Public Service Comm. of West Virginia, 262 U.S. 679, 692-93 (1923).

> [I]t is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with risks on investments in other enterprises having

> corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

FPC v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).

While interpretations of these quotations may vary somewhat, they provide general guidelines for the regulator to determine a fair rate of return.

Q. WOULD YOU PLEASE EXPLAIN HOW YOU CALCULATED YOUR OVERALL RATE OF RETURN?

A. Yes. The overall rate of return is calculated using the weighted average cost of capital method, which is generally the interaction of the following components: the percentage of debt, the percentage of preferred stock, the percentage of common equity, the cost of debt, the cost of preferred stock, and the cost rate of common equity. First, it is necessary to determine the proportion of each type of capital (capital structure) which has financed the rate base and assign the appropriate cost rate to each capital structure component. The capital structure may be actual or imputed if the actual capital structure is not representative of the industry norm. The cost rates of debt and preferred stock are fixed and can be computed accurately.

The cost rate of common equity is not fixed and is much more difficult to measure.

The overall rate of return is then calculated using the proportions of each type of capital and the cost rates of each type of capital. On OTS Exhibit No. 1, Schedule 1, I demonstrate the interaction of the capital structure and the cost rates of each type of capital. By multiplying each capital component ratio by its associated cost rate, a weighted cost rate is derived. The overall rate of return is the sum of weighted cost rates.

III. COMPANY'S POSITION

A. Summary

Q. WHAT IS THE COMPANY'S RATE OF RETURN CLAIM IN THIS CASE?

A. Dr. Jeff D. Makholm, the Company's rate of return witness, concluded that the Duquesne should be afforded an opportunity to earn an 11.65 percent return on common equity.[1/] However, the Company has

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[1/] Dr. Makholm's recommended cost rate of common equity is 11.65 percent. (Duquesne Statement No. 12, page 3) The direct testimony of D. J. Clayton (Duquesne Statement No. 2, page 47), states that 11.50 percent is the Company's claimed cost of common equity.

requested an 11.50 percent cost of common equity, which results in a 9.61 percent total weighted average cost of capital. The following table summarizes the Company's claimed weighted cost of capital, the discount rate and its individual components:

	Capital Structure (%)	Cost Rate (%)	Weighted Cost Rate (%)	After-Tax Cost of Capital Discount Rate (%)
Long-Term Debt	50.23	8.51	4.27	2.50
Preferred Stock	9.69	7.45	0.72	0.72
Common Equity	40.08	11.50	4.61	4.61
Total	100.00		9.20	7.83

Source: Duquesne Volume VII, Item No. H-1, Schedule 1, Page 2 of 2 and Volume IX, Item No. L-8, page 1 of 1.

B. Basis

Q. PLEASE STATE THE BASIS FOR THE COMPANY'S CLAIM.

A. Duquesne's recommended rate of return is summarized on Volume VII, Item No. H-1, page 2 of 2, and discussed in the direct testimony of Mr. Donald J. Clayton, (Duquesne Statement No. 2, page 44-47).

Dr. Makholm stated on page 7, of Duquesne Statement 12, that his 11.65 percent recommendation for the cost of equity is based on a Discounted Cash Flow (DCF) model analysis performed on a proxy group of U.S. electric utilities. However, to be conservative, Mr, Clayton reduced the company's claim to 11.50 percent (Duquesne Statement No. 2, page 47). The Company's after-tax discount rate for use in computing net present value of stranded cost is 7.83 percent and can be found in Volume IX, Item No. L-8, page 1 of 1 and sponsored by the witness D.J. Clayton.

IV. OTS' POSITION

A. Summary

Q. PLEASE STATE YOUR SPECIFIC FAIR RATE OF RETURN/DISCOUNT RATE RECOMMENDATION FOR DUQUESNE IN THIS PROCEEDING.

A. The following table summarizes my recommended rate of return/discount rate for Duquesne:

	Capital Structure (%)	Cost Rate (%)	Weighted Cost Rate (%)	After-Tax Cost of Capital Discount Rate (%)
Long-Term Debt	50.23	8.51	4.27	2.50
Preferred Stock	9.69	7.45	0.72	0.72
Common Equity	40.08	10.50	4.21	4.21
Total	100.00		9.20	7.43

Based upon my analysis, I recommend a cost rate of 10.50 percent for common equity and an overall rate of return of 9.20 percent. The after-tax overall cost of capital discount rate is 7.43 percent.[2/] My recommended 10.50 percent cost rate of common equity represents the maximum of my range of 9.50 - 10.50 percent. I will discuss my recommendation of 10.50 percent cost rate of common equity directly.

[2/]The tax savings computation is computed by multiplying the tax rate of 41.493 percent by the weighted cost of long-term debt of 4.27 percent. That result is 1.77 percent. Then subtract the result of 1.77 percent from the weighted cost of long-term debt to arrive at the after-tax cost of long-term debt. In this instance the result is 2.50 percent. The sum of the weighted after-tax cost rates is the after-tax overall cost of capital discount rate.

B. Elements Adopted:

Q. HAVE YOU ADOPTED ANY ELEMENTS OF THE COMPANY'S RECOMMENDATION IN ARRIVING AT YOUR POSITION?

A. Yes. I adopted the Company's test year capital structure, which consists of 50.23 percent long-term debt, 9.69 percent preferred stock, and 40.08 percent common equity. I have also adopted the cost rates which accompany the long-term debt and preferred stock as presented in Duquesne Volume VII, Item No. H-2 and H-7.

C. Elements Disputed:

Q. HOW DOES YOUR RECOMMENDATION DIFFER FROM THE COMPANY'S CLAIM?

A. My recommended rate of return differs from Duquesne's claim in the area of the cost of common equity capital. I recommend a cost of common equity of 10.50 percent in lieu of the 11.65 percent recommended by Dr. Jeff D. Makholm and the 11.50 percent Company claim recommended by Mr. Clayton. Based upon the evidence that I have gathered regarding

an appropriate market based cost rate of common equity, the Company's 11.50 percent cost of common equity is excessive.

Q. IN THE DETERMINATION OF YOUR RECOMMENDED COST RATE OF COMMON EQUITY, DID YOU USE THE SAME ELECTRIC BAROMETER GROUP (EBG) OF U.S. ELECTRIC UTILITIES AS DR. MAKHOLM?

A. No. I have used thirteen electric companies that satisfy specific selection criteria in lieu of Dr. Makholm's barometer group. I will discuss the barometer group directly later on in this testimony.

V. CAPITAL STRUCTURE/COMMON EQUITY RATIO

Q. HOW DOES THE COMPANY'S TEST YEAR END COMMON EQUITY RATIO COMPARE TO YOUR ELECTRIC BAROMETER GROUP?

A. An examination of historical common equity ratios for the EBG indicates that the Company's recommended 40.08 percent common equity ratio is lower than the average of the group. On Schedule 3, of OTS Exhibit

No. 1, I have shown that common equity ratios in 1996, for the EBG average is 47.58 percent with a median of 47.01 percent. Since common equity costs more than debt and preferred stock, the use of Duquesne's lower than average common equity ratio will result in a lower than average overall cost of capital. Generally, a higher common equity ratio indicates a lower financial risk. Therefore, while Duquesne's capital structure is acceptable, a higher than average cost of equity is warranted.

VI. COST RATE OF COMMON EQUITY

A. Basis for Determining the Cost Rate of Common Equity:

Q. WHAT IS THE BASIS FOR DETERMINING A COST RATE OF COMMON EQUITY?

A. Comprehensive financial analysis will produce a cost rate of common equity within a range of reasonableness. The determination of a cost rate of common equity within that range requires the analyst to exercise informed judgement based on financial and investors' expectations during various segments of the business cycle. The marketplace must be consulted for some insight into the cost rate of common equity since

investors determine the price at which common equity capital will be provided.

The determination of the cost rate of common equity also requires the review of historic and current financial and economic data as well as prospective estimates of inflation rates, interest rates, and the state of our economy in general. A proper matching of these cost indicators to the current and expected phase of the business cycle is necessary in order to provide a cost rate of common equity recommendation which will allow the utility an opportunity to earn a satisfactory, but not excessive, return. Management's efficient pursuit of earning that return will preserve its financial soundness. As a result, the Company will be able to compete for new capital in the marketplace with companies of comparable risk.

B. Methodology Used: Discounted Cash Flow (DCF) Analysis:

Q. HOW DID YOU ARRIVE AT YOUR RECOMMENDED COST RATE OF COMMON EQUITY?

A. I used the discounted cash flow (DCF) method to determine the cost rate of common equity. To compute the various components of the DCF

method, I relied upon current, historical and forecasted market data for the Electric Barometer Group.

In developing my analysis, I also analyzed historical, current and prospective interest rates. This is necessary to insure that my recommended market determined cost of equity reflects changes in economic conditions.

Q. WOULD YOU PLEASE DISCUSS THE UNDERLYING PRINCIPLES OF THE DCF METHOD?

A. Yes. The DCF method, which is sometimes referred to as the "dividend yield plus growth rate" method, recognizes that when investors buy stock, they expect to receive a total return consisting of the cash flows from the dividends and capital appreciation. The cost rate yielded by the DCF technique for a public utility is the sum of the expected dividend yield on the stock during the coming year and the expected growth in dividends per share.

The formula for the DCF method is as follows:

$$k = D1/Po + Gn$$

where:

k	=	expected rate of return
D1	=	indicated dividend payment expected during the course of the next year
Po	=	current stock price
Gn	=	dividend growth expected over the long-run period "n"

Q. HOW IS THE DIVIDEND YIELD PORTION OF THE DCF METHOD DETERMINED?

A. The dividend yield portion of the DCF formula is determined by a basic calculation. The expected dividend is divided by a representative stock price. I use the indicated expected dividend payment and a representative stock price that I located in publications such as the Standard & Poor's Stock Guide and Barron's National Business and Financial Weekly. The use of spot prices may result in an unrepresentative dividend yield since stock prices tend to vary on a daily, weekly or monthly basis. To determine my dividend yield, I used the current dividend yield presented in the September 1, 1997 Barron's National Business and Financial Weekly, and the 52-week average dividend yield.

Q. BRIEFLY, HOW IS THE GROWTH RATE PORTION OF THE DCF METHOD DETERMINED?

A. The growth rate component of the DCF method is more subjective and difficult to determine than the dividend yield. The dividend growth rate is used to estimate perpetual capital appreciation. One approach to deriving a dividend growth rate is to use historical data. However, it is very important not to rely solely on historical information when reputable analysts' forecasts are available, such as those found in The Value Line Investment Survey or the Standard & Poor's Earnings Guide. A DCF analysis which is developed by using analysts' forecasted growth rates is indicative of estimated future economic conditions and specific company and industry risk factors.

C. *Barometer Group Selection*:

Q. WHAT BAROMETER GROUP HAVE YOU CHOSEN TO DETERMINE THE COST OF EQUITY CAPITAL FOR DUQUESNE?

A. Duquesne does not have market data available on its common stock. This is because Duquesne is a wholly-owned subsidiary of DQE. As a

consequence, it is appropriate to use a suitable proxy or barometer group of publicly traded electric companies who provide similar services and products as Duquesne, to determine the rate of return on common equity for Duquesne. Obviously, the companies within an industry will differ in some ways from one another which is why I focus on the similarities. This can be accomplished by analyzing some of the key market information and risk indicators. My barometer group consists of the following publicly traded electric companies:

(1) Atlantic Energy, Inc.,
(2) Baltimore Gas & Electric Co.,
(3) Boston Edison Company,
(4) Carolina Power & Light Company,
(5) Dominion Resources, Inc.,
(6) Duke Power Company,
(7) GPU, Inc.,
(8) IES Industries,
(9) PECO Energy Company,
(10) PP&L Resources, Inc.,
(11) Public Service Enterprise Group,Inc.,
(12) Rochester Gas & Electric Corporation,
(13) Unicom Corporation.

Q. WHAT IS THE CRITERIA FOR YOUR BAROMETER GROUP SELECTION?

A. The electric barometer group of thirteen electric companies satisfy the following selection criteria: electric companies located in the eastern and

central United States; similar financial risk to Duquesne; and nuclear generating generally in excess of 30 percent (Duquesne 29 percent).

D. Risk Comparison:

Q. DID YOU USE DUQUESNE LIGHT COMPANY IN YOUR RISK ANALYSIS AS PRESENTED ON OTS EXHIBIT NO. 1, SCHEDULE 3?

A. No. I used DQE the parent company of Duquesne Light Company.

Q. WHY DID YOU USE DQE'S DATA RATHER THAN DUQUESNE LIGHT COMPANY'S DATA IN YOUR RISK ANALYSIS?

A. Duquesne Light Company dose not have market data available which can be used in a risk comparison analysis. DQE has market data available to be used in a risk comparison analysis. Therefore, it is necessary to look at to DQE's market data as a proxy for Duquesne. Since 92.5 percent of DQE's operating revenues come from Duquesne's sale of electricity, I believe this is appropriate.

Q. WHAT IS THE EBG'S PERCENTAGE OF ELECTRIC OPERATING REVENUES TO TOTAL REVENUES?

A. The EBG's median percentage of electric operating revenues to total revenues is 91.46 percent.

Q. WHAT ANALYSIS OF MARKET DATA AND RISK INDICATORS DID YOU PERFORM?

A. My risk comparison of the barometer group to Duquesne (DQE) is presented on OTS Exhibit No. 1, Schedule 3. Items of comparison are nuclear generation percentage; total capital; equity ratio; beta safety rank and financial strength.

Q. PLEASE EXPLAIN THE IMPORTANCE THAT NUCLEAR GENERATION EXPOSURE HAS ON DUQUESNE LIGHT COMPANY.

A. The percentage of nuclear generation is a variable where an expected large stranded cost associated with nuclear plant is possible. The average percentage of nuclear generation for the barometer group is 35.85 percent, and the median is 32.00 percent and the range is from 15.00 to 67.00

percent. DQE's data reflects nuclear generation of 29.00 percent. It is readily apparent that the barometer group of electric companies is largely exposed to the risk associated with nuclear generation. DQE's percentage of nuclear generation is slightly lower than the median of the range, which indicates a lower risk associated with nuclear generation than the average.

Q. PLEASE DESCRIBE DUQUESNE'S (DQE) FINANCIAL RISK PROFILE IN COMPARISON TO THE BAROMETER GROUP.

A. Investment risk is composed of financial risk and business risk. Financial risk is the percent of debt in the capital structure employed to finance the fixed capital. Common equity ratios for electric companies are essentially the inverse of the debt ratio; therefore, I used common equity ratios from OTS Exhibit No. 1, Schedule 3 to measure financial risk. DQE's common equity ratio of 45.15 percent and Duquesne's common equity ratio of 40.08 percent is lower than the barometer group's average of 47.58 percent and median of 47.01 percent. The range of the common equity ratios for the EBG is 43.74 to 53.66 percent.

Q. PLEASE DESCRIBE DQE'S INVESTMENT RISK PROFILE IN COMPARISON TO THE BAROMETER GROUP.

A. DQE's investment risk profile is presented on OTS Exhibit No. 1, Schedule 3. I have provided a comparison of the EBG and DQE in the areas of Beta (column 5), safety rank (column 6), and financial strength (column 7). DQE's beta of 0.75 compares favorably to the EBG's average of 0.78 and median of 0.70. DQE's safety rank of 2 is higher than the EBG's average of 2.4 and median of 3.0. DQE's financial strength of **A** is higher than the EBG's average rating of **B++** and median of **B++** which indicates that DQE is somewhat financially stronger than the EBG. Overall, DQE's measures of investment risk by these three indicators, shows a lower investment risk in comparison to the electric barometer group.

Q. WHAT DO YOU CONCLUDE FROM YOUR COMPARISON OF THE RISK INDICATORS FOR DQE AND THE EBG AS INDICATED ON OTS EXHIBIT NO.1, SCHEDULE 3?

A. Based upon my analysis of the risk indicators for DQE and the EBG, I believe the barometer group is a very close representation of an electric utility with DQE's characteristics.

E. Alternative Investments:

Q. HAVE YOU STUDIED THE GENERAL CONDITION OF BOND YIELDS AND CHANGES IN DIVIDEND YIELDS FOR THE ELECTRIC BAROMETER GROUP?

A. Yes. I have provided a comparison of the EBG's common stock dividend yields to yields on Moody's A rated public utility bonds, long-term Government bonds, intermediate term Government bonds and short-term Government issues for the period 1981 through 1996. This analysis is shown on OTS Exhibit No. 1, Schedule 5. On OTS Exhibit No. 1, Schedule 6, I provide an analysis of forecasted A rated utility bond yields and interest rates from Blue Chip Financial Forecasts.

Q. WHAT IS THE SIGNIFICANCE OF THE FORECASTS IN TERMS OF PREDICTING THE EXPECTED COST RATE OF COMMON EQUITY FOR ELECTRIC UTILITIES?

A. The present level and forecasted trends of interest rates must be viewed in a historical perspective when attempting to exercise judgement regarding the cost rate of common equity for an electric company. The present and

forecasted levels of interest rates are relatively low in terms of the level of rates experienced during the period 1981 through 1996. The expected cost rate of common equity for a electric company should reflect the fact that returns on alternative income paying investments have declined and are expected to remain low and stable.

Q. HOW DO THE 1996 DIVIDEND YIELDS AND BOND YIELDS COMPARE TO YIELDS EXPERIENCED DURING THE HISTORIC PERIOD OF 1981 TO 1995?

A. My analysis on Schedule 5, indicates that the 1996 average for the EBG's common stock dividend yields and yields on utility bonds and government securities are at relatively low levels in terms of yields experienced since 1981. The 1981 yields were at their highest since 1946 (Source: Moody's Bond Record). The following is a summary of how the 1996 average yields compare to the 1981-1995 range of dividend yields and bond yields:

	Recent 1996	Range 1981-1995
EBG Div. Yield	6.55	6.55 - 11.62
Moody's "A" Utl Bond	7.75	7.59 - 15.95
LT Govt. Bond	6.72	6.46 - 13.30
Inter. Govt. Bond	6.09	5.26 - 13.83
ST Govt.	5.57	3.96 - 14.25

The information in the table above indicates that the electric barometer group dividend yields and long-term bond yields are near the low end of the 1981-1995 range. It also indicates that shorter-term Government securities tend to be more volatile than long-term bonds and utility stock yields.

Q. OF WHAT IMPORTANCE IS YOUR ANALYSIS OF HISTORICAL DIVIDEND YIELD AND INTEREST RATE INFORMATION TO THE COST OF COMMON EQUITY ESTIMATION PROCESS FOR ELECTRIC UTILITIES?

A. The importance of the above analysis is to demonstrate that electric company dividend yields generally reflect changes in yields on alternative income paying investments such as bonds. Since the dividend yield makes up the greatest portion of the expected total return for a electric company, it is logical that assumptions made about the level and trend of dividend yields and yields on alternative investments generally hold true for the total expected return on common equity.

Q. HAVE YOU ANALYZED FORECASTED BOND YIELDS?

A. Yes. On OTS Exhibit No. 1, Schedule 6, I have summarized bond yield forecasts as presented in the Blue Chip Financial Forecasts. These forecasts are published monthly. I have analyzed the forecasts published for the month of October 1997 and the long-range estimates consensus published in June 1997. I analyzed the October 1997 forecast to note the direction yields are expected to take over the short-run (4th quarter of 1997 through 1st quarter of 1999). The long-range consensus demonstrates the continuity of the forecasts. Blue Chip revises its monthly forecasts to reflect the most updated consensus regarding interest rate expectations for the current quarter and the next five quarters. My analysis of the October 1997 forecast shows an expected decrease in A rated utility bond yields of 20 basis points from the fourth quarter of 1997 through the 1st quarter of 1999 (7.60 to 7.40 percent). The same holds true for the long-term Treasury bond yield. The long-term Treasury bond yield from the 4th quarter of 1997 through the 1st quarter of 1999 is expected to decline by 10 basis points from 6.50 percent to 6.40 percent.

Q. WHAT INFORMATION IS PRESENTED IN THE LONG-RANGE CONSENSUS FORECASTS?

A. The long-range consensus forecasts are the consensus forecasts of bond yields and the prime rate as presented at the bottom of OTS Exhibit No. 1, Schedule 6. This analysis is entitled a "Long-Range Estimate Consensus", which is published in the June 1997 issue of the Blue Chip Financial Forecast. The long-range estimates are provided separately for each year 1998 through 2002 and collectively as one forecast for the years 2003 through 2007.

Q. WHAT DOES THE LONG-RANGE ESTIMATE CONSENSUS SURVEY PUBLISHED BY BLUE CHIP INDICATE ABOUT THE EXPECTED LEVEL OF BOND YIELDS?

A. The long-range forecasts at the bottom of Schedule 6, show that bond yields are expected to decline through the year 2007. A rated utility bonds are expected to decline from 7.70 percent in 1998 to 7.20 percent in 2002, and to 7.10 percent during 2003-2007. The long-term Treasury bond yield reflects a similar decline. The 1998 yield is 6.60 percent and is expected to decline to 6.20 percent in 2002 and to 6.10 percent in 2003-2007.

F. DCF Analysis - Dividend Yield:

Q. WOULD YOU PLEASE EXPLAIN HOW YOU ARRIVED AT YOUR DIVIDEND YIELD FOR THE EBG?

A. Yes. The computation of my recommended dividend yield is presented on OTS Exhibit No. 1, Schedule 4. The dividends used in deriving the dividend yields shown on this schedule are the prices which are stated in the Barron's National Business and Financial Weekly. To determine my dividend yield, I gave weight to the 52-week average dividend yield, the current dividend yield and the medians. The dividend used to determine the dividend yields for each company is the current dividend and current price reported in the September 01, 1997 Barron's National Business and Financial Weekly. On OTS Exhibit No. 1, Schedule 4, column 2, lines 15 and 16, I show the median 52-week and median current dividend yield of 6.91 and 6.86 percent, respectively. In column 7, lines 13 and 14, I show the average 52-week and average current dividend yield of 7.02 and 6.92 percent. As I previously discussed, I used 7.00 percent as a representative dividend yield in my DCF analysis. The 7.00 percent is the unadjusted dividend yield that I used to develop my Discounted Cash Flow method results (OTS Exhibit No. 1, Schedule 7).

Q. DID YOU ADJUST YOUR DIVIDEND YIELD TO REFLECT NEXT PERIOD GROWTH?

A. Yes. As shown on OTS Exhibit No. 1, Schedule 7, I computed a yield adjustment by multiplying the 7.00 percent dividend yield by one-half the next period dividend growth rate. This adjustment is made because the dividend from the Barron's National Business and Financial Weekly may or may not reflect the annualized increases in quarterly dividends. Therefore, this adjustment reflects any annualized effect if increases in quarterly dividends occur. I have adjusted the dividend yield by one-half my 2.50 to 3.50 percent dividend growth rate recommendation to produce an adjusted dividend yield. This adjustment increases the yield by 9 to 12 basis points to a range of 7.09 to 7.12 percent (see note 1 at line 6 of OTS Exhibit No. 1, Schedule 7).

G. DCF Analysis - Growth Rate:

Q. WHICH SPECIFIC ELEMENTS DID YOU ANALYZE IN THE DETERMINATION OF YOUR DCF GROWTH RATE?

A. I have analyzed historical growth in dividends per share (DPS) and earnings per share (EPS) for the EBG. These are presented on OTS

Exhibit No. 1, Schedule 8. I have also reviewed the forecasted earnings and dividend growth rates as presented by Value Line and Standard & Poor's on OTS Exhibit No. 1, Schedule 8.

Q. WHAT ARE THE RESULTS OF YOUR GROWTH RATE ANALYSIS FOUND ON OTS EXHIBIT NO. 1, SCHEDULE 8?

A. On Schedule 8, column 2 and 3, I show the results of the historical compound dividend (normalized 5-year) and historical log-linear dividend (5-year). The period of time covered in this analysis is a five-year historical and five-year forecasted frame. The average historical compound dividend and log-linear dividend is 1.64 percent and 1.77 percent. The medians are 2.21 percent and 1.45 percent.

The historical compound earnings (normalized 5-year) and historical log-linear earnings (5-year), are found in column 4 and 5. The average historical compound earnings and log-linear earnings is 2.73 percent and 2.92 percent. The medians are 3.09 percent and 4.09 percent.

Forecasted dividends from the Value Line Investment Survey for the EBG reflect an average of 0.38 percent and median of 0.50 percent (column 6). Forecasted earnings from the Value Line Investment Survey for the EBG reflect an average of 3.58 percent and median of 3.50 percent

(column 7). Forecasted earnings from the Standard & Poor's Earnings Guide for the EBG reflect an average of 2.92 percent and median of 3.00 percent (column 8).

Q. DO YOU HAVE A PREFERENCE OF GROWTH ELEMENTS FROM OTS EXHIBIT NO. 1, SCHEDULE 8, WHICH YOU BELIEVE TO BE MOST RELEVANT IN YOUR DETERMINATION OF THE PROSPECTIVE GROWTH RATE FOR USE IN THE DCF MODEL?

A. Yes. Earnings for utilities can be volatile and growth rates computed from those earnings may not be indicative of long-term growth potential. Yearly fluctuations in earnings can result in distorted growth rates. Dividend growth rates, however, are less volatile and more indicative of management's long-term earnings expectations. Normally, I place the most emphasis on historical dividend growth rates for use in the DCF method to determine the cost of equity. However, due to the depressed dividend growth, I have given primary weight to expected earnings growth rates, simply because more information is implicitly contained in these estimates. Most of the research evidence indicates that analysts' growth forecasts are superior to historically-oriented growth measures. The

historical data is accounted for both in the forecasted growth as well as in expectations of a wide array of economic variables. To give significant weight to the historical growth information would result in a double count.

Q. EXPLAIN THE SPECIFIC JUDGMENT YOU EXERCISED TO DETERMINE THAT A 2.50 TO 3.50 PERCENT GROWTH RATE IS APPROPRIATE.

A. My 2.50 to 3.50 percent growth rate recommendation represents the forecasted average earnings and dividend growth rates as reported on OTS Exhibit No. 1, Schedule 8. The average historical earnings and dividend growth rates are in the 1.64 to 2.92 percent range. The average forecasted earnings growth rates are 2.92, 3.58 and the average forecasted dividend growth rate is 0.38 percent. The median forecasted earnings growth rates are 3.00 and 3.50 percent with a forecasted dividend growth rate of 0.50. The median historical earnings and dividend growth rates range from 1.45 to 4.09 percent. However, the historical earnings growth rate of 4.09 percent is unlikely to be sustainable for the EBG. The forecasted earnings median growth rates of 3.00 and 3.50 percent reflects sustainable growth which I have used in my DCF analysis.

Q. WOULD YOU PLEASE SUMMARIZE THE RESULTS OF YOUR DCF ANALYSIS?

A. Yes. On OTS Exhibit No. 1, Schedule No. 7, I have presented the results of my DCF analysis. In column 2, I first adjusted my 7.00 percent recommended dividend yield by one-half of the 2.50 percent low end of my growth rate range. The adjusted dividend yield is 7.09 percent. The 9.59 percent low end of my DCF range is the sum of the 7.09 percent adjusted dividend yield and the 2.50 percent growth rate.

On Schedule 7, column 3, I adjusted my 7.00 percent recommended dividend yield by one-half of the 3.50 percent high end of my growth rate range. The adjusted dividend yield is 7.12 percent. The 10.62 percent high end of my DCF range is the sum of the 7.12 percent adjusted dividend yield and the 3.50 percent growth rate.

Q. BASED ON THE RANGE OF DCF RETURNS DESCRIBED IN THE RESPONSE ABOVE, WHAT COST RATE OF COMMON EQUITY DO YOU BELIEVE IS REASONABLE FOR A PUBLICLY TRADED ELECTRIC COMPANY?

A. Based on my DCF analysis, I believe that 9.50 to 10.50 percent represents a reasonable cost rate range of common equity for a publicly traded electric company.

Q. DID YOU INCORPORATE A DCF ANALYSIS FOR DQE?

A. No. In comparison to my 7.00 percent recommended dividend yield for the EBG, DQE's current yield is aberrationally low. This is probable due to investors expectations of a 26 percent increase in the dividend that would result from DQE's merger with Allegheny Power System. It is clear that DQE's current dividend yield is not reflective of the Company's long-term earnings potential. Therefore, I do not believe it is appropriate to use it in a current DCF analysis to determine Duquesne Light Company's cost rate of common equity.

H. Value Line Analysis:

Q. HAVE YOU PERFORMED AN ADDITIONAL ANALYSIS TO DETERMINE THE EXPECTED RETURN FOR THE NEXT THREE TO FIVE YEARS FOR THE EBG?

A. Yes. On OTS Exhibit No. 1, Schedule 9, I calculated the expected total DCF method return for the Value Line electric utilities using forecasted information found in the Value Line Investment Survey.

Q. WHY DID YOU PERFORM THIS ADDITIONAL ANALYSIS?

A. Value Line provides forecasted growth rates for both earnings and dividends and a year ahead dividend yield.

In this analysis, I used the forecasted dividend yield and growth rates provided to investors by the Value Line Investment Survey. Value Line's dividend yield is based upon a forecasted year-ahead dividend divided by the current price. The growth rate is forecasted three-to-five years hence. The results of the analysis reflect current and forecasted data.

Q. WHAT ARE THE RESULTS OF YOUR DCF ANALYSIS USING VALUE LINE'S FORECASTED GROWTH INFORMATION?

A. The mean total expected common equity return of the EBG using Value Line's forecasted dividend growth rates is 7.17 percent. The median of the total common equity return using dividends growth is 7.50 percent. The range of total equity returns using dividend growth is 3.10 through

9.10 percent. The mean total expected common equity return of the EBG using Value Line's earnings growth rates is 10.37 percent. The median of the total expected equity return using earnings growth rates is 10.00 percent. The range of total expected equity returns using earnings growth is 8.50 through 13.10 percent.

Q. DO YOU HAVE AN EXPLANATION FOR THE DIFFERENCES BETWEEN THE FORECASTED TOTAL EQUITY RETURN USING DIVIDEND GROWTH AND THE FORECASTED TOTAL EQUITY RETURN USING EARNINGS GROWTH?

A. Yes. While earnings growth rates are expected to continue to increase during the forecasted period, dividend growth rates are not expected to increase at the same pace. In the electric utility markets, investors should not look for great increases in dividends during the next three to five years. I believe that in response to a perceived increase in business risk resulting from the transition to a competitive environment, dividend growth is being restrained in order to strengthen equity ratios. The electric environment is changing and those electric utilities that will fair best are those with low rates relative to their competitors and those that are

financially strong. However, low rates will slow earnings growth and consequently, dividend increases.

Q. DO THE RESULTS OF YOUR VALUE LINE ANALYSIS SUPPORT THE REASONABLENESS OF YOUR 9.50 - 10.50 RECOMMENDATION?

A. Yes. The results using forecasted earnings growth rates indicate that my 9.50 - 10.50 recommendation is fair and reasonable.

VII. RECOMMENDATION FOR COST RATE OF COMMON EQUITY

Q. BASED ON YOUR 9.50 TO 10.50 PERCENT MARKET DERIVED COST RATE RANGE OF COMMON EQUITY, WHAT COMMON EQUITY COST RATE DO YOU RECOMMEND FOR DUQUESNE?

A. Given that Duquesne's test-year capital structure represents a below average business position with a current **BBB+** senior debt rating, I recommend the 10.50 percent upper end of the 9.50 to 10.50 percent range of my market derived cost rate of common equity. As I have stated earlier, Duquesne has a lower common equity ratio which suggests higher

financial risk. The S&P benchmark from the Standard and Poor's Global Sector Review in July of 1994 reflect a 48 percent debt to total capital is below average; whereas, a 54 percent debt to total capital ratio is average, and a 59 percent debt to total capital is above average.

VIII. OVERALL WEIGHTED COST OF CAPITAL

Q. WHAT OVERALL WEIGHTED COST OF CAPITAL DO YOU RECOMMEND FOR DUQUESNE?

A. On OTS Exhibit No. 1, Schedule No. 1, column 4, I have presented the calculation of the overall weighted cost of capital for Duquesne. My recommended 10.50 percent cost rate for common equity combined with the Company's historic test year December 31, 1996 capital structure and the embedded cost rate of 8.51 percent for long-term debt and 7.45 percent cost rate for preferred stock, results in an overall weighted cost of capital of 9.20 percent.

IX. PRE-TAX INTEREST COVERAGE

Q. HAVE YOU PERFORMED ANY OTHER CALCULATIONS TO TEST THE FAIRNESS AND REASONABLENESS OF YOUR 9.20 PERCENT OVERALL RATE OF RETURN RECOMMENDATION?

A. Yes. An interest coverage analysis demonstrates the fairness of my overall recommendation. OTS Exhibit No. 1, Schedule 9 shows that my 9.20 percent overall rate of return range provides pre-tax interest coverage of 2.97 times.

Q. HOW DID YOU CALCULATE THE PRE-TAX INTEREST COVERAGE?

A. I have calculated pre-tax interest coverage using the current state and Federal income tax rates of 9.99 percent and 35 percent, respectively. Based upon these tax rates, the combined effective state and Federal income tax rate is 41.49 percent. The tax rate complement is 58.51 percent. As shown on OTS Exhibit No.1, Schedule 9, column 6, I divided the weighted cost rate of common equity and preferred stock by the effective tax rate complement to determine the pre-tax rate of return on common equity. To compute the 2.97 times pre-tax coverage, the pre-tax

overall rate of return of 12.70 percent is divided by the 4.27 percent weighted cost rate of long-term debt.

Q. WHAT BENCHMARK DID YOU USE TO COMPARE THE REASONABLENESS OF YOU RESULTS?

A. I used the S&P utility financial benchmark ratios for electric utilities published in the Standard and Poor's Global Sector Review of July 1994.

Q. WHAT IS THE CURRENT CREDIT RATING FOR DUQUESNE LIGHT COMPANY?

A. The current credit rating for Duquesne light Company is an investment grade rating of **BBB+**. (Source: Standard & Poor's Bond Guide, September 1997)

Q. WHAT ARE STANDARD & POOR'S PRE-TAX INTEREST COVERAGE BENCHMARK FOR THE A and BBB RATED BONDS?

A. The pre-tax interest coverage benchmark for an **A** rating range between 2.75 to 4.50 times and the **BBB** is in the range of 1.75 to 3.50 times.

Q. HOW DOES THE PRE-TAX INTEREST COVERAGE RESULTING FROM YOUR OVERALL RATE OF RETURN RECOMMENDATION COMPARE TO THE EBG PRE-TAX INTEREST COVERAGE?

A. My overall rate of return recommendation adjusted to a pre-tax return of 12.28 percent provides pre-tax interest coverage of 2.97 times. I have presented pre-tax interest coverage for the EBG for the most recent five years on OTS Exhibit No. 1, Schedule 11. The group medians range from 2.91 to 3.19 times. The group averages range from 2.77 to 3.43 times. My recommendation produces a 2.97 times pre-tax interest coverage within the range of coverage of the EBG.

Q. HOW DOES THE PRE-TAX INTEREST COVERAGE RESULTING FROM YOUR OVERALL RATE OF RETURN RECOMMENDATION COMPARE TO THE S&P BENCHMARK?

A. The 2.97 times interest coverage is fairly consistent with S&P's standard of 2.50 times required for an electric utility with a bond rating of **BBB**. Duquesne's long-term debt rating is **BBB+**.

X. DISCOUNT RATE

Q. WHAT AFTER-TAX WEIGHTED COST OF CAPITAL DO YOU RECOMMEND FOR THE COMPANY FOR USE IN ITS PRESENT VALUE CALCULATION RELATED TO THE DETERMINATION OF STRANDED COST?

A. On OTS Exhibit No. 1, Schedule No. 1, column 6, I have presented the calculation of the overall weighted cost of capital for Duquesne for use in its present value calculation related to the determination of stranded cost. My recommended 10.50 percent cost rate for common equity combined with the Company's historic test year December 31, 1996 capital structure and the embedded cost rates for long-term debt and preferred stock, results in an overall weighted discount cost of capital of 7.43 percent. This is 40 basis points lower than the Company recommendation of 7.83 percent. The Company's computation can be found on Volume IX, Item No. L-8, page 1 of 1.

XI. CRITIQUE OF DUQUESNE'S COST OF CAPITAL TESTIMONY

Q. PLEASE SUMMARIZE YOUR CRITIQUE OF DUQUESNE'S COST OF CAPITAL TESTIMONY.

A. I have four primary areas of disagreement concerning Dr. Makholm's cost of capital testimony.

- First, Dr. Makholm's barometer group selection is inappropriate.
- Second, Dr. Makholm's adjustment to his dividend yield by an ex-dividend stock price is incorrect.
- Third, Dr. Makholm's growth rate selection is higher than a reasonable, sustainable growth rate.
- Fourth, Dr. Makholm's adjustment to his DCF model result for selling and issuance costs is inappropriate.

A. Barometer group selection as a proxy for Duquesne

Q. WHAT SPECIFICALLY DO YOU FIND INAPPROPRIATE ABOUT DR. MAKHOLM'S BAROMETER GROUP?

A. Dr. Makholm's barometer group lacks a substantial similarity to Duquesne and my barometer group in that, of his seventeen companies, eight companies do not have nuclear power generation. Also, thirteen of his seventeen companies have purchased power as a large portion of their generation. Dr. Makholm makes this observation of his proxy group, however, does not believe it is an important fact in this case (Duquesne Statement No.12, page 20, 4-7). I believe his barometer group is not a representation of an electric utility with DQE's characteristics, and is not a fair and reasonable proxy to use to determine a market based expected cost of common equity for Duquesne.

Q. WHY IS IT IMPORTANT TO INCLUDE NUCLEAR GENERATION IN THE AS A CRITERIA AS A PROXY?

A. Nuclear power plants will impact revenues in the future because of the high expense of recovery. The percent of nuclear generating is a variable where an expected large stranded cost associated with nuclear plant stands.

B. Inappropriate adjustment to the stock price for the "ex-dividend"

Q. **PLEASE PROVIDE A BRIEF DESCRIPTION OF DR. MAKHOLM'S ADJUSTMENT TO THE STOCK PRICE FOR THE EX-DIVIDEND.**

A. Dr. Makholm performed an ex-dividend date adjustment (on all of the stock prices, Duquesne Statement No. 12, page 21, line 12-13) which he claims is to remove the known effect that the next quarterly dividend payment has on the stock price. The adjustment is made by removing from the stock price the portion of the dividend which has already accrued (Duquesne Statement No. 12, page 23, line 5-6).

Q. **IS THIS ADJUSTMENT FOR EX-DIVIDEND APPROPRIATE FOR USE IN THE DCF ANALYSIS?**

A. No. First, Dr. Makholm used a 52-week closing price average for the stock price. This would negate any use of an adjustment to the stock price. Any changes in stock price for seasonal or quarterly events would average out. Second, the stock price change, can not in any-way, be attributed to one factor such as a dividend accumulation or payment. The market price of a stock is moved up or down by many factors and events

and not just one item. I am not aware of any academic evidence which supports an ex-dividend adjustment to dividend yields as it relates to the DCF model. Also, I am unaware of any financial publications that provide ex-dividend adjusted dividend yields to investors for their investment decision making. I believe that if this ex-dividend adjustment was a significant input into investors' decision making process, the main stream financial publications would provide this information.

Q. WHAT DO YOU CONCLUDE FROM YOUR ANALYSIS OF DIVIDEND YIELD PRESENTED BY DR. MAKHOLM AND YOUR RECOMMENDED DIVIDEND YIELD FOR USE IN THE DCF MODEL?

A. Based upon my analysis of Duquesne Statement No. 12, Exhibit JDM - 6, which contains the average dividend of 1.86 and average adjusted stock price of $26.79, the dividend yield result is 6.94 percent. Dr. Makholm's dividend yield is acceptable for use in the Dcf model. However, his result is a matter of happenstance in that it is comparable to my recommended dividend yield of 7.00 percent.

C. Inappropriate Growth Rate

Q. IS THERE ANYTHING WRONG WITH DR. MAKHOLM'S DETERMINATIONS OF HIS GROWTH RATE?

A. Yes. The results of Dr. Makholm's individual growth rate analyses, produces results of 3.47, 4.31 and with an average of 3.89 percent (Exhibit JDM - 7). The evidence presented on Exhibit JDM - 7, shows that ten of the seventeen companies have an average growth rate below 3.50 percent. It is in my opinion that a growth rate above 3.50 percent is not sustainable. My discussion on growth rates in this testimony explains that a growth rate above my 3.50 percent is not sustainable in the current or expected competitive environment.

D. Inappropriate Adjustment for Selling and Issuance Costs

Q. DR. MAKHOLM USES 5.00 PERCENT FOR SELLING AND ISSUANCES COSTS IN HIS DCF MODEL CALCULATION ACCORDING TO THE FORMULA ON DUQUESNE STATEMENT NO. 12, PAGE 28. IS THIS ADJUSTMENT APPROPRIATE?

A. No. Although selling and issuance costs exist on new issuances, I have not made an adjustment for them. I believe that selling and issuance costs are an additional cost of capital that are incurred at the time of issuance. However, as presented in Duquesne Statement No. 12, Exhibit JDM - 11, Duquesne's last offering was in September 1981. The current market price of the common stock already reflects these items, as investors have already capitalized these expenses in determining the market price at the time of purchase. My analysis as well as Dr. Makholm's is market based and already takes these items into consideration. As a result I have made no additional adjustment to account for selling and issuance costs. Dr. Makholm also should not make an adjustment to his DCF model result. The only purpose that this adjustment serves is to overstate Duquesne's cost rate of common equity. Moreover, at this time Duquesne is not issuing any new common stock.

Q. WHAT IS THE EXTENT OF DR. MAKHOLM'S OVERSTATEMENT TO THE COST RATE OF COMMON EQUITY FOR DUQUESNE?

A. I have independently determined that an appropriate cost rate of common equity for a electric company falls within the range of 9.50 to 10.50

percent. Therefore, it is my opinion that Dr. Makholm's 11.65 percent recommendation is overstated by at least 115 basis points (11.65 vs. 10.50 percent equals a 1.15 percent difference).

Q. WHAT DO YOU CONCLUDE GIVEN YOUR CRITIQUE OF DR. MAKHOLM'S COMMON EQUITY COST RATE RECOMMENDATION?

A. The ALJ and Commission should give weight only to the DCF method to determine a proper cost rate of common equity. I recommend that the ALJ and Commission consider only reasonable and supportable growth rates and a proper dividend yield such as my recommended 7.00 percent in determining a DCF-based cost of common equity as presented in my direct testimony. I have recommended a reasonable and sustainable growth rate such as the 2.50 to 3.50 percent range used in my DCF analysis upon which my 10.50 percent recommendation is based.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes. However, I reserve the right to make any necessary adjustments to my recommendation as information may become available which would indicate an adjustment.

Appendix A
Witness: E. V. Jeschke

Eric Van Jeschke

Educational and Professional Background

EDUCATION

The Pennsylvania State University - Capitol Campus
Bachelor of Business Administration - Accounting
From September 1979 to March 1982

The Pennsylvania State University - Berks Campus
Associate Business Administration
From September 1977 to May 1979

ADDITIONAL EDUCATION

University of Utah, Seventeenth Annual Eastern Utility Rate Seminar, from October 22 through 27, 1989.

Department of the Treasury
Internal Revenue Service
Federal Income tax course to provide volunteer tax assistance to taxpayers through the VITA and TCE programs (Volunteer Income Tax Assistance and Tax Counseling for the Elderly).

BUSINESS EXPERIENCE

Commonwealth of Pennsylvania
Public Utility Commission
Office of Trial Staff

Responsible for analysis and preparation of testimony concerning fair rate of return in fixed utility rate cases.
From April 1996 to Present

Commonwealth of Pennsylvania
Public Utility Commission
Office of Trial Staff
Telecom./Water Division
Finance Section

Responsible for analysis and preparation of testimony concerning fair rate of return in fixed utility rate cases.
From March 1994 to March 1996

Commonwealth of Pennsylvania
Public Utility Commission
Office of Trial Staff
Finance Division
Rate of Return Section

Responsible for analysis and preparation of testimony concerning fair rate of return in fixed utility rate cases.
From September 1989 to March 1994

Commonwealth of Pennsylvania
Public Utility Commission
Office of Special Assistants
Tariff Section
North Office Building
Harrisburg, Pennsylvania 17120

From November 1988 to August 1989

Commonwealth of Pennsylvania
Department of Revenue
Bureau of Corporation Taxes
Taxing Division
Strawberry Square
Harrisburg, Pennsylvania 17120
From October 1985 to November 1988

Pennsylvania Hospital Insurance Company
One Phico Drive
Mechanicsburg, Pennsylvania 17055
From June 1982 to March 1985

United States Treasury Department
Bureau of Government Financial Operations
Audit Staff
Washington, D.C. 20226
From June 1980 to December 1980
From June 1981 to December 1981
Cooperative Work Assignment (Two 6 month periods)

Rate of Return Analysis

I have reviewed and analyzed the fiscal data submitted by 171 fixed utilities to determine the reasonableness of the requested rate of return. Of these reviews, 43 cases required the preparation of direct testimony. Of the prepared direct testimonies, 19 of these cases have been entered into the case record and 18 of these cases I have made oral presentation which was vigorously contested on specific issues during proceedings before Commission Administrative Law Judges.

R-00974104, R-00974104C001-C003

OTS Exhibit No. 1
Witness: E. V. Jeschke
Date: November 7, 1997

Pgh 12/17/97
E.V.J.

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

DUQUESNE LIGHT COMPANY

Docket No. R-00974104

Exhibit to Accompany the

Direct Testimony

of

Eric Van Jeschke

Office of Trial Staff

Concerning:

Fair Rate of Return

OTS Exhibit No. 1
Schedule 1
Witness: E. V. Jeschke

Duquesne Light Company

Summary of Fair Rate of Return Recommendation
and
After-Tax Cost of Capital Conclusion Based on Discount Rate

	(1)	(2)	(3)	(4)	(5)	(6)
		Capital Structure Ratios	Cost Rate	Weighted Cost Rate	Tax Savings on Debt @41.493%	After-Tax Cost of Capital Discount Rate
1	Long-Term Debt	50.23%	8.51%	4.27%	1.77%	2.50%
2	Preferred Stock	9.69%	7.45%	0.72%		0.72%
3	Common Equity	40.08%	10.50%	4.21%		4.21%
4		100.00%		9.20%		7.43%

5 Note: Test Year Estimated at December 31, 1996
Tax Savings Computation: 41.493% x 4.27% = 1.77%
4.27% - 1.77% = 2.50%

OTS Exhibit No. 1
Schedule 2
Witnes: E. V. Jeschke

CapitalizationRatios
For
Duquesne Light Company

	(1)	(2)	(3)
		Amount ($000)	Percentage of Total Capitalization
(1)	Long–Term Debt	$1,240,762	50.23%
(2)	Preferred and Preference Stock	$239,330	9.69%
(3)	Common Equity	$990,236	40.09%
(4)	Total	$2,470,328	100.00%

(5) Source: DLC Volume V11, Item No. H–1, Page 2 of 2

OTS Exhibit No. 1
Schedule 3
Witness: E. V. Jeschke

Summary of Risk Indicators for Duquesne Light Company
and the Barometer Group of Electric Companies

	(1) Company	(2) Generating Percent Nuclear	(3) Total Capital ($Million)	(4) Equity Ratio	(5) Beta	(6) Safty Rank	(7) Financial Strength
(1)	Atlantic Energy, Inc.	15.00%	1,964.20	43.74%	0.70	3	B+
(2)	Baltimore Gas & Electric Co.	40.10%	6,491.34	47.94%	0.80	2	B++
(3)	Boston Edison Company	30.00%	2,598.61	45.13%	0.75	3	B+
(4)	Carolina Power & Light Company	38.00%	5,528.09	50.20%	0.80	1	A
(5)	Dominion Resources, Inc.	32.00%	11,604.90	47.01%	0.70	2	B++
(6)	Duke Power Company	42.00%	9,428.69	53.66%	0.70	1	A+
(7)	GPU, Inc.	23.00%	7,319.65	45.21%	0.85	3	B++
(8)	IES Industries	23.00%	1,524.50	45.90%	0.65	3	B++
(9)	PECO Energy Company	43.00%	9,928.63	49.90%	0.90	2	B++
(10)	PP&L Resources, Inc.	31.00%	6,434.00	44.42%	0.75	2	A
(11)	Public Service Enterprise Group, Inc.	32.00%	11,819.40	49.52%	0.70	3	B++
(12)	Rochester Gas & Electric Corporation	50.00%	1,579.51	50.89%	0.90	3	B+
(13)	Unicom Corporation	67.00%	14,419.52	44.97%	0.90	3	B+
(14)	Average (Mean)	35.85%	6,972.39	47.58%	0.78	2.4	B++
(15)	Median	32.00%	6,491.34	47.01%	0.70	3	B++
(16)	DQE	29.00%	3,156.66	45.15%	0.75	2	A

(17) Source: Compustat Database, year–end 1996 Col 3 & 4
Value Line Investment Survey Sept. 12, 1997 or July 11, 1997; Col 2, 5 6 & 7

(18) Note: Col 5 Beta: (1.00 = Market)
Col 6 Safety Rank: (Scale = 1 highest to 5 lowest)

OTS Exhibit No. 1
Schedule 4
Witness: E. V. Jeschke

Electric Barometer Group
Dividend Yield Analysis

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		Atlantic Energy, Inc.	Baltimore Gas & Electric Company	Boston Edison Company	Carolina P & L Company	Dominion Resources Inc.	Duke Power Company	GPU, Inc.	IES Industries
1	52 Week High	$18.38	$28.75	$28.94	$38.25	$41.38	$51.19	$36.56	$33.75
2	52 Week Low	$16.00	$24.75	$21.75	$32.75	$33.25	$41.88	$30.50	$28.13
3	Average Stock Price	$17.19	$26.75	$25.35	$35.50	$37.31	$46.53	$33.53	$30.94
4	Current Stock Price	$17.31	$27.00	$28.25	$33.75	$36.00	$48.44	$33.63	$30.63
5	Current Dividend	$1.54	$1.64	$1.88	$1.88	$2.58	$2.20	$2.00	$2.10
6	52 Week Average Dividend Yield	8.96%	6.13%	7.42%	5.30%	6.91%	4.73%	5.96%	6.79%
7	Current Yield	8.90%	6.07%	6.65%	5.57%	7.17%	4.54%	5.95%	6.86%

		PECO Energy Company	PP&L Resources, Inc.	P.S. Enterprise Group, Inc.	Rochester Gas & Elect. Corporation	Unicom Corporation	Average	DQE
8	52 Week High	$27.38	$24.50	$29.25	$24.31	$28.50		$32.13
9	52 Week Low	$18.75	$19.00	$22.88	$17.88	$18.50		$26.50
10	Average Stock Price	$23.06	$21.75	$26.06	$21.09	$23.50		$29.31
11	Current Stock Price	$23.81	$21.94	$24.81	$23.56	$23.63		$31.75
12	Current Dividend	$1.80	$1.67	$2.16	$1.80	$1.60		$1.36
13	52 Week Average Dividend Yield	7.80%	7.68%	8.29%	8.53%	6.81%	7.02%	4.64%
14	Current Yield	7.56%	7.61%	8.71%	7.64%	6.77%	6.92%	4.28%
15	Median (52 week)	6.91%						
16	Median (Current)	6.86%						

Source: Barron's National Business and Financial Weekly September 01, 1997

OTS Exhibit No. 1
Schedule 5
Witness: E. V. Jeschke

Electric Company Barometer Group Dividend Yields
Dividend Yields of DQE
and Various Alternative Investment Interest Rates

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Dividend Yield Electric Barometer Group	Dividend Yield DQE	Moody's A Rated Utility Bond	Long-Term Government Bond	Intermediate Government Bond	Short-Term Government Bond
1	1981	11.62	14.31	15.95	13.30	13.83	14.25
2	1982	10.94	13.05	15.86	12.25	12.24	12.07
3	1983	9.91	12.64	13.66	11.09	10.93	10.24
4	1984	10.50	14.67	14.03	12.57	12.55	11.71
5	1985	8.77	12.98	12.47	10.54	10.38	9.47
6	1986	7.01	10.31	9.58	8.37	8.07	7.36
7	1987	7.50	9.60	10.10	8.94	8.40	7.58
8	1988	8.27	7.84	10.49	9.02	8.62	8.17
9	1989	7.57	6.21	9.77	8.74	8.70	8.79
10	1990	7.49	5.96	9.86	8.77	8.44	8.11
11	1991	6.93	5.27	9.36	8.03	7.23	6.12
12	1992	6.58	5.13	8.69	7.57	6.49	4.84
13	1993	5.80	4.68	7.59	6.46	5.26	3.96
14	1994	6.78	5.41	8.30	7.19	6.37	5.77
15	1995	6.78	4.72	7.89	7.05	6.67	6.52
16	1996	6.55	4.47	7.75	6.72	6.09	5.57

17 Source: Moody's Bond Record
S&P Compustat Data Base
Barron's National Business and Financial Weekly

OTS Exhibit No. 1
Schedule 6
Witness: E. V. Jeschke

Summary of Forecasts for Selected Interest Rates

	(1)	(2)	(3)	(4)	(5)	(6)
			October 1997 Blue Chip Financial Forecasts			
	Period	A Rated Utility Bond Yield %	30 Year Treasury Bond Yield %	5 Year Treasury Note Yield %	3 Month Treasury Bill Yield %	Prime Rate %
1	4th QTR '97	7.60	6.50	6.20	5.20	8.60
2	1st QTR '98	7.60	6.60	6.20	5.40	8.70
3	2nd QTR '98	7.60	6.50	6.20	5.40	8.70
4	3rd QTR '98	7.50	6.50	6.10	5.30	8.60
5	4th QTR '98	7.50	6.40	6.10	5.30	8.50
6	1st QTR '99	7.40	6.40	6.00	5.20	8.50
7	*Source:*	*Blue Chip Financial Forecasts, Vol. 16, No. 10 Dated: October 01, 1997*				

			Long–Range Estimates Consensus			
		A Rated Utility Bond Yield %	30 Year Treasury Bond Yield %	5 Year Treasury Note Yield %	3 Month Treasury Bill Yield %	Prime Rate %
8	1998	7.70	6.60	6.30	5.40	8.50
9	1999	7.30	6.30	5.90	5.00	8.00
10	2000	7.20	6.20	5.80	4.80	7.80
11	2001	7.20	6.20	5.80	4.80	7.80
12	2002	7.20	6.20	5.80	4.80	7.80
13	2003–2007	7.10	6.10	5.70	4.70	7.60
14		Source: Blue Chip Financial Forecasts, Vol. 16, No. 6 Dated: June 1, 1997				

OTS Exhibit No. 1
Schedule 7
Witness: E. V. Jeschke

Barometer Group Of Electric Companies
Summary Of Discounted Cash Flow Method

	(1)	(2)	(3)
		Based Upon 2.50% Growth Rate %	Based Upon 3.50% Growth Rate %
1	Recommended Dividend Yield	7.00	7.00
2	Dividend Yield Adjustment (1)	0.09	0.12
3	Adjusted Dividend Yield	7.09	7.12
4	Growth Rate	2.50	3.50
5	Indicated Rate Of Return	9.59	10.62
6	Note: (1)	7.00 X (.0250/2) =	0.09
		7.00 X (.0350/2) =	0.12

OTS Exhibit No. 1
Schedule 8
Witness: E. V. Jeschke

Summary of Dividend and Earnings Growth Rates
from the Barometer Group of Electric Companies

		Historical Dividends		*Historical Earnings*		*Forecasted Dividends and Earnings*		
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Company	Historical Compound Dividend (1)	Historical Log–Linear Dividend (2)	Historical Compound Earnings (1)	Historical Log–Linear Earnings (2)	Forecasted Value Line Dividend	Forecasted Value Line Earnings	Forecasted S&P Earnings (3)
(1)	**Atlantic Energy, Inc.**	0.57%	0.19%	–2.23%	–3.02%	–5.50%	4.50%	2.00%
(2)	**Baltimore Gas & Electric Co.**	2.43%	2.65%	5.93%	4.51%	2.50%	7.00%	4.00%
(3)	**Boston Edison Company**	3.13%	2.67%	5.34%	4.14%	0.50%	2.50%	2.00%
(4)	Carolina Power & Light Company	3.62%	3.50%	2.77%	4.09%	3.00%	4.50%	4.00%
(5)	Dominion Resources, Inc.	2.21%	1.42%	–0.48%	0.16%	0.00%	5.00%	4.00%
(6)	Duke Power Company	4.36%	4.18%	7.02%	5.64%	4.50%	4.00%	4.00%
(7)	GPU, Inc.	5.75%	4.65%	3.83%	5.94%	2.50%	6.50%	4.00%
(8)	IES Industries	0.32%	0.00%	3.09%	0.20%	0.00%	1.50%	2.00%
(9)	PECO Energy Company	5.38%	6.48%	1.44%	0.45%	–4.50%	2.50%	2.00%
(10)	PP&L Resources, Inc.	1.59%	0.81%	0.07%	0.54%	0.00%	2.00%	3.00%
(11)	Public Service Enterprise Group, Inc	0.31%	0.00%	1.96%	2.53%	0.50%	1.50%	2.00%
(12)	Rochester Gas & Electric Corporatic	2.05%	1.45%	3.32%	4.47%	0.00%	3.50%	2.00%
(13)	Unicom Corporation	–10.37%	–5.05%	3.47%	8.29%	1.50%	1.50%	3.00%
(14)	*Average (Mean)*	1.64%	1.77%	2.73%	2.92%	0.38%	3.58%	2.92%
(15)	Median	2.21%	1.45%	3.09%	4.09%	0.50%	3.50%	3.00%
(16)	DQE	5.96%	6.17%	6.97%	6.91%	5.00%	3.00%	4.00%

(17) Source: The Value Line Investment Survey
Standard & Poor's Earnings Guide September 1997

(18) Note: (1) Normalized 5–year (2) Log–Linear 5–year (3) 5–year projected EPS growth rate

OTS Exhibit No. 1
Schedule 9
Witness: E. V. Jeschke

Value Line Investment Survey
Discounted Cash Flow Analysis

			Forecasted Growth Rates		Total Equity Return	
	(1)	(2)	(3)	(4)	(5)	(6)
	Company Name	Year Ahead Dividend Yield (%)	Earnings Per Share (%)	Dividends Per Share (%)	Using EPS (%)	Using DPS (%)
1	**Atlantic Energy, Inc.**	6.60	4.50	−5.50	13.10	3.10
2	**Baltimore Gas and Electric Company**	5.90	7.00	2.50	12.90	8.40
3	**Boston Edison Company**	6.50	2.50	0.50	9.00	7.00
4	**Carolina Power & Light Company**	5.50	4.50	3.00	10.00	8.50
5	**Dominion Resources, Inc.**	7.00	5.00	0.00	12.00	7.00
6	**Duke Power Company**	4.40	4.00	4.50	8.40	8.90
7	**GPU, Inc.**	6.00	6.50	2.50	12.50	8.50
8	**IES Industries**	7.00	1.50	0.00	8.50	7.00
9	**PECO Energy Company**	6.95	2.50	−4.50	9.45	2.45
10	**PP&L Resources**	7.30	2.00	0.00	9.30	7.30
11	**Public Service Enterprises Group, Inc**	6.60	1.50	0.50	10.10	9.10
12	**Rochester Gas & Electric Corporation**	7.50	3.50	0.00	11.00	7.50
13	**Unicom Corporation**	7.00	1.50	1.50	8.50	8.50
14	**Mean**	6.79	3.58	0.38	10.37	7.17
15	Median	7.00	3.50	0.50	10.00	7.50
16	**DQE**	4.40	3.00	5.00	7.40	9.40

17 Source: Value Line Investment Survey

18	Atlantic Energy, Inc.	September 12, 1997	GPU, Inc.	September 12, 1997
19	Baltimore Gas and Electric Co.	September 12, 1997	IES Industries	July 11, 1997
20	**Boston Edison Company**	**September 12, 1997**	**PECO Energy Company**	**September 12, 1997**
21	Carolina Power & Light Company	September 12, 1997	PP&L Resources	September 12, 1997
22	DQE	September 12, 1997	P. S. Enter. Group, Inc	September 12, 1997
23	Dominion Resources, Inc.	September 12, 1997	Rochester G & E Corp.	September 12, 1997
24	**Duke Power Company**	**September 12, 1997**	**Unicom Corporation**	**July 11, 1997**

OTS Exhibit No. 1
Schedule 10
Witness: E. V. Jeschke

Duquesne Light Company

Summary of Fair Rate of Return Recommendation
and
Interest Coverage

	(1)	(2)	(3)	(4)	(5)	(6)
		Capital Structure Ratios	Cost Rate	Weighted Cost Rate	Effective Tax Rate Complement	Pre-Tax Return
1	Long-Term Debt	50.23%	8.51%	4.27%		4.27%
2	Preferred Stock	9.69%	7.45%	0.72%	58.51%	1.23%
3	Common Equity	40.08%	10.50%	4.21%	58.51%	7.19%
4		100.00%		9.20%		12.70%

5	Pre-Tax Interest Coverage	2.97 Times
6	Post-Tax Interest Coverage	2.15 Times

7 Note: Test Year Estimated at December 31, 1996

OTS Exhibit No. 1
Schedule 11
Witness: E. V. Jeschke

Pre–Tax Interest Coverage
For the Barometer Group of Electric Companies

(1)	(2)	(3)	(4)	(5)	(6)
	Company	**1996**	**1995**	**1994**	**1993**	**1992**
(1)	**Atlantic Energy, Inc.**	2.56	3.21	3.07	3.51	3.58
(2)	**Baltimore Gas & Electric Co.**	2.99	3.04	2.90	2.81	2.46
(3)	**Boston Edison Company**	3.06	2.42	2.45	2.24	1.85
(4)	***Carolina Power & Light Company***	4.31	3.81	3.44	3.33	3.44
(5)	**Dominion Resources, Inc.**	N/A	N/A	N/A	N/A	N/A
(6)	**Duke Power Company**	5.14	4.91	4.63	4.72	3.55
(7)	**GPU, Inc.**	3.25	4.30	2.16	3.43	3.29
(8)	**IES Industries**	2.95	3.05	3.26	3.31	2.54
(9)	**PECO Energy Company**	3.23	3.41	2.53	2.97	2.30
(10)	**PP&L Resources, Inc.**	3.77	3.63	2.72	3.33	3.18
(11)	**Public Service Enterprise Group, Inc.**	2.93	3.01	2.94	2.79	2.45
(12)	**Rochester Gas & Electric Corporation**	3.76	2.85	2.91	2.81	2.55
(13)	**Unicom Corporation**	3.15	3.02	1.98	1.11	1.99
(14)	**Average (Mean)**	3.43	3.39	2.92	3.03	2.77
(15)	**Median**	3.19	3.13	2.91	3.14	2.55

(17) Source: Compustat Database

R-00974104, R00974104C0001-C0002

OTS Statement No. 2
Witness: Darren D. Gill
Dated: November 7, 1997

12/17/97

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

DUQUESNE LIGHT COMPANY

Docket No. R-00974104

Direct Testimony

of

Darren D. Gill

Office of Trial Staff

Concerning:

Nuclear and Non-Nuclear Plant Decommissioning
Non-Utility Generation (NUG) Issues

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Darren D. Gill. My business address is P.O. Box 3265, Harrisburg, Pennsylvania 17105-3265.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Pubic Utility Commission in the Office of Trial Staff as an Fixed Utility Valuation Engineer.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I am a 1991 graduate of the Pennsylvania State University, University Park, Pennsylvania, where I earned a Bachelor of Science Degree in Nuclear Engineering. Concurrently, in 1991, I was awarded a Bachelor of Science Degree in Applied Physics from Shippensburg University, Shippensburg, Pennsylvania. Attached to my testimony as Appendix A is a statement which more fully describes my educational background and employment experience.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony in this proceeding is to recommend reductions to Duquesne Light Company's (Duquesne or the Company) claim for nuclear and non-nuclear plant decommissioning.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I have divided my direct testimony into three sections. Section I contains my discussion and recommendation concerning the Company's claim for nuclear plant decommissioning. Section II contains my discussion and recommendation concerning the Company's claim for non-nuclear plant decommissioning. Section III summarizes my recommendations.

SECTION I - NUCLEAR PLANT DECOMMISSIONING

Q. WHAT IS NUCLEAR PLANT DECOMMISSIONING?

A. Nuclear plant decommissioning is the dismantlement, decontamination, removal and disposal of the components of a nuclear generating facility at the end of its useful life.

Q. WHAT ARE THE NUCLEAR PLANT SITES FOR WHICH DUQUESNE HAS CLAIMED AT LEAST A SHARE OF THE DECOMMISSIONING RESPONSIBILITY?

A. The Company has claimed at least a share of the decommissioning responsibility for the Beaver Valley and Perry nuclear sites.

Q. HOW DOES DUQUESNE CURRENTLY HANDLE THE FUNDS IT RECEIVES FOR NUCLEAR PLANT DECOMMISSIONING EXPENSE?

A. As required by NRC regulations and applicable Commission orders, funds collected for nuclear plant decommissioning expenses are deposited in external nuclear decommissioning trust funds, which the IRS has designated as qualified for tax purposes. In a qualified fund, the Company can claim a current tax deduction for amounts paid into the fund for both federal and state tax purposes. In addition, the earnings on the fund are not treated as taxable income to the Company.

Q. WHAT IS DUQUESNE'S CLAIM RELATED TO NUCLEAR PLANT DECOMMISSIONING IN THIS PROCEEDING?

A. As depicted in OTS Exhibit No. 2, Schedule 1, Duquesne's estimate for decommissioning of Beaver Valley 1 & 2 and Perry is $1,378 million (in year-end 1997 dollars). Based on Duquesne's partial ownership share in Beaver Valley 1 & 2 and Perry, the Company's total estimated decommissioning expenses are $307.7 million in year-end 1997 dollars.

Q. DO YOU AGREE WITH THE COMPANY'S ESTIMATE OF $1,378 MILLION FOR TOTAL NUCLEAR PLANT DECOMMISSIONING COSTS?

A. I do not agree with the Company's estimate of $1,378 million for total nuclear plant decommissioning costs.

Q. WHY DO YOU DISAGREE WITH THE COMPANY'S ESTIMATE OF $1,378 MILLION FOR TOTAL NUCLEAR PLANT DECOMMISSIONING COSTS?

A. The Company's estimate of nuclear plant decommissioning costs is inflated because the Company has included contingency factors of 21.7% for Beaver Valley 1, 21.74% for Beaver Valley 2, and 16.71% for Perry in its estimate.

Q. MR. GILL, PLEASE DEFINE "CONTINGENCY FACTOR".

A. A contingency factor is an addition to the estimated cost of a project which acts as a "specific provision for unforeseeable elements of cost within the defined project scope." (Ref. American Association of Cost Engineers (AACE), "Project and Cost Engineers' Handbook").

Q. WHY DO YOU DISAGREE WITH THE USE OF A CONTINGENCY FACTOR IN THE NUCLEAR PLANT DECOMMISSIONING ESTIMATE?

A. The inclusion of a contingency factor is improper because it is simply the incorporation of an estimate for unknown circumstances on top of what is already an estimate of expenses to be incurred well into the future. I have been informed by counsel that Section 2804 (4)(III)(F) of the recently enacted electric restructuring legislation permits the company to seek to increase its allowance for nuclear plant decommissioning costs should new information become available. Since this opportunity is available to the Company, it is inappropriate for the Company to inflate its nuclear plant decommissioning claim with a contingency factor.

Q. WHAT EFFECT DOES REMOVING CONTINGENCIES HAVE ON THE COMPANY'S CLAIM?

A. It reduces the estimate of nuclear plant decommissioning costs. The total estimate for nuclear plant decommissioning should be $1,155 million, as a result of the removal of $222.9 million in contingencies. Based on Duquesne's partial ownership share in Beaver Valley 1 & 2 and Perry, the Company's share of total estimated decommissioning expenses should be $255.9 million in 1997 dollars (Ref. OTS Exhibit No. 2, Schedule 1).

Q. HOW DOES DUQUESNE PROPOSE TO RECOVER PROJECTED COSTS ASSOCIATED WITH NUCLEAR PLANT DECOMMISSIONING?

A. Duquesne proposes to recover the costs currently in rates and projected amounts in excess of the costs currently in rates through the CTC. Duquesne currently contributes a cost of service amount of $8,762,097 annually for nuclear decommissioning and has requested an annual CTC amount of $8,762,097, which reflects continued contributions at the regulated cost of service level.

Q. DO YOU AGREE WITH DUQUESNE'S PROPOSED METHOD FOR RECOVERY OF PROJECTED NUCLEAR PLANT DECOMMISSIONING COSTS?

A. I do not agree with Duquesne's proposed method for recovery of projected nuclear plant decommissioning costs.

Q. WHY DO YOU DISAGREE WITH DUQUESNE'S PROPOSED METHOD FOR RECOVERY OF PROJECTED NUCLEAR PLANT DECOMMISSIONING COSTS?

A. Duquesne's proposed method improperly allocates all decommissioning costs to current regulated customers and fails to allocate any of the costs to the deregulated customers.

Q. HOW DOES DUQUESNE'S PROPOSAL ALLOCATE AN IMPROPER AMOUNT OF DECOMMISSIONING COSTS TO CURRENT REGULATED RATEPAYERS?

A. Under the Company's proposal, current regulated ratepayers would be paying all costs related to decommissioning a plant from which they received power during only part of the plant's service life. Customers receiving power from Duquesne as a result of deregulation, and not in the

Duquesne distribution company's service territory, would not contribute anything toward the decommissioning of a plant from which they would receive service.

Q. MR. GILL, HOW DO YOU RECOMMEND DUQUESNE RECOVER PROJECTED NUCLEAR DECOMMISSIONING COSTS?

A. I recommend that Duquesne receive recognition of $3.5 million in stranded costs to properly reflect the level of decommissioning funding that currently regulated ratepayers will be responsible for at December 31, 1998.

Q. MR. GILL, PLEASE DESCRIBE HOW YOU CALCULATED $3.5 MILLION AS THE STRANDED COST ASSOCIATED WITH NUCLEAR DECOMMISSIONING?

A. OTS Exhibit No. 2, Schedule 2 shows my calculation of the OTS level of stranded cost related to nuclear decommissioning to be recovered through the CTC.

Column 1 shows the OTS' estimate of $255.9 million for Duquesne's share of nuclear decommissioning in 1997 dollars, based on its partial ownership of the Beaver Valley 1 & 2 and Perry nuclear plants.

Column 2 inflates the OTS' 1997 estimate by 4.0% annually to arrive at the decommissioning estimate in 1998 dollars.

Column 3 shows the net present value of the OTS decommissioning estimate in 1998 dollars.

Column 4 shows the results of the calculated in-service ratio at December 31, 1998. This ratio is the number of years the plant will have been in service at December 31, 1998 divided by the total age of the plant at the decommissioning year.

Column 5 calculates the amount of total decommissioning costs which current regulated ratepayers are responsible for at December 31, 1998.

Column 6 shows the amounts that will be accrued in the decommissioning funds at December 31, 1998.

Column 7 shows the OTS recommended stranded cost level of $3.5 million which represents the difference between the amount current regulated ratepayers have contributed to the decommissioning fund and their total liability at December 31, 1998.

Column 8 shows the Pennsylvania jurisdictional allocation of nuclear decommissioning expenses.

SECTION II - NON-NUCLEAR PLANT DECOMMISSIONING COSTS

Q. WHAT IS NON-NUCLEAR PLANT DECOMMISSIONING?

A. Non-nuclear plant decommissioning is the dismantlement, removal and disposal of the components of a non-nuclear electric generating facility at the end of its useful life.

Q. HOW ARE NON-NUCLEAR DECOMMISSIONING EXPENSES CURRENTLY HANDLED IN PENNSYLVANIA?

A. The Commission has traditionally allowed a utility to recover the net of positive salvage and cost of removal on a current basis for book and ratemaking purposes. The Commission has used a five year average of actually experienced net salvage as a leveling device.

Q. WHAT IS DUQUESNE'S CLAIM RELATED TO NON-NUCLEAR PLANT DECOMMISSIONING IN THIS PROCEEDING?

A. For non-nuclear electric generating units totally or jointly owned by Duquesne, the Company estimates total decommissioning expenses of $274.4 million in 1997 dollars (Ref. Duquesne Statement No. 13, page 4, lines 16-19).

Q. DO YOU AGREE WITH THE COMPANY'S ESTIMATE OF APPROXIMATELY $274.4 MILLION FOR TOTAL NON-NUCLEAR PLANT DECOMMISSIONING COSTS?

A. I do not agree with the Company's estimate of approximately $274.4 million for total non-nuclear plant decommissioning costs.

Q. WHY DO YOU DISAGREE WITH THE COMPANY'S ESTIMATE OF APPROXIMATELY $274.4 MILLION FOR TOTAL NON-NUCLEAR PLANT DECOMMISSIONING COSTS?

A. The Company's estimate of non-nuclear plant decommissioning costs is inflated because the Company has included a contingency factor of approximately 15% in its estimate (Ref. Duquesne Statement No. 13, page 23, lines 22-24).

Q. WHY DO YOU DISAGREE WITH THE USE OF A CONTINGENCY FACTOR IN THE NON-NUCLEAR PLANT DECOMMISSIONING ESTIMATE?

A. As I stated previously, the inclusion of a contingency factor is improper because it is simply the incorporation of an estimate for unknown circumstances on top of what is already an estimate of expenses to be incurred well into the future.

Q. WHAT EFFECT DOES REMOVING THE CONTINGENCY FACTOR HAVE ON THE COMPANY'S CLAIM?

A. It reduces the estimate of non-nuclear plant decommissioning costs. The Company's estimate of total decommissioning expenses should be $232.8 million in 1997 dollars. This is the result of the removal of $41.6 million in contingencies (Ref. OTS Exhibit No. 2, Schedule 3).

Q. HOW DOES DUQUESNE PROPOSE TO RECOVER PROJECTED COSTS ASSOCIATED WITH NON-NUCLEAR PLANT DECOMMISSIONING?

A. Duquesne proposes to incorporate the costs of decommissioning the fossil generating stations in each station's expense level. Duquesne proposes to

include these costs as components of the total revenue requirement for each generating unit beginning in the final year of plant operation.

Q. DO YOU AGREE WITH DUQUESNE'S PROPOSED METHOD FOR RECOVERY OF PROJECTED NON-NUCLEAR PLANT DECOMMISSIONING COSTS?

A. I do not agree with Duquesne's proposed method for recovery of projected non-nuclear plant decommissioning costs.

Q. WHY DO YOU DISAGREE WITH DUQUESNE'S PROPOSED METHOD FOR RECOVERY OF PROJECTED NON-NUCLEAR PLANT DECOMMISSIONING COSTS?

A. Duquesne's proposed method allocates an excessive amount of decommissioning costs to current regulated customers, and fails to allocate enough of the costs to deregulated customers.

Q. HOW DOES DUQUESNE'S PROPOSAL ALLOCATE AN IMPROPER AMOUNT OF DECOMMISSIONING COSTS TO CURRENT REGULATED RATEPAYERS?

A. As a result of the Company's proposal to treat decommissioning as an expense item beginning in the plant's last year of operation, current regulated ratepayers would be paying, in some instances, all costs related to decommissioning a plant from which they received power during only part of the plant's service life. Consequently, in those same instances, customers receiving power from Duquesne as a result of deregulation and not in the Duquesne distribution company's service territory, would not contribute anything toward the decommissioning of a plant from which they would receive service.

Q. MR. GILL, HOW DO YOU RECOMMEND DUQUESNE RECOVER PROJECTED NON-NUCLEAR PLANT DECOMMISSIONING COSTS?

A. First, I recommend Duquesne remove all expenses and revenues associated with non-nuclear plant decommissioning from the revenue requirement or 'market value' calculation, since the responsibility to fund decommissioning belongs with both currently regulated ratepayers and future deregulated ratepayers. I then recommend that Duquesne receive recognition of $41.6 million in stranded costs to properly reflect the level

of decommissioning funding that currently regulated ratepayers will be responsible for at December 31, 1998.

Q. MR. GILL, PLEASE DESCRIBE HOW YOU CALCULATED $41.6 MILLION AS THE STRANDED COST ASSOCIATED WITH NON-NUCLEAR PLANT DECOMMISSIONING?

A. First, I calculated the net present value of the Company's claim using the OTS discount rate. I then subtracted the contingency factor included in the Company's estimate from the net present value calculation. Finally, I applied an in-service ratio for each plant at January 1, 1999, to the OTS total recommended funding level. The result of these calculations is the OTS recommended stranded cost level.

Q. WOULD YOU PROVIDE A BRIEF EXPLANATION OF OTS EXHIBIT NO. 2, SCHEDULES 4 AND 5?

A. Yes. OTS Exhibit No. 2, Schedules 4 and 5 detail my calculation of the OTS level of stranded cost related to non-nuclear plant decommissioning to be recovered through the CTC.

Schedule 4 shows the Company's claim for non-nuclear plant decommissioning net present valued to January 1, 1999, dollars using the OTS discount rate of 7.43% provided by OTS witness Jeschke.

Schedule 5, Column 1 carries over the net present value of Duquesne's claim from Schedule 4.

Column 2 shows the contingency percentage included in the Company's decommissioning estimates.

Column 3 is derived by removing the contingency factors from the estimates in Column 1.

Column 4 shows the results of the calculated in-service ratio at January 1, 1999. This ratio is the number of years the plant will have been in service at January 1, 1999, divided by the total age of the plant at the decommissioning year.

Column 5 calculates the amount of total decommissioning costs which current regulated ratepayers are responsible for at December 31, 1998.

Column 6 shows the Pennsylvania jurisdictional allocation of non-nuclear plant decommissioning expenses.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS CONCERNING DUQUESNE'S CLAIM FOR NON-NUCLEAR PLANT DECOMMISSIONING COST RECOVERY?

A. Yes. I recommend the Commission require the Company to place all funds received for non-nuclear plant decommissioning into a non-qualified trust fund.

Q. WHY DO YOUR RECOMMEND THE COMMISSION REQUIRE THE COMPANY TO PLACE ALL FUNDS RECEIVED FOR NON-NUCLEAR PLANT DECOMMISSIONING INTO A NON-QUALIFIED TRUST?

A. Requiring the Company to place all funds received for non-nuclear plant decommissioning into a non-qualified trust is the only means to insure the funds contributed for decommissioning will be available at the time the plants are actually decommissioned.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THAT IF A TRUST IS NOT ESTABLISHED, THERE MAY NOT BE SUFFICIENT FUNDS AVAILABLE AT THE TIME THE PLANTS ARE ACTUALLY DECOMMISSIONED.

A. If Duquesne is not required to place funds associated with non-nuclear plant decommissioning into a trust, then the Company could use the funds received for non-nuclear decommissioning for any purpose it deemed necessary. Thus, when the plants are ultimately ready for decommissioning, the funds may not be available. If this situation occurs, funds that have already been provided by ratepayers will have to be duplicated by future taxpayers in the event the federal government or other entity needed to perform the decommissioning of Duquesne's non-nuclear stations.

SECTION III - SUMMARY

Q. MR. GILL, WOULD YOU PLEASE SUMMARIZE YOUR RECOMMENDATIONS?

A. *Nuclear Decommissioning*

I recommend the Commission require Duquesne to remove all nuclear plant decommissioning costs from its market value analysis. Furthermore, I recommend the Commission allow a projection of $1,154.7 million in total for nuclear decommissioning costs associated with Beaver Valley 1 & 2 and Perry, of which Duquesne's share is

$255.9 million. As components of this figure, first, I recommend that Duquesne receive recognition of $3.5 million in stranded costs to bring the fund up to its projected December 31, 1998 level. The Pennsylvania jurisdictional allocation of stranded costs is also $3.5 million. Finally, I recommend the Commission require the remaining dollars to fund nuclear decommissioning be recovered from the competitive market, with annual payments over the lives of the plants deposited into a qualified trust fund.

Non-nuclear decommissioning

I recommend the Commission require Duquesne to remove all non-nuclear plant decommissioning costs from its market value analysis. Furthermore, I recommend the Commission allow a total projection of $232.8 million for non-nuclear plant decommissioning costs. In order to insure sufficient decommissioning funds at the retirement dates of Duquesne's non-nuclear plants, I recommend Duquesne receive recognition of $41.6 million in stranded costs to bring the fund up to its projected December 31, 1998 level. The Pennsylvania jurisdictional allocation of stranded costs is also $41.6 million. I recommend the Commission require the remaining $16.0 million, of the OTS recommended funding level of $57.6 million, be recovered from the competitive market. Finally, I recommend the Commission direct

Duquesne to place funds received for non-nuclear plant decommissioning into a non-qualified trust fund.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

Professional and Educational Experience
of
Darren D. Gill

Education

The Pennsylvania State University, University Park, PA, Bachelor of Science, Nuclear Engineering, 1991

Shippensburg University, Shippensburg, PA, Bachelor of Science, Applied Physics, 1991

Professional Experience

April 1996 - Present: Pennsylvania Public Utility Commission, Fixed Utility Valuation Engineer in the Office of Trial Staff. Participates in the review and prosecution of natural gas and electric, telecommunications, water and sewer rate filings in the areas of valuation, depreciation, rate base, rate structure, and purchased gas.

July 1994 to March 1996: Pennsylvania Public Utility Commission, Fixed Utility Valuation Engineer - Rate Structure/Engineering Section, Energy Division, Office of Trial Staff. Participates in the review and prosecution of natural gas and electric rate filings in the areas of valuation, depreciation, rate base, rate structure, and purchased gas.

November 1991 to May 1994: NSS Numanco, Nuclear Division, Nuclear Engineer/Plant Outage Specialist. Provided technical support in the areas of health physics, nuclear plant refueling (reactor dis/reassembly and fuel movement), and LASER welding, tube repair and shot peening on steam generators. These duties were performed at various nuclear generating sites throughout the United States.

Professional Affiliations

Engineers Society of Pennsylvania

American Nuclear Society (ANS) National Member

Testimony Presented Before The Pennsylvania Public Utility Commission

National Fuel Gas Distribution Corporation, 1307(f) Filing - R-00953487

North Penn Gas Company and PFG Gas, Inc., Rate Case Filing - R-00953524

PG Energy, Inc., Rate Case Filing - R-00963612

North Penn Gas Company, Tariff Filing - R-00963782

Equitable Gas Company, 1307(f) Filing - R-00973895

Pennsylvania Electric Company, Petition - P-00900450

Equitable Gas Company, Rate Case Filing - R-00963858

PECO Energy Company, Electric Rate Restructuring Filing - R-00973953

Metropolitan Edison Company, Rate Restructuring Filing - R-00974008

Pennsylvania Electric Company, Rate Restructuring Filing - R-00974009

R-00974104, R00974104C0001-C0002

OTS Exhibit No. 2
Witness: Darren D. Gill
Dated: November 7, 1997

12/17/97

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

DUQUESNE LIGHT COMPANY

Docket No. R-00974104

Exhibit to Accompany the

Direct Testimony

of

Darren D. Gill

Office of Trial Staff

Concerning:

Nuclear and Non-Nuclear Plant Decommissioning
Non-Utility Generation (NUG) Issues

Total Cost Estimate to Decommission Beaver Valley 1 & 2 and Perry

Ref.	LaGuardia total estimate in 1997 dollars x 1000 *Note 1	Duquesne share of LaGuardia Total estimate in 1997 dollars x 1000 *Note 2	OTS total estimate in 1997 dollars x 1000 *Note 3	Duquesne share of OTS total estimate in 1997 dollars x 1000
Beaver Valley 1	$350,661	$166,564	$288,127	$136,860
Bwaver Valley 2	$377,009	$51,801	$309,687	$42,551
Perry	$649,928	$89,300	$556,874	$76,514
Total	$1,377,598	$307,665	$1,154,688	$255,926

*Note 1: Ref. LaGuardia Decommissioning Studies.

Note 2: Ref. Laguardia Decommissioning Studies x Duquesne Ownership Share

*Note 3: Ref. LaGuardia Decommissioing Studies, less contingencies.

OTS Exhibit No. 2
Schedule 1

Duquesne Light Company
Docket No. R-00974104

CALCULATION OF OTS RECOMMENDED STRANDED COST LEVEL ASSOCIATED WITH NUCLEAR DECOMMISSIONING

	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
	OTS estimate in 1997 dollars x 1000	OTS estimate in 1998 dollars x 1000	Net present value of OTS decommissioning estimate in 1998 dollars x 1000	In-service ratio at Dec. 31, 1998	OTS total fund allowance in 1998 dollars x 1000	Decomm. fund total @ Dec. 31, 1998 x 1000		OTS recommended stranded cost level	PA jurisdict. allocation
Ref.		*Note 1	*Note 2		= (3) * (4)	*Note 3		= (4) - (5)	
Beaver Valley 1	$136,860	$142,334	$81,084	57.50%	$46,623	$39,621		$7,002	$7,002
Beaver Valley 2	$42,551	$44,253	$17,516	30.00%	$5,255	$8,074		($2,819)	($2,819)
Perry	$76,514	$79,575	$31,497	30.00%	$9,449	$10,145		($696)	($696)
Total	$255,925	$266,162	$130,097	N/A	$61,327	$57,840		$3,487	$3,487

*Note 1: Estimates in 1998 dollars are derived by inflating 1997 estimates by 4.0% annually.

*Note 2: Inflated by 4.0% annually to decommissioning date, net present valued using 7.5%

*Note 3: Ref. Duquesne Exhibit DJC-7 (Revised)

OTS Exhibit No. 2
Schedule 2

Total Cost Estimates to Decommission Non-Nuclear Plants

Power Station	LaGuardia total estimate in 1997 dollars x 1000	Total contingencies included in LaGuardia estimate in 1997 dollars x 1000	OTS total estimate in 1997 dollars x 1000
Reference	(1)*	(2)*	(3) = (1) - (2)
Elrama	36,559	6,216	30,343
Cheswick	36,379	5,471	30,908
Eastlake 5	29,839	4,350	25,489
Sammis 7	32,432	4,709	27,723
Brunot Island	18,722	2,757	15,965
Phillips	N/A	N/A	N/A
Mansfield 1,2, &3	120,520	18,147	102,373
Total	274,451	41,650	232,801

*Note: Refer to LaGuardia Decommissioning Studies, Appendix C

OTS Exhibit No. 2
Schedule 3

Duquesne Light Company
Docket No. R-00974104

OTS NET PRESENT VALUE CALCULATION USING DUQUESNE'S PROJECTED NON-NUCLEAR PLANT DECOMMISSIONING COSTS

Plant	NPV @ 1/1/99 ($000)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Elrama	29,872	0	0	0	0	0	0	0	4,918	6,883	6,883	6,883	6,883	3,786	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cheswick	14,488	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4,504	9,113	11,877	11,877	11,877	7,373	2,764	0	0	0	0	0
Eastlake 5	4,247	0	0	0	0	0	0	0	0	0	0	0	0	0	995	2,266	2,821	2,821	2,821	1,826	636	0	0	0	0	0	0	0	0
Sammis 7	4,819	0	0	0	0	0	0	0	0	0	0	0	0	973	2,235	2,999	2,999	2,999	2,026	764	0	0	0	0	0	0	0	0	0
Brunot Island	8,391	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4,669	5,726	5,726	5,726	5,726	1,157	0	0	0	0	0	0	0	0
Phillips	5,686	0	0	0	0	0	0	0	1,332	2,351	2,351	2,351	2,351	1,020	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mansfield 1	7,715	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,104	6,684	6,684	6,684	6,684	3,579	0	0	0	0	0
Mansfield 2	547	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	236	509	509	509	509	272	0	0	0	0
Mansfield 3	1,446	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	775	1,669	1,669	1,669	1,669	894	0
Total	87,843																												

Note 1: NPV calculated using OTS discount rate of 7.43%.

OTS Exhibit No. 2
Schedule 4

Duquesne Light Company
Docket No. R-00974104

CALCULATION OF OTS RECOMMENDED STRANDED COST LEVEL ASSOCIATED WITH NON-NUCLEAR PLANT DECOMMISSIONING

Plant	NPV of Duquesne's Funding Level Estimate @ 1/1/99 ($000)	Contingency Percentage Included in Company Estimate	OTS Total Funding Level @ 1/1/99 to Decommission @ end of Service Life ($000)	In-Service Ratio @ 1/1/99	**OTS Recommended Stranded Cost Level ($000)**	PA Jurisdictional allocation ($000)
Reference	(1)*	(2)**	(3) = (1)*[1-(2)]	(4)	**(5) = (3)*(4)**	(6)
Elrama	20,672	15.00%	17,571	86.00%	**15,111**	15,111
Cheswick	14,408	15.40%	12,189	62.22%	**7,584**	7,584
Eastlake 5	4,247	15.00%	3,610	65.00%	**2,347**	2,347
Sammis 7	4,819	15.00%	4,096	67.50%	**2,765**	2,765
Brunot Island	8,391	15.00%	7,132	65.00%	**4,636**	4,636
Phillips	5,598	15.00%	4,758	100.00%	**4,758**	4,758
Mansfield 1	7,715	15.00%	6,557	55.00%	**3,607**	3,607
Mansfield 2	547	15.00%	465	52.50%	**244**	244
Mansfield 3	1,446	15.00%	1,229	45.00%	**553**	553
Total	67,843		57,609		**41,605**	41,605

* Note 1: Calculated using the OTS discount rate of 7.43%
**Note 2: Reference LaGuardia Decommissioning Studies, Appendix C, Detailed Cost Tables

OTS Exhibit No. 2
Schedule 5

R-00974104, R-00974104 0001-0002

OTS Statement No. 2-SR
Witness: Darren D. Gill
Dated: December 11, 1997

Pgh 12/17/97
E. Colbert

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

DUQUESNE LIGHT COMPANY

Docket No. R-00974104

Surrebuttal Testimony

of

Darren D. Gill

Office of Trial Staff

Concerning:

Nuclear and Non-Nuclear Plant Decommissioning

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Darren D. Gill. My business address is P.O. Box 3265, Harrisburg, Pennsylvania 17105-3265.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Pubic Utility Commission in the Office of Trial Staff as an Fixed Utility Valuation Engineer.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THESE PROCEEDINGS?

A. Yes. I prepared and submitted direct testimony, OTS Statement No. 2.

Q. MR. GILL, WHAT WILL YOUR SURREBUTTAL TESTIMONY ADDRESS?

A. I will address the rebuttal testimony of Duquesne's witness Mr. LaGuardia related to nuclear and fossil plant decommissioning.

Q. PLEASE REFER TO MR. LAGUARDIA'S REBUTTAL TESTIMONY, PAGES 9 AND 10. HOW DOES MR. LAGUARDIA CHARACTERIZE THE BASIS FOR YOUR ELIMINATION OF CONTINGENCIES FROM THE COMPANY'S NUCLEAR AND FOSSIL DECOMMISSIONING ESTIMATES?

A. Mr. LaGuardia believes that I am relying on Commission precedent from the last PP&L rate case at Docket No. R-00943271 as the basis for my recommendations.

Q. IS MR. LAGUARDIA'S CHARACTERIZATION OF THE BASIS FOR YOUR ELIMINATION OF CONTINGENCY FACTORS CORRECT?

A. No. While it is my understanding that the Commission's treatment of contingency factors in the PP&L rate case supports my position herein, it is not the basis for my adjustment. At no point in my testimony do I refer to the PP&L rate case discussed by Mr. LaGuardia. As I state on page 5 of my direct testimony, I believe that the addition of contingencies incorporates an additional estimate on top of what is already an estimate. Should new information become available, the Electricity Generation Customer Choice

and Competition Act allows that the Company may come to the Commission with further estimates.

Q. PLEASE REFER TO PAGES 10-11 OF MR. LAGUARDIA'S REBUTTAL TESTIMONY. HOW DOES MR. LAGUARDIA ATTEMPT TO REFUTE YOUR POSITION THAT DECOMMISSIONING ESTIMATES ARE INFLATED THROUGH THE USE OF CONTINGENCIES?

A. Mr. LaGuardia states on page 11, lines 5-7 of his rebuttal testimony that contingencies are not an inflation of costs but "a recognition of actual costs incurred in recent experience with decommissioning activities that were not foreseeable in advance".

Q. IS THERE ANY MERIT TO HIS STATEMENT?

A. No. An estimate of costs which will be incurred at the point of decommissioning, based on recent experience, is reflected in each line item of Mr. LaGuardia's cost study. Increasing decommissioning estimates above reasonably known and measurable levels, through the inclusion of contingencies, is an improper inflation of costs.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

R-00974104, R-00974104C0001-C0002

OTS Statement No. 4
Witness: P.J. Metro
Dated: November 7, 1997

Pgh 12/17/97
E. H.

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

DUQUESNE LIGHT COMPANY

Docket No. R-00974104

Direct Testimony

of

Paul J. Metro

Office of Trial Staff

Concerning:

Electric Rate Restructuring

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Paul J. Metro. My business address is P.O. Box 3265, Harrisburg, Pennsylvania, 17105-3265.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission in the Office of Trial Staff as a Fixed Utility Valuation Engineer.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I am a 1982 graduate of The Pennsylvania State University, University Park, Pennsylvania, where I earned a Bachelor of Science Degree in Mineral Economics. Immediately subsequent to graduation, I attended The Pennsylvania State University and met the requirements for a Bachelor of Science Degree in Industrial Engineering. I am also a graduate of The Pennsylvania State University with a Masters of Engineering Degree, majoring in Engineering Science with an emphasis on Industrial Engineering/Operations Research. I have been employed by the Pennsylvania Public Utility Commission since May of 1985. Attached to

this testimony as Appendix A is a statement which more fully describes my educational background and employment experience.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to recommend adjustments to Duquesne Light Company's (Duquesne or Company) Rate Restructuring filing.

Q. MR. METRO, HOW IS YOUR TESTIMONY ORGANIZED?

A. I have organized my testimony by (1) addressing the Company's position on stranded cost calculations associated with owned generation; (2) explaining the OTS proposed stranded cost calculation methodology; (3) explaining the OTS position on Regulatory Assets; and (4) explaining the final OTS recommended stranded cost levels.

Stranded Cost

Company Position

Q. MR. METRO WHAT IS DUQUESNE'S PROPOSAL CONCERNING STRANDED COST RECOVERY?

A. Duquesne is proposing an alternate approach to the recovery of stranded costs as compared to the approaches used by other electric utilities in previously filed rate restructuring cases. Duquesne is proposing to separate its current generation rate into two pieces. The first piece equates a generation rate to a market rate determined by selling a block of power in the market place. The second piece is the difference between the current generation rate and the market rate. This is a residual amount that Duquesne will equate to its Competitive Transition Charge (CTC).

Duquesne proposes to charge base rates up to current levels (rate cap) with any excess earnings achieved under the cap being utilized to mitigate transition or stranded costs for the benefits of ratepayers. Duquesne avers that Section 2804(4)(v) of the Electric Generation Customer Choice Competition Act (Act) permits Duquesne to continue charging base rates at the current cap. (See Duquesne Statement No. 1, page 11).

Q. IS DUQUESNE PROPOSING A SPECIFIC LEVEL OF STRANDED COSTS TO BE RECOVERED THROUGH THE CTC?

A. No, not at this time.

Q. MR. METRO, HOW DOES DUQUESNE PROPOSE TO CALCULATE ITS CTC?

A. Duquesne proposes to use a market based determination of the value of Duquesne's generation to calculate its CTC . Each year during the transition period, Duquesne will conduct a public solicitation, or "request for proposals" (RFP) to sell a substantial block of power for a one year term. Customer specific CTCs will be set by using (1) the market prices established by the RFP; (2) information about each customer's baseline consumption; and (3) information on class load shapes. Duquesne avers that the purpose of the customer specific CTC methodology is to ensure that customers who are more expensive to serve receive a higher credit and those that are less expensive to serve receive a lower credit. Duquesne believes that this methodology is consistent with Section 2808(a) of the Act, which states that CTCs should be set in a manner that does not shift interclass or intraclass costs. (See Duquesne Statement No. 1, page 17).

Q. WILL DUQUESNE USE PROJECTED MARKET RATES TO DETERMINE STRANDED COSTS RELATED TO GENERATION?

A. Duquesne proposes not to project market rates until after the year 2005. The market rate projections will be determined by a panel of experts. This will be more fully explained later in this testimony.

Q. WHY IS DUQUESNE PROPOSING NOT TO PROJECT MARKET RATES INITIALLY?

A. Duquesne believes that Section 2803 of the Act requires that each utility has the burden of demonstrating known and measurable net electric generation related costs, determined on a net present value basis over the life of the asset or liability as part of its restructuring plan (See Duquesne Statement No. 3, page 6). Duquesne avers that a market based determination can reasonably satisfy that standard (Ibid).

Duquesne is proposing that a final determination of its stranded costs not be made in this filing. Instead, Duquesne proposes to initiate a final valuation of stranded costs computed over the life of Duquesne's generating assets, in the year 2003. The valuation will be provided by an unbiased

three member arbitration panel. Duquesne proposes that the panel establish a market value based on objective evidence, not market price forecasts. The objective market evidence may include consummated market transactions in the relevant market, such as forward contracts, futures contracts, and or comparable generating unit asset sales. (See Duquesne Statement No. 1, pages 14 and 15).

Q. DUQUESNE DID NOT PROJECT MARKET RATES BETWEEN 1999 AND 2005. DID THEY PROJECT MARKET RATES AFTER THE YEAR 2005?

A. Yes. Duquesne, for purposes of calculating the stranded cost related to generation assets, needed to project market rates starting January 1, 2006. This was done in tandem with Duquesne's proposal for market valuation instead of administration valuation of stranded costs. Duquesne believes that by the end of the year 2005, a readily available and known market will exist for electric energy commodities so that a more accurate determination of the Company's generation related stranded costs can be determined.

This valuation will be performed by the Company at the end of the year 2003, as I described earlier.

Q. IF THE PANEL'S VALUATION DEMONSTRATES THAT DUQUESNE WILL FULLY RECOVER ITS STRANDED COSTS WITHIN THE TRANSITION PERIOD, WILL DUQUESNE REDUCE THE TRANSITION PERIOD ACCORDINGLY?

A. Yes, Duquesne states that it will reduce the transition period if the panel's valuation demonstrates that Duquesne will fully recover its stranded costs within the transition period. However, if the panel's valuation demonstrates that Duquesne cannot recover its stranded costs during the transition period, the valuation will provide the basis for any further relief that Duquesne is entitled to seek under the Act. (See Duquesne Statement No. 1, pages 15 and 16).

Q. IF MARKET RATES RISE SUFFICIENTLY PRIOR TO THE YEAR 2003 SUBSEQUENTLY REVEALING THAT DUQUESNE WILL OVER RECOVER ITS STRANDED COSTS, WILL DUQUESNE AGREE TO ACCELERATE THE FINAL VALUATION?

A. Duquesne states that if the market prices were to rise sufficiently prior to the year 2003 it would be possible that the residual market value at the end of the year 2005 will exceed the unamortized book value of generation. The proposed solution is to trigger an early final market valuation based on established price triggers for the years 2001 and 2002. Duquesne calculated the market prices for generation for each of these years based on an adjusted percentage of the forecasted high market price ceiling. The trigger price for the year 2001 is $28.5/mwh and for the year 2002 is $29.2/mwh. The early trigger price is that market price which would be likely to establish a high enough residual value to allow an early end to the rate cap and further collection of the CTC (See Duquesne Statement No. 2, page 41).

Q. IS THERE ANY OTHER CONDITION THAT WOULD TRIGGER AN EARLY DETERMINATION OF THE FINAL MARKET BASED VALUE OF THE COMPANY'S PLANTS?

A. Yes, the second trigger is an excess Return on Equity (ROE) spillover proposal proposed by the Company.

Q. HOW DOES THE SECOND TRIGGER RELATE TO THE COMPANY'S ROE SPILLOVER PROPOSAL?

A. The Company avers that its proposed ROE spillover adjustment will ensure that the Company does not have excessive earnings during the Transition Period and that customers are given the proper credit through a shortening of the rate cap period if the Company's actual results are better than expected. The Company proposes to establish a collar on its earnings of + or - 1/2 % around its claimed ROE of 11.5%. If the Company's earnings exceed 12%, it would establish a deferred revenue credit account which would ultimately be used to fund accelerated depreciation and amortization. If the Company's earnings fall below 11% an adjustment to the deferred revenue account will be made to increase the Company's earnings to the

11% ROE level or to eliminate the credit and balance in the account, which ever is smaller. If at any time during the transition period, the balance in the deferred revenue credit account, when netted against the Company's net book value of generating and regulatory assets, was equal to the estimated net book value as of December 31, 2005, the final market based valuation would be triggered.

Q. MR. METRO, PLEASE SUMMARIZE DUQUESNE'S STRANDED COST POSITION AS IT PERTAINS TO GENERATING ASSETS?

A. Duquesne proposes to establish a generation rate based on market rates. It will calculate a CTC based on the difference between the current generation rate and the market based rate.

Duquesne proposes not to project market rates between the years 1999 through 2005. Duquesne is currently not proposing any stranded costs for the years 1999 through 2003. Duquesne will monitor the annual market rates through a RFP to sell a block of power for a one year term. At the end of the year 2003, Duquesne will create a panel that will valuate

the difference between the market rate that the RFP's produced versus the market rate at which its generating units produced electricity.

The CTC will collect a pool of dollars that will be compared to the book value of generation related assets[1] (net of amortization) as of December 31, 2005. At the end of the year 2003 the panel will recommend to the Commission a CTC that will recover any remaining level of stranded costs. If no stranded costs associated with generating plant exists at that time, there would be no CTC.

Duquesne has proposed two trigger mechanisms to insure that it does not overcollect stranded costs. One trigger mechanism relates to certain levels of market rates for the years 2001 ($28.5/mwh) and 2002 ($29.2/mwh). If the RFPs are greater than these trigger levels, then Duquesne will no longer collect the CTC and will end the rate cap. The other trigger mechanism relates to a ROE spillover "bank" that may reduce stranded costs depending on the ROE earned by the Company.

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[1] Duquesne considers regulatory assets, decommission costs, NUG costs, and generation assets as generation related.

OTS Position

Q. MR. METRO, DO YOU AGREE WITH DUQUESNE'S PROPOSAL NOT TO CALCULATE STRANDED COSTS PRIOR TO THE YEAR 2005?

A. No, not in its present form. However, with some modifications, I would recommend that the Commission adopt the proposal.

Q. WHAT MODIFICATIONS DO YOU RECOMMEND TO DUQUESNE'S PROPOSAL CONCERNING STRANDED COST RECOVERY?

A. I have two modifications to Duquesne's stranded cost proposal. The first modification concerns a rate cap extension. The second modification relates to the Company's ROE adjustment proposal.

Q. MR. METRO, WOULD YOU PLEASE EXPLAIN YOUR RATE CAP EXTENSION PROPOSAL?

A. Yes. As can be seen in Revised Duquesne Exhibit DJC-3, the Company has estimated, as of December 31, 2005, a range of stranded costs based on

estimated high and low market values projected forward from the year 2006. According to this exhibit, Duquesne would have a negative $233 million or zero (0) stranded costs, based on its high market value projection. Based on Duquesne's low market value projection, the Company would have approximately $423 million of stranded costs.

Keep in mind that under Duquesne's market value approach during the year 2003, a panel would determine a final valuation of the Company's stranded costs computed over the life of Duquesne's generating assets, as of December 31, 2005. With this fact in mind, it is evident that the Company is proposing to collect whatever stranded costs are determined by the panel during the years 2004 and 2005 through the Company's CTC. This stranded cost amount could be zero dollars or $423 million or $846 million. No one knows with certainty what amount the panel will determine is stranded as of December 31, 2005. If the amount turns out to be double Duquesne's estimated upper range amount, then the ratepayers could be responsible for the payment of a very large CTC amount over a two year span.

In order to prevent such an occurrence, I recommend that a bench mark be established that would extend the rate cap and CTC collection period. If the panel determines Duquesne's stranded cost amount to be greater than Duquesne's estimated high range of stranded costs ($423 million), then I recommend that the rate cap and CTC collection period be extended for whatever time period that is needed to collect the additional stranded costs at the recovery rate in effect at that time.

Q. MR. METRO, PLEASE EXPLAIN YOUR SECOND RECOMMENDATION?

A. My second recommendation concerns the Company's ROE spillover adjustment proposal. The Company has utilized its calculated return on equity of 11.5% for the bench mark amount. I recommend that the Commission utilize the OTS' ROE level recommended by OTS witness Mr. Jeschke of 10.5% with a dead band from 10% to 11%.

Q. WOULD YOU SUPPORT THE COMPANY'S MARKET VALUE APPROACH TO STRANDED COSTS IF YOUR TWO MODIFICATIONS WERE ACCEPTED?

A. Yes I would. In my opinion, Duquesne's market value approach to stranded costs is superior to a "regulator administered" approach. In a regulator administered approach, the projection of market rates over a 30 year period would be necessary to attempt to determine the net present value of the company's stranded costs. The regulator administered approach is not accurate by any account.

Q. MR. METRO, IS DUQUESNE'S MARKET VALUATION APPROACH PERMITTED UNDER THE ACT?

A. I am advised by legal counsel, that OTS will argue that Duquesne's market valuation proposal is permitted under the ACT.

Q. MR. METRO, WHY DO YOU BELIEVE THAT ANY MARKET RATE PROJECTIONS ARE INACCURATE?

A. There is uncertainty regarding the future market place prices. No analyst can project the market prices accurately over the long run (more than three years), or even the short run (up to three years). I believe that any utility's stranded cost claim is in error if it is based on 30 year market rate projections. In my opinion, the utilities will err in their favor in the calculation of the stranded cost.

Q. HAS THE COMMISSION EXPERIENCED INACCURATE RATE PROJECTIONS IN OTHER ELECTRIC INDUSTRY MATTERS?

A. Yes. A good example of the problems that arise by attempting to project market prices over the long run is the situation of non-utility generators (NUGS). In the 1980's and early 1990's, NUG contracts were examined based upon anticipated future market prices and avoided costs. As the electric industry is experiencing now, the projections of future market prices and avoided costs were very inaccurate and needlessly cost ratepayers many millions of dollars.

Q. MR. METRO, IN YOUR ANALYSIS OF OTHER RATE RESTRUCTURING FILINGS, HAVE THE ELECTRIC COMPANIES USED THE SAME MARKET PLACE RATES?

A. No. In my opinion, the disparity of market place rates lends support to my argument that no analyst can project the market prices accurately over the long run (more than three years), or even the short run (up to three years). The electric utilities cannot even agree to the same market place rate within the PJM service territory. OTS Exhibit No. 4, Schedule 1 shows the market rates filed by PECO Energy, PP&L, and GPU. As can be seen in this schedule, the marketplace rates are diverse, when, in my opinion, they should really be the same number.

Q. DO YOU AGREE WITH DUQUESNE'S ESTIMATED VALUES OF THE MARKET RATES THAT IT USED IN ITS STRANDED COST CALCULATIONS?

A. I agree with Duquesne's marketprice projections that utilize the high range of market price. Duquesne Exhibits MMS-4, L-9 show the range of market rates up to the year 2015. The high range of market prices appear to be

reasonable when compared to the market prices that were used in the PECO settlement and advocated by myself in the GPU rate restructuring filing. (See OTS Exh. #4, Sch. 1).

In my opinion, there is a locational pricing difference between the PJM (Pennsylvania, New Jersey, Maryland Interconnection) and the West Penn/Duquesne service territory. In fact, West Penn's witness Dr. Pifer testifies to this pricing differential in West Penn Statement No. 6, page 5, Docket No. R-973981). Dr. Pifer states that from January 1996 to June 1997 there was a 10.2% pricing differential between the high PJM than in ECAR (East Central Area Reliability Coordination Agreement).[2]

However, as I stated above, I believe that the market rate projections are in error, and the errors are in favor of the utilities. Keeping that in mind, it is my opinion, that Duquesne's proposal to initiate a final valuation of stranded costs in the year 2003, computed over the life of the generating assets, improves and enhances the market rate projection process. The final determination of market rate projections will be performed by a panel

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[2] Duquesne is a member of ECAR.

during the year 2003. By that time, a real competitive electric market will be flourishing and more accurate market rates will be calculated.

Q. IF THE COMMISSION DETERMINES THAT DUQUESNE'S MARKET VALUATION APPROACH IS NOT PERMITTED UNDER THE ACT, DO YOU HAVE AN ALTERNATIVE RECOMMENDATION CONCERNING DUQUESNE'S STRANDED COSTS?

A. Yes I do. If the Commission determines that Duquesne's market valuation approach is not permitted under the ACT I recommend that Duquesne file a CTC based on stranded costs as of January 1, 1999. This CTC would be based on the stranded costs quantified but not claimed in the Company's filing.

Q. MR. METRO, WHAT IS THE OTS POSITION CONCERNING DUQUESNE'S STRANDED COSTS?

A. OTS proposes modifications to Duquesne's proposal to use market valuation to determine stranded costs in the year 2003. However, if the

Commission does not except the concept of market valuation of stranded costs, then the OTS proposes an alternative that calculates stranded costs based on a projected market rate approach.

Since Duquesne has not quantified or claimed stranded costs related to generating plant, the OTS recommended level of stranded costs is $952,618,000 which include stranded costs related to regulatory assets and decommissioning only. I have not included any stranded costs relating to generating plant since the Company has made no claim for generating plant. The OTS recommended total stranded cost in the alternative is based on the following components:

Generating Plant	$0
Regulatory Asset	$907,526,000
Fossil Decommissioning	$ 41,605,000
Nuclear Decommissioning	$ 3,487,000
Total	$952,618,000

DEFERRED CARETAKER COSTS

Q. WHAT ARE DEFERRED CARETAKER COSTS?

A. Deferred caretaker costs are preservation costs associated with maintaining the Phillips and Brunot Island generating plants.

Q. WHAT IS THE COMPANY'S CLAIM FOR DEFERRED CARETAKER COSTS?

A. Duquesne's claim for deferred caretaker costs is $6,772,000.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. With restructuring, these plants will be "deregulated" and Duquesne will never be able to recover the costs of preserving the plants for future needs of its customers unless it can recover the costs through the Competitive Transition Charge (CTC). According to DQE, fairness requires this to be done (See Duquesne Statement No. 4, page 14).

Q. DOES DUQUESNE HAVE ANY ALTERNATIVES TO COLLECTING THESE PRESERVATION COSTS FROM CUSTOMERS THROUGH THE CTC?

A. Yes. Currently, Duquesne is uncertain about the future of these cold reserved units. Between now and the assumed dismantling dates, the Company will continue to examine the economic viability of either selling or using the stations. If the Company sells or reactivates these units, it would have the opportunity to recover the preservation costs.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM TO RECOVER THESE DEFERRED CARETAKER COSTS THROUGH THE CTC?

A. No.

Q. WHAT IS YOUR RECOMMENDATION REGARDING DUQUESNE'S REGULATORY ASSET CLAIM FOR THESE DEFERRED CARETAKER COSTS?

A. I recommend that the Company's deferred caretaker costs claim of $6,772,000 be denied.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. At Docket No. P-900485, the Commission approved deferred accounting treatment for preservation costs associated with maintaining the Phillips and Brunot Island generating plants. The Company was granted the right to seek recovery of these deferred costs upon the return to commercial operation of the plants. This made sense if the costs were required to preserve the benefit of those plants for future ratepayers. However, since these plants will not be used to meet the future needs of its regulated customers, there is no benefit to ratepayers associated with these costs and Duquesne should not be permitted to recover these preservation costs from customers.

COLD RESERVED UNITS

Q. WHAT ARE THE "COLD RESERVE" UNITS AT BRUNOT ISLAND AND PHILLIPS POWER STATIONS?

A. These units (Brunot Island 3 and 4: Phillips 1, 2, 3 and 4) were put in cold reserve in 1986 and removed from base rates at Docket No. R-860378.

Q. WHAT IS THE COMPANY'S STRANDED COST CLAIM FOR THE COLD RESERVED UNITS?

A. The Company has included the net undepreciated cost of these units in its claim for stranded costs of $106,800,000.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company avers that the current market for electricity does not support the reactivation of either the Phillips power station or units 3 and 4 at Brunot Island. As such, the Company plans to maintain Phillips and Brunot Island units 3 and 4 in cold reserve status.

Q. DO YOU AGREE WITH THE COMPANY'S STRANDED COST CLAIM TO RECOVER THE NET UNDEPRECIATED COST OF THESE COLD RESERVED UNITS?

A. No.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE STRANDED COST CLAIM FOR THE COLD RESERVE UNITS?

A. I am recommending that the stranded cost claim of these cold reserve units be denied.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. The Electricity Generation Customer Choice and Competition Act ("Act") (under the definition of "Transition or Stranded Costs") states at 66 Pa. C.S. §2803 that stranded costs include any costs attributed to physical plant no longer used and useful because of the transition to retail competition. While these cold reserve units remain Company property, they were excluded from rate base prior to the Act. The Act did not create the situation of these units being deemed uneconomical. As stated above, Duquesne is uncertain about the future of these cold reserved units. If the Company sells or reactivates these units, after deregulation, it would have the opportunity to recover its net undepreciated costs. Property not used to serve customers should not be considered stranded and its value should not be recovered from customers by including it in the CTC.

Q. WHAT IS THE OTS RECOMMENDED LEVEL OF REGULATORY ASSETS?

A. The OTS recommended level of regulatory assets is $907,526,000. This amount was calculated by subtracting $6.8 million deferred caretaker costs and $106.8 million related to the cold reserve units from the Company's regulatory asset presentation of $1,021,126,000.

Q. MR. METRO, WHICH OTS WITNESS DISCUSSES THE OTS POSITION ON FOSSIL AND NUCLEAR DECOMMISSIONING ALLOWANCES?

A. OTS witness Mr. Gill in Statement No. 2 addresses the OTS position on fossil and nuclear decommissioning.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APPENDIX A

Professional and Educational Experience
of
Paul J. Metro

Education

The Pennsylvania State University, University Park, Bachelor of Science, Mineral Economics, 1982

Earned additional credits in Industrial Engineering from 1982-1984, The Pennsylvania State University, University Park

The Pennsylvania State University, Capitol Campus, Master of Engineering Science, Industrial Engineering/Operations Research Emphasis, 1992.

Professional Experience

April 1996 to Present: Pennsylvania Public Utility Commission, Fixed Utility Valuation Engineer in the Office of Trial Staff - Participates in the review and prosecution of gas, electric, telecommunications, water, and sewer rate filings in the areas of valuation, depreciation, rate base, rate structure, and purchased gas.

March 1994 to March 1996: Pennsylvania Public Utility Commission, Fixed Utility Valuation Engineer - Rate Structure/Engineering Section, Energy Division, Office of Trial Staff. Participates in the review and prosecution of natural gas and electric rate filings in the areas of valuation, depreciation, rate base, rate structure, and purchased gas.

December 1987 to March 1994: Pennsylvania Public Utility Commission, Fixed Utility Valuation Engineer - Engineering Section, Engineering and Rate Design Division, Office of Trial Staff. Participates in the review and prosecution of gas, electric, telecommunications, water, and sewer rate filings in the areas of valuation, depreciation, rate base, rate structure, and purchased gas.

September 1986 to December 1987: Pennsylvania Public Utility Commission, Fixed Utility Valuation Engineer - Engineering Section, Rate Design Division, Office of Trial Staff. Participated in the review and prosecution of gas, electric, telecommunications, and water rate filings in the areas of cost of service and tariff rules and regulations.

May 1985 to September 1986: Pennsylvania Public Utility Commission, Fixed Utility Valuation Engineer - Valuation Section, Gas Division, Bureau of Rates. Participated in the review and prosecution of gas rate filings in the areas of valuation, depreciation, rate structure, purchased gas, and cost of service.

Professional Affiliations

Engineers Society of Pennsylvania

Testimony Presented Before The Pennsylvania Public Utility Commission

Equitable Gas Company, Transportation Investigation, R-870666

UGI Corporation - Gas Division, Transportation Investigation, R-870665

National Fuel Gas Distribution Corporation, General Rate Case, R-870719

Equitable Gas Company, 1307(f) Proceeding, R-880932

Pennsylvania Gas & Water Company, 1307(f) Proceeding, R-880958

Equitable Gas - Energy Company, General Rate Case, R-880941

Equitable Gas Company, General Rate Case, R-880971

Equitable Gas Company, 1307(f) Proceeding, R-891238

Lake Latonka Water Company, General Rate Case, R-891257

Philadelphia Electric Company, General Rate Case, R-891364

Equitable Gas Company, 1307(f) Proceeding, R-901645

Roaring Creek Water Company, General Rate Case, R-901625

Equitable Gas Company, General Rate Case, R-901595

West Penn Power Company, General Rate Case, R-901609

Pennsylvania Gas & Water Company, 1307(f) Proceeding, R-901699

Western Utilities, Inc., General Rate Case, A-210017

T.W. Phillips Gas & Oil Co., 1307(f) Proceeding, R-911889

Columbia Gas of Pennsylvania, Inc., General Rate Case, R-901873

Columbia Gas of Pennsylvania, Inc., 1307(f) Proceeding, R-911921

Pennsylvania Gas & Water Company, 1307(f) Remand Proceeding, R-901699

Olwen Heights Water Company, General Rate Case, R-891226

Peoples Natural Gas Company, General Rate Case, R-922180

Pennsylvania Gas & Water Company, Transportation Tariff Filing, R-922169

Pennsylvania Gas & Water Company, 1307(f) Filing, R-922324

West Penn Power, General Rate Case, R-922378

Peoples Natural Gas Company, 1307(f) Filing, R-932598

Equitable Gas Company, 1307(f) Filing, R-932599

National Fuel Gas Distribution Company, General Rate Case, R-932548

Pennsylvania Gas & Water Company, Transportation Tariff Filing, R-932655

Allied Gas Company ET AL, Transportation Tariff Filing, R-932662

Peoples Natural Gas Company, General Rate Case, R-932866, R-932915

Peoples Natural Gas Company, 1307(f) Filing, R-943028

Columbia Gas of Pennsylvania, 1307(f) Filing, R-943029

Equitable Gas Company, 1307(f) Filing, R-943022

Pennsylvania Gas & Water Company, Tariff Filing, R-943078

Pennsylvania Power & Light Company, General Rate Case, R-943271

Equitable Gas Company, Transportation Filing, R-943272

UGI Utilities, Inc., General Rate Case, R-953297

Equitable Gas Company, 1307(f) Filing, R-953320

National Fuel Gas Distribution Corporation, 1307(f), R-953487

Equitable Gas Company, 1307(f) Filing, R-963576

PFG Gas, Inc. and North Penn Gas Co., General Rate Case, R-963524

PECO Energy Company, Electric Securitization Filing, R-973953

Peoples Natural Gas Company, 1307(f) Filing, R-973896

Equitable Gas Company, General Rate Case, R-963858

OTS Exhibit No. 4
Witness: P.J. Metro
Dated: November 7, 1997

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

DUQUESNE LIGHT COMPANY

Docket No. R-00974104

Exhibit to Accompany the

Direct Testimony

of

Paul J. Metro

Office of Trial Staff

Concerning:

Electric Rate Restructuring

Market Rate Study

Year	Met Ed $/MWh	Penelec $/MWh	Peco1 $/MWh	Peco2 $/MWh	Peco3 $/MWh	PP&L $/MWh	Average $/MWh	West Penn $/MWh	Difference %	OTS Mkt Rate $/MWh	Difference %	Peco Settlement Rates $/MWh	OTS Recommended Market Rates $/MWh
1999	2.61	2.50	2.84	2.45	2.61	2.63	2.64	1.66	37.09%	2.38	10%	2.80	1.99
2000	3.02	2.85	3.15	2.78	3.13	2.85	2.96	1.83	38.25%	2.67	10%	2.80	2.24
2001	3.19	3.00	3.66	3.22	3.50	3.14	3.29	2.02	38.51%	2.96	10%	3.20	2.52
2002	3.34	3.14	3.82	3.39	3 64	3.39	3.45	2.23	35 42%	3.11	10%	3.50	2.83
2003	3.54	3.28	3.99	3.57	3.75	3.42	3.59	2.45	31.60%	3.23	10%	3.70	3.18
2004	3.68	3.41	4.17	3.76	3 89	3.51	3.74	2.70	27.75%	3.36	10%	3.97	3.57
2005	3.53	3.54	4.34	3.93	4.14	3 47	3.83	2.97	22.37%	3.44	10%	4.07	4.01
2006	3.61	3.63	4.48	4.11	4.33	3.55	3 85	3.07	22.31%	3.56	10%	4.77	4.10
2007	3.69	3.72	4.66	4.30	4.50	3.78	4.11	3.17	22 84%	3.70	10%	5.37	4.20
2008	3.75	3.78	4 82	4.49	4.70	3.90	4.24	3.29	22.39%	3.82	10%	5.57	4.30
2009	3.82	3.84	5.01	4.70	4.87	4.01	4.37	3.41	22.02%	3.94	10%		4.40
2010	3.93	3.97	5.21	4.90	5.06	4.01	4.51	3.53	21.76%	4.06	10%		4.50
2011	4.05	4.06	5.41	5.11	5.11	4.00	4.62	3.62	21.70%	4.16	10%		4.70
2012	4.23	4.18	5.54	5.33	5 30	4.10	4.78	3.73	21.97%	4.30	10%		4.80
2013	4.50	4.51	5.73	5.56	5.50	4.24	5 01	3 87	22.68%	4.50	10%		4.90
2014	5.14	4.75	6.04	5 83	5.75	4.29	5.30	4.02	24.14%	4.77	10%		5.00
2015	24.50	4.97	6.22	5.97	5.84	4.42	8 65	4.14	52.16%	7.79	10%		5.10
2016	24.92	5.13	6.46	6.19	6.07	4.51	8.88						
2017			6.78	6.46	6.34	4.63	6.05						
2018			7.02	6.69	6 56	4.77	6 28						
2019			7.41	7.01	6.89	4.89	6.55						
2020			7.68	7.27	7.15	5.01	6.78						
2021			8.13	7.61	7.50	5.14	7.09						
2022			8.65	7.98	7.89	5.30	7.45						
2023			8.97	8 28	8.19	5.49	7.73						
2024			9.31	8.59	8.50	5 81	8.05						
2025			10.69	9.33	9.33	7.69	9.26						
2026			10.83	9.35	9.54	7.86	9.39						
2027			11.24	9.70	9.89	8.04	9.72						
2028			11.66	10.07	10.27	8.23	10 06						
2029			12.10	10.44	10.65	8.42	10.40						
2030						8.61	8 61						
2031						8.81	8.81						
2032						9 01	9.01						
2033						9.22	9.22						
2034						9.33	9.33						
2035						9.42	9.42						
2036						9.64	9.64						
2037						9.86	9.86						
2038						10 09	10 09						
2039						10.32	10.32						
2040						10.56	10.56						
2041						10.8	10.8						
2042						11.05	11.05						
2043						11.31	11.31						
2044						11.57	11.57						

GPU - Source:Vol. II, Statement No. 4, Exhibit DJR-9, pages 13-14

PECO - Exhibit TPH-6

PP&L - Source:Exhibit JRS 1

Duquesne - Source Exhibit MMS-5 and MMS-4

West Penn - Source Exhibit HWP-2

R-00974104, R-00974104C0001-Cover

OTS Statement No. 4-SR
Witness: P.J. Metro
Dated: December 11, 1997

Pgh 12/17/97
C. Hollwest

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

DUQUESNE LIGHT COMPANY

Docket No. R-00974104

Surrebuttal Testimony

of

Paul J. Metro

Office of Trial Staff

Concerning:

Electric Rate Restructuring

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Paul J. Metro. My business address is P.O. Box 3265, Harrisburg, Pennsylvania, 17105-3265.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission in the Office of Trial Staff as a Fixed Utility Valuation Engineer.

Q. DID YOU PREVIOUSLY SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes I did. I am responsible for OTS Statement No. 4.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my testimony is to rebut Duquesne Light Company's (Duquesne) witness Mr. Clayton concerning its regulatory asset claim for deferred caretaker costs and cold reserved units and to address the OTS recommended level of total stranded costs.

COLD RESERVE UNITS AND DEFERRED CARETAKER COSTS

Q. WHAT IS THE COMPANY'S REBUTTAL POSITION CONCERNING THE COLD RESERVED UNITS AND THE CARETAKER COSTS?

A. Duquesne witness Mr. Clayton avers that the Company's claim for its cold reserved units (Phillips and Brunot Island) and the associated caretaker costs represents the only fair treatment for a mitigation strategy of which the Commission was well aware, but that ultimately proved unsuccessful. The Company also avers that it should not be penalized because it was unable to make a silk purse out of a sow's ear on these particular assets (See Duquesne Statement No. 2-R, page 35). The Company provides no basis or explanation for its contention that the Commission was "well aware" of a mitigation strategy and that such "awareness" should somehow permit recovery of these costs as "stranded".

Q. MR. METRO, BRIEFLY SUMMARIZE THE OTS POSITION CONCERNING THE COLD RESERVED UNITS AND THE CARETAKER COSTS?

A. The OTS position concerning the cold reserve units is that property that is not used to serve customers should not be considered stranded and its value

should not be recovered from customers by including the cold reserved units in the stranded cost calculation. The OTS position concerning the caretaker costs associated with the cold reserved units is that since these plants will not be used to meet the future needs of the regulated customers, there is no benefit to the ratepayers associated with these deferred costs and these costs should not be permitted to be recovered.

Q. MR. METRO, DO YOU AGREE WITH MR. CLAYTON'S REBUTTAL TESTIMONY CONCERNING THE COLD RESERVED UNITS AND THE CARETAKER COSTS?

A. No. The Company had two options when it decided to place the two plants into cold reserve. The first option was to take the plants out of rate base and place these plants into the account classified as plant held for future use. This is the option the Company chose. The alternative option was to retire the units. Under this option, the Company would have credited plant and debited the depreciation reserve. The Company would have recovered the net book value and a return over the remaining life of these units.

Using 20/20 hindsight, the Company made a bad decision. Now, the Company is attempting to recover from this bad decision by classifying the cold reserved units as "stranded". The units are not used and useful

and should not be permitted to be included as stranded costs. These series of events were not the result of or related to deregulation. However, the Company is attempting to take advantage of the deregulation legislation to rectify prior bad business decisions.

OTS RECOMMENDED TOTAL STRANDED COST LEVEL

Q. MR. METRO, DID OTS RECOMMEND A LEVEL OF STRANDED COSTS RELATED TO GENERATING PLANT IN ITS DIRECT TESTIMONY?

A. No. The Company made no specific claim for stranded costs related to generating plant. The Company provided a schedule showing a range of possible stranded costs levels at different market rates. Since the Company did not make a specific claim for generating plant stranded costs and the OTS agreed with the Company's market valuation approach, I did not provide an estimation of the Company's generating plant stranded costs.

However, since the OCA and DII did provide specific stranded cost levels for generating plant in their direct testimonies, the Company responded in its rebuttal testimony with a alternative plan for a specific claim for generating plant stranded costs.

Q. SINCE THE COMPANY HAS NOW ESTIMATED A STRANDED COST AMOUNT FOR GENERATING PLANT AS AN ALTERNATIVE TO THE OCA AND DII, ARE YOU PREPARED TO ADDRESS THE OTS RECOMMENDED LEVEL OF GENERATING PLANT STRANDED COSTS?

A. Yes. The OTS recommended level of total stranded costs is $1,395.85 million. OTS Exhibit 4R, Schedule 1 shows the composition of the $1,395.85 million. The OTS recommended market value is $159 million. This amount was calculated by the Company as the plant margin under the delayed entry portfolio (See Duquesne Exhibit DJC-20, page 1 of 49).

Q. MR. METRO, WHY DID YOU UTILIZE THE DELAYED ENTRY PORTFOLIO FOR THE MARKET VALUE?

A. I utilized the delayed entry portfolio for two reasons. First, the delayed entry portfolio provides for a plant margin between the low and high market value portfolios. This provides for a fair and balanced **estimation** for the market rate. Second, according to Duquesne witness Mr. Schnitzer, the delayed entry case assesses the impact which would result if new combined cycle capacity is not economic until after the year 2006 (See Duquesne Statement No. 1, page 35). This is important because the market

rate will dictate the development of new capacity. In addition, it is unlikely that new combined cycle capacity would be economic to build in the year 2006 based on Duquesne's results of the 1997 Solicitation, particularly if the required new entry prices are at the high end of the range projected by Duquesne (Ibid).

Q. MR. METRO, YOU STATED THAT THE DELAYED ENTRY PORTFOLIO PROVIDES FOR A FAIR AND BALANCED ESTIMATION OF THE MARKET RATE. WHAT IS YOUR OPINION CONCERNING THE ACCURACY OF THIS MARKET RATE?

A. It is my opinion that all market rate projections are inaccurate as there is uncertainty regarding the future market place prices. No analyst can project the market prices accurately over the long run (more than three years), or even the short run (up to three years). I believe that any utility's stranded cost claim is in error if it is based on long run market rate projections. In my opinion, the utilities will err in their favor in the calculation of the stranded cost. Given that, I recommend that the market rates utilized in determining stranded generating costs, under the OCA and DII alternatives, be based on the delayed entry portfolio.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

OTS Exhibit No. 4-SR
Witness: P.J. Metro
Dated: December 11, 1997

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

DUQUESNE LIGHT COMPANY

Docket No. R-00974104

Exhibit to Accompany the

Surrebuttal Testimony

of

Paul J. Metro

Office of Trial Staff

Concerning:

Electric Rate Restructuring

OTS EXHIBIT NO. 4SR
SCHEDULE 1
WITNESS: PJ METRO

DUQUESNE LIGHT COMPANY

Summary of Stranded Cost Estimates
As of December 31, 1998
(Millions $)

	DLCo	OTS
Generating Plant		
Net Book Value of Generating Plant	$ 917.61	$ 852.03
Working Capital	-	-
M&S and Fuel-Related Sunk Costs	41.11	-
PV of BV2 Lease Expense	278.24	287.19
Net Book Value	1,236.96	1,139.22
PV of Decommissioning	123.90	45.10
PV of Costs Independent of Operation	208.23	-
Estimated Market Value	(27.40)	(159.00)
Stranded Generating Plant	1,541.69	1,025.32
Regulatory Assets		
SFAS 109	$ 179.00	$ 179.00
Post-2005 Unamortized Debt Cost	19.04	19.04
Pre-2006 Unamortized Debt Cost	9.80	9.80
Deferred Rate Sync. Costs	30.26	30.26
Deferred Employee Costs	17.80	17.80
Deferred Nuclear Maintenance	1.90	1.90
DOE Decom and Decon.	4.19	4.19
Deferred Coal Costs	13.50	13.50
Deferred Caretaker Costs	3.92	-
BV2 Training Costs	1.58	1.58
Low Level Radioactive Waste	2.27	2.27
Coal Cost Equalization	0.12	0.12
Other	0.53	0.53
Pre-Accrue Nuclear Outages	13.25	13.25
Gain on Sale/Leaseback	55.13	55.13
Deferred Rate Sync. Costs (Tax)	0.27	0.27
BV-2 (Tax)	0.17	0.17
Deferred Fuel Costs	8.66	8.66
Transition Costs	10.59	10.59
SFAS 106	2.47	2.47
SFAS 109 Plant	-	-
Total Regulatory Assets	$ 374.45	$ 370.53
Total Stranded Costs	$ 1,916.14	$ 1,395.85
Percent of Company Claim	100.00%	72.85%

Document No. D04-1241-002

DECOMMISSIONING COST ESTIMATE
for the
BEAVER VALLEY POWER STATION
UNITS 1 AND 2

DRAFT

prepared for

Duquesne Light Company

August, 1997

prepared by

TLG Services, Inc.

Bridgewater, Connecticut

TABLE C-1
SAFSTOR COST ESTIMATE (DECON SCENARIO)
BEAVER VALLEY POWER STATION UNIT 1
(Thousands of 1997 Dollars)

Columns may not total due to rounding

Activity	Decon	Remove	Pack	Ship	Bury	Other	Contingency	Total	License Termination	Clean	Waste Volume, CF A	B	C	>C	M-Hrs	M-Rem
Period 5 Undistributed Costs																
1. Insurance						178	18	196	196							
2. Property taxes																
3. Heavy equipment rental		2471					371	2842		2842						
4. Small tool allowance		104					16	119		119						
5. Plant energy budget						16	2	18		18						
6. Site Security						426	64	490		490						
Subtotal Undistributed Costs Period 5		2575				620	470	3665	196	3469						
Staff Costs																
DOC Staff Cost						2481	372	2854		2854						
Utility Staff Cost						863	129	992	893	99						
TOTAL PERIOD 5		12496				4031	2470	18997	1974	17023					173488	
TOTAL COST TO DECOMMISSION	9878	81030	5098	6027	52999	163099	62534	380661	327210	23451	78293	8926	340	543	912227	504

TOTAL COST TO DECOMMISSION WITH 21.7% CONTINGENCY:	**$380,661,440**
TOTAL NRC LICENSE TERMINATION COST IS 93.31% OR:	**$327,210,112**
NON-NUCLEAR DEMOLITION COST IS 6.69% OR:	**$23,451,352**
TOTAL RADWASTE VOLUME BURIED:	**88,101 CUBIC FEET**
TOTAL SCRAP METAL REMOVED:	**23,105 TONS**
TOTAL CRAFT LABOR REQUIREMENTS:	**912,227 MAN-HOURS**
TOTAL PERSONNEL RADIATION EXPOSURE:	**504 MAN-REM**

TABLE C-2
DECON COST ESTIMATE
BEAVER VALLEY POWER STATION UNIT 2
(Thousands of 1997 Dollars)

Columns may not total due to rounding

Activity	Decon	Remove	Pack	Ship	Bury	Other	Contingency	Total	License Termination	Clean	Waste Volume, CF A	B	C	>C	M-Hrs	M-Rem
Period 3 Undistributed Costs																
1. Insurance						1370	137	1508	1508							
2. Property taxes																
3. Heavy equipment rental		3089					463	3552		3552						
4. Small tool allowance		156					23	180		180						
5. Plant energy budget						22	3	25		25						
6. NRC ISFSI Fees						1381	138	1519	1519							
7. Emergency Planning Fees						206	21	226	226							
8. Site Security						3644	547	4191		4191						
9. HP Technicians						696	104	800		800						
Subtotal Undistributed Costs Period 3		3245				7319	1437	12000	3253	8748						
Staff Costs																
DOC Staff Cost						7811	1172	8983		8983						
Utility Staff Cost						10927	1639	12566	11309	1257						
TOTAL PERIOD 3		**25644**	**128**	**99**	**1028**	**28099**	**8404**	**63402**	**16883**	**46520**	**9129**				**295255**	
TOTAL COST TO DECOMMISSION	**9901**	**71176**	**5422**	**6265**	**59854**	**157049**	**67322**	**377009**	**321783**	**55227**	**88213**	**11582**	**340**	**543**	**1142099**	**844**

TOTAL COST TO DECOMMISSION WITH 21.74% CONTINGENCY:	**$377,009,280**
TOTAL NRC LICENSE TERMINATION COST IS 85.35% OR:	**$321,782,688**
NON-NUCLEAR DEMOLITION COST IS 14.65% OR:	**$55,226,604**
TOTAL RADWASTE VOLUME BURIED:	**100,677 CUBIC FEET**
TOTAL SCRAP METAL REMOVED:	**26,889 TONS**
TOTAL CRAFT LABOR REQUIREMENTS:	**1,142,099 MAN-HOURS**
TOTAL PERSONNEL RADIATION EXPOSURE:	**844 MAN-REM**

DECOMMISSIONING COST STUDY

for the

PERRY NUCLEAR POWER PLANT UNIT 1

Prepared for

CENTERIOR ENERGY

May 1994

prepared by

TLG Services, Inc.
Bridgewater, Connecticut

TABLE C (continued)
DECON COST ESTIMATE FOR PERRY NUCLEAR POWER PLANT UNIT 1

Activity	Decon	Remove	Pack	Ship	Bury	Other	Cntgcy	Total	LicTerm	Clean	A CF	B CF	C CF	>C CF	M-Hrs	M-Rem
Staff Costs																
DOC Staff Cost						5703	855	6559		6559						
Utility Staff Cost						4351	653	5004	4504	500						
TOTAL PERIOD 3		38545				14421	7848	60814	4933	55880					705984	
TOTAL COST TO DECOMMISSION	13730	72579	13299	2838	108297	219665	71938	502345	432798	69547	299605	33849	680	712	1988107	1387

TOTAL COST TO DECOMMISSION WITH 16.71% CONTINGENCY:	$502,345,312	
TOTAL NRC LICENSE TERMINATION COST IS 86.16% OR	$432,798,112	
NON-NUCLEAR DEMOLITION COST IS 13.84% OR:	$ 69,547,184	
TOTAL RADWASTE VOLUME BURIED:	334,846	CUBIC FEET
TOTAL SCRAP METAL REMOVED:	25,375.7	TONS
TOTAL CRAFT LABOR REQUIREMENTS:	1,988,107.1	MAN-HOURS
TOTAL PERSONNEL RADIATION EXPOSURE:	1,387.1	MAN-REM
TOTAL CRAFT LABOR COST WITH 24.07% CONTINGENCY:	$ 67,959,352	

Perry Nuclear Power Plant

Increases from 1993 to 1997

Cost Center		1993 $	1997$	Comments
Decontaminatio	Labor	$ 9,737,193	$ 11,313,359	Labor escalation as calculated below
	Equip & Mat.	$ 11,857,856	$ 11,857,856	assume no escalation
Removal	Labor	$ 58,176,784	$ 75,328,945	Labor escalation as calculated below
	Equip & Mat.	$ 30,626,562	$ 30,626,562	assume no escalation
Packaging	Labor	$ 1,046,373	$ 1,354,697	Labor escalation as calculated below
	Equip & Mat.	$ 13,607,334	$ 13,607,334	assume no escalation
Shipping		$ 3,334,123	$ 3,334,123	assume no escalation
Burial		$ 122,011,464	$ 159,364,205	Burial escalation as calculated below
Staffing		$ 153,560,336	$ 176,214,018	DLC escalator of 3.5% per year
Other		$ 96,868,184	$ 96,868,184	assume no escalation
License Termination Surveys		$ -	$ 12,000,000	New item (additional cost over 1993 estimate)
ISFSI		$ -	$ 45,000,000	New item, from Beaver Valley 1997 study
ISFSI property taxes		$ -	$ 10,538,455	PA does not have property taxes
Totals		$ 502,346,309	$ 646,926,038	

Burial additional costs:

1993 $/CF	$ 282.85		From 1993 Misc. Site Data file
1997 $/CF	$ 360.00		Estimate based upon new CNSI rates @ Barnwell, S.C.
Delta $/CF	$ 87.15		
1993 CF	$ 334,846		From 1993 cost run
Base $/CF change:		$ 29,181,829	
Contingency @ 28% avg		8,170,912	
Total Base Burial $/CF delta:		$ 37,352,741	

Craft Labor escalator:	Weighting %	Weighted % increase	
Laborer	65%	18.85%	Weighting % based upon TLG experience
Craftsman	30%	9.15%	Weighting % based upon TLG experience
Foreman	5%	1.48%	Weighting % based upon TLG experience
Effective labor escalator		129.49%	

Fully-burdened labor rates (from Centerior)

Worker Class	1993 Total Cost	1997 Total Cost	Delta	Laborer	Craftsman	Foreman
AWFM	$ 31.28	$ 39.36	26%			25.91%
AWJM	$ 30.41	$ 35.45	17%		16.57%	
BMFM	$ 31.47	$ 47.26	50%			50.17%
BMJM	$ 30.11	$ 44.70	48%		48.46%	
CAFM	$ 29.23	$ 36.84	26%			25.01%
CAJM	$ 27.80	$ 35.30	27%		26.96%	
IWFM	$ 31.41	$ 40.35	28%			28.46%
IWJM	$ 29.99	$ 38.14	27%		27.18%	
ELJW	$ 28.02	$ 35.86	28%			27.96%
ELFM	$ 29.32	$ 37.27	27%			27.11%
ELJM	$ 27.75	$ 35.57	28%		28.16%	
LBFM	$ 22.68	$ 29.03	28%	28.00%		
LBJM	$ 22.11	$ 28.00	27%	26.64%		
MWFM	$ 29.20	$ 39.16	34%			34.11%
MWJM	$ 27.77	$ 37.46	35%		34.89%	
OEMM	$ 28.52	$ 35.05	23%			22.90%
OEOA	$ 28.01	$ 34.45	23%			22.99%
PAJS	$ 27.10	$ 36.06	33%			33.06%
PAJB	$ 26.69	$ 35.56	33%			33.20%
PFFM	$ 31.75	$ 40.31	27%			26.96%
PFJM	$ 31.18	$ 39.70	27%		27.33%	
PLFM	$ 31.26	$ 40.04	28%			28.09%
PLJM	$ 30.57	$ 39.13	28%		28.00%	
RFFM	$ 29.18	n/a	n/a			
RFJM	$ 28.16	$ 38.03	39%		38.60%	
SMFM	$ 30.66	$ 39.14	28%			28.06%
SMJM	$ 29.42	$ 37.93	29%		28.93%	
TMJM	$ 22.84	$ 29.97	32%	33.38%		
Column averages				28.00%	30.61%	29.57%

Document No. D04-1242-002

DISMANTLING COST STUDY
for the
CHESWICK POWER STATION

prepared for

Duquesne Light Company

prepared by

TLG Services, Inc.

Bridgewater, Connecticut

May 1997

TABLE C-1
CHESWICK POWER STATION UNIT 1
DISMANTLING COST ESTIMATE

Activity	Remove ($000's)	Ship ($000's)	Bury ($000's)	Other ($000's)	Cntgcy ($000's)	Total ($000's)	Carbon Steel (Tons)	Stainless Steel (Tons)	Copper (Tons)	Other (Tons)	Craft Labor (Man-Hrs)
Staff Costs											
DOC Staff Cost				1863	279	2143					
Utility Staff Cost				2481	372	2853					
TOTAL PERIOD 2	22765			4761	4112	31640	35717	104	824	51	350774
PERIOD 3											
Site Closeout Activities											
9 Remove Rubble	2997				450	3447					5736
10 Grade & landscape site	208				31	239					2442
Period 3 Additional Costs											
11 3 Ash Basin Remediation			8	596	91	695					
Subtotal Period 3 Activity Costs	3205		8	596	571	4380					8178
Staff Costs											
DOC Staff Cost				9	1	10					
Utility Staff Cost				1240	186	1426					
TOTAL PERIOD 3	3205		8	1844	759	5816					8178
TOTAL COST TO DECOMMISSION	27445	64	158	7858	5471	40996	35717	104	824	51	358952

TOTAL COST TO DECOMMISSION WITH 15.4% CONTINGENCY: $40,995,936

TOTAL SCRAP METAL REMOVED:

Carbon Steel	35,717 TONS
Stainless Steel	104 TONS
Copper	824 TONS
Total	36,644 TONS

SCRAP CREDIT:

Carbon Steel	3,571,651
Stainless Steel	57,200
Copper	988,334
Total	4,617,184

ADJUSTED COST TO DISMANTLE: $36,378,752

TOTAL CRAFT LABOR REQUIREMENTS: 358,952 MAN-HRS

Document No. D04-1234-002

DISMANTLING COST STUDY
for the
ELRAMA POWER STATION

FILE COPY

prepared for

Duquesne Light Company

prepared by

TLG Services, Inc.

Bridgewater, Connecticut

April 1997

TABLE C-2
ELRAMA POWER STATION UNIT 4
DISMANTLING COST ESTIMATE

Activity	Remove ($000's)	Ship ($000's)	Bury ($000's)	Other ($000's)	Cntgcy ($000's)	Total ($000's)	Carbon Steel (Tons)	Stainless Steel (Tons)	Copper (Tons)	Other (Tons)	Craft Labor (Man-Hrs)
PERIOD 3											
Site Closeout Activities											
10 Grade & landscape site	175				26	201					1998
Period 3 Additional Costs											
11 Ash Basin Remediation			153	596	112	861					
Subtotal Period 3 Activity Costs	175		153	596	139	1062					1996
Staff Costs											
DOC Staff Cost				8	1	9					
Utility Staff Cost				1240	186	1426					
TOTAL PERIOD 3	175		153	1844	326	2497					1996
TOTAL COST TO DECOMMISSION	14385	64	303	6000	3258	24011	19002	784	973	9	192715

TOTAL COST TO DECOMMISSION WITH 16.7% CONTINGENCY: $24,010,622

TOTAL SCRAP METAL REMOVED:

Carbon Steel	19,002 TONS
Stainless Steel	784 TONS
Copper	973 TONS
Total	20,760 TONS

SCRAP CREDIT:

Carbon Steel	1,900,188
Stainless Steel	431,441
Copper	1,168,190
Total	3,499,820

ADJUSTED COST TO DISMANTLE: $20,510,802

TOTAL CRAFT LABOR REQUIREMENTS: 192,715 MAN-HRS

Document No. D04-1270-002

DISMANTLING COST STUDY

for the

BRUCE MANSFIELD, BRUNOT ISLAND, EASTLAKE 5, AND SAMMIS 7 POWER STATIONS

prepared for

Duquesne Light Company

prepared by

TLG Services, Inc.

Bridgewater, Connecticut

August 1997

TABLE C-1
BRUCE MANSFIELD PLANT
DISMANTLING COST ESTIMATE

Activity	Remove ($000's)	Bury ($000's)	Other ($000's)	Cntgcy ($000's)	Total ($000's)	Carbon Steel (Tons)	Stainless Steel (Tons)	Copper (Tons)	Other (Tons)	Craft Labor (Man-Hrs)
TOTAL PERIOD 2	**100494**		**7230**	**16159**	**123882**	**140096**	**4895**	**3250**	**201**	**1723681**
PERIOD 3										
Site Closeout Activities										
10 Remove Rubble	8826			1324	10150					16898
11 Grade & landscape site	937			141	1077					11010
Period 3 Additional Costs										
Ash Basin Remediation		207	596	120	923					
Subtotal Period 3 Activity Costs	9763	207	596	1585	12151					27908
Staff Costs										
DOC Staff Cost			8	1	9					
Utility Staff Cost			1240	186	1426					
TOTAL PERIOD 3	**9763**	**207**	**1843**	**1772**	**13585**					**27908**
TOTAL COST TO DECOMMISSION	**110306**	**207**	**10468**	**18147**	**139127**	**140096**	**4895**	**3251**	**203**	**1751589**

TABLE C-1
BRUCE MANSFIELD PLANT
DISMANTLING COST ESTIMATE

Activity	Remove ($000's)	Bury ($000's)	Other ($000's)	Cntgcy ($000's)	Total ($000's)	Carbon Steel (Tons)	Stainless Steel (Tons)	Copper (Tons)	Other (Tons)	Craft Labor (Man-Hrs)
TOTAL COST TO DECOMMISSION WITH 15% CONTINGENCY:					$139,126,976					
TOTAL SCRAP METAL REMOVED:				Carbon Steel	140,096 TONS					
				Stainless Steel	4,895 TONS					
				Copper	3,251 TONS					
				Total	148,242 TONS					
SCRAP CREDIT:				Carbon Steel	$11,768,042					
				Stainless Steel	$2,937,127					
				Copper	$3,901,716					
				Total	$18,606,885					
ADJUSTED COST TO DISMANTLE:					$120,520,091					
TOTAL CRAFT LABOR REQUIREMENTS:					1,751,589 MAN-HRS					

TABLE C-2
BRUNOT ISLAND POWER STATION
DISMANTLING COST ESTIMATE

Activity	Remove ($000's)	Other ($000's)	Cntgcy ($000's)	Total ($000's)	Carbon Steel (Tons)	Copper (Tons)	Other (Tons)	Craft Labor (Man-Hrs)
PERIOD 3								
Site Closeout Activities								
10 Remove Rubble	977		147	1124				1871
11 Grade & landscape site	112		17	129				1332
Subtotal Period 3 Activity Costs	1090		163	1253				3204
Staff Costs								
DOC Staff Cost		8	1	9				
Utility Staff Cost		3	0	3				
TOTAL PERIOD 3	**1090**	**11**	**165**	**1265**				**3204**
TOTAL COST TO DECOMMISSION	**15639**	**2740**	**2757**	**21136**	**14721**	**932**	**14**	**227897**

TOTAL COST TO DECOMMISSION WITH 15% CONTINGENCY: **$21,135,778**

TOTAL SCRAP METAL REMOVED:

Carbon Steel	14,721	TONS
Copper	932	TONS
Total	15,653	TONS

SCRAP CREDIT:

Carbon Steel	$1,295,432
Copper	$1,118,551
Total	$2,413,982

ADJUSTED COST TO DISMANTLE: **$18,721,796**

TOTAL CRAFT LABOR REQUIREMENTS: **227,897 MAN-HRS**

TABLE C-3
EASTLAKE UNIT 5
DISMANTLING COST ESTIMATE

Activity	Remove ($000's)	Other ($000's)	Cntgcy ($000's)	Total ($000's)	Carbon Steel (Tons)	Copper (Tons)	Other (Tons)	Craft Labor (Man-Hrs)
PERIOD 3								
Site Closeout Activities								
10 Remove Rubble	2295		344	2640				4447
11 Grade & landscape site	116		17	133				502
Subtotal Period 3 Activity Costs	2411		362	2773				4948
Staff Costs								
DOC Staff Cost		9	1	10				
Utility Staff Cost		7	1	8				
TOTAL PERIOD 3	**2411**	**15**	**364**	**2790**				**4948**
TOTAL COST TO DECOMMISSION	**23426**	**5571**	**4350**	**33347**	**37614**	**854**	**56**	**357404**

TOTAL COST TO DECOMMISSION WITH 15% CONTINGENCY: **$33,346,750**

TOTAL SCRAP METAL REMOVED:

Carbon Steel	37,614	TONS
Copper	854	TONS
Total	38,468	TONS

SCRAP CREDIT:

Carbon Steel	$2,482,543
Copper	$1,024,752
Total	$3,507,295

ADJUSTED COST TO DISMANTLE: **$29,839,455**

TOTAL CRAFT LABOR REQUIREMENTS: **357,404 MAN-HRS**

TABLE C-4
SAMMIS UNIT 7
DISMANTLING COST ESTIMATE

Activity	Remove ($000's)	Other ($000's)	Cntgcy ($000's)	Total ($000's)	Carbon Steel (Tons)	Copper (Tons)	Other (Tons)	Craft Labor (Man-Hrs)
PERIOD 3								
Site Closeout Activities								
10 Remove Rubble	3493		524	4017				6767
11 Grade & landscape site	58		9	66				251
Subtotal Period 3 Activity Costs	3551		533	4084				7018
Staff Costs								
DOC Staff Cost		9	1	10				
Utility Staff Cost		7	1	8				
TOTAL PERIOD 3	3551	16	535	4101				7018
TOTAL COST TO DECOMMISSION	25640	5750	4709	36099	38456	845	55	379364

TOTAL COST TO DECOMMISSION WITH 15% CONTINGENCY: $36,099,080

TOTAL SCRAP METAL REMOVED:

Carbon Steel	38,456 TONS
Copper	845 TONS
Total	39,300 TONS

SCRAP CREDIT:

Carbon Steel	$2,653,433
Copper	$1,013,504
Total	$3,666,937

ADJUSTED COST TO DISMANTLE: $32,432,143

TOTAL CRAFT LABOR REQUIREMENTS: 379,364 MAN-HRS