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Duquesne Statement No. 12-R

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

Rebuttal Testimony
of
Jeff D. Makholm, Ph.D.

Contents:

Response to Intervenor Testimony Regarding Cost of Capital and Other Related Issues

I. INTRODUCTION

Q. What is your name?

A. Jeff D. Makholm.

Q. Are you the same Jeff D. Makholm who submitted direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. My purpose in providing rebuttal testimony is to respond to the testimony of Eric Van Jeschke testifying on behalf of the Office of Trial Staff. I will also have comments on issues of cost of capital as they appear in the testimony of Matthew Kahal, testifying on behalf of the Office of Consumer Advocate and Jonathan D. Muehl, testifying on behalf of David Hughes.

Q. How is your testimony organized?

A. I will first summarize my rebuttal testimony with respect to each of the three witnesses for whom I have rebuttal comments. Then I will deal with each witness in order.

II. SUMMARY OF TESTIMONY

Q. Please summarize your testimony.

A. I deal with three witnesses in my rebuttal testimony:

1. Mr. Van Jeschke produces a recommendation regarding rate of return that suffers from various problems. His calculations are obscure and resist replication, his use of data is highly subjective, and his financial calculations are unsupported by a careful application of theoretical methods. His "reasonable range" (9.5 to 10.5 percent) looks unreasonable on its face, given the returns granted by other Commissions around the country.

2. Mr. Kahal uses a rate of return of 10 percent in his testimony without any support or justification of his own (other than the out-of-context fact that such a number was used in another case). Further, he recommends departures from the traditional treatment of certain debt costs, to the unjustified detriment of Duquesne.

3. Mr. Muehl presents testimony regarding missed opportunities for stranded cost mitigation, excessive dividends paid to Duquesne's stockholders and "sound public policy" that are

unsupported by analysis. His assertions about what Duquesne might have done reveal basic misunderstandings about the nature of utility ratemaking.

III. REBUTTAL TO SPECIFIC WITNESSES

Q. What is the purpose of this section of your testimony?

A. In this section, I will deal with the following witnesses: (1) Mr. Van Jeschke testifying for the Office of Trial Staff; (2) Mr. Kahal testifying on behalf of the Office of Consumer Advocate; and (3) Mr. Muehl, testifying on behalf of David Hughes.

A. Rebuttal to Mr. Van Jeschke

Q. How is your rebuttal to Mr. Van Jeschke organized?

A. First, I will critique Mr. Van Jeschke's proxy group and address his specific criticisms of mine. Second, I will critique Mr. Van Jeschke's DCF calculation and address his specific criticisms of my DCF. Third, I will critique Mr. Van Jeschke's additional *Value Line* analysis. Lastly, I will demonstrate that the ROE he recommends is not reasonable compared to returns recently granted to electric utilities throughout the United States.

1. Proxy Groups

Q. Are there problems with Mr. Van Jeschke's proxy group?

A. Yes. There are two. First, the financial risk criteria he uses for inclusion into the proxy group are not clear. Second, I conclude that some specific companies he includes should not be used in a DCF calculation.

Q. Why do you say Mr. Van Jeschke's financial risk criteria are unclear?

A. Mr. Van Jeschke states plainly that only utilities from the eastern and central U.S. are included in the proxy group (though he provides no rationale for the importance of this criterion). He also is specific in the amount of nuclear generation required for inclusion into the group. In contrast, the only information he gives about the financial risk criteria is that included companies are "similar in financial risk."

Q. Why is that a problem?

A. Because we have no idea of what Mr. Van Jeschke means by similar. For example, total capitalization appears to be one of his criterion, since it is listed in OTS Exhibit No. 1, Schedule 3. The range of total capitalization varies from about $1.5 billion (IES Industries) to $14.4 billion (Unicom Corp.). Given DQE's capitalization of about $3.2 billion, it is not clear how different in capitalization a company would have to be, in order to be excluded from this group.

Another criterion, beta, raises similar questions. The range of betas is from .65 to .90, a substantial difference. It is unclear whether Mr. Van Jeschke eliminates some companies from his proxy group because they had betas beyond this range, or are all eastern and central utilities with 30 percent nuclear generation included in his proxy group? We simply do not know.

The other criteria: equity ratio, safety rank and financial strength share this same difficulty. It is impossible to tell whether Mr. Van Jeschke had specific financial criteria in mind that his proxy group members had to meet in order to be similar to the Company, or whether any company that met only the location and nuclear generating criteria were included in the group. If the latter is true, then the discussion of financial risk is irrelevant, since all companies were included regardless of their performance on the risk criteria.

Q. What specific companies in his proxy group do you conclude should not be included?

A. While Mr. Van Jeschke and I differ slightly over criteria like operating revenues from electricity and total capitalization, I do not hold these differences to be critical. However, Mr. Van Jeschke includes four companies, Atlantic Energy, Inc. Baltimore Gas & Electric Co., Duke Power Co. and IES Industries, which are involved in potential mergers. I have stated previously that it is inappropriate to include such companies in a proxy group, as stock prices can be (and are) quite volatile during the period of the potential merger. Since this process can occur over a substantial period of time, a DCF calculation including merger companies would be less reliable. That is to say, the stock prices for such companies would tend to move for reasons related to the merger alone—not reasons reflecting the viability and growth prospects of the firms themselves. Mr. Van Jeschke himself does not include DQE in his proxy group for this very reason. Therefore, I do not understand why he uses Atlantic Energy, Inc., Baltimore Gas & Electric Co., Duke Power Co. and IES Industries.

I also question the use of Boston Edison Co. and Rochester Gas & Electric Corp. in his proxy group since there is some concern in the investment press about the stability of their dividends (see **Exhibit JDM - 16**). Given that the DCF model assumes a growing dividend, I feel it unwise to include a company whose dividend is forecast to decrease. A decreasing dividend would violate a basic assumption of the DCF model.

Q. What specific criticisms of your proxy group made by Mr. Van Jeschke do you wish to address?

A. I wish to address two specific criticisms that Mr. Van Jeschke made concerning my proxy group. First, Mr. Van Jeschke objected to my proxy group because eight members did not have nuclear power generation. Second, Mr. Van Jeschke objected to my proxy group because 13 of the companies had purchased power for a large part of their generation. I will address each of these criticisms in turn.

Q. Is Mr. Van Jeschke correct in criticizing your proxy group because some of the proxy group members did not have nuclear power generation?

A. No. Mr. Van Jeschke noted that I addressed this subject in my direct testimony and then mischaracterized my opinion on the subject. "Dr. Makholm makes this observation of his proxy group, however, does not believe it is an important fact in this case" (p. 42, ll. 5-6). I stated in my testimony that I regularly use nuclear power generation as a criterion, but opted not to in this case. This was because so many electric utilities are involved in mergers, and therefore, are not candidates for inclusion in my proxy group. I also noted in my testimony that nuclear facilities are generally viewed as increasing a utility's risk. In order to obtain a DCF result that was more reliable and stable, I chose to relax the nuclear power generation constraint.

I felt comfortable in doing so because relaxing this constraint produces a more conservative result, that is a result that would underestimate the true ROE—reflecting as it would a lower risk group of non-nuclear companies. This is because nuclear power generation is viewed by the investment community—and Mr. Van Jeschke—as riskier than other forms of power generation. Therefore, I am somewhat surprised by Mr. Van Jeschke's criticism. Had I been able to incorporate this criterion and been comfortable with the proxy group's ability to produce a stable and reliable result, then my recommendation would have been higher. **Exhibit JDM - 17** shows a DCF calculation I performed, using data from the same time period I used in my direct testimony. I began with the proxy group of companies I used in my direct testimony, but I restricted myself to those companies who derive part of their electricity revenues from nuclear power generation. The resulting DCF return would have been **12.37 percent**. I believed the addition of non-nuclear power electric utilities increased the stability and reliability of my recommended return because they increased the size of my proxy group. Mr. Van Jeschke, however, would appear from his testimony to find this higher, *strictly* nuclear proxy group, result more persuasive.

2. DCF Analysis

Q. What will you discuss in this section of your testimony?

A. I will critique Mr. Van Jeschke's method of determining the dividend yield and growth rate. Then I will address some specific criticisms made by Mr. Van Jeschke with regard to my flotation cost adjustment in my DCF.

a. Dividend Yield

Q. Do you agree with Mr. Van Jeschke's method of determining the dividend yield portion of the DCF formula?

A. No. Mr. Van Jeschke uses a dividend yield figure in his DCF model that will bias downward the dividend yield that the DCF model requires. The correct way to calculate the expected dividend payment over the next year is to observe the *past* four payments and multiply them by the expected dividend growth rate. Mr. Van Jeschke, on the other hand, observes the "current" dividend yield (the latest dividend multiplied by and divided by the 52-week average and the current stock price) and multiplies these figures by *half* of the expected growth rate to get next year's dividend yield. This treatment of the dividend yield assures an understatement, on average. **Exhibit JDM - 18** of my rebuttal testimony presents a paper I co-authored in 1992 entitled "Four Common Errors in Applying the DCF Model in Utility Rate Cases" in which I demonstrate how this method of calculating the dividend yield can lead to an incorrect result.

Q. Do you have any other disagreements with Mr. Van Jeschke's calculation of the dividend yield?

A. Yes. Mr. Van Jeschke failed to make an adjustment to account for the ex-dividend date phenomenon.

Q. Does Mr. Van Jeschke dispute the ex-dividend phenomenon?

A. That is not clear to me. Nowhere in his testimony does he deny that stock prices drop on the ex-dividend date. However, he indicates that the stock price change cannot be attributed solely to the ex-dividend phenomenon (page 43, ll. 15-16).

While it may be true that a change in stock price on any given day may not be attributed completely to any one factor, this does not prevent us from understanding phenomena that do occur with great regularity in the financial markets. In my direct testimony, I provided *academic evidence* (which Mr. Van Jeschke indeed called for) that the phenomenon exists.[1] This evidence demonstrates that the value of a share drops by an amount approximately equal to its dividend on the ex-dividend date.

A simpler and more common sense example demonstrates that the phenomenon must exist. If an investor had two shares of the same common equity, one that gave him the right to the next

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[1] The following references, found on page 22 of my direct testimony, discuss the ex-dividend date and provide evidence that the ex-dividend date phenomenon occurs in the financial markets: E. F. Brigham, *Financial Management Theory and Practice*, 3rd Edition, (New York: The Dryden Press, 1982), 687. Empirical evidence of this phenomenon can be found in articles written by J. A. Cambell and W. Beranek, "Stock Price Behavior on Ex-Dividend Dates," *Journal of Finance*, 10, 4, (December 1955), 425-429; D. Durand and A. M. May, "The Ex-Dividend Behavior of American Telephone and Telegraph Stock," *Journal of Finance*, 15, 1, (March 1960), 19-31; and E. J. Elton and M. J. Gruber, "Marginal Stockholder Tax Rates and the Clientele Effect," *Review of Economics and Statistics*, (February 1970), 68-74.

dividend and the other that did not, should he reasonably be willing to sell them at the same price? The answer is no. One share is worth more, by the value of the next dividend.[2]

The ex-dividend phenomenon is a valid phenomenon—theoretically explained and empirically verified. Mr. Van Jeschke recommends that we simply ignore it. Since the effect of the phenomenon is always to underestimate the true required return on equity, I conclude we must attempt to correct the bias. My ex-dividend date adjustment does just that.

Q. Do you agree with Mr. Van Jeschke that the adjustment is not necessary when using a 52-week average stock price?

A. No. Mr. Van Jeschke suggests that the ex-dividend phenomenon would somehow average out for seasonal or quarterly effects. This is untrue. As I stated and showed in my direct testimony (**Exhibit JDM-5**), the correct calculation can be approximated (to a high degree of accuracy in this case) by making *one-half* of the full adjustment for the group when a proxy group is used. That is, an adjustment that assumed that the ex-dividend date is 45 days away works virtually, on average for the group, as well as a specific adjustment for each company. The adjustment properly accounts for the ex-dividend date effect.

In sum, the effect is a fact of life in the stock markets. If one measured the stock price during the course of a quarter, the only time that the presence of the next dividend would not influence the stock price should be on the ex-dividend date itself. During the rest of the period, the company would be accruing earnings that investors would reasonably anticipate receiving at the quarter's end. In that event, the average ex-dividend adjustment over the period of the quarter would be about half of the next dividend and not zero as Mr. Van Jeschke opines.

As I stated, a complete discussion of the average ex-dividend date adjustment appears on page 23 of my direct testimony and is demonstrated in **Exhibit JDM-5**.

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[2] **Exhibit 18** also includes a discussion of the ex-dividend date error.

b. Growth Rate

Q. Do you agree with Mr. Van Jeschke's method of determining growth?

A. Mostly, no. I think it is important to state first that I agree with Mr. Van Jeschke's use of forward-looking analysts' forecasts of future growth. As my direct testimony indicates, I conclude they are the best estimate we have of what investors might expect future growth to be. However, I find Mr. Van Jeschke's discussion of historical vs. forecast growth rates ambiguous and his process of determining the growth rate highly subjective.

Q. Please explain.

A. Mr. Van Jeschke goes to a great deal of trouble to calculate historical growth rates for the companies in his proxy group. In fact, he computes four separate historical growth rates for each company. On page 29, lines 13-15 of his direct testimony, he says that he normally places the most emphasis on historical dividend growth when estimating the DCF cost of equity. Some three lines later in his testimony he says, "Most of the research evidence indicates that analysts' growth forecasts are superior to historically-oriented growth measures" (p. 29, ll. 18-19). If the research evidence does indeed suggest this—and I conclude that it does—then Mr. Van Jeschke has no basis for his "normal" reliance on historical data.

Mr. Van Jeschke states that he would be double counting the importance of historical data if he used it in this testimony, because historical data is accounted for in forecast growth. If true, this suggests that his normal estimates, that rely mostly on historical data, underemphasize the importance of analysts' forecasts.

I also wondered why Mr. Van Jeschke calculated the historical growth rates *at all*, given that he intended to use forecast growth rates. It gives the appearance that Mr. Van Jeschke had an acceptable growth rate in mind before he began his analysis and that he found a method of dismissing estimates that disagreed substantially with his preconceived growth rate.

Q. Are there any other examples of similar subjectivity?

A. Yes. One of his methods of determining historical growth yielded a growth rate of 4.09 percent. He rejected it out-of-hand, saying that it was "...unlikely to be sustainable for the EBG (*electric barometer group*)" (page 30, line 16).

Further, Mr. Van Jeschke criticized my growth rate because one of the estimates, taken from analysts' forecasts, was 4.31 percent. He presented no methodological or empirical disagreement with the estimate. He simply stated that, "It is my opinion that a growth rate above 3.50 percent is not sustainable" (p. 45, ll. 8-9). He offered no rationale or evidence to support his opinion.

Mr. Van Jeschke cannot have it both ways. Either investor analysts' forecasts are good estimates of investor-expected growth, or they are not. By his own admission, research indicates they are better than historical growth methods. What we are trying to determine in this part of the proceeding is what *investors* require as a fair rate of return on equity.

Q. Why did you feel that Mr. Van Jeschke's method for determining growth was subjective?

A. Because it is impossible to understand exactly how he derives his specific estimates. Mr. Van Jeschke overwhelms us with the quantity of his estimates. He calculates compound, log-linear historical and forecast growth rates from multiple sources, and he computes their medians and means. All of these data points provide a patina of objectivity. But they are a thin veneer covering a process that is essentially subjective. The multitude of historical growth rates he calculated do not appear to be used at all in his recommended growth rate. Growth rates above 3.50 percent are summarily dismissed. Finally, it is not even clear how he uses the growth rates he finds acceptable to obtain his range of 2.50 percent to 3.50 percent.

In response to the question in his direct testimony that asks him to explain the *specific* judgment he exercised to determine the 2.50 percent to 3.50 percent range, Mr. Van Jeschke simply lists all of his growth calculations. He never specifically says how he obtains his range.

c. DCF Result

Q. Do you agree with the manner in which Mr. Van Jeschke establishes his DCF range of 9.50 percent to 10.50 percent?

A. No.

Q. Why not?

A. It is another example of how Mr. Van Jeschke subjectively changes the results of his empirical work to produce a lower return. Using his own methodology, Mr. Van Jeschke obtained a DCF range of 9.59 percent and 10.62 percent (p. 31). Later, when asked what he believed a reasonable range to be, he indicated a range of 9.50 percent and 10.50 percent (p. 35). In moving down from 9.59 to 10.62 percent to 9.50 to 10.50 percent, Mr. Van Jeschke appears to simply have removed his "dividend yield adjustment" (p. 31), with no explanation at all. Although the loss is only 9 and 12 basis points in this one specific instance, the problem is that this subjective rearrangement occurs throughout the testimony and always to the Company's disadvantage.

Q. But doesn't Mr. Van Jeschke select the top of his range as his recommended return?

A. Yes, Mr. Van Jeschke tries to give the appearance of reasonableness in suggesting the higher return. But this comes after his previous subjective adjustments such as ignoring growth rates higher than 3.50 percent and arbitrarily reducing his DCF range.

Further, Mr. Van Jeschke's generosity raises some additional questions. He uses the Company's capital structure and senior debt rating as the reason for granting the higher part of his range. If these are important factors, why are they not more clearly a part of his proxy group criteria? For example, if the Company's current capital structure represents a special risk, then to be comparable, his proxy group should reflect it. Also, if the Company's BBB+ senior debt rating truly suggests additional risk, his proxy group companies should share those characteristics as well. If these issues are truly important, I believe that they should be addressed in his proxy group criteria, before the opportunity exists for subjective adjustments to calculated results.

d. Flotation Cost Adjustment

Q. What specific criticism of your flotation cost adjustment would you like to address?

A. Mr. Van Jeschke claims that my flotation cost adjustment is not appropriate because the expenses were incurred in the past at the time of issuance and are now reflected in the market price of the common stock.

Q. Do you agree that the Company should not be compensated for the expenses?

A. Absolutely not. Mr. Van Jeschke is correct in stating that the Company incurred these costs at the time of issuance. He failed to note, however, that there are three ways a company can be fully compensated for these expenses. *First*, the Commission could allow the Company to recover these expenses automatically in the year they are incurred as an expense component of the revenue requirement (or the expense could be amortized over a number of years). This treatment would include issuance expenses as an expense, when they occur, to be deferred, amortized and collected from customers over a specified period agreeable to the Commission and the Company.. This would even-out the collection of these expenses, and cushion their short-term impact on rates.

Second, the Commission could allow the issuance expense to be included in rate base (like the treatment of interest charges on construction work in progress). This would allow the Company to earn a return *on* the expenses, as opposed to a return *of* the expenses.

Third, the Commission could adjust the cost of capital upward over the life of the issue. This adjustment in effect allows the Company to earn a return *on* the issuance expenses, even though the expenses are not in rate base. The financial result and the revenue requirement are the same as for the second method. All three of these methods compensate the utility for the actual issuance expenses that were incurred.

The Commission, however, did not compensate the Company for the expenses of its issuances when they were incurred, or at any time thereafter. The result of this was a loss of value to the Company. Investors reacted to this loss of value by reducing what they were willing to pay for the Company's shares. Nowhere in his direct testimony does Mr. Van Jeschke claim that selling and issuance costs are anything other than legitimate costs. And nowhere does he provide evidence that a company should not be compensated for legitimate costs it incurs. It is clear, therefore, that the Company deserves to be compensated for these expenses. My flotation cost adjustment is an effort to give back to the Company, what would otherwise be taken away. Mr. Van Jeschke is simply wrong to imply that just because legitimate and verifiable costs have occurred in the past (costs that have never been recovered), they should be ignored.

3. Mr. Van Jeschke's Additional *Value Line* Analysis

Q. What will you address in this section of your testimony?

A. Mr. Van Jeschke performed an additional analysis using *Value Line Investment Survey* to support his recommendation.

Q. Do you agree with his methodology?

A. No. Mr. Van Jeschke uses the "Annual Rates" found in a box on the left-hand side of the *Value Line* page. I do not use these "Annual Rates" because they incorporate some historical data to form the *Value Line* forecast.

Q. Please explain.

A. The *Value Line* annual rates used by Mr. Van Jeschke incorporate data from 1995 and 1996 to forecast growth into the year 2001. I calculate a fully forecast growth rate and feel it is superior to using historical data. Mr. Van Jeschke seemed to agree with me when he noted that research indicated that forecasts are superior to historical growth rates. Mr. Van Jeschke also felt that using historical data would represent double counting, since historic data is already fully accounted for in forecast methods.

Q. Is there any other reason that you don't use these "Annual Rates"?

A. Yes. When the near future is expected to depart from the recent past, these "Annual Rates" can produce unreliable and unusable results. For example, if the company in question has experienced rapid growth in the recent past and anticipates slower growth in the near future, the "Annual Rates" will underestimate future growth . In certain instances it will even predict negative growth rates. Therefore, I conclude that the fully forecast growth rates are superior to the *Value Line* "Annual Rates."

Q. Did you observe any problems in Mr. Van Jeschke's analysis?

A. Yes. Four of Mr. Van Jeschke's proxy group members showed zero dividend growth for the future (Dominion Resources, Inc., IES Industries, PP&L Resources and Rochester Gas & Electric Corporation) while two companies showed *negative* growth rates (Atlantic Energy, Inc. and PECO Energy Company). Inasmuch as dividend growth plays a part in his additional analysis, it is inappropriate to include these six companies in his proxy group, because the DCF model assumes a constantly growing dividend.

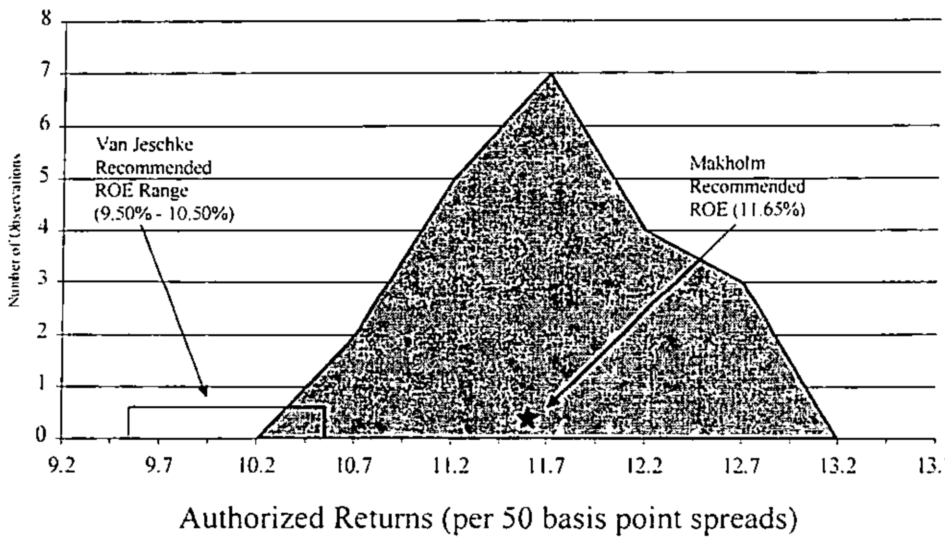
I could not replicate Mr. Van Jeschke's analysis due to the difficulty of obtaining the exact data he used. However, I did use his proxy group to calculate annual DCF using my model and my data. When all thirteen companies from Mr. Van Jeschke's proxy group were used, the DCF result was 11.24 percent—higher than Mr. Van Jeschke's recommended return of 10.50 percent. However, there were three companies which had negative EPS growth according to *Value Line Investment Survey* and *Compustat* (Boston Edison Co., Rochester Gas & Electric Corp. and Unicom Corp.). When these three companies are eliminated from the proxy group, the DCF result is 11.76 percent—still higher than Mr. Van Jeschke's recommended return, but also higher than my recommended return of 11.65 percent.

4. The Unreasonableness of Mr. Van Jeschke's Recommended Return

Q. Do you have any other evidence that his DCF result is unreasonably low?

A. Yes. I have submitted his recommended DCF result of 10.50 percent to the same reasonableness check as my recommended return. **Figure 1** below, taken from my direct testimony (p. 31), shows the range of electric utilities' returns on equity authorized by regulatory commissions throughout the country between April 1995 and March 1997. The figure also shows the number of decisions associated with each authorized return. As the figure shows, my recommended return of 11.65 rests almost in the middle of the distribution. I have also inserted Mr. Van Jeschke's recommended return into the figure. A return on equity of 10.50 percent clearly falls into the extreme low tail of the figure. This suggests that Mr. Van Jeschke's recommendation is unreasonably low compared to recent authorized returns.

Figure 1
Comparison of Authorized Returns on Equity



B. Rebuttal to Mr. Kahal

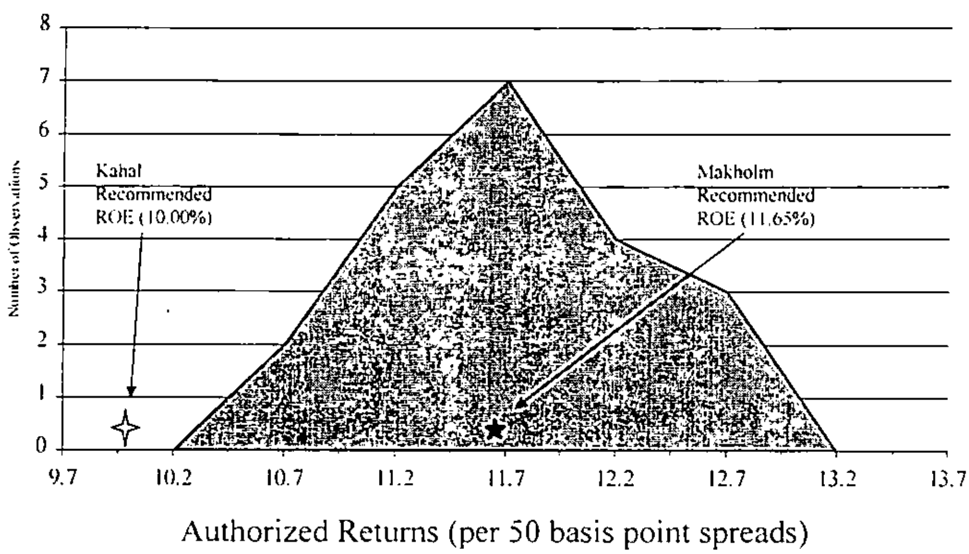
Q. What are your rebuttal comments on the testimony of Mr. Kahal?

A. I have two comments. The first pertains to Mr. Kahal's unsupported use of 10 percent as a reasonable return on equity to use for Duquesne in this case. The second concerns the way in which Mr. Kahal has altered traditional practices in Pennsylvania regarding the recovery of acquisition costs for debt.

Q. What comments do you have regarding Mr. Kahal's use of 10 percent as the rate of return to use for Duquesne?

A. The 10 percent number he uses is inappropriate in this case. Mr. Kahal offers no support for his number, other than using a reference to the securitization case of PECO Energy. He introduces no evidence and makes no attempt to argue that circumstances in that PECO case, or the reasoning the Commission applied in order to arrive at such a figure in a different case, at a different time, are transferable to this case. As such, other than a bald assertion that 10 percent "should apply to Duquesne as well" (p. 26), there is no support for that fugure at all in Mr. Kahal's testimony. That assertion should not be considered as evidence on the cost of capital for Duquesne or any electric utility like Duquesne. Furthermore, as **Figure 2** shows, Mr. Kahal's 10 percent figure simply looks unreasonable compared to what other Commissions around the country have found regarding the fair rate of return on equity.

Figure 2
Comparison of Authorized Returns on Equity



Q. What about the issue of unamortized debt acquisition costs?

A. As explained in the rebuttal testimony of Donald J. Clayton, unamortized debt costs represents underwriters' discounts, premiums and expenses paid by Duquesne to issue and refinance debt. In other words, they are real-world expenses that Duquesne—and every other such utility—incurs in order to place its debt securities with investors. The expenses are always there, they are prudently incurred, and every jurisdiction has ways of recovering them.

Q. How are such debt issuance costs normally treated?

A. They are normally treated by subtracting such expenses and discounts from the principal amount of a debt issue in order to derive "net proceeds." The actual interest expense is then calculated as a percent of the "net proceeds" (which makes it a bit higher than if calculated on the principal amount) in order to amortize the expenses and discounts over the life of the issue.

Q. Have you performed such calculations yourself as part of other cost of capital assignments in the past?

A. Yes. They represent a very common way of handling such costs.

Q. What is the issue in this case regarding such costs?

A. Mr. Kahal (in conjunction with his colleague Mr. Thomas S. Catlin) is attempting to change the traditional way of dealing with such expenses and discounts in a way that lowers Duquesne's overall rate of return vis-a-vis what Duquesne would receive under traditional treatment.

Mr. Clayton has proposed to recover the old, post-2005 expense (*i.e.*, the portion that would normally have been recovered in the normal way after that date) before 2005. That is a reasonable and consistent treatment, in my opinion. Messrs. Kahal and Catlin propose to treat the post-2005 recovery as a regulatory asset, which would lower the cost of debt in the return calculations, as well as increase the apparent leverage. Both effects lower the return to Duquesne, as Mr. Clayton correctly states, and both are unwarranted departures from the traditional practice of dealing with such issuance costs. I thus recommend that Mr. Clayton's approach to this issue be retained, and that Messrs. Kahal's and Catlin's deviation from traditional practice be rejected.

C. Rebuttal to Mr. Muehl

Q. What is Mr. Muehl's testimony?

A. Mr. Muehl presents some calculations that purport to show that Duquesne has transferred "wealth" from rate-payers to stockholders "in excess of that which would be reasonable for a regulated utility" (p. 6).

Q. Do you agree with Mr. Muehl?

A. No. He confuses a number of concepts central to utility ratemaking, and he uses market data that is not pertinent to the question of the cost of capital to which Duqnesne is entitled by law. He makes inconsistent recommendations regarding what he thinks Duquesne might have done to mitigate stranded costs in the past, and he injects a "psychological point of view" (p. 3) into how the company should have acted to justify its dividend policy. He also makes a mistake in asserting that Duquesne should operate on a "cash flow" basis rather than on the basis of a fair return on the company's invested capital (tied to that capital's cost) which has guided the regulation of public utilities in the United States at least since the *Hope Natural Gas* Supreme Court decision of 1944.

Mr. Muehl apparently believes that Duquense could have done more to mitigate its stranded costs, and that Duquense could live with some sort of "enforced rate reductions." However, because his beliefs are based neither on a realistic view of how shareholders are compensated for the use of their capital nor how actual utility rates are made, he provides no recommendations upon which the Commission could possibly act.

Q. Please explain.

A. Mr. Muehl's ultimate conclusions are based on examining a single 10-year holding period for Duquesne's stock. Besides the fact that Mr. Muehl selectively uses a period of time designed to maximize the returns to Duquesne's shareholders, he never confronts the irrelevance of such comparisons in the context of rate-setting. Utilities and Commissions do not set rates for utilities on the basis of relative movements in stock prices or on investor returns to holding a particular stock. They set rates on the basis of *costs*, one of which is the cost of capital. His data is irrelevant to rate-setting cases.

Mr. Muehl's inconsistencies regarding the rate-setting process can be characterized by his apparently equivalent view of accelerated depreciation and write-downs. He states (p. 3): "[a]

simple and effective way for a company to mitigate its stranded costs is to accelerate the depreciation of its stranded assets, or to simply write down the value of those assets." He does not appear to realize that depreciation expense is a traditional part of utility rates, and that accelerating depreciation will raise those rates, not lower them. His statements regarding Duquesne's psychological point of view (p. 3) also relate to his mistaken notions about how regulators handle depreciation (as though it were not a part of rates).

He also confuses "cash flow" with cost recovery. He states: "it seems reasonable to expect that the lower rates [set by enforced rate reductions due to accelerated depreciation or write-downs] set by the regulators would still allow the company sufficient cash flow to continue serving its customers" (p. 4). Mr. Muehl does not appear to realize that rates are based on actual costs, including the cost of capital, not some notion of future cash flow needs. Utilities in the United States do not set their rates on a "cash flow" basis.

Q. What are your summary comments related to Mr. Muehl's testimony?

A. I conclude that he has basic misunderstandings about how the regulatory process works or how rates are set. As such, I do not think his testimony has any usefulness in this proceeding.

Q. Does this conclude your rebuttal testimony?

A. Yes.

BOSTON EDISON NYSE-BSE

RECENT PRICE **26** | P/E RATIO **9.8** (Trailing: 10.3; Median: 11.0) | RELATIVE P/E RATIO **0.60** | DIV'D YLD **7.2%** | VALUE LINE **165**

High:	27.8	28.0	18.8	22.1	20.3	24.9	26.3	32.6	29.9	29.5	30.1	27.4
Low:	21.2	16.8	12.5	15.4	16.5	18.3	22.3	26.4	21.5	23.1	21.8	24.0

Target Price Range 2000 | 2001 | 2002

TIMELINESS **4** Below Average (Relative Price Perform- ance Next 12 Mos.)

SAFETY **3** Average (Scale: 1 Highest to 5 Lowest)

BETA .70 (1.00 = Market)

2000-02 PROJECTIONS

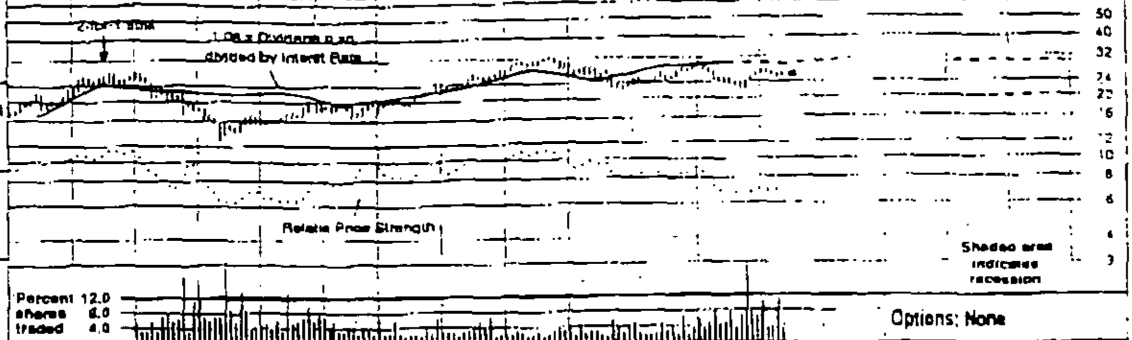
	Price	Gain	Ann'l Total Return
High	30	(+15%)	10%
Low	20	(-25%)	2%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	0	0	0	0	0	0	0

Institutional Decisions

	3Q96	4Q96	1Q97
to Buy	44	46	53
to Sell	48	39	39
Hld's(000)	18560	17048	19139



1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	© VALUE LINE PUB., INC.	00-02
38.91	36.01	35.30	41.81	37.14	29.95	31.56	31.74	32.95	32.27	31.39	31.54	32.84	34.01	33.92	34.35	36.30	35.00	Revenues per sh	35.00
4.48	4.47	5.41	5.67	6.75	5.55	4.95	5.13	5.73	5.38	5.75	5.88	5.95	6.69	6.23	7.31	7.50	7.40	"Cash Flow" per sh	7.75
2.08	1.59	1.80	2.43	2.52	2.58	1.97	1.86	1.90	1.30	1.96	2.10	2.28	2.41	2.08	2.61	2.65	2.45	Earnings per sh A	2.50
1.40	1.41	1.48	1.56	1.67	1.75	1.80	1.82	1.75	1.54	1.60	1.68	1.72	1.78	1.84	1.88	1.88	1.88	Div'd Decl'd per sh B ■	1.88
4.81	4.65	4.99	8.39	6.74	4.73	8.26	6.47	6.12	6.58	5.09	5.16	5.63	4.85	4.15	4.25	2.90	3.10	Cap'l Spending per sh	3.25
16.01	15.86	16.10	16.85	17.71	19.38	19.37	19.38	16.73	17.22	17.92	18.77	19.42	20.11	20.61	21.09	21.90	22.45	Book Value per sh C	24.50
28.44	29.33	30.29	31.50	32.42	36.91	37.43	37.89	38.53	33.10	42.05	44.78	45.13	45.54	48.00	48.51	48.51	48.51	Common Shs Outst'g D	48.51
5.2	7.1	7.6	5.9	7.8	9.8	11.4	8.5	9.3	11.6	10.6	11.9	13.1	10.7	12.3	9.7	Bold figures are	Value Line	Avg Ann'l P/E Ratio	10.5
.63	.78	.84	.55	.63	.66	.76	.71	.70	.85	.68	.72	.77	.70	.82	.61	estimates		Relative P/E Ratio	.75
12.9%	12.5%	10.6%	11.0%	8.5%	7.0%	8.0%	11.5%	9.9%	8.3%	7.7%	6.8%	5.8%	6.9%	7.2%	7.4%			Avg Ann'l Div'd Yield	7.3%

1181.1	1202.7	1289.4	1258.6	1319.7	1411.8	1482.3	1548.6	1628.5	1666.3	1760	1600	Revenues ($mill)	1700
86.7	84.2	90.1	71.6	94.7	107.3	118.2	125.0	112.3	141.5	145	130	Net Profit ($mill)	135
33.8%	24.9%	26.7%	28.1%	16.5%	9.9%	22.8%	30.3%	37.2%	38.3%	38.0%	38.0%	Income Tax Rate	38.0%
20.2%	27.2%	11.6%	11.1%	9.5%	7.3%	5.5%	6.0%	4.2%	1.6%	1.0%	1.0%	AFUDC % to Net Profit	1.0%
47.9%	50.3%	52.3%	54.6%	53.8%	50.7%	53.7%	50.1%	49.1%	46.1%	46.0%	43.0%	Long-Term Debt Ratio	39.0%
42.2%	38.2%	35.5%	34.1%	35.7%	39.0%	37.0%	40.4%	41.8%	44.5%	46.5%	49.0%	Common Equity Ratio	54.0%
1718.9	1922.0	1814.7	1966.7	2111.4	2152.4	2368.0	2269.4	2364.7	2296.5	2290	2210	Total Capital ($mill)	2260
2108.0	2278.3	2399.5	2529.1	2611.0	2720.0	2844.6	2930.0	2955.6	2956.6	2860	2770	Net Plant ($mill)	2475
7.1%	6.5%	7.5%	6.4%	7.1%	7.5%	7.0%	7.5%	7.0%	8.2%	8.5%	8.0%	% Earned Total Cap'l	8.0%
9.7%	8.8%	10.4%	8.9%	9.7%	10.1%	10.8%	11.0%	9.3%	11.4%	11.5%	10.5%	% Earned Net Worth	10.0%
10.1%	9.5%	11.2%	9.2%	10.2%	10.8%	11.7%	11.9%	9.8%	12.3%	12.0%	11.0%	% Earned Com Equity E	10.5%
.8%	2%	.9%	.5%	2.0%	2.5%	2.9%	3.2%	1.2%	3.5%	3.5%	2.5%	% Retained to Com Eq	3.0%
93%	98%	94%	95%	84%	80%	78%	76%	69%	75%	73%	79%	% All Div'ds to Net Prof	75%

CAPITAL STRUCTURE as of 3/31/97
Total Debt $1379.6 mill. Due in 5 Yrs $592.8 mill.
LT Debt $1056.6 mill. LT Interest $94.6 mill.
(LT interest earned: 3.4x)
Leases, Uncapitalized Annual rentals $22.8 mill.
Pension Liability None in '96 vs. $42.7 mill. in '95
Pfd Stock $211.0 mill. Pfd Div'd $15.3 mill.
1,230,000 shs: 4.25%-8.25%, cum., redeemable at $102.80-$103.625. Incl. 380,000 shs. 7.27%, cum., subj. to mand. redemp. at $102.91. Excl. redemp. & issuance costs & pfd. stock due within one year. Incl. 400,000 shs. 8.25% redeemed 6/1/97.
Common Stock 48,514,973 shs. as of 5/12/97

ELECTRIC OPERATING STATISTICS

	1994	1995	1996
% Change Retail Sales (KWH)	+1.7	+1.2	+2.9
Avg. Indust. Use (MWH)	942	952	1005
Avg. Indust. Revs. per KWH (¢)	9.28	9.60	9.59
Capacity at Peak (Mw)	3484	3466	3385
Peak Load, Summer (Mw)	2798	2785	2703
Annual Load Factor (%)	58.9	60.0	63.4
% Change Customers (avg.)	+.7	-.3	+.6
Fixed Charge Cov. (%)	192	197	240

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '94-'96 to '00-'02
Revenues	-.5%	1.0%	.5%
"Cash Flow"	1.0%	3.0%	2.5%
Earnings	-.5%	5.5%	1.0%
Dividends	1.0%	2.5%	.5%
Book Value	1.5%	3.5%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1994	377.4	368.7	449.1	353.4	1548.6
1995	379.7	380.8	498.6	369.4	1628.5
1996	387.8	389.8	498.0	390.7	1666.3
1997	422.7	425	510	402.3	1760
1998	375	370	480	375	1600

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1994	.35	.44	1.46	.16	2.41
1995	.36	.48	1.46	d.22	2.08
1996	.44	.50	1.58	.09	2.61
1997	.35	.55	1.65	.10	2.65
1998	.30	.50	1.55	.10	2.45

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1993	.425	.425	.425	.425	1.70
1994	.44	.44	.44	.44	1.76
1995	.455	.455	.455	.455	1.82
1996	.47	.47	.47	.47	1.88
1997	.47	.47			

BUSINESS: Boston Edison Comany supplies electricity to an area of approximately 590 square miles in eastern Massachusetts, encompassing Boston and 39 surrounding towns and cities. Territory has a population of about 1.5 mlion; company serves approximately 658,000 customers. Discontinued steam service in '88. Revenue breakdown, '96: residential, 27% commercial, 50%; industrial, 9%; other, 14%. Generating sources, '96: nuclear, 30%; gas, 19%; oil, 9%; purchased, 42%. Fuel costs: 33% of revenues. '96 reported deprec. rate: 3.3%. Est'd plant age: 8 years. Has 3,400 employees, 35,600 stockholders. Chairman, President & C.E.O., Thomas J. May, Inc.: MA. Address: 800 Boylston Street, Boston, MA 02199. Tel.: 617-424-2000. Internet: http://www.bostonedison.com

Boston Edison is cose to filing a regulatory settlement. The agreement with the state attorney general still hasn't been signed, but we expect a filing with the Massachusetts Department of Public Utilities (DPU) later this nonth.

The settlement wold provide a transition to competitin ... Boston Edison would reduce its rate 10% at the start of 1998, or whenever cutomers get to choose their electricity suppier. It would recover stranded investment through an access charge on customen' bills. The utility would divest its fossi generation. The return on equity would be set at 8% initially, but it probably wouldbe 1.25%-1.5% higher by the time customer choice begins, because *Boston Edison would get credit* for mitigating some straded investment. The distribution operation would remain regulated, with an ROE cap of 12.5%. The DPU, which has approved a similar settlement for another utilty, might issue an order by the end of thethird quarter.

... but it would hur earnings. Despite the fact that the utilitywould recoup all of its stranded investmen, the effects of the 10% rate cut and the ower allowed ROE probably would result in an earnings decline. We estimate that 1998 profits would fall about 5%-10%, to $2.40-$2.50 a share.

Boston Edison wants to form a holding company. It has received the go-ahead from shareholders, and assuming that the DPU approves, the new structure could be in place by yearend. This would enable the company to separate its nonutility ventures (partnerships with gas and telecommunications providers) from its regulated utility operations.

Finances are improving. The fixed charge coverage is only slightly below the industry average, and the common equity ratio has increased significantly since the early 1990s. We have raised the company's Financial Strength rating from B to B+.

Although this stock offers an above-average yield, we think better selections are available elsewhere. The dividend appears secure, but unless Boston Edison's nonutility ventures increase the company's earnings materially, we project no dividend hike over the 3- to 5-year period. Also, the ultimate effects of regulatory restructuring are still uncertain.

Paul E. Debbas, CFA *June 13, 1997*

(A) Excl. nonrecurring gain (loss): '89, ($2.78); '90, 41¢. Incl. restructuring charge: '95, 44¢. Next earnings report due late July. (B) Next div'd meeting about June 26. Goes ex about July 8. Approx. div'd payment dates: 1st of Feb., May, Aug., Nov. ■ Div'd reinvestment plan available. (C) Incl. deferred charges. In '96: $241.7 mill., $4.98/sh. (D) In millions, adj. for split. (E) Rate base: Net original cost. Rate allowed on common equity in '95: 11.75%; earned on avg. com. eq., '96: 12.4%. Regulatory Climate: Average.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	80

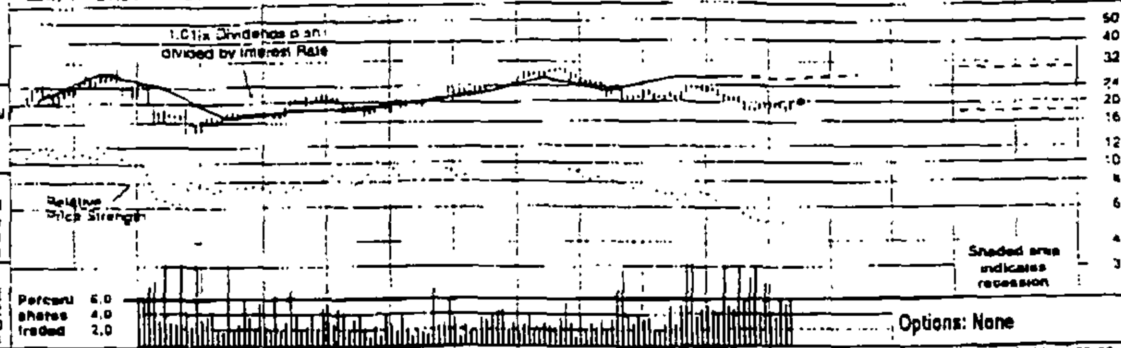
ROCHESTER G. & E. NYSE-RGS

RECENT PRICE 20 | P/E RATIO 8.7 (Trailing: 8.8, Median: 11.0) | RELATIVE P/E RATIO 0.53 | DIV'D YLD 9.0-6.0% | VALUE LINE 191

TIMELINESS 3 Average (Relative Price Performance Next 12 Mos.)
SAFETY 3 Average (Scale: 1 Highest to 5 Lowest)
BETA .65 (1.00 = Market)

High:	29.9	25.9	18.3	22.1	21.8	23.9	25.3	29.8	28.4	24.1	23.8	20.4
Low:	21.3	14.3	14.8	17.0	16.9	17.8	21.0	24.1	19.9	20.0	17.9	18.0

Target Price Range 2000 | 2001 | 2002



2000-02 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+50%)	17%
Low	18	(-10%)	6%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	1	0	0	0	0
Options	0	0	0	0	0	0	9	0	0
to Sell	0	0	1	0	0	0	0	0	0

Institutional Decisions

	3Q1996	4Q1996	1Q1997
to Buy	40	40	32
to Sell	34	38	50
Hld's(000)	11738	11222	10624

1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	© VALUE LINE PUB., INC.	00-02
31.29	31.01	30.98	30.53	26.08	25.60	24.28	25.14	27.06	26.44	26.58	25.64	25.71	26.57	26.43	27.13	*27.80*	*27.95*	Revenues per sh	*31.75*
5.71	5.15	5.42	5.23	5.34	5.08	4.92	5.14	5.24	5.00	5.15	4.75	4.72	4.58	4.53	5.45	*5.80*	*5.95*	"Cash Flow" per sh	*7.00*
2.84	2.81	3.23	3.64	3.81	3.33	2.42	2.25	2.15	1.72	1.81	1.83	2.00	1.79	1.69	2.32	*2.30*	*2.30*	Earnings per sh A	*2.25*
1.49	1.75	1.84	2.04	2.20	2.20	2.03	1.50	1.52	1.58	1.62	1.68	1.72	1.76	1.80	1.80	*1.80*	*1.80*	Div'd Decl'd per sh B ■	*1.80*
7.08	7.89	8.32	8.80	8.52	5.77	4.27	3.72	4.00	4.03	3.86	3.65	3.83	3.18	2.94	3.00	*2.65*	*3.35*	Cap'l Spending per sh	*2.75*
20.84	21.09	22.09	22.78	23.79	24.93	16.99	17.69	18.28	18.42	18.41	18.86	19.70	19.78	19.71	20.25	*20.75*	*21.25*	Book Value per sh C	*22.50*
19.61	21.99	24.41	25.68	28.50	29.25	30.12	30.79	31.26	31.42	32.10	34.92	36.91	37.67	38.45	38.85	*38.85*	*38.85*	Common Shs Outst'g D	*38.50*
4.4	5.2	5.5	4.3	5.7	7.6	7.6	7.8	9.0	11.2	11.2	12.8	13.7	12.7	13.0	8.7	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	*10.5*
.53	.57	.48	.40	.46	.52	.51	.63	.68	.83	.72	.78	.81	.83	.87	.55			Relative P/E Ratio	*.75*
11.8%	12.0%	10.4%	12.9%	10.2%	8.5%	11.0%	8.7%	7.8%	8.2%	8.0%	7.2%	6.3%	7.8%	8.2%	8.9%			Avg Ann'l Div'd Yield	*7.8%*

CAPITAL STRUCTURE as of 3/31/97
Total Debt $667.0 mill. Due in 5 Yrs $110.2 mill.
LT Debt $647.0 mill. LT Interest $47.4 mill.
(LT interest earned: 4.3x)
Leases, Uncapitalized Annual rentals $5.9 mill.

Pension Liability None
Pfd Stock $112.0 mill. Pfd Div'd $6.8 mill.
670,000 shs. 4.0% to 7.5% cum. ($100 par), callable at $101 to $105; 550,000 shs. 6.60%-7.65% cum., subject to mandatory redemption beginning 9/1/97. Excl. pfd. stock due within one year.
Common Stock 38,851,464 shs.
as of 4/30/97

1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998		00-02
731.5	774.0	845.7	830.9	853.3	895.5	949.0	1000.8	1016.3	1054.0	*1080*	*1085*	Revenues ($mill)	*1095*
80.2	78.1	72.8	59.9	64.6	70.4	78.8	74.4	71.9	97.5	*95.0*	*95.0*	Net Profit ($mill)	*85.0*
32.4%	33.9%	32.5%	34.8%	33.9%	35.9%	33.5%	37.7%	40.7%	40.4%	*38.5%*	*40.5%*	Income Tax Rate	*40.5%*
9.6%	5.0%	5.9%	9.0%	5.5%	3.3%	2.4%	3.2%	4.8%	2.2%	*1.0%*	*1.0%*	AFUDC % to Net Profit	*1.0%*
57.3%	55.3%	53.4%	51.6%	48.4%	45.8%	47.2%	45.9%	44.9%	41.9%	*40.0%*	*40.0%*	Long-Term Debt Ratio	*42.5%*
34.7%	38.0%	39.9%	41.4%	42.5%	45.8%	45.9%	46.5%	47.5%	50.9%	*54.5%*	*55.0%*	Common Equity Ratio	*53.5%*
1474.8	1434.6	1433.2	1397.5	1390.2	1438.4	1583.9	1602.3	1596.1	1545.5	*1475*	*1495*	Total Capital ($mill)	*1450*
1474.8	1510.1	1546.3	1580.0	1604.8	1629.3	1668.5	1686.9	1671.0	1660.4	*1625*	*1615*	Net Plant ($mill)	*1450*
7.9%	7.8%	7.5%	6.6%	6.9%	7.0%	6.7%	6.3%	6.2%	7.9%	*8.0%*	*7.5%*	% Earned Total Cap'l	*7.5%*
12.7%	11.5%	10.9%	8.9%	9.0%	9.0%	9.4%	8.8%	8.2%	10.9%	*10.5%*	*10.5%*	% Earned Net Worth	*10.0%*
14.1%	12.6%	11.7%	9.3%	9.8%	9.4%	9.8%	9.0%	8.5%	11.4%	*11.0%*	*11.0%*	% Earned Com Equity E	*10.5%*
3.3%	4.2%	3.6%	.9%	1.2%	1.1%	1.4%	2%	NMF	2.6%	*2.5%*	*2.5%*	% Retained to Com Eq	*2.5%*
79%	70%	72%	91%	89%	90%	87%	98%	105%	79%	*80%*	*80%*	% All Div'ds to Net Prof	*79%*

ELECTRIC OPERATING STATISTICS

	1994	1995	1996
% Change Retail Sales (KWH)	+.2	-2.8	+.3
Avg. Indust. Use (MWH)	1358	1451	1504
Avg. Indust. Revs. per KWH (¢)	8.08	8.01	7.63
Capacity at Peak (Mw)	1600	1619	1617
Peak Load, Summer (Mw)	1374	1425	1305
Annual Load Factor (%)	58.8	57.8	61.9
% Change Customers (yr-end)	+.6	+.8	+.2
Fixed Charge Cov. (%)	289	288	305

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '94-'96 to '00-'02
Revenues	-.5%	--	3.0%
"Cash Flow"	-.5%	-1.0%	6.5%
Earnings	-6.0%	.5%	2.5%
Dividends	-2.0%	2.5%	Nil
Book Value	-2.0%	1.5%	2.0%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1994	310.1	217.1	229.9	243.7	1000.8
1995	281.1	219.6	245.1	270.5	1016.3
1996	309.2	235.6	234.8	274.4	1054.0
1997	314.8	*240*	*250*	*275.2*	*1080*
1998	*320*	*240*	*250*	*275*	*1085*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1994	.87	.20	.09	.63	1.79
1995	.75	.34	.65	d.05	1.69
1996	1.05	.25	.49	.52	2.32
1997	1.02	*.25*	*.55*	*.48*	*2.30*
1998	*1.00*	*.25*	*.55*	*.50*	*2.30*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1993	.43	.43	.43	.43	1.72
1994	.44	.44	.44	.44	1.76
1995	.45	.45	.45	.45	1.80
1996	.45	.45	.45	.45	1.80
1997	.45	.45			

BUSINESS: Rochester Gas and Electric Corporation produces and distributes electricity (67% of revenues) and distributes gas (33%) in parts of nine counties centering around Rochester, New York. Service area population: about 1,000,000. Electric (gas) revenue breakdown, '96: residential, 38% (73%); commercial, 31% (15%); industrial, 22% (2%); other utilities, 2%; other, 9% (10%). Generating sources, '96, nuclear, 50%; coal, 18%; hydro & other, 3%; purchased, 29%. Fuel costs: 27% of revenues. '96 reported depreciation rate: 3.0%. Estimated plant age: 13 years. Has 1,960 employees, 33,675 stockholders. Chairman & C.E.O.: Roger W. Kober. President & C.O.O.: Thomas S. Richards. Inc.: NY. Address: 89 East Avenue, Rochester, NY 14649-0001. Tel.: 716-546-2700.

Rochester Gas and Electric has reached a regulatory settlement with the staff of the New York State Public Service Commission and some intervenor groups. Under the agreement, through mid-2002 the utility's electric rates would be lowered by a total of $72.1 million over and above rate reductions that were specified in a previous settlement. Customers would gradually get the right to choose their electricity supplier, beginning in mid-1998, with all ratepayers having their choice by mid-2002. RG&E would have an opportunity to recover its stranded costs, but not a guarantee of recovery. If the return on equity exceeds 11.8% over the life of the agreement, half of the excess would be used to reduce regulatory assets or stranded costs. The commission must still approve the settlement; its decision is expected by the end of the third quarter.

The rate reductions are necessary, but RG&E must find a way to offset their effects on earnings. The utility's rates are high, and although it hasn't lost any electric customers, it has had to forgo some revenue through discounted prices and avoidance of performance awards. The effects of lower rates would be minimal in the short run, but they would reduce share earnings by $0.40 in 2001. We assume in our projections that the settlement is adopted, and that the company will be able to offset most of the effects of the rate cuts through modest sales growth, cost control, and share repurchases.

A dividend reduction isn't necessarily imminent, but it can't be ruled out either. If RG&E can reach our earnings estimates of $2.30 a share in 1997 and 1998, then the payout ratio will be 80%. That's high, but it isn't high enough to make the dividend unsustainable at the current level. Still, because RG&E's dividend policy states that increased competition and uncertainty "will require consideration ... of a dividend payout ratio that is lower over time", a dividend cut is possible.

This stock is unsuitable for most utility investors. If the dividend holds at the current level, then speculative accounts should benefit from the high yield. But other investors should avoid these shares due to the uncertainty surrounding the dividend and the effects of competition.

Paul E. Debbas, CFA *June 13, 1997*

(A) Excludes nonrecurring losses: '85, 27¢; '87, $8.07; '89, 5¢; '91, 21¢. Next earnings report due late July. '96 earnings don't add to total due to rounding. (B) Next div'd meeting about June 17. Goes ex about June 26. Approximate div'd payment dates: 25th of Jan., Apr., July, Oct. ■ Div'd reinvestment plan available. (C) Incl. deferred debs. In '96: $450.6 mill., $11.60/sh. (D) In millions. (E) Rate base: Net original cost. Rate allowed on com. eq. in '93: 11.5%; earned on average com. eq., '96: 11.4%. Regulatory Climate: Below Average.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	35
Earnings Predictability	70

Duquesne Light Company
Comparable Group Criteria

Company	Total Capitalization ---($ Million)--- (a)	Revenue from Electricity ---(Percent)--- (b)
Atlantic Energy, Inc.	$ 1,800.3	100 %
Baltimore Gas & Electric Co.	5,960.4	70
Carolina Power & Light Co.	5,359.9	100
Dominion Resources, Inc.	10,476.0	91
Duke Power Co.	9,110.8	92
GPU, Inc.	6,741.7	100
IES Industries	1,365.9	59
PECO Energy Co.	9,308.5	90
PP&L Resources, Inc.	6,179.0	100 [1]
Public Service Enterprise Group	10,527.0	65
Average	$ 6,682.9	86.7 %

[1] Based on 1994 data.

Source: *Utility Compustat II,* Standard & Poor's Compustat Services, Inc.

Duquesne Light Company
Annual DCF, Comparable Group of Companies

Company	Dividends Paid Q2 '96	Q3 '96	Q4 '96	Q1 '97	Dividend Sum (D_0)	Average Adjusted Price (P_0) [1]	B*R+S*V Growth [2]	EPS Growth Estimate [3]	Average Growth (g)	DCF Cost of Equity [4]
	(Dollars)						(Percent)			
					[(a)+(b)+(c)+(d)]					
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Atlantic Energy, Inc.	$ 0.39	$ 0.39	$ 0.39	$ 0.39	$ 1.54	$ 17.03	3.50 %	8.06 %	5.78 %	15.85 %
Baltimore Gas & Electric Co.	0.39	0.40	0.40	0.40	1.59	26.42	5.81	9.03	7.42	14.22
Carolina Power & Light Co.	0.46	0.46	0.47	0.47	1.85	35.58	2.61	3.11	2.86	8.49
Dominion Resources, Inc.	0.65	0.65	0.65	0.65	2.58	37.29	3.24	5.72	4.48	12.09
Duke Power Co.	0.51	0.53	0.53	0.53	2.10	46.06	4.94	3.49	4.22	9.22
GPU, Inc.	0.49	0.49	0.49	0.49	1.94	33.16	5.43	8.71	7.07	13.66
IES Industries	0.53	0.53	0.53	0.53	2.10	30.03	2.82	3.73	3.27	10.88
PECO Energy Co.	0.44	0.44	0.45	0.45	1.77	22.70	3.40	2.63	3.01	11.47
PP&L Resources, Inc.	0.42	0.42	0.42	0.42	1.67	21.65	2.87	0.48	1.68	9.94
Public Service Enterprise Group	0.54	0.54	0.54	0.54	2.16	26.34	2.91	2.96	2.93	11.82
	$ 0.48	$ 0.48	$ 0.48	$ 0.48	$ 1.93	$ 29.62	3.75 %	4.79 %	4.27 %	11.76 %

[1] Equals the June 16, 1997 closing stock price adjusted for the ex-dividend date.
[2] B*R+S*V uses a five year average of S, multiplied by current V.
[3] Calculated using 1996 and five year projected data.
[4] Annual DCF equals $[D_0*(1+g)/P_0/(1-5.00\%)+g]$.

Sources: *Utility Compustat II,* Standard & Poor's Compustat Services, Inc.
The Value Line, Investment Survey, Edition 1, June 13; 1997, Edition 5, April 11, 1997 and Edition 11, May 23, 1997.
Factset Security Price History Report.

Our DCF model; Van Jeschke's proxy group excluding companies with negative projected EPS growth

Duquesne Light Company
Average Adjusted Stock Price
Comparable Group of Companies

Company	Average Stock Price [1]	Last Dividend Paid	Average Adjusted Price
	(Dollars)		
			[(a)-(b)/2]
	(a)	(b)	(c)
Atlantic Energy, Inc.	$ 17.22	$ 0.39	$ 17.03
Baltimore Gas & Electric Co.	26.62	0.40	26.42
Carolina Power & Light Co.	35.82	0.47	35.58
Dominion Resources, Inc.	37.61	0.65	37.29
Duke Power Co.	46.32	0.53	46.06
GPU, Inc.	33.40	0.49	33.16
IES Industries	30.29	0.53	30.03
PECO Energy Co.	22.92	0.45	22.70
PP&L Resources, Inc.	21.86	0.42	21.65
Public Service Enterprise Group	26.61	0.54	26.34
			$ 29.62

[1] Average of weekly (Friday) close prices from July 17, 1996 to July 11, 1997.

Sources: *The Value Line Investment Survey,* Edition 1, June 13, 1997; Edition 5, April 11, 1997 and Edition 11, May 23, 1997.
Factset Security Price History Report.

Duquesne Light Company
Sustainable Growth, Comparable Group of Companies

Company	R Estimated Return on Common Equity [1]	D_r Estimated Dividend [2]	V_e Estimated Book Equity [2]	V Book Equity Per Share 1996	V Book Equity Per Share 1995	R_{av} Return on Average Equity [3]	B [4]	B*R [5]	Average S*V [6]	B*R+S*V
	----(Percent)----	(Dollars)				(Percent)				
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Atlantic Energy, Inc.	9.5 %	$ 1.00	$ 17.00	$ 15.00	$ 15.48	9.35 %	37.09 %	3.47 %	0.03 %	3.50 %
Baltimore Gas & Electric Co.	12.0	1.78	24.15	19.35	19.06	12.09	39.03	4.72	1.09	5.81
Carolina Power & Light Co.	13.0	2.14	22.20	17.77	16.93	13.32	27.60	3.68	-1.06	2.61
Dominion Resources, Inc.	10.5	2.58	30.50	27.17	26.88	10.56	19.87	2.10	1.14	3.24
Duke Power Co.	13.0	2.50	31.30	24.25	23.36	13.24	39.69	5.26	-0.31	4.94
GPU, Inc.	11.5	2.20	32.50	25.27	24.70	11.63	41.80	4.86	0.57	5.43
IES Industries	10.5	2.10	22.75	20.84	20.75	10.52	12.28	1.29	1.53	2.82
PECO Energy Co.	11.0	1.84	23.70	20.87	20.39	11.13	30.23	3.36	0.04	3.40
PP&L Resources, Inc.	11.0	1.67	19.00	16.88	16.29	11.19	21.47	2.40	0.47	2.87
Public Service Enterprise Group	11.5	2.22	25.25	22.33	22.25	11.52	23.68	2.73	0.18	2.91
	11.4 %	$ 2.00	$ 24.84	$ 20.97	$ 20.61	11.45 %	29.27 %	3.39 %	0.37 %	3.75 %

[1] 2000-2002 estimate.
[2] 2000-2002 estimated per share dividends and book value.
[3] $R_{av}=(2*R*V_{96})/(V_{96}+V_{95})$.
[4] $B=1-(D_e/(R_{av}*V_e))$.
[5] $B*R=B*R_{av}=(R_{av}-D_e/V_e)$.
[6] S*V equals five year average of S, multiplied by current V, where S = annual growth rate of common shares outstanding and V = fraction of new funds provided that accrues to original shareholders.

Sources: *Utility Compustat II*, Standard & Poor's Compustat Services, Inc.
The Value Line, Investment Survey, Edition 1, June 13; 1997, Edition 5, April 11, 1997 and Edition 11, May 23, 1997.

Duquesne Light Company
S and V Data, Comparable Group of Companies

Company	S 1992	1993	1994	1995	1996	Average S[1]	V [2]	S*V
								[(f)*(g)]
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Atlantic Energy, Inc.	0.0203	0.0194	0.0073	-0.0334	0.0000	0.0027	0.1011	0.0003
Baltimore Gas & Electric Co.	0.1570	0.0215	0.0123	0.0001	0.0013	0.0384	0.2837	0.0109
Carolina Power & Light Co.	0.0000	0.0000	-0.0414	-0.0486	-0.0107	-0.0201	0.5274	-0.0106
Dominion Resources, Inc.	0.0472	0.0452	0.0400	0.0335	0.0340	0.0400	0.2853	0.0114
Duke Power Co.	0.0000	0.0000	0.0000	0.0000	-0.0316	-0.0063	0.4958	-0.0031
GPU, Inc.	0.0000	0.0514	0.0000	0.0582	0.0000	0.0219	0.2605	0.0057
IES Industries	0.0220	0.1569	0.0169	0.0251	0.0216	0.0485	0.3148	0.0153
PECO Energy Co.	0.0030	0.0069	0.0005	0.0034	0.0024	0.0033	0.1105	0.0004
PP&L Resources, Inc.	0.0025	0.0027	0.0273	0.0312	0.0282	0.0184	0.2548	0.0047
Public Service Enterprise Group	0.0496	0.0543	0.0053	0.0000	-0.0536	0.0111	0.1639	0.0018
						0.0158	0.2798	0.0037

[1] Average of five most recent years.
[2] V = (1-(1995 Book Value per Share/Average Stock Price)).

Sources: *Utility Compustat II,* Standard & Poor's Compustat Services, Inc.
Factset Security Price History Report.

Duquesne Light Company
EPS Growth Estimate

Company	EPS 1996	EPS 2000-2002 Estimated	Estimated Growth [1]
	---------(Dollars)--------		--(Percent)--
	(a)	(b)	(c)
Atlantic Energy, Inc.	$ 1.12	$ 1.65	8.06 %
Baltimore Gas & Electric Co.	1.85	2.85	9.03
Carolina Power & Light Co.	2.66	3.10	3.11
Dominion Resources, Inc.	2.65	3.50	5.72
Duke Power Co.	3.37	4.00	3.49
GPU, Inc.	2.47	3.75	8.71
IES Industries	2.04	2.45	3.73
PECO Energy Co.	2.24	2.55	2.63
PP&L Resources, Inc.	2.05	2.10	0.48
Public Service Enterprise Group	2.42	2.80	2.96
	$ 2.29	$ 2.88	4.79 %

[1] Growth equals [(2000-2002 estimate/1996 actual)^0.20]-1.

Sources: *Utility Compustat II,* Standard & Poor's Compustat Services, Inc.
The Value Line, Investment Survey, Edition 1, June 13, 1997; Edition 5, April 11, 1997 and Edition 11, May 23, 1997.

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FOUR COMMON ERRORS IN APPLYING THE DCF MODEL IN UTILITY RATE CASES

By

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The DCF model, properly used, is an objective tool that can be used to obtain objective results. Despite the questions raised by its detractors, the DCF model remains an attractive and easily understood method for determining the fair rate of return on equity.

Over the past two decades, the "Discounted Cash Flow" model (DCF) has emerged as the primary tool for determining the fair rate of return on equity for utilities in the United States. It is referenced in the documents of most regulatory commissions and in their decisions. Despite this apparent acceptance, the use of the DCF model and its results remain controversial.

Much of the disagreement in utility rate cases involves judgmental questions regarding the use of *empirical* data. This sort of disagreement is not surprising. Disagreement over the *theoretical* construction of the DCF model, however, is largely unnecessary. The DCF model, properly used, is an objective tool that can be used to obtain objective results. Despite the questions raised by its detractors, the DCF model remains an attractive and easily understood method for determining the fair rate of return on equity. In short, it is a good tool that is often used poorly.

The appeal of the DCF model is its relative simplicity, though that simplicity leads to the kinds of application errors that we will examine here. The way that utilities pay dividends and issue new stock requires adjustments to the basic model in order for the DCF model to be used correctly in rate of return proceedings.

After a brief description of the basic DCF model, we will describe what we observe to be four of the most common errors in applying the model that needlessly contribute to rate of return discord. These errors are the "Ex-Dividend Date" Error, the "Current Dividend Yield" Error, the "Sustainable Growth" Error, and the "Flotation Cost" Error.

The Basic DCF Model

The DCF methodology grew out of Professor Myron J. Gordon's work on stock valuation models that was first published in complete form in 1962.[1] According to the model, investors view a company as a money machine that produces dividends on a quarterly basis. At the end of each quarter, some of the earnings that have accrued over that quarter are retained by the company to create future earnings. The rest are paid out as dividends and the process begins anew. To investors, the value of a share of stock is the dividends it will pay out during the period the investor holds the stock, plus any capital appreciation earned at the time the stock is sold. The DCF model estimates the "cost of equity" by computing the discount rate that equates a stock's current market price with the present value of all future expected dividends and capital gains. Stated simply, the DCF methodology shows that a firm's cost of equity is equal to its dividend yield (dividend per share divided by stock price) plus its expected long-term dividend growth rate. This equation, known in the financial literature as the "periodic" DCF model, can be found in Appendix A.

To investors, the value of a share of stock is the dividends it will pay out during the period the investor holds the stock, plus any capital appreciation earned at the time the stock is sold.

Like most theoretical models, the DCF employs assumptions, not all of which hold true in the real world. While these theoretical abstractions from the real world are almost always necessary in practice, it is important to distinguish between those assumptions that do not bias the calculated result over time and those that *do*. The latter type, which are the source of the four most common DCF errors we observe and describe here, are easy to remedy.

The "Ex-Dividend" Date Error

The DCF model requires the measurement of a current stock price as one of its inputs. It assumes that the stock price will be observed *on the "ex-dividend" date*. The ex-dividend date is the date upon which the right to the next dividend (to be paid out a few days hence) no longer accompanies a share of stock. In other words, an investor who purchases a share of stock on the ex-dividend date will have to wait a full quarter (90 days) before receiving a dividend payment.

If the stock price is measured on any other date, or if an average stock price is used in the DCF equation, the resulting cost of equity calculation will be too low. To understand why this is so, consider again the money machine analogy. At the beginning of a new quarter—that is,

[1] See: Gordon, Myron J., *The Investment, Financing and Valuation of the Corporation*, Richard D. Irwin Inc., 1962.

immediately after the previous dividend was paid—a company begins to accrue new earnings (and therefore potential dividends) and its market value increases. The DCF model assumes that these potential dividends accrue evenly throughout the quarter. On the day it pays out dividends, we would expect the market value of the firm (i.e., its stock price) to drop. In fact, stock prices do indeed drop by an amount approximately equal to the quarterly dividend on the ex-dividend date.[2]

. . . it is important to distinguish between those assumptions that do not bias the calculated result over time and those that *do*.

According to the basic DCF model, the stock price should be measured when the next dividend is one *full* quarter away, on the ex-dividend date. If the stock price is measured a week after the ex-dividend date, then seven days of potential dividends will have accrued and the observed stock price will be slightly higher (by approximately the amount of the accrued portion of the quarterly dividend). The basic DCF model misinterprets this slightly higher stock price not merely as a soon-to-occur dividend payment date, but rather as a lower discount rate—i.e., a lower cost of equity capital. This downward bias, while different in each case, can mean roughly $1 to $2 million *per year* in equity return for an average electric utility, depending on the equity component of rate base.[3]

This error is easy to remedy by referring to the ex-dividend date of the company in question. The remedy can take one of three forms. Either: (1) use the traditional DCF model but measure stock prices only on the ex-dividend date; (2) alter the traditional DCF model to account for the nearer dividend payment at the time the price is measured; or (3) use the traditional DCF model at any date or average of dates but remove from the observed stock price the effect of nearer dividend payments.

We consider the third option the easiest and most applicable to utility rate cases, where the need for current information makes it undesirable to wait until the ex-dividend date to measure the stock price. This method makes use of the fact that the stock price accrues the next anticipated dividend in

2 A discussion of the importance of the ex-dividend date appears in most financial texts. As an example, see: E.F. Brigham, *Financial Management Theory and Practice, 3rd Edition*, 1982, page 687.

3 The ex-dividend date adjustment has recently been adopted as a regular component of the fair rate of return in proceedings before the New York Public Service Commission. It was first instituted in Opinion 90-29 (Brooklyn Union Gas Company), where it was proposed by Dr. Makholm.

a generally linear fashion, meaning that halfway between ex-dividend dates, approximately half of the next anticipated dividend is embedded in the observed stock price. It is possible, therefore, to use a stock price observed on any date if that stock price is reduced by the amount of the next dividend that has already been capitalized into the stock price. The third option removes that proportion of the next expected dividend from the stock price. This modification to the DCF model, which removes the effect of accrued dividends, can be found in Appendix B.

The Current Dividend Yield Error

Many rate of return analysts (including those at the FERC who employ the agency's "generic" rate of return formula) use a "hybrid" of the traditional DCF model that causes a mathematical understatement of the cost of equity, on average.[4] This error is due to the incorrect estimation of the next period's dividend yield in the traditional DCF model.

The correct way to calculate the expected dividend payments over the next year is to observe the *past* period's dividend payments and to multiply them by the expected long-term dividend growth rate. However, many analysts incorrectly use the "current" dividend yield published in the trade press (the latest quarterly dividend multiplied by four and divided by the current price) and multiply it by *half* the expected growth rate to get next period's dividend. The reasoning behind this hybrid DCF model is that if the "past" dividend yield is simply the sum of the four previous dividends divided by the stock price and the "future" dividend yield is the same period's dividend multiplied by one plus the growth rate, then the "current" dividend yield must be halfway between the two (i.e., the current yield and half of the growth rate). This is incorrect and leads to an understatement of the cost of equity capital, on average.

The following example shows this[5]: A hypothetical company has the following characteristics at its ex-dividend date:

Current price	=	$20
Expected dividend growth	=	5 percent
Latest quarterly dividend	=	$0.40

[4] We should note that, just recently, the FERC discontinued its practice of relying on a generic rate of return calculation.

[5] A more rigorous mathematical proof of Dr. Makholm's shows that the dividend yield understatement is equal to $g(1/2)\ D_{t-1}$, or one-half of the last dividend multiplied by the rate of growth.

The *current* dividend yield in this scenario is 8.0 percent [(4 x .40)/20]. Using the current dividend yield approach, one would then increase this figure by one-half of the expected growth rate to get the *next* period's dividend yield of 8.2 percent (8.0 x [1 + (.05/2)])

We expect, however, that sometime during the next year the $0.40 dividend will increase by the 5 percent expected growth rate to $0.42 (.40 x 1.05). This could occur during any one of the four quarterly dividend periods. The following table shows what happens to the expected dividend yield under the four alternate scenarios:

Table 1: Use of Current Yield Understates Expected Dividend Yield

Dividend of $0.40 increases to $0.42:	Expected Dividend	Expected Dividend Yield	Current Dividend Yield	Difference
1st quarter hence	$1.68	8.4%	8.2%	0.2%
2nd quarter hence	$1.66	8.3%	8.2%	0.1%
3rd quarter hence	$1.64	8.2%	8.2%	----
4th quarter hence	$1.62	8.1%	8.2%	-0.1%
Average		8.25%	8.2%	0.05%

The example shown in Table 1 demonstrates that, on average, the "current dividend yield" method understates the true expected dividend yield by .05 percent. While this expected error seems small, it is an assured bias in the calculated result and is easily avoided by using the last period's dividends multiplied by the expected dividend growth rate. In addition, this "small" understatement can cost the average utility over $1 million per year in equity return.

The Sustainable Growth Error

Since the DCF dividend growth rate cannot be observed directly because it exists in the minds of investors, one of the most popular methods for estimating it is the "sustainable growth" or "plowback" method. This method produces a forward-looking sustainable growth rate by multiplying the fraction of earnings a company expects to retain by the expected return on book equity. This is a valid method of estimating future dividend growth since growth in the dividends can only occur if a portion of the expected equity return is reinvested instead of being paid out as dividends.

The basic DCF model assumes that the only source of equity financing is the retention of earnings. In practice, however, the issuance and sale of new common stock at prices *in excess of book value* can also be a source of earnings growth for existing shareholders. If shares are sold when the price is above book value, a portion of the funds go to current shareholders as share appreciation.

. . . the issuance and sale of new common stock at prices *in excess of book value* can also be a source of earnings growth for existing shareholders.

The failure to recognize this second source of growth most often results in a significant understatement of the investors' expected growth rate. That is, if investors expect this additional growth and that expectation is reflected in what they pay for a share of stock, and if a rate of return analyst fails to take this source of growth into account when applying the retention growth formula, then the calculated cost of capital is too low.

It is, of course, possible for utilities to issue new shares at prices either *above or below* book value. In practice, however, it is considerably more likely that new shares will be issued above book value rather than below. There are three reasons for this. *First*, there is an obvious reluctance on the part of utility managements to dilute share prices. They will—and do—try to avoid equity financings when stock prices are low by instead issuing debt. *Second*, a considerable amount of new utility equity takes the form of employee stock plans. When stock prices are high (that is, above book value), utilities issue *new* shares to fund these plans. When stock prices are below book value, utilities can—and do—fund these plans by purchasing *existing* shares in the market, thereby avoiding dilution. *Third*, historical stock prices reveal many more years of prices above book value than below.

If stocks are sold at a price that exceeds book value and if this is not reflected in the retention growth rate formula, then the cost of equity will be understated, on average. The size of this understatement will depend on the particular case involved but on average is likely to be in the range of $3 to $5 million *per year* of equity return.[6]

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6 This assumes that the retention growth rate is used exclusively in the DCF model.

The expanded growth rate, which incorporates growth from equity issuances at prices above book value, reduces to the standard version either when the company does not regularly sell new stock or when the new stock is sold at a price that equals book value. The formula for this growth rate can be found in Appendix C.[7]

The Flotation Cost Error

The issuance (flotation) of common equity involves both direct expenses and underwriting fees. These costs are often measured as a percentage of the total common equity issuance. Because of these issuance costs, the net proceeds of a common equity issuance will *always* be less than the total purchase price of the securities issued. If no adjustment is made in the fair rate of return to reflect these expenses, and if no other provision is made to reimburse the utility for these expenses, the resulting fair rate of return on equity calculations will be too low.[8]

Because of . . . issuance costs, the net proceeds of a common equity issuance will *always* be less than the total purchase price of the securities issued.

The DCF model can be used for calculating the proper return *on net proceeds* to compensate the utility for its issuance expenses. The only necessary change to the model is to reduce the observed stock price by an amount equal to the flotation cost percentage. This reduction is necessary because the prevailing observed stock price represents the gross proceeds to the investor, not the net proceeds to the utility. The conventional form of the issuance expense adjustment can be found in Appendix D.

This adjustment is applicable to *total* common equity (common stock plus retained earnings), not just the common stock account. Since the cash "paid in" by investors is greater than the net proceeds that the company "takes in," the company must earn a greater return on the smaller net proceeds balance to compensate investors adequately for their expected cost of capital on the "paid in" investment. But the money "paid back" to the investors in any year, the dividend, reflects only a portion of the cost of capital. The

7 A positive adjustment to the sustainable growth rate to reflect stock issuances at prices above book values has become a regular component of the fair rate of return before the New York Public Service Commission. It was first instituted in Opinion 90-29 (Brooklyn Union Gas Company), where it was proposed by Dr. Makholm.

8 A good discussion of the controversy surrounding the issuance and selling expense adjustment can be found in *Utilities Cost of Capital*, R. A. Morin, Public Utilities Reports, Inc, 1984, pp. 98-111, and in a comprehensive article on the subject in *Public Utilities Fortnightly*, May 2, 1985, entitled "Common Equity Flotation Costs and Rate Making," by Brigham, E. F. *et al.*

other portion is retained earnings, the funds used to finance future growth and future dividends. If the retained earnings account does not receive a selling and issuance return adjustment, it will not grow at a rate sufficient to allow for the payments of dividends at investors' expected growth rate in the future.

To understand this relationship better, compare two companies with the same cost of capital and issuance expense percentage. One pays out all its earnings as dividends (i.e., it retains no earnings), while the other pays no dividends (i.e., it retains all earnings). If we applied an issuance expense adjustment only on the "common stock" balance, while ignoring the retained earnings, investors in the company that retains no earnings would receive a greater return than investors in the company that retains all its earnings. This penalizes the second company, whose selling expense percentage was the same, simply because it decided to finance itself through retained earnings rather than by issuing new stock.

Conclusion

As long as rate base/rate of return regulation is the standard by which electric and gas utilities in the U.S. are regulated, there will be extensive debate regarding the "fair" rate of return. The true cost of equity capital will remain unobservable and a utility's risk will not be measured with scientific precision. The process, however, can be made somewhat less contentious if there is agreement on the proper basic DCF model as well as a proper theoretical treatment for the four problems identified here.

APPENDIX A

The Basic DCF Model

The following equation, referred to in this paper as the "Basic" DCF model, is known in the financial literature as the "periodic" DCF model:

$$k_e = \frac{D_0(1+g)}{P_0} + g \qquad (1)$$

where:
k_e = the cost of equity;
D_0 = the previous dividend paid;
g = the dividend growth rate; and
P_0 = the stock price.

APPENDIX B

The Ex-Dividend Date Adjustment

The following equation adjusts the basic DCF model to account for the ex-dividend date phenomenon:

$$\tilde{k}_e = \frac{D_0(1+g)}{\tilde{P}_0} + g \qquad (2)$$

where:
$\tilde{k}_e$ = the cost of equity adjusted for the ex-dividend date;
D_0 = the previous dividend paid;
g = the dividend growth rate; and
$\tilde{P}_0$ = the observed stock price minus the accrued dividend

$$= P_0 - \left[\frac{\text{days until next ex-dividend date}}{90}\right] * [\text{next dividend}].$$

APPENDIX C

The Expanded Growth Rate Formula That Adjusts
For The Issuances Of Equity At Prices Above Book Value

The basic DCF sustainable growth rate must be expanded to allow for continuous new equity financing. In the expanded formula, two activities are recognized: (1) investment decisions, which earn the rate of R_{av}, and (2) stock financing operations, which earn the rate $S*V$. The sustainable growth would then be:

$$g = B*R_{av} + S*V$$

where:
B = the fraction of earnings expected to be retained;
R_{av} = the expected return on average equity; (3)
S = the funds raised from the sale of stock as a fraction of existing common equity; and
V = the fraction of funds raised from the sale of stock that accrues to shareholders at the start of the period.

The $S*V$ term is a measure of the effect on current investors' expected dividend growth due to the sale of stock at prices above or below book value.

APPENDIX D

The Flotation Cost Adjustment

The following formula adjusts the basic DCF model to account for selling and issuance expenses:

$$r = \frac{D_1}{P_0(1-f)} + g$$

where:
r = the required return adjusted for issuance expenses; (4)
D_1 = the next period's dividend;
P_0 = the stock price;
f = the flotation cost percentage; and
g = the dividend growth rate.

The $(1-f)$ term represents net common equity proceeds as a percentage of gross common equity proceeds.

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E. Hollert

VOLUME IV

Duquesne Statement No. 13

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

Direct Testimony
of
Thomas LaGuardia

Contents:

Regarding Fossil and Nuclear Decommissioning Costs.

Duquesne Statement No. 13

DIRECT TESTIMONY OF THOMAS S. LAGUARDIA

I. QUALIFICATIONS

Q. Please state your name and business address.

A. Thomas S. LaGuardia, 148 New Milford Road East, Bridgewater, CT 06752

Q. What is your occupation?

A. I am President of TLG Services, Inc. (TLG)

Q. What are your responsibilities with TLG?

A. I am responsible for the technical and business management of engineering and field services in the areas of decontamination, decommissioning, waste management and general engineering for nuclear and fossil-fueled generating stations.

Q. What is your educational and professional background?

A. I completed my Bachelor of Science in Mechanical Engineering at Polytechnic Institute of Brooklyn in 1962 and my Master of Science in Mechanical Engineering at the University of Connecticut in 1968. I am a registered Professional Engineer in Connecticut (No. 10393), New York (No. 059389) and New Jersey (No. 38193). I have been actively conducting business as TLG since January 1, 1994. TLG acquired certain operating assets on January 1, 1994 from TLG Engineering, Inc. I founded

TLG Engineering in April, 1982. I was employed by Nuclear Energy Services in Danbury, Connecticut, from 1973 until I founded TLG Engineering. My prior employment was with Gulf Nuclear Fuels Corporation, formerly United Nuclear Corporation (UNC), and Combustion Engineering.

II. PURPOSE AND SCOPE

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is two-fold. First, I will present the results of the decommissioning cost studies prepared by TLG for the Beaver Valley Power Station, Units 1 and 2 (Beaver Valley), and the Perry Nuclear Power Plant Unit 1 (Perry). The primary objective in preparing these studies was to develop accurate cost estimates to decommission the nuclear units. This will allow the owners to verify the adequacy of current funding levels and, if necessary, adjust contributions to reflect current cost projections. The studies are not detailed decommissioning engineering plans and, therefore, do not commit the owners to a specific course of action for the stations following the ultimate cessation of operations.

Second, I am presenting the results of dismantling cost studies prepared by TLG for the following fossil-fueled power plants:

Station	No. of Units	Megawatts (per unit)
Cheswick	1	570 MWe
Elrama 1,2	2	100 MWe
Elrama 3	1	112 MWe
Elrama 4	1	175 MWe
Bruce Mansfield	3	825 MWe
East Lake 5	1	800 MWe
W.H. Sammis 7	1	650 MWe
Brunot Island CTs	3	25 MWe
Brunot Island CTs	3	59 MWe
Brunot Island steam	1	144 MWe

Q. What is covered by the term "decommissioning" as used with reference to the Duquesne Light generating stations?

A. Decommissioning is the planned and orderly retirement of a generating station. In the case of nuclear plant decommissioning, it requires the complete removal and controlled disposal of radioactive materials to levels prescribed by the U.S. Nuclear Regulatory Commission (NRC) and termination of the NRC license(s). The owner may then dismantle the remaining non-contaminated systems and structures. In the case of a fossil-fueled power plant, upon retirement the facility may either be rendered safe indefinitely (through on-going maintenance, repair and security measures) or dismantled. A specific discussion of public safety and dismantling is included later in this testimony.

Q. Please summarize the costs identified in the nuclear decommissioning and fossil dismantling studies.

A. Decommissioning of the two nuclear units at Beaver Valley was estimated to cost approximately $727.7 million (in 1997 dollars). Decommissioning of the Perry nuclear unit was estimated to cost at least $650 million (in 1997 dollars). The studies assume that the units will complete their fully licensed operating lives and that the stations will be completely dismantled following the removal of radioactivity. Low-level radioactive wastes were destined for the operating Barnwell Low-Level Radioactive Waste Management Facility located in South Carolina due to the uncertainties associated with the availability of both the Midwest and Appalachian Compacts. High-level waste (spent fuel) was assumed to be stored on-site until the transfer to the Department of Energy's (DOE) geologic repository could be completed.

Dismantling and demolishing of the aforementioned fossil-fired steam electric generating stations was estimated to cost approximately $274.4 million (1997 dollars). The fossil estimates address 17 units at the six sites and included the razing of site structures to grade. Each site was decommissioned upon the cessation of the final unit's operation. A credit was included for the potential value of the scrap steel and copper generated in the dismantling process.

III. EXPERIENCE

Q. Do you have experience in the design and construction of fossil-fueled generating stations?

A. Yes. During my employment with Combustion Engineering, Inc. from 1962 to 1968, I was a boiler design, performance and construction engineer for 500 megawatt electric (MWe) coal-fired power boilers and merchant and Naval oil-fired marine boilers.

Q. What decommissioning experience do you have?

A. My decommissioning experience began as site representative for UNC during the BONUS reactor decommissioning in 1969 and 1970. BONUS was a 17 MWe demonstration power reactor located in Puerto Rico that was owned by the U.S. Atomic Energy Commission (USAEC), now the U.S. Department of Energy (USDOE), and operated by the Puerto Rico Water Resources Authority. It was the largest reactor decommissioned by entombment up to that time. The program involved extensive chemical decontamination of radioactive systems, selective piping and component removal, and entombment of the reactor vessel within a massive concrete barrier. The entombment has a design life of 125 years. My role as site representative was to act as a technical liaison and provide project engineering and schedule management assistance during system decontamination, component removal, vessel entombment and facility close-out.

Following the BONUS program, I was lead engineer for UNC during the Elk River Reactor decommissioning between 1970 - 1973. Elk River was a 20 MWe demonstration power reactor located in the state of Minnesota that was owned by the USAEC and operated by United Power Association. Elk River was decommissioned by complete dismantling. The program involved segmentation of the reactor vessel and internals using remotely-operated cutting torches, as well as the packaging, shipping and controlled burial of the segments. Similarly, radioactive piping and components were removed, packaged, shipped and buried. Radioactive concrete was demolished by controlled blasting, and nonradioactive concrete was demolished by wrecking ball to completely dismantle the facility. Initially, my role for UNC was Consulting Engineer and later Lead Engineer for UNC technical support for on-site activities.

I was Project Engineer, while at Nuclear Energy Services, for the detailed engineering and planning of the Shippingport Station Decommissioning Project from 1979 - 1982. Shippingport was a 72 MWe light water breeder reactor located in the state of Pennsylvania, owned by the USDOE and operated by Duquesne Light. The facility is now dismantled, and TLG Engineering, with its joint venture partner, Cleveland Wrecking Company, dismantled all of the clean and contaminated piping and components and removed contaminated concrete. My role for TLG/Cleveland was Project Director, and I selected and managed an on-site project management team to hire and supervise work crews to accomplish the dismantling. All work was completed on schedule and within budget.

I also assisted Atomic Energy of Canada, Ltd. in the detailed engineering and planning for the decommissioning of the 238 MWe Gentilly Unit 1 reactor located in Three Rivers, Canada. My role was to provide overall decommissioning consulting services and detailed cost estimation of alternatives.

TLG Engineering worked with the Northern States Power Company between 1988-89 in the preparation of the decommissioning plan for the Pathfinder Atomic Power Plant. Pathfinder, located in Sioux Falls, S.D., was a 60 MWe reactor initially placed in a safe storage condition (SAFSTOR) after an abbreviated operating life. TLG Engineering prepared detailed cost and schedule estimates and vessel activation estimates, analyzed the reactor vessel to be used as its own shipping container, and prepared the decommissioning plan in support of plant decommissioning.

TLG Engineering has also assisted the Sacramento Municipal Utility District since 1989 with the decommissioning planning for the Rancho Seco Nuclear Generating Station. This work included a detailed reactor vessel activation analysis, preparation of decommissioning alternative cost and schedule estimates, and assistance with the preparation of the decommissioning plan originally using the SAFSTOR method and more recently reflecting the DECON method.

TLG Engineering worked with the Long Island Lighting Company in the planning for the decommissioning of the Shoreham Nuclear Power Station. This work included the preparation of a detailed reactor vessel activation analysis, cost estimates, schedules, management organization, waste volume estimates and draft decommissioning plan.

In 1990, TLG Engineering was selected by Cintichem, Inc. (a subsidiary of Hoffman-LaRoche) as Decommissioning Co-Manager of a 10 megawatt thermal (MWt) research reactor and associated hot cells and facilities. TLG's staff prepared a reactor core activation analysis as well as cost and schedule estimates for the project. TLG Engineering assisted in the preparation of the decommissioning plan, which has received NRC approval. TLG's field management staff has been on-site assisting in the project management and supervision of the work crews in decommissioning and dismantling the facility. The program is essentially complete. My role in the project was Senior Decontamination and Decommissioning Expert on the Nuclear Safeguards Committee.

TLG has also been involved in the engineering and planning activities associated with the decommissioning of the Yankee Rowe, Trojan and Big Rock Point nuclear units. This work includes activation analyses, preparation of decommissioning alternative cost and schedule estimates, and assistance with the preparation of the decommissioning plans. In addition, TLG was selected to prepare the steam generators and the pressurizer at Trojan for transport to the burial facility at Richland, WA. TLG was responsible for certifying package integrity, overseeing the grouting of the components and preparing any supporting transportation analyses. The project was successfully completed in October 1995. TLG is currently supporting Portland General Electric (PGE) in the detailed planning required for completing the decontamination and dismantling of the Trojan nuclear unit, including the intact removal and disposal of the reactor vessel and the highly radioactive internal components.

In addition, TLG prepared the decommissioning plan for Dresden Unit 1 and the Environmental Reports (ER) for Dresden Unit 1 and Indian Point Unit 1. Under my supervision and direction, TLG has prepared site-specific decommissioning studies for 80% of the nuclear units in the United States and approximately 150 fossil-fueled units.

TLG was responsible for overseeing the dismantling and demolition of a fossil-fueled steam plant for a major Connecticut hospital facility. In connection with this demolition project, I participated in the site inspection and cost estimate development. The work was subcontracted and TLG personnel supervised the contractors.

Q. Have you prepared or co-authored any studies and reports on decommissioning cost estimating and technology?

A. Yes. While at Nuclear Energy Services, I was Principal Investigator for the Atomic

Industrial Forum's National Environmental Studies Project (NESP) decommissioning study entitled "An Engineering Evaluation of Nuclear Power Reactor Decommissioning Alternatives" (AIF/NESP-009). The Atomic Industrial Forum (now NEI) is an industry supported advocate and sponsor of research to promote the advancement of nuclear power. This study evaluated the costs, schedules and environmental impacts of decommissioning 1100 MWe reactors (Pressurized Water Reactors [PWRs], Boiling Water Reactors [BWRs], and High Temperature Gas-Cooled Reactors [HTGRs]).

I also co-authored the "Decommissioning Handbook" for the USDOE. The Handbook reported the state-of-the-art in decommissioning technology (as of 1980), including decontamination, piping and component removal, vessel segmentation, concrete demolition, cost estimating and environmental impacts.

At TLG Engineering, in 1986, I co-authored "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates" (AIF/NESP-036) for the Atomic Industrial Forum's National Environmental Studies Project. The Guidelines identify the elements of costs to be included in the estimation of decommissioning activities for each of the principal decommissioning alternatives. Specific guidance in cost estimating methodology and reference cost data is provided in this study. The major objective of this study is to provide a basis for consistent cost estimating methodology.

In 1986, TLG Engineering also prepared a study for the NRC, which I co-authored, entitled, "Identification and Evaluation of Facilitation Techniques for Decommissioning Light Water Power Reactors" (published as an NRC contractor report - NUREG/CR-3587). The study evaluated the costs and benefits of techniques to reduce occupational exposure and waste volume from decommissioning.

TLG personnel also authored the paper "How to Determine the Cost of Dismantling a Fossil-Fuel Electric Power Plant" (A. Carlstrom, Cost Engineering Magazine, April, 1989).

Q. Were the decommissioning and dismantling studies prepared for the Duquesne Light generating stations prepared under your direction and supervision?

A. Yes. I developed the basic methodology used by TLG to estimate the costs to dismantle both nuclear and fossil-fueled power plants. I trained my engineering and estimating staff in this methodology.

During the preparation of the cost estimates, I provided guidance and interpretation to the TLG staff on how to estimate specific activities. I reviewed the results of each cost estimate to ensure the results were reasonable and representative of the features of each unit. Finally, I supervised the preparation of the report summarizing the results of the estimates.

Q. What was the basis for the decommissioning studies?

A. The decommissioning studies for the nuclear units were developed using detailed engineering drawings, together with plant description and inventory documents. These drawings and documents were used to identify the general arrangement of the facilities and to estimate building concrete volumes, steel quantities, the numbers and size of components, and the degree of site restoration required.

For the fossil studies, the information available on the Duquesne Light generating units was supplemented with TLG's data base for plants of similar size and type. This provided the basis for estimating the disposition of the components and structural materials addressed in the dismantling of each site.

Because decommissioning is labor-intensive, representative labor rates for the geographical region and for each craft or salaried work group are essential for a meaningful site-specific decommissioning cost estimate. Accordingly, typical craft labor rates and utility salary data were used in the estimate. This type of information is obtained from the utility's existing labor costs for the area/site.

Low-level radioactive waste, for purposes of the cost estimates, was assumed to be shipped to a operating burial facility in Barnwell, South Carolina. Since there is considerable uncertainty as to the availability of the facilities designated for the

Appalachian States and Midwest Compacts, the burial costs for radioactive materials were developed from rate schedules published for the Barnwell Low-Level Radioactive Waste Management Facility, which is a reasonable proxy for shallow land burial.

Q. For purposes of the estimate, when did you assume the units at each site would be dismantled?

A. For the fossil studies, we assumed dismantling would occur upon retirement of the last unit at each site. This approach is reasonable because it would be more difficult and costly to protect the operating units from potential damage when demolishing the retired units. Moreover, the dismantling staff and crew would only have to mobilize and demobilize once for the site instead of each time a unit is retired. Using the same staff and crew would take maximum advantage of the lessons learned as the units are dismantled in sequence.

The nuclear units were assumed to shutdown upon the expiration of their operating licenses. We also assumed that decommissioning activities would be coordinated between the two units at a station (Beaver Valley) to the maximum extent possible.

IV. METHODOLOGY

Q. What methodology was used to prepare the estimates?

A. The methodology used to develop the cost estimates followed the basic approach presented in the AIF/NESP-036 study report, "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," and the DOE "Decommissioning Handbook." The basic methodology described in these documents for preparing dismantling estimates is widely accepted by the electric power industry and regulatory agencies throughout the United States, including the NRC, and is applicable for nuclear as well as fossil plants.

Q. How was this methodology applied to the Duquesne Light generating units?

A. The aforementioned references recommend the use of a unit factor method for estimating decommissioning activity costs to standardize the estimating calculations. Unit factors describe the sequence of events required to remove a specific plant or structural component, the labor and material needed to support the activities identified, the impact of expected working conditions on the duration of performance and the associated cost (on a per unit basis). Unit factors for activities such as concrete removal ($/cu yd), steel removal ($/ton), and cutting costs ($/in) were developed from the labor information provided by Duquesne Light. Consumable material and equipment rental costs (crane and truck rental, operating costs for heavy equipment, torch cutting gas consumption, etc.) were taken in large part from R.S. Means, "Building Construction Cost Data," a standard construction industry cost guide. The costs for removal, shipping and disposal were then estimated using the item quantity (cu yds, tons, inches, etc.) developed from plant drawings and inventory documents. The activity duration critical path for key activities, such as the removal of the nuclear steam supply system, boiler or turbine, were used to determine the total dismantling program schedule.

The program schedule is used to determine the period-dependent costs such as program management, administration, field engineering, equipment rental, and security. The salary and hourly rates are typical for personnel associated with period-dependent costs. In addition, collateral costs were included for heavy equipment rental or purchase, safety equipment and supplies, energy costs, permits, taxes, and insurance.

The activity-dependent, period-dependent, and collateral costs were added to develop the total dismantling costs. A contingency was added to allow for the effect of unpredictable program problems on costs. Such a contingency is appropriate for a project of this size and type, for the reasons explained hereafter. The total dismantling costs plus contingency provide the total project cost. One of the primary objectives of every dismantling program is to protect public health and safety. The cost estimates for the dismantling activities include the necessary planning, engineering and implementation to provide this protection to the public.

Q. Has the NRC approved site-specific cost estimates utilizing TLG's cost estimating methodology?

A. Yes. The NRC has reviewed TLG's cost estimating methodology and is completely familiar with it. TLG prepared decommissioning estimates for inclusion within the decommissioning plans submitted by Northern States Power, New York Power Authority, Sacramento Municipal Utility District, Yankee Atomic Electric Company, Portland General Electric, Southern California Edison and Consumers Power Company for the Pathfinder Atomic Power Station, Shoreham Nuclear Station, the Rancho Seco Nuclear Generating Station, Yankee Nuclear Power Station, Trojan Nuclear Plant, San Onofre Nuclear Generating Station Unit 1 and for the Big Rock Point Plant, respectively. The Decommissioning Plans for each of the units have been approved by the NRC, with the exception of the Big Rock Point submittal, which is still pending.

Q. What are the major differences between nuclear and fossil power plants?

A. The major difference is the radioactivity inherent in nuclear power plants. Removal of radioactively contaminated piping, components and structures from a nuclear plant is more difficult and costly than for comparable items at a fossil plant. The activities of decontaminating, removing, packaging, shipping and burying radioactive materials from a nuclear plant require strict radiological controls, special containments and packaging, and licenses for the transport for disposal. There are many more opportunities for problems to arise in nuclear plant decommissioning than in fossil plants.

Because fossil plants have no radioactivity dismantling them is comparable to reverse construction. There are fewer potential hazards for the worker and, therefore, productivity is higher overall than with nuclear plants and the overall potential for problems is lower.

Q. Does your experience in the decommissioning of nuclear power plants aid in the preparation of a dismantling study for a fossil-fueled power plant?

A. Yes. The parallelism in approach between nuclear plant decommissioning and fossil plant dismantling enables us to rely on the field experience from nuclear decommissioning to prepare fossil plant studies. In particular, the following major areas of planning and estimating exhibit similar characteristics.

1. <u>Site Characterization</u>

The process and planning to identify the composition and extent of radionuclide contamination at nuclear power plants is similar to that required for potentially hazardous materials in fossil-fueled power plants.

2. <u>Sequencing of Work Activities</u>

Identifying systems that are essential or non-essential to the decommissioning task and establishing the sequence for their removal entails the same considerations in both nuclear and fossil plants. Essential systems include electric power, lighting, heating, ventilation and liquid processing systems.

For example, power and lighting would be retained as long as possible to avoid bringing in temporary services prematurely.

3. Management Staff

Identification of utility and decommissioning (dismantling) staffing composition and levels follows the same process in both types of units. The specific job functions will differ but the logic is the same. Management staff costs are period-dependent; that is, they are a function of the overall project duration.

4. Removal of Non-Contaminated Equipment/Structures

Removal of non-contaminated piping, components and structures are activity-dependent. The methods for their removal are identical for most of the systems and structures in each type of plant. Piping diameters and lengths are essentially identical (size-for-size plants), and the removal rate will be the same. Clean components, such as feedwater heaters and pumps, condensate pumps, demineralizer systems, etc., in nuclear plants, are the same sizes and types found in fossil plants. Steel and concrete structures are removed in the same manner in both types of plants. Removal of equipment unique to fossil plants, such as coal handling and air cleaning systems, relates to the weight of sub-components, and is accomplished by rigging and segmentation.

5. Scheduling

The scheduling of work activities for either type of plant follows the proven planning techniques of activity precedence networks and critical path management. An activity precedence network is a flow diagram of sequenced activities based upon the priority or "precedence" of completing one or more activities before starting another activity. The critical path is the longest sequence of work activities in a precedence network from project initiation to completion.

6. Collateral Cost

Collateral costs are neither activity-dependent nor period-dependent costs. They include items such as engineering, energy, licenses, permits, and taxes, etc. These items are identical in both types of plants, although specific cost values will differ.

7. Contingency

Contingency, as described more completely later in this testimony, is a cost allowance for field-related problems that are likely to occur. These problems include, for example, tool and equipment breakdown, late deliveries of supplies and equipment, and adverse weather. These field problems occur in both nuclear and fossil plant dismantling, although the specific allowances differ in each case.

8. Field Experience

The field experience in both nuclear and fossil plant dismantling for clean equipment is essentially the same. Heavy lifts of components weighing 50 to 450 tons are common in both plant types, and the planning and implementation activities are virtually identical.

In summary, nuclear plant decommissioning experience is directly applicable to fossil plant dismantling.

Q. How does this estimating process differ from construction estimating?

A. There is very little difference in the elements of cost between fossil plant dismantling and construction. Both activities must account for labor, materials, equipment, services and collateral costs (as defined earlier). The activities related to construction are similar to those for dismantling. Specifically, construction activities such as rigging components into position and welding connecting piping are comparable to dismantling activities such as cutting connecting piping and rigging components out of the structures. In the case of construction however, the pipe welds must be inspected by non-destructive methods (such as X-Ray examination), and cut out and re-welded if flaws in the weld are identified. This re-work causes schedule delays and incurs additional expense. In the case of dismantling, the pipe need only be cut once. Problems in dismantling occur when plant drawings and specifications do not properly reflect the plant as constructed. This occurs when changes to the plant are made that have not been recorded on the as-built drawings. This can result in additional dismantling costs. However, in general, fossil dismantling estimating is comparable to construction cost estimating.

V. CONTINGENCY

Q. What is meant by "CONTINGENCY" as used in cost estimating?

A. In simplest terms, "contingency" is equivalent to "experience." Unit costs used to estimate work tend to be ideal numbers that must be adjusted to fit the real world of experience. Professional cost engineers use the term contingency to refer to these predictable costs confirmed through experience.

Q. Is the use of contingency a long established approach to cost estimating?

A. Yes. The NRC standard formula for calculating decommissioning costs (as defined in 10 CFR §50.75 and based upon studies originally prepared by Pacific Northwest Laboratory in 1978-80) provides for such a contingency, and cost engineers routinely include contingency dollars in project cost estimates.

Q. What level of contingency is incorporated within the decommissioning cost estimates relied upon by the NRC for rulemaking?

A. A 25% contingency factor was applied to the costs estimated for decontaminating and dismantling the nuclear units used as model plants in the estimates prepared for the

NRC.

Q. What is the purpose of the contingency?

A. The purpose of the contingency is to allow for the costs of high probability program problems occurring in the field where the occurrence, duration, and severity cannot be accurately predicted and, as a consequence, their associated costs have not been included in the basic estimate. The American Association of Cost Engineers (AACE) (in their Cost Engineers Notebook) defines contingency as follows:

> *Contingency - specific provision for unforeseeable elements of cost within the defined project scope; particularly important where previous experience relating estimates and actual costs has shown that unforeseeable events which will increase costs are likely to occur.*

Past decommissioning experience has shown that unforeseeable elements of cost are likely to occur in the field and may have a cumulative impact. Fossil-fueled and nuclear power plants share some of the same potential problems leading to the need for contingency in cost estimates. These problem areas include:

Schedule slippages:	leading to crew overtime payments and/or project extensions
Weather delays:	loss of productivity, overtime, slippages
Labor strikes:	loss of productivity, slippages
Workers injuries:	production interruptions, additional safety training, workers compensation claims, possible increased insurance premiums
Material shipping:	rescheduling of activities, out-of-scope backcharges from subcontractors

Equipment breakdowns:	rescheduling of activities, out-of-scope backcharges from subcontractors
Regulatory inspections:	insurance inspectors, Occupational Safety and Health Act (OSHA) inspectors, federal and state EPA inspectors, state building inspectors
Hazardous materials:	special handling requirements beyond planned requirements

Nuclear power plants additionally have to deal with the special handling requirements of radioactive materials for decontamination, removal, packaging, shipping and disposal. A more extensive discussion of nuclear contingency is included in the AIF/NESP-036 Guidelines Study (Chapter 13) referred to earlier.

In the AIF study, individual contingencies ranged from 10% to 75%, depending on the degree of difficulty judged to be appropriate from our actual decommissioning experience. The overall contingency, when applied to the appropriate components of nuclear plant decommissioning costs, results in an average contingency of up to 25%.

For fossil plant dismantling, the absence of radioactive materials and their attendant potential problems simplifies the dismantling process. Individual activity contingency estimates for fossil-fueled power plants amount to an overall average of approximately 15% contingency. Independent of our preparation of this estimate for Duquesne Light, R.S. Means, "Building Construction Cost Data," suggests that a 15% contingency factor for conventional construction be used.

Q. Is a contingency an integral component of the estimate?

A. Yes. The purpose of a contingency is to provide assurance that sufficient funding is available to accomplish the intended tasks during the decontamination and dismantling process. Contingency funds are expected to be fully expended throughout the program. The contingency allowance is used in estimating decommissioning-related activities regardless of when they are performed, i.e., the contingency, in itself, does not offer protection against evolving costs and would be equally prudent on an estimate being planned in the near term as it would for future work.

Q. What experience does TLG have with the application of contingencies?

A. Contingencies are an integral part of the estimating methods employed by TLG. In addition, the use of a contingency has been recognized by many state regulatory agencies as well as the Federal Energy Regulatory Commission (FERC or Commission) as a valid cost component in decommissioning estimates. Most recently, in Docket No. ER95-1042-000, the Presiding Administrative Law Judge reaffirmed that "Commission policy supports the use of contingencies ... and, consistent with Commission precedent, there is nothing unreasonable about SERI's 21 percent contingency factor [the level requested in the decommissioning cost for the Grand Gulf Nuclear Station]. It is allowed." The use of a contingency has also been approved in estimates submitted before numerous state regulators.

Q. Have you compared estimates and actual costs for decommissioning projects that have been undertaken to date.

A. Yes. Based upon information available, TLG's estimates for recent work performed are on average within 4% of the actual costs reported (including contingency).

Q. Is the variation between estimated and actual costs due to contingency costs?

A. No. The differentials were either the result of modifications in the management of the intended program or savings in disposal costs negotiated by the licensee with the burial facility during the project. Northern States Power (NSP) had originally planned to decommission the Pathfinder facility using a decommissioning contractor. However, the company was able to realize a savings by using surplus personnel from its two operating nuclear stations to manage and perform the required decontamination and dismantling activities. Chem-Nuclear (operator of the Barnwell, South Carolina disposal facility) was awarded the large component removal project at Yankee Rowe. As the operator of one of the only commercially available disposal facilities, disposal cost reductions were not only possible but competitively advantageous in securing larger contracts. Since the contingency, as applied in the TLG's estimates, is not pricing or scope related, the correlation of estimated and actual project costs validates the need for contingency in decommissioning planning.

Q. Pennsylvania Power & Light Company's Pennsylvania base rate proceeding at Docket No. R-00943271 was the Pennsylvania Public Utility Commission's most recent opportunity to review a utility's decommissioning cost estimate prepared by TLG. In that case, did the Commission accept the inclusion of a contingency in the decommissioning expense approved for the Susquehanna Steam Electric Station

(SES)?

A. No. The Pennsylvania Pubic Utility Commission (Pennsylvania PUC) adopted the ALJ's recommendation to disallow the contingency, although for reasons different than those offered by the ALJ. The ALJ characterized the contingency as a "safety factor" that may or may not be required. The Pennsylvania PUC, in its Order and Opinion dated September 27, 1995, equated contingency with the uncertainty in "evolving costs" over the funding lifetime. That is, they assumed that the contingency was included to reflect the forces that would drive increases in basic decommissioning costs in the future. Therefore, they recommended that "periodic cost updates should be substituted for the use of a one-time contingency factor."

Q. Do you agree with the definition of contingency as defined by either the ALJ or Pennsylvania PUC in Docket R-00943271?

A. No. Both the ALJ and the Pennsylvania PUC deviated from the definition and application of contingency as stated within the cost estimates developed by TLG for the Susquehanna SES. The ALJ interpreted contingency as a "safety factor." Rather, contingency funds are an integral part of the base estimate and are expected to be fully expended throughout the program. Absent the contingency, there is a significant probability that sufficient funding would not be available to accomplish the intended tasks. If expenses are accrued on the basis of an estimate without contingency, or from which contingency has been removed, the orderly progression of events in the decommissioning process can be disrupted and the financial success of the project can be jeopardized.

For example, one of the more technologically challenging tasks in decommissioning a commercial nuclear station is the disposition of the reactor vessel and internal components which have become highly radioactive after a lifetime of exposure to neutrons produced in the reactor core. The removal, segmentation and packaging of these highly radioactive components forms the basis for the critical path (schedule) for decommissioning operations. Cost and schedule are inter-dependent and any deviation in schedule has a significant impact on cost.

Disposition of the reactor vessel internals involves the underwater cutting of the complex components containing millions of curies of radioactive material. Costs are based upon optimum segmentation, handling and packaging scenarios. The schedule is primarily dependent upon the turn-around time for the heavily shielded shipping casks, including preparation, loading and decontamination of the containers for transport. The number of casks required is a function of the pieces generated in the segmentation activity, a value calculated on optimum performance of the tooling employed in cutting the various subassemblies. The risk and uncertainty associated with this task is that the expected optimization may not be achieved, resulting in delays and additional program costs. For this reason, a contingency is included to properly reflect the consequences of the expected inefficiencies in this complex activity, along with related concerns associated with specialty tooling modifications and repairs, field changes, discontinuities in the coordination of plant services, unexpected conditions, systems failure, water clarity, lighting, computer cutting software corrections, etc. Experience has shown that many of these problem areas have occurred during, and in support of, the reactor vessel segmentation activity. Contingency dollars are an integral part of the total cost to complete this task. Exclusion of this component puts at risk a successful completion of the intended tasks and, potentially, follow-on activities.

The following listing is a composite of activities, assembled from past decommissioning programs, in which contingency dollars were spent to respond to, compensate for, and/or provide adequate funding of decontamination and dismantling tasks.

Incomplete or Changed Conditions:

- Unavailable/incomplete operational history which led to a re-contamination of a work area, as a sealed cubicle incorrectly identified as being non-contaminated, was breached without controls;
- Surface coatings covering contamination that, due to an incomplete characterization, required additional cost and time to remediate;
- Additional decontamination, controlled removal and disposition of previously undetected (although at some sites, suspected) contamination due to enhanced access of formerly inaccessible areas

and components;

- Unrecorded construction modifications, facility upgrades, maintenance, enhancements, etc., which precipitated scheduling delays, more costly removal scenarios, additional costs (e.g., for re-engineering, shoring, structural modifications), and compromised worker safety.

Adverse Working Conditions:

- Lower than expected productivity due to heat exhaustion in underground vaults, resulting in a change in the working hours (shifting to cooler periods of the day) and additional manpower;
- Confined space, low-oxygen environments where supplied air was necessary and additional safety precautions prolonged the time required to perform required tasks;

Maintenance, Repairs and Modifications

- Facility refurbishment required to support site operations, including those needed to provide new site services as well as to maintain the integrity of existing structures;
- Damage control, repair and maintenance from bird fouling of

equipment and controls;

- Building modification, i.e., re-supporting of floors to enhance loading capacity for heavily shielded casks;
- Upgrading onsite roadways to handle heavier and wider loads; roadway rerouting, excavation and reconstruction;
- Requests for additional safety margins by a vendor;
- Requests to analyze accident scenarios beyond those defined by the removal scenario (requested by the NRC to comply with "total scope of regulation");
- Additional collection and processing of site run-off due to disturbance of natural site contours and drainage;
- Concrete coring for removal of embedments and internal conduit, piping and other potentially contaminated material not originally identified;
- Modifications required to respond to higher than expected worker exposure, water clarity, water disassociation and hydrogen generation from high temperature cutting operations;
- Additional waste containers needed to accommodate cutting particulates, inefficient waste geometries and excess material.

Labor

- Turnover of personnel, e.g., craft and health physics. Replacement of labor is costly, involving additional training, badging, medical exams, and associated processing procedures. Recruitment costs are incurred for more experienced personnel and can include relocation and living compensation;
- Additional personnel required to comply with NRC mandates and requests;
- Replacement of personnel due to non-qualification and/or incomplete certification (e.g., welders).

Schedule

- Schedule slippage due to a conflict in required resources, i.e., the licensee was forced into a delay until prior (non-licensee) commitments of outside resources were resolved;
- Weather related delays in the construction of facilities required to support site operations (with compensation for delayed mobilization made to vendor);
- Rejection of material by NRC inspectors, requiring refabrication and causing program delays in activities required to be completed prior to initiating decommissioning operations.

Weather

- Frozen crane hydraulics prior to a major lift;
- Destruction of an exterior asbestos containment enclosure due to violent winds.

Although not included within the application of the contingency, the factors listed below have an equal probability of affecting the cost and performance of the decommissioning program:

- Transition activities and costs: ancillary expenses associated with eliminating up to 80% of the site labor force shortly after the cessation of plant operations. Added cost for worker separation packages throughout the decommissioning program, state mandated retraining and retention incentives for key personnel;
- Delays in approval of the decommissioning plan due to intervention, public participation in local advisory committees, state and local hearings, etc.;
- Regulatory changes, such as those affecting worker health and safety, site release criteria, waste transportation, and waste disposal; and
- Policy decisions altering federal and state commitments, e.g., in the ability to accommodate certain waste forms for disposition, or in the

timetable for such.

These concerns (with the exception of the first, which in some instances can be quantified), are typically addressed in a Risk and Uncertainty analysis against which probabilities are assigned and confidence traded against cost. Other areas addressed in such an analysis would include the probabilities associated with the uncertainties in predicting the costs of goods and services prior to their actual purchase, scope omission and error, escalation, schedule, scope growth, and “Acts-of-God”.

Q. How are these uncertainties addressed in decommissioning funding?

A. While uncertainties can be addressed through probabilistic assessment, these areas of uncertainty are more in line with the “evolving costs” referred to by the Pennsylvania PUC. TLG has and continues to address these changes in periodic updates, rather than through the use of contingency. However, the opportunity to revisit an estimate and adjust collections may not always be available.

VI. DECOMMISSIONING REGULATIONS

Q. *Are there any federal regulations applicable to nuclear plant decommissioning?*

A. Yes. The NRC published the Final Rule entitled "General Requirements for Decommissioning Nuclear Facilities" in the Federal Register of June 27, 1988 (53 Fed. Reg. 24018) to establish technical and financial criteria for decommissioning licensed facilities. The regulations addressed decommissioning planning needs, timing, funding methods, and environmental review requirements with the intent to assure that decommissioning of all licensed facilities would be accomplished in a safe and timely manner and that adequate licensee funds would be available for this purpose. In 1996, the NRC published revisions to the general requirements for decommissioning nuclear power plants. The Commission amended the decommissioning regulations to clarify ambiguities and codify procedures and terminology as a means of enhancing efficiency and uniformity in the decommissioning process. The amendments allow for greater public participation and better define the transitioning process from operations to decommissioning. The decommissioning cost estimates prepared for Duquesne Light's stations fully satisfy the requirements set forth in these regulations.

Q. Describe the decommissioning alternatives delineated in the NRC Rule for nuclear utilities.

A. The supplemental information to the NRC Rule (53 Fed. Reg. 24022-23) describes three decommissioning alternatives as acceptable: DECON (prompt removal/dismantling), SAFSTOR (mothballing) and, under special circumstances, ENTOMB (entombment). They are defined as follows:

> **DECON** is the alternative in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are

removed or decontaminated to a level that permits termination of the license and allows the property to be released for unrestricted use shortly after cessation of operations;

SAFSTOR is the alternative in which the nuclear facility is placed and maintained in a condition that allows the nuclear facility to be safely stored and subsequently decontaminated (deferred decontamination) to levels that permit termination of the license and release for unrestricted use.

ENTOMB is the alternative in which radioactive contaminants are encased in a structurally long-lived material, such as concrete; the entombed structure is appropriately maintained and continued surveillance is carried out until the radioactivity decays to a level permitting termination of the license and unrestricted release of the property.

It should be noted, however, that the NRC provides that delayed decommissioning following initial mothballing or entombment activities should not exceed 60 years, unless it can be shown that a longer period is necessary to protect public health and safety (10 CFR 50.82 (b) (1)). This rule discourages the use of the ENTOMB alternative unless specific advantages can be shown (see 53 Fed. Reg. 24023-24). The presence of long-lived radioisotopes at commercial generating units diminish any advantage from delay. However, both the DECON and SAFSTOR alternatives are considered reasonable options for decommissioning the Duquesne Light nuclear stations.

Q. Is it necessary to select a specific decommissioning method at this time?

A. No. The actual method or combination of methods selected to decommission the generating units should be based on a detailed economic, engineering and environmental evaluation of the alternatives considering the sites and surroundings at the time of decommissioning and reflecting the latest experience in the decommissioning of similar nuclear power facilities.

Q. What are your recommendations regarding the alternative selection?

A. I recommend that, for planning purposes, decommissioning cost funding be based upon an integrated scenario for the removal of two Beaver Valley units. In this scenario Unit 1 would be placed in safe-storage awaiting the cessation of operations at Unit 2, a period of approximately 11 years. Decommissioning of Unit 1 would then be assimilated within the decontamination and dismantling processes identified for Unit 2 to maximize cost sharing and experience gained in the decommissioning. The relatively short safe-storage period for Unit 1 would minimize system and facility degradation and minimize the effort required to re-configure the plant to support decommissioning operations.

I recommend for the single Perry unit using the DECON alternative. This alternative provides the most reasonable means for terminating the license for the site in the shortest possible time, consistent with the NRC's timeliness objectives. Furthermore, this alternative avoids the long-term costs and commitments associated with the maintenance, surveillance and security requirements of the conventional delayed dismantling alternatives.

The recommended alternatives allows use of the plant's knowledgeable current operating staff, a valuable asset to a well-managed, efficient decommissioning program. All equipment needed to support decommissioning operations such as cranes, ventilation systems and radwaste processing equipment would be fully operational or can be made available without significant expense.

Q. Would you describe the process of decommissioning a nuclear power reactor utilizing the DECON alternative?

A. Yes. The conceptual approach that the NRC has identified in their amended 10 CFR Part 2, 50 and 51 regulations is to divide decommissioning into three phases. Phase I commences with the effective date of permanent cessation of operations and involves the transition of both plant and licensee from reactor operations, i.e., power production to facility de-activation and closure. During Phase I, notification is to be provided to the NRC certifying the permanent cessation of operations and the removal of fuel from the reactor vessel. The licensee would then be prohibited from operating the reactor. Within two years of notification to cease reactor operations, the licensee must provide a Post-Shutdown Decommissioning Activities Report (PSDAR). This report would provide a description of the licensee's planned decommissioning activities, a corresponding schedule and an estimate of expected costs. The PSDAR should also address whether environmental impacts associated with the proposed decommissioning scenario have already been considered in a previously prepared environmental statement(s). Ninety days after the NRC's receipt of the PSDAR, the licensee can initiate certain decommissioning activities without specific NRC approval, under a modified §50.59 review process. The amended regulations would permit the licensee to expend up to 3% of the generic decommissioning cost for planning, with an additional 20% available following the 90-day waiting period and certification of permanent defueling. Remaining funds would be available to the licensee with submittal of a detailed, site-specific cost estimate.

Phase II as identified by the NRC in its rule, addresses licensed activities during a storage period. The Phase II requirements are applicable to the dormancy phases of deferred decommissioning alternatives, i.e., SAFSTOR and ENTOMB.

Phase III pertains to the activities involved in license termination. The submittal of an application to terminate the license, along with a termination plan, marks the start of this phase. The termination plan should contain a detailed site characterization, i.e., location, type and amount of radioactivity, a description of any remaining dismantling activities to be accomplished, detailed plans for a final survey and the planned end use of the site. An updated cost-to-complete would be required along with the reporting of any new or altered environmental consequences.

TLG's estimate for DECON addresses Phases I and III in three subperiods, as follows:

Period 1 - Site Preparations: This period begins upon shutdown of the facility and involves site preparations to initiate decommissioning. The reactor would be defueled, with the fuel placed in the spent fuel pool until it is cooled sufficiently to be transferred to DOE or an alternative storage facility. Transportation and disposal of spent fuel at a DOE facility is not considered part of decommissioning, and no costs associated with these activities are included in the decommissioning estimates. However, transportation and disposal can affect the decommissioning schedule due to the presence of such material on-site. The potential impact of these activities on the schedule has been addressed in the study. Wastes remaining from plant operations would be removed from the site, and all systems that are not essential to decommissioning would be isolated and drained.

Period 2 - Decommissioning Operations: This period begins upon NRC acceptance of the PSDAR and the mobilization of the decontamination and dismantling workforce. This phase of the work involves the removal of radioactivity from the site and concludes with termination of the NRC operating license. The activities in this period include selective decontamination of contaminated systems, e.g., using aggressive chemical solvents to dissolve corrosion films holding radionuclides, thereby reducing radiation levels. Decontamination will reduce personnel exposure and permit workers to operate in the immediate vicinity of most components while cutting and removing them for controlled disposition at a low-level radioactive waste burial facility. Although the on-site decontamination processes are effective for their intended purposes, they are not designed to reduce residual radioactivity to the levels necessary to release the material as clean scrap. Therefore, all contaminated components will have to be removed for controlled burial.

Contaminated piping connecting major components will be cut and removed. Selected major components such as the reactor recirculation pumps, moisture separators and feedwater heaters will then be removed intact and sealed so that they may be shipped as their own containers for disposal. Smaller components, such as sampling system pumps, filters, filter housings, strainers, etc., will be loaded into containers and shipped for burial.

The reactor vessel and its internals will be segmented and remotely loaded into steel liners for transport to the burial facility in heavily shielded shipping casks. The reactor vessel and internals will have sufficiently high radiation levels to require all cutting to be done underwater or behind heavy shields, using cutting torches operated by remote control to reduce radiation exposure to the workers.

Concrete immediately surrounding the reactor vessel is expected to be radioactive and will be removed by controlled blasting. This blasting process is well-developed and safe and is the most cost effective way to remove the heavily-reinforced concrete from the structure. The surface of sections of interior floors within areas of the Reactor Building (Containment) and other buildings in the power block is expected to be contaminated from exposure to contaminated air/water as a result of plant operations. This contamination will be removed by scarification (surface removal) so that the remaining surface will be clean and will not require costly controlled burial.

Finally, an extensive radiation survey will be performed to ensure all radioactivity above the levels specified by the NRC has been removed from the site. With NRC confirmation, the facility may be released for unrestricted access, and the operating license terminated (once the spent fuel has been relocated to an independent licensed facility).

Period 3 - Site Restoration: This period, which begins once the operating license termination activities have concluded, involves the demolition of all remaining structures to a depth, typically, of three feet below grade. Clean rubble would be used on-site for fill, and additional soil would be used to cover each subgrade structure.

Q. Please describe the process of dismantling a fossil power plant and how that process was reflected in the Duquesne Light estimates.

A. Approximately three months prior to final shutdown, engineering and planning would begin on the preparation of the Dismantling Engineering Plan (Plan) and Environmental Report (ER). The Plan describes the status of the facility at shutdown, work to be accomplished, safety analyses associated with each of the major activities, general procedures and sequence to be followed, and final site condition upon completion of all work. Similarly, the ER would evaluate environmental effects to workers and the public and waste generation effects on the site and environment. These documents would be submitted to the Environmental Protection Agency and other applicable regulatory agencies for review, approval, and authorization to proceed. The sequence of work would proceed as follows:

Period 1 - Site Preparations: Site preparations would begin upon shutdown of the facility and would involve site work needed to initiate dismantling. It is assumed that all fuel was burned prior to shutdown or was transferred to another operating unit.

Period 2 - Dismantling Operations: This work would begin upon receipt of all necessary regulatory approvals. This phase of the work involves the removal of all components of the boiler, air quality treatment systems (electrostatic precipitators, flue gas desulfurization systems, etc.), fuel handling systems (coal conveyors, crushers, oil storage tanks, etc.), the turbine-generator, and the condensate and feedwater systems. In general, the boiler will be dismantled in a bottoms-up mode, whereby the lower sections of the boilers will be cut at grade level, and remaining upper sections lowered to grade or scaffolding erected to cut the upper sections of the boiler furnace. This method of dismantling is necessary for the top-hung type of boiler that is supported from the steel structure. Care must be taken to ensure that sections are removed uniformly from the bottom to avoid any unbalanced load on the steel structure that may cause it to become unstable.

Steel structures used to support the boiler and turbine-generator components will be dismantled by controlled demolition and lowering sections to grade by cranes to prevent injury to workers on lower floors. The steel structures will be dismantled from the top down which essentially reverses the construction sequence.

Concrete structures such as boiler foundations, floors, turbine-generator pedestals and support buildings will be demolished by conventional wrecking methods. These may include the use of wrecking balls, pneumatically-operated rams on a backhoe, or controlled blasting.

Period 3 - Site Restoration: Site restoration involves the re-grading of all areas that were disturbed by the dismantling process. Structures will be removed to three feet below grade to permit re-vegetation of the site or to eliminate at-grade hazards. Clean rubble would be used on site for fill, and additional soil would be used to cover each subgrade structure. The site would be graded and stabilized.

VII. HIGH-LEVEL RADIOACTIVE WASTE

Q. Does the estimated cost of decommissioning include an allowance for disposal of high-level radioactive waste?

A. No. It is important to note that, although decommissioning of a site cannot be complete without the removal of all spent fuel and source material, the disposition of high-level waste is outside the scope of decommissioning. In accordance with the Nuclear Waste Policy Act of 1982 (Public Law 94-425), the DOE is required by law to enter into contracts with owners and/or generators of spent fuel, pursuant to which the DOE is contractually responsible for final disposition of spent fuel as high-level nuclear waste. To cover the cost of spent fuel disposition, the DOE assesses the facility operator 1 mill/kWh based on electrical generation. Therefore, the cost of <u>disposal</u> of spent fuel is accounted for separately and is specifically excluded from the decommissioning cost estimates.

Q. Does the presence of spent fuel on-site, following plant shutdown, impact the decommissioning processes?

A. Yes. Although the decommissioning studies do not address the removal or disposal of spent fuel from the nuclear sites, they do consider the constraint that the presence of spent fuel on the site can impose on other decommissioning activities. In particular, the decommissioning scheduling performed in support of the cost studies recognizes delays due to the present uncertainties surrounding the disposal of spent fuel in the United States. It is currently anticipated that both Beaver Valley and Perry will need to provide for extended storage and caretaking of their respective spent fuel inventories until such time as off-site disposal becomes an option.

The presence of the spent fuel storage facilities will necessarily delay the final release of the sites for alternative/unrestricted use. This delay is reflected in the increased cost of the period-dependent activities. To the extent possible, the decommissioning estimates were structured around the spent fuel areas of the stations and their availability for decontamination, such that delays in decommissioning other portions of the facility could be minimized. The study assumed that an Independent Spent Fuel Storage Installation (ISFSI) would be available at each site in support of plant operations. These facilities are assumed to be expanded to accommodate the additional spent fuel residing in the spent fuel storage pools at shutdown so that the Reactor Building can be released for decommissioning (for the DECON scenario). Decommissioning would proceed on the surrounding facilities and non-essential systems during the transfer period. Current expectations are for the last spent fuel bundles to remain at the Beaver Valley site until 2043, and at the Perry site until ____.

Q. What is the basis for the spent fuel management plan?

A. The transfer of spent fuel from the two stations to the government's geologic or interim storage facility is based upon a 2010 startup date and fuel shipments at the acceptance rate proposed in current legislation.

VIII. SITE RESTORATION

Q. Does the process of decommissioning extend beyond the removal of contaminated and activated material from the site?

A. Yes. There are additional activities, beyond the removal of contaminated material, that will be undertaken in the process of releasing the site for alternative use. This work includes costs for the remaining dismantling and grading operations.

Q. Are there any regulations or codes applicable to dismantling?

A. Yes. The Building Officials & Code Administrators (BOCA) National Building Code, widely adopted by most states, including Pennsylvania, requires that retired structures may not be left in an unsafe condition. Specifically, Section 120.1, "Right to Deem Unsafe," states:

> *All buildings or structures that are or hereafter shall become unsafe, unsanitary or deficient in adequate means of egress facilities, or which constitute a fire hazard, or are otherwise dangerous to human life or the public welfare, or which involve illegal or improper use, occupancy or maintenance, shall be deemed unsafe buildings or structures. All unsafe structures shall be taken down and removed or made safe and secure, as the code official deems necessary and as provided for in this section. A vacant building, unguarded or open at door or window shall be deemed a fire hazard and unsafe within the meaning of this code.*

(Emphasis Added)

A retired power plant fits this definition of an unsafe structure which must be taken down and removed or made safe and secure.

Q. Why is dismantling after a power plant is taken out of service the appropriate alternative?

A. Securing, maintaining and guarding retired power plants indefinitely is costly, requiring either a full-time guard force or intrusion detection devices and alarms monitored by local law enforcement agencies, as well as general building maintenance to keep the structures in a safe condition.

Q. Can power plant components be reused in repowering?

A. The designs of new generation power plants are not likely to use the same size and configuration of components, nor require the same type of building enclosures. Optimum facility design will be sized to match the megawatt size of a replacement power plant, if any, either larger or smaller. For example, new combustion turbine-generators are modular, self-contained units that don't need a building enclosure. Combined cycle units may require larger turbine buildings to enclose the waste heat steam generators which supply steam to the turbine. The cost to renovate older buildings and bring them to current safety code standards, combined with the less-than-optimum facility design makes reuse of the existing buildings an unlikely scenario. Furthermore, the existing components are likely to be of an obsolete design, more costly to operate and maintain and may not be compatible with new instrumentation and control systems.

Q. Please describe the cost components of site restoration.

A. The largest component of the site restoration costs is for dismantling the decontaminated structures. Next largest are costs incurred to remove certain non-contaminated systems and components. This work must be accomplished to provide access to all areas of the plant for the radiation surveys required by the NRC prior to license termination and release of the site for another use.

Q. Why is it necessary to dismantle the remaining structures at the site?

A. Efficient removal of the contaminated materials and verification that the radionuclide concentrations are below the stringent NRC limits will require substantial damage to many of the structures. Blasting, coring, drilling, scarification (surface removal), and the other decontamination work will damage power block structures including the Reactor, Radwaste and Turbine Buildings.

Verifying that subsurface radionuclide concentrations meet NRC site release requirements may require removal of grade slabs and lower floors, potentially weakening footings and structural supports. This will be necessary for those facilities and plant areas where historical records indicate the potential of radionuclides having been present in the soil, where inventory losses have been recorded, or where required to confirm that subsurface process and drain lines did not leak over the operating life of the units.

It is also important to remember that the structures were custom designed and built to support a specific nuclear unit that went into service in the 1970s in the case of Beaver Valley 1 and the 1980s in the case of Beaver Valley 2 and Perry. They would most likely be an impediment rather than a benefit to any potential future plant, if one were ever to be constructed at the site. Moreover, the facility's infrastructure degrades without continual maintenance. Unless the site is redeveloped shortly after release of its NRC license, the value in reusing plant facilities quickly diminishes. For example, following NASA's development of TVA's abandoned Yellow Creek nuclear power plant for its Advanced Solid Rocket Motor program, a Lockheed spokesman was quoted as stating: "[t]he abandoned nuclear power plant contributed little to the NASA project. Some of the power and water infrastructure was used but had to be reconstructed after eight years of neglect."

Dismantling is clearly the most appropriate and cost-effective option and should serve as the foundation for the decommissioning cost estimate. It is unreasonable to anticipate that these structures would be repaired and preserved after the radiological contamination is removed.

Q. Why is it necessary to dismantle a fossil-fired plant?

A. Remediation of fossil-fired facilities is inherently destructive, including creation of large access ways, dismantling of peripheral structures, controlled blasting, removal of roofs and walls, excavation of footings, etc. Precluding reconstruction, a retired fossil facility poses hazards including large interior open areas, pits, shafts and underground tunnels. With many of the plant services removed from service, the structures would be unheated, dark, littered with concrete rubble and structural debris obstructing means of egress. Condensation and groundwater intrusion and bird infiltration would soon create hazardous conditions, promoting unsanitary biological infestations, accelerating corrosion and general facility deterioration. A dedicated and systematic maintenance program is necessary to maintain the facility in a "safe" condition. Security measures are necessary to limit the liability inherent in casual or deliberate intrusion by the public. These maintenance and surveillance programs are expensive.

The steel and concrete or brick structures at fossil sites were not designed to prevent deliberate intrusion. Large glass windows, sheet metal siding, loading ramps and multiple ingress points allow easy entry into the station confines. Visitation of older, shutdown units has conclusively demonstrated both the speed and effects of facility deterioration. Such deterioration includes broken windows, leaking roofs, torn or damaged siding, obstructed stairwells with poor egress, and unsanitary conditions caused by the effects of weather, corrosion, ground water intrusion and vermin. Stacks, mine openings, fill ponds and lagoons with steep sloped banks, and river intake structures are high exposure liabilities and inherently dangerous to human life.

The alternative to perpetual caretaking and site surveillance is to dismantle the site as soon as practical. This activity is the most cost-effective when included within the schedule for site remediation, due to resources available on-site and the expected condition of the facilities.

The Pennsylvania Public Utilities Commission has acknowledged that dismantling of the decommissioned structures, following license termination at nuclear power plants, is an appropriate measure to protect public health and safety. The same safety concerns exist at retired fossil power stations, and for this reason TLG recommends dismantling fossil power plant structures

IX. SALVAGE AND SCRAP

Q. How was scrap or salvage credit included in the overall estimate?

A. Credit for carbon steel, stainless steel and copper scrap was included in the overall fossil estimates based on current published scrap values. No credit was included for salvage of any components because these components will be of an obsolete design by the time these plants are dismantled. The labor cost to recover potentially salvageable materials (valves, pumps, motors, etc.), and to store, protect, package and transport these components is not warranted. As such, these materials were considered as scrap.

No positive value was assumed for the scrap generated in the decommissioning of the nuclear units primarily due to the off-setting expense of the surveying required to verify to a 100% confidence level that material leaving the site has no detectable radionuclide contamination.

X. DECOMMISSIONING FEASIBILITY

Q. What is the feasibility of the decommissioning premise?

A. There is extensive experience in the United States and in other countries for the complete dismantling of fossil and nuclear power plants and other large industrial facilities such as chemical refineries and steel mills. This directly related experience shows that the generating units can be completely dismantled safely.

Between 1960 and 1995, 103 licensed nuclear reactors in the U.S. were designated for decommissioning or were in the process of being decommissioned. Of these, sixteen were designed as commercial nuclear power plants, four were demonstration nuclear power plants, eight were licensed test reactors, and 55 were research reactors. The remaining 20 were critical (non-power producing) reactors and/or critical facilities decommissioned or scheduled to be decommissioned. They have been or will be totally dismantled, and their licenses have been or will be terminated. Many other reactor facilities in Europe, Japan and Canada have been successfully decommissioned using demonstrated techniques. France has decommissioned 13 reactors, Germany 6, Italy 8, Japan 7, Switzerland 2, United Kingdom 5 and Canada 2.

The International Atomic Energy Agency (IAEA) indicates that 147 decommissioning programs have been undertaken or completed by its member countries. However, no breakdown is available for the various types of reactors from the IAEA.

The feasibility of decommissioning in the U.S. is well documented in the successful dismantling of Shippingport Atomic Power Station, Elk River Reactor, Walter Reed Army Research Reactor, Ames Laboratory Reactor and Sodium Reactor Experiment (SRE) facilities. Internationally, the decommissioning programs underway in England (Windscale Reactor), Germany (Gundremmingen), and Japan (Japan Power Demonstration Reactor) are further evidence of demonstrated technology. The basic activities of cutting pipe, segmenting vessels, demolishing reinforced concrete and decontaminating contaminated systems and structures are the same on a unit cost factor basis ($/cut, $/cubic yard, etc.) regardless of the size of the structure or megawatt rating of the plant. For example, a contaminated 12-inch diameter pipe in a 3000 MWt plant takes as long to cut as it does in a 58 MWt plant, although the length of pipe to be cut will be greater in the larger plant.

The major activities include removal of contaminated piping and components using conventional power hack saws, oxyacetylene torches or plasma arc torches within a contamination control tent. Removal of the reactor vessel and internals can be accomplished using an arc-gouging fuel gas torch or an arc saw, which is currently capable of cutting through carbon and stainless steel up to 12 inches thick (current vessels are less than 10 inches thick).

The remote manipulator technology required to cut the reactor vessel and internals was developed by Oak Ridge National Laboratory for the Elk River Reactor dismantling. This technology uses the plasma arc torch for cutting. This same tool was used in the SRE vessel cutting activity. Many of the tools and techniques used in decommissioning have been used in operating plants for maintenance and equipment replacement programs. Such technology, therefore, is not unique and further shows the feasibility of decommissioning.

Controlled blasting concrete demolition methods are well developed and have been used extensively in the mining industry. These same techniques were successfully employed in the demolition of the Elk River Reactor, where eight-foot thick, heavily reinforced concrete sections of the biological shield were safely removed with explosives without damaging or interfering with the operation of adjacent operating power generating units. The successful application of these decommissioning techniques in both small and large nuclear power plants assures decommissioning feasibility. Both the technology and the methodology for efficient decommissioning are available and fully tested.

Q. Does this conclude your prepared direct testimony?

A. Yes.

R-00974104, R-00974104C0001-C0002

Duquesne Statement No. 13-R

Pgh 12/17/97
E. Hulburt

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

Rebuttal Testimony
of
Thomas LaGuardia

DOCUMENT FOLDER

Contents:

Response to Intervenor Testimony Regarding
Fossil and Nuclear Decommissioning Costs

REBUTTAL TESTIMONYOF THOMAS S. LAGUARDIA

I. INTRODUCTION

Q. Please state your name and business address.

A. Thomas S. LaGuardia, 148 New Milford Road East, Bridgewater, CT 06752.

Q. Have you previously participated in this proceeding?

A. Yes. I submitted direct testimony on behalf of the Duquesne Light Company (Duquesne Light). A statement of my qualifications is contained in my direct testimony.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony addresses issues pertaining to fossil and nuclear decommissioning raised in the testimony of Mr. Lane Kollen, on behalf of the Duquesne Industrial Intervenors ("DII"); Mr. Darren D. Gill, on behalf of the Office of Trial Staff ("OTS"); Mr. Thomas S. Catlin, on behalf of the Pennsylvania Office of Consumer Advocate ("OCA"); Mr. Bruce Biewald, on behalf of the Environmentalists; and Dr. Robert B. Weisenmiller, on behalf of Hospital Shared Services, as follows:

- Validity And Accuracy Of The Cost Estimates To Decommission Fossil-Fired Stations (Mr. Kollen);
- The Need For, And Appropriateness Of, Contingency (Messrs. Gill and Catlin);

- "Uncertainty" Of Current Decommissioning Estimating Methods and the Experience Available from Which to Develop and Evaluate Decommissioning Cost Estimates (Dr. Weisenmiller and Mr. Biewald); and
- Potential Value Of Retired Generating Sites (Mr. Catlin).

Q. Would you please summarize your rebuttal in each of these areas?

A. I disagree with the witnesses identified, and I believe that:

There is sufficient experience in the dismantling of fossil-fired stations, and in particular the major components of such stations as part of unit retrofits and maintenance, to accurately estimate site remediation costs. The Commission has recognized that large operating plant structures, even if not radiologically contaminated, created a "special" threat to public health and safety. As such, retired fossil-fired stations should be dismantled and removed promptly.

Contingency funds are expected to be fully expended throughout the program. It is not a "safety factor" or "cushion." An estimate without contingency, or from which contingency has been removed, can disrupt the orderly progression of events and jeopardize the financial success of the project. Contingency (in itself) does not offer protection against evolving costs and would be equally prudent on an estimate being planned in the near term as it would for future work. The accuracy of TLG's estimates (including contingency) has been confirmed in decommissioning activities undertaken at Yankee Rowe, Trojan, Shoreham, Pathfinder, and Cintichem.

Commercial utilities have demonstrated much of the technology required to decommission a nuclear power plant. The tooling and techniques relied upon in the replacement of large components or handling highly-activated material are similar to those required in the final dismantling process. The accuracy of current estimating tools can be shown in their ability to accurately predict the cost of decommissioning and decommissioning related activities that have been accomplished to date. Based upon these criteria, the ability to estimate and accomplish large-scale decontamination and dismantling activities within budget has been demonstrated.

The property upon which Duquesne Light's generating units are sited only has value if sold or reused for new generation. The suitability of the current sites for future generation has not been determined and will depend upon the generating technologies available in the future, local load growth and demand, and the development of adjacent property. Consideration of property value would be speculative at best.

II. FOSSIL DECOMMISSIONING

Q. Do you agree with Mr. Kollen's characterization of TLG's fossil decommissioning studies as "inherently speculative and uncertain"?

A. No, not with the current site-specific cost estimates. The technology and knowledge required to dismantle a fossil-fired station is available today. Proper application of these "resources" reduces the level of uncertainty in planning and, consequently, in cost estimating. Some uncertainty in the ultimate cost of decommissioning is unavoidable until the facility is ultimately shutdown and its final condition determined. Decommissioning plans and estimates are based upon known factors and conditions. "Unknowns" will most likely add to the cost of decommissioning. Consequently, it is unlikely that decommissioning costs are overestimated. The greater probability is that they are underestimated.

Q. Do the retirement dates assumed in the TLG dismantling studies affect the cost calculated to dismantle a fossil-fired station?

A. No. The dismantling studies represent the cost to dismantle the station as it is presently constructed and configured, with current technology and under existing regulations. Life extension or premature closure of a fossil-fired facility would not substantially alter the cost to dismantle the structures or remediate the site.

Q. Mr. Kollen cites Commission precedent as consistently rejecting fossil decommissioning costs "because the costs are not known and measurable." Would you agree that the costs are not known or measurable?

A. No. Currently, there is sufficient experience in the dismantling of fossil-fired stations, and in particular the major components of such stations as part of unit retrofits and maintenance, to accurately estimate site remediation costs. Utilities such as Public Service Electric & Gas Company and Florida Power & Light Company have actively dismantled retired fossil-fired stations.

Q. Has the Commission previously recognized the need for dismantling conventional structures?

A. Yes. As early as 1985, in Pa. P.U.C. v. Pennsylvania Power Company (Docket R-850267), the Commission evaluated the need to dismantle the non-radioactive portions of nuclear units and decided to include the costs of dismantling these structurally compromised, non-contaminated structures as part of the nuclear decommissioning costs. The Commission determined that such facilities will have to be dismantled or removed in order to adequately protect the public and meet applicable safety requirements imposed by local building ordinances. Thus, in Pa. P.U.C. v. Pennsylvania Power Co., 67 Pa. P.U.C. 91 (1988), the Commission stated: "Given current requirements both in Ohio and Pennsylvania regarding abandoned structures, the prudent course is to plan for the removal of all the structures." The Commission recognized that large operating plant structures, even if not radiologically contaminated, created a "special" threat to public health and safety that merited an exception to its general policy of not funding prospective net negative salvage of utility property.

Q. Why is this extension of the definition of "special threat to public health and safety" important?

A. If retired fossil-fueled power plants are not secured and maintained with respect to site security, roof repair, painting, vegetation, animal control, etc., the buildings and site will become a hazard to the public health and safety. Asbestos insulation will separate from the piping and components and become airborne, corrosion of structural steel support members will weaken the buildings, and corrosion of steel floor gratings will make them unsafe for any personnel traffic, much less for use in future dismantling activities.

Accordingly, these conditions represent a "special threat to public health and safety" that justify dismantling of fossil-fired plant structures. The cost of this dismantling should be handled in the same manner as the nuclear decommissioning expense, i.e., properly funded.

Q. Does the dismantling of fossil-fired stations involve any extraordinary safety problems?

A. Yes. Work in abating and removing asbestos, PCBs, acids and caustics is hazardous work for which trained professional companies must be employed. Asbestos removal work is, in many respects, more hazardous than radioactive equipment removal work. Federal and state regulations require workers to have complete medical examinations including electrocardiograms, x-ray examinations, and pulmonary function tests. All workers must successfully complete 32 hours of asbestos removal training (40 hours for supervisors, additional 8-hour courses for asbestos sampling technicians). Workers are required to wear full protective clothing (coveralls, boots, gloves, caps), use air purifying or supplied air masks for respiratory protection, and carry and monitor portable air samplers. All work must be performed in double-walled tents maintained under negative pressure. Upon leaving an asbestos work area, workers are required to remove their protective clothing (but not their respirator) and shower to remove residual asbestos fibers. After showering, they enter a third enclosure to remove the respirator and change into street clothes. This process is repeated at least four times a day, considering the need for breaks and lunch. All materials brought out of the work area (asbestos materials, tools and equipment) and into a "cargo area" must be double bagged, stripped of the outer bag in the cargo area, and rebagged for disposal or storage.

Similarly, workers involved in cutting lead-painted surfaces by any cutting technique are required to have separate, but similar training for worker safety and lead contamination control.

In summary, this work is hazardous and "special" from the perspective of its potential impact on public health and safety. Accordingly, it should be handled from a financial planning standpoint in the same manner as nuclear power plant decommissioning; namely, by recognizing that it will be done and properly compensating utilities for these costs.

Q. Are the number of assumptions used in the estimates indicative of the overall accuracy of the reported costs?

A. No. TLG has made it a practice to clearly identify the bases for its estimates to eliminate any chance for confusion or misinterpretation. We have attempted to identify every major assumption that can affect the cost estimates either in a positive or negative manner. Clearly identifying each and every assumption minimizes the degree of speculation as to what is, or is not included in the estimate. Mr. Kollen simply missed the point of our care for accuracy in these estimates. The number of assumptions identified as the basis for an estimate is an affirmation of the validity of an estimate, not a weakness.

III. CONTINGENCY

Q. What is meant by the term "contingency" as used in cost estimating?

A. In simplest terms, "contingency" is equivalent to "experience." Unit factors used to estimate work costs tend to be ideal numbers that must be adjusted to fit the real world of experience. Professional cost engineers use the term contingency to refer to these predictable costs confirmed through experience. TLG considers contingencies to be an integral part of the estimating methods it employs. Accordingly, TLG always recommends inclusion of a contingency in a decommissioning cost estimate.

Q. Is the application of contingency a long established approach to cost estimating?

A. Yes. The NRC standard formula for calculating decommissioning costs for nuclear units provides for contingency, and cost engineers routinely include contingency dollars in project cost estimates.

Q. What level of contingency is incorporated within the decommissioning cost estimates relied upon by the NRC for rulemaking?

A. A 25% contingency factor was applied to the costs estimated for decontaminating and dismantling the nuclear units used as model plants in the estimates prepared for the NRC. While their across-the-board contingency is certainly appropriate, in our studies we have used even more precise line-by-line contingencies.

Q. Did TLG, as Mr. Kollen contends, use contingency to address future uncertainties?

A. Absolutely not. Contingency, as used within the TLG's estimates, addressed events occurring during the decontamination and dismantling process. Contingency is used in the estimation of decommissioning and decommissioning related activities regardless of the schedule for performance, i.e., contingency (in itself) does not offer protection against evolving costs and would be equally prudent on an estimate being planned in the near term as it would for future work.

Q. Mr. Gill eliminates contingency in his calculations of fossil decommissioning costs on the basis that the Commission had eliminated contingencies built into PP&L's nuclear decommissioning cost estimates in Docket No. R-00943271. Do you agree with this rationale?

A. No. Precedent, while appropriate in one instance, may be inappropriate given additional considerations or evidence to the contrary. Thus, in Pa. P.U.C. v. Pennsylvania Power Company (Docket R-850267), the Commission approved TLG's cost estimates for the Beaver Valley Unit 1 and Perry 1 nuclear power plants with the full knowledge that the estimates included a 25% contingency to account for unanticipated difficulties which may be experienced. The Commission did not characterize contingency, in that context, as speculative or its inclusion as inappropriate.

The PP&L ruling needs to be considered in light of my comments in my direct testimony regarding the ALJ's and the Commission's misunderstanding of the nature and purpose of contingency.

Q. Is contingency generally recognized by regulators as a necessary component of a cost estimate?

A. Yes. Contingency is recognized, and its inclusion approved by the Nuclear Regulatory Commission, Federal Energy Regulatory Commission, and numerous state commissions including Alabama, Arizona, California, Connecticut, Florida, Iowa, Louisiana, Michigan, Minnesota, Missouri, North Carolina, New Hampshire, Texas, Virginia and Wisconsin. The California Public Utility Commission mandated a 50% percent contingency for Pacific Gas & Electric's Diablo Canyon estimates, which was later reduced for consistency with Southern California Edison's use of an approved 40% percent contingency in its estimates for the San Onofre nuclear units. While the level of contingency can vary, its inclusion is both prudent and financially responsible.

Q. Are the decommissioning estimates for Duquesne Light's nuclear units inflated through the use of contingency, as Mr. Gill contends?

A. No. Contingency funds are expected to be fully expended throughout the program. It is not a "safety factor" or "cushion." An estimate without contingency, or from which contingency has been removed, can disrupt the orderly progression of events and jeopardize the financial success of the project.

Contingency is not an overstatement of costs, but a recognition of actual costs incurred in recent experience with decommissioning activities that were not foreseeable in advance. TLG's actual field experience on large power plant decommissioning projects, including Shippingport, Pathfinder, Shoreham and Yankee Rowe, have shown that contingency dollars are needed to cover unforeseen costs of events that occur in the field, as I described in my direct testimony.

Q. Does contingency provide protection against future inflation and escalation of the estimates to decommission?

A. No, as I have stated previously, contingency in itself does not offer protection against evolving costs, including inflation and escalation of the estimates to decommission.

Q. Is Mr. Catlin's reduction of the contingency percentage to 10% appropriate and justified?

A. No. Mr. Catlin's use of a 10% contingency is below that recommended by TLG in its site-specific decommissioning cost studies. Funding to this lower level will ultimately produce a shortfall in the collections needed to decontaminate and dismantle Duquesne Light's generating units, based upon the total cost calculated by a site-specific estimate.

The Commission's *Proposed Policy Statement Regarding Nuclear Decommissioning Cost Estimate and Cost Recovery,* which Mr. Catlin uses to support his position, was never issued as a final policy statement.

Q. Why is contingency, as applied within the decommissioning cost estimates, appropriate and justified?

A. The basis for the inclusion of contingency is provided within my direct testimony. TLG's experience as the largest subcontractor in the decommissioning of the Shippingport Atomic Power Station provided a test for its cost estimating methodology, including the use of contingency factors. All work on this program was competitively bid and required the highest degree of accuracy in estimating individual activity costs. TLG relied upon this same cost estimating methodology in preparing its bids for Shippingport that it used in developing the decommissioning estimates for Duquesne Light's generating units. Not only was TLG a successful bidder at Shippingport, but it was the only subcontractor to complete its assigned task(s) within budget and on schedule. This success provided field confirmation of TLG's empirical data base used to produce its estimates.

The accuracy of TLG's estimates have also been confirmed in decommissioning activities undertaken at Yankee Rowe, Trojan, Shoreham, Pathfinder, and Cintichem. Each estimate contained a level of contingency appropriate with the activities identified for the specified decommissioning program.

IV. COST ESTIMATING AND DECOMMISSIONING EXPERIENCE

Q. Do you agree with Dr. Weisenmiller's assessment that "there is almost no established track record associated with decommissioning large-scale utility nuclear power" [p. 74]?

A. No. First, the power output or physical size of a nuclear unit is not indicative of the difficulty that may be encountered in its decommissioning. The decommissioning of the Shippingport Atomic Power Station and Fort St. Vrain demonstrated "large scale" decommissioning technology and involved activities significantly more complex than at the larger Shoreham Nuclear Station. Second, Dr. Weisenmiller has chosen to ignore the very large data base accumulated from decommissioning-related activities. Steam generators have been removed (e.g., at North Anna, Surry, Turkey Point, Millstone 2, Yankee Rowe, Trojan, Point Beach, Palisades, and Robinson), reactor internals disassembled and segmented (e.g., at Shoreham, Millstone 2, St. Lucie, and Yankee Rowe), and reactor recirculation piping replaced (e.g., at Vermont Yankee and Nine Mile 1).

Commercial utilities have demonstrated much of the technology required to decommission a nuclear power plant. The tooling and techniques relied upon in the replacement of large components, e.g., steam generators, or handling highly activated material, e.g., in the disassembly of reactor vessel thermal shields, are similar to those required in the final dismantling process. Through system and equipment change-outs, backfits, and general plant modifications, the processes required to decontaminate and decommission a commercial nuclear facility have been proven and refined.

The remote manipulator technology required to cut the reactor vessel and internals was originally developed by Oak Ridge National Laboratory for the Elk River Reactor dismantling. Controlled blasting concrete demolition methods are well developed and have been used extensively in the mining industry. These same techniques were successfully employed in the demolition of the Elk River Reactor, where eight-foot thick, heavily reinforced concrete sections of the biological shield were safely removed with explosives without damaging or interfering with the operation of adjacent operating power generating units.

Between 1960 and 1995, 103 licensed nuclear reactors in the U.S. were designated for decommissioning, or were in the process of being decommissioned. Of these, sixteen were designed as commercial nuclear power plants, four were demonstration units, eight were licensed test reactors, and 55 were research reactors. The remaining 20 were critical (non-power producing) reactors and/or critical facilities decommissioned or scheduled to be decommissioned. They have been or will be totally dismantled, and their licenses have been or will be terminated.

There has also been a substantial amount of work done in decommissioning industrial facilities and U.S. Department of Energy (DOE) surplus facilities. Information on the technologies used to support these decommissioning efforts is widely disseminated and generally applicable to decommissioning commercial nuclear power plants. The decommissioning of DOE facilities can be much more complex that commercial facilities due to the need to address the substantial quantities of mixed waste (radiological and hazardous material together) generated by the decontamination processes, and the hazards posed by the transuranic elements.

Industrial facilities utilize many of the same decontamination and dismantling technologies relied upon in the decommissioning of nuclear power plants. While the processes are comparable, the cost and schedule to terminate site license(s) are typically much less than for their commercial counterparts due to absence of spent fuel and the required costs associated with fuel storage and caretaking.

Decontamination and dismantling technologies used in decommissioning foreign reactors are generally consistent with those employed at U.S. facilities, although the differences in the radiological release criteria for radioactively contaminated material have allowed for more experimentation and diversity in material disposition. The International Atomic Energy Agency (IAEA) indicates that 147 decommissioning programs have been undertaken or completed by its member countries. France has decommissioned 13 reactors, Germany 6, Italy 8, Japan 7, Switzerland 2, United Kingdom 5, and Canada 2.

Certainly, one can expect continued advances in technology, but new technology will not necessarily decrease uncertainty and does not guarantee cost savings. There is a risk in forecasting decommissioning costs, as Dr. Weisenmiller states. However, based upon past experience, the expectation of additional regulatory changes in the future and the significant uncertainties associated with both high and low-level radioactive waste management, the probability is significantly greater that the cost of decommissioning is being understated.

Q. Mr. Biewald uses an escalated 1975 estimate for decommissioning a large commercial reactor to support his claim that decommissioning cost estimating "is not a mature, stable undertaking." Is this a valid example?

A. No. Decommissioning estimates consist of three major elements of costs as properly identified by the NRC in its Decommissioning Rule (10 CFR Part 50.75(b)(2). These are labor, energy and burial costs. The percentages of each element are specific to each plant and estimate. The appropriate inflation factor for labor, energy and burial differ significantly, and burial represents the largest difference of the three. Using a single inflation factor based on a national Consumer Price Index, or other similar factor is wrong and misleading.

Mr. Biewald ignores economic factors beyond general inflation in his manipulation of data. For example, disposal costs for low level radioactive waste in 1975 were less than $2 per cubic foot for burial at the Barnwell, South Carolina facility. Today, costs at this facility exceed $300 per cubic foot. Estimates performed today would have to recognize this increase. However, the increase in waste disposal costs does not, by any means, reflect upon the adequacy of the estimating tools or maturity of the estimating techniques used in assembling a decommissioning estimate. The accuracy of current estimating tools can be shown in their ability to accurately predict the cost of decommissioning and decommissioning related activities that have been accomplished to date. Based upon these criteria, the ability to estimate and accomplish large-scale decontamination and dismantling activities within budget has been demonstrated.

Q. Would you expect, as Mr. Biewald suggests, decommissioning costs to contain the same "institutional uncertainties" evident in nuclear power plant construction?

A. No. The trends of cost overruns exhibited in nuclear plant construction costs are not currently seen in recent decommissioning projects. Furthermore, construction costs of the 1970's and 1980's were plagued with NRC design and backfit changes that caused havoc with construction budgets and schedules. During the late 1970's, plants under construction were experiencing construction interest rates approaching 20 percent. This fly-up in interest rates was a significant cause of plant construction costs exceeding their budgets, considering that the interest was almost 60 percent of the total costs.

Construction activities require each installed component, each weld, each startup test to be inspected and approved/verified with appropriate QA documentation to demonstrate full compliance with its safety function. In decommissioning, once a component or pipe is cut, you are done. There is no going back to reweld it to cut it in a better manner. Accordingly, the problems facing construction costs are not likely to be encountered in decommissioning.

Q. Do you agree with Mr. Biewald that large increases in the estimated cost for decommissioning indicate a high degree of uncertainty in the current decommissioning cost estimates which are developed in the same manner?

A. No. The large increases reflect changes in scope or inflationary factors which are accounted for in periodic updates to the estimate(s). They are not necessarily indicative of uncertainties in the estimate.

V. LAND VALUE

Q. Mr. Catlin presumes that the "value" of Duquesne Light's fossil generating sites "will serve to offset some, if not all of the decommissioning cost." Did TLG consider the market value of Duquesne Light's existing generating facilities and the associated property on which they are located?

A. No. The land and infrastructure associated with the fossil generating facilities was not considered to have a net value in the fossil dismantling studies prepared by TLG. The sites are not assumed to be completely restored (i.e., greenfield), with subsurface foundations and buried plant services abandoned. In addition, concrete rubble generated in the dismantling process is assumed to be used as fill for below-grade voids. Ponds will be closed and stabilized, however, their presence and the requirement for continuing monitoring restricts the future use of the site and any potential commercial value.

It is important to note that the dismantling studies addressed only the costs to remediate the primary generating facilities. No allowance was included for the cleanup of possible site areas contaminated by fuel oil, PCBs or other hazardous materials that may be present in the soil from years of operation.

Q. Does the existing infrastructure, including access to the transmission grid, add to the value of the property?

A. Not necessarily. The property only has value if sold or reused for new generation. The suitability of the current sites for future generation has not been determined and will depend upon the generating technologies available in the future, local load growth and demand, and the development of adjacent property. For example, combustion turbines may or may not require the infrastructure of an existing generating site. Typically, this equipment is optimally situated closer to the load or demand points. An existing generating site may not be the most advantageous location, depending upon the redistribution of industry and commercial customers and load growth in the intervening years, i.e., since the original generating plant was constructed.

Q. Do you agree with Mr. Catlin that "it would be inappropriate to require ratepayers to fund Duquesne's fossil decommissioning costs in advance."

A. No. The ratepayers who have benefitted from the power produced by the generating units should pay for their share of the decommissioning expense.

Q. Why should the Commission approve the funding of dismantling of fossil-fired stations in advance of the work being performed and not until the costs are actually incurred?

A. The establishment of a fund or reserve for fossil decommissioning will allow Duquesne Light to proceed in an expeditious manner once the stations are retired. The longer these units lay dormant, the more difficult and hazardous the process of dismantling becomes. As previously explained, asbestos becomes friable and the structural integrity of the buildings is compromised. The cost of dismantling increases due to these factors and increasingly stringent regulation from state and federal agencies such as EPA, OSHA and the Department of Labor. Prompt dismantling is the most cost-effective solution.

Q. Does the future use of a site have a bearing on the extent of site restoration assumed in the current decommissioning cost studies?

A. Whether or not new generation facilities are constructed and operated at the sites in the future does not alter the assumptions in Duquesne Light's decommissioning studies. Generation technology continues to evolve. It would be unreasonable to assume that facilities developed as much as 40 to 50 years ago will be able to adapt to the prototypical generating plant of the future. It simply is not prudent to expect that it would be technologically or economically feasible to mold a new, state-of-the-art generating plant to fit existing, antiquated facilities and equipment.

Q. Should collection of fossil decommissioning costs be deferred until Duquesne Light identifies a plan for ultimate reuse of the site(s)?

A. It is neither realistic nor equitable to postpone recovery of such costs. Decommissioning activities must take place, and it is appropriate to make basic assumptions about the usefulness of the facilities which will have expended their useful life during the operation of a power plant. However, it is impractical, indeed not feasible, for utilities -- or other property owners for that matter -- to develop detailed, specific site plans for 30 to 40 years into the future. The uncertainty in forecasting detailed, specific site plans so far into the future simply renders such an undertaking impractical.

Q. Does this conclude your rebuttal testimony?

A. Yes.

END