BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00061346

Duquesne Light Company

Statement No. 7

Direct Testimony of Julie M. Cannell

I. INTRODUCTION

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

A. My name is Julie M. Cannell. I am the president of my own advisory firm, J.M. Cannell, Inc. My business address is P.O. Box 199, Purchase, NY 10577.

Q. Please describe your professional and educational background.

A. My firm, J.M. Cannell, Inc., provides advisory services to electric utility companies and other firms and organizations with an interest in the industry. Prior to establishing my firm in February 1997, I was employed by the New York-based investment manager, Lord Abbett & Company, from June 1978 to January 31, 1997. During my tenure with Lord Abbett, I was a securities analyst specializing in the electric utility and telecommunications services industries; portfolio manager of America's Utility Fund, an equity utility mutual fund, for which Lord Abbett was a subadvisor; portfolio manager of numerous institutional equity portfolios; and co-director of Lord Abbett's Equity Research Department. Further information on my background can be found in Exhibit JMC-1.

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

A. I have been asked by the Company to discuss the perspective of investors with respect to the return on equity for Duquesne Light Company ("Duquesne Light" or "Company") in the context of the current rate case.

Q. Please summarize the key points of your testimony.

A. As my testimony will explain, investors now require a higher return when investing in the industry due to the changing nature of the industry through a *hybrid deregulated structure and attendant increased risk.* The investment industry itself has undergone major changes in recent years, including a dramatic growth in the amount of capital controlled by institutional investors and hedge funds. Performance pressures have significantly shortened the timeframe during which an investment must realize its expected return.

In making their assessments of utility companies, credit rating agencies and investors consider various factors, key among them the regulatory environment. Regulators influence a utility's capital structure and returns that may be earned on that capital. Those factors in turn determine a company's creditworthiness as well as its ability to provide stable earnings and dividends. While the credit rating agencies have mixed views on Duquesne's outlook, they are universal in emphasizing the importance of the Company's rate case. All three agencies noted their expectation for the proceeding to result in improved cash flow. Despite that positive anticipation, however, Moody's Investors Service (Moody's), Standard & Poor's (S&P), and Fitch Ratings (Fitch) all specifically warn that, should the outcome be adverse, a downgrade of the Company's ratings could result. Security analysts also expect a constructive outcome from the case, but view the proceeding as a risk factor in their outlook.

In my judgment, the investment community would find an 11.75% return on equity for the Company to be reasonable. Such a return level would provide Duquesne Light with the necessary cash flow to improve its credit quality and also meet the expectations of equity investors. Importantly, an 11.75% ROE would benefit customers by strengthening the Company's finances and lowering its future cost of capital.

Q. Please summarize what in your experience allows you to provide testimony about the viewpoint of investors.

A. As a securities analyst, I specialized in the electric utility industry and the individual companies comprising it. And as a portfolio manager, I applied that knowledge, along with investment fundamentals, toward investment decisions on behalf of institutions and individual investors. Moreover, I have reviewed the various reports of analysts and rating agencies, which have addressed the Company and its regulatory situation.

Q. As an analyst or portfolio manager, did you follow the Company?

A. Yes, I did. The Company's small market capitalization precluded the inclusion of the stock in Lord Abbett's portfolios, but I monitored the Company as a potential investment for America's Utility Fund, which did not have market capitalization investment restrictions.

Q. Please describe how your testimony is organized.

A. There are three parts to my testimony.

How Investors Evaluate Investments in Utility Companies — This section discusses why investors choose to invest in electric utilities, with particular emphasis on why the regulatory climate in which the utility operates is of such importance to investors. This section of the testimony also discusses why the risk of investing in the electric utility industry has risen substantially in recent years on an industry-wide basis and why markets today react so swiftly and strongly to unfavorable news about a company. It further details the risk present in distribution-only companies.

<u>Investors' Perceptions Related to the Present Proceeding</u> -- This section reviews the investment community's perceptions of Duquesne Light and Pennsylvania regulation. This review is based on a number of recent publications by credit rating agencies and investment analysts discussing their perceptions of the rate case and the Company's regulatory environment.

<u>Return on Equity</u> – This section discusses Duquesne Light's request for an 11.75% return on equity, which will be addressed in greater detail in testimony supported by Mr. Paul Moul. My conclusion is that the Company's proposal is one that investors view as important and constructive. An allowed ROE of 11.75% would lead to a more robust stream of earnings and cash flow, and would be viewed favorably by rating agencies and the investment community at a time when increased financial stability is very important to the Company.

<u>II. HOW INVESTORS EVALUTE INVESTMENTS IN UTILITY COMPANIES</u>

Q. Why is it important to consider the opinions of the investment community?

A. Investors provide the capital necessary to maintain and expand the Company's infrastructure, which in turn enables Duquesne Light to provide reliable service to customers. The terms on which the Company is able to obtain that capital have a direct and measurable impact on ratepayers and the amounts they pay for delivery service. For example, if credit rating agencies such as Moody's, S&P, or Fitch believe that the utility's revenues will be diminished by adverse business or regulatory decisions, those rating agencies would lower their credit ratings for the utility, which would raise the cost of debt. And because the cost of debt is a component of the weighted average cost of capital, the increased costs of capital would be passed on to ratepayers in the form of higher rates. In fact, based on Duquesne Light's current debt ratings, a slight downgrade could significantly increase its cost of debt, since current debt ratings are barely investment grade, as will be discussed later.

The same is true for equity investors. If individual or institutional investors believe that the return they are offered is too low in light of the risk involved, they will either sell their stock or elect not to purchase the stock, which generally drives the stock price down. Although lower stock prices would appear at first blush to be a concern only to investors, they also affect ratepayers. When a utility has to go to the equity markets to obtain capital, a low stock price requires it to issue more shares of stock to obtain the same amount of money that it would have received for fewer shares if the per share price had been higher. Because of the resulting increase in the number of shares outstanding, more dollars would have to be expended toward dividends, resulting in less retained earnings for reinvestment in the company.

The corollary is that when investors believe they are investing in a company that enjoys fair, consistent regulation and a reasonable rate of return, those investors charge less for their capital. And when debt and equity investors demand less for their capital, utility rates remain lower and utilities have more ready access to the capital markets. Thus, a utility and its ratepayers have a shared interest in meeting the expectations of investors and credit rating agencies. Regulators share this interest as well, because fair treatment of one utility decreases the costs of capital for all utilities in that regulatory jurisdiction.

Q. Are you suggesting that the Pennsylvania Public Utility Commission should cater to the desires of investors, who typically want the highest possible returns?

A. No. I realize that the Pennsylvania Public Utility Commission ("PUC" or "Commission") has to balance the interests of both investors, who want higher returns, and ratepayers, who want lower rates. My point is that the Commission's decision on rate of return is not simply a zero-sum game. If the rate of return is within a zone of reasonableness, both the utility and ratepayers win. If the rate of return is set too low, both the utility and ratepayers lose because of the effect on the cost of capital. The next part of my testimony is devoted to explaining why that correlation of interests exists.

Q. What goals lead investors to invest in electric utilities?

A. Historically, electric utilities have been regarded as investment vehicles that provide stable performance through the ups and downs of market cycles and changing economic conditions. Electric utilities have historically earned a reasonable return even when conditions were not favorable for other companies. Accordingly, electric utility stocks have been particularly valuable holdings when conditions were not favorable to investments in more volatile industry sectors. In other words, investors might see greater returns from investment in other industries when times were good, but they would lose less on electric utility stocks when times were less favorable.

In addition, the reliability of electric utilities' earnings streams have historically permitted most of the companies to continue to pay regular dividends during both good and bad economic cycles. For investors with a need for regular cash income, the prospect of regular dividends has been an important consideration in making a decision to invest in electric utility stocks.

Based on these factors, investors have traditionally viewed electric utility stocks as bond substitutes. In other words, electric utility stocks have provided regular cash returns in the form of dividends and the shares themselves were seen to have a stable underlying value. Electric utilities historically have paid out a large proportion of their earnings as dividends, and their large construction programs have kept them dependent on the capital markets. As a result, electric utility stocks as a group have tended to move closely in line with the direction of interest rates, but in an inverse relationship. That is, utility stock prices rose when interest rates fell, and vice versa. These factors made electric utilities a preferred investment during economic slowdowns or recessions and owning them was a way of balancing the risks in a stock portfolio that included stocks in more volatile industries.

Q. Have the recent changes in the industry increased the risk of investing in electric utilities?

A. Yes. Investors now understand that the predictability of the electric utility industry's earnings, across the sector, has been undermined by the restructuring that has taken place in many parts of the country, including Pennsylvania. These risks are in addition to the risks posed by technological, economic, environmental and other policy changes that affect the industry. These increased risks mean that investors no longer perceive electric utilities as a group as being as much the "safe havens" they once were.

Investors' goals, however, have not fundamentally changed. They still look to electric utilities primarily as defensive investments, and still look for stable performance and regular dividends as the reason to invest in electric utilities. But investors also understand that the investment risk in electric stocks has risen significantly, and that there is more risk than before that could serve to frustrate investors' goals for investing in this sector.

In the end, investors have a very large universe of stocks from which to select; with few exceptions, they have no requirement to own electric utility stocks. Consequently, investors now require a higher return for investing in the electric utility industry to balance the increased risk associated with it.

Q. How do these concerns affect Duquesne Light?

A. Markets tend to make judgments about investment risks that apply to industry sectors as a whole. Company specific risk factors are additive to sector risk. In other words, investors first determine the risk involved in investing in a particular sector. They then add to that sector risk the specific risks applicable to individual companies.

Q. Does Duquesne face additional risks as a wires-only utility?

A. Yes, it does. When the Company was an integrated utility involved in the broad provision of generation, transmission, and distribution services, Duquesne Light was able to spread the risks involved in any of those businesses across a broader base. However, as a wires-only company now, focusing on energy delivery, Duquesne Light has all of its assets concentrated in a single line of business and thus is fully exposed to any risks, including those pertaining to size and scope, that may impact its core business. In addition, Duquesne Light can no longer control the ultimate cost to the customer, because of the loss of integration. This creates a greater risk that it will not be able to respond to competition.

Q. Please discuss the earnings risk of being concentrated in a single line of business.

A. A single-business company would face financial exposures with which an integrated company would not necessarily have to contend. One segment of the business would typically be able to tap the broader financial resources of the corporation when facing financial difficulty. The distribution utility may still face public and political scrutiny for generation-related problems that are now beyond the utility's control. The distribution utility, if it continues to have any retail generation supply obligations, like Duquesne Light, is more reliant on the suppliers of that power than it was when it owned and operated its own generating facilities. The loss of a major supplier of generation services could pose a real financial threat to the wires-only utility that could be better managed by an integrated company, with a much broader base of revenues and resources. A *related risk is the uncertainty surrounding price recovery of power supplies* connected to default service obligations. In the absence of rules governing such recovery, the distribution company, which is still required to serve as a provider of last resort, could face extreme financial distress. An additional risk is heightened economic sensitivity due to geographic concentration. As an integrated company, the Company owned generation assets. During a recessionary period in Pennsylvania, Duquesne Light could face a decrease in load growth, or even a decline in distribution revenues. If the Company still owned generation, it might have been able to offset some of that shortfall by selling power into the wholesale market. As a wires-only company, Duquesne Light would be exposed to the economic situation with no potential to offset it. The Company is also at a disadvantage in trying to promote economic development in its service territory. Without regulated generation, it has considerably less flexibility in offering economic development rates to customers in its service territory since competing suppliers could simply bypass the utility and offer a lower price for generation that would not be burdened with a subsidy for another customer.

Q. Are there other risks involving single line of business concentration?

A. Yes. Another set of risks pertains to advances in technology. One such issue is distributed generation, which is a technology that permits power to be generated on small-scale machines that can be sited near a manufacturing facility, in a commercial business or even a residence. Distributed generation potentially can have a serious adverse impact on a utility's delivery system because distributed generation can facilitate bypass of the system. To the extent that customers see distributed generation as a means of controlling their price, reliability and power quality, even in areas where the utility (such as Duquesne Light) provides high reliability and quality, they may choose distributed generation in an effort to take more of their operations under their own control. The extent of the risk depends largely on factors beyond the utility's control (economics of production and installation of distributed generation, and the extent of governmental support, for example), and it is unknown how many customers will choose bypass or when the loss will occur. However, in light of an event such as the massive blackout of August 14, 2003 and the attendant widespread concerns about system reliability, the bypass risk has likely increased.

Q. What other risks do you see technology posing to wires-only utilities?

A. The advances in technology have made some industries less dependent on geography. There will be continuing pressure to retain customers who can relocate out of the utility's service area or who can take actions that are equivalent to relocation. Manufacturers and commercial businesses can choose to relocate to other parts of a state, or to other states or regions. Bypass may increasingly become economic for these customers as well as customers who do not wish to or cannot move. There will be pressure to discount prices to retain these customers. Duquesne Light no longer controls the cost of power and may not be able to discount enough to compete. Furthermore, the effect of lost customers is exacerbated for the Company because it is a much smaller company after generation divestiture and no longer has the balance sheet of an integrated company on which to fall back; so its financial strength could be stretched by customer loss. The Company simply has fewer units over which to spread its fixed costs.

Q. You've discussed the mounting risks you see a distribution company facing. Do those risks have the potential to reduce the company's earnings and cash flow streams and increase their volatility?

A. Yes. A single line of business increases exposures to enterprise credit risk, operating issues, prospective new costs, and technology issues, all of which can have negative financial ramifications. Moreover, since these factors are in large part beyond a company's control, the company's investors have little guidance and more uncertainty. Uncertainty leads to investor concern and demands for higher investment returns.

Q. Please turn now to utility regulation. Why is the perception of regulatory climate of such importance to investors?

A. Equity investors today are still seeking companies that can offer stability in earnings and dividends. Fixed income investors look for stable and adequate cash flows to ensure payment of principal and interest when due, as indicated by stable credit ratings. The ability to pay dividends and sustain credit ratings is directly related to the consistency and sufficiency of a utility's earnings, which depend in large part on how the utility is regulated. If there is uncertainty about whether regulation will allow a utility the opportunity to earn a reasonable return in future years, then that uncertainty will lead investors to avoid holding investment positions in the utility, all other things being equal.

As a result, I believe that investors selecting electric utility stocks today place a very high value on consistent and constructive regulation. And with a new round of base rate case filings underway in the industry, I think it likely that the quality of regulation will receive renewed investor attention.

Q. In your experience as an analyst and portfolio manager, could a perceived change in a company's regulatory climate affect your investment opinion?

A. Absolutely. During my tenure as an active investor, a company's regulatory environment was a critical factor in my assessment of its investment attractiveness. An adverse regulatory decision could be a key determinant in my recommendation or decision to sell a stock already owned or not make an investment in one under consideration.

Q. Who are typical investors in utility stocks?

A. There are two kinds of investors: individuals, who generally seek stability and income from their utility holdings, and institutions, which generally seek total return (i.e., price appreciation plus dividend income) from their utility investments.

Q. How has the investment industry itself changed in recent years?

A. In recent years, institutional investors and hedge funds have grown dramatically in the amount of capital they control. This growth has had a significant impact on the speed with which the market reacts to unfavorable developments. It has led the market to be much more reactive and much less forgiving than it may have been in the past. In the context of a regulatory decision, investors won't necessarily wait, as they would have in the past, to see how the ramifications of a decision might play out. Rather, they simply sell their shares if a regulator's decision runs counter to their expectations.

Q. What has led to that change in the market's reaction?

A. The market is now heavily populated by institutional investors, who play a significant role in the marketplace.

Q. Why are institutional investors of such importance generally?

A. Because of the sheer size of their investment positions, institutions can effectively direct the course of individual securities, and sometimes can move the market as a whole. Institutional investors include financial institutions such as mutual funds, investment companies, insurance companies, commercial and investment banks, and various types of public retirement funds. They approach the investment selection process from the standpoint of a portfolio. An investment portfolio is a collection of stocks selected to achieve the highest possible return within a commensurate level of risk. Therefore, institutional investors keep electric utilities in their portfolios only when such stocks contribute to achieving the desired risk/return relationship.

It should be remembered that, generally, the customers of institutional investors are individuals and it is they who ultimately gain or suffer loss from changes in the value of the institution's investments. Anyone who has a stake in a retirement plan, owns a mutual fund, or has a trust fund, for example, is directly or indirectly a client of an institutional investor. But the individuals who make the decisions concerning these investments are paid money managers, and how they see their responsibilities to the clients they serve, and the way that their performance is judged, have a great deal to do with how they react to developments in the market.

Q. Why are institutional investors important to Duquesne and Duquesne Light Holdings?

A. Institutional investors today hold 57% of Duquesne Light Holdings' ("DQE") total common shares. Such investors warrant significant attention because they can dramatically change the market for DQE's shares. Because institutional investors own large blocks of shares relative to the volumes typically traded, their activity in moving in or out of the company's shares is often noticeable as a significant change in the price and volume of shares being traded for the company. This change may be picked up by other institutional investors, by the investment community in general, and eventually by individual investors. These other entities will then look to see what is driving this trend in the stock and whether the trend is likely to continue or disappear. If they see support for the trend, they may follow the lead of the firms that initially began to move the market, and by following the leaders, the late movers may further strengthen the trend.

Q. Why might an institutional investor choose not to hold investments in a particular electric utility?

A. Several factors might be drivers. First, institutional investors have fiduciary responsibilities. For example, managers of pension assets fall under Federal ERISA laws, which mandate that a portfolio manager's decisions meet the so-called "prudent man" standard. That is to say, he or she is expected not to make investment decisions that are unduly risky or to retain stocks that are unduly risky given the investment goals of the portfolio and the function of the stock within it.

In addition, institutional investors have performance pressures. It is not enough for stocks in a portfolio simply to increase in value. Rather, relative performance is what counts. Investment performance is gauged against a market proxy (such as the Standard & Poor's 500 Index) or a peer group of investors (i.e., investors with a similar style, such as value, growth, growth & income, small cap, etc.). Mutual fund rating organizations such as Morningstar track and publicize the relative performance for mutual funds, while various pension consultants perform the same service for their client organizations.

Q. **Are there other reasons why an institutional investor might refrain from making an investment in a stock like DQE?**

A. Yes. DQE has a thin float; that is, a relatively small amount of the company's stock trades on a daily basis. During my tenure at Lord Abbett, such stocks used to be called "to-whomers" when the time came to reduce a position. In other words, it was easy to buy the stock, but difficult to sell on an orderly basis; there wasn't necessarily a line of buyers lining up "to whom" the stock could be sold. Because of that, there is vulnerability to price risk on the way out of a stock, with an attendant negative impact on investment performance.

Q. **How thinly does DQE's stock trade?**

A. DQE's average daily trading volume for the last 6 months has been 513,000 shares. That compares to a stock like Duke Energy, for example, with average daily trading volume of 3.6 million shares over the same period.

Q. What happens when an institutional investor underperforms?

A. The results can vary, but eventually, underperformance will result in lost business and personnel changes. Mutual fund shareholders can sell their fund shares. A pension plan sponsor can fire the professional investor or reduce the assets under their investor's management. And, of course, poor performance also disadvantages the individual, who has entrusted his monies to the institution for management.

Q. How long a period does an institutional investor have before performance becomes an issue?

A. Again, it can vary. But there is little argument that institutional investors no longer have the luxury of a long time horizon in which to show performance. Investors want results. And with the public visibility that investment results now have (through organizations such as Morningstar and the various pension consultants) and the resulting performance pressure, most investment organizations are now operating with a much shorter time horizon than in years past. Generally speaking, a long investment time horizon today can be as short as 12-18 months. So, a stock that is unlikely to perform within the prescribed time horizon is usually not attractive for purchase or continued investment by an institutional investor.

Q. What does this mean for investments in regulated utilities specifically?

A. This shortened time frame means that if there is bad news, institutional investors are more likely to react quickly. In the instance of a rate proceeding, these investors are unlikely to wait to see what the outcome of the next rate decision will be. That would represent an opportunity cost to them. Rather, institutional investors would be more prone to sell their shares on the news of an adverse regulatory outcome. This would not be good for ratepayers either, for the reasons discussed earlier.

Q. Do all institutional investors function within the time frames you describe?

A. No. There is a type of institutional investor called a hedge fund that frequently buys and sells the same stock during the course of a day.

Q. What impact do hedge funds have on the market in general and stocks in particular?

A. Their impact can be dramatic. Hedge funds are well known for trading in information; their actions are frequently event-driven. Sometimes that information is factual and other times it falls into the category of rumor. Because investors at hedge funds have wide information networks and are in frequent communication with companies and a broad range of other investors, they have the ability and the power to create volatility, which in turn impacts the movement of stock prices. The number of hedge funds participating in the market and the funds' assets have grown exponentially in recent years—recent estimates put the numbers at over 8500 firms with assets of $1.26 trillion globally in 2005, with the top 134 U.S. hedge funds' assets at almost $631 billion, compared to 610 firms with $39 billion in assets in 1990. Thus, they have become a very strong force both in the market and in stocks in which they are interested. When they like an industry group or a stock, hedge funds can provide substantial support to stock prices. But conversely, when they become disenchanted, their tendency is to sell quickly and without remorse. Although their focus is not on contributing to orderly markets, hedge funds are a formidable presence in the market place and must be reckoned with.

Q. Can you give an example of how hedge funds might traffic in DQE's stock?

A. Yes. Investors have been aware of the current proceeding for months. Hedge funds assuredly made assumptions about the details of the case, including its resolution, prior to the filing. If, when the PUC's decision is ultimately announced, the details fall short of those expectations, the hedge funds could put significant pressure on the stock either through outright sales, or short-selling (i.e., selling stock that is borrowed in anticipation that the price of the stock will drop before the borrowed stock must be replaced). Hedge funds seek to get ahead of the broader market and react to news before the market can. Accordingly, if hedge funds decide to make moves on DQE's shares based on the order in this proceeding, they will begin to do so within hours of the release of the order.

Q. You mentioned short-selling. Is that something that could affect DQE?

A. Yes. DQE has one of the highest levels of "short-interest" in the industry. While a typical utility has a 2% short position, DQE's position over the last 12 months has ranged from 10.9% to 16.0%. The implications of that much short interest is that there has been downward pressure on the stock that could be even more significant should an event occur that is contrary to investor expectations.

Q. What role do credit agencies play in investors' expectations?

A. In the wake of financial disasters, bankruptcies, and the ensuing severe erosion in investor confidence in the past few years, credit issues have become critically important not only to fixed income investors, but also to equity investors. While credit downgrades initially impacted only the most troubled companies, a spillover effect soon was seen on healthy utilities. Part of this was due to the fact that the rating agencies came under harsh criticism that they had failed to catch problems early enough in companies such as Enron Corp. As a result, they began to heighten their scrutiny of all entities under their watch and became far more proactive in making rating changes. As well, "headline risk" began to come into play, as investors worried that –when credit problems in an industry are in the headlines—any company in the sector could be vulnerable to a downgrade. Thus, equity investors now closely watch the actions of the credit agencies, because any change in ratings can have a significant impact on a company's stock price.

Q. What happens when a credit downgrade occurs?

A. In the simplest terms, it becomes more expensive for a company to raise money in the capital markets because a downgrade raises a company's risk profile and consequently, increases the cost of debt. And because of the increased linkage these days between ratings and stock prices, the price frequently reacts—sometimes quite strongly—to a downgrade. To take an extreme example, Moody's cut the ratings of Allegheny Energy and its subsidiaries to "junk," or below investment-grade, status on October 1, 2002. The prior day, September 30, Allegheny's stock price closed at $13.10. By October 8, when the company announced that it was in technical default with creditors, the stock closed at $3.80. Thus, in the space of a week, Allegheny's stock price—and the value of a shareholder's investment—lost 71% of its value. Although this is an extreme example, it is nonetheless indicative of why the markets now watch changes in credit ratings so closely.

III. INVESTORS' PERCEPTIONS OF THE CURRENT PROCEEDING

Q. Why is it important to consider the opinions of the investment community?

A. Suffice it to say, investors provide the capital necessary to maintain and expand the Company's infrastructure, which in turn enables Duquesne Light to provide reliable service to its customers. Perceptions of the investment community matter. The availability and cost of necessary funding ultimately impacts the Company's customers.

Q. How have you gauged investors' perceptions of the issues in this proceeding?

A. To supplement my own knowledge of the industry, I have reviewed various reports related to DQE and Duquesne Light written by the credit rating agencies and investment analysts. A clear picture of investors' perceptions emerges from these reports, which is in keeping with my own views.

Q. Which credit agency reports have you reviewed?

A. I have examined reports written by Moody's, Standard & Poor's, and Fitch Ratings, which are the three key credit rating agencies.

Q. Why is a utility's regulatory environment important in general to the rating agencies?

A. The rating agencies appraise companies on the basis of creditworthiness. They evaluate current financial soundness and attempt to discern how that might change in the future. One of the key factors in assessing a utility's financial picture is the regulatory climate in which the company operates, because regulators influence the utility's capital structure and establish allowed returns that may be earned on that capital. Thus, a regulatory environment characterized by consistency and predictability is one that lends itself to a company's having a sounder financial base. Conversely, a regulatory situation defined by a lack of stability can have a deleterious impact on a utility's credit profile.

Q. How do the rating agencies view Duquesne and its regulatory situation?

A. While their opinions vary somewhat, it is clear that all three agencies place significant emphasis on the outcome of the current rate proceeding and the impact it will have on the Company's financial health.

Q. Please elaborate.

A. In an August 2005 report, Moody's affirmed Duquesne's credit ratings and revised the outlook to stable from negative. Among the factors the agency cited for its actions was the expectation that the Company would "file transmission and distribution rate cases that will result in improved cash flow and provide for recovery of planned capital expenditures" which Moody's quantified as $500-$600 million.[1] The agency went on to say that "a rating upgrade could be considered if the company … obtains a reasonable rate outcome"[2] in the anticipated case. Conversely, Moody's noted, "A rating downgrade could also occur if there is a sustained deterioration of its cash flows or an increase in

[1] Moody's Investors Service, "Moody's Affirms the Ratings of Duquesne Light Holdings (Sr. Unsec. Shelf (P)Baa3) and Duquesne Light Company (Issuer Rating Baa2): Revises Outlook to Stable from Negative," August 4, 2005.
[2] Ibid.

leverage resulting in weaker credit metrics that would include the ratio of FFO [funds from operations] to consolidated debt being in the low teens or below."[3]

Q. What is Fitch Ratings' opinion of the Company?

A. As did Moody's, Fitch also revised its outlook on the Company last year, raising it to "Positive" from "Stable," but from a lower rating level than Moody's. In noting its concerns, the rating agency pointed to "regulatory risk associated with planned T&D expenditures,"[4] Fitch further pointed out that "DLC's [Duquesne Light's] planned T&D related capital expenditure program includes $500 million-$600 million over 2005-2007, and should be funded with internal cash flow and equity infusions from the parent, but will require rate base treatment in early 2007."[5] Additionally the agency noted the expected increased returns from the utility's prospective T&D rate case.[6] Fitch concluded its commentary with the warning that "Inadequate equity returns from DLC's T&D rate case and the inability to offset the cash impact . . . could adversely impact Holdings' ratings."[7]

Q. How does Standard & Poor's view Duquesne?

A. Unlike the other two agencies, S&P has a "negative" outlook on Duquesne. In an August 2005 rating assessment, S&P observed "In a forthcoming rate case, Duquesne Light intends to seek a revenue increase to recover higher costs, including capital spending on its transmission and distribution system."[8] The

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[3] Ibid.
[4] Fitch Ratings, "Fitch Affirms Duquesne Light Holdings; Revised DLC Outlook to Positive." April 14, 2005.
[5] Ibid.
[6] Ibid.
[7] Ibid.
[8] Standard & Poor's, "Research Update: Duquesne Light Holdings' $320 Million Notes Rated 'BBB-,' August 10, 2005.

agency said it is anticipating that Duquesne's "expected rate increase,"[9] when fully reflected, should serve to improve DQE's funds from operations in 2007. However, in its outlook on the Company, S&P cautioned that "the negative outlook reflects multiple challenges confronting DLH could result in lower ratings;" among those challenges are "a poor outcome in the rate case.[10] The outlook could move to stable with "further clarity" on the proceeding.[11]

Q. You noted rating agencies' respective outlooks on the Company; what ratings do they have on its debt?

A. S&P and Fitch have "BBB-" ratings on Duquesne Light's senior unsecured debt; Moody's designates it Baa2.

Q. What is the significance of a "BBB-" rating?

A. While "BBB-" is still officially an investment grade rating, it is only one notch above a so-called "junk" (i.e., below-investment grade) rating. In fact, some investors view "BBB-" as already residing in "junk" territory. When a company loses its investment grade rating, several things occur. First, its cost to access the capital markets rises markedly. Second, being below investment grade can result in collateral calls. That in turn can prompt the rating agencies to make further downgrades of the company's debt. As noted previously in my testimony in the example of Allegheny Energy, a downgrade spiral can also have a disastrous impact on the company's stock price. The road back can be a long one.

Q. What conclusion do you draw from the rating agencies' reports?

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[9] Ibid.
[10] Ibid.
[11] Ibid.

A. While the agencies have mixed views on Duquesne's outlook, they are universal in emphasizing the importance of the Company's rate case. All three agencies noted their expectation for the proceeding to result in improved cash flow. Despite that positive anticipation, however, Moody's, S&P, and Fitch all specifically warn that should the outcome be adverse, a downgrade of the Company's already low ratings could result.

Q. Please turn your attention now to the thoughts of security analysts regarding Duquesne Light. What are their opinions about the Company's regulatory circumstances?

A. Several investors have commented on the prospects for a Duquesne Light rate review and its impact on the Company's investment attractiveness. Lehman Brothers recently upgraded its investment opinion on DQE to "Equal Weight" from "Underweight" due to the stock's relative underperformance over the preceding twelve months despite no change in fundamentals. The firm noted, though, that "significant risks still exist—including … regulatory treatment…"[12] In fact, in the summary of its action, Lehman wrote, "We believe the key to this story is the upcoming (1H'06) PAPUC rate case where DQE is investing between $500M and $600M in its infrastructure between '05-'07 for an increased rate base of between $1.5-$1.6B. The regulatory environment appears to be reasonably constructive."[13]

Q. What other analysts are focusing on the rate case?

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[12] Lehman Brothers. "Duquesne Light Holdings: Recommendation Change: Upgrading Our Rating to a 2-Equal Weight," January 5, 2006.
[13] Ibid.

A. Last fall, Jeffries & Co. also upgraded its investment opinion, to "Buy" from "Hold." In its investment summary, the firm said, "We believe the company should be able to fund its $1 dividend from utility earnings, assuming a reasonable outcome in the company's rate case."[14] Among the weaknesses/risks Jefferies cited in its investment proposition is:

> "DLC ("Duquesne Light") expects to apply for a T&D rate increase in 2006. DLC has not had a T&D rate increase since 1987. This would be the company's first rate case since the Pennsylvania market was deregulated. ... Based on our conversations with the Pennsylvania Public Utilities Commission (PUC) Staff, the past experience in the state is to provide recovery for this type of spending, and therefore we feel comfortable that most of the company's new investment would be allowed in the rate base and be recoverable."[15]

Q. What is the import of these analysts' comments?

A. Both firms are very clear in conveying that the current rate proceeding is of critical importance to the Company. Lehman said it directly: the key to the stock's investment proposition is the rate case. Jefferies, in the summary of its investment opinion, held that a reasonable outcome in the case is needed to underpin the utility's earnings to support the dividend. At the same time that both firms make it clear that the rate case poses a significant risk for Duquesne Light, they also expressed optimism about the outcome. Lehman noted the "reasonably constructive" nature of Pennsylvania regulation. Jeffries pointed to the PUC's history of providing recovery for T&D spending such as the Company has already undertaken and still faces.

Q. Did the analysts also convey their expectations for a return on equity award in the rate case?

[14] Jefferies & Company, Inc., "Duquesne Light Hldgs. Rising from the Dumps," October 14, 2005.
[15] Ibid.

A. Yes, they did. Jeffries conveyed that its … "forecast model assumes an equity ratio of 49% and an ROE of 10.87%"[16] and Lehman said its "estimates factor in an ROE of 10.5%."[17]

Q. Does that mean that investors expect an ROE allowance between 10.5% and 10.87%?

A. No. I believe that the estimated ROE allowances of Jeffries and Lehman represent the floor of a range of expected allowances from 10.5% to 12% that investors would consider to be reasonable. I note that the analysts' estimates are close to the 10.7% ROE allowance granted PPL Electric Utilities, Inc. in December 2004, the PUC's last decision in an electric distribution rate case. Further, the analysts' assumptions appear to reflect uncertainty about the supportiveness of regulation in the current climate of rising energy prices and interest rates, and thus are likely erring on the side of conservatism in anticipating the rate case's outcome. Indeed, this regulatory uncertainty is also reflected in Lehman's recent ranking of state utility commissions from an investor perspective. While I mentioned previously that Lehman characterized Pennsylvania regulation as "reasonably" constructive, the firm ranked Pennsylvania "Tier 4" on a 5-tiered scale, with Tier 1 being "Most Shareholder Oriented" and Tier 5 being "Most Consumer Oriented." Lehman's rankings were based on 6 criteria: 1) elected versus appointed commissions; 2) performance-based ratemaking mechanism or not; 3) allowed ROEs; 4) settlements versus

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[16] Ibid.

[17] Lehman Brothers, "Duquesne Light Holdings: Change of Earnings Forecast: Weak Q4: Weaker 2006," February 15, 2006

litigation 5) rate levels; and 6) a subjective investor friendless rating.[18] That is part of the reason I have concluded that Lehman's 10.5% ROE is at the bottom of the expected range of outcomes. It also bears mention that, in Lehman's 2004 regulatory study, Pennsylvania regulation was assigned a "2" rating, one of eight states at that level, which reinforces the concept of additional uncertainty at the present time.[19]

Q. **Did Lehman comment further on ROE awards in general?**

A. Yes. The firm presented projections for annual allowed returns on equity for the industry for 2006 through 2010. For this period, Lehman is estimating an 11.30% ROE award for each of those years. The firm notes, however, that "Primarily because of regulatory lag and increased financing expenses, utilities suffer subpar returns during periods of heavy capital investment." Further, "…as the sector becomes FCF [free cash flow] neutral (by late 2005), utilities tend to earn 225 bps [basis points] below their allowed ROEs. . . . As FCF trends downward through 2007, this implies more substantial under-earning over the next few years." Lehman's projections of projected earned ROE are: 2006, 9.02%; 2007, 8.71%; 2008, 9.13%; 2009, 9.57%; and 2010, 9.83%.

Q. **What are the implications of Lehman's industry ROE analysis for Duquesne?**

A. There are several points to be made. First, the firm is projecting an 11.3% average allowed ROE for the industry over each of the next five years. That projection would reinforce the likelihood that Jeffries' and Lehman's ROE

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[18] Lehman Brothers, "Capital Lessons," March 15, 2006.

[19] Lehman Brothers, "They're Back! Twenty-Six Rate Cases This Year Give Rise to the Regulators;" March 5, 2004.

estimates for Duquesne are conservative and represent the low end of the range, and that Mr. Moul's recommendation of an 11.25%-11.75% ROE range with an 11.5% midpoint is comfortably within a band of 10.5%-12.0% expected by investors. Second, Lehman is anticipating an allowed ROE level of 11.3% over each of the next five years, but an earned ROE ranging from 143 basis points on the high end (2010) to 259 basis points on the low end (2007) below the allowed ROE due to cash flow pressures. The Company's free cash flow is already being pressured by significant spending on transmission and distribution infrastructure. In that context, the lower the return on equity that Duquesne is *allowed*, the lower the *earned* return on equity that will actually be achieved.

Q. Are there additional inferences to be drawn from investors' views of the Company?

A. Yes. One of the key factors analysts use to evaluate the quality of a regulatory climate is the consistency of a commission's decisions. Investors value certainty and predictability; a lack of consistency in a commission's decisions serves to increase the investment risk associated with a utility. With an unpredictable track record of regulatory decisions, investors are unable to anticipate reliably the future actions of a commission. That in turn depresses valuations—i.e., lowers the price of a stock and increases a company's cost of borrowing. In a study the Edison Electric Institute commissioned me to conduct last year of investor's perceptions of state regulation, respondents were asked to cite the regulatory factors they felt characterized a constructive environment as well as a non-constructive environment. On the positive side of the ledger, one of the top set of factors was a regulatory climate that is "fair, stable, predictable, and consistent." The top factor cited by the respondents as characterizing a non-constructive environment was a climate that is "arbitrary, inconsistent, and unwilling to acknowledge the economic realities that utilities face." One investor summed up that type of non-constructive regulation as "regulatory purgatory."[20]

Q. Have other comments than those in the previously cited reports been made about the quality of Pennsylvania regulation?

A. Yes. Following the PUC's December 2004 decision in PPL Electric Utilities' rate case, a number of analysts wrote reports on the outcome. Merrill Lynch, citing as the reason for its report "Constructive Outcomes to PA and UK Rate Cases," noted "The Pennsylvania rate case outcome is more favorable than the ALJ recommendation, which was for a 10.25% ROE and a slightly lower equity ratio. The rate increase will represent a substantial improvement to the utility's current low single-digit ROE."[21] Lehman Brothers also opined, in a report entitled "Good Rate Outcomes Point to Stronger EPS," that "PPL has reached constructive rate outcomes in both PA and the UK . . ."[22]

Q. Have other investors offered opinion on regulatory quality in general?

A. Yes. Bank of America Securities publishes an annual study of regulation, in which it lists characteristics it believes comprise a state commission that is supportive of credit quality.[23] Although the list is extensive, the two top factors pertain to decisions that are supportive of credit quality and the authorized return

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[20] J.M. Cannell, Inc., "State Utility Regulation: An Assessment of Investor Perceptions," August 2005.
[21] Merrill Lynch, "PPL Corp.: Rate Cases Wrapped Up," December 3, 2004.
[22] Lehman Brothers, "PPL Corp.: Change of Earnings Forecast: Good Rate Outcomes Point to Stronger EPS," December 14, 2004.
[23] Bank of America Securities, "Kaleidoscope of Power: Regulation in Focus," March 2005.

on equity and equity ratios. Regarding the first factor, the firm notes that: "The commission consistently adopts regulatory policies and makes decisions that have the result of producing strong, stable cash flow and interest coverage."[24] As to equity returns and levels, Bank of America opines: "Higher authorized returns on equity and higher approved equity ratios used in setting the fair rate of return provide higher interest coverages for regulated utilities. It is our view that the utilities that have higher equity ratios than the industry average do so in large part because historically, their state commissions recognize the benefit and permit the companies to pass costs through rates."[25] While Bank of America Securities does not rank the various regulatory commissions, it does provide data on each to permit investors to draw their own conclusions.

Q. **What inference do you draw from the various analysts' comments about the quality of regulation in general and Pennsylvania regulation in particular as they pertain to this regulatory proceeding?**

A. In my opinion, investors—both equity and debt—would clearly view a PUC decision that is consistent with the Company's request to be reflective of the continuation of constructive regulation in Pennsylvania. The PUC demonstrated to investors in its December 2004 decision for PPL Electric Utilities that it would support utilities' need to invest significant levels of capital to maintain a strong and reliable electric infrastructure. For the PUC to deviate from that positive example in the current case would send a strong signal to investors that the quality

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[24] Ibid.
[25] Ibid.

of Pennsylvania regulation is inconsistent and not supportive of utilities' needs to access the capital markets.

IV. RETURN ON EQUITY FOR DUQUESNE LIGHT

Q. How do you believe Duquesne's requested return on equity of 11.75% comports with investors' perceptions?

A. I believe that the investment community would find an 11.75% ROE supportive for the company. It is within the range of investors' expectations for ROE allowances in 2006.

Q. Why do return on equity rewards vary among state commissions and companies?

A. As Mr. Moul's testimony sets forth, generic factors such as interest rates and industry issues contribute to a determination of return on equity, but in the final analysis, the appropriate ROE level is specific to the company in question. For example, as noted previously Duquesne has a number of risk factors relevant to a wires-only utility that increase its risk, which should argue for a higher allowed ROE as compensation for that greater risk level.

Q. In the current interest rate environment, do you consider investors' expectations in the Company's prospective ROE award to be reasonable?

A. Yes, I do. Interest rates, as evidenced by fifteen 25 basis point increases by the Federal Reserve since 2004, are rising. And the interest rate factor is not the only one that investors are taking into account. I believe that, because of the greater risks that the industry is facing, investors are now requiring a higher risk premium on their utility investments. Thus, I think that the broader interest rate environment should not be considered in isolation in terms of establishing ROEs for utility companies. I would caution that establishing an anemic ROE award at the current time could quickly reverse the earnings prospects for the utility. With already limited financial flexibility and an existing weak cash flow situation, coupled with bond ratings barely above investment grade, Duquesne Light's need to access the capital markets could become greater as the risk of credit downgrades becomes even more pronounced, which in turn would result in a vicious negative cycle.

Q. *Please comment on Mr. Moul's ROE recommendation.*

A. Mr. Moul notes that the cost of equity capital for the Company is within a range of 11.25% and 11.75%. Investment risk in the electric utility industry is higher than it has been, and investors are requiring greater levels of compensation to assume that added risk. As an input in valuation models, earnings levels logically translate into the attractiveness of a stock, other factors being equal. A reasonable ROE award should sustain the Company's earnings power and affect the potential for future dividend growth. Conversely, a lower ROE could potentially undermine investors' expectations for dividend sustainability.

Q. Could a return on equity award that is consistent with investor expectations also be expected to provide benefits to Duquesne Light's customers?

A. Absolutely. A higher ROE permits the realization of a stronger earnings stream. In turn, that can improve a company's stock's valuation prospects, which results in a higher stock price. Thus, when a company needs to tap the equity markets for capital needed to meet customer needs, it can get more for its money. Said another way, each share sold brings more equity into the Company with the same commitment by the Company to generate earnings and pay dividends to support the value of that share. In regard to debt financing, a higher ROE awarded to Duquesne Light's would be viewed as a sign of constructive regulation and would be positive for the Company's credit rating. Importantly, customers' rates will eventually reflect this lower cost of capital.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

Figure JMC-1

JULIE M. CANNELL
P.O. Box 199
Purchase, New York 10577

BUSINESS EXPERIENCE:

1997-	J.M. CANNELL, INC.	
		President of firm providing advisory services specializing in the electric utility industry.
1977 - 1997	LORD ABBETT & COMPANY, New York, New York	
1995 - 1997		Equity Portfolio Manager. Responsibility for management and client servicing of ten institutional equity portfolios with total assets in excess of $700M. Actively and successfully involved in new institutional business marketing effort.
1994-1996		Associate Director of Equity Research. Provided oversight of departmental activities, including supervision of analysts' research efforts and support staff functions.
1992-1995		Portfolio Manager, America's Utility Fund. Full portfolio management responsibility for the fund since its May 1992 inception.
1978-1995		Securities Analyst. Sole responsibility for analysis of and stock recommendations for the electric utility and telecommunications.. industries. Other areas of coverage previously included housing (2 years) and pollution control (1 year).
Summer 1977		Research Assistant in Utilities.
1973-1976	UNIVERSITY OF COLORADO. Colorado Springs, Colorado.	
		Public Services Librarian Instructor in Bibliography to undergraduate and M.B.A. students

1971-1973 CAMERON COLLEGE, Lawton, Oklahoma.

Reference Librarian

EDUCATION:

1978	COLUMBIA UNIVERSITY, MBA - Finance
1971	EMORY UNIVERSITY, M.Ln. - Librarianship
1970	MARY BALDWIN COLLEGE, B.A. - English

MEMBERSHIPS:

Chartered Financial Analyst (C.F.A.)
CFA Institute
New York Society of Security Analysts
Wall Street Utility Group

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00061346

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APR - 7 2006

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

Duquesne Light Company

Statement No. 8

Direct Testimony of Robert L. O'Brien

Q. Please state your full name and business address.

A. My name is Robert O'Brien and my business address is 1753 Via Mazatlan, Rio Rico, Arizona 85648.

Q. By who are you employed?

A. I am employed by R. J. Rudden Associates, a business unit of the Enterprise Management Solutions Division of the Black & Veatch Corporation ("Rudden") as a Principal Consultant.

Q. Please describe your role in this proceeding.

A. I will testify regarding the overall revenue requirement, pro forma adjustments for the future test year ended December 31, 2006 ("FTY") and the historic year ended December 31, 2005 ("HY"), portions of the measures of value and the cash working capital calculation included in the Duquesne Light Company ("Duquesne", "Duquesne Light" or "Company") filing of the request for general rate relief before the Pennsylvania Public Utilities Commission ("Commission") in this docket.

Q. Please summarize your professional experience and educational background.

A. I joined Rudden in January 2000 as Vice President and have provided services to clients in the areas of Strategic Planning, State Regulatory Operations, Financial Planning, Rate Case Preparation and Rate Case Model Design. In January 2005, Rudden was acquired by Black & Veatch ("B&V") and is currently a unit of the Enterprise Management Solutions Division ("EMS") of B&V. Prior to joining Rudden, I was employed by Citizens Communications Company (formally Citizens Utilities Company) ("Citizens") from 1975 to 1999, most recently holding the positions of Vice President, Strategic Planning and Regulatory Affairs for Citizens' Public Utilities Sector (1997 to 1999) and Vice President, Corporate Regulatory Affairs (1978 to 1997). From 1967 to 1975 I was employed as controller by a series of companies engaged in the financial, communications, educational and printing industries. Prior to 1967, I was employee by Ernst & Young and attained the status of Senior Auditor after four years, including two years work experience during the 5-year work-study program at the University of Cincinnati. I graduated from the University of Cincinnati in 1965 with a Bachelor of Business Administration with a major in Accounting. I am a Certified Public Accountant.

Q. Have you previously testified before the Commission or other regulatory commissions?

A. Yes, I have testified before this Commission many times on behalf of Citizens' Water Companies or Divisions and Telephone Operations in Pennsylvania. In all, I have testified or presented testimony in over 200 proceedings before the state regulatory commissions in Arizona, California, Colorado, Hawaii, Idaho, Illinois, Indiana, Montana, Nevada, Ohio, Pennsylvania, Tennessee, Vermont and West Virginia for utility operations of electric, natural gas, communications, water and wastewater companies. I have presented testimony in company specific proceedings for general rate increases, commission ordered rate reviews, purchased energy pass through proceedings, acquisitions and sales of utility companies, disaster relief requirements and recovery of acquisition premiums. I have testified on the subjects of all measures of value elements including deferred income taxes and cash working capital and on revenues, rate design and rate of return. In addition, I have testified regarding all operating expenses including income taxes. Finally, I have testified in generic proceedings related to income taxes, purchased energy pass through clauses and changes in regulation of the communications and electric industries.

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

A. I will testify regarding

1. Revenue Requirement for Future Test Year 2006
2. Pro forma Plant in Service
3. Pro Forma Accumulated Depreciation
4. Cash Working Capital
5. Pro forma adjustments to expenses
6. Pro forma Depreciation Expense
7. Portions of the Historic Year 2005 presentation

Q. Before discussing the specific adjustments and schedules you sponsor, please describe the relationship of your work to that of the other Company witnesses.

A. In general, my assignment was to prepare pro forma adjustments to the Company's 2006 budget amounts to obtain a total Company pro forma test year presentation by Federal Energy Regulatory Commission ("FERC") account classifications for Mr. Crowley to use in his Jurisdictional Separation Study which determines the pro forma earnings at present rates and the revenue increase required for the Company's Pennsylvania jurisdictional distribution assets. As a starting point, I used the budgeted data provided by Ms. Betta, Mr. Coward, Mr. Macioce and other Company personnel. Where this data was not in FERC account format, I distributed the data to FERC accounts. In addition, I developed, working with Company personnel, pro forma adjustments based on total Company operations. Finally, I presented the total Company pro forma measures of value and operating results for the 2006 FTY to Mr. Crowley who, through the Jurisdictional Separation Study, determined the amounts correctly assigned to the Pennsylvania jurisdiction for the Company's distribution operations.

Q. Was this process also applied to the recorded year 2005?

A. Yes, in most part it was. The Commission requires that the Company, in addition to filing a fully adjusted future test year filed as DLC Exhibit 2, also file an adjusted historic year, which is included as DLC Exhibit 3. The Company used the recorded data for 2005 as the starting point. Pro forma adjustments, based on total Company levels of operations, were made to the recorded 2005 HY data and those totals were provided to Mr. Crowley who determined the jurisdictional amounts associated with the Company's Pennsylvania distribution business.

Q. What are the specific schedules you will sponsor in this proceeding?

A. I sponsor and will testify supporting all or parts of the following schedules for both DLC Exhibit 2, the 2006 FTY, and DLC Exhibit 3, the 2005 HY, where applicable:

1. Schedule C-2, Pro Forma Electric Plant in Service
2. Schedule C-3, Pro Forma Accumulated Depreciation
3. Schedule C-4, Cash Working Capital

4. Schedule D-2, Adjusted Operating Income at Present Rates
5. Schedule D-3, Adjustments to Net Operating Income
6. Schedule D-4, Summary of Adjustments by FERC Account
7. Schedule D-5, Summary of Revenue Adjustments
8. Schedule D-7, Annualization of Salaries and Wages
9. Schedule D-8, Normalization of Rate Case Expenses
10. Schedule D-9, Pensions and Employee Benefits Adjustment
11. Schedule D-10, Uncollectible and CAProgram Adjustments
12. Schedule D-11, Stay Warm Program Normalization
13. Schedule D-12, Employer 401(k) Contribution
14. Schedule D-13, Storm Restoration Cost Normalization
15. Schedule D-14, Normalization of Settlement Claims Payments
16. Schedule D-15, Annualization of Communications Expense
17. Schedule D-16, Annualization of Payroll Tax Expense
18. Schedule D-17, Depreciation Expense

REVENUE REQUIREMENT FOR FUTURE TEST YEAR

Q. Please describe how the Company's FTY 2006 Measure of Value was determined.

A. First, with regard to the utility plant in service and accumulated depreciation, the Company began with the closing balances at December 31, 2005 then added the budget amounts for 2006 capital expenditures which will be closed to plant in 2006 along with the appropriate 2006 plant retirements. The accumulated depreciation for 2006 was determined using the year end 2005 balances plus the budgeted depreciation expense and the 2006 plant retirements and other appropriate elements. A pro forma adjustment was made to plant to reflect the addition of a portion of the pension contribution and other adjustments to employee benefits that will be capitalized. The accumulated deferred income taxes ("ADIT") reflects a calculated amount for the Federal ADIT excluding ADIT on contributions-in-aid-of-construction ("CIAC"). This pro forma calculation was made to remove the ADIT on CIAC because the Company follows the Commission partial-gross-up procedure to recognize the income taxes due upon receipt of CIAC. Materials and supplies and customer deposits are reflected based on a 13-month average and working capital has been calculated using lead-lag study procedures. Each of these components of the measures of value will be described in my testimony or the testimony of other Company witnesses.

Q. Please describe how the revenues at present rates were determined.

A. Revenues at present rates reflect the budgeted revenues for Duquesne Light for the year ended December 31, 2006 as adjusted to reflect the removal of Seams Elimination Cost Adjustment ("SECA") revenues, the annualization of customers to year-end 2006 levels and an adjustment to recognize the difference between the revenue the Company expects to receive compared to the calculated revenue using billing determinates, also referred to as the bill frequency analysis ("BFA") adjustment.

Q. Please describe how the operating expenses for the FTY were determined.

A. The pro forma FTY expenses were calculated using the Duquesne Light 2006 budget as a starting point. The budget, which is prepared based on corporate activities and related cost elements, such as payroll, employee benefits, etc., was distributed to FERC accounts using the distribution actually experienced by the Company during the historical year 2005. The budgeted data was then adjusted to the pro forma amounts as will be described in connection with DLC Exhibit 2, Schedule D, pro forma adjustments. The adjustments are presented by cost element and then distributed to the appropriate FERC account for use by Mr. Crowley in his Jurisdictional Separation Study.

Q. Please describe the calculation of depreciation expense for the future test year.

A. The pro forma depreciation expenses for the FTY was determined using the year-end December 31, 2006 plant in service balances by FERC account and the depreciation rates contained in the Depreciation Study presented by Mr. Spanos included as Statement No. 10.

Q. How were the pro forma gross receipts and other taxes calculated?

A. In general the taxes are based on the Company's budgeted data and updated based on the pro forma adjustments. For example, budgeted payroll tax expense was increased to match the annualization of payroll rates and the gross receipts tax ("GRT") was calculated to match the pro forma revenue level at present rates. The GRT expense was increased to reflect the GRT that will be incurred as a result of the revenue increase requested by the Company.

Q. How were income taxes calculated?

A. Income taxes were calculated by Mr. Macioce as shown on Schedule D-18, page 1 of both DLC Exhibit Nos. 2 and 3 using regulatory procedures normally followed by the Commission. These include the use of synchronized interest expense, normalization of the Federal method difference, flow-through of other tax/book differences, recognition of the amortization of the unamortized investment tax credit and the use of a consolidated tax adjustment.

Q. How were these elements included in the determination of the distribution rate increase being requested by the Company?

A. Each of the budgeted and pro forma adjustment amounts, which will be described in testimony related to the specific filing schedule or requirement, were used to determine the total Company pro forma measures of value, revenues and expenses. These total Company amounts were provided to Mr. Crowley as the basis for the Jurisdictional Separation Study which determined the fully distributed costs and the revenue requirement for the Pennsylvania distribution operations.

Q. Is Mr. Crowley's Jurisdictional Separation Study being used to determine the cost of transmission service in this proceeding?

A. No, it is not. The cost of transmission service is calculated using the FERC Formula Method, which will be described by Mr. Crowley.

PRO FORMA PLANT IN SERVICE

Q. Please describe DLC Exhibit 2, Schedule C-2.

A. Schedule C-2 contains 8 pages and presents the Company's utility plant in service amounts for the FTY with pro forma adjustments.

Q. Please describe how the utility plant in service of $2.4 billion shown on DLC Exhibit 2, Schedule C-2, page 1, line 39 was determined.

A. That amount reflects the pro forma balance at December 31, 2006 which is based on the closing plant balances at December 31, 2005 and the budgeted plant additions using the 2006 capital expenditures as presented by Mr. Coward and retirements using a three-year average of retirements from prior years. In addition, two pro forma adjustments were made to add the capitalized portion of the Company's 2006 pension contribution as well as the capitalized portion of the additional Company's anticipated 401(k) match for employee performance to the plant additions for 2006. As will be described in connection with Schedule D-12, this additional match increases the Company match by $0.25 for each $1.00 contributed by employees up to the limits prescribed in the Company's plans.

Q. Why did the Company make an adjustment for the pension contribution?

A. The Company has made, and will be making ongoing pension contributions of $20 million for 2006 and each of the next several years. Consistent with the Commission's practice of using the contribution to the pension trust for ratemaking purposes, the Company has calculated its pension expense claim and its pro forma plant additions using the actual payment amount of $20 million for the FTY. This results in an increase in the budgeted expense for pensions and also an increase in the pension costs to be capitalized in 2006, which has been budgeted based on the estimated 2006 SFAS 87 pension amount calculated by the

Company's actuary and then used by the Company is $2.27 million. Of that total amount, $1.14 million is included in the budgeted expenses and $1.13 is included in the employee benefits capitalized. The adjustment to reflect the addition of the $8.8 million of pension costs capitalized was added to the budgeted construction expenditures for 2006 as shown in Schedule C-2, pages 5 and 6. The expense portion of $8.9 million is shown as an adjustment to FTY expenses on Schedule D-9, page 1, on line 13.

Q. Please describe what is contained on Section C-2, page 2.

A. Page 2 presents the budgeted year end plant balances summarized by FERC account categories for the end of FTY with the pro forma adjustment for pension costs and the 401(k) additional Company match, which results in the year end balance for the FTY in column 4.

Q. Please describe pages 3 and 4 of Schedule C-2.

A. Pages 3 and 4 show the plant in service balance budgeted as of the end of the FTY by FERC account in column 2. The pro forma adjustments were included in each plant account as shown in column 3, as calculated on Schedule C-2, pages 5 and 6, columns 3 and 4. The final FTY end amounts are contained in column 4 and brought forward to Schedule C-2, page 1.

Q. Please describe Schedule C-2, pages 5 and 6.

A. Pages 5 and 6 contain the Company's budgeted additions of plant for 2006 plus the pro forma adjustments by FERC account. The adjustment for the pension contribution and the adjustment for the 401(k) match will be described in connection with the calculations of each amount on Schedules D-9, page 1 and D-

12 respectively. Each of the adjustments was distributed to the FERC accounts based on the amount of budgeted additions, by account, as a ratio to the total additions.

Q. Why were the pension and 401(k) adjustments to plant distributed to FERC accounts based on the ratio of 2006 budgeted additions in each FERC account to the total 2006 additions?

A. This ratio procedure was used because these amounts associated with these adjustments would be part of the Company's employee benefits included in the capitalization overheads and therefore were distributed based on the budgeted expenditures closed to plant.

Q. Please describe pages 7 and 8.of Schedule C-2.

A. Pages 7 and 8 of Schedule C-2 present the retirements associated with the plant additions presented on pages 5 and 6. The retirements for 2006 were determined by a review of the major construction projects and the elimination of projects where no retirement was involved. For the remaining projects, an average of the three prior years' retirements to plant additions was used or the retirement cost was determined using the oldest vintage for the plant account.

Q. Who conducted these reviews and made the determinations?

A. The reviews and determinations were made by members of the Company's asset accounting staff in conjunction with members of Mr. Coward's construction team.

Q. What is the pro forma plant-in-service amount included in the Company's measures of values?

A. The total amount for the Company is $2.4 billion as shown on Schedule C-2, page 1, line 39 and on Schedule D-1, page 3, line 1, column 1. The amount used in establishing the jurisdictional distribution rates for Duquesne Light is the $1.9 billion shown on Schedule D-1, page 3, line 1, column 2. This amount is the result of certain plant being directly charged or allocated to the Company's FERC-jurisdictional business, as shown in the Jurisdictional Separation Study presented by Mr. Crowley.

ACCUMULATED DEPRECIATION

Q. Please describe DLC Exhibit 2, Schedule C-3.

A. This schedule contains 6 pages which presents the pro forma accumulated depreciation for the FTY.

Q. Please describe page 1 of Schedule C-3.

A. Page 1 presents the pro forma accumulated deprecation for the FTY by FERC account. This is based on the Company's budgeted plant additions presented in Schedule C-2 plus an adjustment for the depreciation related to the pro forma adjustments described in connection with pages 5 and 6 of Schedule C-2.

Q. What is contained on the remaining five pages of Schedule C-3?

A. Page 2 reflects a summary of the FTY year-end balances for accumulated depreciation as budgeted for 2006 with the adjustment for the 2006 depreciation on the pro forma adjustments to plant. Pages 3 and 4 contain the detail accumulated depreciation by FERC account is used by Mr. Crowley in the

Jurisdictional Separation Study. Pages 5 and 6 contain budgeted 2006 amounts for the cost of removal.

Q. **What is the total Company and Pennsylvania jurisdictional amount of accumulated depreciation included in the Company's Measures of Value for the FTY?**

A. The total Company amount is $746.9 million which is shown on Schedule C-3, page 1, line 39 and on Schedule D-1, page 3, line 2, column 1. The jurisdictional distribution amount is $613.1 million which is shown on page 3, line 2, column 2 of Schedule D-1.

CASH WORKING CAPITAL

Q. **Please describe DLC Exhibit 2, Schedule C-4, page 1.**

A. This is a summary of the Cash Working Capital ("CWC") calculations which are detailed on pages 2 to 16 of this schedule. The detail for each of these elements, which total $51.7 million shown on line 6 and included on page 3, line 4, column 1 in the Measures of Value summarized on DLC Exhibit 2, Schedule D-1, page 3 of 3 will be described in detail on the separate pages. The Pennsylvania jurisdictional distribution amount, shown on Schedule D-1, page 3, line 4, column 2 is $50.1 million which is supported by Mr. Crowley.

Q. **Please describe how the CWC was determined.**

A. The total CWC, based on total Duquesne Light operations was determined in the manner described in the schedules following page 1 of Schedule C-4 and each of the CWC components was then separated into the distribution related components by Mr. Crowley. The separated amount of the CWC was used as one of the elements to establish the proposed distribution revenue requirement.

Q. Please describe page 2 of Schedule C-4.

A. Page 2 contains a summary of the calculation of the revenue collection lag and the operating expense lag. The revenue lag-days are shown on line 1 and the expense lag-days for each of the expense components on lines 3 to 6 and summarized on lines 7 and 8. The net of these, a lag in the collection of revenue of 25.54 days shown on line 9, is multiplied by the Operating Expense per Day on line 10 to arrive at a base CWC amount of $35.5 million for operating expenses, as shown on line 11. The operating expenses per day, $1.4 million on line 10, is determined by dividing the total pro forma expense of $507.1 million, which excludes uncollectible and customer assistance program ("CAP") expense amounts, on line 7 in column 2 by the number of days in a year, 365. The other components of CWC are shown on lines 12 to 15 and will be described in connection with those supporting schedules. Finally, there is a reconciliation to the operating and maintenance expenses on lines 17 to 23 which show the total pro forma operating expenses of $537.9 million and those not included in the CWC O&M expenses of $78.8 million shown on line 6 in column 2.

Q. Please describe the revenue lag calculation shown on Schedule C-4, page 3.

A. The revenue lag days, 53.97 as shown on line 21, were determined using the ratio of the average monthly accounts receivable balance for the year 2005 shown in column 2 and the revenues from customer billings as shown in column 3 which results in an accounts receivable turnover rate of 9.93 as shown in column 4. The

9.93 accounts receivable turnover rate is equivalent to a 36.76 lag-day (365 days divided by 9.93 accounts receivable turnover rate) which is calculated and shown in column 5 on line 17. This payment lag is added to the 2-day lag between the meter reading day and the day the bills are sent and recorded as an account receivable by the Company which is shown on line 19. Finally, the service period lag of 15.21 days, which is the time from the mid-point of the service period until the meter reading date. This is then added to the billing and payment lag periods which results in a total revenue lag of 53.97 days as shown on line 21.

Q. **How was the mid-point of the service period calculated?**

A. The mid-point of the service period is equal to an average month, 365 days per year divided by 12 which results in 30.42 days and then divided by 2 to reflect the mid-point, or 15.21 days.

Q. **Please describe the calculations on page 4 of Schedule C-4.**

A. Page 4 presents the revenue by class of service for the years 2003 to 2005.

Q. **Please describe page 5 of Schedule C-4.**

A. Schedule C-4, page 5 shows the calculation of the expense lags used in the CWC calculation. Lines 1 to 5 reflect the payroll expense lag separated into the union and non-union payroll categories. The payroll amounts reflect the pro forma payroll for the FTY as calculated on Schedule D-7. The lag periods for the union and non-union are shown for each category and reflect the actual payment cycles. Lines 6 to 12 show the payment lead for the pension payment made by the Company in 2006 and planned for the next several years as described by Ms. Betta in her testimony. The Company currently plans to make annual pension payments in the amount of $20 million on or about the 31st of January. As such I have used that date to establish the payment lead for this expense. As shown on lines 6 to 8, approximately 49.7 percent of the annual payment will be capitalized and included in plant. The remaining 50.3 percent, $10.1 million on line 8 has been used to establish the lead days to be applied to the expense amount in the FTY in this proceeding. As shown on lines 9 to 11, the mid-point of the service period, the FTY, is July 1 which is 151 days after the planned payment date of January 31st of each year. This lead period was applied to the pro forma pension expense from Schedule D-9, page 1, line 12 which is shown on Schedule C-4, page 2, line 4.

Q. Please describe the lag day determination for the purchased energy costs shown on line 13 of Schedule C-4, page 5.

A. Line 13 reflects the lag in payment related to the purchased energy costs which is based on an agreement between Duquesne Light and its major energy supplier. This agreement provides that the Company shall wire transfer funds for energy delivered 35 days after the energy is delivered. As such, the payment is made 35 days after the delivery of service, for each day service is delivered. This is shown on line 13 and brought forward to Schedule C-4, page 2, line 5.

Q. Please describe the final expense lag calculation shown on Schedule C-4, page 5, lines 14 to 18.

A. The final expense lag calculation on lines 14 through 18, presents a calculation of an average payment lag for all remaining expenses. Page 6 of Schedule C-4 summarizes each of four months used to calculate the lag in payment of expenses.

The average lag days from these four months, the 34.86 days shown on line 13, column 4, was used to determine the lag days for all other expenses.

Q. Please describe how you determined the amounts shown on Schedule C-4, page 6 for the O&M expense lag.

A. I selected four months and requested that the Company provide a listing of all cash disbursements during those four months in a format that would show the payee, the date the service was provided or the invoice date, the amount of the disbursement, the date the payment cleared the bank, the account to which the disbursement was charged and other data associated with the disbursements. Each month's listing contained thousands of cash disbursements.

Q. What steps did you take to determine the cash disbursements used in your CWC study?

A. I added columns to the Company's schedule to show the number of days it took each disbursement to clear the bank and to calculate the dollar days (the amount of the disbursement times the number of days the payment took to clear the bank) and sorted the disbursements by amount of the disbursement. I then eliminated disbursements that would not be associated with expenses as recorded by the Company.

Q. What disbursements did you eliminate from the balances shown on page 6 of Schedule C-4?

A. First, I eliminated all disbursements over $200,000 because it is unlikely that the Company would have a single monthly disbursement for general operating expenses that would exceed $200,000 in a month. Second, I eliminated all expenditures under $1,000 since those amounts, while number of transactions is significant, would not have a significant impact on the overall lag days. Finally, I eliminated all disbursements charged to asset and liability accounts, except accounts payable, since those would not be part of the expenses recorded by the Company. Once these eliminations were completed, the remaining disbursements, approximately 700 per month as shown in column 1 on lines 1, 4, 7 and 10 of page 6 of Schedule C-4, were used to calculate the lag for the general expenses. The lag days on the lines entitled, "Total Test Month Disbursements Used" for each month and summarized on line 13 for all months was used to calculate the O&M expense payment lag on Schedule C-4, page 2, line 7.

Q. **Schedule C-4, page 6 also contains disbursement lags for the accounts payable. Why is that shown separately?**

A. Since some costs are charged to expense through accounts payable, it was appropriate to examine the lag in the payment of accounts payable separately from the lag for expenditures charged directly to expense. The amounts on the line entitled, "Total Test Month A/P Disbursement" show the data for the accounts payable payments and the last line in each month, summarized on line 15, reflects the lag days for only the expense items.

Q. **Please describe how the amount for the average prepayments of $4.2 million included on line 12 of Schedule C-4, page 2 was determined.**

A. That amount is calculated on page 16 and reflects a thirteen month average of estimated amounts for 2006. The monthly estimates for 2006 are based on the monthly averages in 2004 and 2005 which are also shown on page 16.

Q. Please describe the calculation of the accrued tax component of working capital shown on line 13 of Schedule C-4, page 2 and also on page 7.

A. These calculations on page 7 of Schedule C-4 use the pro forma expense at proposed rates shown in column 1 and the 12 month accrued factor shown in column 2. The result of the multiplication of those components is shown in column 3 and used as the working capital related to the taxes paid by the Company. The 12-month accrual factor for each of the tax expense items is calculated on pages 10 through 14.

Q. Please describe the calculation of the interest expense lag shown on page 8 and included on line 14 of Schedule C-4, page 2.

A. This calculation measures the lag associated with the semi-annual payment of interest relative to the revenue lag calculated on page 3 of Schedule C-4. The pro forma interest expense is the amount resulting from the synchronized interest calculation resulting from the use of the pro forma measures of value and the weighted cost of debt included in the rate of return. This calculation is shown on lines 1 to 4 of page 8. The daily amount is calculated on line 5 which is multiplied by the difference in the lag days of 37.3 for a reduction to the working capital of $4.6 million as shown on line 9 and included on page 2 on line 14.

Q. Please describe the calculation for the working capital component related to the preferred stock payments.

A. This calculation, as shown on page 9 of Schedule C-4 follows the same procedures as the calculation for interest expense on page 8. The pro forma dividend amount is calculated on lines 1 to 4 and the per day amount shown on line 5. The lag days are calculated based on the quarterly dividend payment and the result is an addition to working capital of $169,000 as shown on line 9 and also on line 15 of Schedule C-4, page 2.

Q. Please describe the calculations on pages 10 to 15 of Schedule C-4.

A. These pages provide the calculations of the 12-month accrued factor used on page 7 to determine the CWC related to the taxes paid by the Company. The revenue components of the calculation on lines 1 to 4 of each page 10 to 13 are contained on pages 14 and 15. The payment dates and percent due for each of the tax expense items listed on Schedule C-4, page 7 are shown on lines 5 to 8 of pages 10 to 13 and the total percent available for each tax expenditure is shown on line 10 of each schedule. The average percent available for each tax expenditure is shown on line 11 in column 1 and brought forward to page 7 of Schedule C-4.

Q. Why is a separate calculation made for each of the tax expenses?

A. This is necessary because each of the tax expense items has separate payment dates, with the exception of the Pennsylvania Income Tax and the Pennsylvania Capital Stock Tax. As shown on page 10 of Schedule C-4, 25 percent of the estimated amount for the Federal income tax payments are due on April 15th, June 15th, September 15th and December 15th of each year. Using a separate calculation for each tax expense provides a matching of the cash requirement for payment of those expenses with the anticipated revenues.

Q. Is the same true for the other taxes on pages 11 to 13 of Schedule C-4?

A. Yes, it is.

Q. What is the amount of CWC included in measures of value?

A. That amount is the $51.7 million shown on Schedule C-4, page 1, line 6 and on Schedule D-1, page 3, line 4, column 1 for the total Company and $50.1 for the jurisdictional distribution amount on Schedule D, page 3, line 4, column 2.

CUSTOMER DEPOSITS

Q. **Please explain how the amount for the customer deposits that was deducted from measures of value as shown on line 8 of DLC Exhibit No. 2, Schedule D-1, page 3, column 1 was determined.**

A. That amount reflects the balance budgeted to be in the customer deposit account at December 31, 2006 as reflected in account number 235.

Q. Why was the year-end amount used instead of an average for the FTY?

A. The year-end amount was used because the balance in this account has been decreasing in each of the last several years, from $2.2 million at the end of 2004 to $1.7 million at the end of 2005 and projected to be $1.4 million at the end of 2006. As such, it was deemed to be more appropriate to use the year-end amount to match the use of year-end plant, number of customers, employees and other elements used for the FTY.

PRO FORMA ADJUSTMENTS TO REVENUES

Q. Please describe DLC Exhibit 2, Schedule D-2.

A. This schedule contains a summary showing revenues, operating expenses, depreciation and taxes other than income taxes at present rates, beginning with the Company's budget for the test year 2006, column 1, and pro forma adjustments to annualize and/or normalize those test year revenue and expenses in column 2. The pro forma data in column 3, which also includes a calculation of income taxes at present rates, was used by Mr. Crowley in his Jurisdictional Separation Study. Mr. Crowley also calculates the overall revenue requirement and revenue increase for the Pennsylvania jurisdiction for distribution service provided by the Company. The budget amounts in column 1 are supported by the testimony of Ms. Betta, while the adjustments to revenue and expense elements will be discussed in my testimony. The separate revenue and expense adjustments summarized in column 2 are detailed on Schedule D-3 for the expense adjustments and Schedule D-5 for the revenue adjustments.

Q. **Please describe DLC Exhibit 2, Schedule D-3.**

A. This schedule contains two pages and presents a summary of the adjustments to revenue on lines 1 to 15 in column 2, which are shown by separate adjustment on Schedule D-5. In addition, each separate expense adjustment is shown on lines 18 through 31 in columns 3 through 11 on page 1 and columns 1 through 6 on page 2. Each of the expense adjustments has been calculated by type of expense, such as payroll, pension, etc., and then distributed to the correct FERC account as will be described in connection with the expense adjustment explanations.

Q. **Please describe the adjustments to revenue shown in column 2 on Schedule D-3.**

A. The adjustments summarized in column 2 are shown in detail on Schedule D-5 which shows a total of 5 adjustments to revenue. Adjustment # 1 in column 2 reflects the elimination of the SECA revenues the Company has collected because the Company expects all collections for SECA to be completed by the end of 2006. As such, the Company has eliminated these revenues as well as the amortization of the expense related to these revenues, as shown on page 2 of Schedule D-3, line 29 of approximately $9.0 million. The Company has also removed the related GRT expense.

Q. What is adjustment # 2 shown in column 4 of Schedule D-5?

A. This adjustment annualizes revenues for the number of customers at the end of 2006, the FTY. The Company calculated this amount by first determining what test year kWh sales would have been by tariff schedule if all the customers at December 31, 2006 had been served throughout the year at the same average annual use per customer contained in the 2006 budget. This amount was then compared with the 2006 budgeted sales and the difference provided the annualization adjustment to sales, stated in kWh. Then, the average revenue per billing determinant by tariff schedule, in cents per kWh, was multiplied by the sales adjustment, in kWh, to compute the annualized revenue adjustment. This additional revenue of approximately $1.5 million was included on a pro forma basis to adjust revenues to the end of the FTY.

Q. Please describe the calculation of adjustment # 3 to revenue on Schedule D-5.

A. This adjustment is the result of a comparison of the calculated revenues from the billing model used to determine the revenues at present and proposed rates to the actual revenues received by the Company. This adjustment reflects the recognition that a utility will not actually receive the revenues calculated using a bill frequency analysis ("BFA") because of partial bills, billing and other adjustments that take place during the course of the BFA measurement period. This is a normal adjustment when setting rates using BFA data. In my experience, if the calculated to recorded revenue ratio is within one percent, the BFA is deemed to be accurate and there is an adjustment to the BFA calculated revenue to reflect that difference.

Q. How did the Company make the recorded revenue to BFA calculated revenue comparison for the 2006 FTY?

A. Since 2006 recorded revenue data is not available, the Company used 2005 recorded and BFA data for the comparison.

Q. What was the result of the comparison of the recorded revenue for 2005 and the calculated revenue using the 2005 billing determinates?

A. The BFA calculated revenues at the tariff rates for 2005 were $710.5 million while the comparable recorded revenue was $709.5 million, a difference of approximately $1.0 million or 0.14 percent, far less than the one percent level. The comparison also showed that the calculated revenues would exceed the revenue the Company was likely to receive and therefore there should be a reduction in the BFA calculated revenues at present rates to reflect this difference. As such, I reflected an estimate of $900,000 as my BFA adjustment for the FTY as shown on line 16 in column 5.

Q. Please describe the State Tax Adjustment Surcharge ("STAS") reclassification in column 6 of Schedule D-5.

A. This adjustment rolls-in the STAS credits back to the tariff schedules to which they relate. As shown on lines 1, 10 and 12 in column 6, this adjustment does not impact on the Company's revenue level or revenue requirement.

Q. Please describe the final revenue adjustment # 5, shown in column 7 of Schedule D-5.

A. This adjustment reflects a reconciliation between two groupings of billing determinates that the Company used to calculate its revenues, one for its budget and another for calculating revenues at present and proposed rates in this proceeding. The Company has calculated and grouped its billing determinates by customer classification, Residential, Commercial, Industrial and Street Lighting for budget and reporting purposes and made such a calculation for the budgeted revenues which are shown in column 2. For rate making purposes it is necessary for the Company to make its revenue calculations based on its tariff and rate schedules which, in some instances, contain customers from more than one rate schedule. The BFA calculation was made using the billing determinates based on the tariff schedule classifications and not the customer classifications. The Company felt it was necessary to reflect an adjustment to eliminate any revenue distortion from the use of these two very similar, but slightly different billing determinate bases. The adjustment # 5 reflects an adjustment of $65,000 increasing the recorded revenue to the level of the BFA based revenue calculation. This adjustment reduces the Company's overall revenue increase requirement.

PRO FORMA ADJUSTMENTS TO EXPENSES

Q. Does the Company budget its operating expenses by FERC account?

A. No, it does not. The Company normally budgets its operating expenses by cost element or corporate activity, such as payroll, employee benefits, rent, etc.

Q. Please describe how the Company developed the 2006 budget by FERC account for this rate application.

A. First, the Company prepared its 2006 budget by cost element. Once the budget for 2006 was finalized, Duquesne Light used the recorded 2005 FERC balances as the basis for the distribution of the 2006 budget expenses by FERC account. This was done by first analyzing 2005 to develop a chart showing each cost element within each FERC account. Once this was completed, the budgeted cost categories were distributed to the same FERC accounts using the ratio actually experienced in 2005.

For example, I determined how much of the $55.7 million in payroll was charged to each FERC account for 2005 and then, using the ratio of the amount charged to each FERC account in 2005 to the total for payroll for 2005, I distributed the 2006 budgeted payroll to those FERC accounts. This process was used for each cost category to transform the 2006 expense category budget to a FERC based budget.

Q. Why was it necessary to transform the 2006 cost category budget to a FERC based budget?

A. In order to develop a Jurisdictional Separation Study and a Class Cost of Service Study for the FTY, it was necessary to have the budget data by FERC account. This permits Mr. Crowley to allocate the payroll and other expenses based on standard allocators depending on which FERC account the payroll or other expenses are charged. Different FERC accounts result in different expense charges to the Company's distribution service. This FERC account classification is also required by Mr. Gorman for his Class Cost of Service Study. Since the Company did not have a procedure to budget by FERC account, I used the 2005 recorded data as the basis for the budget distribution.

Q. Did Company personnel review the process to determine if there were any significant changes expected in 2006 that would have to be recognized differently?

A. Yes. Company personnel reviewed the results of the ratio process and, upon completing its review, determined that there would have to be some adjustments to the distribution of some expenses. These included specific items such as a change in the distribution of outside consultant costs because of an adjustment in 2005 which transferred costs from account number 908 to account number 904. This was required because the actual CAP enrollment and anticipated costs exceeded approved Universal Service plan levels. As a result, the Manager, Universal Services sought approval to utilize some of Duquesne Light's Low Income Usage Reduction Program (recorded in account 908) accrued funds from previous program years to cover the additional CAP costs (recorded in account 904). Approval from the Bureau of Consumer Services was received in August 2005. This transfer is not anticipated in 2006 and therefore account 908 was increased before the remainder of the outside service cost element budget was allocated using the recorded 2005 balances. There were several such adjustments made to the general process of distributing the Cost Element budget amounts to the FERC accounts.

Q. Does this process result in a fair presentation of the Company's 2006 budgeted expenses by FERC account?

A. Yes, it does.

Q. Please describe DLC Exhibit 2, Schedule D-3.

A. Schedule D-3 contains two pages which show the 2006 budget summarized by FERC account categories and showing each of the pro forma adjustments by expense category and FERC account category, which result in the pro forma expenses for the test year 2006. Each of the adjustments will be described in connection with the specific schedule. For example, the adjustment in column 4 for Salaries and Wages will be described in connection with Schedule D-7 both in the amount of the adjustment and the distribution to the FERC accounts shown on lines 21 to 26. These total Company amounts which are used by Mr. Crowley to determine the costs associated with the distribution portion of Duquesne's operation. Each of the cost elements are identified in the headers of each column on pages 1 and 2 and each adjustment is described in connection with a separate schedule showing the calculation of the adjustment.

Q. What is contained on DLC Exhibit 2, Schedule D-4?

A. Schedule D-4 consists of two pages which show, by FERC account, the FTY budget amounts for the total Company in column 1, the total Company pro forma adjusted budget amounts in column 2 and the Pennsylvania jurisdictional amounts determined by Mr. Crowley's Jurisdictional Separation Study in column 3.

Q. What are the total pro forma present rate revenue and expense amounts that will be used by the Company to determine the Pennsylvania jurisdictional revenue requirement and rate increase?

A. Those are the amounts in column 3 that include only the Pennsylvania jurisdictional elements as determined by Mr. Crowley.

Q. Why is it necessary to show the total Company data?

A. Duquesne Light used the total Company amounts to distribute its budgeted expenses and make its pro forma FTY adjustments and therefore we are showing these amounts for comparison. Mr. Crowley used the pro forma total Company revenues at present rates and total Company expenses as his starting point for the Jurisdictional Separation Study and the Pennsylvania jurisdictional revenue requirements.

Q. Please describe DLC Exhibit 2, Schedule D-7.

A. Schedule D-7 contains two pages and shows the calculation of the annualization adjustment for salaries and wages ("S&W") for the FTY. Column 1 contains the 2006 budget data which is described in the testimony of Ms. Betta which shows that $56.9 million (line 16) of the total payroll was charged to expense in the 2006 budget. Column 5 shows the annualization adjustment of $2.8 million distributed to the expense accounts with a pro forma S&W expense in the amount of $59.7 million as shown in column 6 on line 16.

Q. How was the annualization adjustment calculated?

A. The calculation, shown on page 2 of Schedule D-7. The basis for the calculation was the budgeted S&W charged to expense of $56.9 million, shown in column 4 on line 3, and by component as shown in columns 2 and 3, which included all employees, including new hires in 2006, as they are projected to be hired during the calendar year 2006. Also included is the 4 percent pay rate increase, as required by the current union contract for the union members which will become effective on October 1, 2006 and a 4 percent pay raise for management employees which will become effective on January 1, 2007. The adjustment shown on page 2 of Schedule 7 provides for an annualization of the employees to reflect the number projected for the end of 2006 and of those pay rate increases to reflect them in expense in the FTY. This results in an increase in the annual S&W of $2.8 million as shown on line 19, column 7. This amount was then distributed to each FERC account based on a ratio equal to the distribution of the base S&W as summarized on page 1 in column 5.

Q. Please describe DLC Exhibit 2, Schedule D-8.

A. Schedule 8 shows the adjustment to normalize the rate case expenses for the FTY. The Company has expended approximately $1.8 million through the end of 2005 and has budgeted an additional $3.3 million for 2006. The normalization adjustment, which normalizes the costs over a three-year period, includes one-third, or $1.7 million as a normalized expense for the FTY.

Q. Does this amount include charges for both the Pennsylvania jurisdiction distribution and the FERC transmission cases?

A. Yes, it does. Since a good portion of the work impacts both jurisdictions, we have included an estimate of the total expenditures for all work. Mr. Crowley has distributed a portion of the total normalized amount to the Pennsylvania jurisdiction and a portion to the FERC jurisdiction.

Q. Please describe DLC Exhibit 2, Schedule D-9?

A. Schedule D-9 contains the annualization of the employee benefits on lines 1 to 5 in the amount of $328,000 which is associated with the annualization of S&W discussed earlier in connection with Schedule D-7. The calculation of the normalization of benefits is based on the change in the number of employees shown on page 2 of this schedule. The adjustment for pension costs shown on lines 6 to 13 adjusts the budgeted charges to capital and expense to reflect the use of the 2006 pension contribution payment amount of $20 million. The expense adjustment is calculated as the difference between the percent charged to expense of $10.1 million shown on line 9 and the budgeted amount charged to expense of $1.1 million using the SFAS 87 procedure as shown on line 11. It is my understanding that the Commission has used the reasonable level of the pension contribution in the FTY to determine the allowance for pension expense, after capitalizing a portion of the contribution for ratemaking purposes.

Q. Is the Company requesting specific accounting provisions related to pension costs under SFAS 87 and the ratemaking treatment of pension costs?

A. Yes, it is. These matters are explained in Ms. Betta's testimony.

Q. Please describe DLC Exhibit 2, Schedule D-10.

A. Schedule D-10 reflects the adjustment to the Company's budgeted uncollectible expenses, Customer Assistance Program ("CAP") and other customer related programs that are explained in the testimony of Ms. Sandoe. Lines 1 to 4 calculate a three-year average of the estimated amount for the uncollectible expenses, excluding the CAP and other programs to be used in determining the level of the uncollectibles to be provided for in the determination of the jurisdictional revenue increase required. Line 7 reflects the amount of CAP and uncollectible expense included in the Company's 2006 budget and lines 8 to 10 reflect adjustments to the CAP expenses for the FTY. The total CAP and uncollectible included for the FTY at present rates is $27.7 million of which $8.5 is the budget for uncollectibles and $19.2 million is for the budget and pro forma adjustments related with CAP as detailed in the adjustments.

Q. Please describe how you calculated the three-year average factor for use in determining the revenue increase required.

A. I first estimated the amount of the uncollectibles for each year to remove the CAP and related expenses which will be addressed separately. The uncollectible amounts for each year are shown on lines 1 to 3 in column 2 and are divided by the annual revenues for each year. These calculations were initially done using estimates for the uncollectible amounts and the CAP amounts, which resulted in an average percent of 1.07 which is shown on line 5 and was used to determine the uncollectible expense to be provided for in the revenue requirement determinations. When the final breakdown of CAP versus uncollectible expenses was provided, the actual average three-year percent for uncollectibles was 1.31 percent as shown on line 4 but the initial calculation of 1.07 percent was not changed at that time due to the status of the overall rate filing.

Q. How does the Company's budget amount of $8.5 million for uncollectibles at present rates for the FTY compare with this three-year average?

A. It is approximately the same as the average. The percent for budget 2006 of 1.23 on line 3 is slightly below the 1.31 percent shown on line 4 for the three-year average and also slightly below the average (1.35 percent) for the years 2004 (1.05 percent) and 2005 (1.65 percent) which are shown separately on lines 1 and 2.

Q. Is the budget estimate of $8.5 million for the uncollectible amount at present rates a reasonable level for the FTY?

A. Yes, it is. It is approximately the same as the average for the prior two years.

Q. Why did you exclude an estimated amount for the CAP related expenses?

A. I am proposing to establish a separate adjustment for the CAP costs to recognize the number of CAP customers added during the test year, recognition that the CAP customers will need additional assistance related to the revenue increase requested by the Company and finally to recognize that the Company will have additional CAP customers in 2007 and 2008 when the new rates from this rate application will become effective. Lines 8, 9 and 10 respectively reflect these adjustments.

Q. Please describe the adjustment to annualize CAP to the year-end customer level.

A. The CAP budget was determined estimating the number of CAP customers during the course of the FTY. The number of CAP customers is expected to grow from 23,000 customers at the end of 2005 to 25,000 customers at the end of the FTY

2006. This adjustment on line 8 of Schedule D-10 estimates the CAP costs annualized at the year-end 2006 level of customers.

Q. Please explain the adjustment on line 9 of Schedule D-10.

A. This adjustment is designed to recover the costs of increasing the discount for customers in CAP at the end of 2006 to include a provision that would keep the amount required to be paid by the customer at the same level before and after the Company's requested revenue increase becomes effective. This pro forma expense will provide the necessary revenue and will allow the Company to retain the present rate CAP customer payment level even after the rate increase.

Q. What is the last component of the CAP adjustment shown on line 10 of Schedule D-10?

A. The Company expects to add approximately 2,000 customers per year to CAP in 2007 and would expect CAP to continue to grow in 2008. This adjustment reflects the historic growth in CAP customer participation continuing into 2007 and 2008 once the new rates from this proceeding have become effective. The Company has used the average increase in CAP customer participation for 2007 and 2008 to calculate the cost of adding those customers to CAP once the new rates have become effective.

Q. What is the total for the uncollectible and CAP-related costs included in the Company's request for recovery in this case?

A. The amount is $27.7 million which includes approximately $8.5 million for uncollectibles and $19.2 million for CAP.

Q. Please describe DLC Exhibit 2, Schedule D-11.

A. Schedule D-11 shows the adjustment for a normalized level of costs associated with the Company's Stay Warm programs that were initiated in 2005 to cover the heating season ending March 31, 2006, and will continue into 2006 and thereafter as explained by Ms. Sandoe. The Company is not seeking to recover any costs for the 2005/2006 winter period or for the portion of the test year costs that will be incurred in the 2006 heating season beginning on December 1, 2006 before new rates from this proceeding are expected to be effective. The $1.2 million is the Company's estimate of the normalized annual expenses for these programs that the Company plans to operate on an ongoing basis if approval for recovery of these costs is obtained in this proceeding.

Q. Please describe the adjustment on DLC Exhibit 2, Schedule D-12.

A. This adjustment reflects an additional Company contribution to the employees' 401(k) account to recognize the employees' attaining safety or other non-financial goals for the FTY. The Company does not budget for this match, but the employees have attained the goals most of the recent years and the Company believes it is appropriate to provide for this amount in the expenses for the FTY. The calculation on Schedule D-12 shows the amount of the additional match distributed to capital and expense using the factors for the FTY. The portion charged to capital is reflected as an adjustment to the test year plant additions included on DLC Exhibit 2, Schedule C-2 and the expense portion is shown on line 6.

Q. What is the basis for the employer 401(k) match?

A. The Company has a Management Plan and an IBEW plan which provides that the Company will match a percent of each dollar an employee contributions to a 401(k) account up to the limits of each plan. The additional match included in this adjustment reflects an additional $0.25 of each eligible employee dollar contributed to the 401(k) account if the performance objectives.

Q. Please describe the adjustment shown on DLC Exhibit 2, Schedule D-13.

A. This adjustment reflects the Company's best estimate for the FTY storm restoration expenses, which is based on the average of the cost of insurance coverage from 2003 to 2006. The Company is currently reviewing its coverage options because the cost of this coverage, when viewed with the substantial increase in the per event deductible, has been increasing significantly over the last several years. The per incident deductible was $1.0 million in 1998 and was increased to $2.5 million in 2002 due to adverse loss experience.

The cost of storm restoration coverage has increased over the last several years from $336,000 with a $1.0 million per incident deductible in 1998 to an estimated cost for the 2006/2007 coverage period of $950,000 compared to an annual cost of $824,000 for the 2005/2006 coverage, both with a per incident deductible of $2.5 million. In addition, the most recent insurance coverage had a recovery cap of $5.0 million per incident. This means that the Company would not recover storm restoration costs up to the deductible, the first $2.5 million, and would be limited in its recovery to costs exceeding $2.5 million up to $7.5 million making the maximum the Company could recover $5.0 million, the difference between the deductible and the recovery cap.

Q. How has the Company estimated its expense in the FTY, as filed?

A. The Company has included an estimated expense for the FTY of $897,000 which is the average of the annual insurance premium over the four years 2003 to 2006. This is slightly less than the 2006 annual premium estimated by the Company for such coverage, without considering the level of deductible that should be included as part of a normalized test year expense. The Company believes it is necessary to consider both the annual premium and the deductibles to establish a reasonable level of costs for storm restoration expenses for the FTY. The actual adjustment is $691,000 because the Company had already included, in the 2006 budget, the last three months of the 2005 premium which extended coverage to March 31, 2006.

Q. What is the Company proposing in this filing?

A. The Company is proposing to establish an expense for storm restoration cost of $897,000 as shown on DLC Exhibit 2, Schedule 13, line 6. In addition, the Company proposes to request Commission approval for the deferral and future recovery in rates of specific storm restoration costs which are significantly above the annual estimate of $897,000 on a case by case basis. The Company would make a separate filing with the Commission for deferral approval of each incident so the related costs and expenditures can be reviewed separately.

Q. Please describe DLC Exhibit 2, Schedule D-14.

A. Schedule D-14 presents an adjustment to recognize settlements of damage and injury claims. The adjustment reflects the average of the amounts the Company has incurred over the last three years, 2003 to 2005, beyond what was budgeted for during those periods. The Company budgets only for such claims related to the operations areas of the Company where Company personnel are involved. The Company does not budget for claims related to actions of third parties that do not directly involve Company operations personnel. The amounts budgeted by the Company related to Company personnel have approximately equaled the claims over recent years and are not included in the calculation of this adjustment. The pro forma adjustment relates solely to claims brought by third parties concerning Company property or other activities for which the Company does not budget. These would include instances where someone is injured by a putting a ladder on a Company electric wire or has some other action which generates a claim. The Company has included an adjustment of $157,000, the average of these third party claims over the last three years as its expense in the test year.

Q. Please describe DLC Exhibit 2, Schedule D-15 and the adjustment for Communications Annualization.

A. This adjustment recognizes the annualization of the costs of a new communications system that will be implemented by the Company beginning in July 2006. The $75,000 monthly rental charge has been budgeted to begin in July and therefore the Company has budgeted a total of $450,000 for the second six-months of the test year. This adjustment annualizes that amount for the entire test year and is based on Commission approval of this transaction by July 2006

Q. Would you briefly describe the nature of this communication rental charge?

A. This agreement provides for an increase in the level of service to Duquesne Light related to Duquesne's Sonet Network ("DSN"). The existing Master Fiber

Services Agreement does not provide sufficient diversity, rotating rings or other elements required for the Company's current and future operations. This new agreement will provide the additional fiber capacity and service required by the Company. These point-to-point, unlit, single mode fiber optic strands will be used exclusively by Duquesne Light for the term of the agreement.

Q. Are you responsible for the adjustments on DLC Exhibit 2, Schedule D-16?

A. Yes, I am. Mr. Macioce is responsible for the budget amounts in column 2.

Q. Please describe the adjustments on Schedule D-16.

A. There are two types of adjustments reflected on Schedule D-16. The first adjusts payroll taxes in accordance with the S&W annualization adjustment discussed in connection with Schedule D-7. The annualization of the payroll related taxes and unemployment insurance shown on lines 5 to 8 in column 4 are reflected on page 2 of Schedule D-16. The amount of the S&W annualization is shown on line 1 in column 4 and the related increases in the taxes and unemployment insurance amounts are calculated on lines 2 through 13. The second relates to changes in the GRT resulting from the adjustments to revenues at present rates discussed in connection with DLC Exhibit 2, Schedule D-5. The expense reduction of $559,000 shown in column 4 on line 9 reflects the reductions in present rate revenues shown on Schedule D-5.

PRO FORMA DEPRECIATION EXPENSE

Q. Please describe the adjustment to depreciation expense.

A. The deprecation expense adjustment reflects the use of the balance of plant, by FERC account, at the end of the FTY and the new depreciation rates presented by Mr. Spanos, which will be effective beginning on January 1, 2007. As shown on Schedule D-17, page 2, line 64, column 10, the annualized depreciation expense is $70.8 million, which is $11.3 million greater than the pro forma depreciation expense for 2006 calculated in column 9. The budgeted depreciation expense also includes $3.975 million, calculated on pages 3 and 4 of Schedule D-17 at both the current and proposed depreciation rates, for the annual amortization of the salvage as prescribed by the Commission. The total pro forma depreciation expense therefore is the total of those amounts or $74.8 million shown on page 6, line 64, column 10.

Q. What are the reasons for the increase in pro forma depreciation expense?

A. There are two reasons for the increase. The first is that the pro forma depreciation expense uses the new depreciation rates proposed by Mr. Spanos. Using these rates effective January 1, 2007 will match the depreciation expense with the revenue set by the Commission in this proceeding. The third is the use of the year end 2006 plant balances. The combination of these two adjustments, as shown on Section D-2, Schedule 2, reflects the total change in depreciation from the 2006 budget and the pro forma expense.

REVENUE REQUIREMENT FOR HISTORIC TEST YEAR

Q. Please describe how the Company's presentation for the HY 2005 was determined.

A. The Company's presentation for the HY 2005 was determined using recorded data from 2005 with pro forma adjustments to measures of value, revenues and expenses similar to those used for the FTY 2006. The pro forma HY 2005 data was first calculated on a total Company basis and then was separated into the distribution elements by Mr. Crowley. These adjustments and separation process will be described in connection with those sections of the Company's presentation.

Q. Please identify the portions of DLC Exhibit 3, Historic Year 2005 data that you are sponsoring.

A. I sponsor or co-sponsor the following schedules for DLC Exhibit 3:

1. Schedule C-2, Pro Forma Electric Plant in Service
2. Schedule C-3, Pro Forma Accumulated Depreciation
3. Schedule C-4, Cash Working Capital
4. Schedule D-2, Adjusted Operating Income at Present Rates
5. Schedule D-3, Adjustments to Net Operating Income
6. Schedule D-4, Summary of Adjustments by FERC Account
7. Schedule D-5, Summary of Revenue Adjustments
8. Schedule D-7, Annualization of Salaries and Wages
9. Schedule D-8, Normalization of Rate Case Expenses
10. Schedule D-9, Pensions and Employee Benefits Adjustment
11. Schedule D-10, Uncollectible and CAP Adjustments
12. Schedule D-15, Annualization of Communications Expense
13. Schedule D-16, Annualization of Payroll Tax Expense

14. Schedule D-17, Depreciation Expense

Q. Are the pro forma adjustments included in DLC Exhibit 3 for the HY basically the same as those included in DLC Exhibit 2 for the FTY?

A. Yes, they are.

Q. Please identify the pro forma adjustments included in DLC Exhibit 3, Schedules C-2 and C-3.

A. The only pro forma adjustment is for the capitalization of a portion of the pension contribution which is shown on Schedule C-2, pages 3 and 4 and explained in connection with DLC Exhibit 2, Schedules C-2 and D-9.

Q. Has the CWC shown DLC Exhibit 3, Schedule C-4 been determined using the same procedures and principles used in DLC Exhibit 2?

A. Yes, it has. The CWC final amount is shown on DLC Exhibit 3, Schedule C-4, page 1 of 6.

Q. Has the Company made similar pro forma adjustments to the expenses contained on DLC Exhibit 3, Schedules D-2 to D-15 for the HY as were made for the FTY and described in connection with those schedules in DLC Exhibit 2 for the FTY?

A. Yes, with several exceptions where the adjustments are not required for the HY. These include the pro forma adjustments in the FTY shown on DLC Exhibit 2, Schedules 10 to 13. In each of these instances there was no pro forma adjustment made because the HY recorded balance reflected an expense level that was reasonable.

Q. Please briefly describe these items.

A. The pro forma adjustment for the normalization of the Stay Warm expense presented on Exhibit 2, Schedule D-11 for the FTY of $1.2 million was not needed for the HY because, as shown on that schedule, the Company expected a normalized expense for 2005 of $1.3 million of which approximately $1.0 million was recorded in the HY 2005. In addition, the Company recorded amounts for the Storm Restoration Insurance (pro forma adjustment included on DLC Exhibit 2, Schedule D-12) and for the claims settlement expense (pro forma adjustment on DLC Exhibit 2 Schedule D-13), and therefore it was not necessary to include pro forma adjustments in DLC Exhibit 3 for the HY.

Q. Were there any adjustments that should have been made, but were not?

A. Yes, there were. First, the Company should have made an additional adjustment to remove SECA revenues from Other Revenues in the amount of $1.9 million but did not. This was an oversight and would have reduced revenues for HY 2005 at present rates, but would not have any impact on the pro forma revenue at 2006 proposed rates. In addition, the additional match for the 401(k) incentive was not accrued at the end of 2005 and should have been a pro forma adjustment for 2005. This would have reduced the net operating income at pro forma present rates, but again would not have reduced the pro forma revenue. The rate of return on DLC Exhibit 3, Schedule D-1 would have been slightly lower if this pro forma expense adjustment had been made.

Q. Are the pro forma adjustments for the Taxes-Other Than Income Taxes and Depreciation Expense contained in *DLC Exhibit 3* for the *HY basically* the same as those contained in DLC Exhibit 2 for the FTY?

A. Yes, they are and they are contained on Schedules D-16 and D-17 respectively.

Q. Finally, have the results of the recorded HY data and the pro forma adjustments contained in DLC Exhibit 3 for the HY been provided to Mr. Crowley for his Jurisdictional Separation Study?

A. Yes, they have. The results of Mr. Crowley's separation study are shown on DLC Exhibit 3, Schedule C-1, in column 2 and Schedule D-1 on pages 1 to 3 in columns designated for the Pennsylvania jurisdictional data on each of those pages.

Q. Does this complete your prefiled testimony?

A. Yes, it does.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00061346

Duquesne Light Company

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PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

Statement No. 9

Direct Testimony of Larry A. Crowley

Q. Please state your name and your business affiliation.

A. My name is Larry A. Crowley. I am a Senior Associate Consultant with R J Rudden Associates, a business unit of the Enterprise Management Solutions Division of the Black & Veatch Corporation.

Q. Please describe your educational background and professional experience.

A. I have a Bachelor of Science degree in Economics from the University of Maryland. I have over 30 years of extensive electric utility industry experience, including corporate strategic planning, organizational development, new business development, regulatory affairs, transmission system planning, and generation and resource planning. My regulatory experience includes the preparation and filing of testimony and exhibits before various regulatory commissions, including testifying as an expert witness before the Idaho Public Utilities Commission, the Oregon Public Utilities Commission, the Nevada Public Service Commission, the Colorado Public Utilities Commission, the Wisconsin Public Utilities Commission, the Michigan Public Service Commission, the North Dakota Public Service Commission, the Montana Public Service Commission, the Texas Public Utility Commission, and the Federal Energy Regulatory Commission. A summary of my professional experience is attached as Appendix A to this testimony.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Duquesne Light Company.

Q What is the scope of your testimony in this proceeding?

A. My testimony addresses the preparation of jurisdictional separation studies using total system data for the 12 months ending December 31, 2005, the historic period, and for the 12 months ending December 31, 2006, the future test year being used by the Company in this proceeding. My testimony also addresses the calculation of the Company's Pennsylvania jurisdictional revenue deficiency and revenue requirements for distribution delivery service provided by the Company. In addition, my testimony addresses the calculation of estimated transmission expenses the Company will incur under the PJM Open Access Transmission Tariff ("OATT") to provide retail transmission delivery service to its POLR customers. Finally, my testimony addresses the Company's reclassification of distribution plant made in accordance with FERC guidelines, commonly referred to as the "7 Factor Test," as set forth in FERC Order No 888, dated April 24, 1996.

Q. Please explain how the Company's Pennsylvania jurisdictional cost of service and revenue requirements for distribution delivery service was determined.

A. This filing is based on the investments and expenses incurred by the Company to provide distribution service to its Pennsylvania jurisdictional customers. Accordingly, the Company's historic test year per books (CY 2005) and future test year per budget (TY 2006) operating results are adjusted to eliminate all revenues and expenses associated with the power supply function (Provider of Last Resort or "POLR") service and the recovery of stranded costs through the Competitive Transition Charge ("CTC"). The remaining transmission and distribution investments and expenses are allocated between the Company's federal and Pennsylvania state jurisdictions, respectively. Exhibits LAC-2 and LAC-5 provide specific details regarding the allocation of those costs and the determination of the Company's Pennsylvania jurisdictional distribution service revenue requirements.

Q. Have you prepared or supervised the preparation of various exhibits or Cost of Service Statements for this proceeding?

A. Yes, I have prepared or supervised the preparation of the following exhibits or Cost of Service Statements for this proceeding:

Exhibit No	Description
LAC-1	Cost of Service Statement C-1: Measures of Value and Rates of Return for the 12 Months Ending December 31, 2006.
LAC-2	Jurisdictional Separation Study prepared for the 12 Months Ending December 31, 2006.
LAC-3	Cost of Service Statement D-1: Operating Income – Pro Forma at Present and Proposed Rates for the 12 Months Ending December 31, 2006.
LAC-4	Cost of Service Statement C-1: Measures of Value and Rates of Return for the 12 Months Ending December 31, 2005.
LAC-5	Jurisdictional Separation Study prepared for the 12 Months Ending December 31, 2005.

LAC-6	Cost of Service Statement D-1: Pro Forma at Present and Proposed Rates for the 12 Months Ending December 31, 2005.
LAC-7	Appendix A - Development of Retail Transmission Expense and Summary of Results

Q. Have you calculated the revenue deficiency for the Company's distribution delivery service in Pennsylvania?

A. Yes I have. The revenue deficiency for distribution delivery service in the Company's Pennsylvania electric jurisdiction is $143.7 million based on the future test period ending December 31, 2006.

Q. Please generally describe the methodology used to separate Total Company costs between the Pennsylvania and FERC jurisdictions.

A. The cost of providing service is measured through the use of the Company's accounting and operating data for a specific 12-month period of time. In this instance, I am using the total system information provided by the Company and adjusted by Mr. Robert O'Brien for the future 12-month period ending December 31, 2006, which is the test year being used in this proceeding to determine distribution delivery revenue requirements.

Normally, in order to establish a methodology for separating costs among jurisdictions for a multi-jurisdictional Company, a three-step process is generally used. The steps are referred to as classification, functionalization and allocation of costs. In all three steps, recognition is given to the way in which the costs are incurred by relating these costs to the way in which a utility is designed and operated to provide electric service. The methodology being used to separate costs by jurisdiction and to calculate the Pennsylvania jurisdictional revenue requirement for distribution delivery service in this case is the same methodology used by the Company in previous regulatory filings before this Commission.

Q. Would you please briefly explain the meaning of classification, functionalization, and allocation?

A. Classification refers to the identification of costs as being related to one of three components; demand-related, energy-related or customer-related. In addition to classification, costs are functionalized; that is identified with utility operating functions such as power supply, transmission and distribution. Individual plant items are examined and, where possible, the associated investment costs are assigned to one or more operating functions. Once the Company's total system costs are classified and assigned to the appropriate function they may be allocated among the Company's jurisdictions.

The process of allocation is the apportioning of the Company's total functionalized and classified system investments and costs among jurisdictions by use of allocation factors. Allocation factors are an array of numbers or values which represent the jurisdictional value or share of the total system quantity. Once each individual account has been allocated to the various jurisdictions, it is possible to summarize the allocated results of rate base and net income by jurisdiction. The allocated results are stated in summary form to measure adequacy of revenues for the jurisdiction under consideration. The measure of adequacy is typically the rate of return earned on rate base which is compared to the requested rate of return.

Q. Have you prepared an exhibit that summarizes the calculation of the Pennsylvania jurisdictional revenue deficiency?

A. Yes. I prepared Exhibit LAC-3 consisting of three tables and pages. This exhibit, also identified as Statement D-1, summarizes the results of the jurisdictional separation study prepared for the 12 months ending December 31, 2006 (Exhibit LAC-2 that is described in detail later in this testimony.

Table 1, page 1 of this exhibit, sets forth the earned rate of return at current rates and earned rate of return at proposed rates for the Company's Pennsylvania jurisdiction. As shown in column 3 of this table, the revenue deficiency previously identified results in a total distribution revenue requirement of $437.9 million, which would provide the revenues necessary to earn the claimed overall rate of return of 9.08 percent after taxes.

Table 2, page 2 of this exhibit sets forth Total Company Operating income and summarizes the calculation of the jurisdictional revenue deficiency for the Company's Pennsylvania jurisdiction. References are provided for the supporting cost of service statements for each component of the Total Company income statement. As shown on this table, the revenue deficiency for the Company's allocated Pennsylvania jurisdiction is $143.7 Million.

Table 3, page 3 of Exhibit LAC-3, summarizes the calculation and allocation of the Company's electric rate base. This table shows the allocated individual components of electric rate base for the Total Company and the

Company's Pennsylvania jurisdiction. References are again provided for the supporting cost of service statements for each component of Total Company rate base. The Company's allocated Pennsylvania electric rate base is $1.2 billion

Q. Please describe Exhibit LAC-1 also noted as Cost of Service Statement C-1.

A. Exhibit LAC-1, Cost of Service Statement C-1, is a one-page exhibit titled "Measures of Value and Rate of Return". This table summarizes the return earned at present rates for the Total Company and the Company's Pennsylvania jurisdiction. References are provided for the supporting cost of service statements for each component of the Total Company rate base and return. This exhibit also shows the return to be earned at proposed rates and the claimed overall rate of return of 9.08% for the Company's Pennsylvania jurisdiction. As noted on the exhibit, the values for the Pennsylvania jurisdiction can be found on Exhibit LAC-2.

Q. Please describe Exhibit LAC-2.

A. Exhibit LAC-2 is the complete Jurisdictional Separation Study ("JSS") detailing the allocation of each component of rate base, operating revenues and expenses by FERC account number for the 12 month future test period ending December 31, 2006. It should also be noted that this exhibit, as well as Exhibit LAC-5, is being filed in response to the Commission's Data Filing Requirements ("DFR") Section 53.53, No. II-D-27. The JSS is designed to show the Total Electric Utility values as developed by Mr. Robert O'Brien (Column 1) and the allocation of those total company values to the Company's Pennsylvania distribution service which is at issue in this proceeding (Column 2). It should be noted that the values shown in Column 3 represent the difference between the Company's Total Electric Utility and the Distribution Service costs shown in Column 2 and are noted as Total All Other jurisdictions. Results from this JSS for the Company's Pennsylvania jurisdiction were provided to Mr. Howard Gorman for his use in preparing class cost of service studies. It should be noted that the JSS allocation model results are being used to determine the distribution delivery service revenue deficiency and revenue requirements and are not being used to determine the Company's revenue requirements for transmission service. The methodology used to calculate the Company's retail transmission expense in this proceeding is described later in this testimony. The JSS model is organized as follows:

Table No	Description
1	Total Electric Rate Base
2	Calculation of Jurisdictional Revenue Deficiency
3	Electric Plant in Service
4	Accumulated Provision for Depreciation
5	Total Operating Revenues
6	Operation & Maintenance Expenses (3 pages)
7	Depreciation & Amortization Expenses (2 pages)
8	Taxes Other Than Income Taxes
9	Income Taxes
10	Income Tax Additions & Adjustments
11	Allocation Factors (5 pages)
12	Working Cash Allowance by Jurisdiction (2 pages)

Q. Please briefly explain the Company's cost allocation treatment for the Borough of Pitcairn which is included in the allocated results shown in Column 3 of Exhibit LAC-2.

A. The Borough of Pitcairn has historically been a "sales for resale" customer of the Company and subject to the jurisdiction of the FERC. Subsequent to electric restructuring, Pitcairn is now purchasing its energy requirements from another wholesale provider and is receiving transmission service under the terms and conditions of the PJM tariff. Therefore, the costs associated with this additional delivery service at 23kV need to be removed in the determination of the costs of providing service to the Company's Pennsylvania distribution delivery customers. Column 3 includes the removal of all revenues and expenses of Pitcairn in order to properly calculate Pennsylvania Distribution delivery revenues and expenses for the future test period ending December 31, 2006. It should be noted that there is currently no charge in place for the delivery service the Company is providing through its 23kV system, which is not currently part of the PJM tariff. However, it is my understanding that this proposed cost allocation and ratemaking treatment for Pitcairn is consistent with prior Company practice filed before this Commission and the Federal Energy Regulatory Commission and that the company will seek to recover these costs through a subsequent and separate rate filing to be made at FERC.

Q. Please describe Table 1 of Exhibit LAC-2.

A. Table 1 is a summary table which consolidates allocated jurisdictional electric rate base information developed on various tables of the JSS. The total

Pennsylvania jurisdictional Electric Rate Base in the amount of $1.2 billion is shown on Line 25, Column 2 of Table 1. References to supporting tables or specific allocation factors are also shown for each component of Total Electric Rate Base and are listed under the column labeled "Allocation Factor or Reference". The amounts shown on Table 1 for electric plant in service, accumulated provision for depreciation, customer deposits and accumulated deferred income taxes are end of test period values.

Q. Please describe Table 2 of Exhibit LAC-2.

A. Table 2 is a summary table which consolidates allocated jurisdictional revenue and expense information developed on various tables of the JSS. In addition, this table details the calculation of revenue deficiency and revenue requirements for the Company's Pennsylvania jurisdiction. The total Pennsylvania jurisdictional revenue deficiency and revenue requirement are $143.7 million and $437.9 million, respectively, as shown on Lines 21 and 22 of Column 2 of Table 2. In addition this table includes the return at the required or claimed rate of return for the Pennsylvania jurisdiction which amounts to $111.9 million (Line 18, Column 2). References to supporting tables or cost of service statements are also provided for each component of this table and are listed under the column labeled "Reference".

The net-to-gross tax multiplier for the Pennsylvania jurisdiction is 1.83727 which is shown on Line 20, Column 2 of this table. The development of this multiplier is detailed on supplemental schedules attached to Cost of Service Statement D-18.

Q. Please describe Table 3 of Exhibit LAC-2.

A. Table 3 of Exhibit LAC-2 sets forth the allocation of electric plant in service including Intangible Plant, Transmission Plant and Distribution Plant. The allocation of General Plant is shown on Table 1. Allocation factors are listed in the column labeled "Allocation Factor". The development of each allocation factor used is shown on Table 11 of this exhibit. Any component of electric plant that is allocated by direct assignment has an allocation factor that begins with the letters "DA" to reflect direct assignment. For example, transmission plant is allocated to the FERC jurisdiction by the direct assignment allocation factor DATX.

Q. Please describe the allocation of Distribution Plant shown on Table 3 of Exhibit LAC-2.

A. The allocation of distribution plant is done by each distribution plant account. Each account is separately allocated to reflect the allocation or direct assignment of distribution plant to the Borough of Pitcairn. The direct assignment or allocation of plant to Pitcairn was done to remove these assets, expenses and revenues from the Company's Pennsylvania distribution cost of service.

Q. Please describe Table 4 of Exhibit LAC-2.

A. Table 4 of Exhibit LAC-2 sets forth the allocation of accumulated provision for depreciation and amortization of electric plant in service including Intangible Plant, Transmission Plant, Distribution Plant and General Plant. Allocation factors are listed in the column labeled "Allocation Factor". The allocation factors used to allocate accumulated provision for depreciation are based on allocated plant balances; therefore the allocation factors used are prefixed with a "P" to indicate a plant-related allocation process. The development of each allocation factor used is shown on Table 11 of this exhibit.

Q. Please describe Table 5 of Exhibit LAC-2.

A. Table 5 of Exhibit LAC-2 sets forth the total operating revenues at present rates for the Company for the 12 months ending December 31, 2006. This table lists the Company's revenues by jurisdiction and Other Operating Revenues by FERC account number. Other Operating Revenues are allocated or directly assigned to the appropriate jurisdiction.

Q. Please describe Table 6 of Exhibit LAC-2.

A. Table 6 of Exhibit LAC-2 consists of three pages and details the Company's Operation and Maintenance Expenses by function and by FERC account number for the 12 months ending December 31, 2006. Allocation factors are listed in the column labeled "Allocation Factor". The development of each allocation factor used is shown on Table 11 of this exhibit. In general, the basis for each allocation may be readily interpreted from the exhibit. Many of the allocations are direct assignment to the appropriate function and begin with a "DA"; other allocation factors are based on plant as previously allocated and begin with a "P". Other allocations are based on use of the "LABOR" allocator which is described in detail on page 1 of Table 11 of this exhibit. Distribution supervision and engineering expenses are allocated by use of the labor component in each functional group of expenses. The total of allocated labor in each functional group becomes the basis for the allocation of Supervision and Engineering expenses.

Q. Please describe Table 7 of Exhibit LAC-2.

A. Table 7 of Exhibit LAC-2 consists of two pages and details the allocation of the Company's Depreciation and Amortization Expense by function or by FERC account number. These expenses have been identified by function or by primary plant account. Allocation is then accomplished on the basis of the related plant account as previously allocated.

Q. Please describe Table 8 of Exhibit LAC-2.

A. Table 8 of Exhibit LAC-2 lists the Company's Taxes Other Than Income Taxes for the 12 month period ending December 31, 2006. As shown on this table, the Company's total Taxes Other Than Income Taxes for the 12 months ending December 31, 2006 are $49.6 million. The Pennsylvania jurisdictional allocation amounts to $24.7 million. Taxes Other Than Income Taxes are listed individually and are allocated in a manner consistent with the basis by which the respective taxes are assessed. For example, all non-revenue related taxes, including the Pennsylvania Public Utility Realty Tax ("PURTA"), are allocated on the basis of combined allocated transmission and distribution plant or property, while payroll taxes are allocated on the basis of functionalized and allocated labor expenses.

The Pennsylvania Gross Receipts Tax ("GRT") is allocated on the basis of the revenues that are subject to the tax using the allocation factor designated as GRTREV. Revenues which are excluded from the GRT include sales for resale (account 447); transmission revenues from EGS suppliers and revenues from transmission service customers AES, Piney Fork and Pitcairn booked in account 456; and revenues from the rental of equipment booked in account 454. Details showing the development of this allocation are shown on page 3 of Table 11 of this exhibit.

Q. Please describe Tables 9 and 10 of Exhibit LAC-2.

A. Tables 9 and 10 of Exhibit LAC-2 summarize the Company's State and Federal Income Taxes for the 12 months ending December 31, 2006 by jurisdiction and the Company's tax adjustments for the test period respectively.

Q. Please describe how you allocated Federal and State Income Taxes shown on Table 9 of Exhibit LAC-2.

A. Total income taxes have not been allocated. The Company's total utility pro forma income taxes have been calculated by Mr. O'Brien and Mr. Macioce. Table 9 sets forth the allocation of each element of the Company's income taxes as calculated by Mr. O'Brien and Mr. Macioce resulting in the respective tax bases being developed and calculated for each jurisdiction. This table does not calculate the Company's income taxes; it simple allocates the income taxes as calculated by Mr. O'Brien and Mr. Macioce. For example, Table 9 shows operating income before taxes which represents adjusted allocated operating revenues less all allocated operating expenses treated on the preceding cost allocation tables of Exhibit LAC-2. Interest expense is allocated on the basis of allocated electric rate base. After the allocation of interest expense, taxable income is then calculated for each jurisdiction and the appropriate tax rate is applied. Final tax amounts result after the allocation of adjustments and tax credits. The allocation of tax adjustments are set forth on Table 10 of this exhibit. Allocation factors are designated in the same form as previously described in this testimony.

Q. How was interest expense calculated?

A. Interest expense was calculated by synchronizing jurisdictional net electric rate base shown on Table 1 of this exhibit and the weighted cost of long-term debt of 2.97 percent. For example, interest expense for the Company's Pennsylvania jurisdiction was calculated using jurisdictional Electric Rate Base of $1.2 billion multiplied by the weighted cost of long-term debt of 2.97 percent shown on Cost of Service Statement B-9. The calculation of interest expense for the Pennsylvania jurisdiction is shown on Table 9 of Exhibit LAC-2.

Q. Please describe Table 11 of Exhibit LAC-2.

A. Table 11 consists of five pages and lists all of the allocation factors used in the preparation of the jurisdictional separation study. The first page sets forth the development of the Labor allocator by jurisdiction; the second page lists the plant-related allocation factors; the third page lists the revenue and tax-related allocation factors; the fourth page lists the distribution plant allocation factors and the amounts of distribution plant directly assigned to other jurisdictions, including Pitcairn, by distribution plant account number; and the fifth page lists the distribution O&M expense allocation factors and the development of the distribution supervision and engineering allocation factors.

Q. Please describe Table 12 of Exhibit LAC-2.

A. Table 12 of Exhibit LAC-2 consists of two pages and details the allocation of Cash Working Capital using the same formula approach and components developed by Mr. O'Brien. Page one sets forth each component of Cash Working Capital developed by Mr. O'Brien. The components are listed and detailed as follows; Operation & Maintenance expenses, prepayments (13-month average balances), accrued taxes, pro forma interest expense (synchronized), and preferred dividend payments. All components are allocated to each jurisdiction based on the application of the formula or criteria used to calculate each component the total utility Cash Working Capital. Page 2 of Table 12 details the calculation of incremental/pro forma income taxes used in the calculation of Cash Working Capital shown on page 1 of Table 12.

Q. Please describe your Exhibits LAC-4 through LAC-6.

A. These exhibits are the same as Exhibits LAC-1 through LAC-3 respectively, prepared for the historic period ending December 31, 2005. Exhibit LAC-4, Cost of Service Statement C-1, is a one-page exhibit titled "Measures of Value and Rate of Return" which summarizes the return earned at present rates for the Total Company and the Company's Pennsylvania jurisdiction for the historic test period ending December 31, 2005. References are provided for the supporting cost of service statements for each component of the Total Company rate base and return. As noted on the exhibit, the values for the Pennsylvania jurisdiction can be found on Exhibit LAC-5.

Exhibit LAC-5 is the complete Jurisdictional Separation Study ("JSS") detailing the allocation of each component of rate base, operating revenues and expenses by FERC account number for the 12 month historic test period ending December 31, 2005. It should also be noted that this exhibit, as well as Exhibit LAC-2 is being filed in response to the Commission's Data Filing Requirements ("DFR") Section 53.53, II-D-27.

Exhibit LAC-6 consists of three pages. This exhibit, also identified as Statement D-1, summarizes the results of the jurisdictional separation study prepared for the 12 months ending December 31, 2005 (Exhibit LAC-5), previously described in this testimony.

Table 1, page 1 of Exhibit LAC-6, summarizes the calculation and allocation of the Company's 2005 electric rate base. This table shows the allocated individual components of electric rate base for the Total Company, the Company's Pennsylvania jurisdiction and for all other jurisdictions. References are also provided for the supporting cost of service statements for each component of Total Company rate base. Tables 2 and 3 summarize allocated results for the historic test period ending December 31, 2005.

DEVELOPMENT OF THE COST OF RETAIL TRANSMISSION SERVICE

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

A. The purpose of this portion of my testimony is to present the Company's estimated cost of providing retail transmission service consistent with the PJM Open Access Transmission Tariff ("OATT"), for all customers who receive such service from the Company. This transmission expense is separate from and in addition to the distribution revenue requirement previously described in my testimony.

Q. Please explain why the transmission expense is established separately from the Company's distribution rates.

A. For those customers who purchase all their electric service from the Company, including the supply of energy, the Company, as the Provider of Last Resort ("POLR") must provide both generation supply and the requisite transmission service to deliver that supply to the Company's distribution system. As a member of PJM and as a load serving entity ("LSE") in the "Duquesne Light Company Zone" of PJM, the Company must purchase the transmission service it needs to serve its load (i.e., its customers) from PJM under the rates, terms and conditions set forth in the PJM OATT as approved by FERC. The expense incurred by the Company to purchase this transmission service from the PJM is recovered through retail transmission rates paid by all POLR customers. For those customers who purchase their power supply from an electric generation suppliers ("EGS"), the EGS supplies the transmission service which it also purchases from the PJM under the PJM OATT for deliveries in the Duquesne Light Company Zone. My testimony estimates the expense the Company will incur as an LSE to purchase transmission service for its POLR customers based on PJM transmission rates expected to be in effect at the end of 2006.

Q. How are transmission rates determined or set in the PJM OATT?

A. In general, rates are filed with the FERC by the company that owns the transmission facilities being used to provide transmission service. Once approved by FERC the approved rates become part of the PJM OATT.

Q. Is the Company's current PJM OATT rate expected to change in 2006?

A. Yes it is. The rate in the PJM OATT for the Duquesne Light Company Zone is designed to recover the Company's revenue requirement as a FERC-jurisdictional transmission owner within the PJM. The Company, as a transmission owner, plans to file a rate case with the FERC in September of this year to recover its current cost of providing transmission service to load serving entities under the OATT. The Company anticipates that these new transmission rates will become effective sometime prior to the end of CY 2006.

Q. Have you calculated an estimate of new rates for transmission service in the Duquesne Light Company Zone under the PJM OATT?

A. Yes I have.

Q. Please briefly describe the methodology used to calculate the new PJM OATT transmission rate.

A. The methodology I used for calculating the new PJM OATT transmission rate is generally referred to as the FERC formula rate template. This methodology is one that has been filed by other similar transmission owning entities of the PJM and other transmission service providers. The formula rate methodology is being used because it reflects the Company's intention for setting its transmission rates this year and in the future and because it harmonizes with the PJM tariff.

Q. Have you prepared or supervised the preparation of an exhibit that calculates the new PJM OATT rate for transmission service in the Duquesne Zone using the FERC template?

A. Yes, I have prepared Exhibit LAC-7 which consists of four pages. This exhibit details the calculation of the of the net revenue requirement and network service rate for transmission service in the Duquesne Light Company Zone using the FERC formula template.

Q. Please briefly describe Exhibit LAC-7 and the FERC formula template.

A. The FERC formula template calculates the specific costs of providing transmission service for any company that is a transmission owning company within the PJM system. The template derives the total cost of providing transmission service and defines the result as the net transmission revenue requirement and network service rate used by the PJM for establishing rates for transmission service within a PJM service zone. This calculation is the sum of return on rate base, transmission-related operation and maintenance expenses, depreciation and amortization expenses, taxes other than income taxes, income taxes and revenue credits that are used to offset transmission cost of service. It should be noted that the formula methodology uses standard FERC ratemaking treatments for classification, functionalization and allocation. These are the same standards I used in preparing the jurisdictional separation studies file in this proceeding as Exhibits LAC-2 and LAC-5. I should also point out that the FERC formula rate methodology uses actual cost data for a defined period as annually reported FERC Form 1. To prepare Exhibit LAC-7, I used actual company data for the 12 moths ending December 31, 2005 without any adjustments normally made for ratemaking purposes. The only adjustment made is one that is typically used in the formula template which allows the inclusion of estimated transmission plant additions anticipated for the following year with all costs that are used being "trued-up" in following years using the actual data for that following year including the previously estimated plant additions from the prior year. Each year thereafter, the Company will complete the formula template using actual data contained in the FERC Form 1 (no later than April 30th) for the year following the previous or initial formula filing.

Q. Have you calculated the Net Revenue Requirement and Network Service Rate for the Duquesne Light Zone using the criteria described in the FERC formula template?

A. Yes I have. The calculated Net Revenue Requirement for retail transmission service in the Duquesne Light Company Zone is $50.7 million which is shown on page 4 of Exhibit LAC-7, Line 152. As defined by the template, this is the total net transmission revenue requirement I provided to Mr. Howard Gorman for use in his class cost of service study. The only cost not included in the template (Exhibit LAC-7) is the Pennsylvania Gross Receipts Tax which Mr. Gorman adds to his class cost of service study for allocation to the Company's rate classes. This cost allocation is described by Mr. Gorman in his testimony. The total Net Revenue Requirement for transmission service in the Duquesne Light Company Zone including the applicable GRT amounts to $53.9 million. I should also add that transmission rates are regulated by the FERC. Once the proposed transmission rate as shown on Exhibit No 7 is approved by the FERC, it becomes part of the PJM OATT and becomes an expense the Company will incur as a load serving entity and pass on to its customers through its retail proposed transmission rates, including the proposed transmission service charge.

Q. In your opinion do the formula-based net revenue requirement and network service rate proposed in this proceeding result in transmission rates that are fair and reasonable?

A. I believe that the net revenue requirement and network service transmission rate set forth in Exhibit LAC-7 conforms to FERC formula precedents and that any PJM OATT transmission rate ultimately flowed through to the Company's customers will be based on a fair and reasonable methodology accepted by FERC.

Q. Please describe the process by which the PJM OATT transmission rate will be revised.

A. In September the Company expects to file with FERC a request to revise tariff sheets to the FERC OATT administered by PJM for the Duquesne Light Company Zone. The filing will propose to implement a formula rate methodology for determining the transmission net revenue requirements. The filing would request authority to increase its transmission rates for all customers who receive service from the Company in a manner consistent with the terms and conditions of the PJM Open Access Transmission Tariff. The Company will propose to make the formula rate and associated PJM tariff provisions of its zone effective sometime prior to the end of CY 2006.

RECLASSIFICATION OF DISTRIBUTION PLANT

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

A. The Company has recently concluded an extensive internal review to revise its line of demarcation between transmission and distribution facilities to be consistent with orders from the FERC. This portion of my testimony describes the makeup of the Company's transmission and distribution systems; FERC's seven-factor functional/technical test used to delineate the jurisdictional line between transmission facilities subject to the FERC's jurisdiction and distribution facilities subject to the Commission's jurisdiction; and the proposed classification of the Company's electric facilities into either transmission or distribution categories.

Q. Please briefly describe the Company's electric system

A. The Company's electric system consists of 10 transmission substations and over 550 distribution substations, about 375 of which are located on customer-owned land which are used to service those customers located at those sites. The Company's higher voltage network has close to 700 circuit-miles of transmission lines consisting of 345kV, 138kV and 69 kV lines, serving both a local area transmission function and an intra-regional transmission function. Distribution and street lighting circuits of 23kV and less consist of approximately 16,420 circuit-miles of lines and cable.

Q. Please briefly describe how the Company uses its 138 and 69kV system.

A. Several major Company bulk power substations connect the 345kV network to the Company's 138 and 69kV network. The 138 and 69kV system loops around high load density areas in the Company's service area. The Company serves some large industrial customers directly from its 138 and 69kV system.

Q. Please describe FERC's Seven-Factor Functional/Technical Test.

A. In its Order No 888, dated April 24, 1996, the FERC proposed a combination of technical and functional measures to assist with the determination of asset classification between transmission and distribution facilities. The FERC's combination of both physical attributes and operating characteristics provides a mechanism to make distinctions about the use and function of a utility's electric plant.

Q. Please discuss each element of FERC's Seven-Factor Functional/Technical Test.

A. The seven factors FERC uses to distinguish distribution from transmission and the Company's application of each of the seven test *factors* is set forth as follows:

1) <u>Local distribution facilities are normally in close proximity to retail customers;</u>

Facilities are in close proximity to retail customers if the facility is physically and electrically located where it can be tapped with distribution transformers to serve load in an economical manner. The Company's 4 KV to 23 KV systems located within a substation or located, either underground or overhead facilities, in public rights-of-way, have this capability and primarily serve retail customers.

2) <u>Local distribution facilities are primarily radial in nature;</u>

Under general utility practices, facilities are defined as radial if alternative supply options do not exist. The Company primarily operates its 4 KV to 23 KV systems in radial configurations.

3) <u>Power flows into local distribution systems; it rarely, if ever, flows out;</u>

Utility systems without local generation always import electrical power and energy. (There may be instances where small generating units may export or sell power under specific load and power supply circumstances). In most, if not all cases, power flows into the Company's 4 KV to 23 KV systems from the company's 69, 138 and 345 KV transmission facilities.

4) <u>When power enters a local distribution system, it is not reconsigned or transported on to some other market;</u>

The Company's 4 KV to 23 KV systems or facilities are typically used to serve local retail customers and are not used as bulk power interconnections with neighboring systems or utilities.

5) <u>Power entering a local distribution system is consumed in a comparatively restricted geographic area;</u>

Distribution systems supply power in an area that is limited geographically in size to a single town, multiple towns, and sections of a town or a city. The company's 4 KV to 23 KV systems are typically used to serve local consumers and not used to transport power across the state or into other areas.

6) <u>Meters are based at the transmission/local distribution interface to measure flows into the local distribution system; and</u>

Meters on a distribution system are located where they can measure the aggregate load on the system. The Company measures power flow into the 4 KV and 23 KV systems at the point of voltage transformation from 69 KV, 115 KV or 345 KV systems.

7) <u>Local distribution systems will be of reduced voltage.</u>

Typically and historically, the electric utility industry has recognized that systems or facilities rated at 69 KV and above, are capable of transmitting bulk power over longer distances, and that systems below these voltages are used to serve local area retail customer needs. The Company's higher voltage system does serve a number of large industrial customers directly from higher voltage facilities while serving the primary role of transmitting bulk power from one location to another.

Q. Please describe the process the Company used to apply the FERC seven-factor test to its facilities.

A. The Company began an extensive review process of its facilities in 2003 using the FERC seven-factor test criteria. The initial review was applied to its facilities based on voltage level and operating characteristics. The following summarizes how the process was applied to specific components of the system.

Q. Please describe how the Company classified its 345kV system.

A. As previously described, the Company's 345kV system is the major bulk power carrier for the Company. The system is primarily comprised of integrated electric facilities that provide parallel paths to interconnect major generation, other transmission systems and lower-voltage systems. The 345kV does not directly interconnect to any retail customers. The application of the FERC seven-factor test to these facilities indicates the 345kV system should be classified as transmission.

Q. Please describe how the Company classified its 138 and 69kV facilities.

A. The 138 and 69kV systems are primarily comprised of integrated electric facilities that provide parallel paths to interconnect major generation, other transmission systems and load and directly interconnect with only a few retail customers. The application of the FERC seven-factor test to these facilities indicates the 138 and 69kV systems should be classified as transmission.

Q. Please describe how the Company would classify its 23 to 4kV lines.

A. These voltage level systems are the primary load serving facilities for the Company with typical load carrying capabilities less than 50 MW. Their technical attributes and functional capabilities match the definition of local distribution under the FERC seven-factor test criteria. These facilities are normally in close proximity to retail customers, are primarily radial in character, and are of reduced voltage. Power usually flows into these local systems, is consumed in a comparatively restricted geographical area and is not typically transported on to some other market. The application of the FERC seven-factor test to these systems supports that they should be classified as local distribution.

Q. In addition to line facilities, are there other Company facilities that need to be classified?

A. Yes, the Company must also classify its substations where voltage is transformed from higher-level voltages such as 345, 138, and 69kV to 23 to 4kV systems.

Q. Please briefly describe the basic components of a substation.

A. Typically, a substation contains high voltage equipment, transformers, low voltage equipment, ancillary equipment, and protection and control equipment including the control house and other shared facilities. The control house contains meters and protective relays that monitor and control the operation of the transmission and local distribution facilities. Both transmission and local distribution systems share the use of a single building. Economics and the efficient use of available land make it prudent to have only one control house at a substation rather than two.

Q. Why has the Company applied the FERC seven-factor test to its substations?

A. Just as the Company applied the FERC seven-factor test to its line facilities, a similar process is appropriate for substation equipment. The Company applied the same test to all equipment located inside its substations to determine the proper classification of these electric facilities. Historically, the Company classified substations with step-down transformers as either 100% transmission or 100% distribution based on the types of lines connected to the substation and the existence of generation. Historically, the Company would classify substations with low voltage facilities as distribution regardless of the presence of higher voltage facilities and dual purpose services (transmission and distribution) being provided at the same substation. All facilities located inside the substation fence boundary were identified the same regardless of their voltage or their primary function. To properly separate these facilities into distribution or transmission, the Company applied the FERC seven-factor test to all equipment located inside its substations.

Q. What where the results of the application of the FERC seven-factor test to the Company's substation facilities?

A. As previously discussed, the Company reviewed all substations that had low-voltage step-down transformers or facilities. This was an extensive process which resulted in the Company first identifying the substations that required reclassification in accordance with the FERC seven-factor test and then reviewing individual pieces of equipment within a particular substation based on its primary function. This process resulted in the development of a line of demarcation between transmission and distribution at all step-down substations; i.e., the points of interconnection between the bulk power network and the facilities serving local area loads. Normally, the line of demarcation was the high-side disconnect switch of the step-down transformer located at the substation.

Q. How were land and land rights classified?

A. Land and land rights associated with transmission facilities were classified as transmission. Land associated with a substation containing only distribution assets were assigned to distribution.

Q. Has the Company's review of its facilities using the FERC seven-factor test resulted in the reclassification of any of its electric substation plant?

A. Yes, the Company has reclassified portions of the equipment located in 22 company-owned substations and 16 substations located on customer-owned land to conform to the criteria of the FERC seven-factor test.

Q. Have you reviewed the Company's data supporting its reclassification of substations?

A. Yes, I reviewed the data for each of the substations involved including single-line diagrams and continuing property records for each substation. I then prepared inventories of equipment and costs for each major component of property located in each substation. I also made site visits to a number of the substations that were being reviewed for reclassification. The purpose of the visits was to physically inspect the equipment that was reclassified.

Q. What impact does the Company's reclassifications have on the Company's rate base?

A. There is no increase or decrease to the Company's total asset investment in plant; there is, however a net reclassification change of approximately $38 million from distribution to transmission.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes it does.

Appendix A
Professional Experience of Larry A. Crowley

Summary

Mr. Crowley has over 30 years of extensive electric utility industry experience including corporate strategic planning, organizational development, new business development, regulatory affairs, transmission system planning, and generation and resource planning. Mr. Crowley's regulatory experience includes the preparation and filing of testimony and exhibits before various regulatory commissions including testifying as an expert witness before the Idaho Public Utilities Commission, the Oregon Public Utilities Commission, the Nevada Public Service Commission, the Colorado Public Utilities Commission, the Wisconsin Public Utilities Commission, the Michigan Public Service Commission, the North Dakota Public Service Commission, the Montana Public Service Commission, the Texas Public Utility Commission, and the Federal Energy Regulatory Commission.

R. J. Rudden Associates, a Black and Veatch Company

Contract associate of R. J. Rudden Associates and H. Zinder & Associates; providing professional consulting services to the energy and regulated utility industries with emphasis on ratemaking, economics, finance and accounting matters. As Senior Associate Consultant, responsibilities include:

- Preparation of regulatory studies including jurisdictional separation studies, revenue deficiency/requirements studies, cost of service studies, and rate design studies
- Providing testimony and litigation support including testifying before regulatory commissions
- Providing assistance for strategic planning initiatives and studies
- Preparing analyses for proposed mergers and acquisitions.

The Energy Strategies Institute, Inc. (ESI) — October 1999 to Present

Founder and Director of ESI, a network of experienced professionals with diverse interests specializing in energy and utility matters, dedicated to developing and implementing practical solutions for energy service providers and customers. The Institute offers experienced utility operation, planning and regulatory expertise including the preparation of exhibits and testimony for jurisdictional separation and revenue requirement studies, class cost of service studies, unbundled cost studies, and rate design studies. Major clients include The Washington Group International, Boise, Idaho; Wisconsin Electric Power Company, Milwaukee, Wisconsin; Montana-Dakota Utilities Company, Bismarck, North Dakota; The US Department of Energy, Office of Renewable Energy and Energy Efficiency, Washington, D.C.; The J.R. Simplot Company, Boise, Idaho; The International Energy Agency, Paris, France; The Riley Creek Lumber Company, Sandpoint, Idaho and The Allied Utility Network, Boise, Idaho.

Idaho Power Resources Corporation (IPRC) **July 1996 to October 1999**

As President of IPRC, a wholly owned subsidiary of Idaho Power Company, responsibilities included establishing, organizing and leading a new independent business division including establishment of the entity, selection and training of staff, systems implementation and day-to-day management of the entity. Responsibilities also included preparation of annual operating budget, strategic plans, business plans (including due diligence and analysis for

mergers and acquisitions), as well as research, development and deployment of new technologies such as PEM fuel cells and solar energy systems.

Idaho Power Company **March 1979 to October 1999**

Idaho Power Company is one of the largest electric utilities serving in Idaho with CY 2004 revenues of $844.5 million, total plant investment of approximately $3.2 billion and over 440,000 customers.

Senior Manager, Strategic Planning January 1991 to October 1999

As Senior Manager of Strategic Planning, responsibilities included:

- Directing all corporate strategic planning activities of the company, including regulatory initiatives and merger and acquisition activities
- Preparation of the annual economic forecast used by the major business units of the company in the preparation of their annual business plans, operating budgets and capital requirements.
- Overseeing the company's research and development programs and projects dealing with new technologies or improvements in operating practices.
- Developing a rate mechanism that tracks and recovers changes or fluctuations in the company's cost of production (PCA), including formulation of the concept, plan and the regulatory strategy to secure approval of the regulatory commissions.
- Directed the litigation team that participated in the PacifiCorp/Utah Power merger appearing before the Idaho PUC and the Federal Energy Regulatory Commission. Negotiated the settlement agreement between the parties, resulting in significant benefits to Idaho Power Company including firm transmission service in Utah, ownership of a major strategic substation, additional transmission revenue and favorable resolution of a number of pending regulatory disputes.
- Negotiated a comprehensive transmission services agreement between the company and Bonneville Power Administration that resulted in annual revenues of approximately $1.5 million.
- Identified new business opportunities for the company and prepared the requisite business plans and analysis.
- Designed and implemented Idaho Power Company's innovative "first-of-its-kind" solar energy program that won unanimous approval from the regulatory commissions.

- Selected by the IEA Executive Committee to chair the Organizing Committee for the 1995 International Executive Conference on Photovoltaics (Solar Energy) sponsored by the International Energy Agency and hosted by Idaho Power Company.
- Selected by the US Department of Energy to represent the United States on the Organizing Committee for the 1999 International Executive Conference on Photovoltaics that was organized under the auspices of the International Energy Agency.

Manager, Power Management 1986 to 1991

As Manager of Power management, responsibilities included:

- the management of a department consisting of 45 senior level engineers, analysts and technical experts dealing with generation resource planning, transmission system planning, wholesale power marketing and wholesale bilateral contract development and administration.
- Responsible for directing all regulatory activities with the Federal Energy Regulatory Commission dealing with wholesale power and transmission services rates, terms and conditions and related contract approvals.
- Responsible for negotiating wholesale power contracts and transmission service agreements that generated $40MM in annual revenues.

Manager of Rates and Regulatory Affairs 1979 to 1986

As Manager of Rates and regulatory Affairs, responsibilities included:

- Preparing all materials required for the Idaho Power's rate filings before the Idaho, Oregon and Nevada state regulatory commissions having jurisdiction over the company, as well as the Federal Energy Regulatory Commission.
- Developed a multi-jurisdictional cost-of-service/revenue requirements model that was accepted by all state and federal commissions having jurisdiction over the company.
- Developed a series of innovative class cost of service and rate design models.
- Developed and directed a load research program for the company.

Wisconsin Electric Power Company – Project Coordinator (Regulatory) 1978 to 1979

As Project Coordinator, responsibilities included:

- All rate and regulatory filings before the Wisconsin and Michigan Public Utility Commissions and the Federal Energy Regulatory Commission.
- Preparing jurisdictional separation and revenue requirement studies, cost-of-service studies, rate design studies, load research information and the testimony related to these studies as required by the commissions in support of retail and wholesale rate filings.
- Developed the first computerized cost-of-service model for the company that was accepted by all three commissions having jurisdiction over the company.

Southeast Colorado Power Association **1971 to 1978**

General Manager
As General Manager, responsibilities included:

- Chief Operating Officer of an electric distribution company with 60 employees.
- Responsible to the Board of Directors for all matters relating to the operation of the company including financial planning, marketing, budgeting, quality of service and all regulatory proceedings before the Colorado Public Utilities Commission.

Duquesne Light Company
Before The Pennsylvania Public Utility Commission

Measures of Value and Rates of Return - Future Period
For the 12 Months Ending December 31, 2006
(X$000)

Line No	Description	Future Period - TY 2006 Total Electric Utility	Future Period - TY 2006 Total PA Jurisdiction (1)	Reference
	Electric Plant			
1	Electric Plant in Service	$ 2,373,450.6	$ 1,930,872.0	C-2
2	Depreciation Reserve	746,884.0	613,162.7	C-3
3	Net Electric Plant in Service	1,626,566.6	1,317,709.3	
	Additions:			
	Working Capital Requirements			
4	Cash Working Capital	51,677.2	50,086.0	C-4
5	Materials & Supplies	17,681.0	11,296.0	C-5
6	Total Working Capital	69,358.2	61,382.0	
	Deductions:			
7	Customer Deposits	(1,413.0)	(1,413.0)	B-1
8	*Accumulated Deferred Income Taxes*	(166,564.0)	(144,820.9)	C-6
9	Total Deductions	(167,977.0)	(146,233.9)	
10	**Total Measure of Value/Rate Base - Net**	1,527,947.8	1,232,857.4	
	Pro Forma Return at Present rates			
11	*Amount - $*		33,738.4	D-1
12	Percent		2.737%	
	Pro Forma Return at Proposed Rates			
13	Amount - $		111,943.5	D-1
14	Percent		9.08%	

(1) See Exhibit No LAC-3/Statement D-1

Duquesne Light Company
Before The Pennsylvania Public Utility Commission
Jurisdictional Separation Study - Future Period
12 Months Ending December 31, 2006
(X$000)

Table No 1 - Total Electric Rate Base

Line No	Description	Allocation Factor or Reference	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Electric Plant in Service				
1	Intangible Plant	Table No 3	29,823.4	23,854.9	5,968.4
2	Transmission Plant	Table No 3	421,376.3	-	421,376.3
3	Distribution Plant	Table No 3	1,686,508.9	1,686,042.0	466.9
4	*General Plant - P90*	*P90ADJ*	*235,742.1*	*220,975.0*	*14,767.0*
5	Total Electric Plant in Service		2,373,450.6	1,930,872.0	442,578.7
	Less:				
6	Accum Provision for Depreciation & Amortization				
7	Intangible Plant	Table No 4	19,198.0	15,356.0	3,842.0
8	Transmission Plant	Table No 4	126,332.0	-	126,332.0
9	Distribution Plant	Table No 4	547,801.0	547,651.7	149.3
10	General Plant	Table No 4	53,553.0	50,155.0	3,398.0
11	Total Accum Provision - Depreciation & Amort		746,884.0	613,162.7	133,721.3
12	**Net Electric Plant in Service**		1,626,566.6	1,317,709.3	308,857.3
	Other Rate Base Items:				
13	Cash Working Capital	Table No 12	51,677.2	50,086.0	1,591.2
	Materials & Supplies - Account 154:				
14	Transmission Plant	P50	6,207.0	-	6,207.0
15	Distribution Plant	P60	8,671.0	8,668.6	2.4
16	General Plant	P90	2,803.0	2,627.4	175.6
17	Intangible or Other Plant	P10	-	-	-
18	Construction Category	TXDT	-	-	-
19	Total Materials & Supplies		17,681.0	11,296.0	6,385.0
	Less:				
20	Customer Deposits - Account 235	DADT	(1,413.0)	(1,413.0)	-
	Accumulated Deferred Income Taxes:				
21	Transmission	DATX	(20,269.0)	-	(20,269.0)
22	Distribution	P60	(123,307.0)	(123,272.9)	(34.1)
23	General	P90	(22,988.0)	(21,548.0)	(1,440.0)
24	Subtotal - Other Rate Base Items		(98,618.8)	(84,851.9)	(13,766.9)
25	**Total Electric Rate Base - $**		1,527,947.8	1,232,857.4	295,090.4
26	**Total Electric Rate Base - %**		100.00%	80.69%	19.31%

Duquesne Light Company
Before The Pennsylvania Public Utility Commission
Jurisdictional Separation Study - Future Period
12 Months Ending December 31, 2006
(X$000)

Table No 2 - Calculation of Jurisdictional Revenue Deficiency

Line No	Description	Reference	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
1	**Total Electric Rate Base**	Table No 1	1,527,947.8	1,232,857.4	295,090.4
	Total Operating Revenues				
2	Total Sales Revenues	Table No 5	678,378.0	279,955.0	398,423.0
3	Other Transmission Revenues - PJM Adder	Table No 5	4,358.0	-	4,358.0
4	Other Operating Revenues	Table No 5	33,051.0	14,282.0	18,769.0
5	Total Revenues		715,787.0	294,237.0	421,550.0
	Total Operating Expenses				
6	Operation & Maintenance Expenses	Table No 6	537,880.0	166,288.5	371,591.5
7	Depreciation Expense	Table No 7	74,259.4	62,916.6	11,342.8
8	Amortization Other Expense	Table No 7	3,975.0	3,484.3	490.7
9	Taxes Other Than Income Taxes	Table No 8	49,628.9	24,694.3	24,934.6
10	Total Operating Expenses		665,743.3	257,383.7	408,359.6
11	Operating Income Before Income Taxes	Line 5 - Line 10	50,043.7	36,853.3	13,190.4
	Income Taxes:				
12	Federal	Table No 9	5,631.9	4,337.1	1,294.8
13	State	Table No 9	(851.6)	(1,222.3)	370.6
14	Total Operating Expenses		670,523.6	260,498.6	410,025.0
15	**Net Operating Income**	Line 5 - Line 14	45,263.4	33,738.4	11,525.0
	Return Before Adjustments				
16	Earned Rate of Return - %	Line 15/Line 1		2.737%	
17	Required Rate of Return - %	B-9		9.08%	
18	Return at Required Rate of Return	Line 1 x Line 17		111,943.5	
19	Income Deficiency	Line 18 - Line 15		78,205.0	
20	Net-to-Gross Multiplier	D-18		1.83727	
21	**PA Revenue Deficiency - $**	Line 19 x Line 20		143,683.7	
22	**PA Revenue Requirements - $**			$ 437,920.7	

Duquesne Light Company
Before The Pennsylvania Public Utility Commission
Jurisdictional Separation Study - Future Period
12 Months Ending December 31, 2006
(X$000)

Table No 3 - Electric Plant in Service

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Electric Plant in Service - Account 101/106				
	Intangible Plant:				
1	Organizations	TXDT	100.0	80.0	20.0
2	Franchises & Consents	TXDT	7.0	5.6	1.4
3	*Software - Plant/O&M-related*	*TXDT*	*29,716.4*	*23,769.3*	*5,947.0*
4	Software - Customer-related	DADT	-	-	-
5	Software - Labor-related	LABOR	-	-	-
6	Total Intangible Plant-P10		29,823.4	23,854.9	5,968.4
	Transmission Plant:				
7	Land and Land Rights - 350	DATX	11,035.0	-	11,035.0
8	Structures and Improvements - 352	DATX	7,637.3	-	7,637.3
9	Station Equipment - 353	DATX	184,823.9	-	184,823.9
10	Towers and Fixtures - 354	DATX	69,208.5	-	69,208.5
11	Poles and Fixtures - 355	DATX	10,065.6	-	10,065.6
12	Overhead Conductors & Devices - 356	DATX	43,870.7	-	43,870.7
13	Underground Conduit - 357	DATX	55,964.6	-	55,964.6
14	Underground Conduit & Devices - 358	DATX	38,766.7	-	38,766.7
15	Roads and Trails - 359	DATX	4.0	-	4.0
16	Total Transmission Plant - P50		421,376.3	-	421,376.3
	Distribution Plant:				
17	Land and Land Rights - 360	P360	9,962.0	9,961.3	0.7
18	Structures and Improvements - 361	P361	47,272.0	47,241.7	30.3
19	Station Equipment - 362	P362	299,298.5	299,109.0	189.6
20	Poles, Towers and Fixtures - 364	P364	291,340.0	291,132.2	207.8
21	Overhead Conductors and Devices - 365	P365	301,038.4	301,000.3	38.0
22	Underground Conduit - 366	P366	99,254.7	99,254.7	-
23	Underground Conductors and Devices - 367	P367	190,267.4	190,267.4	-
24	Line Transformers - 368	P368	231,666.7	231,666.7	-
25	OH & UND Services - 369	P369	74,257.6	74,257.6	-
26	Meters & Appurtences - 370	P370	76,191.8	76,191.4	0.4
27	Meter Communication Equipment - 370.1	P3701	33,237.0	33,237.0	-
28	Street Lighting - 373	P373	32,722.9	32,722.9	-
29	Total Distribution Plant - P60		1,686,508.9	1,686,042.0	466.9

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Table No 4 - Accumulated Provision for Depreciation

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Accumulated Provision for Depreciation & Amortization				
1	Intangible Plant:				
2	Organizations	P10	-	-	-
3	Franchises	P10	-	-	-
4	Miscellaneous Intangible Plant	P10	19,198.0	15,356.0	3,842.0
5	Total Intangible Plant - P10		19,198.0	15,356.0	3,842.0
6	Total Transmission Plant	P50	126,332.0	-	126,332.0
	Distribution Plant:				
7	Land and Land Rights	P360	-	-	-
8	Structures and Improvements	P361	23,281.0	23,266.1	14.9
9	Station Equipment	P362	71,824.0	71,778.5	45.5
10	Poles, Towers and Fixtures	P364	108,298.0	108,220.7	77.3
11	Overhead Conductors and Devices	P365	90,537.0	90,525.6	11.4
12	Underground Conduit	P366	27,277.0	27,277.0	-
13	Underground Conductors and Devices	P367	64,429.0	64,429.0	-
14	Line Transformers	P368	54,591.0	54,591.0	-
15	OH & UND Services	P369	31,164.0	31,164.0	-
16	Meters & Appurtences	P370	36,448.0	36,447.8	0.2
17	Meter Communication Equipment	P3701	17,628.0	17,628.0	-
18	Street Lighting	P373	22,324.0	22,324.0	-
19	Total Distribution Plant	P60	547,801.0	547,651.7	149.3
	General Plant:				
20	Land and Land Rights - 389	P90	-	-	-
21	Structures and Improvements - 390	P90	21,673.0	20,293.4	1,379.6
22	Office Equipment & Equipment - 391	P90	(1,226.0)	(1,148.0)	(78.0)
23	Transportation Equipment - 392	P90	16,705.0	15,641.7	1,063.3
24	Stores Equipment - 393	P90	688.0	644.2	43.8
25	Tools, Shop and Garage Equipment - 394	P90	3,069.0	2,873.6	195.4
26	Laboratory Equipment - 395	P90	1,181.0	1,105.8	75.2
27	Power Operated Equipment - 396	P90	620.0	580.5	39.5
28	Communication Equipment - 397	P90ADJ	10,741.0	10,068.2	672.8
29	Miscellaneous Equipment - 398	P90	102.0	95.5	6.5
30	Total General Plant		53,553.0	50,155.0	3,398.0
31	**Total Accumulated Provision for Depreciation**		746,884.0	613,162.7	133,721.3

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Table No 5 - Total Operating Revenues

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Electric Operating Revenues				
	Sales of Electricity:				
1	Total Sales to Ultimate Customers		678,378.0	279,955.0	398,423.0
2	Other Transmission Revenues - PJM Adder	DATX	4,358.0	-	4,358.0
3	Total Sales of Electricity	REV	682,736.0	279,955.0	402,781.0
	Other Operating Revenues				
	Forfeited Discounts/Account 450:				
4	Late Payment Charges	DADT	3,000.0	3,000.0	-
5	Returned Check Charges	DADT	50.0	50.0	-
6	Total Account 450		3,050.0	3,050.0	-
7	Miscellaneous Service Revenues/Account 451	DADT	2,135.0	2,135.0	-
	Rent from Electric Property/Account 454:				
8	Rent - Electric Property	DADT	8,047.0	8,047.0	-
9	Customer Work - Reimbursement	DADT	400.0	400.0	-
10	Customer Work - Reimbursement O&M Fixed	DADT	300.0	300.0	-
11	Total Account 454		8,747.0	8,747.0	-
	Other Electric Revenues/Account 456:				
12	Customer Choice - EGS Transmission	DATX	15,454.0	-	15,454.0
13	Other Electric Revenues	DADT	350.0	350.0	-
14	SECA Credits - Other (EGS)	DATX	-	-	-
15	Transmission Revenue - AES/APS	DATX	2,580.0	-	2,580.0
16	Transmission Revenue - APS/Piney Fork	DATX	288.0	-	288.0
17	Non-Firm Transmission Service	DATX	447.0	-	447.0
18	Total Account 456		19,119.0	350.0	18,769.0
19	**Total Other Operating Revenues**		33,051.0	14,282.0	18,769.0
20	**Total Operating Revenues**	PAREV	715,787.0	294,237.0	421,550.0

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Table No 6 - Operation & Maintenance Expenses

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Purchased Power Expenses:				
1	Purchased Power - Acct 555	DAPS	358,515.0	-	358,515.0
2	Other Power Supply Expense - Acct 556	DAPS	-	-	-
3	Total Purchased Power Expenses		358,515.0	-	358,515.0
	Transmission Expense:				
4	Operation Supervision & Engineering-560	DATX	1,352.0	-	1,352.0
5	Load Dispatching-561	DATX	166.0	-	166.0
6	Station Expenses-562	DATX	98.7	-	98.7
7	Overhead Line Expenses-563	DATX	27.4	-	27.4
8	Underground Line Expenses-564	DATX	58.2	-	58.2
9	Transmission of Electricity by Others-565	DATX	(4.4)	-	(4.4)
10	Miscellaneous Transmission Expenses-566	DATX	2,466.2	-	2,466.2
11	Rents-567	DATX	-	-	-
12	Maintenance Supervision & Engineering-568	DATX	218.0	-	218.0
13	Maintenance of Structures-569	DATX	629.2	-	629.2
14	Maintenance of Structures-570	DATX	562.4	-	562.4
15	Maintenance of Station Equipment-571	DATX	1,312.8	-	1,312.8
16	Maintenance of Underground Facilities-572	DATX	29.9	-	29.9
17	Total Transmission Expenses		6,916.4	-	6,916.4
	Distribution Expense - Operation:				
18	Operation Supervision & Engineering-580	PDIS1	1,590.9	1,590.7	0.2
19	Load Dispatching-581	P60	365.5	365.4	0.1
20	Station Expenses-582	P362	179.5	179.4	0.1
21	Overhead Line Expense-583	P364/5	207.6	207.5	0.1
22	Underground Line Expense-584	P367	426.8	426.8	-
23	Street Lighting & Signal Systems-585	P373	0.0	0.0	-
24	Meter Expenses-586	P370	1,770.9	1,770.9	0.0
25	Customer Installations Expense-587	DADT	28.0	28.0	-
26	Miscellaneous Expenses-588	DADT	10,946.0	10,946.0	-
27	Rents-589	DADT	-	-	-
28	Total Distribution Operation Expenses		15,515.2	15,514.7	0.5

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Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Distribution Expense - Maintenance:				
1	Maintenance Supervision & Engineering-590	PDIS2	351.9	351.7	0.1
2	Maintenance of Structures-591	P362	16.5	16.5	0.0
3	Maintenance of Station Equipment-592	P362	1,517.7	1,516.7	1.0
4	Maintenance of OH lines-593	P364/5	12,452.5	12,447.3	5.2
5	Maintenance of Underground lines-594	P366	968.1	968.1	-
6	Maintenance of Line Transformers-595	P367	78.6	78.6	-
7	Maintenance of Street Lighting & Signals-596	P368	736.4	736.4	-
8	Maintenance of Meters-597	P369	1,449.4	1,449.4	-
9	Maintenance of Miscellaneous Plant-598	P370	168.9	168.9	0.0
10	Total Distribution Maintenance Expenses	P3701	17,739.8	17,733.5	6.3
11	Total Distribution Expenses	P373	33,255.0	33,248.2	6.7
	Customer Accounting Expense:				
12	Supervision-901		1,906.3	1,906.3	-
13	Customer Assistance-902		4,036.9	4,036.9	-
14	Records & Collections-903		8,117.9	8,117.9	-
15	Uncollectible Accounts-904		28,940.0	28,940.0	-
16	Miscellaneous Expenses-905		-	-	-
17	Total Consumer Accounts Expense	CWAC	43,001.0	43,001.0	-
	Customer Services Expense:				
18	Customer Service-Supervision-907		-	-	-
19	Customer Service-Customer Assist-908		2,190.8	2,190.8	-
20	Customer Service-Information-909		-	-	-
21	Customer Service-Misc Service & Info-910		-	-	-
22	Total Customer Service & Info Expenses	CWCS	2,190.8	2,190.8	-
	Sales Expense:				
23	Supervision-911		-	-	-
24	Demonstration and Selling Expenses-912		-	-	-
25	Advertising Expenses-913		-	-	-
26	Miscellaneous Sales Expenses-916		-	-	-
27	Total Sales Expense		-	-	-

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Table No 6 - Operation & Maintenance Expenses

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Administrative & General Expenses:				
1	Administrative and General Salaries-920	LABOR	24,231.8	22,689.3	1,542.5
2	Office Supplies and Expenses-921	LABOR	5,100.2	4,775.6	324.6
3	Administrative Exps Transferred - Credit-922	LABOR	-	-	-
4	Outside Services Employed-923	LABOR	11,502.9	10,770.7	732.2
5	Property Insurance-924	PLANT	1,384.3	1,126.4	257.9
6	Injuries and Damages-925	LABOR	6,381.2	5,975.0	406.2
7	Employee Pensions and Benefits-926	LABOR	18,811.2	17,613.8	1,197.4
8	Regulatory Commission Expenses-928	LABOR	6,467.0	6,055.3	411.7
9	General Advertising Expenses-930.1	LABOR	2,069.4	1,937.6	131.7
10	Miscellaneous General Expenses-930.2	LABOR	6,890.4	6,451.8	438.6
11	Rents-931	LABOR	2,767.4	2,591.3	176.2
12	Total Operation A & G Expenses		85,605.8	79,986.9	5,618.9
13	Maintenance of General Plant-935	LABOR	8,396.0	7,861.5	534.4
14	Total Administrative & General Expenses		94,001.7	87,848.4	6,153.4
15	**Total Operation & Maintenance Expenses**		537,880.0	166,288.5	371,591.5

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Table No 7 - Depreciation & Amortization Expenses

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Depreciation & Amortization Expense - Accts 403/404				
	Intangible Plant:				
1	*Organizations*	P10	-	-	-
2	Franchises	P10	-	-	-
3	*Miscellaneous Intangible Plant*	*P10*	2,365.4	1,892.0	473.4
4	Total Intangible Plant - P10		2,365.4	1,892.0	473.4
	Transmission Plant:				
5	Land and Land Rights	DATX	-	-	-
6	Structures and Improvements	DATX	257.0	-	257.0
7	Station Equipment	DATX	5,175.0	-	5,175.0
8	Towers and Fixtures	DATX	1,550.0	-	1,550.0
9	Poles and Fixtures	DATX	198.0	-	198.0
10	Overhead Conductors & Devices	DATX	794.0	-	794.0
11	Underground Conduit	DATX	1,103.0	-	1,103.0
12	Underground Conduit & Devices	DATX	543.0	-	543.0
13	Roads and Trails	DATX	-	-	-
14	Total Transmission Plant - P50		9,620.0	-	9,620.0
	Distribution Plant:				
15	Land and Land Rights	P360	-	-	-
16	Structures and Improvements	P361	1,201.0	1,200.2	0.8
17	Station Equipment	P362	6,944.0	6,939.6	4.4
18	Poles, Towers and Fixtures	P364	6,264.0	6,259.5	4.5
19	Overhead Conductors and Devices	P365	6,894.0	6,893.1	0.9
20	Underground Conduit	P366	2,015.0	2,015.0	-
21	Underground Conductors and Devices	P367	4,205.0	4,205.0	-
22	*Line Transformers*	*P368*	*6,904.0*	*6,904.0*	-
23	OH & UND Services	P369	1,188.0	1,188.0	-
24	Meters & Appurtences	P370	2,133.0	2,133.0	0.0
25	Meter Communication Equipment	P3701/DADT	4,214.0	4,214.0	-
26	Street Lighting	P373/DADT	717.0	717.0	-
27	Total Distribution Plant - P60		42,679.0	42,668.5	10.5

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Table No 7 - Depreciation & Amortization Expenses

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	General Plant:				
1	Land and Land Rights - 389	P90	-	-	-
2	Structures and Improvements - 390	P90	3,978.0	3,724.8	253.2
3	Office Equipment & Equipment - 391	P90	2,521.0	2,360.5	160.5
4	Transportation Equipment - 392	P90	3,045.0	2,851.2	193.8
5	Stores Equipment - 393	P90	134.0	125.5	8.5
6	Tools, Shop and Garage Equipment - 394	P90	937.0	877.4	59.6
7	Laboratory Equipment - 395	P90	674.0	631.1	42.9
8	Power Operated Equipment - 396	P90	18.0	16.9	1.1
9	Communication Equipment - 397	P90ADJ	8,238.0	7,722.0	516.0
10	Miscellaneous Equipment - 398	P90	50.0	46.8	3.2
11	Total General Plant		19,595.0	18,356.0	1,239.0
12	**Total Depreciation & Amortization Expense**		74,259.4	62,916.6	11,342.8
	Amortization of Salvage & Regulatory Assets				
	Intangible Plant:				
13	Total Intangible Plant	P10	-	-	-
	Transmission Plant:				
14	Total Transmission Plant	P50	489.0	-	489.0
	Distribution Plant:				
15	Total Distribution Plant	P60	3,475.0	3,474.0	1.0
	General Plant:				
16	Total General Plant	P90	11.0	10.3	0.7
17	**Total Amortization of Salvage & Regulatory Assets**		3,975.0	3,484.3	490.7
	Unamortized Investment Tax Credit				
18	Transmission	P50	308.0	-	308.0
19	Distribution	P60	1,066.0	1,065.7	0.3
20	General	P90	81.0	75.9	5.1
21	Total - To Table No 9 - Income Taxes		1,455.0	1,141.6	313.4

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Table No 8 - Taxes Other Than Income Taxes

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Taxes Other Than Income Taxes				
	Non-revenue related:				
1	PA Real Estate Tax	TXDT	293.0	234.4	58.6
2	Pennsylvania - PURTA	TXDT	1,335.0	1,067.8	267.2
					-
3	Capital Stock	TXDT	2,300.0	1,839.7	460.3
4	Insurance Premiums	TXDT	-	-	-
5	Miscellaneous Taxes	TXDT	375.0	300.0	75.0
6	Subtotal		4,303.0	3,441.9	861.1
	Payroll Taxes:				
7	FICA	LABOR	3,969.4	3,716.7	252.7
8	FUTA	LABOR	515.9	483.0	32.8
9	SUTA	LABOR	73.7	69.0	4.7
10	City of Pittsburgh	LABOR	306.0	286.5	19.5
11	Subtotal		4,865.0	4,555.3	309.7
	Revenue Related:				
12	State Gross Receipts:				
13	Pennsylvania	GRTREV	40,460.9	16,697.1	23,763.8
14	Other states		-		-
15	**Total Taxes Other Than Income Taxes**		49,628.9	24,694.3	24,934.6

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Table No 9 - Summary of Income Taxes

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
1	Revenues	Table No 5	715,787.0	294,237.0	421,550.0
2	Less: Operating Expenses	Table No 2, L 10	665,743.3	257,383.7	408,359.6
3	Operating Income Before Income Taxes		50,043.7	36,853.3	13,190.4
	Interest Expense				
4	Electric Rate Base	Table No 1, L 24	1,527,947.8	1,232,857.4	295,090.4
5	Weighted Cost of Debt	B-9	2.97%	2.97%	2.97%
6	Synchronized Interest Expense		45,379.0	36,615.0	8,764.0
7	**Base Taxable Income**		4,664.7	238.3	4,426.4
8	State Tax Deductions (Over) Under Book	Table 10, Pg 2	(13,189.6)	(12,473.4)	(716.2)
	Pennsylvania State Income Taxes:				
9	Taxable Income		(8,524.9)	(12,235.1)	3,710.2
10	Less State Flow Through Tax Deductions	EPIS	-	-	-
11	State Taxable Income		(8,524.9)	(12,235.1)	3,710.2
12	State Income Tax Rate - 9.99%		9.99%	9.99%	9.99%
13	State Income Tax Expense		(851.6)	(1,222.3)	370.6
	Federal Income Taxes:				
14	Federal Taxable Income		(7,673.3)	(11,012.8)	47.6
15	Less Federal Flow Through Tax Deductions	Table No 10	-	-	-
16	Federal Taxable Income		(7,673.3)	(11,012.8)	47.6
17	Federal Tax Rate - 35%		35.0%	35.0%	35.0%
18	Federal Income Tax Expense		(2,685.6)	(3,854.5)	16.7
19	**Deferred Federal Taxable Income**	Table 10, Pg 2	30,613.0	28,819.2	1,793.8
20	Federal Tax Rate		35.0%	35.0%	35.0%
21	Federal Income Tax Expense		10,714.6	10,086.7	627.8
	Amortization of Investment Tax Credit	ITC	(1,455.0)	(1,141.6)	(313.4)
22	Less Consolidated Income Tax Offset	TXDT	(942.0)	(753.5)	(188.5)
23	Total Combined Federal Income Tax Expense		5,631.9	4,337.1	1,294.8
24	Total Income Tax Expenses		4,780.3	3,114.9	1,665.4

(X$000)

Table No 10 - Income Tax Additions & Adjustments

Line No	Description	Allocation Factor/Reference	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Total Tax Depreciation:				
1	Intangible Plant	P10	-	-	-
2	Transmission Plant	P50	10,556.0	-	10,556.0
3	Distribution Plant	P60	53,133.0	53,118.3	14.7
4	General Plant	P90	23,760.0	22,271.7	1,488.3
5	Totals		87,449.0	75,389.9	12,059.1
	Pro Forma Book Depreciation:				
6	Intangible Plant	Table No 7	2,365.4	1,892.0	473.4
7	Transmission Plant	Table No 7	9,620.0	-	9,620.0
8	Distribution Plant	Table No 7	42,679.0	42,668.5	10.5
9	General Plant	Table No 7	19,595.0	18,356.0	1,239.0
10	Totals		74,259.4	62,916.6	11,342.8
	State Tax Deductions (Over) Under Book:				
11	Intangible Plant	Line 6 - Line 1	2,365.4	1,892.0	473.4
12	Transmission Plant	Line 7 - Line 2	(936.0)	-	(936.0)
13	Distribution Plant	Line 8 - Line 3	(10,454.0)	(10,449.8)	(4.2)
14	General Plant	Line 9 - Line 4	(4,165.0)	(3,915.6)	(249.4)
15	Totals		(13,189.6)	(12,473.4)	(716.2)
	Deferred Federal Income Taxes:				
	Total Straight Line Tax Depreciation				
16	Intangible Plant	P10	-	-	-
17	Transmission Plant	P50	9,543.0	-	9,543.0
18	Distribution Plant	P60	35,921.0	35,911.1	9.9
19	General Plant	P90	11,372.0	10,659.7	712.3
20	Totals		56,836.0	46,570.7	10,265.3
	Total Tax Depreciation:				
21	Intangible Plant	P10	-	-	-
22	Transmission Plant	P50	10,556.0	-	10,556.0
23	Distribution Plant	P60	53,133.0	53,118.3	14.7
24	General Plant	P90	23,760.0	22,271.7	1,488.3
25	Totals		87,449.0	75,389.9	12,059.1
	Federal Tax Deductions (Over) Under Book:				
26	Intangible Plant	Line 16 - Line 21	-	-	-
27	Transmission Plant	Line 17 - Line 22	(1,013.0)	-	(1,013.0)
28	Distribution Plant	Line 18 - Line 23	(17,212.0)	(17,207.2)	(4.8)
29	General Plant	Line 19 - Line 24	(12,388.0)	(11,612.0)	(776.0)
30	Totals		(30,613.0)	(28,819.2)	(1,793.8)

(X$000)

Table No 11 - Allocation Factors

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Development of the Labor Allocator				
	Power Supply Expense:				
1	Demand-related	D10	-		-
2	Energy-related	E10	-		-
3	Subtotal Power Supply-Z30		-		-
4	Subtotal Power Supply-(%)	Z30	-		-
5	Supervision & Engineering	Z30	-		-
6	Total Production		-		-
7	Transmission Expense - P50	DATX	1,963.2	-	1,963.2
8	Distribution Expense - P60	P60	18,289.9	18,284.8	5.1
9	Customer Accounting - Z90	CWAC	10,374.5	10,374.5	-
10	Customer Service & Information	CWCS	293.8	293.8	-
11	Subtotal Before A & G		30,921.3	28,953.1	1,968.3
12	Subtotal Before A & G - %	LABORSUB	100.00%	93.635%	6.365%
13	Administrative & General	LABORSUB	28,849.6	27,013.2	1,836.4
14	Total Labor Expense-Labor		59,770.9	55,966.3	3,804.7
15	Total Labor Expense-Labor (%)	LABOR	100.00%	93.635%	6.365%
	Development of Allocator - Direct Assignment of General Plant to Distribution:				
16	Total General Plant - Accounts 389-398 - $	Table No 1	235,742.1		
17	Less Account 397 Directly Assigned to Dist	DADT	3,753.0	3,753.0	-
18	Balance to be Allocated	LABOR	231,989.1	217,222.0	14,767.0
19	Revised General Plant Allocation Factor-$		235,742.1	220,975.0	14,767.0
20	Revised General Plant Allocation Factor-%	P90ADJ	100.00%	93.736%	6.264%

(X$000)

Table No 11 - Allocation Factors

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Development of Plant-related Allocation Factors:				
	Development of Plant Allocator less Intangible Plant (P101)				
1	Transmission Plant		421,376.3	-	421,376.3
2	Distribution Plant		1,686,508.9	1,686,042.0	466.9
3	General Plant		235,742.1	220,975.0	14,767.0
4	Total - $		2,343,627.3	1,907,017.0	436,610.2
5	Total - %	P101	100.00%	81.37%	18.63%
6	Allocated Intangible Plant - $		29,823.4	23,854.9	5,968.4
7	Allocated Intangible Plant - %	P10	100.00%	79.99%	20.01%
8	Net Electric Plant in Service-$		1,626,566.6	1,317,709.3	308,857.3
9	Net Electric Plant in Service-%	NTPLT	100.00%	81.01%	18.99%
10	Total Electric Rate Base-$		1,527,947.8	1,232,857.4	295,090.4
11	Total Electric Rate Base-%	BASE	100.00%	80.69%	19.31%
12	Electric Plant in Service-$		2,373,450.6	1,930,872.0	442,578.7
13	Electric Plant in Service-%	EPIS	100.00%	81.35%	18.65%
14	Transmission Plant - Allocated (P50)		421,376.3	-	421,376.3
15	Distribution Plant - Allocated (P60)		1,686,508.9	1,686,042.0	466.9
16	Total Transmission & Distribution Plant - $		2,107,885.2	1,686,042.0	421,843.2
17	Total Transmission & Distribution Plant - %	TXDT	100.00%	79.99%	20.01%
18	Total Distribution Plant-$		1,686,508.9	1,686,042.0	466.9
19	Total Distribution Plant-%	P60	100.00%	99.972%	0.028%
20	Transmission Plant - $		421,376.3	-	421,376.3
21	Transmission Plant - %	P50	100.00%	0.00%	100.00%
22	General Plant - $		235,742.1	220,975.0	14,767.0
23	General Plant - %	P90	100.00%	93.74%	6.26%

(X$000)

Table No 11 - Allocation Factors

Line No	Description	Allocation Factor		(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Development of Revenue and Tax-related Allocation Factors:					
1	Transmission & Distribution Taxable Inc-$			3,619.6	238.3	3,381.3
2	Transmission & Distribution Taxable Inc-%	TDTAX		100.00%	6.58%	93.42%
3	Federal Income Taxes (FIT)-$			5,631.9	4,337.1	1,294.8
4	Federal Income Taxes (FIT)-%	FIT		100.00%	77.01%	22.99%
5	*Federal Income Tax Additions/Deductions-$*			(17,212.0)	(17,207.2)	(4.8)
6	Federal Income Tax Additions/Deductions-%	FITADD		100.00%	99.97%	0.03%
7	State Income Taxes (SIT)-$			(851.6)	(1,222.3)	370.6
8	State Income Taxes (SIT)-%	SIT		100.00%	143.52%	-43.52%
9	Billed Revenues - TY2006 - $			682,736.0	279,955.0	402,781.0
10	Billed Revenues - TY2006 - %	REV		100.00%	41.00%	59.00%
11	Billed Revenues-Combined - TY2006 - $			682,736.0	662,059.0	20,677.0
12	Billed Revenues-Combined - TY2006 - %	REV1		100.00%	96.97%	3.03%
13	Total Revenues - TY2006 - $			715,787.0	294,237.0	421,550.0
14	Total Revenues - TY2006 - %	PAREV		100.00%	41.11%	58.89%
15	Revenues Subject to GRT - TY2006 - $			685,786.0	283,005.0	402,781.0
16	Revenues Subject to GRT - TY2006 - %	GRTREV	(*)	100.00%	41.27%	58.73%

(*) Power Supply excludes Sales for Resale; Transmission excludes EGS and FERC Customers; Distribution excludes Acct Nos 451, 454, Other Revenues in 456.

(X$000)

Table No 11 - Allocation Factors

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Development of Distribution Plant Allocation Factors and Direct Assignments:				
1	Total Distribution Land & Land Rights-$		9,962.0	9,961.3	0.7
2	Total Distribution Land & Land Rights-%	P360	100.00%	99.993%	0.007%
3	Distribution Substation - Structures - $		47,272.0	47,241.7	30.3
4	Distribution Substation - Structures - %	P361	100.00%	99.94%	0.06%
5	Distribution Substation - Station Equipment-$		299,298.5	299,109.0	189.6
6	Distribution Substation - Station Equipment-%	P362	100.00%	99.94%	0.063%
7	Total Distribution Lines, Poles, etc-$		291,340.0	291,132.2	207.8
8	Total Distribution Lines, Poles, etc-%	P364	100.00%	99.93%	0.07%
9	Total Overhead Conductors & Devices-$		301,038.4	301,000.3	38.0
10	Total Overhead Conductors & Devices-%	P365	100.00%	99.99%	0.01%
11	Total Distribution Underground-$		190,267.4	190,267.4	-
12	Total Distribution Underground-%	P367	100.00%	100.00%	0.00%
13	Total Distribution Line Transformers-$		231,666.7	231,666.7	-
14	Total Distribution Line Transformers-%	P368	100.00%	100.00%	0.00%
15	Distribution Services-$		74,257.6	74,257.6	-
16	Distribution Services-%	P369	100.00%	100.00%	0.00%
17	Total Meters-$		76,191.8	76,191.4	0.4
18	Total Meters-%	P370	100.00%	100.00%	0.00%
19	Total Overhead Lines-Accounts 364/365-$		592,378.4	592,132.5	245.9
20	Total Overhead Lines-Accounts 364/365-%	P364/5	100.00%	99.96%	0.04%
21	Street Lighting-$		32,722.9	32,722.9	-
22	Street Lighting-%	P373	100.00%	100.00%	0.00%

(X$000)

Table No 11 - Allocation Factors

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Distribution Operation & Maintenance Expense Allocators				
	Supervision & Engineering-Operation:				
1	Load Dispatching	P60	365.5	365.4	0.1
2	Substations	P362	179.5	179.4	0.1
3	Lines	P364/5	207.6	207.5	0.1
4	Underground	P367	426.8	426.8	-
5	Street Lighting	P370	0.0	0.0	0.0
6	Meters	P373	1,770.9	1,770.9	-
7	Subtotal-$		2,950.3	2,950.0	0.3
8	Subtotal-%	PDIS1	100.00%	99.99%	0.01%
	Supervision & Engineering-Maintenance:				
9	Substations	P362	1,517.7	1,516.7	1.0
10	Lines	P364/5	12,452.5	12,447.3	5.2
11	Underground	P367	968.1	968.1	-
12	Street Lighting	P370	736.4	736.4	0.0
13	Meters	P373	1,449.4	1,449.4	-
14	Subtotal-$		17,124.0	17,117.9	6.1
15	Subtotal-%	PDIS2	100.00%	99.96%	0.04%
16	Total Operation & Maintenance Expenses - $		537,880.0	166,288.5	371,591.5
17	Total Operation & Maintenance Expenses - %	OMEXP	100.00%	30.92%	69.08%

Duquesne Light Company
Before The Pennsylvania Public Utility Commission
Jurisdictional Separation Study - Future Period
12 Months Ending December 31, 2006
(X$000)

Table No 12 - Working Cash Allowance by Jurisdiction

Line No	Description	Allocation Factor/ Reference		(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Working Cash Allowance - Schedule C-4:					
1	Total O & M expenses			537,880.0	524,803.5	13,076.5
2	Less Purchased Power Expenses			-	-	-
3	Total O & M Expenses less Purchased Power			537,880.0	524,803.5	13,076.5
	Non-cash Items:					
4	Uncollectible Expenses - Account 904			28,940.0	28,940.0	-
5	Uncollectible Expenses - Incremental			-	-	-
6	Other Expenses			-	-	-
7	Net Expenses for CWC Calculation	1394		508,940.0	495,863.5	13,076.5
8	Number of (Lead)/Lag Days /365*Weighted $	$25.53	X	35,604.5	34,689.7	914.8
9	Prepayments: 13-month Average Balance	EPIS	X	4,200.0	3,416.8	783.2
	Accrued Taxes - Allocated;					
10	Federal Income Taxes	FIT		5,631.9	46,447.5	(40,815.6)
11		-3.42%		(192.5)	(1,587.9)	1,395.4
12	PA State Income Taxes	SIT		(851.6)	12,131.2	(12,982.9)
13		-1.34%		11.4	(162.0)	173.4
14	PA Gross Receipts Tax @ 40%	40.00%		40,460.9	47,652.1	(7,191.1)
15		36.16%		14,632.6	17,233.2	(2,600.6)
16	PA Capital Stock Tax @ 40%	40%		2,300.0	1,839.7	460.3
17		-1.34%		(30.7)	(24.6)	(6.1)
18	PA Public Utility Realty Tax @ 40%	40%		1,335.0	1,067.8	267.2
19		23.66%		315.9	252.7	63.2
20	Subtotal Accrued Taxes		X	14,736.6	15,711.5	(974.9)
21	Pro Forma Interest - Synchronized (365 days)	Page 20, Line 20		45,379.0	36,615.0	8,764.0
22		Page 20, Line 23	X	(4,634.9)	(3,739.7)	(895.1)
23	*Preferred Dividend Payments*	*BASE*	X	169.0	136.4	32.6
24	Total Working Capital Components - $			51,805.8	50,214.6	1,591.2
25	Total Working Capital Components - %	CWCA		100.00%	96.93%	3.07%
26	*Total Working Capital Components - $*	*CWCA*		*51,805.8*	*50,086.0*	*1,719.8*
27	Total Working Capital Components - %	CWCA		99.75%	96.68%	3.32%

Duquesne Light Company
Before The Pennsylvania Public Utility Commission
Jurisdictional Separation Study - Future Period
12 Months Ending December 31, 2006
(X$000)

DFR II-D-27
Sponsor: Larry A Crowley
Exhibit LAC-2

Table No 12 - Working Cash Allowance by Jurisdiction

Line No	Description	Allocation Factor/ Reference	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Work Papers/Formula - CWC:				
1	Federal Income Taxes - Proforma		5,631.9	4,666.4	965.5
2	Federal Income Taxes - Incremental		-	-	-
3	Revenue Deficiency		-	142,560.3	(142,560.3)
4	Less: Uncollectible Expenses	0.0107	-	1,525.4	(1,525.4)
5	Less; Gross Receipts Tax @ 5.9%	0.059	-	8,411.1	(8,411.1)
6	Subtotal - Taxable Income		-	132,623.8	(132,623.8)
7	State Tax Expense @ 9.99%	0.0999	-	13,249.1	(13,249.1)
8	Federal Taxable Income - Incremental		-	119,374.7	(119,374.7)
9	Total Federal Income Taxes @ 35%	0.350	-	41,781.1	(41,781.1)
10	Total Federal Income Taxes		5,631.9	46,447.5	(40,815.6)
11	State Income Taxes - Proforma		(851.6)	(1,117.9)	266.2
12	Incremental State Taxes		-	13,249.1	(13,249.1)
13	Total State Income Taxes		(851.6)	12,131.2	(12,982.9)
14	Gross Receipts Tax - Proforma		40,460.9	39,241.0	1,219.9
15	Gross Receipts Tax - Incremental		-	8,411.1	(8,411.1)
16	Total Gross Receipts Tax		40,460.9	47,652.1	(7,191.1)
	Pro Forma Interest Expense - CWC:				
17	Total Electric Rate Base - Allocated	Table No 1	1,527,947.8	1,232,857.4	295,090.4
18	Long-term Debt Ratio	B-9	43.03%	43.03%	43.03%
19	Embedded Cost of Long-term Debt	B-9	6.90%	6.90%	6.90%
20	Pro Forma Interest Expense	L17*L18*L19	45,379.0	36,615.0	8,764.0
21	Daily Amount	Line 20/365	124.3	100.3	24.0
22	Interest Payment Lag Days		37.3	37.3	37.3
23	Total Interest for Working Capital	Line 21 * Line 22	(4,634.9)	(3,739.7)	(895.1)

Duquesne Light Company
Before The Pennsylvania Public Utility Commission

Operating Income
Pro Forma at Present and Proposed Rates - Future Period
12 Months Ending December 31, 2006
(X$000)

Table No 1
Earned Rate of Return with Additional Revenue Requirements - PA Jurisdiction

Line No	Description	(1) ROR Before Additional Revenues	(2) Proposed Additional Revenues	(3) ROR With Additional Revenues
1	Total Electric Rate Base	$ 1,232,857.4	-	$ 1,232,857.4
	Total Operating Revenues:			
2	Total Sales Revenues	279,955.0	143,683.7	423,638.7
3	Sales for Resale	-	-	-
4	Other Operating Revenues	14,282.0	-	14,282.0
5	Total Revenues	294,237.0	143,683.7	437,920.7
	Total Operating Expenses:			
6	Operation & Maintenance Expenses	166,288.5	1,537.4	167,825.9
7	Depreciation Expense	62,916.6	-	62,916.6
8	Amortization Expense	3,484.3	-	3,484.3
9	Taxes Other Than Income Taxes	24,694.3	8,477.3	33,171.6
10	Total Operating Expenses	257,383.7	10,014.8	267,398.5
11	Utility Operating Income Before Taxes	36,853.3	133,668.9	170,522.2
	Income Taxes:			
12	Federal	4,337.1	42,110.4	46,447.5
13	State	(1,222.3)	13,353.5	12,131.2
14	Total Operating Expenses	260,498.6	65,478.7	325,977.2
15	Total Operating Income - $	$ 33,738.4	$ 78,205.0	$ 111,943.5
16	Earned Rate of Return - %	2.737%		9.08%

Duquesne Light Company
Before The Pennsylvania Public Utility Commission

Operating Income
Pro Forma at Present and Proposed Rates - Future Period
12 Months Ending December 31, 2006
(X$000)

Table No 2
Determination of Jurisdictional Revenue Deficiency

Line No	Description	Reference	(1) Total Company	(2) Total PA Jurisdiction	(3) PA JSS Reference
1	Total Electric Rate Base	Table No 1	$ 1,527,947.8	$ 1,232,857.4	Table No 1
	Total Operating Revenues				
2	Total Sales Revenues	D-3	678,378.0	279,955.0	Table No 5
3	Sales for Resale/Other Transmission	D-3	4,358.0	-	Table No 5
4	Other Operating Revenues	D-3	33,051.0	14,282.0	Table No 5
5	*Total Revenues*		*715,787.0*	*294,237.0*	
	Total Operating Expenses				
6	Operation & Maintenance Expenses	D-4	537,880.0	166,288.5	Table No 6
7	Depreciation Expense	D-17	74,259.4	62,916.6	Table No 7
8	Amortization Expense	D-17	3,975.0	3,484.3	Table No 7
9	Taxes Other Than Income Taxes	D-16	49,628.9	24,694.3	Table No 8
10	Total Operating Expenses		665,743.3	257,383.7	
11	*Utility Operating Income Before Taxes*		*50,043.7*	*36,853.3*	
	Income Taxes:				
12	Federal	D-2	5,631.9	4,337.1	Table No 9
13	State	D-2	(851.6)	(1,222.3)	Table No 9
14	Total Operating Expenses		670,523.6	260,498.6	
15	Total Operating Income		45,263.4	33,738.4	
	Return Before Adjustments				
16	Earned Rate of Return - %			2.7366%	
17	Required Rate of Return - %	B-9		9.0800%	
18	Return at Required Rate of Return			$ 111,943.5	
19	Income Deficiency - $			78,205.0	
20	Revenue Deficiency - Tax Multiplier	D-18		1.83727	
21	Revenue Deficiency-$			*$ 143,683.7*	

Duquesne Light Company
Before The Pennsylvania Public Utility Commission

Operating Income
Pro Forma at Present and Proposed Rates - Future Period
12 Months Ending December 31, 2006
(X$000)

Table No 3
Electric Rate Base - Pennsylvania

Line No	Description	Reference	(1) Total Company	(2) Total PA *Jurisdiction*	(3) PA JSS *Reference*
1	Electric Plant in Service		$ 2,373,450.6	$ 1,930,872.0	Table No 1
2	Accumulated Provision for Depreciation	C-2	746,884.0	613,162.7	Table No 1
3	Net Electric Plant in Service	C-3	1,626,566.6	1,317,709.3	
	Other Rate Base Items - Additions:				
4	Cash Working Capital	C-4	51,677.2	50,086.0	Table No 12
5	Materials & Supplies	C-5	17,681.0	11,296.0	Table No 1
6	Total Additions		69,358.2	61,382.0	
7	Total Rate Base Before Deductions		1,695,924.8	1,379,091.3	
	Other Rate Base Items - Deductions:				
8	Customer Deposits - Account 235	B-1	(1,413.0)	(1,413.0)	Table No 1
9	Accumulated Deferred Income Taxes	C-6	(166,564.0)	(144,820.9)	Table No 1
10	Total Deductions		(167,977.0)	(146,233.9)	
11	Total Electric Rate Base		$ 1,527,947.8	$ 1,232,857.4	

Duquesne Light Company
Before The Pennsylvania Public Utility Commission

Measures of Value and Rates of Return - Historic Period
For the 12 Months Ending December 31, 2005
(X$000)

Line No	Description	Historic Period - CY 2005 Total Electric Utility	Historic Period - CY 2005 Total PA Jurisdiction (1)	Reference
	Electric Plant			
1	Electric Plant in Service	$ 2,168,015.9	$ 1,811,124.8	C-2
2	Depreciation Reserve	727,522.0	596,521.2	C-3
3	Net Electric Plant in Service	1,440,493.9	1,214,603.6	
	Additions:			
	Working Capital Requirements			
4	Cash Working Capital	52,607.2	51,120.7	C-4
5	Materials & Supplies	15,558.0	14,270.3	C-5
6	Total Working Capital	68,165.2	65,391.0	
	Deductions:			
7	Customer Deposits - Account 235	(1,713.0)	(1,713.0)	B-1
8	Accumulated Deferred Income Taxes	(156,153.0)	(134,871.8)	C-6
9	Total Deductions	(157,866.0)	(136,584.8)	
10	**Total Measure of Value/Rate Base - Net**	1,350,793.1	1,143,409.8	
	Pro Forma Return at Present rates			
11	Amount - $		48,307.5	D-1
12	Percent		4.22%	
	Pro Forma Return at Proposed Rates			
13	Amount - $		$ 124,538.0	D-1
14	Percent		10.89%	

(1) See Exhibit No LAC-6

(X$000)

Table No 1 - Total Electric Rate Base

Line No	Description	Allocation Factor or Reference	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Electric Plant in Service				
1	Intangible Plant	Table No 3	27,136.0	22,373.4	4,762.6
2	Transmission Plant	Table No 3	338,613.4	-	338,613.4
3	Distribution Plant	Table No 3	1,593,387.5	1,592,920.7	466.9
4	General Plant - P90	P90ADJ	208,879.0	195,830.7	13,048.3
5	Total Electric Plant in Service		2,168,015.9	1,811,124.8	356,891.1
	Less:				
6	Accum Provision for Depreciation & Amortization				
7	Intangible Plant	Table No 4	18,645.0	15,372.7	3,272.3
8	Transmission Plant	Table No 4	124,295.0	-	124,295.0
9	Distribution Plant	Table No 4	532,887.0	532,728.5	158.5
10	General Plant	Table No 4	51,695.0	48,420.0	3,275.0
11	Total Accum Provision - Depreciation & Amort		727,522.0	596,521.2	131,000.8
12	**Net Electric Plant in Service**		1,440,493.9	1,214,603.6	225,890.2
	Other Rate Base Items:				
13	Cash Working Capital	Table No 12	52,607.2	51,120.7	1,486.5
	Materials & Supplies - Account 154:				
14	Transmission Plant	P50	1,091.0	-	1,091.0
15	Distribution Plant	P60	11,371.0	11,367.7	3.3
16	General Plant	P90	3,096.0	2,902.6	193.4
17	Intangible or Other Plant	P10	-	-	-
18	Construction Category	TXDT	-	-	-
19	Total Materials & Supplies		15,558.0	14,270.3	1,287.7
	Less:				
20	Customer Deposits - Account 235	DADT	(1,713.0)	(1,713.0)	-
	Accumulated Deferred Income Taxes:				
21	Transmission	DATX	(20,080.0)	-	(20,080.0)
22	Distribution	P60	(117,394.0)	(117,359.6)	(34.4)
23	General	P90	(18,679.0)	(17,512.2)	(1,166.8)
	Subtotal - Other Rate Base Items		(89,700.8)	(71,193.8)	(18,507.0)
24	**Total Electric Rate Base - $**		1,350,793.1	1,143,409.8	207,383.2
25	**Total Electric Rate Base - %**		100.00%	84.65%	15.35%

(X$000)

Table No 2 - Calculation of Jurisdictional Revenue Deficiency

Line No	Description	Reference	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
1	**Total Electric Rate Base**	Table No 1	1,350,793.1	1,143,409.8	207,383.2
	Total Operating Revenues				
2	Total Sales Revenues	Table No 5	695,345.0	282,557.0	412,788.0
3	Other Transmission Revenues - PJM Adder	Table No 5	9,314.0	-	9,314.0
4	Other Operating Revenues	Table No 5	36,104.0	16,053.0	20,051.0
5	Total Revenues		740,763.0	298,610.0	442,153.0
	Total Operating Expenses				
6	Operation & Maintenance Expenses	Table No 6	538,032.0	151,073.8	386,958.2
7	Depreciation Expense	Table No 7	68,924.0	59,883.8	9,040.2
8	Amortization Expense	Table No 7	3,200.0	2,756.8	443.2
9	Taxes Other Than Income Taxes	Table No 8	50,307.7	24,585.6	25,722.0
10	Total Operating Expenses		660,463.7	238,300.1	422,163.6
11	Operating Income Before Income Taxes	Line 5 - Line 10	80,299.3	60,309.9	19,989.4
	Income Taxes:				
12	Federal	Table No 9	12,994.5	9,647.8	3,346.7
13	State	Table No 9	3,691.3	2,354.6	1,336.7
14	Total Operating Expenses		677,149.4	250,302.5	426,847.0
15	**Net Operating Income**		63,613.6	48,307.5	15,306.0
	Return Before Adjustments				
16	Earned Rate of Return - %	Line 15/Line 1		4.225%	
17	Required Rate of Return - %	B-9		9.11%	
18	Return at Required Rate of Return	Line 1 x Line 17		104,164.6	
19	Income Deficiency	Line 18 - Line 15		55,857.1	
20	Net-to-Gross Multiplier	D-18		1.84261	
21	**PA Revenue Deficiency - $**	Line 19 x Line 20		102,922.9	
22	**PA Revenue Requirements - $**			$ 401,532.9	

(X$000)

Table No 3 - Electric Plant in Service

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Electric Plant in Service - Account 101/106				
	Intangible Plant:				
1	Organizations	TXDT	100.0	82.4	17.6
2	Franchises & Consents	TXDT	7.0	5.8	1.2
3	Software - Plant/O&M-related	TXDT	27,029.0	22,285.2	4,743.8
4	Software - Customer-related	DADT	-	-	-
5	Software - Labor-related	LABOR	-	-	-
6	Total Intangible Plant-P10		27,136.0	22,373.4	4,762.6
	Transmission Plant:				
7	Land and Land Rights - 350	DATX	11,034.7	-	11,034.7
8	Structures and Improvements - 352	DATX	7,518.4	-	7,518.4
9	Station Equipment - 353	DATX	146,478.7	-	146,478.7
10	Towers and Fixtures - 354	DATX	64,348.9	-	64,348.9
11	Poles and Fixtures - 355	DATX	9,301.1	-	9,301.1
12	Overhead Conductors & Devices - 356	DATX	42,565.2	-	42,565.2
13	Underground Conduit - 357	DATX	37,289.4	-	37,289.4
14	Underground Conduit & Devices - 358	DATX	20,072.9	-	20,072.9
15	Roads and Trails - 359	DATX	4.0	-	4.0
16	Total Transmission Plant - P50		338,613.4	-	338,613.4
	Distribution Plant:				
17	Land and Land Rights - 360	P360	9,967.8	9,967.1	0.7
18	Structures and Improvements - 361	P361	47,319.8	47,289.5	30.3
19	Station Equipment - 362	P362	270,859.7	270,670.1	189.6
20	Poles, Towers and Fixtures - 364	P364	281,432.8	281,225.0	207.8
21	Overhead Conductors and Devices - 365	P365	279,777.8	279,739.8	38.0
22	Underground Conduit - 366	P366	90,830.2	90,830.2	-
23	Underground Conductors and Devices - 367	P367	187,280.9	187,280.9	-
24	Line Transformers - 368	P368	211,823.6	211,823.6	-
25	OH & UND Services - 369	P369	74,101.4	74,101.4	-
26	Meters & Appurtences - 370	P370	87,780.8	87,780.4	0.4
27	Meter Communication Equipment - 370.1	P3701	19,779.4	19,779.4	-
28	Street Lighting - 373	P373	32,433.3	32,433.3	-
29	Total Distribution Plant - P60		1,593,387.5	1,592,920.7	466.9

(X$000)

Table No 4 - Accumulated Provision for Depreciation

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Accumulated Provision for Depreciation & Amortization				
1	Intangible Plant:				
2	Organizations	P10	-	-	-
3	Franchises	P10	-	-	-
4	Miscellaneous Intangible Plant	P10	18,645.0	15,372.7	3,272.3
5	Total Intangible Plant - P10		18,645.0	15,372.7	3,272.3
6	Total Transmission Plant	P50	124,295.0	-	124,295.0
	Distribution Plant:				
7	Land and Land Rights	P360	-	-	-
8	Structures and Improvements	P361	22,028.0	22,013.9	14.1
9	Station Equipment	P362	80,147.0	80,090.9	56.1
10	Poles, Towers and Fixtures	P364	103,308.0	103,231.7	76.3
11	Overhead Conductors and Devices	P365	86,976.0	86,964.2	11.8
12	Underground Conduit	P366	26,237.0	26,237.0	-
13	Underground Conductors and Devices	P367	60,465.0	60,465.0	-
14	Line Transformers	P368	53,365.0	53,365.0	-
15	OH & UND Services	P369	29,972.0	29,972.0	-
16	Meters & Appurtences	P370	34,816.0	34,815.8	0.2
17	Meter Communication Equipment	P3701	14,141.0	14,141.0	-
18	Street Lighting	P373	21,432.0	21,432.0	-
19	Total Distribution Plant	P60	532,887.0	532,728.5	158.5
	General Plant:				
20	Land and Land Rights - 389	P90	-	-	-
21	Structures and Improvements - 390	P90	19,565.0	18,320.5	1,244.5
22	Office Equipment & Equipment - 391	P90	(1,742.0)	(1,631.2)	(110.8)
23	Transportation Equipment - 392	P90	16,742.0	15,677.0	1,065.0
24	Stores Equipment - 393	P90	677.0	633.9	43.1
25	Tools, Shop and Garage Equipment - 394	P90	2,915.0	2,729.6	185.4
26	Laboratory Equipment - 395	P90	1,152.0	1,078.7	73.3
27	Power Operated Equipment - 396	P90	604.0	565.6	38.4
28	Communication Equipment - 397	P90ADJ	11,682.0	10,952.2	729.8
29	Miscellaneous Equipment - 398	P90	100.0	93.6	6.4
30	Total General Plant		51,695.0	48,420.0	3,275.0
31	**Total Accumulated Provision for Depreciation**		727,522.0	596,521.2	131,000.8

(X$000)

Table No 5 - Total Operating Revenues

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Electric Operating Revenues				
	Sales of Electricity:				
1	Total Sales to Ultimate Customers		695,345.0	282,557.0	412,788.0
2	Sales for Resale/ Other TX (PJM Adder)	DAPS/TX	9,314.0	-	9,314.0
3	Total Sales of Electricity	REV	704,659.0	282,557.0	422,102.0
	Other Operating Revenues				
	Forfeited Discounts/Account 450:				
4	Late Payment Charges	DADT	2,934.0	2,934.0	-
5	Returned Check Charges	DADT	72.0	72.0	-
6	Total Account 450		3,006.0	3,006.0	-
7	Miscellaneous Service Revenues/Account 451	DADT	2,944.0	2,944.0	-
	Rent from Electric Property/Account 454:				
8	Rent - Electric Property	DADT	8,717.0	8,717.0	-
9	Customer Work - Reimbursement	DADT	510.0	510.0	-
10	Customer Work - Reimbursement O&M Fixed	DADT	524.0	524.0	-
11	Total Account 454		9,751.0	9,751.0	-
	Other Electric Revenues/Account 456:				
12	Customer Choice - EGS Transmission	DATX	14,827.0	-	14,827.0
13	Other Electric Revenues	DADT	352.0	352.0	-
14	SECA Credits - Other (EGS)	DATX	1,930.0	-	1,930.0
15	Transmission Revenue - AES/APS	DATX	2,556.0	-	2,556.0
16	Transmission Revenue - Piney Fork	DATX	288.0	-	288.0
17	Non-Firm Transmission Service	DATX	170.0	-	170.0
18	Firm Transmission Service	DATX	280.0	-	280.0
	Total Account 456		20,403.0	352.0	20,051.0
19					
	Total Other Operating Revenues		36,104.0	16,053.0	20,051.0
20					
	Total Operating Revenues	PAREV	740,763.0	298,610.0	442,153.0

(X$000)

Table No 6 - Operation & Maintenance Expenses

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Purchased Power Expenses:				
1	Purchased Power - Acct 555	DAPS	373,971.0	-	373,971.0
2	Other Power Supply Expense - Acct 556	DAPS	-	-	-
3	Total Purchased Power Expenses		373,971.0	-	373,971.0
	Transmission Expense:				
4	Operation Supervision & Engineering-560	DATX	1,242.0	-	1,242.0
5	Load Dispatching-561	DATX	156.0	-	156.0
6	Station Expenses-562	DATX	90.0	-	90.0
7	Overhead Line Expenses-563	DATX	27.0	-	27.0
8	Underground Line Expenses-564	DATX	58.0	-	58.0
9	*Transmission of Electricity by Others-565*	DATX	(5.0)	-	(5.0)
10	Miscellaneous Transmission Expenses-566	DATX	2,796.0	-	2,796.0
11	Rents-567	DATX	-	-	-
12	Maintenance Supervision & Engineering-568	DATX	208.0	-	208.0
13	Maintenance of Structures-569	DATX	630.0	-	630.0
14	Maintenance of Structures-570	DATX	482.0	-	482.0
15	Maintenance of Station Equipment-571	DATX	1,315.0	-	1,315.0
16	Maintenance of Underground Facilites-572	DATX	30.0	-	30.0
17	Total Transmission Expenses		7,029.0	-	7,029.0
	Distribution Expense - Operation:				
18	Operation Supervision & Engineering-580	PDIS1	1,522.0	1,521.8	0.2
19	Load Dispatching-581	P60	349.0	348.9	0.1
20	Station Expenses-582	P362	168.0	167.9	0.1
21	Overhead Line Expense-583	P364/5	195.0	194.9	0.1
22	Underground Line Expense-584	P367	398.0	398.0	-
23	Street Lighting & Signal Systems-585	P373	-	-	-
24	Meter Expenses-586	P370	1,682.0	1,682.0	0.0
25	Customer Installations Expense-587	DADT	26.0	26.0	-
26	Miscellaneous Expenses-588	DADT	10,703.0	10,703.0	-
27	Rents-589	DADT	-	-	-
28	*Total Distribution Operation Expenses*		15,043.0	15,042.5	0.5

(X$000)

Table No 6 - Operation & Maintenance Expenses

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Distribution Expense - Maintenance:				
1	Maintenance Supervision & Engineering-590	PDIS2	335.0	334.9	0.1
2	Maintenance of Structures-591	P362	16.0	16.0	0.0
3	Maintenance of Station Equipment-592	P362	1,454.0	1,453.0	1.0
4	Maintenance of OH lines-593	P364/5	11,736.0	11,730.9	5.1
5	Maintenance of Underground lines-594	P366	969.0	969.0	-
6	Maintenance of Line Transformers-595	P367	75.0	75.0	-
7	Maintenance of Street Lighting & Signals-596	P368	707.0	707.0	-
8	Maintenance of Meters-597	P369	1,385.0	1,385.0	-
9	Maintenance of Miscellaneous Plant-598	P370	184.0	184.0	0.0
10	Total Distribution Maintenance Expenses	P3701	16,861.0	16,854.7	6.3
11	Total Distribution Expenses	P373	31,904.0	31,897.2	6.8
	Customer Accounting Expense:				
12	Supervision-901		1,819.0	1,819.0	-
13	Customer Assistance-902		4,398.0	4,398.0	-
14	Records & Collections-903		7,869.0	7,869.0	-
15	Uncollectible Accounts-904		19,115.0	19,115.0	-
16	Miscellaneous Expenses-905		-	-	-
17	Total Consumer Accounts Expense	CWAC	33,201.0	33,201.0	-
	Customer Services Expense:				
18	Customer Service-Supervision-907		-	-	-
19	Customer Service-Customer Assist-908		680.0	680.0	-
20	Customer Service-Information-909		-	-	-
21	Customer Service-Misc Service & Info-910		-	-	-
22	Total Customer Service & Info Expenses	CWCS	680.0	680.0	-
	Sales Expense:				
23	Supervision-911		-	-	-
24	Demonstration and Selling Expenses-912		-	-	-
25	Advertising Expenses-913		-	-	-
26	Miscellaneous Sales Expenses-916		-	-	-
27	Total Sales Expense		-	-	-

(X$000)

Table No 6 - Operation & Maintenance Expenses

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Administrative & General Expenses:				
1	Administrative and General Salaries-920	LABOR	23,484.0	21,990.2	1,493.8
2	Office Supplies and Expenses-921	LABOR	5,597.0	5,241.0	356.0
3	Administrative Exps Transferred - Credit-922	LABOR	-	-	-
4	Outside Services Employed-923	LABOR	11,348.0	10,626.1	721.9
5	Property Insurance-924	PLANT	1,458.0	1,218.2	239.8
6	Injuries and Damages-925	LABOR	6,762.0	6,331.9	430.1
7	*Employee Pensions and Benefits-926*	LABOR	17,970.0	16,826.9	1,143.1
8	Regulatory Commission Expenses-928	LABOR	6,397.0	5,990.1	406.9
9	General Advertising Expenses-930.1	LABOR	2,026.0	1,897.1	128.9
10	Miscellaneous General Expenses-930.2	LABOR	5,657.0	5,297.2	359.8
11	Rents-931	LABOR	2,363.0	2,212.7	150.3
12	Total Operation A & G Expenses		83,062.0	77,631.3	5,430.7
13	Maintenance of General Plant-935	LABOR	8,185.0	7,664.3	520.7
14	Total Administrative & General Expenses		91,247.0	85,295.6	5,951.4
15	**Total Operation & Maintenance Expenses**		538,032.0	151,073.8	386,958.2

(X$000)

Table No 7 - Depreciation & Amortization Expenses

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Depreciation & Amortization Expense - Accts 403/404				
	Intangible Plant:				
1	Organizations	P10	-	-	-
2	Franchises	P10	-	-	-
3	Miscellaneous Intangible Plant	P10	-	-	-
4	Total Intangible Plant - P10		-	-	-
	Transmission Plant:				
5	Land and Land Rights	DATX	-	-	-
6	Structures and Improvements	DATX	253.0	-	253.0
7	Station Equipment	DATX	4,273.0	-	4,273.0
8	Towers and Fixtures	DATX	1,441.0	-	1,441.0
9	Poles and Fixtures	DATX	183.0	-	183.0
10	Overhead Conductors & Devices	DATX	770.0	-	770.0
11	Underground Conduit	DATX	735.0	-	735.0
12	Underground Conduit & Devices	DATX	281.0	-	281.0
13	Roads and Trails	DATX	-	-	-
14	Total Transmission Plant - P50		7,936.0	-	7,936.0
	Distribution Plant:				
15	Land and Land Rights	P360	-	-	-
16	Structures and Improvements	P361	1,202.0	1,201.2	0.8
17	Station Equipment	P362	6,284.0	6,279.6	4.4
18	Poles, Towers and Fixtures	P364	7,851.0	7,845.2	5.8
19	Overhead Conductors and Devices	P365	7,307.0	7,306.0	1.0
20	Underground Conduit	P366	1,871.0	1,871.0	-
21	Underground Conductors and Devices	P367	5,039.0	5,039.0	-
22	Line Transformers	P368	7,056.0	7,056.0	-
23	OH & UND Services	P369	1,390.0	1,390.0	-
24	Meters & Appurtences	P370	2,458.0	2,458.0	0.0
25	Meter Communication Equipment	P3701/DADT	2,508.0	2,508.0	-
26	Street Lighting	P373/DADT	713.0	713.0	-
27	Total Distribution Plant - P60		43,679.0	43,667.0	12.0

(X$000)

Table No 7 - Depreciation & Amortization Expenses

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	General Plant:				
1	Land and Land Rights - 389	P90	-	-	-
2	Structures and Improvements - 390	P90	2,034.0	1,904.6	129.4
3	*Office Equipment & Equipment - 391*	*P90*	*2,757.0*	*2,581.6*	*175.4*
4	Transportation Equipment - 392	P90	2,931.0	2,744.6	186.4
5	Stores Equipment - 393	P90	137.0	128.3	8.7
6	Tools, Shop and Garage Equipment - 394	P90	932.0	872.7	59.3
7	Laboratory Equipment - 395	P90	705.0	660.2	44.8
8	Power Operated Equipment - 396	P90	18.0	16.9	1.1
9	Communication Equipment - 397	P90ADJ	7,743.0	7,259.3	483.7
10	Miscellaneous Equipment - 398	P90	52.0	48.7	3.3
11	Total General Plant		17,309.0	16,216.8	1,092.2
12	**Total Depreciation & Amortization Expense**		68,924.0	59,883.8	9,040.2
	Amortization Other				
	Intangible Plant:				
13	Total Intangible Plant	P10	2,152.0	1,774.3	377.7
	Transmission Plant:				
14	Total Transmission Plant	P50	-	-	-
	Distribution Plant:				
15	Total Distribution Plant	P60	-	-	-
	General Plant:				
16	Total General Plant	P90	1,048.0	982.5	65.5
17	**Total Amortization Other**		3,200.0	2,756.8	443.2
	Unamortized Investment Tax Credit				
18	Transmission	P50	382.0	-	382.0
19	Distribution	P60	1,319.0	1,318.6	0.4
20	General	P90	99.0	92.8	6.2
21	Total - To Table No 9 - Income Taxes		1,800.0	1,411.4	388.6

(X$000)

Table No 8 - Taxes Other Than Income Taxes

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Taxes Other Than Income Taxes				
	Non-revenue related:				
1	PA Real Estate Tax	TXDT	200.0	164.9	35.1
2	Pennsylvania - PURTA	TXDT	733.0	604.4	128.6
					-
3	Capital Stock	TXDT	2,250.0	1,855.1	394.9
4	Insurance Premiums	TXDT	-	-	-
5	Miscellaneous Taxes	TXDT	67.0	55.2	11.8
6	Subtotal		3,250.0	2,679.6	570.4
	Payroll Taxes:				
7	FICA	LABOR	4,310.4	4,036.2	274.2
8	FUTA	LABOR	47.8	44.7	3.0
9	SUTA	LABOR	515.0	482.2	32.8
10	City of Pittsburgh	LABOR	398.0	372.7	25.3
11	Subtotal		5,271.2	4,935.9	335.3
	Revenue Related:				
12	State Gross Receipts:				
13	Pennsylvania	GRTREV	41,786.5	16,970.2	24,816.3
14	Other states		-		-
15	**Total Taxes Other Than Income Taxes**		50,307.7	24,585.6	25,722.0

(X$000)

Table No 9 - Summary of Income Taxes

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
1	Revenues	Table No 5	740,763.0	298,610.0	442,153.0
2	Less: Operating Expenses	Table No 2, L 10	660,463.7	238,300.1	422,163.6
3	Operating Income Before Income Taxes		80,299.3	60,309.9	19,989.4
	Interest Expense				
4	Electric Rate Base	Table No 1, L 24	1,350,793.1	1,143,409.8	207,383.2
5	Weighted Cost of Debt	B-9	2.99%	2.99%	2.99%
6	Synchronized Interest Expense		40,388.7	34,188.0	6,200.8
7	**Base Taxable Income**		39,910.6	26,122.0	13,788.6
8	State Tax Deductions (Over) Under Book	Table 10, Pg 2	(2,961.0)	(2,552.3)	(408.7)
	Pennsylvania State Income Taxes:				
9	Taxable Income		36,949.6	23,569.7	13,379.9
10	Less State Flow Through Tax Deductions	EPIS	-	-	-
11	State Taxable Income		36,949.6	23,569.7	13,379.9
12	State Income Tax Rate - 9.99%		9.99%	9.99%	9.99%
13	State Income Tax Expense		3,691.3	2,354.6	1,336.7
	Federal Income Taxes:				
14	Federal Taxable Income		33,258.3	21,215.1	12,043.3
15	Less Federal Flow Through Tax Deductions	Table No 10	-	-	-
16	Federal Taxable Income		33,258.3	21,215.1	12,043.3
17	Federal Tax Rate - 35%		35.0%	35.0%	35.0%
18	Federal Income Tax Expense		11,640.4	7,425.3	4,215.1
19	**Deferred Federal Taxable Income**	Table 10, Pg 2	11,703.0	12,601.7	(898.7)
20	Federal Tax Rate		35.0%	35.0%	35.0%
21	Federal Income Tax Expense		4,096.1	4,410.6	(314.5)
	Amortization of Investment Tax Credit	ITC	(1,800.0)	(1,411.4)	(388.6)
22	Less Consolidated Income Tax Offset	TXDT	(942.0)	(776.7)	(165.3)
23	Total Combined Federal Income Tax Expense		12,994.5	9,647.8	3,346.7
24	*Total Income Tax Expenses*		*16,685.7*	*12,002.4*	*4,683.4*

(X$000)

Table No 10 - Income Tax Additions & Adjustments

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Total Tax Depreciation:				
1	Intangible Plant	P10	-	-	-
2	Transmission Plant	P50	8,509.6	-	8,509.6
3	Distribution Plant	P60	42,832.6	42,820.0	12.6
4	General Plant	P90	19,153.8	17,957.3	1,196.5
5	Totals		70,496.0	60,777.3	9,718.7
	Pro Forma Book Depreciation:				
6	Intangible Plant	P10	2,152.0	1,774.3	377.7
7	Transmission Plant	P50	7,764.0	-	7,764.0
8	Distribution Plant	P60	39,101.0	39,089.5	11.5
9	General Plant	P90	18,518.0	17,361.2	1,156.8
10	Totals		67,535.0	58,225.1	9,309.9
	State Tax Deductions (Over) Under Book:				
11	Intangible Plant	Line 6 - Line 1	2,152.0	1,774.3	377.7
12	Transmission Plant	Line 7 - Line 2	(745.6)	-	(745.6)
13	Distribution Plant	Line 8 - Line 3	(3,731.6)	(3,730.5)	(1.1)
14	General Plant	Line 9 - Line 4	(635.8)	(596.1)	(39.7)
15	Totals		(2,961.0)	(2,552.3)	(408.7)
	Deferred Federal Income Taxes:				
	Total Straight Line Tax Depreciation				
16	Intangible Plant	P10	-	-	-
17	Transmission Plant	P50	9,871.6	-	9,871.6
18	Distribution Plant	P60	37,157.8	37,147.0	10.9
19	General Plant	P90	11,763.6	11,028.7	734.8
20	Totals		58,793.0	48,175.7	10,617.3
	Total Tax Depreciation:				
21	Intangible Plant	P10	-	-	-
22	Transmission Plant	P50	8,509.6	-	8,509.6
23	Distribution Plant	P60	42,832.6	42,820.0	12.6
24	General Plant	P90	19,153.8	17,957.3	1,196.5
25	Totals		70,496.00	60,777.3	9,718.7
	Federal Tax Deductions (Over) Under Book:				
26	Intangible Plant	Line 16 - Line 21	-	-	-
27	Transmission Plant	Line 17 - Line 22	1,362.0	-	1,362.0
28	Distribution Plant	Line 18 - Line 23	(5,674.7)	(5,673.0)	(1.7)
29	General Plant	Line 19 - Line 24	(7,390.3)	(6,928.6)	(461.7)
30	Totals		(11,703.0)	(12,601.7)	898.7

(X$000)

Table No 11 - Allocation Factors

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Development of the Labor Allocator				
	Power Supply Expense:				
1	Demand-related	D10	-	-	-
2	Energy-related	E10	-	-	-
3	Subtotal Power Supply-Z30		-		-
4	Subtotal Power Supply-(%)	Z30	-	-	-
5	Supervision & Engineering	Z30	-	-	-
6	Total Production		-		-
7	Transmission Expense - P50	DATX	1,874.0	-	1,874.0
8	Distribution Expense - P60	P60	17,474.1	17,469.0	5.1
9	Customer Accounting - Z90	CWAC	9,911.4	9,911.4	-
10	Customer Service & Information	CWCS	281.1	281.1	-
11	Subtotal Before A & G		29,540.6	27,661.5	1,879.1
12	Subtotal Before A & G - %	LABORSUB	100.00%	93.639%	6.361%
13	Administrative & General	LABORSUB	28,105.2	26,317.4	1,787.8
14	Total Labor Expense-Labor		57,645.8	53,978.9	3,666.9
15	Total Labor Expense-Labor (%)	LABOR	100.00%	93.639%	6.361%
	Development of Allocator - Direct Assignment of General Plant to Distribution:				
16	Total General Plant - Accounts 389-398 - $	Table No 1	208,879.0		
17	Less Account 397 Directly Assigned to Dist	DADT	3,753.0	3,753.0	-
18	Balance to be Allocated	LABOR	205,126.0	192,077.7	13,048.3
19	Revised General Plant Allocation Factor-$		208,879.0	195,830.7	13,048.3
20	Revised General Plant Allocation Factor-%	P90ADJ	100.00%	93.753%	6.247%

(X$000)

Table No 11 - Allocation Factors

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Development of Plant-related Allocation Factors:				
	Development of Plant Allocator less Intangible Plant (P101)				
1	Transmission Plant		338,613.4	-	338,613.4
2	Distribution Plant		1,593,387.5	1,592,920.7	466.9
3	General Plant		208,879.0	195,830.7	13,048.3
4	Total - $		2,140,879.9	1,788,751.4	352,128.5
5	Total - %	P101	100.00%	83.55%	16.45%
6	Allocated Intangible Plant - $		27,136.0	22,373.4	4,762.6
7	Allocated Intangible Plant - %	P10	100.00%	82.45%	17.55%
8	Net Electric Plant in Service-$		1,440,493.9	1,214,603.6	225,890.2
9	Net Electric Plant in Service-%	NTPLT	100.00%	84.32%	15.68%
10	Total Electric Rate Base-$		1,350,793.1	1,143,409.8	207,383.2
11	Total Electric Rate Base-%	BASE	100.00%	84.65%	15.35%
12	Electric Plant in Service-$		2,168,015.9	1,811,124.8	356,891.1
13	Electric Plant in Service-%	EPIS	100.00%	83.54%	16.46%
14	Transmission Plant - Allocated (P50)		338,613.4	-	338,613.4
15	Distribution Plant - Allocated (P60)		1,593,387.5	1,592,920.7	466.9
16	Total Transmission & Distribution Plant - $		1,932,000.9	1,592,920.7	339,080.3
17	Total Transmission & Distribution Plant - %	TXDT	100.00%	82.45%	17.55%
18	Total Distribution Plant-$		1,593,387.5	1,592,920.7	466.9
19	Total Distribution Plant-%	P60	100.00%	99.971%	0.029%
20	Transmission Plant - $		338,613.4	-	338,613.4
21	Transmission Plant -%	P50	100.00%	0.00%	100.00%
22	General Plant - $		208,879.0	195,830.7	13,048.3
23	General Plant - %	P90	100.00%	93.75%	6.25%

(X$000)

Table No 11 - Allocation Factors

Line No	Description	Allocation Factor		(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Development of Revenue and Tax-related Allocation Factors:					
1	Transmission & Distribution Taxable Inc-$			37,313.0	26,122.0	11,191.0
2	Transmission & Distribution Taxable Inc-%	TDTAX		100.00%	70.01%	29.99%
3	Federal Income Taxes (FIT)-$			12,994.5	9,647.8	3,346.7
4	Federal Income Taxes (FIT)-%	FIT		100.00%	74.25%	25.75%
5	Federal Income Tax Additions/Deductions-$			(5,674.7)	(5,673.0)	(1.7)
6	Federal Income Tax Additions/Deductions-%	FITADD		100.00%	99.97%	0.03%
7	State Income Taxes (SIT)-$			3,691.3	2,354.6	1,336.7
8	State Income Taxes (SIT)-%	SIT		100.00%	63.79%	36.21%
9	Billed Revenues - TY2006 - $			704,659.0	282,557.0	422,102.0
10	Billed Revenues - TY2006 - %	REV		100.00%	40.10%	59.90%
11	Billed Revenues-Combined - TY2006 - $			704,659.0	682,633.0	22,026.0
12	Billed Revenues-Combined - TY2006 - %	REV1		100.00%	96.87%	3.13%
13	Total Revenues - TY2006 - $			740,763.0	298,610.0	442,153.0
14	Total Revenues - TY2006 - %	PAREV		100.00%	40.31%	59.69%
15	Revenues Subject to GRT - TY2006 - $			703,156.0	285,563.0	417,593.0
16	Revenues Subject to GRT - TY2006 - %	GRTREV	(*)	100.00%	40.61%	59.39%

(*) Power Supply excludes Sales for Resale; Transmission excludes EGS and FERC Customers;
Distribution excludes Acct Nos 451, 454, Other Revenues in 456.

(X$000)

Table No 11 - Allocation Factors

Line No	Description	Allocation Factor		(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Development of Distribution Plant Allocation Factors and Direct Assignments:					
1	Total Distribution Land & Land Rights-$			9,967.8	9,967.1	0.7
2	Total Distribution Land & Land Rights-%	P360		100.00%	99.993%	0.007%
3	Distribution Substation - Structures - $			47,319.8	47,289.5	30.3
4	Distribution Substation - Structures - %	P361		100.00%	99.94%	0.06%
5	Distribution Substation - Station Equipment-$			270,859.7	270,670.1	189.6
6	Distribution Substation - Station Equipment-%	P362		100.00%	99.930%	0.070%
7	Total Distribution Lines, Poles, etc-$			281,432.8	281,225.0	207.8
8	Total Distribution Lines, Poles, etc-%	P364		100.00%	99.926%	0.074%
9	Total Overhead Conductors & Devices-$			279,777.8	279,739.8	38.0
10	Total Overhead Conductors & Devices-%	P365		100.00%	99.986%	0.014%
11	Total Distribution Underground-$			187,280.9	187,280.9	-
12	Total Distribution Underground-%	P367		100.00%	100.00%	0.00%
13	Total Distribution Line Transformers-$			211,823.6	211,823.6	-
14	Total Distribution Line Transformers-%	P368		100.00%	100.00%	0.00%
15	Distribution Services-$			74,101.4	74,101.4	-
16	Distribution Services-%	P369		100.00%	100.00%	0.00%
17	Total Meters-$			87,780.8	87,780.4	0.4
18	Total Meters-%	P370		100.00%	100.00%	0.00%
19	Total Overhead Lines-Accounts 364/365-$			561,210.6	560,964.7	245.9
20	Total Overhead Lines-Accounts 364/365-%	P364/5		100.00%	99.96%	0.04%
21	Street Lighting-$		#	32,433.3	32,433.3	-
22	Street Lighting-%	P373		100.00%	100.00%	0.00%

(X$000)

Table No 11 - Allocation Factors

Line No	Description	Allocation Factor	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Distribution Operation & Maintenance Expense Allocators				
	Supervision & Engineering-Operation:				
1	Load Dispatching	P60	349.0	348.9	0.1
2	Substations	P362	168.0	167.9	0.1
3	Lines	P364/5	195.0	194.9	0.1
4	Underground	P367	398.0	398.0	-
5	Street Lighting	P370	-	-	-
6	Meters	P373	1,682.0	1,682.0	-
7	Subtotal-$		2,792.0	2,791.7	0.3
8	Subtotal-%	PDIS1	100.00%	99.99%	0.01%
	Supervision & Engineering-Maintenance:				
9	Substations	P362	1,454.0	1,453.0	1.0
10	Lines	P364/5	11,736.0	11,730.9	5.1
11	Underground	P367	969.0	969.0	-
12	Street Lighting	P370	707.0	707.0	0.0
13	Meters	P373	1,385.0	1,385.0	-
14	Subtotal-$		16,251.0	16,244.8	6.2
15	Subtotal-%	PDIS2	100.00%	99.96%	0.04%
16	Total Operation & Maintenance Expenses - $		538,032.0	151,073.8	386,958.2
17	Total Operation & Maintenance Expenses - %	OMEXP	100.00%	28.08%	71.92%

(X$000)

Table No 12 - Working Cash Allowance by Jurisdiction

Line No	Description	Allocation Factor/ Reference		(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Working Cash Allowance - Schedule C-4:					
1	Total O & M expenses			538,032.0	525,044.8	12,987.2
2	Less Purchased Power Expenses			-	-	-
3	Total O & M Expenses less Purchased Power			538,032.0	525,044.8	12,987.2
	Non-cash Items:					
4	*Uncollectible Expenses - Account 904*			*19,115.0*	*19,115.0*	-
5	Uncollectible Expenses - Incremental			-	-	-
6	Other Expenses			-	-	-
7	Net Expenses for CWC Calculation	1422		518,917.0	505,929.8	12,987.2
8	Number of (Lead)/Lag Days /365*Weighted $	$25.32	X	36,001.0	35,100.0	901.0
9	Prepayments: 13-month Average Balance	EPIS	X	4,264.8	3,562.7	702.1
	Accrued Taxes - Allocated:					
10	Federal Income Taxes	FIT		57,777.1	52,499.2	5,277.9
11		-3.42%		(1,975.2)	(1,794.8)	(180.4)
12	PA State Income Taxes	SIT		17,892.2	15,943.1	1,949.1
13		-1.34%		(238.9)	(212.9)	(26.0)
14	PA Gross Receipts Tax @ 40%	40.00%		50,828.0	48,964.0	1,864.1
15		36.16%		18,381.8	17,707.7	674.1
16	PA Capital Stock Tax @ 40%	40%		2,250.0	1,855.1	394.9
17		-1.34%		(30.0)	(24.8)	(5.3)
18	PA Public Utility Realty Tax @ 40%	40%		733.0	604.4	128.6
19		23.66%		173.5	143.0	30.4
20	Subtotal Accrued Taxes		X	16,311.1	15,818.2	492.8
21	Pro Forma Interest - Synchronized (365 days)	Page 20, Line 20		40,433.7	34,226.0	6,207.7
22		Page 20, Line 23	X	(4,129.8)	(3,495.7)	(634.0)
23	Preferred Dividend Payments	BASE	X	160.0	135.4	24.6
24	Total Working Capital Components - $			52,607.1	51,120.7	1,486.4
25	Total Working Capital Components - %	CWCA		100.00%	97.17%	2.83%
26	Total Working Capital Components - $	CWCA		52,607.1	51,120.7	1,486.4
27	Total Working Capital Components - %	CWCA		100.00%	97.17%	2.83%

(X$000)

Table No 12 - Working Cash Allowance by Jurisdiction

Line No	Description	Allocation Factor/ Reference	(1) Total Electric Utility	(2) Total PA Jurisdiction	(3) Total All Other (1) - (2)
	Work Papers/Formula - CWC:				
1	Federal Income Taxes - Proforma		12,994.5	10,466.1	2,528.4
2	Federal Income Taxes - Incremental				
3	Revenue Deficiency - as calculated		109,531.6	100,122.6	9,409.0
4	Revenue Deficiency - Adjustment		43,714.4	43,714.4	-
5	Total Revenue Deficiency at 2006 Rates		153,246.0	143,837.0	9,409.0
6	Less: Uncollectible Expenses	0.0134	2,053.1	1,927.0	126.1
7	Less: Gross Receipts Tax @ 5.9%	0.0590	9,041.5	8,486.4	555.1
8	Subtotal - Taxable Income		142,151.4	133,423.6	8,727.8
9	State Tax Expense @ 9.99%	0.0999	14,200.9	13,329.0	871.9
10	Federal Taxable Income - Incremental		127,950.5	120,094.6	7,855.9
	Total Federal Income Taxes @ 35%	*0.3500*	*44,782.7*	*42,033.1*	*2,749.6*
11	Total Federal Income Taxes		57,777.1	52,499.2	5,277.9
12					
13	State Income Taxes - Proforma		3,691.3	2,614.1	1,077.2
	Incremental State Taxes		14,200.9	13,329.0	871.9
14	Total State Income Taxes		17,892.2	15,943.1	1,949.1
15					
16	Gross Receipts Tax - Proforma		41,786.5	40,477.6	1,308.9
	Gross Receipts Tax - Incremental		9,041.5	8,486.4	555.1
	Total Gross Receipts Tax		50,828.0	48,964.0	1,864.1
17					
18	Pro Forma Interest Expense - CWC:				
19	Total Electric Rate Base - Allocated	Table No 1	1,350,793.1	1,143,409.8	207,383.2
20	Long-term Debt Ratio	B-9	42.64%	42.64%	42.64%
21	*Embedded Cost of Long-term Debt*	B-9	7.02%	7.02%	7.02%
22	Pro Forma Interest Expense	L17*L18*L19	40,433.7	34,226.0	6,207.7
23	Daily Amount	Line 20/365	110.8	93.8	17.0
	Interest Payment Lag Days		37.3	37.3	37.3
	Total Interest for Working Capital	Line 21 * Line 22	(4,129.8)	(3,495.7)	(634.0)

Duquesne Light Company
Before The Pennsylvania Public Utility Commission

Operating Income
Pro Forma at Present and Proposed Rates - Historic Period
12 Months Ending December 31, 2005
(X$000)

Table No 1
Earned Rate of Return with Additional Revenue Requirements - PA Jurisdiction

Line No	Description	(1) ROR Before Additional Revenues	(2) Proposed Additional Revenues	(3) ROR With Additional Revenues	(4) Additional Revenue Adjustment for 2006 Rates (*)	(5) ROR With Additional 2006 Rate Adjustment
1	Total Electric Rate Base	$ 1,143,409.8	-	$ 1,143,409.8	-	$ 1,143,409.8
	Total Operating Revenues:					
2	Total Sales Revenues	282,557.0	102,922.9	385,479.9	37,540.2	423,020.1
3	Sales for Resale	-	-	-	-	-
4	Other Operating Revenues	16,053.0	-	16,053.0	-	16,053.0
5	Total Revenues	298,610.0	102,922.9	401,532.9	37,540.2	439,073.1
	Total Operating Expenses:					
6	Operation & Maintenance Expenses	151,073.8	1,378.9	152,452.7	502.9	152,955.6
7	Depreciation Expense	59,883.8	-	59,883.8	-	59,883.8
8	Amortization Expense	2,756.8	-	2,756.8	-	2,756.8
9	Taxes Other Than Income Taxes	24,585.6	6,072.5	30,658.1	2,214.9	32,873.0
10	*Total Operating Expenses*	238,300.1	7,451.3	245,751.4	2,717.8	248,469.2
11	Utility Operating Income Before Taxes	60,309.9	95,471.6	155,781.5	34,822.4	190,603.9
	Income Taxes:					
12	Federal	9,647.8	30,076.9	39,724.7	10,970.3	50,694.9
13	State	2,354.6	9,537.6	11,892.2	3,478.8	15,371.0
14	Total Operating Expenses	250,302.5	47,065.8	297,368.3	17,166.8	314,535.1
15	Total Operating Income - $	$ 48,307.5	$ 55,857.1	$ 104,164.6	$ 20,373.3	$ 124,538.0
16	Earned Rate of Return - %	4.225%		9.11%		10.892%

(*) The total revenue increase for 2005 derived from the application of the proposed 2006 rates equals - $ 140,463.1

Operating Income
Pro Forma at Present and Proposed Rates - Historic Period
12 Months Ending December 31, 2005
(X$000)

Table No 2
Determination of Jurisdictional Revenue Deficiency

Line No	Description	Reference	(1) Total Company	(2) Total PA Jurisdiction	(3) PA JSS Reference
1	Total Electric Rate Base	Table No 1	$ 1,350,793.1	$ 1,143,409.8	Table No 1
	Total Operating Revenues				
2	Total Sales Revenues	D-3	695,345.0	282,557.0	Table No 5
3	Sales for Resale/Other Transmission	D-3	9,314.0	-	Table No 5
4	Other Operating Revenues	D-3	36,104.0	16,053.0	Table No 5
5	Total Revenues		740,763.0	298,610.0	
	Total Operating Expenses				
6	Operation & Maintenance Expenses	D-4	538,032.0	151,073.8	Table No 6
7	Depreciation Expense	D-17	68,924.0	59,883.8	Table No 7
8	Amortization Expense	D-17	3,200.0	2,756.8	Table No 7
9	Taxes Other Than Income Taxes	D-16	50,307.7	24,585.6	Table No 8
10	Total Operating Expenses		660,463.7	238,300.1	
11	Utility Operating Income Before Taxes		80,299.3	60,309.9	
	Income Taxes:				
12	Federal	D-2	12,994.5	9,647.8	Table No 9
13	State	D-2	3,691.3	2,354.6	Table No 9
14	Total Operating Expenses		677,149.4	250,302.5	
15	Total Operating Income		63,613.6	48,307.5	
	Return Before Adjustments				
16	Earned Rate of Return - %			4.22%	
17	Required Rate of Return - %	B-9		9.11%	
18	*Return at Required Rate of Return*			*$ 104,164.6*	
19	Income Deficiency - $			55,857.1	
20	Revenue Deficiency - Tax Multiplier	D-18		1.84261	
21	Revenue Deficiency-$			$ 102,922.9	

Operating Income
Pro Forma at Present and Proposed Rates - Historic Period
12 Months Ending December 31, 2005
(X$000)

Table No 3
Electric Rate Base - Pennsylvania

Line No	Description	Reference	(1) Total Company	(2) Total PA Jurisdiction	(3) PA JSS Reference
1	Electric Plant in Service				
2	Accumulated Provision for Depreciation	C-2	$ 2,168,015.9	$ 1,811,124.8	Table No 1
3	Net Electric Plant in Service	C-3	727,522.0	596,521.2	Table No 1
			1,440,493.9	1,214,603.6	
	Other Rate Base Items - Additions:				
4	Cash Working Capital	C-4			
5	Materials & Supplies	C-5	52,607.2	51,120.7	Table No 12
6	Total Additions		15,558.0	14,270.3	Table No 1
7	Total Rate Base Before Deductions		68,165.2	65,391.0	
			1,508,659.1	1,279,994.6	
	Other Rate Base - Deductions:				
8	Customer Deposits - Account 235				
9	Accumulated Deferred Income Taxes	B-1	(1,713.0)	(1,713.0)	Table No 1
10	Total Deductions	C-6	(156,153.0)	(134,871.8)	Table No 1
			(157,866.0)	(136,584.8)	
11	Total Electric Rate Base				
			$ 1,350,793.1	$ 1,143,409.8	

Appendix A - Development of Retail Transmission Expense & Summary of Results

Duquesne Light Company

	Formula Transmission Rate		Notes	FERC Form 1 Page No or Instruction	CY 2005
	Blue (Dark) Shaded cells are input cells				
	Allocators				
	Wages & Salary Allocation Factor				
1	Transmission Wages Expense	(RCM Section WPs; I261)	CY 2005 Actual	p354.19.b	1,811,991
2	Total Wages Expense	(RCM Section WPs; I356)		p354.25b	55,692,833
3	Less A&G Wages Expense	(RCM Section WPs; I353)		p354.24b	27,153,190
4	Total			(Line 2 - 3)	28,539,643
5	**Wages & Salary Allocator**			(Line 1 / 4)	6.349%
	Plant Allocation Factors				
6	*Electric Plant in Service*		(Note)	p207.95g	2,159,275,000
7	Common Plant In Service - Electric			(Line 24)	0
8	Total Plant In Service			(Sum Lines 6 & 7)	2,159,275,000
9	Accumulated Depreciation (Total Electric Plant)			p219.28c	708,877,000
10	Accumulated Intangible Amortization		(Note)	p200 21c	18,646,000
11	Accumulated Common Amortization - Electric		(Note)	p356	0
12	Accumulated Common Plant Depreciation - Electric		(Note)	p356	0
13	Total Accumulated Depreciation			(Sum Lines 9 to 12)	727,523,000
14	Net Plant			(Line 8 - 13)	1,431,752,000
15	Transmission Gross Plant			(Line 29 - Line 28)	386,852,032
16	**Gross Plant Allocator**			(Line 15 / 8)	17.916%
17	Transmission Net Plant			(Line 39 - Line 28)	258,091,060
18	**Net Plant Allocator**			(Line 17 / 14)	18.026%
	Plant Calculations				
	Plant In Service				
19	Transmission Plant In Service		(Note)	p207.58.g	338,020,000
20	For True up only - remove New Transmission Plant Additions for Current Calendar Year		For True Up Only	Attachment 6	0
21	New Transmission Plant Additions for Current Calendar Year (weighted by months in service)			Attachment 6	33,972,000
22	**Total Transmission Plant In Service**			(Line 19 - 20 + 21)	371,992,000
23	General & Intangible			p205.5 g & p207.90.g	234,052,000
24	Common Plant (Electric Only)		(Notes &)	p356	0
25	Total General & Common			(Line 23 + 24)	234,052,000
26	Wage & Salary Allocation Factor			(Line 5)	6.349%
27	**General & Common Plant Allocated to Transmission**			(Line 25 * 26)	14,860,032
28	**Plant Held for Future Use (Including Land)**		(Note)	p214	174,000
29	*TOTAL Plant In Service*			*(Line 22 + 27 + 28)*	387,026,032
	Accumulated Depreciation				
30	Transmission Accumulated Depreciation		(Note)	p219 25.c	124,295,000
31	Accumulated General Depreciation			p219.27.c	51,695,000
32	Accumulated Intangible Amortization			(Line 10)	18,646,000
33	Accumulated Common Amortization - Electric			(Line 11)	0
34	Common Plant Accumulated Depreciation (Electric Only)			(Line 12)	0
35	Total Accumulated Depreciation			(Sum Lines 31 to 34)	70,341,000
36	Wage & Salary Allocation Factor			(Line 5)	6.349%
37	**General & Common Allocated to Transmission**			(Line 35 * 36)	4,465,971
38	**TOTAL Accumulated Depreciation**			(Line 30 + 37)	128,760,971
39	**TOTAL Net Property, Plant & Equipment**			(Line 29 - 38)	258,265,060

Adjustment To Rate Base

	Accumulated Deferred Income Taxes				
40	ADIT net of FASB 106 and 109	(RCM Section C-3; AO 79)		Attachment 1	-20,080,000
41	Accumulated Investment Tax Credit Account No. 255		(Notes &)	p266.h	-7,995,891
42	Net Plant Allocation Factor			(Line 18)	18.026%
43	**Accumulated Deferred Income Taxes Allocated To Transmission**			(Line 41 * 42) + Line 40	-21,521,359
	Prepayments				
44	Prepayments (Account 165)	(RCM Section 8; K40)	(Note)	p110.46d	6,027,000
45	Net Plant Allocation Factor			Line 18	18.03%
46	**Total Prepayments Allocated to Transmission**			(Line 44 * 45)	1,086,442
	Materials and Supplies				
47	Undistributed Stores Exp	(RCM Section C-3, AA98)	(Note)	p227.5c & 15.c	0
48	Wage & Salary Allocation Factor			(Line 5)	6.349%
49	Total Transmission Allocated			(Line 47 * 48)	0
50	Transmission Materials & Supplies	(RCM Section C-3; AA110/JSS Table No 1)		p227.8c	5,461,000
51	***Total Materials & Supplies Allocated to Transmission***			*(Line 49 + 50)*	***5,461,000***
	Cash Working Capital				
52	Operation & Maintenance Expense			(Line 82)	9,949,403
53	1/8th Rule			x 1/8	12.5%
54	**Total Cash Working Capital Allocated to Transmission**			(Line 52 * 53)	1,243,675
	Network Credits				
55	Outstanding Network Credits		(Note)	From PJM	0
56	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits		(Note)	From PJM	0
57	Net Outstanding Credits			(Line 55 - 56)	0
58	***TOTAL Adjustment to Rate Base***			(Line 43 + 46 + 51 + 54 - 57)	**-13,730,242**
59	**Rate Base**			(Line 39 + 58)	**244,534,819**

O&M Expenses

	Transmission O&M				
60	Transmission O&M	(RCM Section D, V636)		p321.100.b	6,967,000
61	Less Account 566	(PJM related costs)		p321.88.b	2,094,000
62	Less Schedule 12 payments applicable to the entire zone if not excluded in line 61 above		(Note)	PJM Data	0
63	Plus Transmission Lease Payments		(Note)	P200.3.c	0
64	**Transmission O&M**			(Lines 60 - 61 + 62 + 63)	**4,873,000**
	Allocated General & Common Expenses				
65	Common Plant O&M		(Note)	p356	0
66	Total A&G	(RCM Section D; V641)		p323.168.b	79,300,000
67	Less Property Insurance Account 924	(RCM Section 8; AU216-223)		p323.156b	1,458,000
68	Less Regulatory Commission Exp Account 928	(RCM Section 8; AU216-223)	(Note)	p323.160b	4,693,000
69	Less General Advertising Exp Account 930.1	(RCM Section 8; AU216-223)		p323.162b	2,026,000
70	Less EPRI Dues		(Note)	p352-353	0
71	**General & Common Expenses**			(Lines 65 + 66) - Sum (67 to 70)	71,123,000
72	Wage & Salary Allocation Factor			(Line 5)	6.349%
73	**General & Common Expenses Allocated to Transmission**			(Line 71 * 72)	**4,515,621**
	Directly Assigned A&G				
74	Regulatory Commission Exp Account 928	(RCM Section 8, AU221 x Labor %-Line 5)	(Note)	p323.160b	297,960
75	General Advertising Exp Account 930.1		(Note)	p323.162b	0
76	Subtotal - Transmission Related			(Line 74 + 75)	**297,960**
77	Property Insurance Account 924			p323.156b	1,458,000
78	General Advertising Exp Account 930.1		(Note)	p323.162b	0
79	Total			(Line 77 + 78)	1,458,000
80	Net Plant Allocation Factor			(Line 18)	18.026%
81	**A&G Directly Assigned to Transmission**			(Line 79 * 80)	**262,823**
82	**Total Transmission O&M**			**(Line 64 + 73 + 76 + 81)**	**9,949,403**

Depreciation & Amortization Expense

	Depreciation Expense				
83	Transmission Depreciation Expense	(RCM Section D-2, M649)		p336.7b&c	**7,023,000**
84	General Depreciation	(RCM Section D-2; M712+M717)		p336.9b&c	12,926,000
85	Intangible Amortization	(RCM Section D-2; M716)	(Note)	p336.1d&e	2,312,000
86	Total			(Line 84 + 85)	15,238,000
87	Wage & Salary Allocation Factor			(Line 5)	6.349%
88	**General Depreciation Allocated to Transmission**			(Line 86 * 87)	**967,465**
89	Common Depreciation - Electric Only		(Note)	p336.10 b	0
90	Common Amortization - Electric Only		(Note)	p356 or p336.10d	0
91	Total			(Line 89 + 90)	0
92	Wage & Salary Allocation Factor			(Line 5)	6.349%
93	**Common Depreciation - Electric Only Allocated to Transmission**			(Line 91 * 92)	**0**
94	**Total Transmission Depreciation & Amortization**			**(Line 83 + 88 + 93)**	**7,990,465**

Taxes Other than Income

95	**Taxes Other than Income**			Exhibit 8	**904,414**
96	**Total Taxes Other than Income**			**(Line 95)**	**904,414**

Return / Capitalization Calculations

	Long Term Interest				
97	Long Term Interest - Accounts 427 and 428	(RCM Section 7; AK159)		p117.58c through 63c	47,572,772
98	Less LTD Interest on Securitization Bonds		(Note)	Attachment 8	0
99	**Long Term Interest**			(Line 97)	47,572,772
100	**Preferred Dividends**	(RCM Section 7; AK218)	enter positive	p118 29c	7,138,000
	Common Stock				
101	Proprietary Capital	(RCM Section 7; E140)		p112.15d	792,709,122
102	Less Preferred Stock		enter negative	(Line 110)	-133,434,000
103	Less Account 216 1	To reflect accumulated losses at subsidiaries	enter positive	p112.12d	15,903,000
104	**Common Stock**			(Sum Lines 101 to 103)	675,178,122
	Capitalization				
105	Long Term Debt			p112.17d through 20d	637,925,000
106	Less Loss on Reacquired Debt - Account 189		enter positive	p111.67.d	-48,787,618
107	Plus Gain on Reacquired Debt		enter positive	p113.56d	500,000
108	Less LTD on Securitization Bonds	(Note)	enter negative	Attachment 8	0
109	Total Long Term Debt			(Line 105 - 107)	589,637,382
110	Preferred Stock			p112.3d	133,434,000
111	Common Stock			(Line 104)	675,178,122
112	**Total Capitalization**			(Sum Lines 109 to 111)	1,398,249,504
113	Debt %	Total Long Term Debt		(Line 109 / 112)	42%
114	Preferred %	Preferred Stock		(Line 110 / 112)	10%
115	Common %	Common Stock		(Line 111 / 112)	48%
116	Debt Cost	Total Long Term Debt		(Line 99 / 109)	0.0807
117	Preferred Cost	Preferred Stock		(Line 100 / 110)	0.0535
118	Common Cost	Common Stock	(Note)	Fixed	0.1225
119	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 113 * 116)	0.0340
120	Weighted Cost of Preferred	Preferred Stock		(Line 114 * 117)	0.0051
121	Weighted Cost of Common	Common Stock		(Line 115 * 118)	0.0592
122	**Total Return (R)**			(Sum Lines 119 to 121)	**0.0983**
123	**Investment Return = Rate Base * Rate of Return**			**(Line 59 * 122)**	**24,032,905**

Composite Income Taxes

	Income Tax Rates				
124	FIT=Federal Income Tax Rate				35.00%
125	SIT=State Income Tax Rate or Composite		(Note)		9.99%
126	p	(percent of federal income tax deductible for state purposes)		Per State Tax Code	0.00%
127	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			41.49%
128	T/ (1-T)				70.92%
	ITC Adjustment		(Note)		
129	Amortized Investment Tax Credit	(RCM Section C-3; AO95)	enter negative	p266.8f	0
130	T/(1-T)			(Line 128)	70.92%
131	Net Plant Allocation Factor			(Line 18)	18.0262%
132	**ITC Adjustment Allocated to Transmission**			(Line 129 * 130 * 131)	0
133	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		[Line 128 * 123 * (1-(119 / 122))]	11,143,898
134	**Total Income Taxes**			**(Line 132 + 133)**	**11,143,898**

REVENUE REQUIREMENT

	Summary			
135	Net Property, Plant & Equipment		(Line 39)	258,265,060
136	Adjustment to Rate Base		(Line 58)	-13,730,242
137	**Rate Base**		(Line 59)	**244,534,819**
138	O&M		(Line 82)	9,949,403
139	Depreciation & Amortization		(Line 94)	7,990,465
140	Taxes Other than Income		(Line 96)	904,414
141	Investment Return		(Line 123)	24,032,905
142	Income Taxes		(Line 134)	11,143,898
143	**Gross Revenue Requirement**		**(Sum Lines 138 to 142)**	**54,021,085**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
144	Transmission Plant In Service		(Line 19)	338,020,000
145	Excluded Transmission Facilities	(Note)	Attachment 5	0
146	Included Transmission Facilities		(Line 144 - 145)	338,020,000
147	Inclusion Ratio		(Line 146 / 144)	100.00%
148	Gross Revenue Requirement		(Line 143)	54,021,085
149	**Adjusted Gross Revenue Requirement**		(Line 147 * 148)	**54,021,085**
	Revenue Credits & Interest on Network Credits			
150	**Revenue Credits**		Attachment 3	3,293,788
151	**Interest on Network Credits**	(Note)	PJM Data	
152	**Net Revenue Requirement**		**(Line 149 - 150 + 151)**	**50,727,297**
	Network Zonal Service Rate			
153	1 CP Peak	(Note)	PJM Data - 2006	**2,884.5**
154	Rate ($/MW-Year)		(Line 152 / 153)	**17,586**
155	**Network Service Rate ($/MW/Year)**		**(Line 154)**	**$ 17,586.17**

DLC Statement No. 10

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

DIRECT TESTIMONY OF
JOHN J. SPANOS

ON BEHALF OF
DUQUESNE LIGHT COMPANY

CONCERNING DEPRECIATION

DOCKET NO. R-00061346

MARCH 2006

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

RE: DUQUESNE LIGHT COMPANY

DOCKET R-00061346

DIRECT TESTIMONY OF JOHN J. SPANOS

Line
No.

Q. Please state your name and address.

A. John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. With what firm are you associated?

A. I am associated with the firm of Gannett Fleming, Inc.

Q How long have you been associated with Gannett Fleming, Inc.?

A. I have been associated with the firm since college graduation in June 1986.

Q. What is your position in the firm?

A. I am a Vice President.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College of Pennsylvania.

Q. Are you a member of any professional societies?

A. Yes. I am a member of the Society of Depreciation Professionals and the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Have you taken the certification examination for depreciation professionals?

A. Yes, I passed the certification examination of the Society of Depreciation Professionals in September 1997 and was recertified in August 2003.

Q. Will you outline your experience in the field of depreciation?

A. In June 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June 1986 to December 1995, I took part in the preparation of numerous depreciation and original cost studies for utility companies in various industries. Depreciation studies of telephone companies were performed for United Telephone of Pennsylvania, United Telephone of New Jersey and Anchorage Telephone Utility. My work in the railroad industry included depreciation studies for Union Pacific Railroad, Burlington Northern Railroad and Wisconsin Central Transportation Corporation.

Assignments in the electric industry included depreciation studies for Chugach Electric Association, The Cincinnati Gas and Electric Company, The Union Light, Heat & Power Company, Northwest Territories Power Corporation and the City of Calgary - Electric System. Pipeline industry assignments included studies for TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

My work for the gas industry included depreciation studies for Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas and Oil Co., The Cincinnati Gas and Electric Company, The Union Light, Heat & Power Company, Lawrenceburg Gas Company and Penn Fuel Gas, Inc. Assignments in the water industry included depreciation studies for Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

My participation in each of the above studies included assembly and analysis of historical and simulated data, field reviews, the development of preliminary estimates of service life and net salvage, calculations of annual depreciation, and the preparation of reports for submission to state or provincial public utility commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E., the President of Gannett Fleming Valuation and Rate Consultants, Inc.

In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July 1999, I was promoted to the position of Manager, Depreciation and Valuation Studies. In December 2000, I was promoted to my current position as Vice President of Gannett Fleming Valuation and Rate Consultants, Inc. I am responsible for all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory body.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Hampton Water Works Company, Omaha Public Power District, Enbridge Pipe Line Company, Inc., Columbia Gas of Virginia, Inc., Virginia Natural Gas Company, National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions, The City of Bethlehem - Bureau of Water, The City of Coatesville Authority, The City of

Lancaster - Bureau of Water, Peoples Energy Corporation, The York Water Company, Public Service Company of Colorado, Enbridge Pipelines, Enbridge Gas Distribution, Inc., Reliant Energy-HLP, Massachusetts-American Water Company, St. Louis County Water Company, Missouri-American Water Company, Chugach Electric Association, Alliant Energy, Oklahoma Gas & Electric Company, Nevada Power Company, Dominion Virginia Power, NUI-Virginia Gas Companies, Pacific Gas & Electric Company, PSI Energy, NUI - Elizabethtown Gas Company, Cinergy Corporation – CG&E, Cinergy Corporation – ULH&P, Columbia Gas of Kentucky, SCANA, Inc., Idaho Power Company, El Paso Electric Company, Central Hudson Gas & Electric, Centennial Pipeline Company, CenterPoint Energy-Arkansas, CenterPoint Energy – Oklahoma, CenterPoint Energy – Entex, CenterPoint Energy - Louisiana, NSTAR – Boston Edison Company, Westar Energy, Inc., South Jersey Gas Company, Duquesne Light Company, MidAmerican Energy Company, Laclede Gas, Duke Energy Company, Bonneville Power Administration, NSTAR Electric and Gas Company, EPCOR Distribution, Inc. and B. C. Gas Utility, Ltd. My additional duties include determining final life and salvage estimates, conducting field reviews and presenting recommended depreciation rates to management for their consideration.

Q. What is the extent of your formal instruction with respect to utility plant depreciation?

A. I have completed the "Techniques of Life Analysis", "Techniques of Salvage and Depreciation Analysis", "Forecasting Life and Salvage", "Modeling and Life Analysis Using Simulation" and "Managing a Depreciation Study" programs conducted by Depreciation Programs, Inc. Also, I have completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

Q. Have you previously testified on public utility ratemaking matters?

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission, the Commonwealth of Kentucky Public Service Commission, the Public Utilities Commission of Ohio, the Nevada Public Utility Commission, the Public Utilities Board of New Jersey, the Missouri Public Service Commission and the Massachusetts Department of Telecommunications and Energy, the Alberta Energy & Utility Board, the Idaho Public Utility Commission, the Louisiana Public Service Commission, the State Corporation Commission of Kansas, the Oklahoma Corporate Commission, The Public Service Commission of South Carolina, Railroad Commission of Texas – Gas Services Division, the New York Public Service Commission, Illinois Commerce Commission, and the Indiana Utility Regulatory Commission.

Q. What is the purpose of your testimony?

A. My testimony is in support of the depreciation study conducted under my direction and supervision for the utility plant of Duquesne Light Company.

Q. Have you prepared an exhibit presenting the results of your study?

A. Yes. Exhibit JJS1 presents the results of the depreciation calculations as of December 31, 2005, and the service life study conducted as of December 31, 2004, on which the calculations were based. In addition, I am responsible for the responses to the Filing Requirements – Depreciation V-A-2, V-B-1, V-B-2, V-C-1, V-D-1, V-D-2 and V-E-1 which present summaries of the study results as of the historic test year end, December 31, 2005, and the future test year end, December 31, 2006.

Q. Please describe Exhibit JJS1.

A. Exhibit JJS1 titled "Depreciation Study Related to Electric Plant at December 31, 2005," includes the results of the depreciation study as related to the estimated original cost at December 31, 2005. The report also includes explanatory text, statistics related to the estimation of service life, and the detailed depreciation calculations.

Q. What is the basis for the Company's historic and future test year depreciation expense claims in this proceeding?

A. The Company's depreciation expense claims are based on the application of the depreciation rates submitted in the most recent Annual Depreciation Report filing to the plant balances as of December 31, 2005, and December 31, 2006. In addition, a five-year amortization of the variance between the book and calculated accrued depreciation for General Plant determined as of December 31, 2004, is included in the depreciation claims.

Q. What are the bases for the depreciation rates in the most recent Annual Depreciation Report?

A. The bases for these depreciation rates are the estimated survivor curves resulting from the service life study that I conducted incorporating plant accounting date through 2004 and the electric plant in service as of December 31, 2004.

Q. Is it reasonable to apply the depreciation rates calculated as of December 31, 2004, to the plant balances as of the end of 2005 and 2006 for purposes of determining the depreciation expense claims in this proceeding?

A. Yes, it is. The depreciation rates that were used are based on a recent study of service life and the subsequent changes in plant balances are not sufficient to materially change the calculated rates.

Q. Is the Company's claim for annual depreciation in the current proceeding based on the same methods of depreciation as were used in its most recent electric rate proceeding in Docket No. R-00850021?

A. Yes, it is. For most plant accounts, the current claim for annual depreciation is based on the straight line remaining life method of depreciation. For Accounts 391, 393, 394, 395, 397 and 398, the claim is based on the straight line remaining life method of amortization. The annual amortization is based on amortization accounting which distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account.

Q. What group procedure is being used in this proceeding for depreciable accounts?

A. All depreciable accounts utilize the methods and procedures based on the straight line remaining life method, using remaining lives consistent with the average service life procedure for plant installed prior to 1983 and remaining lives consistent with the equal life group procedure for plant installed in 1983 and in later years.

Q. Please describe briefly the straight line remaining life method of depreciation that you used for depreciable property.

A. The straight line remaining life method of depreciation allocates the original cost less accumulated depreciation in equal amounts to each year of remaining service life.

Q. Please describe briefly the average service life procedure that you used in conjunction with the straight line remaining life method for plant installed prior to 1983.

A. In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated survivor curve.

Q. Please describe briefly the equal life group procedure that you used in conjunction with the straight line remaining life method for plant installed in 1983 and in later years.

A. In the equal life group procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the composite remaining life for the surviving original cost of that vintage. The composite remaining life for the vintage is derived by weighting the individual equal life group remaining lives.

In the equal life group procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve.

Q. Has a service life study of the Company's electric utility property been performed?

A. Yes. A service life study has been performed through 2004. The service life study is the basis for the service lives I used to calculate annual accruals.

Q. Briefly outline the procedure used in performing the service life study.

A. The service life study consisted of assembling and compiling historical data from the records related to the electric utility plant of the Company; statistically analyzing such data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning Company practices and plans as they relate to plant operations; and interpreting the above data to form judgments of service life characteristics.

Iowa type survivor curves were used to describe the estimated survivor characteristics of the mass property groups. Individual service lives were used for major individual units of plant, such as large service centers, substation structures, and office buildings within Accounts 352, 361 and 390.1. The life span concept was recognized by coordinating the lives of associated plant installed in subsequent years with the probable retirement date defined by the life estimated for the major unit.

Q. What statistical data were employed in the historical analyses performed for the purpose of estimating service life characteristics?

A. The data consisted of the entries made to record retirements and other transactions related to the electric plant through 2004. These entries were classified by depreciable group, type of transaction, the year in which the transaction took place, and the year in which the plant was installed. Types of transactions included in the data were plant additions, retirements, transfers, and balances. In the presentation of service life statistics, only the significant exposure points that were utilized in determining survivor curves were plotted. This process is utilized to show my judgment in service life determinations.

Q. What was the source of these data?

A. They were assembled from Company records related to its utility plant in service.

Q. Were the methods used in the service life study the same as those used in other depreciation studies for electric utility plant presented before this Commission?

A. Yes. The methods are the same ones that have been presented previously for Duquesne Light Company and for other electric companies before the Pennsylvania Public Utility Commission and that have been accepted by the Commission in its past orders concerning electric utilities.

Q. What approach did you use to estimate the lives of significant structures such as substation buildings, office buildings and service centers?

A. I used the life span technique to estimate the lives of significant structures. In this technique, the survivor characteristics of the structures are described by the use of interim survivor curves and estimated probable retirement dates. The interim survivor curve describes the rate of retirement related to the replacement of elements of the structure such as plumbing, heating, doors, windows, roofs, etc. that occur during the life of the facility. The probable retirement date provides the rate of final retirement for each year of installation for the structure by truncating the interim survivor curve for each installation year at its attained age at the date of probable retirement. The use of interim survivor curves truncated at the date of probable retirement provides a consistent method for estimating the lives of the several years of installation inasmuch as concurrent retirement of all years of installation will occur when the structure is retired.

Q. Has your firm used this approach in other proceedings before this Commission?

A. Yes, we have used the life span technique on many occasions before the Pennsylvania Public Utility Commission.

Q. What are the bases for the probable retirement years that you have estimated for each structure?

A. The bases for the estimates of probable retirement years are life spans for each structure that are based on judgment and incorporate consideration of the age, use, size, nature of construction, management outlook and typical life spans experienced and used by other electric utilities for similar structures. Most of the life spans result in probable retirement years that are many years in the future. As a result, the retirement of these structures is not yet subject to specific management plans. Such plans would be premature. At the appropriate time, analysis of the economics of rehabilitation and continued use or retirement of the structure will be performed and the results incorporated in the estimation of the structure's life span.

Q. Are the factors considered in your estimates of service life presented in Exhibit JJS1?

A. Yes. A discussion of the factors considered in the estimation of service lives is presented by account on pages II-3 through II-27 of Exhibit JJS1.

Q. Please outline the contents of Exhibit JJS1.

A. Exhibit JJS1 is presented in three parts. Part I, Executive Summary, sets forth the scope and basis of study. Part II, Methods Used in Study, includes the estimation of survivor curves, and the calculation of annual depreciation and amortization.

Part III, Results of Study, presents a description of the results, summaries of the depreciation calculations, graphs and tables which relate to the service life study, and the detailed depreciation calculations.

The table on pages III-4 through III-6, presents the estimated survivor curve, the original cost at December 31, 2005, and the book reserve and calculated annual depreciation for each account or subaccount of Utility Plant.

The section beginning on page III-8 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page III-103 presents the depreciation calculations related to original cost. The tabulations on pages III-104 through III-190 present the calculation of annual depreciation by vintage by account for each depreciable group of utility plant.

Q. Please use an example to illustrate the manner in which the study is presented in Exhibit JJS1.

A. I will use Account 365.01, Overhead Conductors and Devices, as my example, inasmuch as it is one of the larger depreciable groups and represents 13 percent of the original cost of depreciable utility plant as of December 31, 2005.

The retirement rate method was used to analyze the survivor characteristics of this group. The life table for the 1964-2004 experience band is presented on pages III-58 through III-60 of Exhibit JJS1. The life table, or original survivor curve, is plotted along with the estimated smooth survivor curve, the 50-R1, on page III-57.

The calculation at December 31, 2005, is presented on pages III-140 through III-142 of Exhibit JJS1 and is based in part on the bringforward of the book reserve. The tabulation in Exhibit JJS1 sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. The totals are brought forward to the table on page III-4 in Exhibit JJS1.

Q. Do you believe Exhibit JJS1 reflects the appropriate survivor curves for Duquesne Light Company to be adopted in this proceeding?

A. Yes, I do. The methods and procedures utilized in the development of survivor curves are consistent with past practices for Duquesne Light Company and Pennsylvania ratemaking regulations. The service life study was completed as of December 31, 2004, and submitted as a part of the Company's most recent Annual Depreciation Report.

Q. Do you believe that the annual depreciation rates and the related depreciation expense claims should be adopted in this proceeding?

A. Yes, I do. The depreciation rates and expense claims are based on appropriate survivor curves and the depreciation procedures are the same as those approved in past filings before this Commission. The only change in approach is the reserve variance adjustment in this proceeding for certain general plant accounts which have implemented amortization accounting. For these accounts, incorporating the remaining life adjustment in the rate would distort the depreciation expense for subsequent additions. The use of a reserve adjustment amount over the next five years allows for the appropriate accrual rate to be booked for these assets going forward.

Q. Does this complete your testimony at this time?

A. Yes, it does.