R-00973953
PECO Statement No. 20-R
Phila. 10/14,15,16/97
B. Holbert

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY
FOR APPROVAL OF ITS RESTRUCTURING PLAN
UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE

REBUTTAL TESTIMONY

OF

J. BARRY MITCHELL

**Regarding PECO Energy's Financial Integrity
Under the Intervenors' Disallowance Proposals**

July 18, 1997

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TABLE OF CONTENTS

REBUTTAL TESTIMONY
OF J. BARRY MITCHELL

I. QUALIFICATIONS

Q. Please state your name and business address.

A. J. Barry Mitchell, 2301 Market Street, Philadelphia, Pennsylvania, 19101

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

A. I am the Vice President of Finance and Treasurer of PECO Energy Company ("PECO Energy" or the "Company").

Q. What are your responsibilities as Vice President of Finance and Treasurer?

A. I am the corporate officer responsible for organizing and implementing the Company's long-term financing, including the issuance of all bonds and other debt instruments. I have responsibility for the Company's investor relations program, including production of the annual report and maintenance of relationships with the investment community, and I oversee the Company's securities reporting obligations. I am also responsible for managing various trust investments, such as the Company's pension and nuclear decommissioning trusts. Finally, I am responsible for performing special studies and analyses for management and other departments and for directing the day-to-day management of the Company's treasury and insurance operations.

Q. What is your educational background?

A. I graduated in 1970 from Lehigh University with a Bachelor of Science Degree in Business Administration. In 1971, I was awarded a Masters Degree in Business Administration from Lehigh University. In 1987, I attended The Executive Program at the Colgate Darden Graduate School of Business Administration, University of Virginia, which covered a broad curriculum including managerial finance, executive decision-making and other topics.

Q. Please summarize your experience with the Company.

A. I have been employed at PECO Energy for more than 25 years. With the exception of a three-year assignment in Corporate Planning in the late 1970s, I have been a part of the Company's Finance Department during the entire period. I was elected to my current position as Vice President of Finance and Treasurer in September 1994.

Q. Have you testified on other occasions before utility regulatory agencies?

A. Yes, I testified in the 1989 Limerick Generating Station Electric Rate Case (Docket R-891364) to describe the Company's need to reflect Limerick 2 and associated common plant in rates in order to earn an adequate rate of return. I testified on the Funding of SFAS 106 Costs (Docket R-00922479) to quantify the effect of adopting SFAS 106 and to provide a rationale for the Company's selection of vehicles in which to fund the cost of postretirement benefits other than pensions. I testified in the FERC Open Access Transmission Tariff (#ER96-641-000) to provide the basis for the Company's return on equity used in calculating its rates. Finally, I testified this year in PECO Energy's securitization proceeding before the Pennsylvania Public Utility Commission.

II. PURPOSE OF TESTIMONY AND SUMMARY OF CONCLUSIONS

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the stranded investment disallowance proposals of the OCA, OTS and PAIEUG by describing the catastrophic effect of those proposals on the Company's financial integrity and on the Company's ability to provide safe, reliable service to its customers and to be a healthy, viable competitor in the emerging electric marketplace.

Q. Please summarize your conclusions.

A. Each of the disallowance proposals of the OCA, OTS and PAIEUG would destroy the Company's financial integrity. Specifically:

- The OCA and PAIEUG proposals would cause a write-off in 1997 or 1998 of at least \$798 million or over \$2.00 per share.
- For all three proposals, the Company would experience a <u>negative</u> net cash flow of \$558-699 million in 1999 and a cumulative <u>negative</u> net cash flow of \$1.1-2.2 billion during the transition period.
- For all three proposals, earnings per share would be negative or slightly positive in 1999, reaching only \$1.15-1.69 in 2005 under the various disallowance proposals.
- For all three proposals, I would expect that the Company's mortgage bond rating would be downgraded below investment grade to "junk bond" status for the duration of the transition period. This downgrading would seriously reduce the Company's ability to access the debt market at economic prices.

The combination of negative net cash flow, significantly reduced earnings per share and a junk bond rating of the Company's mortgage bonds would be devastating to the

Company's financial integrity. As a result, these disallowance proposals would seriously impair the Company's ability to maintain and improve system performance and provide safe, reliable service to its customers and would eliminate PECO Energy as a healthy, viable competitor in the emerging electric marketplace.

III. DEFINING FINANCIAL INTEGRITY

Q. What is meant by the term "financial integrity"?

A. Generally, financial integrity refers to the financial "health" of a company. A company that has financial integrity is able to generate funds, both internally through its own operations and externally by access to the equity and debt markets, to cover all of the costs of its operations (including debt service), to fund needed investments and to provide an adequate income return to shareholders. The ability to access capital markets is an especially important indicator of financial health of companies, such as electric utilities, that are capital intensive.

In addition, financial integrity means that a company has sufficient flexibility in its financial position to respond to unanticipated events. Put differently, a company that can remain viable only if all events are positive is not a company that has financial integrity.

Q. How do you determine a company's financial integrity?

A. Primarily by looking at its net cash flow and its ability to access the equity and debt markets for external capital. There are commonly used financial measures to determine a company's status in each of these areas, and these measures are used as a barometer of a company's financial health. I discuss those measures in detail in the next section of this testimony. A company's ability to internally generate funds is measured by its cash flow. A company's access to the short-term debt market is determined by its creditworthiness, which is reflected in the rating of its commercial paper. A company's ability to access the long-term debt market is also determined by its creditworthiness, which is reflected by its bond rating, which is in turn derived from criteria such as funds from operations as a percentage of total debt, funds from operations interest coverage, the ratio of total debt to total capital, pre-tax interest coverage, and net cash flow as a percentage of capital expenditures. A company's ability to access the common stock equity market is determined by its ability to provide an adequate total return to its shareholders, commonly demonstrated by earnings and dividends per share and cash flow per share. Taken together, these measures are generally accepted in the financial community as key measures for determining a company's financial integrity.

Q. Is the concept of being able to issue "investment grade" bonds related to the concept of financial integrity?

A. Yes. A company with bonds rated investment grade is generally considered to be in good financial health. A company with bonds rated below investment grade -- junk bond status -- is generally considered to be in poor financial health. Junk bonds are considered speculative; their credit protections are considered uncertain. Many institutions, such as pension funds and trust funds, are prohibited from purchasing junk bonds. The senior debt securities of approximately 90% of investor-owned electric utilities in the United States have an investment grade rating.

Q. Are "maintaining financial integrity" and "avoiding bankruptcy" the same thing?

A. Absolutely not. That is like saying that a person in intensive care is healthy just because he is alive. As I mentioned, "financial integrity" means that a company is financially flexible enough to respond to unanticipated events and to access the capital markets economically. Bankruptcy refers to a very different and much more dire situation in which a company is no longer able to meet its financial obligations. A company's financial integrity can be harmed long before the specter of bankruptcy arises.

IV. EFFECT OF THE INTERVENORS' PROPOSALS ON THE COMPANY'S FINANCIAL INTEGRITY

A. CRITERIA FOR DETERMINING FINANCIAL INTEGRITY

Q. Please describe the measure of a company's ability to generate funds internally.

A. Internally generated funds are the cash flow which a company generates through its own operations -- without borrowing. A company should have sufficient cash flow from internally generated funds to cover all of the costs of its operations (including debt service), to fund needed investments and to provide an adequate income return to shareholders.

Q. What determines a company's ability to access the short-term debt market?

A. A company's access to the short-term debt market is objectively measured by its commercial paper rating. The commercial paper rating is a function of, and is correlated to, its long-term bond rating. Exhibit JBM-1 is a Standard & Poor's publication that describes commercial paper rating criteria.

Q. What determines a company's ability to access the long-term debt market?

A. A company's access to the long-term debt market is determined by its creditworthiness, which is objectively measured by its mortgage bond rating. Typically, a company is rated by two or more rating agencies. The Standard & Poor's ("S&P") rating, however, can be used as an overall proxy for the ratings of other rating agencies because S&P publishes more explicit descriptions of the manner in which it arrives at bond ratings and because ratings from the different agencies are very similar. Standard & Poor's evaluates both subjective and objective criteria in assigning a bond rating.

Q. Please describe the subjective criteria used by Standard & Poor's.

A. S&P uses its subjective criteria to assign a "business profile" to a company. The profile is ultimately given a numeric rating of 1 (strong) to 10 (weak). This business profile is determined by evaluating factors such as the regulatory environment of the company, market-related factors that effect the potential market for the company, the company's operations performance, including cost and reliability of service, the company's competitiveness, and its management strength.

Q. What is PECO Energy's current business profile from Standard & Poor's?

A. PECO Energy's business profile is a "7" and thus it is considered as having a below average business profile, based on the subjective S&P criteria.

Q. Please describe the objective measures used by Standard & Poor's.

A. S&P has five objective measures -- funds from operations as a percentage of total debt, funds from operations interest coverage, the ratio of total debt to total capital, pre-tax interest coverage, and net cash flow as a percentage of capital expenditures. These five measures are discussed in a Standard & Poor's publication attached as Exhibit JBM-2.

In 1997, S&P further refined its use of these objective measures to reflect global differences in levels of government support for, and in ownership structures of, electric utilities in different countries and to reflect the potential disaggregation of vertically integrated utilities. As part of that 1997 refinement, S&P now formally places the highest emphasis on the first three ratios listed above -- funds from operations as a percentage of total debt, funds from operations interest coverage, and the ratio of total debt to total capital. Of those, the first two are considered the most relevant and reliable in determining a company's bond rating. A 1997 Standard & Poor's publication describing these refinements is attached as Exhibit JBM-3.

These objective and subjective criteria are combined to reach an overall rating for a company's bonds. The weaker a company's business profile, as determined by the subjective criteria, the stronger its objective measures must be in order to obtain any given rating.

Q. What range of bond ratings can be assigned under this system?

A. Exhibit JBM-4 contains a description of the range of bond ratings. The benchmark targets for each of the five measures that are required to attain each bond rating category are described in Exhibits JBM-2 and JBM-8. A bond rating of "BBB-" or better is considered to be investment grade; all bonds with lower ratings are considered to be junk bonds.

Q. Are there any other financial measures that should be evaluated in determining the Company's financial integrity?

A. Yes. Our mortgage indenture contains certain financial tests for the issuance of first mortgage bonds against property additions. The principal test is a two times coverage ratio of pre-tax earnings to interest on mortgage bonds. If this coverage ratio is not met, the Company is prohibited by the terms of the mortgage from issuing additional bonds against property additions. Although the indenture permits the Company to issue bonds against prior retirements even if it does not meet the two times coverage ratio, failure to meet the ratio is nonetheless an indication that the Company's financial integrity has been impaired.

Q. What determines a company's ability to access the equity market?

A. A company's access to the equity market is determined by the total return a company provides to shareholders through both dividends and the prospects of capital appreciation. Earnings and dividends per share and cash flow per share are commonly used indicators of this aspect of financial integrity. When these measures are unfavorable, a company's ability to raise new external capital by issuing common stock is harmed.

B. THE COMPANY'S CURRENT FINANCIAL INTEGRITY

Q. Please describe PECO Energy's current state of financial integrity.

A. PECO Energy's cumulative net cash flow for the period 1992 through 1996 is approximately $250 million. The Company's commercial paper rating of A2/P2 gives it adequate access to the liquidity provided by the short-term debt market. The Company's current S&P bond rating of BBB+ is investment grade. (The Company's ratings from all rating agencies are provided in Exhibit JBM-5.) The Company also meets the two times coverage ratio test of its mortgage indenture for issuing additional first mortgage bonds against property additions (4.4 times as of 12/31/96). It also pays a regular dividend on both common and preferred stock. PECO Energy would still have reasonable access to the equity markets, although its common stock price has been depressed in recent months.

Q. What does the Company's BBB+ bond rating indicate?

A. According to Standard & Poor's, an obligation that is rated BBB "exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation" than other investment grade ratings. The "BBB-" rating is the lowest rating that is considered investment quality; a drop to the BB level puts a borrower into the junk or speculative category.

Q. How does PECO Energy's bond rating compare to other electric utilities at this time?

A. At this time, approximately 60% of electric utilities have <u>better</u> credit ratings than PECO Energy. (A detailed distribution of electric utility credit ratings is attached as Exhibit JBM-6.)

Q. How does PECO Energy's current bond rating compare to its historical bond ratings?

A. The Company has maintained investment grade bond ratings for at least the last 30 years. (A history of PECO Energy's mortgage bond ratings is included in Exhibit JBM-5.)

Q. How would PECO Energy's own proposal for stranded investment recovery affect these measures of its financial integrity?

A. Under PECO Energy's proposal, although virtually all of the key indicators would be depressed, they would be at levels that should allow PECO Energy to maintain its financial integrity. Specifically, with regard to the key S&P measures described above, the PECO Energy proposal would have some negative effects on the objective criteria, but, I believe, would allow PECO Energy to maintain an investment grade rating throughout the transition period.

On the equity side, current analysts' estimates for PECO Energy's earnings per share for 1999 average $2.48 per share. Under PECO Energy's proposal, earnings per share would be well below that level, or $1.32 per share in 1999. PECO Energy's earnings per share would remain low throughout the transition period, not increasing above $1.65 per share through 2005. On a pro forma basis, PECO Energy would also have low levels of net cash flow under its proposal, with a cumulative net cash flow of $371 million through the transition period.

Q. If PECO Energy is requesting full recovery of stranded investment, why is there an impact on its financial indicators?

A. The structure of the Competition Act has an impact on the Company's financial indicators because it compresses cost recovery into a seven-year period for costs that were to have been recovered over decades. That "compression" results in a significant reduction in earnings per share. In effect, the compressed seven-year recovery period forces PECO Energy and its shareholders to "share the pain" of the transition to competition even with full stranded investment recovery. As I discuss in the next section of my testimony, when the additional stranded investment disallowances proposed by the OCA, OTS and PAIEUG are added to that situation, the effect on PECO Energy's financial integrity is devastating.

C. THE INTERVENORS' DISALLOWANCE PROPOSALS WOULD HAVE A MATERIAL ADVERSE EFFECT ON THE COMPANY'S FINANCIAL INTEGRITY

Q. Have you calculated the effect of the intervenors' disallowance proposals on PECO Energy's financial integrity?

A. Yes. Each of the proposed stranded investment disallowances would have a devastating effect on the Company's financial integrity. PECO Energy has requested approval to recover approximately $6.8 billion of its stranded investment. As discussed in the rebuttal testimony of Mr. Hill, PAIEUG recommends a disallowance of 64% of the revenue requirement that PECO Energy would need to fully recover that amount. The OCA recommends a disallowance of 58% of the revenue requirement; the OTS recommends a disallowance of 47% of the revenue requirement. These disallowance proposals adversely effect all of the key measures of financial integrity.

First, the OCA and PAIEUG proposals would require a major write-off in 1997 or 1998 -- at least $798 million -- because those proposals would have the Commission deny PECO Energy recovery of regulatory assets currently carried on its books and previously authorized for recovery by the PUC. If the Commission were to issue an order accepting these proposals, PECO Energy would be required by accounting rules to write off those regulatory assets.

Second, these proposals would have a material adverse effect on PECO Energy's net cash flow. I would note that in 1999 -- the first year that the stranded investment disallowances would be reflected through a reduced competitive transition charge ("CTC") -- the Company would experience a negative net cash flow of $558-699 million dollars and a cumulative negative net cash flow of $1.1-2.2 billion during the transition period. Under these circumstances, the Company would be unable to generate sufficient internal funds -- indeed, it would need to borrow substantial amounts of money simply to continue its normal operations.

As to the debt market, these proposals would result in significant downgrading of the Company's mortgage bond rating to junk bond status during the transition period. With a junk bond rating, the Company would not have the ability to access the debt market at a reasonable cost. Table JBM-1 provides the pro forma results for the key S&P measures and a projected mortgage bond rating associated with those results. These are pro forma results showing our assessment of where the values of the S&P measures derived from the various proposals would place us with respect to the rating criteria.

During that same period, however, the Company's ability to access the equity capital market would be severely impaired because each of the intervenor's proposals would destroy not only PECO Energy's net cash flow (as described above), but also its earnings per share. During the transition period, the Company's earnings per share would be reduced dramatically. Exhibit JBM-7 shows the impact of each of the intervenors' proposals on these key indicators during the transition period.

TABLE JBM-1

Table 1A -- Effects of OTS Proposal on Key Financial Criteria

	1999	2000	2001	2002	2003	2004	2005
Funds from Operations/ Average Total Debt	14.5%	15.9%	18.8%	20.4%	22.3%	24.2%	26.6%
Funds from Operations Interest Coverage	2.80x	2.81x	3.14x	3.34x	3.54x	3.53x	3.76x
Total Debt/Total Capital	50.5%	52.3%	52.6%	52.6%	52.1%	51.0%	49.5%
Pre-Tax Interest Coverage	1.52x	1.79x	2.32x	2.55x	2.77x	2.81x	3.04x
Net Cash Flow/Capital Expenditures	50.4%	69.3%	82.0%	87.3%	93.0%	97.3%	103.0%
Projected Bond Rating	BB	BB	BB	BB	BB	BBB	BBB

Table 1B -- Effects of OCA Proposal on Key Financial Criteria

	1999	2000	2001	2002	2003	2004	2005
Funds from Operations/ Average Total Debt	13.2%	14.3%	16.7%	17.6%	18.7%	19.6%	20.8%
Funds from Operations Interest Coverage	2.66x	2.64x	2.91x	3.06x	3.18x	3.12x	3.24x
Total Debt/Total Capital	51.4%	54.5%	56.1%	57.5%	58.6%	59.3%	59.7%
Pre-Tax Interest Coverage	1.23x	1.51x	2.00x	2.18x	2.33x	2.33x	2.46x
Net Cash Flow/Capital Expenditures	33.6%	51.0%	65.6%	70.8%	76.2%	79.9%	84.9%
Projected Bond Rating	BB	BB	B	BB	BB	BB	BB

Table 1C -- Effects of PAIEUG Proposal on Key Financial Criteria

	1999	2000	2001	2002	2003	2004	2005
Funds from Operations/ Average Total Debt	12.5%	13.4%	15.7%	16.4%	17.2%	18.0%	18.8%
Funds from Operations Interest Coverage	2.58x	2.55x	2.80x	2.91x	3.00x	2.96x	3.06x
Total Debt/Total Capital	51.7%	54.9%	56.7%	58.4%	59.7%	60.6%	61.3%
Pre-Tax Interest Coverage	1.18x	1.46x	1.93x	2.07x	2.20x	2.21x	2.32x
Net Cash Flow/Capital Expenditures	30.1%	48.2%	63.9%	68.8%	74.1%	78.4%	83.2%
Projected Bond Rating	BB	BB	B	B	B	BB	BB

Q. What result would you expect from this change to the key bond measures?

A. For each of these three proposals, the drop in the values of the measures to junk bond levels lasts many years, so I would expect a downgrade to junk. Moreover, once a Company's bonds are downgraded to junk, it would be extremely difficult regain an investment grade rating. Thus, even for the OTS proposal, for which we project measures equivalent to a BBB rating in 2004 and 2005, I would not expect the Company's debt to be upgraded to investment grade quality during that period. In sum, I would expect, for all three of these proposals, that PECO Energy's mortgage bond rating would drop to junk status and remain there throughout the transition period.

Q. What effect would these proposals have on the Company's commercial paper rating and its access to the short-term debt market?

A. There is a direct correlation between a company's short-term commercial paper rating and its long-term mortgage bond rating. Our current commercial paper rating is A2/P2. If our long-term mortgage bond rating was downgraded from BBB+ to BBB-, we would most likely see a downgrading of our commercial paper to A3/P3. Institutional investors, which are the primary purchasers of commercial paper, are often precluded from buying debt at this low rating, thus reducing the breadth and liquidity of the market for PECO Energy.

The ability to obtain bank financing would also be impaired as most banks use a risk adjusted pricing model to determine credit availability and pricing spreads to customers. A downgrading of long-term bond and commercial paper ratings would be viewed by banks as an increased credit risk of PECO Energy. As a result, the banks would both limit their credit availability and demand additional compensation for this increased risk. Taken together, these effects would significantly limit the Company's ability to manage its operations with the assistance of commercial paper borrowing and other short-term debt.

Q. Does the impairment of access to one portion of the capital market affect the Company's access to other portions of the capital market?

A. Yes. There is a relationship between the ability to economically access the debt and equity markets. To the extent that the ability to access one market is impaired, the ability to access the other is also impaired. For example, the downgrade to junk bond status would adversely affect the Company's ability to access the equity market. Similarly, the inability to access the equity market is considered a negative factor on credit ratings.

Q. What would be the effect of these proposals on the coverage test of PECO Energy's mortgage indenture?

A. Under the OCA and PAEIUG proposals, PECO Energy would not meet the coverage test for issuance of additional first mortgage bonds against property additions in 1999.

Q. Please summarize the effect of the intervenors' proposals.

A. Overall, these proposals would destroy PECO Energy's ability to generate needed funds internally and at the same time would severely impair its access to both the equity and debt markets as external sources of funds.

Q. Could the Company avoid these problems by cutting its dividend?

A. No. Cutting the dividend would increase the damage to the Company's financial integrity and make it even more difficult to access funds. The ability to provide stable or growing dividend income is one of the key factors that allows access to the equity market, so cutting the dividend would directly reduce access to that market. That would then leave the Company even more dependent on the debt market to fulfill its capital needs. Nevertheless, each of the disallowance proposals would significantly jeopardize the Company's ability to maintain the common stock dividend at its current level.

Cutting the dividend would also cause hardship for those Pennsylvanians who hold PECO Energy common stock. This includes about 65,000 Pennsylvania shareholders who are registered with PECO Energy in their own names and an unknown number who hold PECO Energy stock through brokers. According to research by the Edison Electric Institute, the typical utility stockowner is 65 years old, female, and has held the stock for an average of more than nine years. More than 1.3 million shares of PECO Energy common stock are also owned by Pennsylvania pension funds, including the Pennsylvania Public School Employees, the Philadelphia Municipal Pension, the Allentown Police Pension, the William Penn Foundation, the Pennsylvania State Employees Pension Fund, the Pennsylvania School Employees Pension Fund, and the Commonwealth of Pennsylvania Pension Fund. In addition, an unknown but likely substantial number of PECO Energy common shares are owned by individual Pennsylvanians through mutual funds, corporate pension funds, and individual pension funds such as 401(k) savings plans and Individual Retirement Accounts. All of those individuals and pension funds would suffer from a dividend cut.

Q. Could the Company avoid these problems by cutting its costs?

A. No. The magnitude of these disallowances is simply beyond any ability of the Company to address through cost-cutting measures. This is especially true since the Company has engaged in substantial cost-cutting measures in recent years. For example, we have decreased our employee base from 11,000 to 7,200 employees and we have refinanced billions of dollars of outstanding securities at lower rates. (See direct testimony of T. P. Hill, PECO Direct Statement No. 1, pages 21-22.) These cost-cutting measures are already taken into consideration in calculating the dire consequences described above. In other words, we are giving full "credit" for those cost-cutting measures in calculating these effects. Just as importantly, the extensive nature of our past cost-cutting measures means that, while the Company still has the ability to improve its productivity, it cannot improve it enough to overcome the devastation that would be caused by these proposals.

Q. Could the Company avoid these problems by securitization of its stranded costs?

A. No. First, I should note that all of the results I have described already assume that PECO Energy will securitize $1.1 billion of stranded costs, consistent with the Qualified Rate Order that the Commission issued for PECO Energy in May. Additional securitization would have a mixed effect on the Company's financial results. Earnings per share would improve, but cash flow measures -- the same measures that are the key indicators for bond ratings and which for PECO Energy would already be in a depressed state under these proposals -- would be further harmed by additional securitization. While the Company may request approval to securitize additional amounts of stranded investment, doing so would not improve its financial condition enough to overcome the devastating effects of these disallowance proposals.

Q. What are the potential effects on customers of these adverse changes to the Company's financial integrity?

A. Even in a fully competitive marketplace, PECO Energy will continue to serve as the provider of last resort for generation and must continue to provide transmission and distribution services. The Company's inability to maintain financial integrity could seriously jeopardize the Company's ability to continue to provide to customers safe and reliable distribution services and could adversely affect competition by removing PECO Energy as a local Pennsylvania competitor within the new competitive market. In other words, it would effectively <u>reduce</u> competition in the name of competition. These results would be counter to the legislature's express statutory policy of <u>encouraging</u> competition while "maintaining the safety and reliability of the electric system for all parties," which, in the words of the Pennsylvania Assembly, "is of the utmost importance to the health, safety and welfare of the citizens of the Commonwealth."

Q. Explain the relationship of PECO Energy's financial integrity and its ability to participate in the emerging electric marketplace.

A. Put simply, in order to be a participant in the emerging electric marketplace, a company will need the financial strength to make investments – whether those investments are targeted to creating new products, expanding the number of customers served, obtaining new facilities, or other purposes. These disallowance proposals would seriously curtail PECO Energy's ability to make those investments and thus would effectively eliminate PECO Energy as a competitor in the new competitive industry and as a viable, healthy business. In other words, the effect of these disallowance proposals would be to make it impossible for Pennsylvania's largest electric utility to participate in the Commonwealth's new competitive market.

If Pennsylvania is going to have a fair and workable transition to competition, PECO Energy and other Pennsylvania utilities must be viable, healthy businesses as they prepare for and participate in that new marketplace.

Q. Explain the relationship of PECO Energy's financial integrity and its ability to provide safe and reliable service.

A. PECO Energy's ability to provide safe and reliable service depends on its ability to maintain cash flows necessary to both maintain its distribution and transmission networks as well as provide future improvements and upgrades necessitated by regulations and new technology. The Company's projected negative net cash flow and inability to access external sources of capital on reasonable terms will prevent the Company from accessing additional sources of debt and equity necessary to continue to respond to the future and to provide this safe and reliable service.

Q. Does this conclude your testimony?

A. Yes.

Exhibit JBM-1

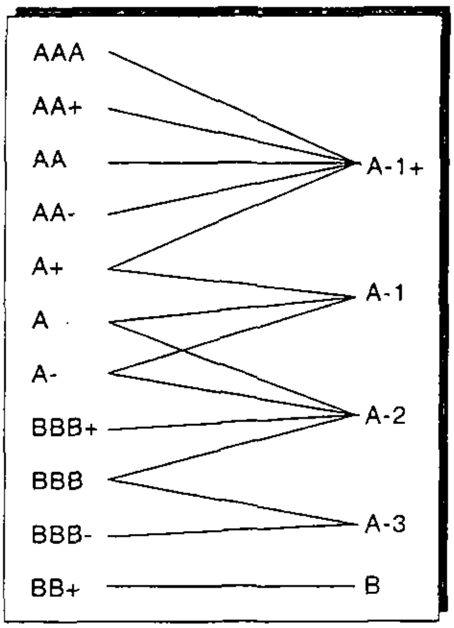
Commercial Paper

Commercial paper consists of unsecured promissory notes issued to raise short-term funds. Typically, only companies of unquestionable credit standing can sell their paper in the money market, although there had been some growth in issuance of lesser quality, unrated paper prior to the junk bond market collapse late in 1989. (Issuance of commercial paper backed by letters of credit (LOC) from first-tier banks has become quite popular. Credit quality of such paper rests entirely on the transaction's legal structure and the bank's creditworthiness. As long as the LOC is structured correctly, credit quality of the direct obligor can be ignored. Legal issues regarding LOC backing are not covered here.

Rating criteria

Evaluation of an issuer's commercial paper (CP) reflects Standard & Poor's opinion of the issuer's fundamental credit quality. The analytical approach is virtually identical to the one followed in assigning a long-term rating, and there is a strong link between the short-term and long-term rating systems *(see chart)*.

CORRELATION OF CP RATINGS WITH BOND RATINGS



In effect, the minimum credit quality associated with the 'A-1+' CP rating is the equivalent of an 'A+' long-term rating. Similarly, for CP to be rated 'A-1,' the long-term rating would need to be at least 'A-'. (In fact, the 'A-/A-1' combination is rare. Typically, 'A-1' CP ratings are associated with 'A+' and 'A' long-term ratings.) Conversely, knowing the long-term rating will not determine a CP rating, considering the overlap in rating categories. However, the range of possibilities is always narrow. To the extent that one of two CP ratings might be assigned at a given level of long-term credit quality (e.g., at the 'A' level), several criteria apply to make that determination.

Overall strength of the credit within the rating category is the first consideration. For example, a marginal 'A' credit likely would have its CP rated 'A-2'; a solid 'A' would almost automatically receive an 'A-1'.

Next come liquidity considerations, which receive greater emphasis in CP ratings than in long-term ratings. The purpose and pattern of commercial paper usage are rating elements. For example, if commercial paper is used only to finance seasonal working-capital requirements, that could contribute to a higher rating. The rating benefits because the assets liquidate in a predictable way and enable repayment of the CP.

Finally, the CP rating perspective sometimes focuses more intensely on the nearer term. The time horizon for a CP rating extends well beyond the typical 30-day life of a CP note, the 270-day maximum maturity for the most common type of CP, or even the one-year tenor used to distinguish between short-term and long-term ratings. Thus, CP ratings are likely to endure over time, rather than change frequently. Nonetheless, occasionally, the near-term outlook is distinct from long-term prospects. For example, there are companies with substantial liquidity, providing protection in the near or intermediate term, but which also have less than stellar profitability, a long-term factor. Similarly, companies with relatively large cash holdings that may be used to fund acquisitions in the future fit in this category.

This distinction, in reverse, often applies after an issuer makes a major acquisition. The analyst's confidence that the firm can restore financial health over the long term is factored into its long-term ratings, while financial stress that dominates the near term may lead to a relatively low CP rating. Use of different time horizons as the basis for long and short-term ratings implies that either one or the other rating will change with time.

Back-up policies

In the past, a key purpose of Standard & Poor's requiring bank-line backup was to ensure that an issuer would be able to meet its obligations in the event of a disruption to the financial markets that might inhibit the normal rollover of commercial paper, even while the issuer's own financial condition remained strong. However, the growth of the CP market prompted a reevaluation. It is Standard & Poor's current judgment that the protection afforded by back-up facilities could not be relied on with a high degree of confidence in the event of widespread disruption of the commercial paper markets. A general disruption of commercial paper markets would be a highly volatile scenario, under which most bank lines would represent unreliable claims on whatever cash would be made available through the banking system to support the market. Standard & Poor's neither anticipates that such a scenario is likely to develop, nor assumes that it never will.

Standard & Poor's continues to emphasize bank-line availability as an important buttress to liquidity, but only in the context of normal market conditions. The change in Standard & Poor's commercial paper back-up policy shifts the focus away from market disruption, while confirming the utility of bank facilities in supporting operations of any entity that incurs short-term obligations in the normal course of business.

A substantial level of liquidity—in the form of bank facilities or readily available liquid resources—is prudent for virtually all issuers and will continue to be necessary to support an investment-grade rating on both commercial paper and long-term debt. From time to time, there will be developments—e.g., bad business conditions, a lawsuit, management changes, a rating change—affecting a single company or group of companies, which may make CP investors nervous and unwilling to roll over the issuer's paper, even though the issuer remains creditworthy. Prearranged bank facilities are often essential in protecting against the risk of default under these circumstances.

Industrial and utility issuers typically provide 100% backup—excess liquid assets or bank facilities—for paper outstanding. However, companies with the highest credit quality can provide a lower percentage of coverage. Issuers rated 'A-1+' need not prearrange 100% coverage because they should be able to raise funds quickly even if some adversities develop. The exact amount is determined by the issuer's overall credit strength and its access to capital markets. Some 'AAA' issuers may have as little as 50% backup.

Importantly, backup must be sufficient to provide the appropriate level of coverage for other maturing short-term debt, not just commercial paper. Backup for 100% of rated commercial paper is meaningless if other debt maturities—for which there is no backup—coincide with those of commercial paper. Thus, the scope of backup must extend to Eurocommercial paper, master notes, syndicated bank notes, and other similar confidence-sensitive obligations.

Quality of back-up facilities

Banks offer various types of credit facilities that differ widely regarding the degree of the bank's commitment to advance cash under all circumstances. Ever weaker forms of commitment, which are less costly to issuers, have become common in recent years and provide banks still greater flexibility to redirect credit at their own discretion.

At the very least, Standard & Poor's expects that all back-up lines be in place and confirmed in writing. "Pre-approved" lines or orally committed lines are viewed as insufficient. Standard & Poor's also is particularly skeptical about reliance on "money-market" lines or similar arrangements which are little more than an invitation to do business at some future date. Payment for the lines—whether by fee or balances—generally creates some degree of moral commitment on the part of the bank. Whether a facility is specifically designated for CP backup is of little significance.

There is no distinction to be made between a 364-day and a 365-day facility. However, it is obviously critical that the facility at all times extends beyond the longest maturity of the paper it is backing. A prudent company will arrange for the continuation of its banking facilities well in advance of their lapsing.

The weaker the credit, the greater the need for more reliable forms of liquidity. Issuers rated 'A-1+' have superior access to capital because of their strong credit profiles; one assumes that banks would not hesitate in honoring lines of credit to such borrowers. By contrast, Standard & Poor's considers it prudent for 'A-1' and 'A-2'—and certainly 'A-3'—CP issuers to have a substantial portion of their banking facilities contractually committed in the form of a revolving credit. These revolvers should provide same-day availability of funds.

As a general guideline, an 'A-1' should have sufficient revolving credit capacity to provide for the next 10 days' maturities of outstanding paper. In the case of 'A-2' and 'A-3' issuers, revolvers should cover at least 15 days of maturing paper. Usually, for 'A-2' and 'A-3' issuers, this would translate into backup of 50% of total outstandings with revolving credits. The rest of the backup should be with other committed facilities, such as compensated lines. Stronger backup may be required in some cases to provide additional protection against potential roll-over problems caused by declining market confidence in the issuer.

Standard & Poor's recognizes that even revolving credit agreements, which usually represent the strongest commitment a bank can make, often include "material adverse change" clauses, allowing the bank to withdraw under certain circumstances. While inclusion of an escape clause weakens the commitment, Standard & Poor's does not consider it critical—or realistic—for most borrowers to negotiate removal of "material adverse change" clauses.

It is important to note that even the strongest form of backup—a revolver with no "material adverse change" clause—does not enhance the underlying credit and does not lead to a higher rating than indicated by the company's own creditworthiness. Credit enhancement can be accomplished only through LOC or another instrument that unconditionally transfers the debt obligation to a higher-rated entity.

Banks providing issuers with facilities for backup liquidity should themselves be sound institutions with the capacity to lend funds as committed. A bank's credit rating can serve as a guide as to its soundness: Possession of an investment-grade rating should indicate sufficient financial strength for the purpose of providing a commercial paper issuer with a reliable source of funding.

Standard & Poor's criteria do not require that the bank's credit rating equal the issuer's rating. Nor do they require that the bank's credit rating be 'AA', 'A', 'A-1', or even 'A-2' to be included in the lineup of banks supporting an issuer's liquidity. There is no reason to presume that any potential difficulties for the bank would coincide with the period during which the issuer would look to it for support. Moreover, higher credit quality of the bank does not translate into an inclination to add assets at a given point in time or to lend to a given borrower. Nonetheless, Standard & Poor's would look askance at situations where most of a company's banks were only marginally investment grade. That would indicate an imprudent reliance on banks which might deteriorate to weak, noninvestment grade status.

Dependence on just one or very few banks is also viewed as an unwarranted risk. Apart from the potential that the bank will not have adequate capacity to lend, there is the chance that it will not be willing to lend to this issuer. Having several banks diversifies the risk that any bank will lose confidence in this borrower and hesitate to provide funds.

Concentration of banking facilities also tends to increase the dollar amount of an individual bank's participation. As the dollar amount of the exposure becomes very large, the bank may be more reluctant to step up to its commitment. In addition, the potential requirement of higher-level authorizations at the bank could create logistical problems with respect to expeditious access to funds for the issuer.

Diversification is desirable up to a point: a company must not spread its banking business so thinly that it lacks a substantial relationship with any of its banks. In the end, it is a solid business relationship with a bank that is the key to whether the bank will stand by its client. Standardized criteria cannot capture or assess the strength of such relationships. Standard & Poor's is interested, though, in any evidence—subjective as it may be—that might demonstrate the strength of an issuer's banking relationships. For example, the nature of credit and noncredit services provided by the bank and the length of the business relationship often can provide some insight.

Guidelines for U.S. industrials and utilities

	Contractual commitment or cash	*Total bank commitment or cash*
A-1+/AAA		50%
A-1+/AA		75%
A-1	10 Days	100%
A-2	15 Days	100%
A-3	15 Days	100%

Exhibit JBM-2

Utilities Rating Service

Industry Commentary

Utilities Rating Criteria

The utilities rating methodology encompasses two basic components: business risk analysis and financial analysis. Evaluation of industry characteristics, the utility's position within that industry, its regulation, and its management provides the context for assessing a firm's financial condition.

Historical analysis is a tool for identifying strengths and weaknesses, and provides a starting point for evaluating financial condition. Business position assessment is the qualitative measure of a utility's fundamental creditworthiness. It focuses on the forces that will shape the utilities' future. For nontelephone utilities, the business position is expressed numerically on a scale of one (above average) through seven (below average).

The credit analysis of utilities is quickly evolving, as utilities are treated less as regulated monopolies and more as entities faced with a host of challengers in a competitive environment. Marketplace dynamics are supplanting the power of regulation, making it critically important to reduce costs and/or market new services in order to thwart competitors' inroads.

The credit analysis of utilities is quickly evolving, as utilities are treated less as regulated monopolies.

Markets and service area economy

Assessing service territory begins with the economic and demographic evaluation of the area in which the utility has its franchise. Strength of long-term demand for the product is examined from a macroeconomic perspective. This enables Standard & Poor's to evaluate the affordability of rates and the staying power of demand.

Standard & Poor's tries to discern any secular consumption trends and, more importantly, the reasons for them. Specific items examined include the size and growth rate of the market, strength of the franchise, historical and projected sales growth, income levels and trends in population, employment, and per capita income. A utility with a healthy economy and customer base—as illustrated by diverse employment opportunities, average or above-average wealth and income statistics, and low unemployment—will have a greater capacity to support its operations.

For electric and gas utilities, distribution by customer class is scrutinized to assess the depth and diversity of the utility's customer mix. For example, heavy industrial concentration is viewed cautiously, since a utility may have significant exposure to cyclical volatility. Alternatively, a large residential component yields a stable and more predictable revenue stream. The largest utility customers are identified to determine their importance to the bottom line and assess the risk of their loss and potential adverse effect on the utility's financial position. Credit concerns arise when indi-

Utilities credit analysis factors

Business risk
- Markets and service area economy
- Competitive position
- Operations
- Regulation
- Management
- Fuel, power, and water supply
- Asset concentration

Financial risk
- Earnings protection
- Capital structure
- Cash flow adequacy
- Financial flexibility/capital attraction

This Industry Commentary was produced through the efforts of many analysts of the Utilities Ratings Group, including Barbara Eiseman, John Bilardello, Richard Siderman, and Curtis Moulton.

vidual customers represent more than 5% of revenues. The company or industry may play a significant role in the overall economic base of the service area. Moreover, large customers may turn to cogeneration or alternative power supplies to meet their energy needs, potentially leading to reduced cash flow for the utility (even in cases where a large customer pays discounted rates and is not a profitable account for the utility). Customer concentration is less significant for water and telecommunication utilities.

Competitive position

As competitive pressures have intensified in the utilities industry, Standard & Poor's analysis has deepened to include a more thorough review of competitive position.

Mounting competition in the electric utility industry derives from excess generating capacity, lower barriers to entering the electric generating business, and marginal costs that are below embedded costs.

Electric utility competition

For electric utilities, competitive factors examined include: percentage of firm wholesale revenues that are most vulnerable to competition; industrial load concentration; exposure of key customers to alternative suppliers; commercial concentrations; rates for various customer classes; rate design and flexibility; production costs, both marginal and fixed; the regional capacity situation; and transmission constraints. A regional focus is evident, but high costs and rates relative to national averages are also of significant concern because of the potential for electricity substitutes over time.

Mounting competition in the electric utility industry derives from excess generating capacity, lower barriers to entering the electric generating business, and marginal costs that are below embedded costs. Standard & Poor's has already witnessed declining prices in wholesale markets, as *de facto* retail competition is already being seen in several parts of the country. Standard & Poor's believes that over the coming years more and more customers will want and demand lower prices. Initial concerns focus on the largest industrial loads, but other customer classes will be increasingly vulnerable. Competition will not necessarily be driven by legislation. Other pressures will arise from global competition and improving technologies, whether it be the declining cost of incremental generation or advances in transmission capacity or substitute energy sources like the fuel cell. It is impossible to say precisely when wide-open retail competition will occur; this will be evolutionary. However, significantly greater competition in retail markets is inevitable.

Gas utility competition

Similarly, gas utilities are analyzed with regard to their competitive standing in the three major areas of demand: residential, commercial, and industrial. Although regulated as holders of monopoly power, natural gas utilities have for some time been actively competing for energy market share with fuel oil, electricity, coal, solar, wood, etc. The long-term staying power of market demand for natural gas cannot be taken for granted. In fact, as the electric utility industry restructures and reduces costs, electric power will become more cost competitive and threaten certain gas markets. In addition, independent gas marketers have made greater inroads behind the city gate and are competing for large gas users. Moreover, the recent trend by state regulators to unbundle utility services is creating opportunities for outsiders to market niche products. Distributors still have the upper hand, but those who do not reduce and control costs, and thus rates, could find competition even more difficult.

Natural gas pipelines are judged to carry a somewhat higher business risk than distribution companies because they face competition in every one of their markets. To the extent a pipeline serves utilities versus industrial end users, its stability is greater. Over the next five years, pipeline competition will heat up since many service contracts with customers are expiring. Most distributor or end-use customers are looking to reduce pipeline costs and are working to improve their load factor to do so. Thus, pipelines will likely find it difficult to recontract all capacity in coming years. Being the pipeline of choice is a function of attractive transportation rates, diversity and quality of services provided, and capacity available in each particular market. In all cases though, periodic discounting of rates to retain customers will occur and put pressure on profitability.

Water utility competition

As the last true utility monopoly, water utilities face very little competition and there is currently no challenge to the continuation of franchise areas. The only exceptions have been cases where investor-owned water companies have been subject to condemnation and municipalization because of poor service or political motivations. In that regard, Standard & Poor's pays close attention to costs and rates in relation to neighboring utilities and national averages. (In contrast, the privatization of public water facilities has begun, albeit at a slower pace than anticipated. This is occurring mostly in the form of operating contracts and public/private partnerships, and not in asset transfers. This trend should continue as cities look for ways to balance their tight budgets.) Also, water utilities are not fully immune to the forces of competition; in a few instances wholesale customers can access more than one supplier.

While LECs face increasing competition, there are favorable industry factors that tend to offset heightened business risk.

Telephone competition

The Telecommunications Act of 1996 accelerates the continuing challenge to the local exchange companies' (LECs) century-old monopoly in the local loop. Competitive access providers (CAPs), both facilities-based and resellers, are aggressively pursuing customers, generally targeting metropolitan areas, and promising lower rates and better service.

Most long-distance calls are still originated and terminated on the local telephone company network. To complete such a call, the long-distance provider (including AT&T, MCI, Sprint and a host of smaller interexchange carriers or "IXCs") must pay the local telephone company a steep "access" fee to compensate the local phone company for the use of its local network. CAPs, in contrast, build or lease facilities that directly connect customers to their long-distance carrier, bypassing the local telephone company and avoiding access fees, and thereby can offer lower long-distance rates. But the LECs are not standing still; they are combating the loss of business to CAPs by lowering access fees, thereby reducing the economic incentive for a high usage long-distance customer to use a CAP. LECs are attempting to make up for the loss of revenues from lower access fees by increasing basic local service rates (or at least not lowering them), since basic service is far less subject to competition. LECs are improving operating efficiency and marketing high margin, value-added new services. Additionally, in the wake of the Telecommunications Act, LECs will capture at least some of the inter-LATA long-distance market. As a result of these initiatives, LECs continue to rebuild themselves—from the traditional utility monopoly to leaner, more marketing oriented organizations.

While LECs, and indeed all segments of the telecommunications sector, face increasing competition, there are favorable industry factors that tend to offset heightened business risk and auger for overall ratings stability for most LECs. Importantly, telecommunications is a declining-cost business. With increased deployment of fiber optics, the cost of transport has fallen dramatically and digital switching hardware and software have yielded more capable, trouble-free and cost-efficient networks. As a result, the cost of network maintenance has dropped sharply, as illustrated by the ratio of employees per 10,000 access lines, an oft cited measurement of efficiency. Ratios as low as 25 employees per 10,000 lines are being seen, down from the typical 40 or more employees per 10,000 ratio of only a few years ago.

In addition, networks are far more capable. They are increasingly digitally switched and able to accommodate high-speed communications. The infrastructure needed to accommodate switched broadband services will be built into telephone networks over the next few years. These advanced networks will enable telephone companies to look to a greater variety of high-margin, value-added services. In addition to those current services such as call waiting or caller ID, the delivery of hundreds of broadcast and interactive video channels will be possible. While these services offer the potential of new revenue streams, they will simultaneously present a formidable challenge. LECs will be entering the new (to them) arena of multimedia entertainment and will have to develop expertise in marketing and entertainment programming acumen; such skills stand in sharp contrast to LECs' traditional strengths in engineering and customer service.

Over the next decade, water systems will increasingly face the task of maintaining compliance.

Operations

Standard & Poor's focuses on the nature of operations from the perspective of cost, reliability, and quality of service. Here, emphasis is placed on those areas that require management attention in terms of time or money and which, if unresolved, may lead to political, regulatory, or competitive problems.

Operations of electric utilities

For electrics, the status of utility plant investment is reviewed with regard to generating plant availability and utilization, and also for compliance with existing and contemplated environmental and other regulatory standards. The record of plant outages, equivalent availability, load factors, heat rates, and capacity factors are examined. Also important is efficiency, as defined by total megawatt hour per employee and customers per employee. Transmission interconnections are evaluated in terms of the number of utilities to which the utility in question has access, the cost structures and available generating capacity of these other utilities, and the price paid for wholesale power.

Because of mounting competition and the substantial escalation in decommissioning estimates, significant weight is given to the operation of nuclear facilities. Nuclear plants are becoming more vulnerable to high production costs that make their rates uneconomic. Significant asset concentration may expose the utility to poor performance, unscheduled outages or premature shutdowns, and large deferrals or regulatory assets that may need to be written off for the utility to remain competitive. Also, nuclear facilities tend to represent significant portions of their operators' generating capability and assets. The loss of a productive nuclear unit from both power supply and rate base can interrupt the revenue stream and create substantial additional costs for repairs and improvements and replacement power. The ability to keep these stations running smoothly and economically directly influences the ability to meet electric demand, the stability of revenues and costs, and, by extension, the ability to maintain adequate creditworthiness. Thus, economic operation, safe operation, and long-term operation are examined in depth. Specifically, emphasis is placed on operation and maintenance costs, busbar costs, fuel costs, refueling outages, forced outages, plant statistics, NRC evaluations, the potential need for repairs, operating licenses, decommissioning estimates and amounts held in external trusts, spent fuel storage capacity, and management's nuclear experience. In essence, favorable nuclear operations offer significant opportunities but, if a nuclear unit runs poorly or not at all, the attendant risks can be great.

Operations of gas utilities

For gas pipeline and distribution companies, the degree of plant utilization, the physical condition of the mains and lines, adequacy of storage to meet seasonal needs, "lost and unaccounted for" gas levels, and per-unit nongas operating and construction costs are important factors. Efficiency statistics such as load factor, operating costs per customer, and operating income per employee are also evaluated in comparison to other utilities and the industry as a whole.

Operations of water utilities

As a group, water utilities are continually upgrading their physical plant to satisfy regulations and to develop additional supply. Over the next decade, water systems will increasingly face the task of maintaining compliance, as drinking water regulations change and infrastructure ages. Given that the Safe Drinking Water Act was authorized in 1974, the first generation of treatment plants built to conform with these rules are almost 20 years old. Additionally, because the focus during this period was on satisfying environmental standards, deferred maintenance of distribution systems has been common, especially in older urban areas. The increasing cost of supplying treated water argues against the high level of unaccounted for water witnessed in the industry. Consequently, Standard & Poor's anticipates capital plans for rebuilding distribution lines and major renewal and replacement efforts aimed at treatment plants.

Operations of telephone companies

For telephone companies, cost-of-service analysis focuses on plant capability and measures of efficiency and quality of service. Plant capability is ascertained by looking at such parameters as percentage of digitally switched lines; fiber optic deployment, in particular in those portions of the plant key to network survival; and the degree of broadband capacity fiber and coaxial deployment and broadband switching capacity. Efficiency measures include operating margins, the ratio of employees per 10,000 access lines, and the extent of network and operations consolidation. Quality of service encompasses examination of quantitative measures, such as trouble reports and repeat service calls, as well as an assessment of qualitative factors, that may include service quality goals mandated by regulators.

Regulation

Regulatory rate-setting actions are reviewed on a case-by-case basis with regard to the potential effect on creditworthiness. Regulators' authorizing high rates of return is of little value unless the returns are earnable. Furthermore, allowing high returns based on noncash items does not benefit bondholders. Also, to be viewed positively, regulatory treatment should allow consistent performance from period to period, given the importance of financial stability as a rating consideration.

The utility group meets frequently with commission and staff members, both at Standard & Poor's offices and at commission headquarters, demonstrating the importance Standard & Poor's places on the regulatory arena for credit quality evaluation. Input from these meetings and from review of rate orders and their impact weigh heavily in Standard & Poor's analysis.

Standard & Poor's does not "rate" regulatory commissions. State commissions typically regulate a number of diverse industries, and regulatory approaches to different types of companies often differ within a single regulatory jurisdiction. This makes it all but impossible to develop inclusive "ratings" for regulators.

Standard & Poor's evaluation of regulation also encompasses the administrative, judicial, and legislative processes involved in state and federal regulation. These can affect rate-setting activities and other aspects of the business, such as competitive entry, environmental and safety rules, facility siting, and securities sales.

As the utility industry faces an increasingly deregulated environment, alternatives to traditional rate-making are becoming more critical to the ability of utilities to effectively compete, maintain earnings power, and sustain creditor protection. Thus, Standard & Poor's focuses on whether regulators, both state and federal, will help or hinder utilities as they are exposed to greater competition. There is much that regulators can do, from allocating costs to more captive customers to allowing pricing flexibility—and sometimes just stepping out of the way.

Alternatives to traditional rate-making are becoming more critical to the ability of utilities to effectively compete.

Under traditional rate-making, rates and earnings are tied to the amount of invested capital and the cost of capital. This can sometimes reward companies more for justifying costs than for containing them. Moreover, most current regulatory policies do not permit utilities to be flexible when responding to competitive pressures of a deregulated market. Lack of flexible tariffs for electric utilities may lure large customers to wheel cheaper power from other sources.

In general, a regulatory jurisdiction is viewed favorably if it permits earning a return based on the ability to sustain rates at competitive levels. In addition to performance-based rewards or penalties, flexible plans could include market-based rates, price caps, index-based prices, and rates premised on the value of customer service. Such rates more closely mirror the competitive environment that utilities are confronting.

A regulatory jurisdiction is viewed favorably if it permits a utility to earn a return based on its ability to sustain rates at competitive levels.

Electric industry regulation

The ability to enter into long-term arrangements at negotiated rates without having to seek regulatory approval for each contract is also important in the electric industry. (While contracting at reduced rates constrains financial performance, it lessens the potential adverse impact in the event of retail wheeling. Since revenue losses associated with this strategy are not likely to be recovered from ratepayers, utilities must control costs well enough to remain competitive if they are to sustain current levels of bondholder protection.)

Natural gas industry regulation

In the gas industry, too, several state commission policies weigh heavily in the evaluation of regulatory support. Examples include stabilization mechanisms to adjust revenues for changes in weather or the economy, rate and service unbundling decisions, revenue and cost allocation between sales and transportation customers, flexible industrial rates, and the general supportiveness of construction costs and gas purchases.

Water industry regulation

In all water utility activities, federal and state environmental regulations continue to play a critical role. The legislative timetable to effect the 1986 amendments to the Safe Drinking Water Act of 1974 was quite aggressive. But environmental standards-setting has actually slowed over the past couple of years due largely to increasing sentiment that the stringent, costly standards have not been justified on the basis of public health. A moratorium on the promulgation of significant new environmental rules is anticipated.

Telecommunications industry regulation

Despite the advances in telecommunications deregulation, analysis of regulation of telephone operators will continue to be a key rating determinant for the foreseeable future. The method of regulation may be either classic rate-based rate of return or some form of price cap mechanism. The most important factor is to assess whether the regulatory framework—no matter which type—provides sufficient financial incentive to encourage the rated company to maintain its quality of service and to upgrade its plant to accommodate new services while facing increasing competition from wireless operators and cable television companies.

Where regulators do still set tariffs based on an authorized return, Standard & Poor's strives to explore with regulators their view of the rate-of-return components that can materially impact reported versus regulatory earnings. Specifically these include the allowable base upon which the authorized return can be earned, allowable expenses, and the authorized return. Since regulatory oversight runs the gamut from strict, adversarial relationships with the regulated operating companies to highly supportive postures, Standard & Poor's probes beyond the apparent regulatory environment to ascertain the actual impact of regulation on the rated company.

Management

Evaluating the management of a utility is of paramount importance to the analytical process since management's abilities and decisions affect all areas of a company's operations. While regulation, the economy, and other outside factors can influence results, it is ultimately the quality of management that determines the success of a company.

With emerging competition, utility management will be more closely scrutinized by Standard & Poor's and will become an increasingly critical component of the credit evaluation. Management strategies can be the key determinant in differentiating utilities and in establishing where companies lie on the business position spectrum. It is imperative that managements be adaptable, aggressive, and proactive if their utilities are to be viable in the future; this is especially important for utilities that are currently uncompetitive.

With emerging competition, utility management will be more closely scrutinized by Standard & Poor's.

The assessment of management is accomplished through meetings, conversations, and reviews of company plans. It is based on such factors as tenure, industry experience, grasp of industry issues, knowledge of customers and their needs, knowledge of competitors, accounting and financing practices, and commitment to credit quality. Management's ability and willingness to develop workable strategies to address their systems' needs, to deal with the competitive pressures of free market, to execute reasonable and effective long-term plans, and to be proactive in leading their utilities into the future are assessed. Management quality is also indicated by thoughtful balancing of public and private priorities, a record of credibility, and effective communication with the public, regulatory bodies, and the financial community. Boards of directors will receive ever more attention with respect to their role in setting appropriate management incentives.

With competition the watchword, Standard & Poor's also focuses on management's efforts to enhance financial condition. Management can bolster bondholder protection by taking any number of discretionary actions, such as selling common equity, lowering the common dividend payout, and paying down debt. Also important for the electric industry will be creativity in entering into strategic alliances and working partnerships that improve efficiency, such as central dispatching for a number of utilities or locking up at-risk customers through long-term contracts or expanded flexible pricing agreements. Proactive management teams will also seek alternatives to traditional rate-base, rate-of-return rate-making, move to adopt higher depreciation rates for generating facilities, segment customers by individual market preferences, and attempt to create superior service organizations.

In general, management's ability to respond to mounting competition and changes in the utility industry in a swift and appropriate manner will be necessary to maintain credit health.

Fuel, power, and water supply

Assessment of present and prospective fuel and power supply is critical to every electric utility analysis, while gauging the long-term natural gas supply position for gas pipeline and distribution companies and the water resources of a water utility is equally important. There is no similar analytical category for telephone utilities.

Electric utilities

For electric utilities emphasis is placed on generating reserve margins, fuel mix, fuel contract terms, demand-side management techniques, and purchased power arrangements. The adequacy of generating margins is examined nationally, regionally, and for each individual company. However, the reserve margin picture is muddied by the imprecise nature of peak-load growth forecasting, and also supply uncertainty relating to such things as Canadian capacity availability and potential plant shutdowns due to age, new NRC rules, acid rain remedies, fuel shortages, problems associated with nontraditional technologies, and so forth. Even apparently ample reserves may not be what they seem. Moreover, the quality of capacity is just as important as the size of reserves. Companies' reserve requirements differ, depending upon individual operating characteristics.

Fuel diversity provides flexibility in a changing environment. Supply disruptions and price hikes can raise rates and ignite political and regulatory pressures that ultimately lead to erosion in financial performance. Thus, the ability to alter generating sources and take advantage of lower cost fuels is viewed favorably.

Fuel diversity provides flexibility in a changing environment.

Dependence on any single fuel means exposure to that fuel's problems: electric utilities that rely on oil or gas face the potential for shortages and rapid price increases; utilities that own nuclear generating facilities face escalating costs for decommissioning; and coal-fired capacity entails environmental problems stemming from concerns over acid rain and the "greenhouse effect."

Buying power from neighboring utilities, qualifying facility projects, or independent power producers may be the best choice for a utility that faces increasing electricity demand. There has been a growing reliance on purchased power arrangements as an alternative to new plant construction. This can be an important advantage, since the purchasing utility avoids potential construction cost overruns as well as risking substantial capital. Also, utilities can avoid the financial risks typical of a multiyear construction program that are caused by regulatory lag and prudence reviews. Furthermore, purchased power may enhance supply flexibility, fuel resource diversity, and maximize load factors. Utilities that plan to meet demand projections with a portfolio of supply-side options also may be better able to adapt to future growth uncertainties. Notwithstanding the benefits of purchasing, such a strategy has risks associated with it. By entering into a firm long-term purchased power contract that contains a fixed-cost component, utilities can incur substantial market, operating, regulatory, and financial risks. Moreover, regulatory treatment of purchased power removes any upside potential that might help offset the risks. Utilities are not compensated through incentive rate-making; rather, purchased power is recovered dollar-for-dollar as an operating expense.

To analyze the financial impact of purchased power, Standard & Poor's first calculates the net present value of future annual capacity payments (discounted at 10%). This represents a potential debt equivalent—the off-balance-sheet obligation that a utility incurs when it enters into a long-term purchased power contract. However, Standard & Poor's adds to the utility's balance sheet only a portion of this amount, recognizing that such a contractual arrangement is not entirely the equivalent of debt. What percentage is added is a function of Standard & Poor's qualitative analysis of the specific contract and the extent to which market, operating, and regulatory risks are borne by the utility (the risk factor). For unconditional, take-or-pay contracts, the risk factor range is from 40%-80%, with the average hovering around 60%. A lower risk factor is typically assigned for system purchases from coal-fired utilities and a higher risk factor is usually designated for unit-specific nuclear purchases. The range for take-and-pay performance obligations is between 10%-50%.

Gas utilities

For gas distribution utilities, long-term supply adequacy obviously is critical, but the supply role has become even more important in credit analysis since the Federal Energy Regulatory Commission's Order 636 eliminated the interstate pipeline merchant business. This thrust gas supply responsibilities squarely on local gas distributors. Standard & Poor's has always believed distributor management has the expertise and wherewithal to perform the job well, but the risks are significant since gas costs are such a large percentage of total utility costs. In that regard, it is important for utilities to get preapprovals of supply plans by state regulators or at least keep the staff and commissioners well informed. To minimize risks, a well-run program would diversify gas sources among different producers or marketers, different gas basins in the U.S. and Canada, and different pipeline routes. Also, purchase contracts should be firm, with minimal take-or-pay provisions, and have prices tied to an industry index. A modest percentage of fixed-price gas is not unreasonable. Contracts, whether of gas purchases or pipeline capacity, should be intermediate term. Staggering contract expirations (preferably annually) provides an opportunity to be an active market player. A modest degree of reliance on spot purchases provides flexibility, as does the use of market-based storage. Gas storage and on-property gas resources such as liquefied natural gas or propane air are effective peak-day and peak-season supply management tools.

Since pipeline companies no longer buy and sell natural gas and are just common carriers, connections with varied reserve basins and many wells within those basins are of great importance. Diversity of sources helps offset the risks arising from the natural production declines eventually experienced by all reserve basins and individual wells. Moreover, such diversity can enhance a pipeline's attractiveness as a transporter of natural gas to distributors and end users seeking to buy the most economical gas available for their needs.

Since pipeline companies no longer buy and sell natural gas and are just common carriers, connections with varied reserve basins and many wells within those basins are of great importance.

Water utilities

Nearly all water systems throughout the U.S. have ample long-term water supplies. Yet to gain comfort, Standard & Poor's assesses the production capability of treatment plants and the ability to pump water from underground aquifers in relation to the usage demands from consumers. Having adequate treated water storage facilities has become important in recent years and has helped many systems meet demands during peak summer periods. Of interest is whether the resources are owned by the utility or purchased from other utilities or local authorities. Owning properties with water rights provides more supply security. This is especially so in states like California where water allocations are being reduced, particularly since recent droughts and environmental issues have created alarm. Since the primary cost for water companies is treatment, it makes little difference whether raw water is owned or bought. In fact, compliance with federal and state water regulations is very high, and the overall cost to deliver treated water to consumers remains relatively affordable.

Asset concentration in the electric utility industry

In the electric industry, Standard & Poor's follows the operations of major generating facilities to assess if they are well managed or troubled. Significant dependence on one generating facility or a large financial investment in a single asset suggests high risk. The size or magnitude of a particular asset relative to total generation, net plant in service, and common equity is evaluated. Where substantial asset concentration exists, the financial profile of a company may experience wide swings depending on the asset's performance. Heavy asset concentration is most prevalent among utilities with costly nuclear units.

Earnings protection

In this category, pretax cash income coverage of all interest charges is the primary ratio. For this calculation, allowance for funds used during construction (AFUDC) is removed from income and interest expense. AFUDC and other such noncash items do not provide any protection for bondholders. To identify total interest expense, the analyst reclassifies certain operating expenses. The interest component of various off-balance-sheet obligations, such as leases and some purchased-power contracts, is included in interest expense. This provides the most direct indication of a utility's ability to service its debt burden.

While considerable emphasis in assessing credit protection is placed on coverage ratios, this measure does not provide the entire earnings protection picture. Also important are a company's earned returns on both equity and capital, measures that highlight a firm's earnings performance. Consideration is given to the interaction of embedded costs, financial leverage, and pretax return on capital.

Capital structure

Analyzing debt leverage goes beyond the balance sheet and covers quasi-debt items and elements of hidden financial leverage. Noncapitalized leases (including sale/leaseback obligations), debt guarantees, receivables financing, and purchased-power contracts are all considered debt equivalents and are reflected as debt in calculating capital structure ratios. By making debt level adjustments, the analyst can compare the degree of leverage used by each utility company.

Furthermore, assets are examined to identify undervalued or overvalued items. Assets of questionable value are discounted to more accurately evaluate asset protection.

Cash flow adequacy relates to a company's ability to generate funds internally relative to its needs. It is a basic component of credit analysis.

Some firms use short-term debt as a permanent piece of their capital structure. Short-term debt also is considered part of permanent capital when it is used as a bridge to permanent financing. Seasonal, self-liquidating debt is excluded from the permanent debt amount, but this situation is rare—with the exception of certain gas utilities. Given the long life of almost all utility assets, short-term debt may expose these companies to interest-rate volatility, remarketing risk, bank line backup risk, and regulatory exposure that cannot be readily offset. The lower cost of shorter-term obligations (assuming a positively sloped yield curve) is a positive factor that partially mitigates the risk of interest-rate variability. As a rule of thumb, a level of short-term debt that exceeds 10% of total capital is cause for concern.

Similarly, if floating-rate debt and preferred stock constitute over one-third of total debt plus preferred stock, this level is viewed as unusually high and may be cause for concern. It might also indicate that management is aggressive in its financial policies.

A layer of preferred stock in the capital structure is usually viewed as equity—since dividends are discretionary and the subordinated claim on assets provides a cushion for providers of debt capital. A preferred component of up to 10% is typically viewed as a permanent wedge in the capital structure of utilities. However, as rate-of-return regulation is phased out, preferred stock may be viewed by utilities—as many industrial firms would—as a temporary option for companies that are not current taxpayers that do not benefit from the tax deductibility of interest. Even now, floating-rate preferred and money market perpetual preferred are problematic; a rise in the rate due to deteriorating credit quality tends to induce a company to take out such preferred stock with debt. Structures that convey tax deductibility to preferred stock have become very popular and do generally afford such financings with equity treatment.

Cash flow adequacy

Cash flow adequacy relates to a company's ability to generate funds internally relative to its needs. It is a basic component of credit analysis because it takes cash to pay expenses, fund capital spending, pay dividends, and make interest and principal payments. Since both common and preferred dividend payments are important to maintain capital market access, Standard & Poor's looks at cash flow measures both before and after dividends are paid.

To determine cash flow adequacy, several quantitative relationships are examined. Emphasis is placed on cash flow relative to debt, debt service requirements, and capital spending. Cash flow adequacy is evaluated with respect to a firm's ability to meet all fixed charges, including capacity payments under purchased-power contracts. Despite the conditional nature of some contracts, the purchaser is obligated to pay a minimum capacity charge. The ratio used is funds from operations plus interest and capacity payments divided by interest plus capacity payments.

Financial flexibility/capital attraction

Financing flexibility incorporates a utility's financing needs, plans, and alternatives, as well as its flexibility to accomplish its financing program under stress without damaging creditworthiness. External funding capability complements internal cash flow. Especially since utilities are so capital intensive, a firm's ability to tap capital markets on an ongoing basis must be considered. Debt capacity reflects all the earlier elements: earnings protection, debt leverage, and cash flow adequacy. Market access at reasonable rates is restricted if a reasonable capital structure is not maintained and the company's financial prospects dim. The analyst also reviews indenture restrictions and the impact of additional debt on covenant tests.

Standard & Poor's assesses a company's capacity and willingness to issue common equity. This is affected by various factors, including the market-to-book ratio, dividend policy, and any regulatory restrictions regarding the composition of the capital structure.

Conclusion

In summary, the risk-adjusted ratio guidelines depict the role that financial ratios play in Standard & Poor's utility rating process, since quantitative measures are viewed in the context of a firm's business risk profile. For a given rating category, expected levels of financial ratios vary with the business or operating risk of a company. A utility with a stronger competitive position, more favorable business prospects, and more predictable cash flows can afford to withstand greater financial risk while maintaining the same credit rating. In most cases, a utility's credit rating should closely relate with its business position assessment. For example, a utility rated in the 'AA' category should have a business position that is at or above average.

TELEPHONE OPERATING COMPANIES

	AA	A	BBB
Pretax interest coverage (x)	over 4.5	3.3-5.0	2.3-4.0
Total debt/total capital (%)	under 42	40-52	50-62
Net cash flow/average total debt (%)	over 32	25-33	20-30
Funds from operations interest coverage (x)	over 6.5	5.0-7.0	3.5-5.5

ELECTRIC UTILITIES

Pretax interest coverage (x)	*AA*	*A*	*BBB*	*BB*
Above-average business position	3.50	2.75	1.75	1.25
Average business position	4.00	3.50	2.50	1.75
Below-average business position	—	4.50	3.50	2.50
Total debt/total capital (%)				
Above-average business position	47	52	59	65
Average business position	42	47	54	60
Below-average business position	—	41	48	54
Funds from operations interest coverage (x)				
Above-average business position	4.00	3.25	2.25	1.75
Average business position	4.50	4.00	3.00	2.00
Below-average business position	—	5.00	4.00	2.75
Funds from operations/total debt (%)				
Above-average business position	26	19	14	11
Average business position	32	25	19	13
Below-average business position	—	34	29	20
Net cash flow/capital expenditures (%)				
Above-average business position	90	70	45	30
Average business position	110	85	60	40
Below-average position	—	105	80	60

GAS DISTRIBUTION COMPANIES

	AA	A	BBB	BB
Pretax interest coverage (x)				
Above-average business position	3.75	3.00	2.00	1.50
Average business position	4.25	3.75	2.75	2.00
Below-average business position	—	4.25	3.25	2.25
Total debt/total capital (%)				
Above-average business position	46	51	58	64
Average business position	41	46	53	59
Below-average business position	—	42	49	55
Funds from operations interest coverage (x)				
Above-average business position	4.25	3.50	2.50	2.00
Average business position	4.75	4.25	3.25	2.25
Below-average business position	—	4.75	3.75	2.50
Funds from operations/total debt (%)				
Above-average business position	27	20	15	12
Average business position	33	26	20	14
Below-average business position	—	32	27	18
Net cash flow/capital expenditures (%)				
Above-average business position	95	75	50	35
Average business position	115	95	65	45
Below-average business position	—	100	75	55

GAS PIPELINE COMPANIES

	AA	A	BBB	BB
Pretax interest coverage (x)				
Above-average business position	4.00	3.25	2.25	1.75
Average business position	4.50	4.00	3.00	2.25
Below-average business position	—	4.50	3.50	2.50
Total debt/total capital (%)				
Above-average business position	44	49	56	62
Average business position	39	44	51	57
Below-average business position	—	41	46	54
Funds from operations interest coverage (x)				
Above-average business position	4.50	3.75	2.75	2.25
Average business position	5.00	4.50	3.50	2.50
Below-average business position	—	5.00	4.00	2.75
Funds from operations/total debt (%)				
Above-average business position	32	25	19	16
Average business position	37	30	24	18
Below-average business position	—	34	29	20
Net cash flow/capital expenditures (%)				
Above-average business position	105	80	60	40
Average business position	125	95	70	50
Below-average business position	—	105	80	60

WATER UTILITIES

	AA	A	BBB	BB
Pretax interest coverage (x)				
Above-average business position	2.75	2.25	1.25	0.75
Average business position	3.25	3.00	2.00	1.00
Below-average business position	—	3.75	2.75	1.50
Total debt/total capital (%)				
Above-average business position	52	56	64	70
Average business position	48	52	59	65
Below-average business position	—	48	54	60
Funds from operations interest coverage (x)				
Above-average business position	3.00	2.50	1.50	1.00
Average business position	3.50	3.25	2.25	1.25
Below-average business position	—	4.00	3.00	1.75
Funds from operations/total debt (%)				
Above-average business position	19	15	10	7
Average business position	25	21	15	9
Below-average business position	—	27	20	12
Net cash flow/capital expenditures (%)				
Above-average business position	75	60	35	20
Average business position	95	75	50	30
Below-average business position	—	90	65	40

Standard & Poor's
A Division of The McGraw-Hill Companies

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Exhibit JBM-3

INDUSTRY COMMENTARY

Rating Methodology For Global Power Companies

Standard & Poor's criteria approach to rating power companies located around the world is flexible, since utilities have different ownership structures, varying government support, and diverse regulatory regimes. In addition, global power companies face distinct macroeconomic environments and unique operating environments, and there are disparate risks for generation, transmission, and distribution. *(For a separate discussion of Standard & Poor's criteria for evaluating energy marketing (or supply) companies, see Standard & Poor's March 12, 1997 CreditWeek.)*

Taking into consideration the disparity in credit risks caused by these factors, Standard & Poor's rating methodology for global power companies incorporates two basic components: business profile (qualitative analysis) and financial profile (quantitative analysis). The two components are inextricable. A utility with a strong business profile, for example, could have less financial protection than one with a weaker business profile and still achieve the same rating. Conversely, a utility with a weak business profile would require a more robust financial profile than one with a stronger business profile in order to get the same rating. This basic matrix is illustrated in table 1.

BUSINESS PROFILE

Standard & Poor's utilizes business profile assessments to measure a power company's qualitative credit fundamentals. Business profiles are expressed numerically on a scale of 1 (strong) to 10 (weak). To determine a business profile, Standard & Poor's analyzes the key qualitative business or operating characteristics typical for any utility. The main criteria examined are:

- Regulation,
- Markets,
- Operations,
- Competitiveness, and
- Management.

IDENTIFYING UTILITY TYPES

The weighting or analytical emphasis that each business profile factor receives is strongly influenced by the type of utility. Standard & Poor's has identified four types of utilities (*see table 2*). The type is determined through analysis of the influence of government ownership (if any), the degree of financial stability derived from the structure of the industry, and the relative competitiveness of the system. There are both investor-owned and government-owned utilities found in all four types, and more than one type may exist within the same country.

Type I utilities ("supported") operate within systems where the utility receives overwhelming government and regulatory support. This support can be explicit, as cases where a government guarantees a utility's obligations, such as Canada. Or it can be in the form of strong and obvious implicit support, such as Greece, whereby the government facilitates the utility's access to external sources of capital or where the utility is a direct instrument of government policy. Type I utilities need not be completely owned by government, but government ownership is usually present. Before attributing support from government, Standard & Poor's reviews the track record of assistance, the procedures and timeliness of support mechanisms, the government's policy objectives for utility ownership, and financial policies. Standard & Poor's looks for evidence that the government would stand behind a debtor in time of financial need. Written and oral statements consistently made

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Table 1

Global Utility Rating Matrix

		Indicative Ratings		
Financial Profile	Weak	A	BBB	BB
	Average	AA	A	BBB
	Strong	AAA	AA	A
		Strong	Average	Weak
		Business Profile		

over time and significant supportive actions build credibility. In addition, Standard & Poor's considers incentives for the government to provide tangible support. Questions asked include: What would be lost if a payment were missed? Would the borrower be able to continue to operate if it defaulted on a debt? Is the name of the borrower closely tied to the government in the market's perception so that a default by the borrower would cause the government difficulties in the capital markets? What are the political realities?

Type II utilities ("sheltered") conduct business where the utility is sheltered from competition and financial variability by the government or regulator. Sheltered utilities are not necessarily owned by government. Japanese investor-owned utilities are an example. These vertically integrated utilities have historically been insulated from competition and protected by a very cooperative, coordinated rate-setting process. While generally highly leveraged, these utilities' financial results are quite stable. Another example is U.S. municipally owned utilities, which have traditionally been sheltered from competitive forces and have enjoyed significant rate-setting flexibility. While categorized as Type II utilities, Standard & Poor's analysis of municipal utilities is evolving as deregulation measures aimed at investor-owned utilities are pressuring municipal utilities to create competitive markets. Moreover, there is an increasing number of city councils or other ratemaking bodies that are reluctant to make either upward or downward rate adjustments. For example, it may become politically unpalatable to end the subsidization of residential rates by commercial and industrial customers even if rate hikes for residential customers are necessary to achieve cost of service rates that are more competitive for the commercial and industrial classes. Similarly, the ability to effect rate reductions necessitated by a more competitive environment may be frustrated by a city's general fund's dependence upon transfers from the electric system.

Type III utilities ("exposed"), such as vertically integrated utilities in the U.S. or distribution companies in the U.K. or Victoria, Australia, are identified by evidence of some regulatory insulation from the forces of competition mixed in with exposure to business risk. Although Type III utilities have certain franchise monopoly characteristics, their financial success may hinge more on their ability to control costs and provide high quality service.

Finally, Type IV utilities ("commodity") are essentially unregulated as to revenue or return. Unregulated generators, such as in Argentina and Chile, owe their success or failure to their ability to operate well at low cost, and are also subject to the sometimes harsh realities of supply and demand.

For Type I utilities, the business profile analysis is not particularly significant since the ratings will reflect the credit quality of the entity providing explicit or strong implicit support. For Type II utilities, the business profile factors of regulation and markets are weighted more heavily than other criteria such as competitiveness or management because of the supportive regulatory umbrella. Conversely, for Type IV utilities, operations, competitiveness, and management are the most heavily weighted criteria. Business profile factor weightings for Type III utilities are more evenly distributed across all five criteria.

Another important point is that many utilities are gradually transitioning from Type II to Type III and perhaps to Type IV. As many countries' electricity sectors undergo structural reform and introduce competition, Standard & Poor's will weigh more heavily the business profile factors of operations, competitiveness, and management. As this occurs, the business profile assessments will fall and rating downgrades could result, absent offsetting improvement in financial profiles.

TYPICAL BUSINESS PROFILES

Owing to the relatively low business risk of large transmission systems and regulated distribution systems (the "wires" business), business profile assessments in this area should fall within the 1-4 range. The generation business is the most risky, reflecting the

Table 2

Utility Types

	Type I Supported	Type II Sheltered	Type III Exposed	Type IV Commodity
Example	France, Ontario	Japan, Denmark	U.S., U.K.	Genco
Primary Credit Determinants	Owner Or Guarantor	Structural Protection, Rate Flexibility	Cost Control Service Quality	Performance & Cost
Debt Servicing Capacity	Not Limited By Stand Along Risks	Usually Highly Leveraged	Moderate	Limited

competitive nature of this business, and generators generally receive business profile assessments in the 7-10 range.

The business profiles of electric systems with elements of integration, either fully vertically integrated from generation through transmission to distribution, or partially integrated via, for instance, generation and transmission, reflect a weighted approach reflecting the relative importance of each business segment to the overall credit. To determine the relative importance, contributions of cash flow and operating income from each segment are compared, as is the amount of capital invested. In addition, credit is given for the benefits of integration. For example, a company owning integrated generation and distribution operations benefits from the natural hedge that integration creates for both businesses. Integrated utilities tend to have business profiles in the 3-7 range.

Because of the importance of the different analytical emphasis accorded to the five business profile factors as influenced by the type of utility, the overall business profile assessment can diverge from the general expectations stated above. For example, certain generators can have strong regulatory support, and would therefore be characterized as Type II utilities. Consequently, their business profile assessment, which could be 3-4, reflects heavy weighting on the supportive regulatory structure.

FINANCIAL PROFILE

Standard & Poor's measures financial strength by a utility's ability to generate consistent cash flow to service its debt, finance its operations, and fund its investment. Standard & Poor's focuses on a utility's financial results for the last five years and on pro forma, five-year projections.

To identify potential financial pressures, Standard & Poor's examines major revenue and expenditure items. Per unit revenues indicate the competitiveness and sustainability of rates, and are contrasted with those in other electric systems. The relative financial performance of electric utilities is quantified through the use of ratio analysis. Because of distortions caused by vastly differing asset valuation practices and depreciation policies around the world, certain leverage and earnings ratios are not particularly useful when conducting comparative analysis. As a consequence, Standard & Poor's has concluded that the proper analytical focus should be on "real" stocks and flows, namely, levels of debt, cash, and cash flow. Financial parameters that are increasingly viewed as relevant and reliable are coverage of fixed financial charges by cash flow and cash flow from operations to total debt. Less comparable measures, such as shareholders' equity, leverage, and reported earnings, are also reviewed but deemphasized.

Tightly regulated transmission and distribution utilities generally face limited business risk and can operate with relatively low operating margins and high leverage. Conversely, generating companies operating in a very competitive environment face much higher business risk and attendant cash flow volatility, and therefore generally can sustain only modest levels of debt. Table 3 lists certain key financial ratios for rated transmission and distribution companies, generators, and vertically integrated utilities. The figures represent the medians of the ratios derived from Standard & Poor's financial projections used in the most recent review of companies rated both publicly and confidentially. Because of the different types of utilities (supported, sheltered, exposed, commodity) in each category (transmission and distribution, generators, and vertically integrated companies), the actual financial ratios for any particular entity may differ significantly from the medians. However, the ratios in the table are useful in demonstrating the typical differences in financial standards appropriate due to differences in business risk.

Below are the major financial profile factors analyzed for transmission companies, distributors, generators, and vertically integrated companies.

Profitability. Profit potential is a critical determinant of credit protection for investor-owned utilities. A company that generates higher profits has a greater ability to generate equity capital internally, attract capital externally, and withstand business adversity. Earnings power ultimately attests to the value of the firm's assets. Profit is less significant for non-U.S. government-owned utilities, but still relevant because higher operating margins provide additional bondholder protection. For U.S. municipal utilities,

Financial Ratio Medians

	Funds from operations interest coverage (x)		Funds from operations to total debt (%)		Total debt to total capital (%)	
	A	BBB	A	BBB	A	BBB
Transmission and distribution cos.	3.25	2.0	15	10	55	65
Generators	6.75	4.25	42	27	35	45
Vertically integrated cos.	4.25	2.75	27	18	45	56

Note: Financial ratio medians are the average of ratios derived from Standard & Poor's financial projections for companies rated both publicly and confidentially.

Standard & Poor's does not measure "profit" per se, but rather looks at financial health as measured by excess margins on a cash flow basis and their ability to provide coverage of revenue bonds and off balance sheet obligations, as measured through fixed-charge coverage.

The more important measures of profitability are:

- Return on average equity,
- Pretax return on average capital, and
- Operating margins.

Earnings are also viewed in relation to a company's burden of fixed charges. Otherwise-strong performance can be affected detrimentally by aggressive debt financing, and the opposite also is true. The primary fixed-charge coverage ratio is pretax interest coverage (pretax income plus interest divided by interest). If preferred stock is outstanding, coverage ratios are calculated both including and excluding preferred dividends, to reflect the company's discretion over paying the dividend when under stress.

To reflect more accurately the ongoing earnings power of the firm, reported profit figures are adjusted. These adjustments remove the effect of foreign-exchange gains and losses, writedowns, and other nonrecurring or extraordinary gains and losses. Unremitted equity earnings of a subsidiary are also excluded. Adjustments are also made for the impact of hyperinflation on nonmonetary assets—gains are subtracted while losses are added back.

Shareholder pressures and accounting standards in certain countries, such as the U.S., can result in companies seeking to maximize profits on a quarter-to-quarter or short-term basis. In other regions, abetted by local tax regulation, it is normal practice to take provisions against earnings in good times to provide a cushion against downturns, resulting in a long run "smoothing" of reported earnings. For example, given local accounting standards, it is common to see a Swiss or German company vaguely report "other income" or "other expenses," which are largely provisions or provision reversals, as large items in a profit and loss account. In meetings with management, Standard & Poor's evaluates provisioning and depreciation practices to see to what extent a company employs noncash charges to reduce or bolster earnings.

There are numerous analytical adjustments to the interest accounts. Interest that has been capitalized is added back. An interest component is computed for debt-equivalents such as operating leases, fixed contractual obligations, and receivable sales. For U.S. utilities, allowance for funds used during construction is removed from income and interest expense.

Moreover, in many regions, notably Japan and Europe, local practice is to maintain a high level of debt while holding a large portfolio of cash and marketable securities. Many companies manage their finances on a net debt basis. When a company consistently demonstrates such excess liquidity, interest income may be offset against interest expense in looking at overall financial expenses. Each situation is evaluated on a case-by-case basis, subject to additional information regarding a company's liquidity position, normal working cash needs, nature of short-term borrowings, and funding philosophy.

Capital structure. The principal capital structure ratio analyzed is total debt to total debt plus equity. However, analyzing debt leverage goes beyond the balance sheet and covers quasi-debt items and elements of hidden financial leverage. Noncapitalized leases, debt guarantees, receivables financing, and purchased-power contracts are all considered debt equivalents and are reflected as debt in calculating capital structure ratios. Moreover, adjustments are made to reflect unfunded pension liabilities. In countries where local practice is to hold significant cash and marketable securities, Standard & Poor's will focus on net debt leverage, which nets out excess liquidity from borrowings.

Some firms use short-term debt as a permanent piece of their capital structure. Short-term debt also is considered part of permanent capital when it is used to bridge to permanent financing. Seasonal, self-liquidating debt is excluded from the permanent debt amount, but this situation is rare as in the case of natural gas utilities. Given the long life of almost all utility assets, short-term debt exposes these companies to interest-rate volatility, remarketing risk, bank line backup risk, and regulatory exposure that cannot be readily offset. The lower cost of shorter-term obligations (assuming a positively sloped yield curve) is a positive factor that partially mitigates the risk of interest-rate variability.

Also important is the term structure of a power company's debt. Amortizing debt is less risky than bullet maturities, and may be more appropriate for certain companies with limited asset lives. Generators, in particular, may have a tendency to rapidly depreciate assets, so they face greater risk of mismatching assets and liabilities when they fund their operations with long-term bullet maturity debt.

What is considered "debt" and "equity" for the purpose of ratio calculation is not always simple. In the case of preferred stock and other hybrid securities, the analysis is based on their features, not the accounting or nomenclature. Pension and retiree health obligations are similar to debt in many respects.

Knowing the true values to assign to a company's assets is important to capital structure analysis. Consequently, assets are examined to identify undervalued or overvalued items. Asset valuation practices differ from country to country, resulting in differences in both a company's reported equity base and its depreciation expense. There is no easy way to compare companies that revalue their assets with those that do not. Rather, Standard & Poor's recognizes that, for all companies, reported asset values often differ from market values. In discussions with management, Standard & Poor's analysts endeavor to gain an appreciation of the realizable values of a company's assets under reasonably conservative assumptions.

Cash flow. Cash flow analysis is critical in all credit rating decisions. Interest or principal obligations cannot be serviced out of earnings, which is just an accounting concept; payment has to be made with cash. Many transactions and accounting entries can affect earnings but not cash, and vice versa. Analysis of cash flow patterns can reveal a level of debt-servicing capability that is either stronger or weaker than might be apparent from earnings. Since both common and preferred dividend payments are important to maintain capital market access, Standard & Poor's looks at cash flow measures both before and after dividends are paid. Working capital analysis is typically not a major factor in utility credit analysis given the relatively minor impact on cash flow from period to period. However, such analysis can be critical for certain utilities operating in developing economies where late payment or nonpayment of bills can drive up receivables. Cash flow is also measured against fixed contractual obligations, capital expenditures, debt maturities, and shareholder dividends. Some of the specific ratios considered are:

- Funds from operations/average total debt (adjusted for excess liquidity and off-balance-sheet liabilities).
- (Funds from operations + interest)/interest.
- (Funds from operations - dividends)/capital expenditures.
- Capital expenditures/average total capital (debt + equity).

Because of the capital-intensive nature of the power industry and the lengthy periods sometimes necessary to construct facilities—particularly generating plants—utilities require extensive and flexible capital planning systems. The ability to limit the use of debt also depends on a utility's skill in managing construction projects and completing any new facilities on schedule and within cost estimates. Accordingly, Standard & Poor's reviews capital priorities for the next five years and beyond under varying assumptions.

Financial flexibility. Financial flexibility incorporates a utility's financing needs, plans, and alternatives, as well as its flexibility to accomplish its financing program under stress without damaging creditworthiness. External funding capability complements internal cash flow. Especially since utilities are so capital intensive, a firm's ability to tap capital markets on an ongoing basis must be considered. Relationships with banks and the availability of bank lines are also reviewed. A utility's debt capacity reflects all the earlier elements: profitability, capital structure, and cash flow. Market access at reasonable rates is restricted if a reasonable capital structure is not maintained and the company's operational and financial prospects dim.

Standard & Poor's also reviews indenture and bank loan covenants. Certain restrictions such as a limit on the ability to issue additional debt provide some comfort as do provisions such as debt service coverage tests that restrict the distribution of dividends unless there is adequate cash flow to provide for projected debt service (interest and principal). Other covenants viewed favorably are those that may reduce credit default risk, such as a requirement for a funded debt-service reserve. Alternatively, very tight covenants can raise default risk by limiting a power company's financial flexibility to raise cash in times of crisis.

For investor-owned utilities, Standard & Poor's assesses a company's capacity and willingness to issue common equity. This is affected by various factors, including stock price, dividend policy, and any regulatory restrictions regarding the composition of the capital structure. For government-owned utilities, analysis focuses on the government's willingness and ability to inject equity as needed or to forgo dividends. An additional measure of financial flexibility important in the analysis of U.S. municipal utilities is ratemaking flexibility and the ability to raise rates taking into account both political and competitive considerations.

TRANSMISSION AND DISTRIBUTION QUALITATIVE ANALYSIS

Reflecting relative low business risk owing to regulation, electric transmission and distribution companies can be generally expected to have business profile assessments of 1-4. However, few companies will receive the top score and some may fall below a 4.

When evaluating electric transmission and distribution companies, Standard & Poor's is most concerned about the *predictability and sustainability* of financial performance. In the near and intermediate terms, certain qualitative factors are expected to play a larger role in determining financial performance. For typical transmission and distribution companies, business profile factors of regulation, markets, and management are more important than operations and competitiveness, although the relative emphasis on the factors *may differ depending on the type of* system. Regardless of type, the regulatory environment will have great impact. Variations in policies and practices among local and national regulatory bodies will be key considerations. The markets and customer composition are also important factors, with weak economic performance and a large industrial sector being less favorable. Importantly, Standard & Poor's will evaluate management, *especially its leadership qualities* and its response to industry changes.

Regulation. Regulation defines the environment in which a utility operates, and has great influence on the company's financial performance. A utility with a marginal financial profile can, at the same time, be considered highly creditworthy due to a supportive regulatory environment. Conversely, unpredictable or antagonistic regulatory action can undermine the financial position of utilities that are very strong from an operational standpoint. To be viewed positively, regulatory treatment should be timely and allow consistent performance from period to period, given the importance of financial stability as a rating consideration. Also important is the transparency of regulatory polices and the length of time that the regulatory framework has been in place. Clearly, there is *concern that the mechanics of a* recently privatized system could be revisited for fine tuning. Because of this, Standard & Poor's also examines the relative ease with which regulation can be changed. That is, a transparent system that requires legislative action to modify is viewed more favorably than one subject more to the whim of ministerial discretion, as in some Asian countries. Also key to Standard & Poor's analysis is the *selection process and membership* of a regulatory body, the regulatory framework, and regulatory policies and practices.

Standard & Poor's evaluation of regulation also encompasses the administrative, judicial, and legislative processes involved in local or national regulation. These can affect rate-setting activities and other aspects of the business, such as competitive entry, *environmental and safety rules*, facility siting, and securities sales. In addition, the terms of a utility's license or franchise often impose obligations to serve any customer and provide a reasonable standard of service, and a variety of other stipulations. Standard & Poor's ratings factor in the impact of such constraints and obligations on a utility's operations and financial performance.

Transmission and distribution *companies are expected to remain* tightly regulated monopolies, with rates set on a cost-plus basis in many circumstances. Under a cost-plus regime, rates are set to recover costs and, for investor-owned utilities, a return on shareholder investment. Under cost-based rates, Standard & Poor's analysis focuses on the predictability of costs and revenues. While a utility may be largely protected from business risk under cost-based rates, the responsiveness of the rate-setting process to changes in a utility's cost structure or to discrepancies between allowed and actual *revenues influences the business* pressures on the company.

One drawback to cost-based ratemaking is the lack of strong incentive for utilities to control costs. Since rates and earnings are closely linked to the amount of invested capital and the cost of capital, utilities may be rewarded more for justifying costs than for containing them. Consequently, Standard & Poor's believes that performance-based ratemaking will *become an increasingly popular* form of ratemaking, particularly for the distribution business. Because financial results can vary depending on a company's ability to meet performance challenges, performance-based systems are inherently somewhat more risky than cost-based systems. Flexible plans incorporating performance-based rewards or penalties could include market-based rates, price caps, *revenue caps, index-based prices* or other yardstick measures, and rates premised on the value of customer service. As with other forms of regulation, the key for credit quality is the extent to which a prudently managed utility can manage the risks contained in a performance-based system.

Markets. Many distribution companies are common carriers. That is, they carry electricity being purchased by customers from *independent suppliers, either* generating companies or marketers. Other distributors *participate in the energy marketing* (supply) business by buying, brokering, or generating electricity through an affiliate, and selling the power to a customer. Risks in the marketing business are discussed fully in Standard & Poor's criteria on energy marketers (*see March 12, 1997 CreditWeek*), and include the significant challenge of matching fuel and power supply with demand. Whether or not a utility is involved in the sale or brokering of electricity or merely distributes the commodity, prospects for the stable growth of revenues and cash flow are ultimately related to the strength of the local economy. Customer growth is important for distributors. And, even for utilities involved only in distribution and not in energy marketing, the outlook for electricity consumption is important because the typical distributor recovers some portion of its distribution costs through a volumetric, per kwh, charge in addition to any fixed monthly or quarterly customer charge that may be in place. Accordingly, assessing a distributor's markets begins with the economic and demographic evaluation of the area in which distribution services are provided. Strength of long-term demand is examined from a macroeconomic perspective, which enables Standard & Poor's to measure trends in investment, income, and employment as indicators of economic change within the service area. The sustainability of increasing demand is also analyzed. Many emerging economies go through periods of very rapid growth followed by severe contractions. This volatility can contribute to significant and unhealthy swings in a utility's revenues.

Standard & Poor's also tries to discern any secular consumption trends and, more importantly, the reasons behind them. Specific items addressed include the size and growth rate of the market, strength of the franchise, historical and projected growth, income levels and trends in population, employment, and per capita income. Other relevant factors include proximity to attractive markets, the quality of public infrastructure, and, particularly in developing countries, the affordability of electricity and customers' ability and willingness to pay their bills.

A distributor with a healthy economy and customer base, as illustrated by diverse employment opportunities, average or above-average wealth and income statistics, and low unemployment, is likely to exhibit greater revenue stability.

For electric distribution utilities, the total number of customers, revenues, and margins are closely scrutinized to assess the depth and diversity of the utility's customer mix. For example, heavy industrial concentration is viewed cautiously since the utility may have significant exposure to cyclical volatility. On the other hand, a large residential component produces a stable and more predictable revenue stream. The utility's largest customers are identified to determine their stability and relevance to the bottom line since loss of one large customer could have an adverse effect on the utility's financial position. Credit concerns arise where any one customer plays a dominant role in the overall economic base of the service area. Moreover, large customers may turn to self generation and leave the distribution system altogether, potentially leading to reduced financial protection for the utility.

Similarly, for electric transmission companies, the total number of customers—largely distributors—is evaluated to assess the depth and diversity of the transmission company's customer mix. The transmission company's largest distribution customers are identified to determine their stability and contribution to revenues. Also important to a transmission company is the strength and diversity of the end-use markets of its distribution customers. Accordingly, these end-use markets are evaluated from a macroeconomic perspective in an analysis identical to that described above for a distribution utility.

Another key consideration for a transmission company is the location of its transmission facilities. A transmission company that is strategically located and connects surplus low-cost generation to growth markets is viewed favorably. On the other hand, a transmission company that connects relatively high-cost generation to a mature or declining area is more at risk. Usage and electric growth levels in the end-use markets will be compared with transmission capacity utilization. Underutilized transmission lines that serve growth markets have positive implications while fully utilized lines that serve mature markets have less favorable implications.

Operations. Transmission and distribution operations are typically low risk relative to generation operations. To evaluate the operations for a transmission or distribution company, Standard & Poor's focuses on the nature of operations from the perspective of cost, reliability, and quality of service. With gradually increasing competition in all segments of the electric power business, utility managers are under increasing pressure to optimize their use of resources as compared to the performance of other utilities and administrative benchmarks. If utilities are not cost effective in meeting service standards, stronger regulatory or competitive pressures are likely. Consequently, emphasis is placed on those areas that require management attention in terms of time or money and which, if unresolved, may lead to political, regulatory, or competitive problems.

In addition, the status of utility plant investment is reviewed, with regard to reliability and utilization, as well as for compliance with existing and contemplated environmental and other regulatory standards. The record of outages, system losses, and capacity utilization are examined. Important considerations include the projected capital improvements necessary to provide high quality and reliable service. Additionally, unique operating challenges could be present that impact costs to a degree where credit quality is impacted. Examples of operating challenges include harsh climates, severe storms, and difficult terrain. The general condition of the assets and how well such assets are maintained is also an important evaluation consideration.

Utilities in emerging countries face additional operating challenges, such as the fundamentals of metering and billing. Certain utilities may struggle with accurate and timely metering and billing because they do not have the appropriate technology, computer infrastructure, or control systems in place. Moreover, getting the bills correct and out in a timely fashion is only part of the issue. Collections can be a nagging problem where political or economic realities prevent service cutoff for nonpayment. In addition, outright theft of electricity service can be a big problem.

Operational characteristics that will support an above-average evaluation for transmission and distribution companies are assets that are in good physical condition and are being well maintained. Additionally, capital expenditures for necessary system improvements must be at manageable levels, yet sufficient to provide for constant renewal and refurbishment of the system. Operating performance, reliability statistics, and efficiency measures are expected to meet industry and regional averages. Having interconnections that provide access to low-cost and diverse power supply sources is viewed favorably, as is limited environmental exposure.

Competitiveness. Competitive pressures in the transmission and distribution businesses are generally quite limited by virtue of franchise monopolies. While introducing competition into the generation business and creating national or international power exchange systems is increasingly popular worldwide, there is near unanimous agreement that transmission and distribution systems should largely remain monopolies. This limited competition is a major factor in the strong business profile assessment for a typical transmission or distribution utility. Franchise monopolies are significant barriers to entry by competitors. Where there are nonexclusive franchises, other barriers to competitors exist such as the siting difficulties caused by public concerns about duplicate utility poles and wires and environmental issues.

Still, transmission and distribution utilities do face competitive pressures in the form of substitute energy sources and customer self-generation and bypass. Electricity competes with other fuels such as natural gas for certain segments of the market like space heating, water heating, and cooking. Thus, high electricity prices, which may be caused by inefficient transmission or distribution service, are cause for concern if customers have alternate energy sources. Self-generation has for many years been a significant concern for larger commercial and industrial customers who have been able to take advantage of certain cogeneration technologies to significantly reduce their reliance on, and, in some cases, disconnect from transmission and distribution systems. In the future, technology could pose a greater threat for transmission and distribution companies. Bypass risk is likely to grow as distributed generation, microgeneration, and self-generation gradually become more economically attractive for smaller and smaller customers. These technological evolutions are likely to be gradual, so the currently configured transmission and distribution networks should continue to play a viable role for the foreseeable future.

Management. Owing to the safety net provided by regulation, evaluation of management is less critical for tightly regulated transmission and distribution companies than for generators or energy marketers operating in a very competitive environment. Still, assessing management remains significant since management's abilities and decisions affect all areas of a company's operations. Moreover, while regulators can heavily influence results, it is ultimately the quality of management that drives the success of a company. Important considerations include strengths and weakness of key members of management, depth and stability of top management, and recent and prospective management changes. Management strategies are also a material determinant in differentiating utilities and in establishing where companies are on the business profile spectrum. Standard & Poor's will assess financial policies, corporate goals, strategies, tactics, plans for both regulated and diversified businesses as well as analyze how effectively they are implemented.

The assessment of management is accomplished through meetings, conversations, and reviews of company plans. It is based on such factors as tenure, industry experience, a grasp of industry issues, and knowledge of customers and their needs. Management's ability and willingness to develop workable strategies to address its system's needs, to execute reasonable and effective long-term plans, and to be proactive in leading its company into the future are assessed. Management quality is also indicated by thoughtful balancing of public and private priorities, a record of credibility, and effective communication with the public, regulatory bodies, and the financial community.

Key financial policy considerations include management's ability to achieve cost-effective operations and, of utmost importance, management's relative commitment to credit quality. This can be assessed by evaluating accounting and financing practices, capitalization and common dividend objectives, and the company's philosophy regarding growth and risk taking.

GENERATION QUALITATIVE ANALYSIS

Generation is the riskiest segment of the electric utility industry due to complex operating risks and the increasingly competitive nature of the business. Risk may be further heightened by absence of the regulatory umbrella. Because of the higher risks, generators can generally be expected to have business profile assessments in the 7-10 range.

Generation is a commodity business. Electrons are physically indistinguishable from each other and therefore compete primarily on price. However, electricity has some characteristics that make it less like other commodities. Centrally sited electricity cannot be stored. Electricity must be used instantaneously as it is produced, and its deliverability can be hampered by transmission constraints. Thus, reliability, deliverability, and some value-added services may distinguish one generating company from another, and perhaps elicit a premium in the marketplace. Value-added services, such as customization and load following, can tailor the shape and firmness (or lack of firmness, for example, interruptible service) of electricity delivered to the customer.

Generation also faces unique operating risks. Because electricity cannot be stored, generating plants cannot afford to have unplanned outages since they are only paid when they run. Furthermore, contractual commitments could force a downed generator into the market to seek replacement power, which could be costly or unavailable if the outage occurs during a peak usage period. Thus, while low production costs will factor heavily into the business profile and success of a generation company, other criteria will be considered when assessing creditworthiness.

Regulation. Some generators may remain highly regulated and achieve superior business profiles than their deregulated brethren due to a more stable revenue stream. For example, some centralized supply system derive credit strength and stability from their highly cohesive nature, stemming in part from direct or indirect cross ownership between generators and distributors, with government entities as ultimate owners. However, most global generators operate in deregulated environments where rates are determined by the market. Even so, regulatory considerations are still pertinent, and vary among global electric utility systems. Regulation typically establishes the basic framework of the electricity market. The market may be primarily a wholesale rather than retail market. The system may mandate that all players bid into a pool or exchange, whereby generators are economically dispatched and the last unit to run sets the market clearing price for all players. A power pool may have rules regarding price bids, dispatch, financial standing of market players, or other factors. Generators may have an obligation to build, or may be limited in building or investing. Furthermore, political stability, legal environment, and contract law influence the generator's operating environment and will be examined under this heading. Clearly, the more commodity-like the environment, the less influential regulation is in the traditional sense. Still, regulation is likely to constrain upside profit potential, while providing little protection on the downside. The lack of economic regulatory protection is considered a negative in terms of credit quality.

Standard & Poor's will seek to determine if the regulatory environment is supportive of credit quality, and if it creates a level playing field. Standard & Poor's will also note the length of time that the regulatory framework has been in place given the potential for a relatively new system to be modified. The U.K. is notorious for having touted its competitive power pool, only to have the regulator step in subsequently and tamper with the pool's market clearing price.

In the U.S., the Federal Energy Regulatory Commission (FERC) has established regulations for nondiscriminatory interstate transmission pricing. Therefore, a transaction between an economic generation company and an end user will not be undermined by inflated wheeling fees. Also in the U.S., market power issues are still being sorted out. FERC may prohibit mergers where bulking up on generation results in a utility being able to exert market power over its competitors. As a result, regulators may limit size and restrict certain contractual arrangements. Regulators may also set prudence requirements (financial creditworthiness) for entrants to the market. Questions asked include: How will prices be established? Will there be a power pool or bilateral contracts only? Bilateral contracts are where buyers and sellers negotiate the terms, including cost, of the transaction. Often times a pool transaction can be hedged to financially simulate a bilateral contract through "contracts for differences." The type of regulatory/legal environment can impact credit quality. For example, in some international systems, short-term marginal cost is determined by a pool, but the tariff also includes a charge to cover the long-run marginal cost of the next capital addition. This pricing system offers some greater assurance to the recovery of fixed costs and therefore lowers risk to the generator.

Markets. Markets for generators are vastly different than for those utilities with defined, franchised service territories. A generator's market expands as far as it can transport its electrons within physical (transmission) and economic (transportation fees) constraints. It typically has no obligation to serve and may be free to hand pick its customers and negotiate its own contracts. While it is anticipated that in the U.S. all customers will be able to choose their supplier (retail wheeling), some countries permit retail access to only the very largest industrial entities. Markets in these countries are primarily wholesale. It is anticipated in the U.S. that residential and small customers will initially tend to stick with their local utility distribution company for supply. However, in pilot programs to date, many customers have exercised their option to choose and left their traditional supplier.

Thus, Standard & Poor's must first determine if the market consists of intermediary or end users, and what its geographical boundaries are. If the generator sells directly to end users, what is the customer mix in terms of residential, commercial, and industrial segments? A diverse customer base within a stable, growing economy would be positive from a credit risk perspective. An economy that is driven by only a handful of products or industries would introduce concentration risk. As electricity markets become more liquid, prices will become more transparent, and energy marketers and financial derivatives will begin to develop. It remains to be seen if marketers can aggregate small customer loads effectively to make them economically desirable.

Further market evaluation would encompass a macroeconomic assessment of electricity supply and demand. In terms of demand, what are the economic prospects, inflationary pressures, and electricity consumption patterns within the country or region where the generating company operates? In developing countries, growth prospects would be higher than in a mature economy such as the U.S. However, strong growth could be subject to extreme volatility due to recessionary or inflationary pressures. If one or a few industries dominate the region, growth prospects could be tied to the fate of that industry.

In terms of supply, who are the other players in the market, and what are the barriers to entry? How much capacity is there relative to demand? Surplus capacity could reduce sales and/or put pressure on margins. A deficit capacity situation would inflate margins over the short term, but encourage other entrants to the market. This would not necessarily be bad, depending on the incremental cost of supply (lower would be a threat to existing generators, higher would enhance the generating company's competitive position) and if the incremental load maintained resource balance, or created a surplus situation. In addition, if transmission constraints are relieved, either through construction or technology, the supply/demand balance will change. Generators may have access to a broader market, but other suppliers will have access to their customers as well. Also, it is necessary to examine the availability and reliability of power supply.

Operations. An analysis of operations overlaps somewhat with examination of markets and competitiveness. The market within which a generating company is a player (local, regional, national, or international) has implications for how it operates. Transmission interconnections and constraints, as well as the location of a plant relative to customers, provides operating limitations and opportunities. Having a strategic location might necessitate that the plant be run constantly to provide system voltage support. And the efficiency of a generator's operations is directly tied to its competitive position.

Managing production inputs effectively is crucial to competitiveness. Suppliers of fuel, labor, and supplies are sources of economic risk to a generator's ability to produce low-cost power. The generator can be at risk if supplies are disrupted or prices are raised. Standard & Poor's will examine the extent to which a generator diversifies risk as opposed to relying on a few suppliers. What has been the historic growth of operating and maintenance expenditures, and how will they be controlled (or reduced) prospectively? Efficient use of technology will enable a generation company to manage its costs more efficiently.

Fuel typically represents about half the cost per kwh. Generators will need to become sophisticated in physical and financial hedging of fuel commodity risk. To the extent that a generation company has contracted to sell its output at a fixed price, it will be necessary to match the length of fuel contracts and hedges to insure that margins are locked in. Some contracts permit a pass through of fuel price changes, which might mitigate the necessity of hedging.

Contracts to sell a portion of production output at negotiated prices can protect generators from price and volume risk. Electricity markets are quite volatile, with prices fluctuating as much as 300% daily in U.S. markets. Contracts for differences are a common way to have price settlement around an erratic market clearing price. The mechanics very simplistically are as follows: A buyer and seller agree on a price for power, for example, 4 cents per kwh. If the market clears at 5 cents per kwh, the seller sells into the pool and receives 5 cents. But the buyer must buy from the pool for 5 cents, which is 1 cent higher than his arrangement. To reconcile their 4 cent agreement, the seller pays the buyer 1 cent. Clearly, strategies will vary depending on how contracts are structured, and how much of production is sold under contract versus on the spot market. These strategies are indicative of management's risk appetite.

In addition to these considerations, Standard & Poor's will examine key statistical efficiency measures, such as capacity factor, availability factor, and heat rate of individual plants as compared to industry peers. Clearly, it is preferable to achieve parameters which exceed industry standards. Capacity factor measures the degree to which a plant is actually run over a certain period of time, while availability indicates what percent of the time it would have been available to operate. Heat rates measure a power plant's fuel efficiency. A low heat rate would indicate less fuel input per unit of output. The average age of the facilities in the portfolio is also important; maintenance expense tends to increase as plants age.

The technologies utilized by a generating company also impact Standard & Poor's assessment of risk. Clearly a new technology is riskier than proven design. Moreover, nuclear facilities present greater-than-average risk in light of complex technology, additional operating challenges and concerns, and decommissioning costs. Also examined is asset concentration risk, which is present where any one unit represents a disproportionate share of capital or output in the portfolio. Construction risk will be considered in terms of the level of capital expenditures, ability to complete projects on time and on budget, and successful start up. Turnkey projects could transfer these construction risks from the generator to the engineering firm. Lastly, environmental risks will be evaluated. Imposition of a carbon tax could have significant financial consequences for coal-fired generation.

Diversity of the generation portfolio reduces the risk of dependence on any one unit, or any one fuel. Different fuel sources and the operating characteristics of the facilities (for example, base load versus peaking) further diversify the portfolio, and dual fuel capabilities at individual plants can enhance flexibility. Clearly, a single unit generator is inherently riskier than a portfolio of assets. The evolution of the merchant power plant introduces a certain speculative element to the generation sector. Unlike their independent power producer predecessors, merchant plants are generally constructed without benefit of contractual commitments for the sale of their output. Thus, success will depend on their ability to produce power consistently below the market's forward price curve for electricity. Since a merchant plant has less margin for error, it must have superior technological, marketing, finance, management, and operating skills and be able to manage the risk of uncertain pricing and markets.

For generators selling into spot or short-term contractual markets, reliability will be important. Generators who cannot deliver consistently on their commitments will loose credibility, and likely customers, in the marketplace. This risk increases to the extent that the generating company is involved in marketing transactions beyond the sale of its own generation. Standard & Poor's believes that the more successful and higher-rated energy marketers will have leading national or regional market positions and have substantial physical and financial liquidity. Size is important because there are informational economies of scale in marketing, and smaller trading firms can be whipsawed. Since Standard & Poor's has a bias toward hard assets, generators have an advantage over energy traders with no owned assets. Standard & Poor's will evaluate the credit impact of those activities on the consolidated credit profile of the business.

Competitiveness. The first step of an analysis of competitiveness would be to compare the generation company's cost of production to those of other market players. Unless there are overriding circumstances (for example, a must-run facility or an environmentally benign power source) a low cost structure is crucial to a generator's success in a competitive environment. As important as the total cost is the variable cost of production, particularly in markets with overcapacity. Since generators resemble other commodity industries, with their high capital costs, long-lived assets, and low labor content, they may pursue predatory price strategies in an attempt to gain market share. Thus, a generator's ability to beat its competitors' costs at the margin gives it a significant edge. In addition to analyzing marginal cost, Standard & Poor's compares a generator's average costs against contract prices, spot prices, pool prices, other producers, and new entrant costs. Comparing costs, however, is not as straightforward as it might appear. The output of a plant greatly affects the cost of a unit of output, as fixed costs are spread over kwhs generated. This can make cost comparisons between base, intermediate, and peaking facilities difficult. The "peakier" the load curve, the higher the price of electricity at peak hours. As a result, a competitive strategy for a load following generator might be to primarily operate during those more lucrative hours. First Hydro generating plant in the U.K., a pumped storage hydro facility, has found this strategy to be quite lucrative. It pumps water into a reservoir during off peak hours, and uses it to generate electricity during high-price peak hours.

Price comparisons will also become difficult as generating companies begin to customize packages for buyers. A package may include a combination of firm and interruptible power, with the interruptible portion being sold many times over. This type of customizing, or load following, is a value-added service which may command a price premium. Being competitive also involves strategies in how to structure contracts, what percent of output to contract out versus sell into a spot market or pool, and what limits to put on percent of output sold to any one customer. Staying competitive will involve both physical and financial hedging strategies, particularly for fuel.

Competition will come from many sources. Suppliers of new and cheaper power generation may represent the greater threat to existing generating companies. New supplies may come from greenfield projects, renovation of existing facilities, or the opening of transmission pathways. Increasing power supply will put downward pressure on rates. Substitute products, particularly natural gas, also pose a competitive threat. This will become more complex as electric and gas markets "converge." Gas may become a greater threat to electricity usage over time due to the interchangeability of energy sources, as well as technological developments such as the gas-fired air conditioner. And further down the road, remote site applications such as the fuel cell may replace generation-produced power. Threat of these alternatives will depend on pricing, switching costs, availability, political and regulatory barriers, and public policy initiatives.

Management. While management decisions affect many areas of generating company operations, an overall assessment of management is incorporated into the credit evaluation. Because of the higher business risk in generation compared to transmission or distribution, management is a critical factor in the credit evaluation of generators and Standard & Poor's holds a generator's management to a higher standard. In evaluating management, Standard & Poor's attempts to define management's risk appetite, and its overall goals and objectives. What strategies have been utilized to implement these goals, and how effective have they been? This dialogue may also provide insight into the degree of management's credibility to articulate, implement, and achieve its goals. Management's financial and diversification policies, including the construction of additional plants and/or diversification into international markets, will be examined in assessing its risk appetite. The degree to which generators engage in energy marketing activities beyond the sale of their own output will be factored into the credit evaluation. Critically important to these activities are the generator's risk management guidelines that provide for the establishment and strict adherence to risk policies, objectives, and limits.

Exhibit JBM-4

Rating Definitions

A Standard & Poor's issue credit rating is a current opinion of the creditworthiness of an obligor with respect to a specific financial obligation, a specific class of financial obligations, or a specific financial program (including ratings on medium term note programs and commercial paper programs.) It takes into consideration the creditworthiness of guarantors, insurers, or other forms of credit enhancement on the obligation and takes into account the currency in which the obligation is denominated. The issue credit rating is not a recommendation to purchase, sell, or hold a financial obligation, inasmuch as it does not comment as to market price or suitability for a particular investor.

Issue credit ratings are based on current information furnished by the obligors or obtained by Standard & Poor's from other sources it considers reliable. Standard & Poor's does not perform an audit in connection with any credit rating and may, on occasion, rely on unaudited financial information. Credit ratings may be changed, suspended, or withdrawn as a result of changes in, or unavailability of, such information, or based on other circumstances.

Issue credit ratings can be either long-term or short-term. Short-term ratings are generally assigned to those obligations considered short-term in the relevant market. In the U.S., for example, that means obligations with an original maturity of no more than 365 days—including commercial paper. Short-term ratings are also used to indicate the creditworthiness of an obligor with respect to put features on long-term obligations. The result is a dual rating, in which the short-term rating addresses the put feature, in addition to the usual long-term rating. Medium-term notes are assigned long-term ratings.

Long-term issue credit ratings

Issue credit ratings are based, in varying degrees, on the following considerations:

1. Likelihood of payment—capacity and willingness of the obligor to meet its financial commitment on an obligation in accordance with the terms of the obligation;
2. Nature of and provisions of the obligation;
3. Protection afforded by, and relative position of, the obligation in the event of bankruptcy, reorganization, or other arrangement under the laws of bankruptcy and other laws affecting creditors' rights. The article on page 58 elaborates on the criteria for differentiating obligations of different priorities.

The issue rating definitions are expressed in terms of default risk. As such, they pertain to senior obligations of an entity. Junior obligations are typically rated lower than senior obligations, to reflect the lower priority in bankruptcy, as noted above. (Such differentiation applies when an entity has both senior and subordinated obligations, secured and unsecured obligations, or operating company and holding company obligations.) Accordingly, in the case of junior debt, the rating may not conform exactly with the category definition.

'AAA' An obligation rated 'AAA' has the highest rating assigned by Standard & Poor's. The obligor's capacity to meet its financial commitment on the obligation is extremely strong.

'AA' An obligation rated 'AA' differs from the highest rated obligations only in small degree. The obligor's capacity to meet its financial commitment on the obligation is very strong.

'A' An obligation rated 'A' is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rated categories. However, the obligor's capacity to meet its financial commitment on the obligation is still strong.

'BBB' An obligation rated 'BBB' exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation.

Obligations rated 'BB', 'B', 'CCC', 'CC', and 'C' are regarded as having significant speculative characteristics. 'BB' indicates the least degree of speculation and 'C' the highest. While such obligations will likely have some quality and protective characteristics, these may be outweighed by large uncertainties or major exposures to adverse conditions.

'BB' An obligation rated 'BB' is less vulnerable to nonpayment than other speculative issues. However, it faces major ongoing uncertainties or exposure to adverse business, financial, or economic conditions which could lead to the obligor's inadequate capacity to meet its financial commitment on the obligation.

'B' An obligation rated 'B' is more vulnerable to nonpayment than obligations rated 'BB', but the obligor currently has the capacity to meet its financial commitment on the obligation. Adverse business, financial, or economic conditions will likely impair the obligor's capacity or willingness to meet its financial commitment on the obligation.

'CCC' An obligation rated 'CCC' is currently vulnerable to nonpayment, and is dependent upon favorable business, financial, and economic conditions for the obligor to meet its financial commitment on the obligation. In the event of adverse business, financial, or economic conditions, the obligor is not likely to have the capacity to meet its financial commitment on the obligation.

'CC' An obligation rated 'CC' is currently highly vulnerable to nonpayment.

'C' The 'C' rating may be used to cover a situation where a bankruptcy petition has been filed or similar action has been taken, but payments on this obligation are being continued.

'D' An obligation rated 'D' is in payment default. The 'D' rating category is used when payments on an obligation are not made on the date due even if the applicable grace period has not expired, unless Standard & Poor's believes that such payments will be made during such grace period. The 'D' rating also will be used upon the filing of a bankruptcy petition or the taking of a similar action if payments on an obligation are jeopardized.

Plus (+) or minus(-): The ratings from 'AA' to 'CCC' may be modified by the addition of a plus or minus sign to show relative standing within the major rating categories.

r This symbol is attached to the ratings of instruments with significant noncredit risks. It highlights risks to principal or volatility of expected returns which are *not* addressed in the credit rating. Examples include: obligations linked or indexed to equities, currencies, or commodities; obligations exposed to severe prepayment risk—such as interest-only or principal-only mortgage securities; and obligations with unusually risky interest terms, such as inverse floaters.

Short-term issue credit ratings

'A-1' A short-term obligation rated 'A-1' is rated in the highest category by Standard & Poor's. The obligor's capacity to meet its financial commitment on the obligation is strong. Within this category, certain obligations are designated with a plus sign (+). This indicates that the obligor's capacity to meet its financial commitment on these obligations is extremely strong.

'A-2' A short-term obligation rated 'A-2' is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rating categories. However, the obligor's capacity to meet its financial commitment on the obligation is satisfactory.

'A-3' A short-term obligation rated 'A-3' exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation.

'B' A short-term obligation rated 'B' is regarded as having significant speculative characteristics. The obligor currently has the capacity to meet its financial commitment on the obligation; however, it faces major ongoing uncertainties which could lead to the obligor's inadequate capacity to meet its financial commitment on the obligation.

'C' A short-term obligation rated 'C' is currently vulnerable to nonpayment and is dependent upon favorable business, financial, and economic conditions for the obligor to meet its financial commitment on the obligation.

'D' A short-term obligation rated 'D' is in payment default. The 'D' rating category is used when payments on an obligation are not made on the date due even if the applicable grace period has not expired, unless Standard & Poor's believes that such payments will be made during such grace period. The 'D' rating also will be used upon the filing of a bankruptcy petition or the taking of a similar action if payments on an obligation are jeopardized.

Investment and speculative grades

The term "investment grade" was originally used by various regulatory bodies to connote obligations eligible for investment by institutions such as banks, insurance companies, and savings and loan associations. Over time, this term gained widespread usage throughout the investment community. Issues rated in the four highest categories, 'AAA', 'AA', 'A', 'BBB', generally are recognized as being investment grade. Debt rated 'BB' or below generally is referred to as speculative grade. The term "junk bond" is merely a more irreverent expression for this category of more risky debt. Neither term indicates which securities Standard & Poor's deems worthy of investment, as an investor with a particular risk preference may appropriately invest in securities that are not investment grade.

Ratings continue as a factor in many regulations, both in the U.S. and abroad, notably in Japan. For example, the Securities and Exchange Commission (SEC) requires investment-grade status in order to register debt on Form-3, which, in turn, is one way to offer debt via a Rule 415 shelf registration. The Federal Reserve Board allows members of the Federal Reserve System to invest in securities rated in the four highest categories, just as the Federal Home Loan Bank System permits federally chartered savings and loan associations to invest in corporate debt with those ratings, and the Department of Labor allows pension funds to invest in commercial paper rated in one of the three highest categories. In similar fashion, California regulates investments of municipalities and county treasurers, Illinois limits collateral acceptable for public deposits, and Vermont restricts investments of insurers and banks. The New York and Philadelphia Stock Exchanges fix margin requirements for mortgage securities depending on their ratings, and the securities haircut for commercial paper, debt securities, and preferred stock that determines net capital requirements is also a function of the ratings assigned.

Issuer credit rating definitions

As explained on page 5 and on page 58, Standard & Poor's also assigns ratings to issuers, reflecting their capacity for meeting financial commitments. The rating symbols are identical to those used for rating issues, and the definitions closely correspond to the issue rating definitions.

Exhibit JBM-5

SUMMARY OF RATINGS OF PECO SECURITIES

	MOODY'S		STANDARD & POOR'S		FITCH		DUFF & PHELPS	
Mortgage Bonds	Baa1	(4/92)	BBB+	(4/92)	A-	(9/92)	BBB+	(4/92)
Unsecured Debt	Baa2	(4/92)	BBB	(4/92)	BBB+	(9/92)	BBB	(4/92)
Preferred Stock	baa2	(4/92)	BBB	(4/92)	BBB+	(9/92)	BBB-	(8/91)
Commercial Paper	P-2	(3/91)	A-2	(4/90)	-------------------		Duff 2	(4/92)

( ) = Date of last change

HISTORY OF MORTGAGE BOND RATINGS

MOODY'S	STANDARD & POOR'S	FITCH	DUFF & PHELPS
Aaa until 12/70	AAA until 11/68	A- until 7/81	A- until 9/78
Aa until 9/74	AA until 10/74	BBB+ until 9/82	BBB+ until 4/80
A until 6/81	A until 2/76	BBB until 9/92	BBB until 4/92
Baa2 until 1/83	A- until 4/80	A- until present	BBB+ until present
Baa3 until 3/91	BBB+ until 6/81		
Baa2 until 4/92	BBB until 9/82		
Baa1 until present	BBB- until 4/90		
	BBB until 4/92		
	BBB+ until present		

Exhibit JBM-6

Distribution of Electric Utility Credit Ratings*

RATING	# IN CATEGORY	% IN CATEGORY
AA+	3	2.5%
AA	4	3.3%
AA-	11	9.0%
A+	22	18.0%
A	17	13.9%
A-	16	13.1%
BBB+	18	14.8%
BBB	13	10.7%
BBB-	6	4.9%
BB+	5	4.1%
BB	2	1.6%
BB-	4	3.3%
B+	1	0.8%
TOTAL	122	100.0%

**STANDARD & POOR'S, AS OF 6/23/97*

Exhibit JBM-7

Impact of Intervenors' Proposals on Key Financial Indicators

Earnings Per Share ($/sh)

	1999	2000	2001	2002	2003	2004	2005
PECO	1.32	1.45	1.62	1.64	1.65	1.59	1.55
OTS	0.07	0.42	1.03	1.22	1.41	1.56	1.69
OCA	(0.17)	0.13	0.67	0.83	0.98	1.09	1.18
PAIEUG	(0.16)	0.14	0.67	0.81	0.95	1.07	1.15

Net Cash Flow (Mil$)

	1999	2000	2001	2002	2003	2004	2005
PECO	(183)	280	2	(172)	(124)	330	236
OTS	(558)	(29)	(216)	(361)	(276)	220	160
OCA	(667)	(137)	(331)	(479)	(400)	89	24
PAIEUG	(699)	(170)	(365)	(517)	(440)	51	(17)

Shares (Mil)

PECO	199	199	199	199	199	199	199
OTS	199	199	199	199	199	199	199
OCA	215	215	215	215	215	215	215
PAIEUG	215	215	215	215	215	215	215

Net Cash Flow Per Share ($/sh)

	1999	2000	2001	2002	2003	2004	2005
PECO	(0.92)	1.41	0.01	(0.86)	(0.62)	1.66	1.19
OTS	(2.80)	(0.15)	(1.09)	(1.81)	(1.39)	1.11	0.80
OCA	(3.10)	(0.64)	(1.54)	(2.23)	(1.86)	0.41	0.11
PAIEUG	(3.25)	(0.79)	(1.70)	(2.40)	(2.05)	0.24	(0.08)

ELECTRIC UTILITIES

Pretax Interest Coverage (x)

Business Position	AA	A	BBB	BB
1	3.50	2.75	1.75	1.25
2	3.65	3.00	2.00	1.40
3	3.80	3.25	2.25	1.55
4	4.00	3.50	2.50	1.75
5		3.80	2.80	2.00
6		4.15	3.15	2.25
7		4.50	3.50	2.50

Total Debt/Total Capital (%)

Business Position	AA	A	BBB	BB
1	47.0	52.0	59.0	65.0
2	45.5	50.5	57.5	63.5
3	44.0	49.0	56.0	62.0
4	42.0	47.0	54.0	60.0
5		45.0	52.0	58.0
6		43.0	50.0	56.0
7		41.0	48.0	54.0

Funds From Operations Interest Coverage (x)

Business Position	AA	A	BBB	BB
1	4.00	3.25	2.25	1.75
2	4.15	3.50	2.50	1.80
3	4.30	3.75	2.75	1.90
4	4.50	4.00	3.00	2.00
5		4.30	3.30	2.25
6		4.65	3.65	2.50
7		5.00	4.00	2.75

Funds From Operations to Total Debt (%)

Business Position	AA	A	BBB	BB
1	26.0	19.0	14.0	11.0
2	28.0	21.0	15.5	11.5
3	30.0	23.0	17.5	12.5
4	32.0	25.0	19.0	13.0
5		28.0	22.5	15.5
6		31.0	25.5	17.5
7		34.0	29.0	20.0

Net Cash Flow to Capital Spending (%)

Business Position	AA	A	BBB	BB
1	90.0	70.0	45.0	30.0
2	96.0	75.0	50.0	33.0
3	102.0	80.0	55.0	36.0
4	110.0	85.0	60.0	40.0
5		91.0	66.0	46.0
6		98.0	73.0	53.0
7		105.0	80.0	60.0

Business Positions: 1—Above average. 2—Somewhat above average. 3—High average. 4—Average. 5—Low average. 6—Somewhat below average. 7—Below average.

Exhibit JBM-8

R-00973953

PECO STATEMENT NO. 21-R

Phila. 10/14,15,16/97
E. Hilbert

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY
FOR APPROVAL OF ITS RESTRUCTURING PLAN
UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE

REBUTTAL TESTIMONY

OF

DAVID J. PRATZON

Regarding Retail Transmission Service; Energy Imbalance and Load Reconciliation Services; Reliability; Independent System Operator; Environmental Tracking; Allocation of Intertie Capacity; Marginal Energy Pricing; Electric Generation Supplier Tariff; and Market Power in Generation and Transmission

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF DAVID J. PRATZON

I. INTRODUCTION

Q. Please state your name and address.

A. David J. Pratzon, PECO Energy Company ("PECO Energy" or "PECO"), 2301 Market Street, Philadelphia, PA 19103.

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

A. I am currently an Interconnection Representative for PECO. I am responsible for developing and articulating PECO's strategy for wholesale (Pennsylvania-New Jersey-Maryland Interconnection ("PJM")) market restructuring and coordinating retail choice program implementation needs with wholesale market rules and requirements.

Q. What is your educational background?

A. I received a Bachelors of Science degree in Electrical Engineering from Brown University in 1972. In 1979, I received a Masters of Science degree in Systems Engineering from the University of Pennsylvania. I am a Registered Professional Engineer in Pennsylvania.

Q. Please describe your prior work experience.

A. From June 1972 through October 1973 I was employed as a field engineer by General Electric Company. From November 1973 through August 1990, I held several increasingly responsible positions on the staff of the PJM Interconnection Office. My areas of responsibility encompassed generation scheduling, including developing a computerized unit commitment system; evaluating system performance; monitoring, accounting and billing for pool interchange and bilateral transactions; and developing and filing inter-utility contracts. Beginning in August 1990 to the present I have been employed by PECO. In addition to my current position, I have held supervisory positions in Demand and Market Planning and Energy and Demand Forecasting.

Q. Have you previously testified?

A. Yes. On May 9, 1997, I testified about transmission access and pricing issues at the Federal Energy Regulatory Commission's ("FERC") Technical Conference on congestion pricing proposals in PJM.

Q. What is the purpose of your testimony?

A. I respond to transmission and PJM-related issues raised by intervenors in this proceeding, specifically Enron witnesses Lynn R. Coles, Paul D. Reising and Dr. Richard D. Tabors, the Environmentalists' witness Bruce Edward Biewald, MAPSA's witness Donald E. Johnstone, FUMO/CEPA's witness Richard H. Silkman, PAIEUG's witness Randall J. Falkenberg and the Department of the Navy's witness Nicholas Phillips, Jr. Among other matters, I will address: (1) PECO's current proposal regarding retail transmission service and ancillary services as part of its restructuring; (2) the distinction between "Wholesale Reconciliation Service" in addition to "Wholesale Energy Imbalance Service," and PECO's proposed treatment of these functions; (3) installed capacity reserve requirements, and the obligations of alternate suppliers in connection therewith; (4) PECO's June 9, 1997 proposal for an Independent System Operator ("ISO"); (5) an intervenor's proposal to require suppliers to "label" or track their energy; (6) the allocation of intertie capacity; (7) energy pricing in the Pennsylvania-New Jersey-Maryland ("PJM") region; (8) the Electric Supplier Generation Tariff proposed by one intervenor; and (9) market power in transmission and generation.

Q. Please briefly summarize your testimony.

A. My testimony can be summarized as follows:

- **Retail Transmission.** Consistent with comments it has received in this proceeding and its Pilot proceeding, Commission guidance, and FERC policy, PECO proposes that alternate suppliers or retail access participants obtain transmission service from PJM directly under the PJM pool-wide transmission tariff ("PJM Tariff").
- **Wholesale Reconciliation and Energy Imbalance Services.** Wholesale Reconciliation Service is necessary in addition to Wholesale Energy Imbalance Service because of the time frame in which each of these functions are required. PECO and alternate suppliers must cooperate so that the PJM Office of Interconnection ("PJM OI") can provide these balancing functions.
- **Reliability.** As a member of PJM, PECO must satisfy certain capacity requirements, including reserve requirements. To ensure that customers who do not participate in the retail access program do not subsidize those customers who do participate, alternate suppliers must provide their share of the PJM installed capacity requirement for load in PECO's service territory.
- **Independent System Operator.** PECO supports, and has proposed to FERC, a strong and effective ISO. However, inasmuch as an ISO is a public utility subject to FERC's exclusive jurisdiction, little can be accomplished in discussing the attributes of an ISO outside of a FERC proceeding. Thus, ISO issues are best reserved for the present ongoing PJM restructuring proceedings before FERC.
- **Environmental Tracking.** For a variety of reasons, this Commission may not be a proper, or the best, forum for considering Mr. Biewald's labeling proposal. Even if it were, the Commission lacks the type of evidentiary record that would allow reasoned consideration of Mr. Biewald's proposal. For instance, Mr. Biewald offers no proof that his proposal would

not unduly burden competition or deter entry by alternate suppliers. Nor does Mr. Biewald disclose the costs of implementing his proposal or say how such costs shall be paid for. In any event, it is PECO's view that environmental tracking as proposed by Mr. Biewald is best handled through the operation of market forces; PECO expects that environmental labeling will occur naturally as part of the marketing efforts of various energy suppliers. Finally, PECO disagrees with Mr. Biewald's conclusion that an ISO is the proper entity to carry-out any environmental tracking proposal.

- **Allocation of Intertie Capacity.** Allocation of intertie capacity is a FERC-jurisdictional matter, and PECO has proposed to FERC an improved tariff structure (compared to the tariff presently in effect) that satisfies the concerns raised by Dr. Tabors. PECO believes, and has proposed, that there should not be any special treatment for intertie capacity, as the PJM Tariff's curtailment provisions are adequate to maintain reliability during times of emergencies.
- **Marginal Energy Pricing.** The PJM market price should be calculated on the basis of incremental costs for the purpose of these restructuring proceedings, and the market price model relied on by PECO appropriately does so.
- **Proposed Electric Generation Supplier Tariff**. The Commission should not consider the Electric Generation Supplier Tariff proposed by Enron's witness Lynn R. Coles for several reasons. In brief, those reasons are that this proceeding is not the best vehicle for addressing that proposal, the proposal is premature, the tariff appears to address items that ought to be in an EDC tariff and the content of the tariff itself is problematic.
- **PECO's Lack of Market Power in Generation and Transmission**. The FERC has already determine that PECO lacks market power in generation and transmission in the context of its

approval of PECO's application for market-based rates power sales authority. The finding of no market power in transmission is based on the availability of transmission service over PECO's transmission facilities under an open access tariff on file with the FERC.

II. RETAIL TRANSMISSION SERVICE

A. Overview

Q. What is your understanding of what is meant by retail transmission service?

A. "Retail transmission service" means the unbundled transmission service used to deliver energy sold to retail choice end-use customers.

Q. What regulatory body has jurisdiction over retail transmission service?

A. As previously noted by PECO witness Mr. Alfred A. Miller (PECO St. No. 2), FERC has concluded that it has exclusive jurisdiction over retail transmission service, and that such service must be provided under its pro forma open-access transmission tariff.

Q. Has this Commission also addressed the jurisdictional boundaries of retail transmission service?

A. Yes. In its January 16, 1997 Order in Docket No. M-00960890, the Commission stated:

> Many commenters have noted that the filing of a separate FERC transmission tariff for pilot programs is unnecessary because the "open

access" tariffs filed at [FERC] by the individual utilities and the power pool -- [PJM] -- specifically cover pilot programs under FERC's Order No. 888. Other commenters have expressed concern that the procedures established in this guideline whereby the Commission reviews the pilot transmission tariff prior to its filing at FERC will result in delay of pilot program implementation.

The Commission agrees with the commenters that it need not review a FERC approved open access transmission tariff for application in the pilot. However, if the utility proposes to use a transmission tariff which is different from the FERC approved tariff, the Commission will adhere to the procedure as outline[d] in the guideline -- that the pilot and the tariff will be reviewed first by the Commission and will receive Commission approval conditioned on the Commission's acceptance of any changes that might be made to the tariff by FERC.

Order at 13-14 (citation omitted, emphasis added). In other words, the Commission recognizes that it need not review the rates, terms, and conditions of retail transmission service under the FERC-approved open access transmission tariff.

B. PECO Energy Proposal For Supplying Retail Transmission Service

Q. Please explain how PECO Energy proposed in its April 1, 1997 filing in this proceeding to provide transmission service to participants and alternate suppliers in the retail access program.

A. In its April 1 filing, PECO proposed to provide transmission service as follows:

> Customers will directly or indirectly obtain unbundled transmission service and retail ancillary services in accordance with the rates, terms, and conditions in the regional [PJM] pool-wide tariff. . . . Customers that have demand metering may obtain their transmission service directly under the PJM Tariff. *In the case of customers that lack demand metering,* during the 54-month period in which PECO's transmission and distribution charges will be capped, PECO proposes to procure network transmission service under the PJM Tariff as Designated Agent for such customers and to recover the associated costs through unbundled charges . . . .

Application of PECO Energy Company at 14. PECO proposed to develop charges for retail transmission service for each customer classification using the same rate design that it used for the transmission portion of its current bundled rates for that classification.

Q. Why did PECO Energy take this approach?

A. PECO believed that this approach would simplify and facilitate the acquisition of transmission service by eliminating the need for alternate suppliers to interface with the PJM OI. The PJM OI's ability to offer transmission and wholesale energy services directly to retail participants or their alternate suppliers in a timely manner also was unclear.

Q. Did this proposal receive support from the intervenors in this proceeding?

A. No. To the contrary, several intervenors objected to the PECO proposal. Enron's witness Mr. Coles was one example.

Q. What was the basis of his objection?

A. Mr. Coles objected to PECO's proposal to act as exclusive agent for customers that lack demand metering. According to Mr. Coles, PECO failed to justify "preclud[ing] a supplier from obtaining generation supply and arranging transmission service directly from [PJM], as opposed to dealing strictly through PECO." Mr. Coles argues that alternate suppliers should be able to act as agents for retail choice customers in procuring transmission service. (Coles at pp. 2-3).

Q. Did PECO Energy make a similar proposal in its Pilot filing in Docket No. P-00971170?

A. Yes. At that time, PECO still offered FERC-regulated transmission service under its own open-access transmission tariff, since a PJM Tariff had not yet been accepted by FERC. PECO proposed to obtain transmission service for all retail choice customers under PECO's tariff.

Q. How was that proposal received by intervenors in that proceeding?

A. Like Enron, the Philadelphia Area Industrial Energy Users Group ("PAIEUG") objected to PECO's proposal, arguing that alternate suppliers should be able to purchase transmission service directly from PJM. According to PAIEUG, "[c]onsistent with the PJM pool-wide, open-access tariff, alternate suppliers and pilot participants must be given the option of purchasing all PJM services on their own behalf." Comments of the Philadelphia Area Industrial Users Group at 18. Similarly, the Mid-Atlantic Power Supply Association stated that "the pilot is greatly devalued if companies, such as PECO, are allowed to control the scheduling aspect of meeting customer requirements, particularly given that competitive suppliers now have access to network transmission service on PJM and should be able to make their own scheduling arrangements." Comments of the Mid-Atlantic Power Supply Association at 17.

Q. Did the Commission address PECO's prior proposal for retail transmission service in its May 8, 1997 order ("May 8 Order") concerning PECO Energy's Pilot filing?

A. Yes. The Commission agreed with PAIEUG, and required that alternate suppliers have the ability to purchase transmission and other services directly from PJM. May 8 Order at 34.

Q. Has FERC provided guidance on retail transmission matters that PECO Energy must take into consideration?

A. Yes. FERC concluded in its Order No. 888, and in subsequent cases, that the rates, terms, and conditions of unbundled retail transmission service are subject to its exclusive jurisdiction. FERC also has held that utilities must provide unbundled retail transmission service under Order No. 888 transmission tariffs. It will permit deviations to the Order No. 888 tariff only in limited circumstances, and only if the affected state public utility commission requests.

Q. In light of these comments and guidance, does PECO Energy propose to modify its approach to providing retail transmission service?

A. Yes. After considering all of the comments received to date, the Commission's May 8 order, and FERC's requirements, PECO now proposes that all alternate suppliers or eligible retail choice customers in the retail access program obtain transmission service directly under the PJM Tariff. The suppliers of retail choice customers can obtain transmission service, or customers that can meet PJM requirements can obtain service themselves. This approach satisfies intervenors' arguments that they can, and desire to, obtain service directly from PJM. It also is consistent with the Commission's order requiring PECO to permit customers to take service without PECO's assistance. Finally, it is consistent with FERC policy requiring public utilities to provide retail transmission service under the Order No. 888 tariff.

Q. Is retail transmission service available under the terms of the PJM Tariff?

A. Yes, FERC has required as much. In Order No. 888, FERC revised its pro forma tariff to clarify that retail choice customers are eligible customers under its tariff. Further, under Section 1.11 of the PJM Tariff, "Eligible Customer" includes "any retail customer taking unbundled Transmission Service pursuant to a state retail access program."

Q. Enron's witness Reising argue against PECO's proposed rates for retail transmission service and ancillary services (see, e.g., Reising at pp. 20-33). Do you have any comment on these arguments?

A. Yes. First, I note that in light of PECO's proposal for all participants or suppliers to take transmission service directly from PJM, these arguments are moot; the FERC-approved rates under the PJM Tariff will apply. Second, FERC has concluded that all rates for unbundled retail transmission service, including ancillary services, are subject to its exclusive jurisdiction. The Commission thus would have no jurisdiction to order PECO to change proposed rates for retail transmission service or related ancillary services.

Q. Given the FERC-jurisdictional status of unbundled retail transmission service, why is PECO Energy submitting testimony related to that issue to the Commission?

A. PECO believes it is important that all customers, alternate suppliers and other parties interested in the customer choice program fully understand its entire "package" associated with retail choice.

C. PECO Energy Proposal For Supplying Ancillary Services

Q. How, in its initial filing in this proceeding, did PECO Energy propose to provide ancillary services?

A. Mr. Cucchi describes the ancillary services required by FERC at page 30 of his testimony (PECO St. No. 15). As he explained, PECO proposed to arrange for ancillary services under the PJM Tariff "as necessary to support the loads of the customers for whom it will act as Designated Agent."

Q. How would retail access participants or suppliers obtain ancillary services under PECO Energy's new proposal?

A. In light of the comments from parties in the Pilot proceeding and this proceeding, and the requirement that ancillary services be made available under a FERC-approved transmission tariff, alternate suppliers or eligible retail choice customers will obtain ancillary services under the PJM Tariff.

Q. How would this proposal fit with Mr. Reising's proposal (page 18) that ancillary services charges should be separately identified?

A. The charges for ancillary services are separately identified under the PJM Tariff. Thus, PECO's proposal is consistent with Mr. Reising's testimony in this regard.

Q. Mr. Reising refers to "retail ancillary services" in his testimony (page 18). Do you have any comment on the concept of retail ancillary services?

A. Yes. It is unclear exactly what is meant by "retail ancillary services." However, I note that all ancillary services associated with retail transmission service will be obtained directly from PJM under the PJM Tariff. Also, as I explained above, I understand that all transmission related ancillary services are subject to FERC's exclusive jurisdiction.

Q. Mr. Reising also argues at page 18 of his testimony that PECO Energy should unbundle its ancillary service charges. Do you have any comment?

A. Yes. PECO currently is quantifying the charges identified by FERC as ancillary services that should be backed out of bundled retail rates. This task has not yet been completed, and as such, is not ready for presentation as part of this proceeding. However, it is PECO's intention completely to remove those charges from bundled retail rates, thereby eliminating any prospect or concern that retail choice customers might be charged twice.

Q. What is the magnitude of the ancillary charges that Mr. Reising is referring to in his testimony?

A. It is my understanding that the total dollar figure is relatively small. Nonetheless PECO is committed to removing that sum from bundled retail rates in as accurate and thorough a manner as possible.

III. WHOLESALE ENERGY IMBALANCE AND RECONCILIATION SERVICES

A. <u>Definition of, and Need For, the Services</u>

Q. Please explain the "Load Balancing" services PECO Energy proposed in its initial filing in this proceeding.

A. "Load Balancing" consists of two separate functions: the need for one arises because energy suppliers do not always provide the amount of energy that they schedule for delivery, and the second one arises because the amount of energy a supplier schedules does not always match the amount of energy its customers actually consume. The first mismatch results in the need to offer Wholesale Energy Imbalance Service. The second mismatch results in the need to offer

Wholesale Reconciliation Service. These are distinct functions because of the time frame in which they are required.

Q. Please elaborate on the distinction between Wholesale Energy Imbalance Service and Wholesale Reconciliation Service.

A. Responsibility for Wholesale Energy Imbalance Service is calculated and charges assessed during the regular PJM interchange development and billing process, usually by the next working day. Responsibility for Wholesale Reconciliation Service, however, can only be determined after individual retail customers' meters are read and evaluated, which may be up to one month later. By that time, PJM has already billed PECO for all net energy delivered to the PECO service territory each hour. This total purchase by PECO includes any deviations between the energy provided by alternate suppliers and their customers' actual consumption. Wholesale Reconciliation Service compensates PECO for these costs.

Q. Did PECO Energy use the terms Wholesale Energy Imbalance Service and Wholesale Reconciliation Service in its initial filing?

A. No. However, it did propose both services at that time. <u>See</u> Cucchi Testimony, PECO St. No. 15 at 32-33. I am adopting this terminology because I believe it will assist the Commission to understand the two services that actually are required and will eliminate confusion on the part of all participants.

Q. Was PECO Energy's proposal for "Load Balancing" service supported by intervenors in their testimony in this proceeding?

A. Yes and no. Enron witness Coles objects to PECO's proposal. Mr. Coles complains that PECO's proposal is complex, that PECO has not provided sufficient cost-support for its proposal, that PECO will enjoy "windfall profits," that its proposed bandwidth is not justified and that PECO need not satisfy the same requirements as the alternate suppliers. (Coles at pp. 4-14).

With regard to the load profile aspect of these services, which I explain below, Mr. Phillips supports use of load profiles generally, but feels that PECO should provide further detail about its proposal. (Phillips at p. 22).

Q. Has PECO Energy's proposal for Wholesale Energy Imbalance Service changed since its initial filing?

A. Yes. At the time of its initial filing, the PJM OI had informed PECO that it would not be able to provide this service to alternate suppliers. PJM has since informed PECO that, in fact, it will be able to provide the service. In light of this change, and PECO's new proposal for retail program participants or their chosen suppliers to take transmission service directly from the PJM OI, PECO now proposes that alternate suppliers also obtain Wholesale Energy Imbalance Service pursuant to the PJM Tariff, or otherwise consistent with that tariff.

Q. Please describe how PECO Energy proposes to treat Wholesale Reconciliation Service.

A. PECO proposes to calculate the amount of Wholesale Reconciliation Service it provides for the customers of each alternate supplier, and to turn this information over to the PJM OI so that they can levy appropriate charges for this service.

Q. Why does PECO Energy believe that it must be the provider of the energy accounting portion of this service?

A. Under current PJM operating and accounting guidelines, PECO <u>must</u> provide this service because all customers in the retail access program will be in PECO's service territory. As a result, their energy use is represented in PECO's interchange energy totals calculated hourly by PJM. PECO must purchase an amount of energy equal to the net flows into its system each hour that result from a supplier's failure to supply the full amount of its customers' loads, or it must generate that power itself to prevent such flows. The amount of energy that PECO generates on purchases for other suppliers' customers is determined through an analysis of the meter readings of those customers. The PJM accounting for Wholesale Reconciliation Service will compensate PECO for the purchases it made or the power it produced to serve other suppliers' customers.

Q. What makes *Wholesale* Reconciliation Service "wholesale"?

A. The provision of such service part of the "energy imbalance" ancillary service under the PJM Tariff. As such, it is subject to FERC's exclusive jurisdiction.

Q. Are both Wholesale Reconciliation Service and Wholesale Energy Imbalance Service available under the PJM Tariff?

A. Yes. The PJM OI is the entity that should provide both of these functions as part of the energy imbalance ancillary service under the PJM tariff. I note that some technical issues must be resolved in order for PJM to be able to perform its part of the Wholesale Reconciliation Service function.

Q. Wholesale Reconciliation Service is tied to the amount of energy suppliers schedule for delivery to the PECO Energy distribution system. How will each supplier determine the amount of energy it will schedule each hour?

A. Mr. Cucchi explains PECO's proposal in his testimony included with PECO's initial filing (PECO St. No. 15 at 32-33). To reiterate, each supplier's delivery obligation for an hour, and thus the amount of energy it will schedule for that hour, will be the total delivery requirement of each of its customers for that hour, including an allowance for losses. The schedule of each supplier's hourly delivery requirement for each day is referred to as that supplier's Aggregated Daily Load Curve ("ADLC").

Q. How will the delivery requirement for each of a supplier's customers be determined?

A. For a customer with a monthly meter--that is, a meter other than an hourly meter, which I will describe below--PECO will use load research data to develop a load profile for a typical customer in that customer's class. This load profile will determine a supplier's obligation to provide energy for that customer for each hour of the applicable month. For a customer with an "hourly meter," which is defined in this context as a meter that can be read remotely and queried automatically at least once a day, thus permitting a reading of that customer's hourly usage each day, the alternate supplier will develop, with input from the customer, the customer's hourly load requirements, and will schedule to supply that amount of energy each hour. One day ahead, PECO will adjust the load profiles for customers with monthly meters to account for differences between the weather assumptions used in the load profile and forecasted weather. Suppliers may do the same for customers with hourly meters. The sum of the forecast hourly energy needs of all of an alternate supplier's customers is that supplier's delivery obligation for that hour.

Q. Why are customers with hourly meters treated differently than customers with monthly meters?

A. Hourly meters provide accurate data concerning energy usage patterns of end-use consumers. Also, these meters are used by large industrial and other customers who consume relatively large amounts of energy, and thus tend to better understand their own energy usage patterns. (I note that as more customers become eligible to participate in the retail access program, it will become increasingly important, particularly for energy scheduling and reliability purposes, for alternate suppliers to be able to forecast the demands of their customers.) By contrast, it is more difficult to know the hourly energy use of customers with monthly meters. PECO will forecast the hourly loads of its retail choice customers with monthly meters to minimize the effects of mismatches between forecasts and actual consumption.

Q. How will the loads of customers with hourly meters be treated when determining their contribution to the need for Wholesale Reconciliation Service?

A. For a supplier's customers with hourly meters, PECO can compare the actual difference between the customers' forecasted (i.e., scheduled) use and actual usage on an hourly basis.

Q. How will the estimated hourly loads of customers with monthly meters be pro-rated?

A. PECO will pro-rate estimated hourly loads by multiplying the customer's hourly energy use estimate by the ratio of the customer's actual metered monthly usage and the estimated total monthly usage used to develop the ADLC.

Q. Now that you have more fully explained these services, please provide an example of how all of this will work.

A. Suppose that an alternate supplier, based on its ADLC, schedules 100 megawatt-hours of transmission service over a particular hour, 50 megawatt-hours for monthly metered customers and 50 megawatt-hours for hourly metered customers. In real-time operations, however, the supplier supplies only 97 megawatt-hours over that hour. That supplier would be subject to a Wholesale Energy Imbalance charge for three megawatt-hours of service, either from PJM or from an alternative source of that service. This imbalance would be identified and cleared shortly after the applicable hour. Based on its customer meter reading schedule, PECO would determine the actual amount of power the supplier's customers with hourly meters consumed that hour. Also, using the method I described above, PECO would estimate the amount of power the supplier's customers with monthly meters consumed that hour. If the supplier's customers actually consumed 110 megawatt-hours in the applicable hour, the supplier would be charged for 10 megawatt-hours of Wholesale Reconciliation Service. If 57 megawatt-hours were consumed by customers with hourly meters and 53 by customers with monthly meters, 7 megawatt-hours of Wholesale Reconciliation Service would be related to the actual energy use of these customers, and 3 megawatt-hours would be related to the difference between the load profiles developed for the monthly metered customers and their allocated energy use for that hour. PECO would report the 10 megawatt-hour total to the PJM OI for accounting purposes.

Q. Is PECO Energy seeking Commission approval of the rates, terms, and conditions of Wholesale Reconciliation Service?

A. No. I am informed that as a transmission-related ancillary service, the rates, terms, and conditions thereof are subject to the exclusive jurisdiction of FERC. PECO is explaining this service so the Commission will have a complete understanding of PECO's proposal, which will assist the Commission when making decisions about those issues that are subject to its jurisdiction. It also is important for all potential suppliers and customers to understand how retail access will operate.

Q. Nonetheless, do you believe the Commission should take any action with regard to Wholesale Reconciliation Service?

A. Yes. The Commission should require that alternate suppliers cooperate with PECO and PJM in administering and billing for these services.

B. <u>Responses to Intervenor Arguments</u>

Q. Mr. Coles argues at page 9 of his testimony that the charges PECO Energy proposed in its initial filing for Wholesale Energy Imbalance Service are not just and reasonable. Do you agree?

A. No. However, this issue has become moot in light of PECO's proposal that all participants in the retail access program take transmission service, including ancillary services, directly under the PJM Tariff. As a result, PECO's proposed charges will no longer apply.

Q. Mr. Coles also appears to object to the charges for Wholesale Reconciliation Service for customers with hourly meters (Coles at 9-12). Please respond to these assertions.

A. Mr. Coles' arguments are moot. PECO has modified its proposal regarding wholesale Reconciliation Service to have the PJM OI perform the billing for this service under tariff conditions.

Q. At page 11 of his testimony, Mr. Coles argues that PECO Energy could obtain a market advantage because, he asserts, PECO Energy will obtain market intelligence through the information necessary to determine a supplier's ADLC. Do you agree?

A. No. As explained by Mr. Cucchi, PECO has instituted a code of conduct that will prevent its energy marketing employees from receiving any market-sensitive information that could be used to PECO's competitive advantage.

Q. Mr. Phillips argues at page 22 of his testimony that further information is required "with respect to the allocation of responsibility for ancillary services, system losses and imbalances between energy actually supplied for a particular customer and that customer's actual consumption." Can you elaborate on this point?

A. Yes. As I have explained, alternate suppliers (or customers taking service directly from PJM) will make their arrangements for ancillary services directly with the PJM OI, including energy imbalance service and transmission losses, consistent with the PJM Tariff. With regard to distribution losses, that will be a part of PECO's distribution tariff, which PECO is in the process of developing.

IV. RELIABILITY

Q. What requirements must PECO Energy satisfy to ensure reliable service?

A. Like all load-serving entities, PECO must have rights to sufficient generation capacity to meet forecasted peak demands in a reliable manner. Currently, this obligation is administered by the PJM OI. PECO's capacity obligations for the 1997-98 and 1998-99 planning years were established under the PJM Agreement. PECO's future obligations will depend on pool rules following PJM's permanent restructuring. I believe, however, that there will be an ongoing reliability obligation for all load serving entities ("LSEs") in the Mid Atlantic Area Council region, if not a specific installed capacity obligation as at present.

Q. Why is there a capacity obligation in PJM?

A. A capacity obligation is a traditional part of planning for supply reliability, and is included in the PJM Agreement. It is meant to serve two functions: (i) adequacy --to ensure that sufficient supplies are available, and (ii) deliverability -- to ensure that energy can be transmitted from chosen supplies to loads.

Q. Should an alternate supplier be subject to a capacity obligation?

A. Yes. Since alternate suppliers will supply a percentage of load in PECO's service territory, they should be responsible for the same percentage of PECO's capacity obligation to PJM for as long as PECO is subject to such an obligation.

Q. How will this work?

A. PECO will determine the capacity obligation of each alternate supplier based on the amount of load it has under contract. An alternate supplier can either obtain resources acceptable to PJM to meet its obligation, or it can purchase capacity to meet its obligation at the PJM capacity deficiency rate.

Q. Why is PECO proposing to determine each alternate supplier's capacity obligation?

A. Because PJM cannot do this directly at this time. When PJM has this capability, and PECO is no longer responsible to PJM for the capacity obligation of alternate suppliers with loads in PECO's service territory, PECO no longer will take on this responsibility.

Q. Is this the venue to address PECO's proposal for allocating a capacity obligation to alternate suppliers?

A. No. The capacity obligation is part of PJM restructuring as ordered by FERC.

Q. Nonetheless, do any intervenors address PECO Energy's proposal?

A. Yes. According to Mr. Coles "market-based price signal[s] and resulting market response" should replace "the concept of planning reserves and traditional planning." (Coles at p. 16). (Planning reserves is another name for a reliability planning method, such as the installed capacity obligation that currently must be met under PJM requirements.)

Q. Does PECO Energy agree with Mr. Coles' assessment?

A. Yes and no. PECO agrees that over time market forces should replace the concept of planning reserves. This view is reflected in the PJM Restructuring Plan filed with FERC on June 9, 1997 by PECO and others, and given Docket No. ER97-3273-000. However, under the current PJM Agreement, PECO must provide the portion of reserves that PJM requires, regardless of the theoretical validity of Mr. Coles' argument. As I mentioned earlier, alternate suppliers should be responsible for providing their share of PECO's reserve obligation based on the load those suppliers are serving in PECO's service territory.

Q. What would be the result if alternate suppliers were not required to meet their share of PECO Energy's reserve obligation?

A. Customers that do not participate in the retail access program would pay the cost of reserves for customers that do, as PECO remains subject to PJM's reserve requirement for all of the load in its service territory. This kind of leaning would not be equitable.

Q. What should the Commission do?

A. The Commission should state that alternate suppliers are responsible for their share of maintaining reliability in the PJM region, and that they must meet their share of whatever PJM requirements are in place at any time.

V. INDEPENDENT SYSTEM OPERATOR

Q. At page 22 of his testimony, Mr. Biewald argues that "a strong and independent system operator should be established to coordinate the dispatch, ensure system reliability, to implement open access to the transmission system, to conduct transmission system planning, and to identify market power problems." Do you agree?

A. I agree that an ISO could bring a number of benefits to the PJM region. In fact, PECO proposed to FERC an ISO that satisfies FERC's ISO criteria in its June 9, 1997 filing in FERC Docket No.

ER97-3273-000. PECO's proposed ISO will address most of Mr. Biewald's respects, including the type of ISO proposed, rate design, congestion pricing and market structure issues.

The PECO-sponsored plan for restructuring PJM (the "Plan") reflects an "end state vision" of a fully unbundled open-access electric marketplace consistent with Order No. 888. The Plan envisions, at the end of a transition period, the following:

(1) An ISO would control and operate the PJM regional transmission system and provide transmission service pursuant to an open-access tariff.

(2) The ISO would be a for-profit corporation, fully independent from the existing PJM transmission owners, yet subject to the FERC's jurisdiction as a transmission owning/controlling public utility. PECO believes that a for-profit entity would control costs, be responsive to the market participants' concerns and, innovate to a greater degree than the non-profit form of ISOs that have been proposed in PJM and elsewhere.

(3) The ISO will have its own Tariff covering all of the transmission assets that it either owns or controls. The proposed ISO Tariff is a FERC Order No. 888-A tariff, with some changes made to adapt the FERC model to the pool context and to ensure that all of FERC's policies are satisfied. Further, given the regional or "network" character of the PJM transmission system, the ISO Tariff implements a three year phase out of zonal rates, at the conclusion of which the entire PJM control area would be considered one zone, subject to a single, system-wide rate. The ISO's transmission services would be unbundled from all other services, including other traditional aspects of power pooling. The Transmission Control Agreements contained in the Plan are intended to maximize the ISO's control over transmission assets absent an actual transfer of title. At a minimum, the ISO would exercise complete operational

control over the regional transmission facilities under Transmission Control Agreements executed with each of the PJM transmission owners. In addition, the ISO would be allowed to negotiate the voluntary purchase of transmission assets and could, where economically and environmentally appropriate, build or otherwise enhance transmission facilities.

(4) The competitive marketplace for electric energy products would be not be institutionalized. Rather, it would arise from the collective activity of buyers and sellers, arranged directly by the principals or using various market-making services. Indeed, there presently exists a vigorous wholesale market operating in the PJM region that arose independent of institutional support.

(5) The ISO, being a transmission provider, would not be involved commercial matters in the energy market. Instead, the ISO would receive information about desired transactions through reporting channels and according to reporting timetables equally applicable to all participants.

(6) The ISO would be fully responsible to plan and reliably operate the transmission system, including providing operating and spinning reserves as ancillary service, but each entity undertaking to be a supplier to end-use customers would have individual responsibility for the ultimate provision of adequate generation to serve its own customers' demands.

(7) The ISO would obtain the generation resources that it needs to provide ancillary services such as operating and spinning reserve, VAR support, and balancing, as well as for redispatch for congestion relief, from voluntary sellers in the marketplace. The ISO's charges for such services would apply to all users at rates set per tariff, and would only be modified prospectively.

(8) In operating the region as a single control area, the ISO would have overriding control in emergency situations or to prevent severe consequences like equipment damage or cascading outages.

Q. At page 18 of his testimony, Mr. Reising argues that "PECO will ultimately be providing transmission and ancillary services via the PJM ISO." Do you have any comment on this statement?

A. Yes. I would like to clarify, as I already have noted, that transmission service in PJM currently is provided under the PJM Tariff. I also note that, at this time, the PJM OI is the system operator for the PJM Control Area. As such, it is responsible for short-term reliability and the transmission service functions of an ISO. PECO and any alternate supplier serving loads in PECO's service territory must abide by the PJM OI's directions with respect to grid operations.

Q. Does this Commission have jurisdiction to dictate the form of an ISO?

A. No. It is my understanding that states do not have any control over ISO functions. I also understand that FERC already has articulated its own guiding principles on the formation of such entities. As such, there is little that can be accomplished as a practical matter outside of a proceeding before FERC.

VI. ENVIRONMENTAL TRACKING

Q. Please describe Mr. Biewald's proposed environmental disclosure requirements.

A. Mr. Biewald proposes, beginning at page 9 of his testimony, that the Commission require suppliers to disclose fuel mix and air emissions data, and to label their energy accordingly. He believes that an ISO should be responsible for implementing his environmental tracking proposal.

Q. Does the Competition Act require such disclosure?

A. No. There is nothing in the Competition Act, or any other legislation, that would require such environmental disclosure.

Q. Would Mr. Biewald's proposal affect competition in Pennsylvania?

A. It is unclear what the impact on competition in Pennsylvania would be, but this certainly is one of the issues that would have to be addressed before implementation of Mr. Biewald's proposal could be properly considered. To the extent that environmental disclosure requirements entail any undue burden and expense, potential alternate suppliers may opt out of participation in the Pennsylvania marketplace in favor of other markets where they do not have to comply with similar requirements.

Q. Could market forces result in voluntary environmental labeling if the Commission does not require it?

A. Yes. If environmental labeling will help suppliers sell power, i.e., if the market demands such information, suppliers will provide it. In other words, this is an issue for suppliers as part of their marketing strategy. I believe that it would be preferable to allow the market to determine the information in which consumers are interested. Please see the rebuttal testimony of Gwendolyn S. King (PECO St. No. 17-R) for further discussion of this issue.

Q. Mr. Biewald also argues, at page 16 of his testimony, that the PJM ISO, when it is operative, should be responsible for implementing the environmental disclosure policies he advocates. Do you agree?

A. No. If the Commission chooses to adopt some sort of environmental disclosure policy, the ISO is not the proper body to implement that policy. An ISO is supposed to be a neutral operator of the transmission system. Except in limited circumstances, it is supposed to have no interest in, or role in, which generators run. (The ISO may need to exercise some level of operational control over generation facilities in order to regulate and balance the power system, especially when transmission constraints limit trading over interfaces. In short, Mr. Biewald's proposal would force the ISO into an area that it should not be in.

Further, requiring the ISO to implement environmental tracking would present an administrative quagmire for the ISO. For example, Mr. Biewald provides no indication of how the ISO would obtain the information necessary to implement his proposal. It will probably be exceedingly difficult for the ISO to keep track of each supplier's real-time environmental mix as more and more suppliers enter the market, and as these suppliers' generating portfolios change on a day-to-day basis.

Finally, based on my understanding that ISO functions are not subject to state jurisdiction, FERC, and not the Commission, is the proper forum for addressing what tasks, if any, an ISO should perform in connection with environmental monitoring.

Q. Does this mean that the ISO should be indifferent to the environmental consequences of its operations?

A. Certainly not. Indeed, the PECO-sponsored PJM restructuring proposal filed at FERC on June 9, 1997 specifically provides that the ISO will consider environmental impacts when conducting its studies for transmission expansion planning. Such consideration is proper in that context given the ISO's role and responsibilities as operator of the regional transmission grid.

Q. Are there any other reasons Mr. Biewald's proposal should not be adopted?

A. Yes. Apart from the jurisdictional questions, a major hurdle his proposal faces is the lack of critical detail and information that would be necessary for proper consideration by this Commission. For example, he fails to provide information on the level of expense that his proposal would involve, and how this expense would be paid. He further fails to detail how the Commission would impose and monitor compliance with tracking requirements on non-PJM companies and out-of-state suppliers. I also note that Mr. Biewald has failed to address whether the Commission could restrict generation sales from out-of-state suppliers if they do not meet the reporting requirement. The absence of answers to these and other questions necessarily limit the Commission's ability to accept Mr. Biewald's proposal.

VII. ALLOCATION OF INTERTIE CAPACITY

Q. Please describe how the capacity of interties between PJM and other control areas is allocated.

A. Currently, a capacity benefit margin ("CBM") is reserved to deliver power from systems outside of the PJM Control Area to serve the LSEs within the PJM Control Area in the event of an emergency. In other words, Available Transfer Capability ("ATC") over the transmission system is reduced to allow for the import of energy into the pool in the event of an emergency. After that, ATC is allocated to the PJM LSEs on the basis of their load ratio shares.

Q. Has any intervenor addressed allocations of tie capacity?

A. Yes. Enron witness Tabors argues that the PJM Members should make their rights to tie capacity available to either their former retail customers or those customers' alternate suppliers. (Tabors at 3)

Q. Does PECO have any fundamental disagreement with Dr. Tabors' testimony?

A. No. The approach Dr. Tabors is proposing is more-or-less the approach that PECO has advocated as part of the PJM restructuring proceedings before FERC. Like Dr. Tabors, PECO does not believe that there should be set asides out of ATC for intertie capacity, but rather that such capacity should be treated in the same manner as all other transmission facilities. PECO sees no reason why the PJM Tariff's curtailment procedures during time of emergencies should not suffice for pool interties.

Q. Do you believe this Commission thus should adopt Dr. Tabors' proposal?

A. No. Although I agree with Dr. Tabors' position, this is not the proper forum for raising issues relating to the allocation of intertie capacity. The question of intertie capacity is a transmission issue that is subject to FERC's exclusive jurisdiction.

Q. Has this issue in fact been raised in any FERC proceeding?

A. Yes. The issue is still before FERC as part of both the PJM restructuring proceedings and a transmission case filed by Duquesne Light Company at FERC. Indeed, the December 31, 1996 Order No. 888 compliance filing for the PJM Interconnection contained side-by-side provisions on ATC, one of which was sponsored by the PECO Group and the other by the Supporting Companies. The PECO Group column proposed a methodology for calculating ATC that did not require any set aside for capacity benefit margin.

Q. Has FERC ruled on these alternative proposals?

A. Yes. By order dated February 28, 1997 Mid-Continent Area Power Pool, 78 FERC ¶ 61,203 (1997), FERC ordered the PJM companies to implement the PECO congestion pricing method and the Supporting Companies' proposal "in all other respects," effective March 1, 1997, subject to refund. This order effectively implemented a set-aside for capacity benefit margin. PECO also invites the Commission and other participants' attention to the extensive discussion of this issue contained in the "Comments of PECO Energy Company Opposing Approval of Settlement Agreement" filed in Duquesne Light Company, FERC Docket No. TX94-8-000 on April 1, 1997.

VIII. MARGINAL ENERGY PRICING

Q. Is the market price of energy in PJM an important factor in these restructuring proceedings?

A. Yes. PECO utilized this price in calculating the value of its generation assets.

Q. What is the basis of the market price of energy in PJM?

A. Today, the PJM pool energy market operates under rules that encourage a company to submit bids to operate its generation. Such bids must be based on the components of the energy price, i.e., incremental costs as a function of output, minimum or no-load costs, and startup costs. PJM, in turn, selects generators that are subject to its central dispatch authority to operate on a cost minimization basis. This is referred to as least-cost dispatch. The PJM OI then sets a "market clearing price" for each hour based on the incremental energy cost of supplying the last megawatt of load on the system. That market clearing price is used to price interchange energy sales in PJM and is the PJM market price proposed by PECO.

Q. When did this pool energy market go into effect?

A. This pool energy market started effective April 1, 1997.

Q. Has any intervenor challenged the market price of energy utilized by PECO?

A. Yes. PAIEUG has submitted testimony to that effect through its witness Randall J. Falkenberg.

Q. What is the basis of Mr. Falkenberg's objection to the PJM market price?

A. Mr. Falkenberg argues that the model relied on by PECO in calculating market price systematically understates the PJM market energy price because it uses incremental cost and does not reflect fuel-related costs such as the no-load and start-up costs.

Q. Why does Mr. Falkenberg maintain that fuel-related costs should be factored into the calculation of the PJM energy market price?

A. He says that inclusion of such costs in calculating the price would be more consistent with operations in a fully competitive environment.

Q. Does Mr. Falkenberg propose a different methodology for calculating market energy price?

A. Yes. He proposes to use average costs as the basis for calculating the PJM energy market price.

Q. Do you agree with Mr. Falkenberg's claim that the PJM market price should include the fuel-related costs he highlights?

A. No. The energy market price in PJM has been and continues to be based on incremental costs. Moreover, this is the approach that has been put in place by FERC. Falkenberg's assertion that market-based bidding will fundamentally change these rules ignores the fact that even if such a move is proposed, no one would be able to predict if and when it would be approved by FERC. And also, it would be speculative to model the PJM energy price on an assumption that a set of rules substantially different from the current rules will be adopted.

Q. Has PECO used the PJM market price in any of its simulations?

A. Yes. PECO has relied on that PJM market price in the model that is the basis of PECO's market price for its generation assets.

Q. What about the start-up and no-load costs that Mr. Falkenberg refers to?

A. Such costs are simply costs of doing business, and come out of a seller's markup from the difference between their quoted energy cost and the market clearing price they receive for their actual sales. Further, where a generating unit is started and run at the request of PJM, and its start-up and no-load exceed its markup, the excess is collected as the transmission ancillary service of operating reserves (spinning) under the PJM Tariff, and not as part of the market price of energy.

IX. ENRON'S PROPOSED ELECTRIC GENERATION SUPPLIER TARIFF

Q. Mr. Coles includes as Exhibit 7 to his testimony a proposed "Electric Generation Supplier Tariff." Do you have general comments on this proposal?

A. Yes, I have several. First, there is the preliminary question of whether a proceeding limited to PECO's restructuring filing is the proper venue for even addressing the necessity and content of a supplier tariff such as the one Enron proposes. Enron's proposed supplier tariff declares that its purpose is as follows: "This tariff is applicable to Electric Generation Suppliers ("Suppliers") that are responsible for supplying all or a portion of the electric power and energy requirements of Customers connected to the Electric Distribution Company ("EDC")." Exhibit 7 LRC-2 at p. 1. Based on the stated purpose of the supplier tariff, it appears that it is intended to apply to all electric suppliers serving load in a retail choice context. As such, Enron's proposal is more properly suited for resolution as part of a rulemaking specifically dedicated to developing an electric supplier tariff.

Second, even if one agreed that Enron's supplier tariff should be addressed here, doing so would be premature at this stage. It would be ill-advised to use the limited time and resources of the Commission and the parties to the various proceedings to address the tariff until the Commission has issued final orders on the diverse restructuring filings.

Third, the intended scope of the supplier tariff is unclear. For example, the proposed tariff appears to address issues that properly fall within the scope of a distribution tariff for the EDC. This could cause inconsistencies and conflicts between the two tariffs.

Finally, the content of the supplier tariff itself raises a myriad of concerns. The following is a list of just a few of the serious problems that PECO has identified:

- there is no discussion of any standards of conduct that should apply to the supplier and any of its utility affiliates (Enron, for instance, is now an affiliate of Portland General Electric Company);
- the tariff intrudes into the sphere of activities that must be controlled by the entity responsible for operating the distribution system (for example, the required frequency for suppliers' provision of balancing data to the EDC under Section 4.2.4);
- the tariff inappropriately seeks to dictate policy on FERC-jurisdictional matters (for example, the tariff does not allow suppliers to self-provide any ancillary services, which is at odds with the Order No. 888-A tariff (Sections 4.2.6 and 4.3.4)); and
- the proposed penalty in Section 4.3.1 is structured in a manner that will make it ineffective in providing sufficient incentives to suppliers to reliably match supply with load.

X. PECO'S LACK OF MARKET POWER IN GENERATION AND TRANSMISSION

Q. Are you familiar with the contentions that intervenors have made regarding PECO's market power in generation and transmission?

A. Yes. MAPSA's witness Johnstone, FUMO/CEPA's witness Silkman and the Environmentalists' witness Biewald each make statements on that subject. Mr. Johnstone says that "PECO's ownership of the transmission and distribution system, as well as generation, results in vertical market power" which "must be broken down and, if possible, eliminated . . . ." (Johnstone, at pp. 3-4). Among other things, he proposes this Commission's rejection of PECO's rate unbundling and proposed code of conduct. Mr. Silkman contends that the objectives of the Competition Act will not be achieved as a consequence of PECO's monopoly over transmission and distribution and that a code of conduct would be inadequate to mitigate that market power. (Silkman, at pp. 17-18). He makes several recommendations, including full divestiture of generating and marketing affiliates and a prohibition on such affiliates serving customers in the EDC's service territory. (Silkman, at pp. 18-20). Mr. Biewald says his "[p]reliminary examination of market concentration in the PJM electricity market suggests that there may be opportunities for abuse of market power in generation if restructuring moves forward." (Biewald, at p. 20). For "removing or mitigating the potential exercise of market power" he recommends that the Commission encourage divestiture and that "limits on the ownership of generating capacity should be established for participants in PJM." (Biewald, at p. 22). In sum, all of these witnesses cite market power as a reason to impose harsh rules to govern, and limitations on, PECO's participation in the emerging competitive electric market.

Q. Are you aware of any facts that would rebut those contentions on market power?

A. Yes. FERC has already made an evaluation of PECO's market power in PJM and has concluded that PECO does not have any.

Q. Please provide further details of the context in which FERC made that determination.

A. On January 31, 1996, PECO filed an application with FERC seeking authorization to engage in wholesale energy sales at market-based rates. As part of that filing at FERC, which I assisted in preparing, PECO submitted a market power study in addition to filing a Company-specific open access transmission tariff. FERC approved PECO's application and granted PECO market-based rates authority.

Q. What is your understanding of the standard that FERC applies in reviewing market-based rates application?

A. FERC conditions the grant of market-based rates approval on its finding that the market-based rates applicant (i) does not have, or has mitigated adequately, market power in generation and transmission; (ii) cannot erect barriers to entry; and (iii) has adequately protected against potential affiliate abuse and reciprocal dealing. In order to prevent the exercise of market power in transmission, FERC has required utilities associated with, or who are themselves, marketers to file an open access transmission tariff.

Q. What specifically did FERC say about PECO's satisfaction of FERC's market power criteria for market-based rates?

A. FERC said that it was satisfied that PECO's share of both installed and uncommitted capacity did not reach levels that would establish market power in generation. In addition, FERC found that PECO had mitigated its market power in transmission by filing an open access transmission tariff. See PECO Energy Co., 74 FERC ¶ 61,336 (1996).

Q. Is transmission service over PECO-owned transmission facilities still provided for under an open-access transmission tariff on file with FERC?

A. Yes. The Company-specific tariff filed in January 1996 was superseded by a Company-specific Order No. 888-compliant tariff on July 9, 1996, which was in turn replaced by the pool-wide PJM Tariff, effective April 1, 1997. I note further that the extent of PECO's "control" over its own transmission facilities is even more attenuated at present given that the PJM Office of Interconnection – and not PECO or any of the other transmission owners – is responsible for administering the PJM Tariff and processing transmission service requests over pool-wide transmission facilities.

Q. How can this Commission draw on FERC's market-based rates analysis for application to its consideration of market power issues in the context of a utility's control over its distribution facilities?

A. The Commission can hold that the filing of a Distribution Tariff by the Electric Distribution Company, with terms and conditions that provides open access over such facilities to alternate suppliers, along with a code of conduct, sufficiently mitigates market power in distribution. Given that the Competition Act requires PECO and other Pennsylvania utilities to do just that, the market power arguments relied on by intervenors with regard to distribution do not provide a sound basis for further restricting PECO's ability to compete in the new marketplace.

Q. Does this conclude your testimony?

A. Yes

R-00973953
PECO STATEMENT NO. 22-R
Phila. 10/14,15,16/97
E. Holbert

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY
FOR APPROVAL OF ITS RESTRUCTURING PLAN
UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE

REBUTTAL TESTIMONY

OF

JUDAH L. ROSE

Providing An Update To PECO's Energy And Capacity Market Price Projections; Providing A Critique Of The Market Price Analysis Of PAIEUG Witness Falkenberg; And Responding To The Testimony of Intervenors

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF JUDAH L. ROSE

I. INTRODUCTION

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

A. My name is Judah L. Rose. I am a Vice President at ICF Resources Incorporated ("ICF"). My business address is 9300 Lee Highway, Fairfax, Virginia, 22031.

Q. Please describe your educational and professional background.

A. After receiving a degree in economics from the Massachusetts Institute of Technology and a Masters Degree in Public Policy from the John F. Kennedy School of Government at Harvard University, I joined ICF Resources. In addition to testifying in other legal proceedings, I have authored numerous articles in industry journals. A copy of my resume provides more detailed information and is attached as Exhibit JLR-1.

Q. Please describe your responsibilities and work at ICF Resources.

A. I direct ICF's wholesale power practice and power marketing practice. In addition, I co-manage ICF's fuel market forecasting practice. I am also Product Director for ICF's WPMM© (Wholesale Power Market Model) software.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony is divided into three sections. First, I provide an update to the electric energy and capacity market price projections prepared by Dr. Venkateshwara in his direct testimony, utilizing the same ICF tools, including the Integrated Planning Model ("IPM"), that he employed. Since the time of Dr. Venkateshwara's direct testimony, he has resigned from ICF. Second, I provide a critique of the market price analysis presented by PAIEUG witness Mr. Falkenberg. Third, I respond to and rebut the direct testimony of witnesses on behalf of the Office of Consumer Advocate ("OCA") and the Philadelphia Area Industrial Energy Users Group ("PAIEUG") regarding their projections.

II. UPDATED MARKET PRICE PROJECTIONS

Q. What was the ICF model you used for your analysis in this proceeding designed to do?

A. ICF's IPM model, developed over the past 20 years, was designed for use by companies, including utilities, to make commercial decisions based on the price and market forecasts the model produces. In fact, ICF's international, national and regional models are routinely used by companies for just that purpose.

Q. Have you conducted an updated analysis of electric energy and capacity market prices?

A. Yes.

Q. Why have you conducted this updated analysis?

A. Some of the intervenors, particularly PAIEUG witness Mr. Falkenberg, focused on the PECO witnesses' sources of heat rate and fuel price assumptions used in their respective models. In order to eliminate areas of controversy in this proceeding, PECO requested that ICF conduct updated analyses utilizing data suggested by the intervenors.

Q. What changes were made in your analysis concerning heat rate assumptions?

A. In our direct testimony, ICF used internally generated heat rate data. Although PAIEUG did not identify any error or bias in ICF's heat rate assumptions, we have updated our analysis using Energy Information Administration ("EIA") Form 860 heat rates in order to eliminate this assumption as a potential ground for dispute.

Q. Does the use of EIA Form 860 heat rates change your projection of market prices?

A. In general, the use of EIA Form 860 heat rate data, rather than ICF heat rate data, did not result in a marked difference in our projection of market price. This confirms that the ICF heat rate data reasonably correspond to the Form 860 data when run in the

ICF model. For example, use of the EIA heat rate data resulted in a decrease of $0.04 per MWh in 1999 and $0.01 per MWh by 2010 in the annual market price of electric energy (all values in 1996 dollars). The results of this analysis are presented in Exhibit JLR - 2. In addition to the use of the EIA Form 860 heat rate data, we also used the latest ICF SO_2 allowance price forecast.

Q. **What changes were made in your analysis concerning fuel price assumptions?**

A. We conducted two additional analyses using different fuel price escalators. First, consistent with the other market price analyses put forth by PECO, we analyzed an alternative case utilizing the fuel price forecast from DRI McGraw Hill's 1997 Energy Service. Second, in order to eliminate fuel price assumptions as a potential ground for dispute with PAIEUG witness Mr. Falkenberg, we conducted an analysis utilizing the fuel price forecast presented in the EIA Annual Energy Outlook 1997. It should be noted that in all cases we used EIA Form 860 heat rates.

Q. **Please summarize the results of your analysis using the updated DRI fuel prices.**

A. In PECO's direct testimony, ICF's model projected a levelized market price of $35.7 per MWh, which corresponded to an estimated market value of generation of $3.49 billion. Our revised analysis, using updated DRI fuel prices, shows a levelized market price of $34.6 per MWh, which corresponds to an estimated market value of $3.08 billion. Detailed results of this analysis are included in Exhibit JLR-3.

Q. Please summarize the results of your updated analysis using EIA fuel prices.

A. Using EIA fuel prices, our model shows a levelized market price of $33.6 per MWh, which corresponds to an estimated market value of $2.69 billion absent PECO accounting-related differences. Detailed results of this analysis are included in Exhibit JLR-4.

Q. Can ICF's model be run using incremental heat rates?

A. The ICF model's current production costing algorithm is not designed to project the market price of energy based on the set of PJM rules described by Dr. Hieronymus.

Q. What impact, if any, would you expect the use of incremental heat rates to have on the results produced by your model?

A. Based on the set of PJM rules described by Dr. Hieronymus, one would expect that the model would produce a decrease in the market price of energy with incremental heat rates.

III. PAIEUG MARKET PRICE ANALYSIS

Q. Please comment on PAIEUG's analysis of the market value of PECO's generating assets.

A. Mr. Falkenberg's market prices for capacity and energy are significantly higher than the ICF forecast because of significant errors in Mr. Falkenberg's analysis. I have concerns about how he projects both his capacity and energy prices.

A. Market Price of Capacity

Q. Please describe your concerns regarding Mr. Falkenberg's analysis of capacity prices.

A. I have identified six critical mistakes in Mr. Falkenberg's analysis relating to capacity prices: (1) an error in his capital fixed charge rate results in an overestimate of value in excess of $350 million; (2) the inappropriate treatment of O&M for new combustion turbine plants results in another overestimate of about $100 million; (3) an improper formula for calculating capacity prices; (4) an overly high estimate of the capital installation costs of a new combined cycle unit, which tends to increase capacity prices; (5) an underestimate of the potential availability performance of new combined cycle units, which tends to inflate capacity prices; and (6) an improper treatment of inflation results in an overestimate of capacity prices of about $150 million. Correcting Mr. Falkenberg's capacity price analysis, even allowing for the potentially offsetting effects of the individual reductions, results in an overall lower market value projection of at least $500 million.

Q. What is your concern about Mr. Falkenberg's levelized fixed charge rate?

A. Mr. Falkenberg used a levelized fixed charge rate of 13.34% in his model. In direct testimony filed by Mr. Falkenberg in Docket No. R-00973594 (Pennsylvania Power & Light Company's restructuring case), he provided a derivation of this rate in Exhibit RJF-7. Mr. Falkenberg presented that same model in both this case and the PP&L case. I believe his levelized fixed charge rate contains two errors that cause an overstatement of this rate. First, he overstates his discount rate by not including the tax benefits of debt. That is, because investors do not pay income tax on the portion of income used to pay the interest on debt, the investor's effective discount rate is reduced. The effect of a lower discount rate is to lower the levelized fixed charge rate. Second, based on PJM filings, the appropriate tax life of a generating asset with a 23 year life is actually 15 years, not 20. The effect of a shorter tax life is a more rapid depreciation of the asset, which helps lower the amount of income taxes an investor pays. These two corrections lower Mr. Falkenberg's levelized fixed charge rate to 12.23%, and lower his capacity price projections by about $3/kW-yr. in real dollars. This correction alone would lower his market value projections by over $350 million.

Q. What is your concern about Mr. Falkenberg's treatment of O&M costs for new combustion turbine plants?

A. Mr. Falkenberg incorrectly estimates O&M for new combustion turbines and thereby overestimates capacity prices by about $3/kW-yr., which translates into approximately $100 to $350 million in excess market value. More specifically, Mr. Falkenberg estimates the non-fuel O&M costs of new combustion turbines at approximately $5.50 to $6.50 per kW-yr., placing all of these costs in the fixed cost category. Mr. Falkenberg totally neglects to account for variable O&M. All other analysts -- ICF, PHB, EDS, and the OCA -- present market price forecasts which properly treat these O&M costs as having both fixed and variable components. Mr. Falkenberg alone has no variable O&M. As a result, Mr. Falkenberg's model maximizes the capacity price, as capacity price is mostly a function of the fixed costs of new capacity, without offsetting effects on the energy price.

A simple example will illustrate this effect: shifting $1.8/kW-yr. of fixed non-fuel O&M to variable O&M can decrease the capacity value of PECO's generating facilities by $13.5 million per year (7,500,000 kW times $1.8/kW-yr.) while increasing the energy value of PECO's generation by only $2 million per year (the units are on the margin 5 percent of the year, increasing prices $1/MWh on about 40 BKWh per year). In other words, the effect of one dollar of fixed non-fuel O&M costs does not have the same effect on the bottom line as does one dollar of variable O&M costs. Rather, the effect of fixed non-fuel O&M is of considerably greater magnitude than variable O&M. Therefore, Mr. Falkenberg's treatment of all non-fuel O&M costs as being fixed, rather than as fixed and variable, results in a very significant overestimate in his model of the cost of new capacity.

Q. **What is your concern about Mr. Falkenberg's method for calculating capacity prices?**

A. Mr. Falkenberg recognizes that new units that are not making energy profits must have a capacity price high enough to allow them to be built and contribute to reliability. He also is aware that if new units are efficient and low cost enough, the capacity price is depressed by the energy profits of the new units. In order to calculate this depressing effect, one must calculate both the energy savings of combustion turbine and combined cycle units and compare them to the fixed costs of combustion turbine and combined cycle units, respectively. Based upon the spreadsheets used in Mr. Falkenberg's analysis, it appears he calculates the difference between a combustion turbine unit's fixed costs and a combined cycle unit's energy profits. This is an incorrect approach. The proper approach is either to calculate the difference between the annual owning cost (i.e. fixed cost) of a combustion turbine unit and a combustion turbine unit's energy profits, or to calculate the difference between the combined cycle unit's annual owning costs and its energy profits, but not to compare the fixed costs of one with the energy profits of the other. By making the improper comparison, Mr. Falkenberg brings into serious question the validity of his capacity pricing mechanism.

Q. What is your concern about Mr. Falkenberg's estimate of the capital installation costs of a new combined cycle unit?

A. Mr. Falkenberg estimates new combined cycle capital costs at $595/kW versus our estimate of $450/kW. Mr. Falkenberg's estimate is too high, and acts to prevent the possibility that the energy profits will offset enough of the fixed costs to depress capacity prices. At a maximum, this prevents Mr. Falkenberg from having to decrease his capacity price; at a minimum, it prevents him from having to characterize his capacity price as inappropriately high.

Q. What is your concern about Mr. Falkenberg's estimates of the potential availability performance of new combined cycle units and their impact on capacity prices?

A. Mr. Falkenberg uses the NERC Generating Availability Data System ("GADS") as the source for new and existing unit availabilities. While these data may be appropriate for evaluating the current availability of existing units in the U.S., they are not a good source for evaluating the availability of new units.

In general, Mr. Falkenberg projects that new combined cycle units will be built to meet reserve margin requirements in PJM. The availability data in GADS for combined cycle units is based upon only 39 existing combined cycle units. Between 1991 and 1995, the equivalent availability of these units was only 80.2%, i.e., the average unit was available to operate at full load 80.2% of the time. This initially seems like a low number, but is explainable given that the average combined cycle unit in the GADS data base is 16 years old, and that two-thirds of the units were built before 1980. However, this is not a representative group on which to project availabilities for new units, especially considering that even the earliest units added in Mr. Falkenberg's model will be only 14 years old by the end of his model horizon.

The effect of this artificially low availability is to increase capacity prices because new combined cycle units are not considered available during as many hours, meaning they are not able to earn energy value during the "unavailable" hours.

Q. Finally, what is your concern about Mr. Falkenberg's treatment of inflation in the context of capacity prices?

A. Mr. Falkenberg assumes that the price of combustion turbines escalates at a constant rate of 3.11%. This figure appears to represent an average rate of inflation. By way of contrast, Mr. Falkenberg uses the EIA projection as the inflation rate for his fuel price analysis. EIA projects relatively low near term inflation, and moderate long-term inflation. The result of this inconsistency is that his capacity prices escalate at a rate above EIA's inflation projection, and cause about a $150 million overstatement of Mr. Falkenberg's projected market value.

Q. Please summarize your analysis of Mr. Falkenberg's capacity prices.

A. Mr. Falkenberg's capacity market price projections are based upon flawed fixed charge rate calculations, characteristics of old units, biased O&M allocations, extremely conservative capital cost projections, a flawed capacity price formula, and inconsistent inflation assumptions. The combination of these biased or erroneous assumptions serves to produce the highest capacity prices component of any market price analysis presented to this Commission. Because of these flaws, I have no confidence in Mr. Falkenberg's projection of the market price of capacity.

B. Market Price of Energy

Q. Please describe your concerns about Mr. Falkenberg's analysis of energy prices.

A. With regard to Mr. Falkenberg's analysis of energy prices, I have three major concerns: (1) the inconsistency between his two models, and his unexplained choice of the one with the higher price; (2) the excessively high number of hours his model runs out of energy and consequently the high number of hours with extremely high prices; and (3) the inappropriately low availability of new combined cycle generation units in his analysis.

Q. What is your concern about how Mr. Falkenberg's two models treat energy prices?

A. Mr. Falkenberg used two models in his projection of the market price of energy and capacity in PJM: the "Probabilistic" model and the "Monte Carlo" model. Both models address the same issues, but one -- the Probabilistic model -- results in significantly higher electrical energy prices. Despite the inconsistency in the projections, Mr. Falkenberg chose the Probabilistic model without further explanation, consequently reducing PECO's stranded costs. The concern, therefore, is that his analysis is biased upward.

Mr. Falkenberg used the Monte Carlo model to project the market revenues and operating characteristics of pumped storage facilities. He then used these results in his Probabilistic model to project the market price of electric energy and capacity for all other generators.

However, there appears to be a large divergence between the two models in one of the most important outputs, the market price of electric energy. This inconsistency is apparent when comparing the average revenue received by pumped storage facilities, an output of the Monte Carlo model, with the average revenue received by some of PECO's steam units, an output of the Probabilistic model. As an example, both the Muddy Run pumped storage facility and the Delaware 7 steam unit operate at about a 15% capacity factor in 1999 in Mr. Falkenberg's two models (14.4% for

Muddy Run and 15.2% for Delaware 7). As a good approximation, both units can be considered to be operating during the 15% of the hours when the market price of electric energy is the highest. It is, therefore, reasonable to expect that the average revenue received for energy by these two units would be very similar for both of Mr. Falkenberg's models. Instead, the Monte Carlo model projects the price to be $32.1 per MWh, while the Probabilistic model, the model chosen by Mr. Falkenberg to project the revenues of all of PECO's remaining generation units, projects that the market price of electric energy will be $48.1 per MWh during these hours. The Probabilistic model thus projects a market price 50% higher than that projected by the Monte Carlo model, yet we would expect them to be very similar. Thus, Mr. Falkenberg's models are internally inconsistent and biased upward, substantially undermining the validity of his results.

Q. What is your concern about the number of hours that Mr. Falkenberg's model runs out of energy?

A. One of the reasons Mr. Falkenberg's Probabilistic model projects such high energy prices during the highest priced hours is that it consistently, and literally, runs out of energy. That is, Mr. Falkenberg's Probabilistic model projects insufficient capacity to meet demand during approximately 100 hours each year. This appears to exceed, by a factor of 20, the average occurrences of this phenomenon in PJM, and also violates most reliability standards. The North American Reliability Council ("NERC") calls for a loss of load probability not to exceed 0.1 days per year.

When the 100 hours of insufficient capacity occur, Mr. Falkenberg's model *assigns a market price for these hours based upon the most expensive generation unit* in the region, which is typically priced at over $100 per Mwh. Assigning a market price based on the most costly generating unit increases the projected market price of energy. We were unable to determine the exact reason Mr. Falkenberg's model projects this significant amount of capacity shortfalls, but one important factor may be the availabilities of units, and in particular, new units. The result of this unrealistic modeling application is that Mr. Falkenberg's model utilizes the highest cost units to a much greater extent than experienced in real-world operations, thereby artificially increasing the projected energy prices.

Q. What are your concerns about the impact of Mr. Falkenberg's assumptions regarding the availability of new units on his energy price projections?

A. As discussed above, Mr. Falkenberg underestimates the potential availability of new combined cycle units by using an inappropriate data source. In addition to tending to inflate capacity prices, this also inflates energy prices by causing Mr. Falkenberg's model to run out of energy, i.e. this projection also adds to Mr. Falkenberg's unserved energy problem.

Consider, for example, a system with a peak load of 850 MW and a reserve margin requirement identical to PJM's of 18%. The reserve margin requires that the system have 1000 MW of capacity (850 MW times 1.18). To meet this requirement, this system is made up of five brand new 200 MW combined cycle units, each with

Mr. Falkenberg's availability projection of 80%. Without any optimization of maintenance (assumed by Mr. Falkenberg in two of three of the market value projections presented in his direct testimony), on average an equivalent of only four units, or 800 MW, would be available to meet the peak load of 850 MW. In contrast, using alternative assumptions that are more appropriate, such as a 90% availability projection, there would be enough capacity. Thus, Mr. Falkenberg's inappropriately low availability may well be a contributing factor to Mr. Falkenberg's excessive energy shortages, which once again leads Mr. Falkenberg incorrectly to predict an inflated market price for energy.

Q. **Please summarize your conclusions regarding Mr. Falkenberg's market price analysis.**

A. The two PAIEUG models -- Monte Carlo and Probabilistic -- project inconsistent market energy prices, and PAIEUG chose the model with the highest prices to project market prices for most of PECO's units. In addition, the Probabilistic model projects an extraordinarily high occurrence of insufficient capacity, and an inappropriately low availability of new capacity. In sum, the PAIEUG analysis is inaccurate, internally inconsistent, and significantly overstates the market price of energy. As such, the PAIEUG analysis should not be relied upon in this proceeding.

IV. SPECIFIC ISSUES RAISED BY INTERVENORS

A. Fuel Prices

Q. All parties agree that fuel prices are a significant input assumption. How does the updated DRI fuel price forecast compare to the ICF fuel price forecast in the analysis presented in PECO's direct testimony?

A. DRI predicts lower gas prices than the ICF forecast. Gas prices are the single most important factor affecting future electricity prices because many existing units operating on the margin, and all projected new units, use natural gas. Everything else being equal, the lower DRI gas prices reduce the market price of electric energy.

Q. How does the EIA fuel price forecast compare with the ICF fuel price forecast?

A. EIA's gas prices are lower than the updated DRI forecast and hence even lower than ICF's. In addition, we note that while ICF's coal and distillate prices are lower than EIA's, ICF's residual oil prices are higher.

Q. Why is it acceptable to run the ICF model using the updated DRI and EIA fuel prices?

A. Using the updated DRI and EIA fuel prices, with their lower gas price projections, is particularly appropriate in this proceeding. If natural gas prices were to be different from the ICF forecast, I would expect the prices to be lower, not higher.

Q. What is the basis for your expectation that if natural gas prices were different

than the ICF forecast, they would be lower?

A. There are three reasons for my expectation in this regard. First, since 1980, natural gas prices consistently have failed to keep pace with general inflation. By way of contrast, all three gas price forecasts described above (ICF, DRI, EIA), and the ICF forecast in particular, indicate a gas price growth rate exceeding inflation.

Second, there is a strong historical trend of over-forecasting gas prices, as shown in Exhibit JLR-5. Over the last ten years, forecasts by public and private entities have nearly all been too high. Even knowledgeable observers continue to be surprised by gas prices continuing to drop.

Third, ICF has carefully reviewed gas reserves and production technology in North America. This detailed and systematic exercise shows that the unexpectedly low gas prices have reflected rapid improvements in gas exploration and production technology. With advancements in technology, it is cheaper to obtain and produce gas now than in the past. Moreover, there are more gas reserves than previously forecasted and, with technological improvements, we can find gas more consistently than in the past. Because technology has improved gas exploration, fewer wells come up dry.

In summary, gas now costs significantly less to locate and extract than in the past. ICF's analysis also indicates that the potential for continued technology advancement is substantial. Therefore, based on all of the factors above, it is reasonable that significant consideration be given in this proceeding to the potential impacts of lower gas prices. In short, <u>all</u> of the forecasts of gas prices used in this proceeding may be too high, leading to inflated market price estimates and low estimates of stranded generating costs.

Q. Please comment on OCA witness Mr. Smith's concern regarding a potential inconsistency between the fuel prices used in Dr. Venkateshwara's analysis and the fuel prices used by Mr. Hill.

A. Mr. Smith correctly notes that the coal prices presented in Dr. Venkateshwara's testimony do not match the coal prices presented in Mr. Hill's testimony. The reason for this is that ICF projects the total fuel price for generating units burning a sulfur-containing fuel such as coal, as both the cost of the fuel and the cost of using sulfur allowances. In Dr. Venkateshwara's exhibits these values are reported separately. The combined number is the correct value. It is the combined number that Mr. Hill uses, so there is no inconsistency.

B. Cost of New Capacity

Q. PAIEUG witness, Mr. Falkenberg, criticizes ICF's projected capital costs of new combined cycle units as used in the ICF model as being too low. Do you agree with this criticism?

A. No. Over time, the capital costs of new combined cycle units will decrease in real terms, that is, not keep up with inflation. The values used in the ICF analysis represent advanced combined cycle units coming on-line well after 2000. In fact, over half of the new combined cycle units added between 1999 and 2015 are coming on-line *after* 2010. This is similar to the trend of technological improvements reducing gas prices and needs to be accounted for in market price analyses. Therefore, the projected capital cost of new combined cycle units used in the ICF model is an appropriate assumption for use in my analysis.

Q. Has ICF considered whether an increase in the cost of a new combined cycle unit would change ICF's estimate of the cost per kilowatt of new capacity?

A. Yes. An informal calculation shows that even increasing the projected cost of a new combined cycle unit by 10%, from $450/kW to $500/kW, increases the market value of PECO's generation assets by only 1.4 to 3.7%, in the analyses using EIA fuel prices and ICF fuel prices, respectively.

Q. How has ICF treated the effects of new power plant costs in its model?

A. ICF has conservatively assumed that capacity prices will be $40/kW-yr. in all years and all cases (1996 dollars). This value is meant to represent the annualized cost of a combustion turbine earning little to no profit in the energy market. This assumption was used even in instances where the annual cost of new gas power plant technology might be offset by profits realized in the energy market, causing capacity prices to be depressed. Indeed, current capacity prices are well below the $40/kW-yr. level.

C. <u>Heat Rates</u>

Q. PAIEUG witness Mr. Falkenberg discusses heat rates for over 20 pages of his direct testimony. Please discuss the heat rates used in Dr. Venkateshwara's

analysis.

A. The heat rates used in the ICF analysis are meant to represent average heat rates. The heat rates are based upon plant specific data, engineering data, and ICF judgment regarding heat rate degradation and improvements. As discussed above, overall the heat rates used in the ICF analysis correspond fairly well to the EIA 860 heat rates.

Q. PECO's two other models use incremental heat rates for their analysis, while ICF's model uses heat rates that are close to average heat rates. Can you comment on the different approaches?

A. Each heat rate input assumption is valid under specific market circumstances and can be a useful tool for predicting the market price of electricity. The different PECO models reflect different analyses of how the market will develop -- that is, whether energy price will reflect average or incremental heat rates. ICF's model projects the former.

D. <u>Levelized Fixed Charge Rate</u>

Q. Please comment on Mr. Falkenberg's criticism of the 12.7% levelized fixed charge rate for new units used in Dr. Venkateshwara's analysis.

A. The 12.7% levelized fixed charge rate for new units was based upon the projected price of marginal capacity in PJM and the projected cost of a combustion turbine. This value was validated using the projected average net annual cost of an investment on the PJM system. Two capital structures were analyzed to check this projection. The first used the average PJM utility capital structure, and the second used a more conservative capital structure, which produced a higher fixed charge rate. The more conservative estimates increased the average cost of debt and equity of PJM utilities by over 2% each. The result of this validation was a levelized fixed charge rate range of 10.8% to 12.7%. ICF chose to use the most conservative rate in the range, 12.7%, which, I note, is higher than Mr. Falkenberg's corrected rate of 12.23%. Had ICF used a lesser rate, such as 10.8%, the ICF projection of generation market value would have declined by about $500 million, increasing PECO's stranded generating costs by $800 million.

Mr. Falkenberg also noted in his direct testimony that the levelized fixed charge rate validation did not include property and other taxes. We accepted his suggestion and updated the analysis to incorporate it. However, we also located an error in our prior discount rate calculation. The run we conducted corrected both of these errors, with the result that the two errors virtually offset each other. The corrected levelized fixed charge rate calculation, provides a range of 10.7% to 12.7%. The 12.7% calculation is presented in Exhibit JLR-6. Therefore, the 12.7% used in the original analysis is still at the conservative end of the range, and continues to be the appropriate rate to use in ICF's analysis.

Q. The intervenors have raised several issues concerning fuel prices, the cost of new capacity, heat rates and the levelized fixed charge rate. Can you summarize your response to the issues raised by the intervenors?

A. The intervenors highlight some useful points. In raising the need to consider the potential impacts of lower gas prices and highlighting trends in new gas power plants, the intervenors have assisted the analytical process. There is very significant potential that technological progress will exceed expectations in a competitive market, thereby depressing fuel prices lower than in our analysis. Accordingly, our market price forecast is conservative.

Indeed, one of the main driving forces underlying deregulation has been the unexpected fall in gas prices combined with the unanticipated improvement in new gas fired power plants. Thus, it would be inappropriate in proceedings designed to address the consequences of these changes not to give them their full weight.

In contrast, other issues raised by the intervenors, such as the difference between Dr. Venkateshwara's and Mr. Hill's projected coal prices, are of little significance. This lack of significance occurs either because the issue is non-existent, or because the effect is negated by another factor such that they cancel each other out. Where the intervenors address a valid concern, such as the previous exclusion of property and other taxes, we have responded to the concern and incorporated it into the model (though in the case of property taxes there were no changes in our estimates). By devoting inordinate emphasis to peripheral issues such as heat rates, the intervenors have diverted attention from the significant issues in determining electricity prices, as discussed above.

Q. Does that conclude your rebuttal testimony?

A. Yes, it does.

JUDAH L. ROSE

EDUCATION

1982 M.P.P., John F. Kennedy School of Government, **Harvard University**

1979 S.B., Economics, **Massachusetts Institute of Technology**

EXPERIENCE

Mr. Rose joined ICF Resources in 1982 and currently serves as Vice President of ICF Resources Incorporated. Mr. Rose directs ICF's wholesale power practice (including assistance to GenCos and IPPs), ICF's power marketing practice, co-manages ICF's fuel market practice and is Product Director for ICF's WPMM© software (Wholesale Power Market Model; see the WPMM website WPMM.com on the WWW). Mr. Rose has publicly testified in state and other legal proceedings, addressed numerous major energy conferences, served as lead negotiator for the Hopi Tribe, authored numerous articles published in Public Utilities Fortnightly, the Electricity Journal and by Enron, written numerous company studies on power, coal, and gas related issues, and managed large consulting projects. Mr. Rose has also worked closely with ICF Kaiser Engineers on large energy projects.

PUBLISHED PAPERS

Mid-Course Strategic Audit: Wholesale Power Marketing at the Crossroads forthcoming

Conducting a Strategic Audit: Gencos/IPPS at the New Dawn forthcoming

Financial Engineering in the Power Sector, Public Utilities Fortnightly: January 1, 1997. with Shanthi Muthiah and Maria Fusco.

Lack of Competition in the Wholesale Maketplace for Power Generation: Does it Make A Difference, The Electricity Journal: Jan/Feb 1997. with Shanthi Muthiah and Maria Fusco.

Price Risk Management: Electric Power vs. Natural Gas, Public Utilities Fortnightly: February 1996. with Charles Mann.

Unbundling the Electric Capacity Price in a Deregulated Commodity Market, Public Utilities Fortnightly: December 1995. with Charles Mann.

FERC's Hourly System Lambda Data as Interim Bulk Power Price Information, Public Utilities Fortnightly, May 1, 1995 with William Booth of the Federal Energy Regulatory Commission.

Natural Gas: The Power Generation Fuel for the 1990s. Published by Enron with Mark Frevert.

TESTIMONY

"Future Wholesale Electricity Prices and the Cajun Bakruptcy," Testimony to Louisiana Public Service Commission, December 1996 and separately to Bankruptcy Court, 1997.

"Future Wholesale Electricity Prices and the Cajun Bankruptcy," Testimony to Bankruptcy Court, forthcoming Saguaro QF, Low Load and Southwest Power Markets" Testimony on a contract arbitration, June 1997.

"Demand for Gas Pipeline Capacity in Florida from Electric Utilities," testimony to Florida Public Service Commission, May 1993.

"The Case for Fuel Flexibility in the Florida Electric Generation Industry," Testimony to the Florida Department of Environmental Regulation (DER), Hearings on Fuel Diversity and Environmental Protection, December 1992.

PROJECT EXPERIENCE

Corporate Strategy

- Conducted a **strategic audit** for a leading gas/power marketer covering key areas of competitive advantages including organization, systems, economies of scale, etc.
- Authored; "Mid-Course Strategic Audit: Electric Power Marketing at the Cross Roads."
- Assisted in a strategy study for a coal hauling railroad. Focus was on extending the value chain.
- Authored a strategy article "GenCos/IPPs: the New Dawn" (in progress).
- Managed **market strategy consulting** assistance to several private companies developing and seeking to market new clean coal technologies including in-furnace sorbent injection, in-duct sorbent injection, joint sulfur dioxide and nitrogen oxide controls, and subbituminous coal upgrading. This assistance included:
    - Market assessments of demand for new technology including demand related to potential future federal acid rain legislation
    - Cost estimation of system and comparison to competing systems
    - Identification of potential technical problems or concerns
    - Business planning including analysis of competing vendors, technologies, definition of market niches, estimation of the costs associated with different strategic approaches to marketing the technology, identification of potential partners for joint ventures and assistance in joint venture negotiations.
    - Negotiation with electric utilities to arrange for new technology demonstrations.

Power Marketing

- Authored ICF Resources' **Bulk Power Service**, a subscription market intelligence project covering 16 U.S. marketplaces.

- Assisted in the development of a **power marketing business strategy** for one of the nation's leading energy companies. Issues addressed included deregulation trends, electric utility economics and industry structure, potential margins, regional differences, retail wheeling, and system lambda.

- Managed the development of the **Wholesale Power Market Model** (WPMM©), for estimating competitive wholesale electricity prices including 8,760 electric energy prices per year. The model has been applied in all regions of the country and is operated in a Microsoft Access environment.

- Developed **market intelligence** assessments for leading power marketing companies on key electric power markets - e.g., ECAR, California, Arizona-New Mexico.

- Provided a scoping overview to DOE on the status and impacts of electric sector ***deregulation***.

- Participated in a scoping level assessment for EIA of the impacts of **deregulation** on the electric power sector.

- Authored for DOE a paper on the importance of interregional **electricity transmission** for electricity supply. This paper estimated some of the benefits of increased interregional transmission capacity including fuel cost savings and reduced oil and gas consumption.

- Authored for EIA an assessment of electric utility **transmission** and distribution capital costs. This assessment led to improvements in the costing module of EIA's Intermediate Future Forecasting System (IFFS).

- Investigated **transmission** line capability issues for DOE including line thermal capacity, system spinning reserve constraints and reactive power constraints.

- Assisted creditors of a financially troubled electric utility cooperative in formulating a plan for eventual repayment of capital. This assistance involved evaluation of the future **markets for bulk power** and powerplant capacity, estimation of avoided power costs and development of a management approach to ensure that the value of the utility's assets could be maximized.

Natural Gas

- Authored the Gas Section of ICF Resources' Energy Service.

- Testified to the Florida Public Service Commission in hearings on a request by SunShine Pipeline Partners for a Certificate of Need to construct a **new gas pipeline** into the state of

- Florida. The certificate was in part granted based on the testimony provided. The principal focus was on the demand for firm pipeline capacity from electric utilities. Other issues examined included demand for natural gas from non-power generators, demand from existing switchable boilers using residual fuel oil, demand from new powerplants, and the accessibility of existing plants to the proposed pipeline. Electricity demand forecasts were developed for the residential, commercial and industrial sectors. Forecasts were also developed for gas, coal and oil generation costs accounting for pipeline reservation charges.

- Conducted an economic analysis for DOE of **natural gas storage**. Analysis included capital cost issues (by type and region) and levelized, average annual cost comparisons with peaking and pipeline gas supply options.

- Analyzed for DOE the use of distillate oil as a back-up fuel for gas-fired **combined cycles**. Issues addressed included NO_x emission regulations, NO_x emissions and combined cycle technology, and gas supply. Used $GASM^2$ to analyze the gas supply impacts of shifting from firm to interruptible supply.

- Wrote the oil section of ICF Resources' Energy Service. Analysis cover **oil-gas competition**.

- Presented paper to IGT, March 1994 Conference on **forecasting** natural gas industry trends.

- Wrote the natural gas section of ICF Resources' Energy Service. Issues addressed included **demand trends, prices, resources** and **E&P technology**. Made presentations on the natural gas industry to several leading U.S. electric utilities.

- Assessed the electric power market potential for gas use for a proposed **pipeline expansion** by a major pipeline company.

- Managed the development of a new model of the U.S. **natural gas industry**, the Gas Systems Analysis Model (GSAM). This model covered such issues as: (1) the role of improvements in exploration, and extraction technology, (2) demand for gas from the residential, commercial, industrial and power generation sectors, (3) inter-regional gas pipeline operation and capacity, (4) **gas storage**, and (5) peaking operations including interruption, air propane injection, etc.

- Conducted an assessment of the impacts of **natural gas vehicles** on the international market for oil. This work was performed as part of ICF Resource's Energy Service, and as part of a review for DOE of the Alternative Fuels Trade Model, which examined the demand for CNG, gasoline, methanol, ethanol, and other motor vehicle fuels.

- Managed analysis of U.S. and worldwide **natural gas "backstop"** prices to assess upper bounds on possible natural gas prices for TVA and DOE.

- Authored widely distributed paper for Enron Power Services on the potential for **natural gas in the electric utility industry** entitled, *Natural Gas: A Power Fuel for the 1990s*.

- Authored paper on the history of **gas-fired combined cycle** powerplants in the U.S for Enron Power Services.

- Authored paper for private subscription clients on recent developments affecting **combustion turbines and combined cycle powerplants** including technological improvements in scrubbers and the impacts of lower natural gas prices.

- Analyzed worldwide **coalbed methane** emissions for DOE.

- Managed a study of the potential to adopt gas marketing techniques to the coal industry.

Coal and Electric Utility Industries

- Assisted in coal contract negotiations with Public Service of New Mexico.

- Authored a study for MAPCo coal on the potential to deliver low medium sulfur coal to Gibson Power Station.

- Assisted in the preparation of cross examination in Georgia proceedings on **coal price forecasts**.

- Assisted in the assessment of Houston Light and Power's coal contracts.

- Author of coal section in ICF Resources' Energy Service. Topics covered included **coal mining labor productivity**, acid rain, UMWA strike, electricity demand and non-utility demand for coal.

- Participated in the preparation of testimony in a **coal contract dispute**.

- Testified to Florida Department of Environmental Regulation (DER now EPA) on **regulation of new powerplants**. The testimony and subsequent reports highlighted competition between coal and natural gas.

- Directed a study for EPRI on improving methodologies for assessing the results of **competitive bids** for new generation sources and DSM. The analysis employed a loss of load probability model to estimate the value of capacity in reducing unserved energy costs and ICF Resources' IPM© model to estimate energy (lambda) and externality (compliance cost) value.

- Co-authored a paper for U.S. Agency for International Development on restructuring the **Coal Industry of Poland**.

- Managed a market based assessment of the **Colorado Coal** industry for a bankrupt utility seeking to renegotiate a coal contract.

- Managed an assessment of the size of the market for **Powder River Basin Subbituminous Coal** associated with utility compliance with the **acid rain** provisions of the 1990 Clean Air Act amendment. This study was conducted for a leading U.S. railroad company.

- Analyzed the impacts on the Florida electric utility industry of new proposed effluent **water quality** standards.

- Managed an assessment of the potential for using Powder River Basin subbituminous coals in cyclone-fired boilers originally designed for bituminous coal for Union Pacific Railroad. Assessment involved calculation of T250 temperatures using ash chemical analyses and development of data base/descriptions on all such conversions.

- Authored paper for private subscription clients on the use of **subbituminous** coal in powerplants originally designed for bituminous coal. Issues addressed included lost plant thermal efficiency costs of plant upgrades, and lost plant capacity (i.e., derate), and several case studies were presented.

- Analyzed **coal demand** at coal-fired powerplants of Northern Indiana Public Service Company (NIPSCO) for a major U.S. coal company. Developed simplified model of NIPSCO'S generation and dispatch system, for analysis.

- Edited a biannual survey of **electric utility industry and coal market** trends for private subscribers of ICF's *Energy Service*. The electric utility section discusses fuel use, capacity utilization, power demand, inter-regional bulk powerflows, avoided costs, new capacity requirements and regulatory and financial developments.

- Participated in the assessment of the environmental impacts of initiatives to encourage electric utility industry **deregulation**: proposed FERC rule changes including revised guidelines for IPPs (Independent Power Producers). Impacts assessed included solid waste, air pollution, etc.

- Authored an assessment of powerplant dispatch, utilization and **fuel consumption** trends for several **lignite**-fired powerplants in the West North Central U.S. This assessment addressed both technical issues which affect availability (e.g., supercritical versus subcritical powerplants), economic issues which affect utility dispatch and system issues such as transmission adequacy.

- Authored an assessment of future utility **dispatch** utilization trends for a large coal-fired power station in the Southwest U.S.

- Estimated the value of a large electric utility under an alternative pricing system where power would be sold at **avoided costs** rather than under prices set by traditional rate of return regulation. This involved computer modeling of the utility system over time and surrounding utility systems.

- Assessed the differences between new bituminous and subbituminous coal-fired powerplants, especially differences in **thermal efficiency** related to fuel moisture content.

- Assisted **a coal transportation** company in contract negotiations with an electric utility. This project involved assessing the utility's dispatching options, variable operating costs, bulk and economy power purchase options and financial health in order to determine the maximum willingness of the utility to pay for coal transportation services.

- Analyzed for the State of Michigan the impact of **powerplant size** on capital costs, operation and maintenance costs, availability and thermal efficiency.

- Authored for DOE analyses of trends affecting the electric utility industry including:

  - Nuclear powerplant availability
  - Inflation
  - New **powerplant costs** including pollution control equipment costs
  - New powerplant construction trends
  - Prospects for new powerplant technologies.

- Analyzed for DOE the issues related to **powerplant retirement** including: refurbishment options, heat rate and availability degradation over time.

- Investigated for private clients involved in litigation the constraints on coal-fired boiler fuel choice imposed by **cyclone furnaces** and wet bottom pulverizer designs.

- Investigated for EPA the constraints on **powerplant cycling** operation imposed by supercritical or universal pressure boiler designs.

Energy Industry Computer Modeling

- Authored CEUM documentation for EPA on the model's treatment of electricity transmission.

- Assisted in managing the redesign and reformatting of the input structures of ICF's Coal and Electric Utilities Model (CEUM). This work was done for the EPA Air Pollution Mission Contract and improved model run time, reduced input preparation costs and made the model more user friendly.

- Managed the development of a hydroelectric powerplant data base which will be added to the Coal and Utility Information System (CUIS).

- Developed a nuclear powerplant data base and included it in the Coal and Utility Information System (CUIS).

- Managed the development of a data base on interregional electric utility transmission connections which can be used to help develop CEUM transmission input specifications.

- Managed the development of a data base on jointly owned utility powerplants and utility holding companies.

- Maintained and upgraded ICF's Coal and Utility Information System (CUIS). Tasks include: validating existing data fields, developing new data fields, developing programs to convert CUIS data into CEUM input structures, and improving programs which convert modelling output into utility specific output using CUIS data.

- Assisted in maintaining and upgrading the Coal and Electric Utilities Model. Projects involved changes in model inputs, structure, and outputs pertaining to emission forecasting, electricity transmission, electricity demand, pollution control equipment, powerplant costs, new powerplant construction and nuclear power.

Renewable Energy

- Analyzed for DOE issues related to **intermittent electricity** production from renewables (wind and solar), and developed methodology for comparing the value of intermittent powerplants to the value of dispatchable technologies. The methodology employed a loss of load probability modeling framework and addressed the following issues: (1) correlation between outages of different intermittent renewable plants, (2) correlation between output of renewables and electric load, (3) spinning reserve and ramp-up required for dispatchable units, and (4) adjustments for energy value when using load duration curves.

- Analyzed the market potential for **biomass** gasification technology for a private developer. Issues included the costs and availability of biomass feedstocks (short rotation woody crops, and sugar cane, agricultural wastes, MSW, sewage sludge, mill and logging residues, animal wastes, etc.), and competition from other biomass technologies, natural gas, and coal.

- Analyzed for the Electric Power Research Institute the value of **intermittent renewables** to electric utilities. Work involved the development of a model of loss of load probability and unserved energy. Issues addressed approximation techniques for capacity states, unserved energy costs, outage state characterizations, emergency power, and characterization of renewables.

- Authored a paper for the Forum on Renewable Energy and Global Climate Change on the **future prospects for renewable energy**.

- Analyzed the **potential for renewable energy** and other CO_2 mitigation alternatives for EPA.

- Analyzed the potential for renewable energy sources to mitigate CO_2 emissions for EPRI and the Central Research Institute of the Electric Power Industry of Japan. Emphasis was on the **contribution to reserve margin**, and intra-annual variations in solar insolation. Six case studies were conducted including one in Japan.

Air Pollution Regulation

- Authored testimony to the Ohio PUC on Cleveland Electric's acid rain compliance plan.
- Authored the Acid Rain Compliance Section in ICF Resources' Energy Service. Also, addressed issues related to NO_x emissions and urban ozone.
- Directed the development for EPRI of a "supply curve" of **CO_2 control options**.
- Directed a bounding study for EPRI on the rapid and complete ("overnight") elimination of coal generation in order to control **CO_2 emissions**. Issues addressed included DSM, biomass, wind, and natural gas prices.
- Managed six electric utility case studies of the long term impacts of **Global Climate Change** and greenhouse gas emission regulations for EPRI and Japan's CRIEPI. Developed assumptions for utility generation options including solar power and assumptions including solar power and assumptions for utility demand including future efficiency and **demand side management (DSM)** options.
- Managed development of supply side information (e.g., natural gas supplies, renewable technologies) for use in an analysis of the utility costs and fuel market impacts of reducing U.S. electric utility **carbon dioxide emissions** for the Department of Energy.
- Analyzed for DOE the impacts of **acid rain** provisions of proposed Administration Bill amendments to the Clean Air Act assuming: (1) availability of clean coal technology, and (2) regulatory incentives for the retrofitting of pollution control system.
- Provided assistance to EPA on **global warming**, related to the costs of carbon dioxide control utilizing these control strategies: (1) CO_2 scrubbers, (2) alternative electricity generation technologies including fuel cells, photovoltaics, solar thermal wind, (3) nuclear power, (4) natural gas substitution, and (6) reforestation.
- Addressed issues related to **global warming**, including: (1) coal mining methane emissions, (2) CO_2 emissions from scrubbing, and (3) CO_2 emissions rates for coal, oil, and natural gas and (4) analysis of CO_2 rates for different types of coal including lignite, subbituminous and low, medium and high volatility bituminous coals.
- Provided assistance to EPA on **stratospheric ozone depletion** issues including estimates of domestic and internal energy use and pollution emission rates associated with CFC use and CFC substitution. Special attention was devoted to the **mobile sources**, its energy use and energy related emissions of carbon monoxide, nitrogen dioxide and other pollutants.
- Analyzed legislative proposals to curb **acid rain** with special emphasis on emission, utility cost, electricity rate, coal production, and mining employment impacts. This was

undertaken as part of the EPA Mission Contract also known as Analytic Support for Evaluating Economic and Environmental Trade-offs of EPA Policies and Regulations. Among the legislative proposal analyzed were the Waxman-Sikorski Bill (HR 3400), the Stafford Bill (S-2203), the Waxman Bill (HR-4567), and the Proxmire Bill (S-2183).

- Analyzed alternative **acid rain** control proposals for EPA under the EPA air pollution mission contract, including: (1) tighter limits on aging powerplants, (2) total emission reduction requirements below historical levels (e.g., six and eight million tons below 1980 levels), and (3) regional average emission rate limits. Also, analyzed alternative implementation scenarios such as required retrofit scrubbing and regional emissions trading ("bubbling").

- Managed a comparison for DOE of historical and forecast estimates of U.S. **sulfur dioxide emissions** developed by different organizations. The goal of the project is to explain differences between the estimates caused by differences in methodology, assumptions and data.

- Analyzed alternative **acid rain** programs for DOE including imposing tighter limits an aging powerplants. Also analyzed implementation policies such as relaxing NSPS scrubbing and emission rate requirements as long as the same total emissions loadings were maintained (i.e., NSPS offsets).

- Analyzed alternative **acid rain** control proposals for a coalition of interest groups led by the National Wildlife Federation and for private utility clients.

- Analyzed the impact of a tighter national **sulfur dioxide ambient air quality standards** (NAAQS) on utility emissions, costs and coal production impacts.

- Analyzed the benefits of sulfur dioxide emission reductions such as reduced regional **acid deposition, sulfate exposure, and visibility degradation**. This analysis used four air transport models in conjunction with CEUM. The purpose of the analysis was to assess the differences in forecast benefits and costs. The value of the benefits were not estimated.

- Analyzed proposed **stack height** regulations using computerized data bases contained in ICF's Coal and Utility Information System (CUIS) and models such as ICF's Coal and Electric Utilities Model (CEUM). This analysis also used air dispersion computer modeling results supplied by SAI.

Air Pollution Control Technology

- Conducted a **business planning** study for the DOE Clean Coal Program

- Authored a **history of sulfur dioxide** scrubbing technology covering R&D, initial installations in England and the U.S. and more recent developments associated with U.S. Clean Air Act amendments of 1970, 1977 and proposed Acid Rain legislation. Prepared for U.S. utility client subject to regulatory review regarding scrubber decisions made in the early 1970s.

- Participated for EPA and other clients in the development of generic and site-specific pollution control **cost estimates**: flue gas desulfurization (i.e., "scrubber") retrofit and new greenfield site installations, combustion modifications for nitrogen oxide controls, post combustion NO_x controls including SCR, natural gas reburning, ESPs, baghouses and other technologies.

- Authored an assessment of the **production capacity** of the flue gas desulfurization industry. This assessment was based on an analysis of historical output, recent consolidation of producers, and the lead times for scrubber system planning, design, construction and testing.

- Managed a study on U.S. DOE coal R&D policy for the Office of Fossil Energy with focus on Clean Coal Technology.

- Authored an assessment of **SO_2 control** technologies for a leading U.S. utility.

- Authored a successful ICF-Kaiser Engineer's/LIFAC North America proposal to the U.S. DOE's Innovative **Clean Coal** Technology (ICCT) program (Round III). The proposed project involved a full scale demonstration of LIFAC SO_2 control technology, using sorbent injection with humidification technology developed in Finland by Tampella Power Corporation. LIFAC NA will conduct the demonstration at Whitewater Valley Unit #2, a 60 MW coal-fired powerplant owned and operated by Richmond Power and Light, a municipally owned utility serving Richmond, Indiana.

- Assisted in the up-front project **set-up** and **negotiations** with DOE which culminated in a $17 million Cooperative Agreement between LIFAC North America and the U.S. DOE. Activities included obtaining necessary regulatory approvals (State of Indiana Certificate of Need and Necessity, environmental permits), arranging a joint venture partnership with Tampella, negotiating with other LIFAC demonstration project participants (e.g., EPRI, Indiana Corporation for Science and Technology), conducting management review.

- Assisted Tampella **market** LIFAC to the U.S. utility industry.

- Participated in **engineering** analysis of LIFAC demonstration at Whitewater Valley Unit #2 including: mass-energy balance development, environmental engineering, design, procurement and construction management, materials selection, etc.

Energy Project Financing/Other Areas

- Assisted in the preparation of the Memorandum of Offering for the project financing of pulverized coal injection facilities at two USS plants (Fairfield and Mon Valley). Analyzed these issues:

  - Steel making economics and costs.
  - Coke prices and economics.

- Alternatives to blast furnaces (e.g., electric arc furnaces, direct steel making.
- Maximum pulverized coal injection coke replacement rates.
- Pulverizer reliability.
- History of blast furnace technology.

- Assisted in the preparation of an **Memorandum of Offering** to potential lenders for project financing of a facility to be built at the USS Gary Indiana steel-making plant. Authored descriptions of technology, specific plants involved, and steel industry developments. This facility will prepare pulverized coal and inject the coal into blast furnaces on site. USS will benefit from the injection by reducing the use of coke and other fuels which are more expensive than coal.

- Authored an assessment of demand for metallurgical coal accounting for trends in demand for steel and in the technology of steel and coke production.

Before joining ICF, Mr. Rose held the following positions:

- **Consultant, National Economic Research Associates (NERA).** Analyzed for EPA financial models that estimate the benefits to utilities of delaying compliance with the Clean Air Act.

- **Teaching Assistant** in probability, statistics and econometrics at Harvard University.

- **Policy Analyst, Israel Ministry of Energy.** Assessed the consequences of the Israel Electric Company's switch from importing oil to importing steam coal. Designed a peak load electricity pricing system for the Israel Electric Company. Also, wrote biweekly assessment of current energy developments for the Minister.

- **Research Assistant, MIT Energy Impacts Project.** Developed for DOE proposals to improve the siting of large-scale energy facilities such as central powerstations and refineries by changing the legal and administrative structure of government regulation. A publications list is available upon request.

- **Teaching Assistant** in Macroeconomics at the Massachusetts Institute of Technology.

SELECTED COMPANY REPORTS

PRIVATE CLIENTS

Global Climate Change

Potential Effects of Climate Change on Electric Utilities, prepared for the Electric Power Research Institute (EPRI), Research Project 2141-11, December 1992.

Potential Effects of Climate Change on Pacific Gas and Electric, prepared for the Electric Power Research Institute (EPRI) and Pacific Gas and Electric (PG&E), Research Project 2141-11, December 1992.

Potential Effects of Climate Change on Southern Company, prepared for the Electric Power Research Institute (EPRI) and Southern Company (SOCO), Research Project 2141-11, December 1992.

Potential Effects of Climate Change on Pennsylvania Power and Light, prepared for the Electric Power Research Institute (EPRI) and Pennsylvania Power and Light (PP&L), Research Project 2141-11, December 1992.

Potential Effects of Climate Change on Salt River Project, prepared for the Electric Power Research Institute (EPRI) and Salt River Project (SRP), Research Project 2141-11, December 1992.

Potential Effects of Climate Change on Hokuriku Electric Power Company, prepared for the Central Research Institute for the Electric Power Industry (CRIEPI) of Japan and the Electric Power Research Institute (EPRI) and Hokuriku Electric Power Company (HEPCo), Research Project 2141-11, December 1992.

Natural Gas

ICF Resources Energy Service 'Natural Gas Forecast, a biannual private subscription service, 1989, 1992

Natural Gas Backstop, prepared for the Tennessee Valley Authority (TVA), November 1992

The History of Natural Gas Combined Cycles in the Utility Sector, prepared for Enron, June 1991

Natural Gas: A Power Fuel for the 1990s, prepared for Enron Power Services, July 1991, revised July 1992

Combustion Turbines: Recent Developments, contained in ICF Resources Energy Service 1989-A, August 1989

Renewable Energy

Renewable Sources of Energy and Energy Market Conditions, Report of the Forum on Renewable Energy and Climate Change, June 14-15, 1989, with Ken Linder

Wind Power Economics, memorandum to Earl Davis, Electric Power Research Institute, December 1992

Biomass Economics, memoranda to Electric Power Research Institute, December 1992

Coal and Electric Utilities

Florida Power's Avoided Costs, prepared for Enron Power Services, September 1992

Delivered Coal Prices at Two Florida Powerplants, prepared for Enron Power Services, July 1992

Crystal River and Acid Rain Compliance prepared for ARCO oil and gas company, November 1991

Colorado Ute/Colowyo Coal Market Assessment, prepared for Pryor, Cashman, Sherman and Flynn, December 14, 1990

Assessment of Mohave Utilization Trends, prepared for Utility Fuels, Inc, November 1987

Analysis of Milton Young Utilization Prospects, prepared for Utility Fuels Inc., April 1988

Powder River Basin Coal: Prospects for Growth, contained in ICF Resources Energy Service 1989-A, August 1989

Technological Trends Affecting Domestic Metallurgical Coal Use, contained in the Energy Service Summer/Fall 1985

Coal Supply: Northern Indiana Public Service's Schahfer 15, prepared for Cyprus Coal Company, May 4, 1989

Assessment of Dakota Lignite Powerplant Trends, prepared for Utility Fuels, Inc., December 29, 1987

Assessment of the Pennsylvania Coal Market, prepared for Delmarva Power and Light, November 1982

Assessment of the Conemaugh Market Area, prepared for The Keystone-Conemaugh Projects, October 1982

Preparation of Generic Environmental Report on Nuclear Power Plant License Renewal, a proposal Submitted to Nuclear Management and Resources Council, Inc., August 17, 1988

Demand Side Management

Preliminary Estimates of Demand Side Management Costs, memorandum jointly prepared with David Kathan for Electric Power Research Institute, December 1992

Utility Water and Solid Waste Pollution

Evaluation of the State of Florida's Proposed Water Quality Standards and the Cost Impact to the Florida Power Industry, Chapter 2, prepared for Florida Electric Power Coordinating Group, August 10, 1990

Acid Rain Economics and Policy

Analysis of Sulfur Dioxide and Nitrogen Oxide Emission Reduction Alternatives with Electricity Rate Subsidies, prepared for the National Wildlife Federation (NWF), et al, October 1985

Analysis of 12 Million Ton SO_2 Reduction Alternatives with SO_2 Control Technology Subsidies, prepared for the Natural Resources Defense Council, July 1983

Analysis of Alternative Averaging Periods for the New Source Performance Standards (Subpart D), prepared for the Utility Air Regulatory Group, April 1984

Analysis of Sulfur Dioxide Emission Reduction Alternatives, prepared for Ohio Edison, November 1985

Analysis of Phased Emission Limit Requirements With and Without LIMB, prepared for Ohio Edison, September 1986

Air Pollution Control Technology

Proposal to Demonstrate LIFAC at Whitewater Valley 2 · Volumes I-IV, presented to the U.S. Department of Energy's Innovative Clean Coal Technology Program on behalf of LIFAC NA, 1989. Proposal accepted for 22 million dollar clean coal demonstration project.

LIFAC Business Planning, presented to Tampella, February 1988

Sorbent Injection Market Assessment: Phase I Overview Report, prepared for Inland Steel Company, August 12, 1987

Analysis of Market Opportunities for Sorbent Injection in the U.S. Utility Industry, prepared for the Inland Steel Company, August 12, 1987

Phase II: Elements of a Business Plan For Sorbent Injection Technology, prepared for Inland Steel Company, November 1987

Joint Venture Partners, presented to Atomic Energy of Canada, Limited, September 22, 1988

Analysis of Market Opportunities for WEST Pollution Control Technology in the U.S. Utility Market: Phase II, prepared for Atomic Energy of Canada Limited, May 1987

Joint Venture Negotiations, presented to Inland Steel, August 30, 1988

Near Term Capacity of the Flue Gas Desulfurization Industry, Appendix C of Analysis of Cost Effective, Phased-In Reductions of Sulfur Dioxide Emissions, prepared for the Alliance for Clean Energy, February 1984

Analysis of the Market Opportunities for Sorbent Injection Technology in the U.S. Industrial Sector, prepared for the Inland Steel Company, August 12, 1987

Market Potential for LIFAC Flue Gas Desulfurization Technology · U.S. Utility Industry and EPRI Members, prepared for the Electric Power Research institute, April 30, 1991

Acid Rain Market Strategy, presented to Burlington Northern Railroad, April, 22, 1991

Description of the Pulverized Coal Injection Facility and Technology, contained Gary PCI Limited Partnership, September 1990, Volume I

The Pulverized Coal Injection Project and Prospects for the United State Steel's Gary Plant, Draft White Paper

GOVERNMENT CLIENTS

Renewable Energy and Climate Change

Utility Studies and Analyses, a proposal to the Solar Energy Research Institute, August 5, 1991

Additional Documentation on CO_2 Control Costs, a memorandum prepared for the U.S. Environmental Protection Agency, April 3, 1989

Natural Gas

Gas Systems Analysis Model (GSAM) · Downstream Issues including Demand, Local Distribution Company Operations, and Gas Pipelines, prepared for DOE's Morgantown Energy Center, draft 1992

Worldwide Coal Mining Methane Emissions, prepared for DOE, November 1992

Electricity Generation and Transmission Planning, Coal

Opportunities in the Polish Coal Industry, prepared for the Agency for International Development (AID), November 1992, draft

Significance of Increased Electricity Transmission for Utility Supply Planning, an Issue Paper from the Alternative Electricity Supply Futures Study, prepared for the Department of Energy, November 1987

New Utility Powerplant Additions, prepared for the U.S. Department of Energy as part of the Alternative Energy Future Project, 1986

New Technology Assumptions, prepared for the U.S. Department of Energy,

Inflation, prepared for the U.S. Department of Energy as part of the Alternative Energy Future Project, 1986

Nuclear Capacity Factors, prepared for the U.S. Department of Energy as part of the Alternative Energy Future Project, 1986

Powerplant Costs, prepared for the U.S. Department of Energy as part of the Alternative Energy Future Project, 1986

Powerplant Life Extension and Refurbishment, prepared for the U.S. Department of Energy as part of the Alternative Energy Future Project, 1986

Powerplant Economies of Scale, a memorandum prepared for Jeff Pillon of the Michigan Electricity Options Study (MEOS) with Bruce Braine, March 6, 1986

Acid Rain

Economic Analysis of the Administration's Proposed Clean Air Act Amendments (Acid Rain Provisions) With Clean Coal Technology, prepared for the U.S. Department of Energy, March 1990.

An Analysis of Sulfur Dioxide Emission Estimates, prepared for the U.S. Department of Energy, February 1987

An Economic Assessment of Long-Term Emission Reduction Alternatives, prepared for the U.S. Department of Energy, May 1985

Preliminary Forecasts of 4, 8, and 12 million Ton Reduction Cases with NO_x Cap · 1995, prepared for the U.S. Environmental Protection Agency, June 1983.

Preliminary Forecasts of 4, 8, and 12 million Ton Reduction Cases with NSPS Offsets, prepared for the U.S. Environmental Protection Agency, June 1983.

Economic Evaluation of Achieving Environmental Objectives Through Sulfur Dioxide Emission Reductions, prepared for the U.S. Environmental Protection Agency, September 1985, Draft

Analysis of a Senate Emission Reduction Bill (S-3041) Assuming the Availability of the LIMB Technology, prepared for the U.S. Environmental Protection Agency, April 1983

Analysis of the Waxman-Sikorski Sulfur Dioxide Emission Reduction Bill (H.R. 3400), prepared for the U.S. Environmental Protection Agency, April 1984

An Economic Analysis of HR-4567: The Acid Deposition Control Act of 1986, prepared for the U.S. Environmental Protection Agency, August 1986

Analysis of a Senate Emission Reduction Bill (S-3041), prepared for the U.S. Environmental Protection Agency, February 1983

Detailed Forecasts: An Economic Assessment of Long-Term Emission Reduction Alternatives, prepared for the U.S. Department of Energy, May 1985

Analysis of Alternative Emission Reduction Strategies: Four/Eight and Twelve Million Ton Reductions and Ten and Twelve State Reductions, prepared for the U.S. Environmental; Protection Agency, October 1984

Analysis of 6 and 8 Million Ton and 30 Year/NSPS and 30 Year 1.2 LB. Sulfur Dioxide Emission Reduction Cases, prepared for the U.S. Environmental Protection Agency, February 1986

NAAQS, NSPS, Visibility, Stack Heights

Analysis of an Alternative Utility New Source Performance Standard and Copper Smelter/Utility Emission Offsets, prepared for the U.S. Environmental Protection Agency, June 1983

Preliminary Economic Assessment of EPA's Proposed Revisions to the Stack Height Regulations, prepared for the U.S. Environmental Protection Agency, November 1984

Final Analysis of the Proposed Stack Height Regulations, prepared for the U.S. Environmental Protection Agency, June 1985

Analysis of Alternative Sulfur Dioxide Ambient Standards, prepared for the U.S. Environmental Protection Agency, August 1984

Analysis of the Promulgated Stack Height Regulations With and Without Emissions Trading, prepared for the U.S. Environmental Protection Agency, August 1986

CFCs

HCFC Analysis · International Energy and Emissions Data, prepared for the Environmental Protection Agency, February 1989, draft

ICF FUEL PRICE AND EIA HEAT RATE CASE
Summary of Results

Year	All Hours Market Price [1] Nominal$/MWh	Realized Market Price for All PECO Units [2] Nominal$/MWh	Associated Fuel Cost for All PECO Units Nominal $/MWh
1999	25.5	28.0	7.4
2000	28.0	31.1	7.9
2001	30.3	34.8	7.9
2002	31.5	36.2	8.1
2003	32.5	37.3	8.2
2004	33.8	38.7	8.4
2005	35.2	40.3	8.6
2006	36.8	42.2	8.9
2007	38.2	43.8	9.2
2008	39.9	45.7	9.5
2009	41.3	47.3	9.8
2010	43.0	49.3	10.2
2011	44.6	51.1	10.6
2012	46.4	53.2	11.1
2013	48.2	55.2	11.5
2014	50.0	57.7	12.2
2015	51.3	60.0	12.9
Levelized 1999-2015	35.6	40.6	9.0

[1] Average energy and capacity revenue received by a 1 MW unit operating in all hours.

[2] These projections represent the market price realized by all PECO units for sales into the PJM bulk power market:

$$\frac{\text{Total Revenues for Capacity and Energy Realized by all PECO Units}}{\text{Total MWh Generated by all PECO Units}}$$

DRI 1997 FUEL PRICE AND EIA HEAT RATE CASE
Summary of Results

Year	All Hours Market Price [1] Nominal$/MWh	Realized Market Price for All PECO Units [2] Nominal$/MWh	Associated Fuel Cost for All PECO Units Nominal $/MWh
1999	24.8	27.3	7.6
2000	27.0	30.1	8.0
2001	29.5	34.0	8.2
2002	30.9	35.6	8.5
2003	31.7	36.5	8.6
2004	32.8	37.8	8.8
2005	34.0	39.2	9.0
2006	35.5	41.0	9.3
2007	36.8	42.4	9.6
2008	38.4	44.2	9.9
2009	39.9	46.0	10.2
2010	41.7	48.1	10.6
2011	43.2	49.7	11.0
2012	44.9	51.7	11.5
2013	46.9	54.0	12.0
2014	49.0	56.8	12.8
2015	50.7	59.5	13.5
Levelized 1999-2015	34.6	39.6	9.3

[1] Average energy and capacity revenue received by a 1 MW unit operating in all hours.

[2] These projections represent the market price realized by all PECO units for sales into the PJM bulk power market:

$$\frac{\text{Total Revenues for Capacity and Energy Realized by all PECO Units}}{\text{Total MWh Generated by all PECO Units}}$$

EIA FUEL PRICE AND EIA HEAT RATE CASE
Summary of Results

Year	All Hours Market Price [1]	Realized Market Price for All PECO Units [2]	Associated Fuel Cost for All PECO Units
	Nominal$/MWh	Nominal$/MWh	Nominal $/MWh
1999	24.8	27.3	7.6
2000	26.4	29.5	7.9
2001	28.6	33.1	8.0
2002	29.6	34.2	8.2
2003	30.5	35.2	8.3
2004	31.6	36.5	8.4
2005	33.0	38.2	8.8
2006	34.8	40.2	9.3
2007	35.9	41.5	9.6
2008	37.3	43.1	9.9
2009	38.6	44.6	10.3
2010	40.1	46.4	10.7
2011	41.6	48.1	11.0
2012	43.3	50.1	11.3
2013	45.1	52.2	11.7
2014	46.9	54.8	12.4
2015	47.7	57.0	13.2
Levelized 1999-2015	33.5	38.5	9.2

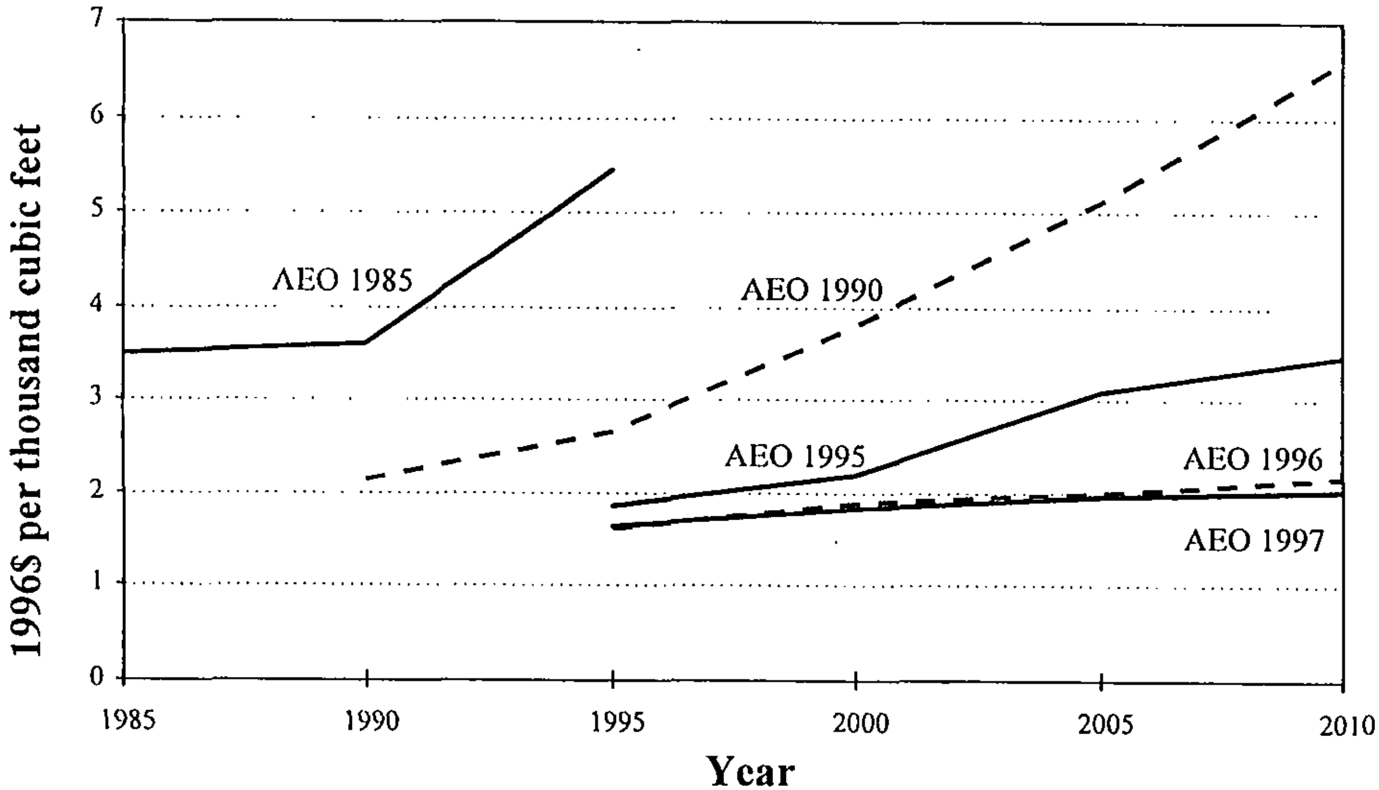
[1] Average energy and capacity revenue received by a 1 MW unit operating in all hours.

[2] These projections represent the market price realized by all PECO units for sales into the PJM bulk power market:

$$\frac{\text{Total Revenues for Capacity and Energy Realized by all PECO Units}}{\text{Total MWh Generated by all PECO Units}}$$

EXHIBIT JLR - 5

Comparison of EIA's Gas Price Forecasts Over Time
(1996$ per thousand cubic feet)



06EK052

Source: Annual Energy Outlook, EIA - 1985, 1990, 1995, 1996, and 1997

EXHIBIT JLR - 6

Corrected Annual Real Fixed Charge Rate Calculation (ARFCR)

Input Assumptions:

Capital Cost:	100,000
Book Life:	23
Rate of Return:	11.95%
Equity Rate:	14.0%
Equity Ratio:	50.0%
Debt Rate:	9.9%
Debt Ratio:	50.0%
Inc. Tax Rate:	41.3%
Other Taxes:	1.00%
Inflation	3.0%
Discount Rate	9.91%

Output:
Levelized Fixed Charge Rate: 12.70%

Year	Depreciation	Accum. Depr.	MACRS Tax Depr. Rate	MACRS Tax Depr. Amount	Deferred Tax	Acc. Def. Tax	Rate Base	Return	Income Tax	Other Taxes	Total Cost	AFCR	Discount Factor	Discounted Cost	Levelized Cost (Real)	Levelized ARFCR
1	4,348	4,348	5.00%	5,000	269	269	100,000	11,950	4,925	1,000	22,222	22.22%	0.910	20,220	12,700	12.7%
2	4,348	8,696	9.50%	9,500	2,128	2,397	95,383	11,398	4,697	1,000	21,443	21.44%	0.828	17,752	12,700	12.7%
3	4,348	13,043	8.55%	8,550	1,735	4,132	88,907	10,624	4,378	1,000	20,351	20.35%	0.753	15,329	12,700	12.7%
4	4,348	17,391	7.70%	7,700	1,384	5,517	82,824	9,897	4,079	1,000	19,324	19.32%	0.685	13,244	12,700	12.7%
5	4,348	21,739	6.93%	6,930	1,066	6,583	77,092	9,212	3,796	1,000	18,357	18.36%	0.624	11,447	12,700	12.7%
6	4,348	26,087	6.23%	6,230	777	7,361	71,678	8,565	3,530	1,000	17,443	17.44%	0.567	9,897	12,700	12.7%
7	4,348	30,435	5.90%	5,900	641	8,002	66,552	7,953	3,277	1,000	16,578	16.58%	0.516	8,558	12,700	12.7%
8	4,348	34,783	5.90%	5,900	641	8,643	61,564	7,357	3,032	1,000	15,736	15.74%	0.470	7,392	12,700	12.7%
9	4,348	39,130	5.91%	5,910	645	9,288	56,575	6,761	2,786	1,000	14,895	14.89%	0.427	6,366	12,700	12.7%
10	4,348	43,478	5.90%	5,900	641	9,929	51,582	6,164	2,540	1,000	14,052	14.05%	0.389	5,464	12,700	12.7%
11	4,348	47,826	5.91%	5,910	645	10,574	46,593	5,568	2,295	1,000	13,210	13.21%	0.354	4,674	12,700	12.7%
12	4,348	52,174	5.90%	5,900	641	11,215	41,600	4,971	2,049	1,000	12,368	12.37%	0.322	3,981	12,700	12.7%
13	4,348	56,522	5.91%	5,910	645	11,860	36,611	4,375	1,803	1,000	11,526	11.53%	0.293	3,376	12,700	12.7%
14	4,348	60,870	5.90%	5,900	641	12,501	31,618	3,778	1,557	1,000	10,683	10.68%	0.267	2,847	12,700	12.7%
15	4,348	65,217	5.91%	5,910	645	13,146	26,629	3,182	1,311	1,000	9,841	9.84%	0.242	2,386	12,700	12.7%
16	4,348	69,565	2.95%	2,950	-577	12,569	21,636	2,586	1,066	1,000	8,999	9.00%	0.221	1,985	12,700	12.7%
17	4,348	73,913	0.00%	0	-1,796	10,773	17,866	2,135	880	1,000	8,363	8.36%	0.201	1,679	12,700	12.7%
18	4,348	78,261	0.00%	0	-1,796	8,978	15,314	1,830	754	1,000	7,932	7.93%	0.183	1,449	12,700	12.7%
19	4,348	82,609	0.00%	0	-1,796	7,182	12,761	1,525	628	1,000	7,501	7.50%	0.166	1,247	12,700	12.7%
20	4,348	86,957	0.00%	0	-1,796	5,387	10,209	1,220	503	1,000	7,071	7.07%	0.151	1,069	12,700	12.7%
21	4,348	91,304	0.00%	0	-1,796	3,591	7,657	915	377	1,000	6,640	6.64%	0.138	914	12,700	12.7%
22	4,348	95,652		0	-1,796	1,796	5,105	610	251	1,000	6,209	6.21%	0.125	777	12,700	12.7%
23	4,348	100,000		0	-1,796	0	2,552	305	126	1,000	5,779	5.78%	0.114	658	12,700	12.7%
24	0	100,000		0	0	0	0	0	0	0	0	0.00%	0.104	0		

R-00973953

PECO STATEMENT NO. 23-R

Phila. 10/14,15,16/97

E. Holbert

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY FOR APPROVAL OF ITS RESTRUCTURING PLAN UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE

REBUTTAL TESTIMONY
OF
JAMES W. SHARPE

REGARDING SFAS 109 ASSET RECOVERY

JULY 1997

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF JAMES W. SHARPE

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James W. Sharpe. My business address is 1100 Campanile Building, 1155 Peachtree Street, Atlanta, Georgia 30309-3630.

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

A. I am a certified public accountant and a tax partner with Coopers & Lybrand L.L.P., an international accounting and business advisory firm. I am the Firm's electric and gas industry leader for the tax line of business.

Q. PLEASE STATE YOUR PROFESSIONAL BACKGROUND AND YOUR CURRENT RESPONSIBILITIES WITH COOPERS & LYBRAND.

A. I have spent the majority of my professional career working in the regulated utility industry. I started my career with South Carolina Electric & Gas Company and worked in the plant accounting department for the first four years of my career. For the next six years, I worked in the tax department and was Director of Income, Property and License Taxes, when I resigned to take a position as Manager of Taxes at Kansas City Power & Light Company.

In 1985, I joined Coopers & Lybrand and was admitted to the Partnership in 1988. Throughout my career with Coopers & Lybrand, I have specialized in the electric and gas public utility industry. As the Firm's electric and gas industry tax leader for the tax line of business, I have direct client responsibility for the delivery of tax services to our electric and gas utility clients. I consult directly with clients and other members of our Firm who provide tax and accounting services to electric, gas, water and telephone regulated utilities. I am responsible for the Firm's utility tax training and I have been a frequent instructor for internal training courses. I have prepared and presented testimony to various state regulatory commissions and the Federal Energy Regulatory Commission with respect to various tax and accounting issues.

I am a frequent speaker on tax and accounting issues before various industry groups, including the Edison Electric Institute, American Gas Association, Exnet and Pennsylvania Electric Association. I frequently write articles for our Firm's publication, *Public Utility Topics*. I am a member of the American Institute of Certified Public Accountants and the Georgia and Pennsylvania CPA Societies. I have a B.S. degree and M.B.A. from the University of South Carolina.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. In my testimony, I respond to the direct testimony of Mr. Lane Kollen on behalf of Philadelphia Area Industrial Energy Users Group ("PAIEUG") and Mr. Thomas S. Catlin on behalf of the Pennsylvania Office of Consumer Advocate. More specifically, my testimony explains the accounting treatment of the SFAS 109 Regulatory Asset if the Commission were to adopt the stranded cost recovery proposals for that asset recommended by Messrs. Catlin and Kollen.

II. SFAS 109 REGULATORY ASSET RECOVERY

Q. HAVE YOU REVIEWED THE TESTIMONY OF MESSRS. CATLIN AND KOLLEN REGARDING THE RECOVERY OF THE SFAS 109 REGULATORY ASSET?

A. Yes

Q. WOULD YOU BRIEFLY SUMMARIZE THEIR PROPOSAL?

A. Yes. Messrs. Catlin and Mr. Kollen propose that PECO recover the "present value" of the SFAS 109 asset over a 27 (Kollen) or 25 (Catlin) year period, and they calculate the net present value using slightly different discount rates. The methodology used by both is the same. The recovery period that Mr. Kollen proposes is based upon the estimated average remaining lives of the generation units. Mr. Catlin proposes that a 25-year period be used. They *contend that the* SFAS 109 Regulatory Asset *should be discounted because the* quantification must be based upon the amounts and pattern of recovery the Company would have obtained under "traditional regulation" (Mr. Kollen's Direct Testimony at Line 21, Page 13 and Mr. Catlin at Line 5, Page 20). Mr. Kollen also states that PECO will not recognize an immediate write-off or write-down of its SFAS 109 Regulatory Asset if the Commission accepts the PAIEUG recommendation

Q. ARE MESSRS. CATLIN AND KOLLEN CORRECT IN THEIR ASSUMPTION THAT THE SFAS 109 LIABILITY WILL BE PAID OVER THE REMAINING

LIVES OF THE GENERATION UNITS, A PERIOD AS LONG AS 25 OR 27 YEARS?

A. No. It is correct that the generating units have an average estimated remaining life of 26.9 years. However, that is not the period in which most of the SFAS 109 asset associated with those generating units will reverse. The deferred tax liabilities related to PECO's SFAS 109 regulatory asset will come due as PECO recovers the Competitive Transition Charge ("CTC"). That is, the tax bill related to the SFAS 109 deferred tax asset will become due and payable to the federal and state tax authorities as PECO recovers the CTC from its customers.

Messrs. Catlin and Kollen assume that the tax bill will be paid over the remaining lives of the generation assets, i.e., over the time period and pattern that would have applied under "traditional regulation." Mr. Catlin and Mr. Kollen seem to ignore the fact that The Electricity Generation Customer Choice and Competition Act ("Competition Act") changes "traditional regulation" for the generation business and restricts PECO to recovery from its customers of its "stranded costs" related to such generation assets over the time period that the CTC may be collected, as specified in the Competition Act. The CTC replaces the book depreciation and amortization expense that normally would be collected under traditional regulation during the generating units' respective remaining lives with an expense that will be collected over 7 years. There is no corresponding tax deduction related to the CTC or amortization of the stranded cost and, thus, the SFAS 109 asset reverses over the 7 year CTC period. In other words, the CTC that represents

PECO's stranded costs in its generating assets replaces book depreciation and that charge in lieu of depreciation will be collected over 7 years rather than 25 or 27 years. Thus, the majority of the tax bill associated with the SFAS 109 asset will become due and payable over the CTC recovery period, *not* over the remaining lives of the generation units.

The remaining lives of the generation plants do not impact the timing of when the tax bill associated with the SFAS 109 regulatory asset becomes due. In effect, all book/tax differences related to stranded costs will reverse over the time period the CTC is collected. While the book/tax differences related to the "market value" of the generation units that are not "stranded" will reverse over the remaining lives of such units, PECO has already taken this longer reversal period into account and reflected it as an increase in the market value of its generating plants, as Mr. Cohn explains in his rebuttal testimony.

In summary, the Competition Act has changed permanently the pattern of capital cost and deferred tax recovery that prevailed under traditional regulation. Thus, any assumption that the deferred taxes booked pursuant to SFAS 109 can continue to be deferred for as long as the remaining lives of PECO's generating plants is simply wrong. PECO's proposal to recover its SFAS 109 regulatory asset over the seven-year CTC recovery period without a return on the unamortized balance matches recovery from customers with PECO's payment obligation to the federal and state governments. In this way, PECO's proposal properly takes into account the net present value component of its SFAS 109 asset.

Q. HAVE YOU REVIEWED MR. WARREN'S REBUTTAL TESTIMONY ON THE SFAS 109 REGULATORY ASSET?

A. Yes.

Q. DO YOU AGREE WITH HIS ANALYSIS OF WHY THE SFAS 109 REGULATORY ASSET SHOULD NOT BE DISCOUNTED?

A. Yes. As Mr. Warren correctly describes, the CTC triggers the loan repayment to the government for tax benefits previously given to customers. Thus, PECO will need a source of funding over the seven-year period that the CTC is in effect in order to pay the tax that will be due and payable to the tax authorities. Any present value discounting will obviously penalize PECO and will result in a real economic loss.

Q. MR. KOLLEN STATES THAT HIS PROPOSAL, IF ADOPTED, WOULD NOT REQUIRE PECO TO RECOGNIZE AN "IMMEDIATE WRITE-OFF OR WRITE DOWN" OF ITS SFAS 109 ASSET. IS HE CORRECT?

A. No. SFAS 109 requires that PECO record its future tax liabilities on its balance sheet. Paragraph 29 of SFAS 109 allows utilities to book an asset for any tax that has been flowed through to ratepayers if it is probable that those tax liabilities will be recovered from customers through future rates. Mr. Kollen states on page 18 of his testimony that "the PAIEUG valuation reflects a net present value based on straight-line amortization over the underlying lives of the generating units, consistent with the expected collection of PECO's future tax entitlements under traditional regulation, as required under the Competition Act." Mr. Kollen misses the point. Under the Competition Act, PECO's generation business will no longer be treated under the traditional regulatory process and there are no future tax entitlements to be had from regulation for the generation of electricity. All benefits from regulation, if any, are gone under the Competition Act. Thus, the full amount of PECO's SFAS 109 regulatory asset related to the generation business must be included in its stranded cost calculation as provided in the Competition Act in order for PECO to avoid a write-off.

Under the accounting rules, the full amount of the SFAS 109 Regulatory Asset related to the generation business will be removed from PECO's books and replaced by a new regulatory asset--stranded costs representing the future revenues that will be collected through the CTC. In effect, the specific SFAS 109 Regulatory Asset will be replaced by a new stranded cost regulatory asset that includes the SFAS 109 Regulatory Asset and the other items that make up PECO's stranded costs. Any difference between the SFAS 109 Regulatory Asset removed from PECO's books and the amount that is allowed by the Commission for that asset in this proceeding will result in a charge to income (a write-off). The accounting treatment is reflected by the following examples.

Assume the Commission allows the full SFAS 109 Regulatory Asset.

Debit	Stranded Cost-Regulatory Asset	$1,687 million
Credit	SFAS 109 Regulatory Asset	$1,687 million

The foregoing entries record the removal of the SFAS 109 Regulatory Asset due to the Restructuring Plan's converting generation to full competition from traditional regulation.

<u>Assume the Commission allows only $1,000 million of SFAS 109 Regulatory Asset</u>

<u>Debit</u>	Stranded Assets-Regulatory Asset	$1,000 million
<u>Debit</u>	Expense (write-off)	$ 687 million
<u>Credit</u>	SFAS 109 Regulatory Asset	$1,687 million

The foregoing entries record the removal of the SFAS 109 Regulatory Asset due to the Restructuring Plan's converting generation to full competition from traditional regulation and record the write-off due to the Commission's not allowing the full amount of the SFAS 109 Regulatory Asset.

As reflected in the above accounting entries, the Commission must allow the full amount of PECO's SFAS 109 Regulatory Asset in order to avoid a write-off. It is because the generation assets will no longer be subject to regulation that the SFAS 109 Regulatory Asset must be removed from PECO's books. Any difference between the amount allowed and the generation-related amount on PECO's books will be a charge to the income statement in the year the Restructuring Plan is final. The required write-off reflects economic reality because PECO will need to pay the tax bill over seven years and the Commission will have reduced the revenues to be collected by discounting based on an assumed payment period of 25 or 27 years. Stated another way, the present value of PECO's required tax payments would exceed the present value of the revenue stream provided for recovery of its SFAS 109 regulatory asset. That difference in present values reflects a real economic loss to PECO and, therefore, necessitates a write-off. Thus, the full amount of the SFAS 109 Regulatory Asset should be allowed by the Commission.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

R-00973953

PECO STATEMENT NO. 24-R

Phila. 10/14,15,16/97

B. Halbert

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY
FOR APPROVAL OF ITS RESTRUCTURING PLAN
UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE

REBUTTAL TESTIMONY

OF

WILLIAM M. STOUT, P.E.

Responding to Opposing Parties' Testimony
Regarding Fossil Decommissioning Costs

July 18, 1997

REBUTTAL TESTIMONY OF WILLIAM M. STOUT, P.E.

Q. Please state your name and business address.

A. William M. Stout. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. With what firm are you associated and what is your position?

A. I am President of the firm of Gannett Fleming Valuation and Rate Consultants, Inc.

Q. What is your educational background?

A. I have a Bachelor of Science degree in Management Engineering from Rensselaer Polytechnic Institute.

Q. Are you a registered professional engineer?

A. Yes, I am registered in the Commonwealth of Pennsylvania.

Q. Are you a member of any professional societies?

A. Yes, I am a member of the National and Pennsylvania Societies of Professional Engineers, the Institute of Industrial Engineers, the American Gas Association (AGA), the American Water Works Association (AWWA), the American Railway Engineering Association and the Society of Depreciation Professionals (SDP). I am a former member of the Rates & Charges Subcommittee of AWWA, a member of the Industry Accounting Committee of AGA and President of SDP.

Page
2
Missing

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

A. While attending Rensselaer, I was employed by the Valuation Division of Gannett Fleming Corddry and Carpenter, Inc., during the summers of 1970, 1971, and 1972. My principal assignments related to valuation studies and computer programming.

After my graduation in June 1973, I was employed by the Valuation Division as a Valuation Engineer. The scope of my depreciation activities has included assembly of basic data, statistical service life analyses utilizing the retirement rate and simulated plant record methods, field surveys, estimation of service life and salvage, calculation of annual and accrued depreciation, and preparation of reports presenting the results of the studies.

The scope of my cost of service activities has included the selection of customers to be demand-metered, the analysis of recorded customer demands, the development of cost allocation factors, the allocation of costs, the analysis of customers' consumption, the application of present and proposed rates to the consumption analysis, the design of rate structures, and the preparation of reports presenting the results of the studies.

Since January 1978, I have testified in support of the studies conducted under my direct supervision. In January 1980, I was assigned to the position of Manager of Depreciation and Cost Allocation Studies conducted by the Valuation Division. In June 1982, subsequent to a corporate reorganization, I became a Vice President of Gannett Fleming Valuation and Rate Consultants, Inc. I became a Senior Vice President in 1991 and attained my current position of President in 1994.

Q. Do your professional activities include participation in continuing professional educational programs?

A. Yes, they do. I have completed the "Fundamentals of Life Estimation," "Forecasting Service Life," and "Making and Administering [Depreciation] Policy" programs conducted by the Center for Depreciation Studies at Western Michigan University. Since 1985, I have been a member of the faculty of Depreciation Programs, Inc., lecturing on "Forecasting Service Life," "Fundamentals of Salvage Analysis," and "Managing a Depreciation Study". I also am an instructor at the annual Advanced Accounting Seminar sponsored by the AGA.

Q. Have you previously testified on the subject of depreciation and other public utility ratemaking matters?

A. Yes. I have testified before the Pennsylvania Public Utility Commission, the Illinois Commerce Commission, the Connecticut Department of Public Utility Control, the New Jersey Board of Public Utilities, the New York Public Service Commission, the West Virginia Public Service Commission, the Arizona Corporation Commission, the Georgia Public Service Commission, the Indiana Utility Regulatory Commission, the Alaska Public Utilities Commission, the Texas Public Utility Commission, the Federal Energy Regulatory Commission, the National Energy Board of Canada, the Canadian Radio-Television and Telecommunications Commission, the Alberta Energy & Utilities Board, the Newfoundland Board of Commissioners of Public Utilities and the United States Tax Court.

Q. What is the purpose of your rebuttal testimony?

A. I have been asked by PECO Energy Company ("PECO" or the "Company") to respond to portions of the direct testimony of Office of Consumer Advocate witness Richard La Capra and Philadelphia Area Industrial Energy Users Group (PAIEUG) witness Lane Kollen.

Q. What are the subjects of your rebuttal testimony?

A. The subjects of my rebuttal testimony are (1) Mr. Kollen's characterization of fossil decommissioning costs as speculative or not known and measurable, (2) Mr. La Capra's conclusion that "it is not normal practice to 'decommission' fossil units," (3) Mr. Kollen's reliance on the Penn-Sheraton decision and (4) Mr. La Capra's conclusion that fossil decommissioning costs would have to be reflected in the market price for electricity.

Q. Do you consider Mr. LaGuardia's estimates of fossil decommissioning for PECO to be speculative or uncertain?

A. No, I do not.

Q. What is the basis for your opinion?

A. Mr. LaGuardia has significant professional experience in power plant decommissioning and cost estimation. He is well-respected throughout the industry. Further, his estimates of decommissioning costs indicate negative net salvage percents that are within the range of negative net salvage percents and costs per kilowatt used in the electric utility industry.

Q. What do you mean by negative net salvage percents?

A. By negative net salvage percents, I am referring to the cost of decommissioning as a percent of the original cost of the fossil fuel production plants.

Q. What is the indicated negative net salvage percent for PECO's fossil stations?

A. The negative net salvage percent is 11 based on Mr. LaGuardia's decommissioning cost estimate of $144.6 million and an original cost of steam production plant of $1,347.1 million.

Q. How does this negative net salvage percent compare to the negative net salvage percents used by other electric utilities?

A. The range of negative net salvage estimates for steam production plant in the New England and Middle Atlantic areas is from 5 to 30 percent negative net salvage.

Q. What is the source of the data related to electric industry net salvage percents?

A. The data were obtained from the most recent annual Depreciation Statistics Report of the Edison Electric Institute/American Gas Association.

Q. How many electric utilities participated in the survey that the Depreciation Statistics Report summarizes?

A. Based on the data for Account 312, Boiler Plant Equipment, generally the largest steam production plant account, a total of 65 electric utilities participated, including 5 from Pennsylvania.

Q. How many states are represented by the 60 non-Pennsylvania electric utilities?

A. There are 33 states represented by the 60 utilities located outside of Pennsylvania.

Q. Do these states include those that are contiguous to Pennsylvania?

A. Yes. The states represented by the reporting utilities include New Jersey, New York, Ohio, Maryland and Delaware.

Q. What is the average cost per kilowatt indicated by Mr. LaGuardia's estimate of fossil decommissioning?

A. The average cost per kilowatt indicated in Mr. LaGuardia's estimate is $51.

Q. How does this average cost per kilowatt compare to the average costs per kilowatt reflected in the negative net salvage, or decommissioning cost, estimates of other electric utilities?

A. The costs per kilowatt reflected in others' estimates of decommissioning costs average $42 to $55 per kilowatt for coal units of similar size and $35 to $52 per kilowatt for gas and oil units.

Q. What is the source of the data related to average cost per kilowatt?

A. The data were obtained from the paper "Power Plant Removal Costs Revisited" presented by John S. Ferguson to the Edison Electric Institute's Property Accounting and Valuation Committee on May 19, 1997. Mr. Ferguson's paper is set forth in Exhibit WMS-1.

Q. What is your conclusion regarding Mr. LaGuardia's estimates of fossil decommissioning costs?

A. Mr. LaGuardia's estimates are not speculative, rather, they are based on sound engineering practice and are consistent with the estimates used throughout the electric utility industry.

Q. Are the estimates of fossil decommissioning for other electric utilities used for ratemaking purposes?

A. Yes, they are. As shown in a 1991 paper by R. C. Caldwell, Jr., most electric utilities that have estimated decommissioning costs recover such costs in rates. The paper is set forth in Exhibit WMS-2.

Q. Have fossil units been dismantled?

A. Yes, they have. Mr. La Capra's conclusion that "it is not normal practice to 'decommission' fossil units" based on the response to Interrogatory OTS-RB-27 is erroneous. The interrogatory response identifies four plants that have been dismantled. In addition, I am personally aware that Duquesne Light Company, a Pennsylvania electric utility, has completely dismantled its Colfax and Reed Power Stations.

Q. **Is there a reason to dismantle fossil units?**

A. Yes. In my opinion, fossil units will be dismantled in order to protect the public health and safety.

Q. **Mr. Kollen also has noted the Commission's previous rejections of claims for fossil decommissioning based on the 1962 Superior Court order referred to as the Penn-Sheraton decision. Are there reasons that this decision should not apply to the determination of stranded costs?**

A. Yes, there are. First, the Competition Act specifically includes within its definition of stranded costs: "Retirement costs attributable to the utility's existing generating plants other than the costs defined in paragraph (1)." Paragraph (1) referred to the unfunded portion of the utility's nuclear generating plant decommissioning costs. Thus, it is clear that the retirement costs referred to must be those related to fossil generating plants.

Second, exclusion of such costs would place PECO in a "Catch-22" situation. Although the market may or may not reflect such costs in the future, the market certainly will not reflect the costs that other electric utilities have already accrued. Since the market will not reflect such costs, regulation, through a competitive transition charge, must.

Q. **What is the basis for your statement that other electric utilities have already accrued decommissioning costs?**

A. I have been involved in utility ratemaking for over 25 years and conducted depreciation studies for utilities in numerous jurisdictions. I also have participated on industry committees for many years. As a result of this experience and participation, I have concluded that every state regulatory commission in the United States other than Pennsylvania permits the recovery of prospective negative net salvage in customer rates. This practice is in accord with Generally Accepted Accounting Principles and recovers decommissioning costs from the customers that are served by the power unit.

Inasmuch as all other commissions permit the recovery of prospective negative net salvage in rates and the papers noted previously in my testimony indicate that other electric utilities estimate fossil decommissioning costs, then other electric utilities have already accrued significant portions of the decommissioning costs for their fossil power plants.

Q. Would these utilities be competitors of PECO and other Pennsylvania electric utilities?

A. Yes. Electric utilities in states adjacent to Pennsylvania have already accrued fossil decommissioning costs.

Q. If electric utilities in the same region have already accrued significant fossil decommissioning costs during the life to date of their power plants, is it logical that future market revenues would recover such costs?

A. No, it is not. The market revenues will not incorporate the catch up for past under accruals that only Pennsylvania's electric utilities need to accrue.

Q. Please summarize your rebuttal testimony.

A. PECO's estimated fossil decommissioning costs are reasonable, not speculative. They are based on sound practice and consistent with levels expected throughout the industry. Fossil stations have been dismantled and will continue to be dismantled in order to protect the public.

Fossil decommissioning costs for Pennsylvania utilities are clearly an element of stranded costs based on the restructuring legislation and the fact that the future market will not support costs which electric utilities in other jurisdictions have already recovered through regulated rates.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

POWER PLANT REMOVAL COSTS REVISITED

John S. Ferguson
Ferguson Associates
Richardson, Texas

Presented at Meeting of

A.G.A. Accounting Services Committee
EEI Property Accounting and Valuation Committee

Orlando, Florida
May 19, 1997

ANNOTATION

Knowledge of expected removal costs of non-nuclear generating stations has always been important for regulatory accounting purposes. This knowledge may become even more important for financial accounting purposes as a result of an accounting standard that has been proposed by the FASB, *Accounting for Certain Liabilities Related to Closure or Removal of Long-Lived Assets*.

POWER PLANT REMOVAL COSTS REVISITED

John S. Ferguson
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Richardson, Texas

The realization that steam generating units will be expensive to remove, relative to their original cost, has caused many utilities to conduct site-specific removal cost estimates. My December 7, 1992, presentation to the A.G.A. Plant Accounting and EEI Property Accounting and Valuation Committees summarized a collection of such estimates that were then a matter of public record for about 400 gas, oil, coal and lignite units. This presentation updates and expands upon the prior presentation for steam units, and adds an internal combustion category comprised of diesel, combustion turbine and combined cycle units.

Knowledge of expected removal costs of non-nuclear generating stations has always been important for regulatory accounting purposes. This knowledge may become even more important for financial accounting purposes as a result of an accounting standard that has been proposed by the Financial Accounting Standards Board (FASB or Board), *Accounting for Certain Liabilities Related to Closure or Removal of Long-Lived Assets*.

THE FASB PROPOSAL

The proposal reflected in the exposure draft issued by the Board on February 7, 1996 requires the estimated future costs for legal or constructive obligations incurred early in the life of assets to be recorded on the balance sheet as liabilities at their present value. Discounting would be at the risk free rate (U.S. Treasury securities of a maturity equal to that of the obligation) applicable when the obligation is incurred, and the rate would never change. The initially recorded liability amounts would have corresponding equal amounts recorded as a cost of the assets. The future accretion of the liability amounts would be recorded as interest expenses and the corresponding asset cost amounts would be depreciated on a ratable basis over the live of the asset. This accounting treatment is referred to herein as *liability treatment*.

The costs for obligations that do not qualify for liability treatment would be depreciated up to the amount of salvage proceeds, and any excess would be expensed when incurred. This accounting treatment is referred to herein as *cash treatment*.

Estimated future salvage proceeds would continue to be handled on a ratable basis through depreciation under either liability or cash treatment.

Constructive obligations are those for which no legal requirement exists, but which cannot be avoided. The cost estimates for determining liability amounts or salvage proceed offsets for cash treatment are to recognize direct costs, future inflation, unforeseen circumstances and near-term future technological advances.

Adoption was proposed to be for fiscal years beginning after December 15, 1996. The cumulative effect of adoption would be recorded upon implementation, based on the assumption that the standard had been in effect at the time the existing assets were placed in service. The Board recently rescheduled publication of the final standard, so implementation will be delayed by at least one year.

IMPLICATIONS OF THE PROPOSED STANDARD

The Securities and Exchange Commission has long required certain financial statement disclosures for the obligations to decommission nuclear power plants. The FASB exposure draft is the first proposal for similar treatment for the removal costs of other types of assets. Therefore, utilities have not usually disclosed the extent of their obligations for non-nuclear generating units or whether such obligations are currently being funded. The proposed standard would require such disclosures for any asset that qualifies for liability treatment, not for just power plants.

The proposed standard would have no effect on depreciation for regulatory accounting purposes, unless regulators change their accounting rules to conform to financial accounting. Entities qualifying for the special accounting under SFAS 71 would record regulatory assets or liabilities for any differences between regulatory accounting and financial accounting. Salvage is treated ratably as a component of depreciation under regulatory accounting, and there is no difference under the exposure draft. Cost of removal is also treated ratably through depreciation under regulatory accounting, but would be treated differently under the exposure draft. The exposure draft requires cost of removal to be segregated into two components for either liability or cash treatment. One component would be handled ratably through depreciation and the other component would be backloaded through the accelerating accretion of a liability or the recording of a period expense upon expenditure.

Regulation commonly backloads the recording of cost of removal relative to the pattern of asset usage or revenue generation. My estimate is that the average gas distribution and electric utility will find the extent of liability treatment backloading to be similar to the extent of regulatory backloading, so the extent of cash treatment backloading would be greater than regulatory backloading.

Continued ratable treatment of salvage through depreciation would require that salvage estimates be segregated from cost of removal estimates. Many of the site-specific estimates I have utilized for this discussion disclose this segregation, but not all do. Therefore, only net salvage estimates are shown herein, and are expressed as net removal amounts.

Power plant removal cost estimates made for regulatory purposes often consider only current conditions, because many regulators will not allow terminal conditions to be reflected in depreciation. The exposure draft requires terminal conditions to be determined for financial accounting. The costs to be discounted under liability treatment are the expected expenditures at the time the obligation is satisfied, expressed at the price level at that time. The exposure draft proposes disclosure of the current cost, the future cost, the discounted cost, and, for the facilities existing at adoption, the cost when placed in service. Terminal conditions would also be necessary under cash treatment to determine if cost of removal exceeds salvage, but there is no balance sheet disclosure of the costs, so may not require the definitive estimates needed for liability treatment.

Electric utilities have long been confronted with proposals to utilize sinking fund depreciation to backload the recording of the usage of high cost facilities, such as power plants. To their credit, regulators have usually denied such proposals, because of the resulting deferral in recording the costs until the facilities are old and unlikely to be very productive. Now sanctioning a quite similar backloading for some of these costs for financial reporting could expand the extent of backloading for regulatory accounting, and proposals to do so have already begun.

SIGNIFICANCE OF COST ESCALATION

Power plant removal is labor intensive, and labor costs are sensitive to cost escalation rates. The significance of cost escalation to financial accounting under the exposure draft is obvious, since terminal conditions are to be reflected. Cost escalation also has significance to regulatory accounting, because the accounting rules of the Uniform Systems of Accounts promulgated by state and federal regulators define salvage and cost of removal. The following definitions are from the Uniform Systems of Accounts for the Federal Energy Regulatory Commission for electric utilities:

> *Salvage value* means the amount received for property retired, less any expenses incurred in connection with the sale or in preparing the property for sale; or, if retained, the amount of which the material recoverable is chargeable to materials and supplies, or other appropriate account.
>
> *Cost of removal* means the cost of demolishing, dismantling, tearing down or otherwise removing electric plant, including the cost of transportation and handling incidental thereto.

Both of these definitions imply measurement at the price level at the time the salvage will be received and the cost of removal will be incurred. The effect of cost escalation is incorporated into actual experience, but, when actual experience does not exist or is not appropriate, estimates in terms of the expected price level at the time salvage would be received and cost of removal would be incurred are required, which is the same as for the exposure draft.

For near-term removals, the effect of future cost escalation would be minimal for both regulatory and financial accounting. However, for generating units expected to be removed well into the future, future cost escalation is likely to have a material effect on the terminal estimates. Discounting backloads the effect of cost escalation under liability treatment and the backloading is even more severe for any costs in excess of salvage proceeds under cash treatment. Thus, escalated amounts would be reflected for financial accounting purposes, and should (but may not) be reflected in depreciation under regulatory accounting.

VALUE OF PLANT SITES

Generating sites are valuable, and claims are sometimes made in regulatory proceedings that site value should be offset against expected removal costs. There is no question that such sites are valuable. However, land is not depreciable, so does not produce salvage. Therefore, site value has no significance to depreciation accounting under either regulatory or financial accounting, and the proposed standard would not alter this situation.

REASONS FOR HIGH REMOVAL COSTS

Insulation containing asbestos, boiler design, ash ponds, flue gas desulphurization units (scrubbers) and site restoration requirements cause steam units to have high removal costs. These factors have little or no effect on internal combustion units, so their removal costs are lower.

Insulation Containing Asbestos

As a general rule, generating units constructed prior to the early 1970's can be expected to have insulation containing asbestos. The hazards of asbestos and the requirements for careful handling are well known, and make removal and disposal of insulation containing asbestos very expensive. Asbestos removal is done by specialized contractors, and demolition can commence only after all asbestos has been removed and the site certified as clean.

Boiler Design

Modern boilers are hung by their top from a multi-story steel superstructure. Older boilers are self-supporting, resting on foundations. Power plants having the older style boilers lend themselves to removal using a wrecking ball, once the asbestos has been removed.

The large superstructures of modern generating units do not allow use of a wrecking ball for boiler demolition, and the explosive techniques commonly used for large buildings may not be safe. Blasting could be utilized to drop the boiler and superstructure in a heap. However, the pile of materials would have to be cut up for removal, but would contain residual stresses that may preclude safely doing so. Therefore, a piecemeal removal procedure that resembles the original construction process may be necessary for modern boilers. This method of boiler removal is expensive, and the combination of the weight of the boiler itself and the superstructure results in a massive foundation that is expensive to remove. The costs will be further increased if there is any asbestos present.

Most existing steam generating units have top-hung boilers.

Ash Ponds and Scrubbers

Ash ponds requires sealing. Scrubbers provide additional facilities to be removed and may provide some scrap. However, scrubbers may produce by-products that have been disposed of on-site and require special handling in the same manner as ash ponds, thereby increasing cost of removal.

Site Restoration

Site restoration costs are sensitive to local regulations and agreements, fuel type and cooling system design. Coal and lignite units require costly activities not required for gas and oil units. Cooling lakes that require modification or removal are expensive to deal with, as is removing or filling circulating water piping. Such circumstances influence the level of cost of removal.

COST ESTIMATES

While many of the cost estimates discussed here include amounts at the price level at the time of removal, I have made use of only the amounts at the price level at the time of the studies. The costs presented are as of 1996, and were calculated from the study costs using an annual escalation rate of 3%.

Figure 1 graphs the net removal costs per kW of capacity for 264 coal and lignite units that average about 294 MW each. Each point represents a complete station or a unit or group of units listed on Figure 2 for which the estimator segregated the costs. Figure 1 demonstrates the sensitivity of cost per kW to unit size, so Figure 2 shows the net removal cost of each station, unit or group of units in total and per kW and categorizes the list into six size groups. Figures 3 and 4 show the same data for 201 gas and oil units that average about 185 MW each.

Figure 5 lists the net removal costs for 133 simple cycle combustion turbine units that average about 47 MW each. Figure 6 shows the same data for diesel and combined cycle units.

Some utilities have conducted removal cost studies for hydraulic generating plants, but very few are in the public record. Such plants are so unique that their cost estimates are unlikely to be of much significance to other utilities.

The cost of $41/kW for the coal and lignite units shown at the bottom of Column 7 of Figure 2 is only about five percent higher than the $39/kW for the gas and oil units shown on Figure 4. This difference is less than would be expected for the larger boilers and extensive fuel systems of coal and lignite units, and is the consequence of two factors - economy of scale (unit size) and the age of the facilities. The average in-service date of the coal and lignite units is 1970 and the average size is nearly 60 percent larger than the average gas and oil unit installed in 1965. If the gas and oil units and the coal and lignite units had been the same age, utility labor cost indices indicate the difference would have been about 50 percent. Listed below are the other average in-service dates of the generating units listed on Figures 2, 4, 5 and 6:

	Coal & Lignite	Gas & Oil
STEAM UNITS		
100 MW or Less	1952	1950
101 - 250 MW	1961	1959
251 - 500 MW	1972	1964
501 - 750 MW	1976	1976
751 - 1000 MW	1975	1976
Over 1000 MW	1977	
SIMPLE CYCLE COMBUSTION TURBINE UNITS		1974
COMBINED CYCLE UNITS		1986

The diesel installation dates were not identified.

CONCLUSION

The costs summarized herein may be of value for evaluating the reasonableness of the terminal net salvage factors utilized for regulatory accounting and the extent to which cost of removal exceeds salvage for obligations requiring cash treatment. However, determining liability amounts needed for financial accounting purposes may require the more specifically applicable cost estimates available only from site-specific demolition studies. Of course, site-specific estimates that support financial reporting would also be useful for regulatory accounting. The summaries herein do not provide a basis for judging the validity of individual site-specific studies.

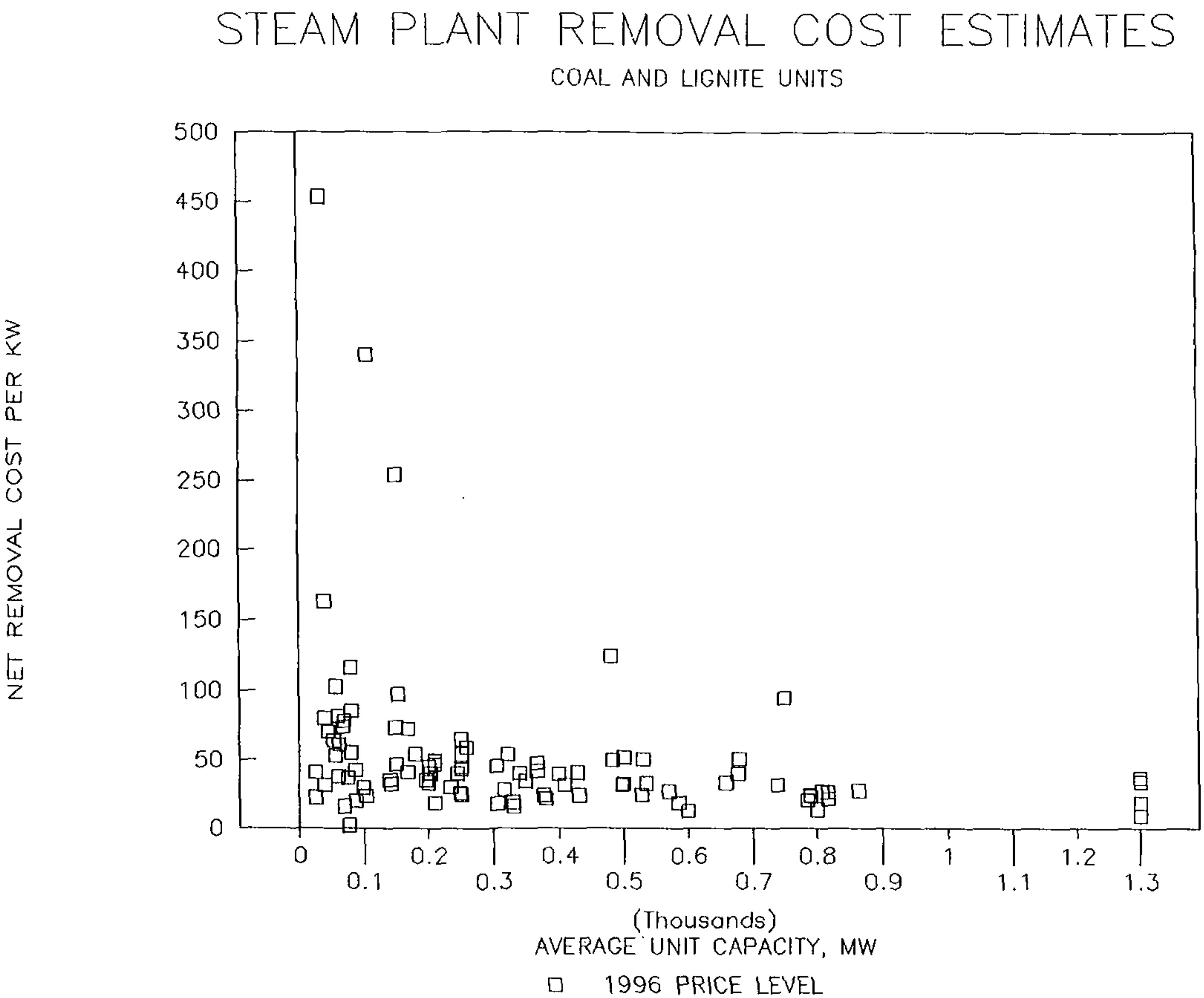
STEAM PLANT REMOVAL COST ESTIMATES
COAL AND LIGNITE UNITS
NET REMOVAL COST PER KW
500
450
400
350
300
250
200
150
100
50
0
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
1.1
1.2
1.3
(Thousands)
AVERAGE UNIT CAPACITY, MW
1996 PRICE LEVEL

Figure 1

17-Apr-97

STEAM PRODUCTION PLANT

Net Salvage Indicated by Engineering Studies of the Removal of Coal and Lignite Units

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
					All Units		100MW or Less		101 - 250MW		251 - 500MW		501 - 750MW		751 - 1000MW		Over 1000MW	
Utility and Plant	Number of Units	Total Owned Capacity MW	Average Capacity MW	Study Date	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW
Company A																		
Station A	5	1,525	305.0	1993	68,526,003	45					68,526,003							
Station B	3	120	40.0	1993	3,814,710	32	3,814,710											
Station C	2	120	60.0	1993	4,554,486	38	4,554,486											
Station D (b)	2	300	250.0	1993	16,259,122	54			16,259,122									
Station E	4	320	80.0	1993	17,536,083	55	17,536,083											
Station F	3	1,021	340.3	1993	40,591,530	40					40,591,530							
Station G (b)	4	2,532	660.0	1993	83,785,935	33							83,785,935					
Company B																		
Station A	3	2,033	677.7	1990	80,213,847	39							80,213,847					
Station B	3	705	235.0	1990	21,295,098	30			21,295,098									
Station C	2	335	167.5	1990	13,627,263	41			13,627,263									
Station D	2	400	200.0	1990	13,340,344	33			13,340,344									
Station E	1	1,300	1,300.0	1990	43,731,061	34											43,731,061	
Station F	2	300	150.0	1990	13,967,889	47			13,967,889									
Company C																		
Station A	3	1,294	431.3	1993	30,919,475	24					30,919,475							
Station B	5	438	87.2	1993	8,892,940	20	8,892,940											
Station C	2	515	257.5	1993	30,277,717	59					30,277,717							
Station D	8	612	76.5	1993	1,544,460	3	1,544,460											
Station E	3	310	103.3	1993	7,226,313	23			7,226,313									
Company D																		
Station A	2	1,479	739.5	1992	46,354,032	31							46,354,032					
Station B	2	964	482.0	1992	47,892,896	50					47,892,896							
Company E																		
Station A	1	818	818.0	1995	17,482,204	21									17,482,204			
Station B (b)	2	272	679.0	1995	13,571,997	50							13,571,997					
Company F																		
Station A	4	160	40.0	1989	12,834,964	80	12,834,964											
Station B	4	3,160	790.0	1989	74,152,785	23									74,152,785			
Station C	4	1,468	367.0	1989	60,941,480	42					60,941,480							
Station D	4	800	200.0	1989	35,963,972	45			35,963,972									
Station E	2	490	245.0	1989	19,586,971	40			19,586,971									
Station F	3	171	57.0	1989	17,582,277	103	17,582,277											
Station G (b)	3	751	807.4	1989	20,228,209	27									20,228,209			
Station H (b)	2	926	865.0	1989	25,471,161	28									25,471,161			
Station I	7	1,250	178.6	1989	67,810,325	54			67,810,325									
Company G																		
Station A	7	1,045	149.3	1993	76,787,019	73			76,787,019									
Station B (b)	2	500	500.0	1993	25,803,655	52					25,803,655							
Station C (b)	1	205	818.0	1993	5,437,410	27									5,437,410			
Station D	2	80	40.0	1993	13,086,499	164	13,086,499											
Station E	2	305	152.5	1993	29,730,916	97			29,730,916									
Company H																		
Station A	1	400	400.0	1993	15,682,300	39					15,682,300							
Station B	1	1,300	1,300.0	1993	23,705,189	18											23,705,189	
Station C	4	995	248.8	1993	25,792,137	26			25,792,137									

STEAM PRODUCTION PLANT

Net Salvage Indicated by Engineering Studies of the Removal of Coal and Lignite Units

17-Apr-97

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
					All Units		100MW or Less		101 - 250MW		251 - 500MW		501 - 750MW		751 - 1000MW		Over 1000MW	
Utility and Plant	Number of Units	Total Owned Capacity MW	Average Capacity MW	Study Date	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW
Company I																		
Station A	4	1,713	428 3	1993	69,505,748	41					69,505,748							
Station B	4	276	69 0	1993	21,581,187	78	21,581,187											
Station C	3	630	210 0	1993	29,382,140	47			29,382,140									
Company J																		
Station A	2	1,060	530 0	1989	53,077,666	50							53,077,666					
Company K																		
Station A	2	138	69 0	1992	2,234,414	16	2,234,414											
Station B	1	350	350 0	1992	11,955,723	34					11,955,723							
Station C (b)	1	428	535 0	1992	13,952,367	33							13,952,367					
Station D	2	50	25 0	1992	1,117,632	22	1,117,632											
Station E	2	110	55 0	1992	5,853,756	53	5,853,756											
Company L																		
Station A (b)	2	500	500 0	1996	15,986,500	32					15,986,500							
Station B (b)	2	200	250 0	1996	12,988,400	65			12,988,400									
Station C	5	1,012	202 4	1996	40,609,000	40			40,609,000									
Company M																		
Station A (b)	1	867	1,300 0	1993	31,466,526	36											7,672,633	
Station B	1	600	600 0	1993	7,672,633	13							7,672,633					
Station C	2	2,600	1,300 0	1993	23,534,748	9											31,217,097	
Station D	3	630	210.0	1993	31,217,097	50			31,217,097									
Station E	2	1,600	800 0	1993	22,157,754	14									22,157,754			
Station F	4	840	210 0	1993	15,537,518	18			15,537,518									
Station G	1	585	585 0	1993	10,797,257	18							10,797,257					
Station H	3	750	250 0	1993	32,208,113	43			32,208,113									
Company N																		
Station A	3	1442	480 7	1994	178,318,194	124					178,318,194							
Station B	3	102	34 0	1994	46,270,093	454	46,270,093											
Station C	2	300	150 0	1994	76,243,700	254			76,243,700									
Station D	2	1500	750 0	1994	142,042,840	95							142,042,840					
Station E	4	425	106 3	1994	144,719,491	341			144,719,491									
Company O																		
Station A	2	995	497.5	1991	31,050,287	31					31,050,287							
Station B	3	160	53 3	1991	10,214,364	64	10,214,364											
Station C	4	560	140 0	1991	19,659,694	35			19,659,694									
Station D	5	2,853	570 6	1991	76,968,866	27							76,968,866					
Station E	2	90	45 0	1991	6,333,984	70	6,333,984											
Station F	5	435	87 0	1991	18,476,510	42	18,476,510											
Station G	1	318	318 0	1991	8,921,773	28					8,921,773							
Company P																		
Station A	1	306	306 0	1990	5,492,641	18					5,492,641							
Company Q																		
Station A	4	323	80 8	1990	27,582,608	85	27,582,608											
Station B	1	168	168 0	1990	12,123,213	72			12,123,213									
Company R																		
Station A (b)	2	250	250 0	1989	6,196,105	25			6,196,105									

17-Apr-97

STEAM PRODUCTION PLANT

Net Salvage Indicated by Engineering Studies of the Removal of Coal and Lignite Units

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
					All Units		100MW or Less		101 - 250MW		251 - 500MW		501 - 750MW		751 - 1000MW		Over 1000MW	
Utility and Plant	Number of Units	Total Owned Capacity MW	Average Capacity MW	Study Date	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW
Company S																		
Station A (b)	2	754	785 4	1993	15,796,636	21									15,796,636			
Station B (b)	2	885	790 0	1995	21,650,765	24									21,650,765			
Company T																		
Station A	4	1,000	250 0	1993	44,293,689	44			44,293,689									
Company U																		
Station A	4	1,635	408 8	1989	51,758,520	32					51,758,520							
Station B	6	1,180	196 7	1989	41,080,857	35			41,080,857									
Company V																		
Station A	2	754	377 0	1995	18,038,390	24					18,038,390							
Station B (b)	1	183	366 0	1995	8,674,660	47					8,674,660							
Station C	6	1,987	331.2	1995	31,817,730	16					31,817,730							
Station D	4	569	142 3	1995	18,346,360	32			18,346,360									
Company W																		
Station A	5	400	80 0	1990	46,448,279	116	46,448,279											
Company X																		
Station A (b)	2	487	527 0	1989	11,813,429	24							11,813,429					
Station B	2	50	25 0	1989	2,041,564	41	2,041,564											
Station C	1	60	60 0	1989	4,905,699	82	4,905,699											
Station D (b)	1	225	330 0	1989	4,250,933	19					4,250,933							
Station E (b)	1	285	380 0	1989	6,049,943	21					6,049,943							
Station F	2	200	100 0	1989	5,938,894	30	5,938,894											
Station G	2	150	75 0	1989	5,508,967	37	5,508,967											
Company Y																		
Station A	6	372	62 0	1987	22,723,718	61	22,723,718											
Station B	2	135	67 5	1987	9,959,646	74	9,959,646											
Station C	1	322	322 0	1987	17,231,860	54					17,231,860							
Total or Average					2,827,783,752	41	317,037,731	63	865,992,745	55	779,687,958	42	540,250,870	39	202,376,925	22	106,325,980	18

NOTES

(a) Annual cost escalation from study date: 3 00%

(b) Jointly owned

STEAM PLANT REMOVAL COST ESTIMATES

GAS AND OIL UNITS

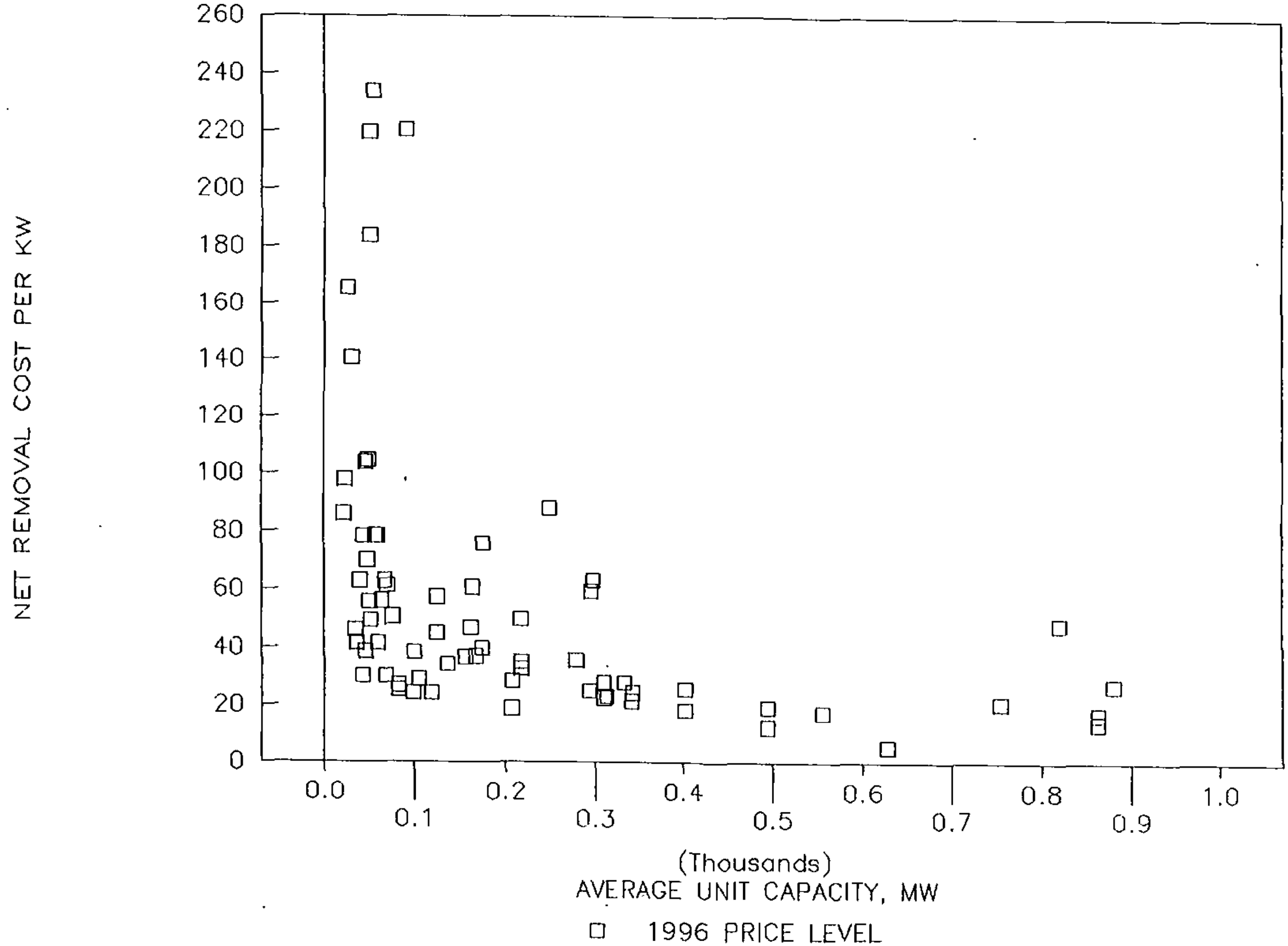

Figure 3

STEAM PRODUCTION PLANT
Net Salvage Indicated by Engineering Studies of the Removal of Gas and Oil Units

17-Apr-97

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
					All Units		100MW or Less		101 - 250MW		251 - 500MW		501 - 750MW		751 - 1000MW	
Utility and Plant	Number of Units	Total Owned Capacity MW	Average Capacity MW	Study Date	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW	Current Removal Cost $	1996 (a) $/kW
Company A																
Station A	1	880	880.0	1993	23,734,030	27									23,734,030	
Company B																
Station A	8	512	64.0	1990	28,794,412	56	28,794,412									
Station B	4	830	207.5	1990	15,545,815	19			15,545,815							
Station C	6	597	99.5	1990	14,366,726	24	14,366,726									
Station D	2	336	168.0	1990	12,411,327	37			12,411,327							
Company C																
Station A	2	1,256	628.0	1993	7,060,437	6							7,060,437			
Company D																
Station A	2	1,112	556.0	1992	19,479,131	18							19,479,131			
Station B	2	61	30.5	1992	8,582,216	141	8,582,216									
Station C	3	494	164.7	1992	29,941,356	61			29,941,356							
Station D	3	138	46.0	1992	14,362,209	104	14,362,209									
Station E	3	147	49.0	1992	15,403,251	105	15,403,251									
Station F	4	202	50.4	1992	11,199,748	56	11,199,748									
Company E																
Station A	2	804	402.0	1995	14,534,501	18					14,534,501					
Station B	2	237	118.5	1995	5,707,547	24			5,707,547							
Station C	2	558	279.0	1995	19,954,162	36					19,954,162					
Station D	2	1,727	863.5	1995	24,110,548	14									24,110,548	
Station E	2	1,727	863.5	1995	29,402,966	17									29,402,966	
Station F	2	96	48.0	1995	6,715,229	70	6,715,229									
Station G	4	1,255	313.8	1995	29,080,614	23					29,080,614					
Station H	2	621	310.5	1995	13,986,443	23					13,986,443					
Station I	3	1,028	342.7	1995	25,014,088	24					25,014,088					
Station J	2	804	402.0	1995	20,603,472	26					20,603,472					
Company F																
Station A	4	240	60.0	1989	18,865,035	79	18,865,035									
Station B	2	115	57.5	1989	9,026,044	78	9,026,044									
Company G																
Station A	2	88	44.0	1993	6,898,692	78	6,898,692									
Station B	4	149	37.1	1993	6,168,536	42	6,168,536									
Company H																
Station A	3	68	22.5	1996	5,820,000	86	5,820,000									
Station B	2	80	40.0	1996	5,035,000	63	5,035,000									
Company I																
Station A	7	1,230	175.7	1993	93,156,101	76			93,156,101							
Station B	2	110	55.0	1993	25,726,924	234	25,726,924									
Station C	2	181	90.5	1993	39,940,360	221	39,940,360									
Station D	1	50	50.0	1993	10,989,212	220	10,989,212									
Station E	4	1,000	250.0	1993	88,063,832	88			88,063,832							
Station F	7	2,070	295.7	1993	122,970,638	59					122,970,638					
Station G	2	100	50.0	1993	18,377,967	184	18,377,967									
Station H	7	2,090	298.6	1993	131,974,538	63					131,974,538					

STEAM PRODUCTION PLANT

Net Salvage Indicated by Engineering Studies of the Removal of Gas and Oil Units

17-Apr-97

(1) Utility and Plant	(2) Number of Units	(3) Total Owned Capacity MW	(4) Average Capacity MW	(5) Study Date	(6) All Units Current Removal Cost $	(7) 1996 (a) $/kW	(8) 100MW or Less Current Removal Cost $	(9) 1996 (a) $/kW	(10) 101 - 250MW Current Removal Cost $	(11) 1996 (a) $/kW	(12) 251 - 500MW Current Removal Cost $	(13) 1996 (a) $/kW	(14) 501 - 750MW Current Removal Cost $	(15) 1996 (a) $/kW	(16) 751 - 1000MW Current Removal Cost $	(17) 1996 (a) $/kW
Company J																
Station A	2	1640	820 0	1994	79,213,159	48									79,213,159	
Company K																
Station A	7	326	46 6	1990	12,553,848	39	12,553,848									
Station B	8	610	76 3	1990	30,913,345	51	30,913,345									
Station C	1	125	125 0	1990	5,612,046	45			5,612,046							
Company L																
Station A	3	300	100 0	1993	11,505,599	38	11,505,599									
Station B	2	588	294 0	1993	14,526,817	25					14,526,817					
Station C	4	210	52 5	1993	10,362,743	49	10,362,743									
Station D	2	272	136 0	1993	9,278,987	34			9,278,987							
Station E	2	416	208 0	1993	11,759,531	28			11,759,531							
Station F	4	93	23 3	1993	9,117,750	98	9,117,750									
Company M																
Station A	3	78	26 0	1990	12,916,064	166	12,916,064									
Company N																
Station A	2	210	105 0	1989	6,110,013	29			6,110,013							
Station B	3	246	82.0	1989	6,613,032	27	6,613,032									
Company O																
Station A	2	326	163 2	1995	15,244,000	47			15,244,000							
Station B	2	666	333 0	1995	18,486,440	28					18,486,440					
Station C	2	990	495 0	1995	19,026,160	19					19,026,160					
Station D	2	137	68 5	1995	4,136,480	30	4,136,480									
Station E	2	313	156 3	1995	11,411,370	37			11,411,370							
Station F	2	684	342 0	1995	14,543,600	21					14,543,600					
Station G	2	250	125 0	1995	14,354,080	57			14,354,080							
Station H	2	620	310 0	1995	17,316,360	28					17,316,360					
Station I	4	140	35 0	1995	6,447,800	46	6,447,800									
Station J	2	435	217 6	1995	15,091,560	35					15,091,560					
Station K	2	435	217.6	1995	14,195,460	33					14,195,460					
Station L	2	435	217 6	1995	21,697,980	50					21,697,980					
Station M	2	1,510	755 0	1995	31,340,840	21									31,340,840	
Station N	4	270	67.5	1995	17,007,360	63	17,007,360									
Station O	2	350	175 0	1995	13,961,650	40			13,961,650							
Station P	2	990	495 0	1995	12,318,800	12					12,318,800					
Station Q	2	120	60 0	1995	4,989,320	42	4,989,320									
Company P																
Station A	5	213	42 6	1989	6,414,349	30	6,414,349									
Company Q																
Station A	3	211	70 3	1990	12,927,193	61	12,927,193									
Total or Average					1,464,396,847	39	392,176,446	67	332,557,655	52	525,321,633	35	26,539,568	11	187,801,544	25

NOTES:

(a) Annual cost escalation from study date: 3 00%

OTHER PRODUCTION PLANT
Net Salvage Indicated by Engineering Studies
for Removal of Units

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Utility and Plant	Number of Units	Total Owned Capacity	Average Capacity	Study Date	Current Removal Cost	1996 (a)
		MW	MW		$	$/kW
SIMPLE CYCLE COMBUSTION TURBINE UNITS						
Company A						
Station A	1	19.2	19.2	1990	65,297	3.4
Station B	1	22.0	22.0	1990	24,718	1.1
Station C	1	17.0	17.0	1990	28,906	1.7
Company B						
Station A	2	67.6	33.8	1992	359,634	5.3
Station B	4	222.8	55.7	1992	1,197,177	5.4
Station C	4	226.8	56.7	1992	2,625,785	11.6
Station D	6	365.4	60.9	1992	1,008,414	2.8
Station E	4	300.0	75.0	1992	8,941,913	29.8
Station F	4	153.4	38.4	1992	667,871	4.4
Station G	6	340.2	56.7	1992	1,118,331	3.3
Station H	4	300.0	75.0	1992	6,999,126	23.3
Station I	1	19.3	19.3	1992	895,895	46.4
Station J	1	19.3	19.3	1992	909,497	47.1
Station K	3	183.6	61.2	1992	675,058	3.7
Station L	4	181.0	45.3	1992	1,233,038	6.8
Station M	1	40.0	40.0	1992	2,147,417	53.7
Company C						
Station A	24	822.0	34.3	1995	526,928	0.6
Station B	12	744.0	62.0	1995	2,136,874	2.9
Station C	12	411.0	34.3	1995	296,860	0.7
Company D						
Station A	1	40	40.0	1993	120,200	3.0
Company E						
Station A	5	152	30.4	1996	1,321,000	8.7
Station B	1	39	39.0	1996	147,000	3.8
Station C	1	39	39.0	1996	147,000	3.8
Company F						
Station A	3	165	55.0	1991	6,350,692	38.5

OTHER PRODUCTION PLANT
Net Salvage Indicated by Engineering Studies
for Removal of Units

(1) Utility and Plant	(2) Number of Units	(3) Total Owned Capacity MW	(4) Average Capacity MW	(5) Study Date	(6) Current Removal Cost $	(7) 1996 (a) $/kW
Company G						
Station A						
Station B						
Station C						
Station D						
Station E						
Station F						
Station G						
Station H						
Station I						
Total	12	380	31.7	1993	967,987	2.5
Company H						
Station A	1	16	16.0	1990	130,152	8.1
Company I						
Station A						
Station B						
Total	3	41	13.7	1989	21,399	0.5
Company J						
Station A						
Station B						
Station C						
Station D						
Station E						
Total	5	713.5	142.7	1995	3,630,750	5.1
Company K						
Station A	3	175.5	58.5	1989	196,780	1.1
Station B	1	18.0	18.0	1989	27,057	1.5
Company L						
Station A	1	22.0	22.0	1990	48,767	2.2
Company M						
Station A	1	19.6	19.6	1990	748,566	38.2
Average or Total					45,716,089	7.3

NOTES:
(a) Annual cost escalation from study date: 3.00%

OTHER PRODUCTION PLANT
Net Salvage Indicated by Engineering Studies
for Removal of Units

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Utility and Plant	Number of Units	Total Owned Capacity	Average Capacity	Study Date	Current Removal Cost	1996 (a)
		MW	MW		$	$/kW
COMBINED CYCLE UNITS						
Company A						
Station A	2	1042.0	521.0	1995	14,237,655	13.7
Station B	2	580.0	290.0	1995	5,943,160	10.2
Station C	2	1224.0	612.0	1995	15,545,556	12.7
Company B						
Station A	2	472.0	236.0	1995	7,861,990	16.7
Station B	2	585.0	292.5	1995	6,063,610	10.4
Average or Total					49,651,971	12.7
DIESEL UNITS						
Company A						
Station A	2	5.5	2.8	1990	11,391	2.1
Company B						
Station A	4					
Station B	3					
Station C	1					
Station D	2					
Station E	3					
Station F		27.5	2.1	1989	99,055	3.6
Average or Total					110,447	3.3

NOTES:
(a) Annual cost escalation from study date: 3.00%

ANNOTATION

Survey of Fossil Steam Plant Decommissioning

Offered by

R. C. Caldwell, Jr.

at

MEETING OF EEI
PROPERTY ACCOUNTING AND VALUATION COMMITTEE

Park Tucson
Tucson, Arizona

December 9–11, 1991

EEI PROPERTY ACCOUNTING AND VALUATION COMMITTEE

John S. Denshuick	Committee Co–Chairman – EEI
J. Phil Williamson	Committee Co–Chairman – EEI

DISCLAIMER

This paper represents the consensus of the author(s). It does not have the specific endorsement of the Property Accounting and Valuation Committee. The thoughts, viewpoints and positions expressed herein are not necessarily those of the EEI or any of their member companies.

Survey of Fossil Steam Plant Decommissioning

Introduction

Since decommissioning costs for fossil fuel plants dramatically effect net negative salvage and thus our newly developed depreciation rates, management at SCE&G was interested in how other utilities were dealing with this subject. Their primary interest included:

1) Who is doing what?

2) Have companies had site specific studies?

3) Have companies included decommissioning in rate making?

4) Have state regulatory commissions allowed it?

5) Why have other companies addressed this issue?

6) What about asbestos removal?

Background

This survey summarizes information related to recovery of decommissioning costs and asbestos removal for Fossil Steam Production Plant. The information was obtained by written survey of the EEI Property Accounting and Valuation Committee Members. The intent of this paper is to provide comparative information to be used by member companies.

The survey was mailed to 99 companies and 57 responded. This represents a 58% response rate. Company responses have been summarized and are attached.

Survey Format

Survey information is presented for each company which responded with applicable data. The questions are listed in the columns across the top of each page and are self–explanatory.

Survey of Fossil Steam Plant Decommissioning

Summary of Results

Of the 57 companies responding to the survey, 29 have developed decommissioning cost estimates.

23 of the 29 companies who developed site specific studies, 12 were done internally, 13 externally and one did both.

Twenty–four companies presently have their decommissioning costs in rate base while twenty–three other companies do not. Of the twenty–three companies who do not, fourteen companies expect it to be approved in rate proceedings while seven other companies do not.

Of the 57 companies responding to the survey, 36 companies plan to recover decommissioning costs through net negative salvage, 1 company through percent of depreciable investment, 4 companies through dollars of net removal cost and 5 companies through other means.

Twenty–two companies currently have allowances for removal of asbestos in their depreciation rates while thirty–three other companies surveyed do not. Fifteen companies have considered this issue for future rates and nineteen have not.

As can be seen in the results of the survey, 22 companies out of the 99 companies surveyed answered the optional question #7, which states "In 25 words or less why are you doing a fossil plant decommissioning study?" Each company that responded, had unique remarks concerning the issue of performing a decommissioning study. These responses are attached.

	QUESTION 1 HAS COMPANY DEVELOPED ESTIMATES FOR DECOMMIS- SIONING COSTS?		QUESTION 2 IS THE COST ESTIMATE BASED ON A SITE SPECIFIC STUDY ?		QUESTION 3 IF QUESTION 2 IS 'YES', HOW WAS STUDY DONE ?		QUESTION 4 IS YOUR RECOVERY OF DECOMMISSIONING PRESENTLY IN RATE BASE ?		QUESTION 4 (b) IF NOT, DO YOU EXPECT IT TO BE APPROVED IN RATE PROCEEDINGS ?		QUESTION 5 HOW WILL YOUR COMPANY RECOVER DECOMMISSIONING COSTS ?				QUESTION 6 DO YOUR CURRENT DEPRECIATION RATES ALLOW FOR REMOVAL OF ASBESTOS ?		QUESTION 6 (b) IF NOT, HAVE YOU CONSIDERED THIS ISSUE. FOR FUTURE RATES ?		QUESTION 7 OPTIONAL ****
COMPANY NAME	YES	NO	YES	NO	INT	EXT	YES	NO	YES	NO	* NET NEGATIVE SALVAGE	** % OF DEPRE INVEST	*** $ OF NET REMOVAL COST	OTHER	YES	NO	YES	NO	RESPONSE
ALLEGHENY POWER	X		X			X	X				X				X				
ARIZONA PUBLIC SERVICE		X		X				X								X		X	
ARKANSAS P & L	X		X		X			X				X				X		X	
BALTIMORE G & E CO		X						X			X				X				
CAROLINA P & L		X						X		X						X		X	X
CENTERIOR ENERGY CORP		X		X				X		X	X					X		X	
CENTRAL LOUISIANA ELEC	X			X			X				X				X				
CENTRAL P & L CO		X														X		X	
CON EDISON CO OF N.Y.		X					X				X				X				
CONSUMERS POWER CO	X		X		X		X				X				X				X
DAYTON P & L	X			X		X	X		X		X					X	X		X
DETROIT EDISON		X						X	X		X				X				X
DUKE POWER COMPANY		X						X		X				X		X		X	X
DUQUESNE LIGHT CO		X						X											
EASTERN UTILITIES		X						X	X					X		X	X		
FLORIDA POWER CORP	X		X			X	X		X				X		X				X
GEORGIA POWER CO	X		X		X			X		X	X				X				X
HAWAIIAN ELECTRIC		X					X				X					X		X	X
HOUSTON L & P CO		X		X			X				X				X				
INDIANAPOLIS P & L		X														X		X	
INTERSTATE POWER CO	X		X		X		X				X					X	X		
IOWA-ILLINOIS G & E		X					X				X					X		X	
KANSAS POWER & LIGHT	X			X			X				X					X	X		
KANSAS CITY P & L	X		X			X		X			X					X	X		X
LOUSIANA P & L	X			X			X				X				X				
METROPOLITAN EDISON	X		X		X			X		X	X					X		X	
MINNESOTA POWER		X		X				X	X		X								
MISSISSIPPI POWER CO	X		X		X		X				X				X				X
MISSISSIPPI P & L		X					X				X				X				
MONTANA-DAKOTA UTIL	X		X		X	X	X		X		X		X		X		X		X
MONTANA POWER CO		X														X		X	
NEVADA POWER CO		X		X				X	X		X					X		X	
NORTHEAST UTILITIES	X		X			X	X						X		X				
NORTHERN STATES POWER	X		X			X	X				X					X		X	
NEW YORK STATE E & G		X												X	X				
ORANGE & ROCKLAND		X						X	X						X				
PACIFICORP		X									X					X	X		

	QUESTION 1 HAS COMPANY DEVELOPED ESTIMATES FOR DECOMMIS-SIONING COSTS?		QUESTION 2 IS THE COST ESTIMATE BASED ON A SITE SPECIFIC STUDY ?		QUESTION 3 IF QUESTION 2 IS 'YES', HOW WAS STUDY DONE ?		QUESTION 4 IS YOUR RECOVERY OF DECOMMISSIONING PRESENTLY IN RATE BASE ?		QUESTION 4 (b) IF NOT, DO YOU EXPECT IT TO BE APPROVED IN RATE PROCEEDINGS ?		QUESTION 5 HOW WILL YOUR COMPANY RECOVER DECOMMISSIONING COSTS ?				QUESTION 6 DO YOUR CURRENT DEPRECIATION RATES ALLOW FOR REMOVAL OF ASBESTOS ?		QUESTION 6 (b) IF NOT, HAVE YOU CONSIDERED THIS ISSUE FOR FUTURE RATES ?		QUESTION 7 OPTIONAL ****
											* NET NEGATIVE SALVAGE	** % OF DEPRE INVEST	*** $ OF NET REMOVAL COST	OTHER					
COMPANY NAME	YES	NO	YES	NO	INT	EXT	YES	NO	YES	NO					YES	NO	YES	NO	RESPONSE
PENN ELECTRIC	X		X			X		X	X				X			X		X	X
[redacted]		X		X				X		X					X				
[redacted]		X		X							X					X		X	
PSI ENERGY	X		X			X	X				X					X		X	X
PUB SERV CO COLORADO	X		X			X					X				X				X
PUBLIC SERVICE E & G	X		X		X			X	X		X					X	X		
[redacted]		X		X			X				X					X		X	
PUGET SOUND P & L		X						X		X						X		X	X
ROCHESTER GAS & ELEC		X												X	X				
SAN DIEGO G & E	X		X			X		X	X		X					X	X		X
SIERRA PACIFIC	X		X			X		X	X		X					X	X		X
SW PUBLIC SERVICE	X			X			X									X	X		
TAMPA ELECTRIC CO	X		X		X			X	X					X		X	X		X
TUCSON ELECTRIC	X		X		X		X				X					X	X		
TU ELECTRIC	X		X			X	X				X					X	X		X
UNION ELECTRIC		X														X		X	
UNITED ILLUMINATING CO	X			X			X				X				X				
VIRGINIA POWER		X														X	X		X
WISCONSIN ELECTRIC	X		X		X			X	X		X				X				X
WISCOUSIN PUB SERV	X		X		X		X				X				X				X
TOTALS	29	28	23	14	12	13	24	23	14	7	36	1	4	5	22	33	15	19	22

NOTE: * NET NEGATIVE SALVAGE AS PART OF THE COMPOSITE DEPRECIATION RATE.
** PERCENT OF DEPRECIABLE INVESTMENT WHERE A SEPARATE RATE FOR DECOMMISSIONING IS USED.
*** DOLLARS OF NET REMOVAL COST WHERE ESTIMATED COST IS AMORTIZED OVER A PERIOD OF TIME.
**** RESPONSES ARE ATTACHED AND IN ORDER BY COMPANY NAME.

[redacted] – RELATES TO QUESTION # 1

– RELATES TO QUESTION # 2

QUESTION 7 – IN 25 WORDS OR LESS WHY ARE YOU DOING A FOSSIL PLANT DECOMMISSIONING STUDY ?

CAROLINA POWER & LIGHT – WE HAVE NOT PERFORMED A FOSSIL PLANT DECOMMISSIONING STUDY. AT THIS TIME WE DO NOT ANTICIPATE ABANDONING FOSSIL PLANT SITES.

CONSUMERS POWER CO – TO FULLY RECOVER ALL COST ASSOCIATED WITH THE RETIREMENT OF A STEAM PLANT INCLUDING DISMANTLEMENT.

DAYTON POWER AND LIGHT COMPANY – COMPANY PLANS TO DISMANTLE ITS POWER PLANTS AFTER RETIREMENT.

DETROIT EDISON – THE COMPANY IS CONSIDERING CONTRACTING (EXTERNAL) FOR A SITE-SPECIFIC DECOMMISSIONING STUDY.

DUKE POWER COMPANY – HAVE NOT YET UNDERTAKEN A STUDY OF FOSSIL DECOMMISSIONING. A STUDY WILL NEED TO BE DONE IN THE FUTURE BUT THE TIMING IS UNCERTAIN.

FLORIDA POWER CORPORATION – REGULATORY AGENCY REQUIRED STUDY FOR ALL FLORIDA ELECTRIC UTILITIES.

GEORGIA POWER – TO RECOVER THE COST IN RATES.

HAWAIIAN ELECTRIC COMPANY, INC. – UNFORTUNATELY, CONDUCTING A PLANT DECOMMISSIONING STUDY DOES NOT HAVE A HIGH PRIORITY AT THIS TIME AND NOT A REQUIREMENT.

KANSAS CITY POWER AND LIGHT COMPANY – THE COMPANY HAS DECOMMISSIONED FOSSIL PLANTS IN THE PAST. THE COMPANY ALSO BELIEVES THAT ENVIROMENTAL CONCERNS WILL PROMPT REGULATORY AGENCIES TO REQUIRE FOSSIL PLANT DECOMMISSIONING IN THE FUTURE.

MISSISSIPPI POWER COMPANY – 1. DISMANTLMENT COSTS ARE A COST-OF-SERVICE. IT SHOULD BE PAID BY CUSTOMERS WHO BENEFIT FROM THE FACILITY. 2. ENVIROMENTAL CONCERNS – CERTAIN COST WILL BE INCURRED TO REMOVE ASBESTOS, RECLAIM ASH PONDS, AND REMOVE COAL/OIL STORAGE FACILITIES. THIS REMOVAL IS REQUIRED BY LAW.

MONTANA – DAKOTA UTILITIES COMPANY – RE: #1 & 2 RETIRED GENERATING STATIONS. RE: #3 INTERNALLY DONE ON RETIRED GENERATING STATIONS. EXTERNALLY DONE ON GENERATING STATIONS CURRENTLY IN SERVICE. RE: #4 THE UNAMORTIZED ESTIMATED DECOMMISSIONING COSTS AND UNRECOVERED NET BOOK VALUE IS INCLUDED FOR RETIRED GENERATING STATIONS AND IS ONLY ALLOWED IN ONE OF THREE JURISDICTIONS FILED. RE: #5 A.) GENERATING STATIONS CURRENTLY OPERATING. C.) RETIRED GENERATING STATIONS.

PENNSYLVANIA ELECTRIC COMPANY – COMPANY PLANS TO DISMANTLE AFTER RETIREMENT AND SALE LAND TO A DEVELOPER. PROPERTY IS LOCATED ON LAKE ERIE WATERFRONT. HOPEFULLY, SALE PROCEEDS WILL OFFSET THE DISMANTLING COSTS.

PSI ENERGY – AS PART OF OUR DEPRECIATION STUDY SUBMITTED IN RATE PROCEEDINGS IN 1989.

PUBLIC SERVICE COMPANY OF COLORADO – DONE TO JUSTIFY NEGATIVE SALVAGE COMPONENT OF DEPRECIATION RATE.

PUGET SOUND POWER AND LIGHT COMPANY – OUR COMPANY HAS DECIDED NOT TO INCLUDE ANY TERMINATION OR DECOMMISSIONING COSTS IN OUR DEPRECIATION RATES AT THIS TIME.

SAN DIEGO GAS AND ELECTIRC – WE ARE TO FILE A RATE CASE TO INCLUDE STEAM PRODUCTION DECOMMISSIONING.

SIERRA PACIFIC POWER COMPANY – COMMISSION REQUIRED AN INVESTIGATION OF DECOMMISSIONING COSTS BUT HAS YET TO ALLOW RECOVERY.

TAMPA ELECTRIC COMPANY – STUDY REQUIRED BY FLORIDA PUBLIC SERVICE COMMISSION.

TU ELECTRIC – DETERMINING THE APPROPRIATE COSTS FOR DISMANTLING PLANTS AFTER RETIREMENT IN LIGHT OF THE CURRENT REGULATIONS.

VIRGINIA POWER – WE ARE CURRENTLY DEVELOPING SOME GENERIC FOSSIL PLANT DECOMMISSIONING COST ESTIMATES BASED ON OTHER COMPANIES' STUDIES AND/OR EXPERIENCE. THE COST ESTIMATES DEVELOPED FOR OUR PLANTS WILL BE PRESENTED TO THE VIRGINIA STATE CORPORATION COMMISSION FOR THEIR REVIEW AND APPROVAL IN 1992. RECOVERY OF THESE COSTS OVER THE OPERATING LIVES OF THE PLANTS IS RECONGNIZED AS NECESSARY BY VIRGINIA POWER, HOWEVER THIS STUDY HAS NOT BEEN MANDATED OR SANCTIONED BY THE VIRGINIA COMMISSION.

WISCONSIN ELECTRIC POWER COMPANY – REMOVAL OF A FOSSIL PLANT REPRESENTS A SIGNIFICANT COST WHICH IS PROPERLY CHARGEABLE TO THE ACCOUNTING PERIODS/RATEPAYERS RECEIVING THE BENEFIT OF THE PLANT. A DETAILED CURRENT STUDY WILL PROVIDE THE MOST APPROPRIATE AMOUNTS TO INCLUDE IN CURRENT RATES.

WISCONSIN PUBLIC SERVICE CORPORATION – ENVIRONMENTAL, ELIMINATION OF UNSAFE STRUCTURE, REGULATORY AGENCIES WILL PROBABLY REQUIRE IT.