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January 29, 1986

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Public Utility Commission

Mr. Jerry Rich, Secretary
Pennsylvania Public Utility Commission
New Filing Section
Room B-18, North Office Buildng
Commonwealth and North Streets
Harrisburg, Pennsylvania 17120

R-850152

RE: PUC v. PECO
Docket No. 8-50152

Dear Secretary Rich:

Enclosed are copies of CEPA, et al. Statements 1 and 2 which are direct testimony on rate structure issues in the above case. These statements were served on all parties in the case and Administratiave Law Judge Matuschak on January 22, 1986 as is indicated by the attached certificate of service.

Sincerely,

John Hanger

John Hanger

/md

DOCUMENT FOLDER

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CERTIFICATE OF SERVICE

I hereby certify that I am this 22nd day of January serving by first class mail CEPA, et al Statements 1 and 2 upon the following:

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DATED: January 22, 1986

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CEPA ET. AL. STATEMENT 1
R-850152

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Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION

V.

PHILADEPHIA ELECTRIC CO.

FOLDE

DOCKETED
FEB 6 1986

DIRECT TESTIMONY

OF

GEORGE GRIER

CONCERNING IMPACT OF RATE STRUCTURE

ON LOW-INCOME HOUSEHOLDS

ON BEHALF OF: CONSUMERS EDUCATION AND PROTECTIVE ASSOC.
ACTION ALLIANCE OF SENIOR CITIZENS
PHILADELPHIA CITIZENS IN ACTION
ASSOCIATION OF COMMUNITY ORGANIZATIONS
FOR REFORM NOW
MR. BRADSHAW

January 22, 1986

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS

A. My name is George Grier. My business address is The Grier Partnership, 6532 East Halbert Road, Bethesda, Maryland, 20817.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND QUALIFICATIONS

A. I am a principal in The Grier Partnership, a research and consulting firm which specializes in analysis of policy- and program-related questions in the public and private sectors. The firm's work has been in several areas including energy, demographics, and analysis of social and economic impacts. Recent activities of the firm in which I have been involved include:

- Analyses of patterns of energy use and expenditures by low-income and elderly households, the characteristics of these households, and the implications of both for utility rate structures, need for energy assistance, and implications for weatherization and other conservation measures.
- Development of computerized data systems and computer models for estimating household energy expenditures under varying conditions such as energy prices, climate, principal fuel used, and characteristics of the household, as well as the budgetary impact of these expenditures.

- Preparation of expert testimony for various legal and administrative proceedings concerning the setting of energy price schedules for different classes of consumers.
- Extensive work with Census Bureau and other federal data files, including the computer tape formats of these files, in demographic and economic analyses for public and private clients.

Prior to forming The Grier Partnership in 1976, a principal member of the firm was Research Staff Director for the Washington Center for Metropolitan Studies, a private non-profit "think tank." In that capacity, she directed the 1975 National Survey of Household Energy Use, which was conducted by the Washington Center for Metropolitan Studies for the Federal Energy Administration, a predecessor agency of the U. S. Department of Energy (DOE). That survey, which was known as the WCMS Household Energy Survey, was the prototype for the closely-similar Residential Energy Consumption Surveys now conducted by DOE.

Since that time, the Partnership has conducted a number of analyses of energy price impacts and related matters for a variety of clients in both the public and private sectors. These have included the U.S. Community Services Administration, the Congressional Research Service,

the National Council of Senior Citizens, the National Consumer Law Center, and the New England Regional Energy Project.

My firm has presented testimony in a number of energy price and utility rate cases before the Federal Energy Regulatory Commission, the Illinois Commerce Commission, the New Jersey Board of Public Utilities, the Pennsylvania Public Utility Commission, and the Public Service Commission of the District of Columbia, among others.

In addition, we have presented papers on energy price impacts and related matters before meetings of the National Conference on Optimal Weatherization, the University of Chicago, the University of North Carolina, the Congressional Research Service of the Library of Congress, the U.S. Community Services Administration, and others.

My own professional experience includes nine years as a principal of The Grier Partnership and nine years as a Vice President and Senior Associate of the Washington Center for Metropolitan Studies, plus service with the Brookings Institution, the District of Columbia Government, and the New York State Government. I hold a Master's Degree in Social Psychology from the University of Pennsylvania, with specialization in survey design and statistics.

My background is more fully described in my resume attached hereto as Exhibit GG-1. A list of my reports and publications on energy issues is included in that exhibit.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In my testimony I shall demonstrate the following facts:

1. Low income consumers (i.e., those who qualify for low-income energy assistance) make up a substantial proportion of all Philadelphia Electric Co. ratepayers.

2. The incomes of these PECo ratepayers are very low. They are much lower, on the average, than generally recognized, and considerably lower than the maximum limits for energy assistance.

3. Many of these low-income consumers have little chance of increasing their incomes through their own efforts, since they consist largely of elderly and handicapped persons and single-parent families with children.

4. Most of these customers already have serious and unavoidable budgetary burdens other than their electricity bills--such as housing, food, and other energy bills.

5. Thus, to impose PECo's requested rate increase on them would impose severe

hardship.

6. Relatively few of these low-income electric ratepayers have air conditioners, and hence they do not contribute substantially to high peak loads. In fact, on the average and as a group, they consume considerably less electricity than high-income ratepayers.

Q. WHAT EVIDENCE DO YOU OFFER FOR YOUR CONTENTIONS?

A. My statements are based chiefly on data from federal sources, mainly the U.S. Census Bureau and the Bureau of Labor Statistics. I have supplemented these sources with data from the Company's studies of its own customers. My data sources are specifically referred to in my exhibits.

Q. WHY DO YOU RELY HEAVILY UPON FEDERAL DATA SOURCES?

A. Because these data are specifically applicable to defining the low-income customer population, and to analyzing its characteristics and its economic situation relative to the affordability of the proposed rate increase. Using Census Bureau computer tapes, I was able to focus in particularly upon low-income electricity consumers in the parts of the Philadelphia metropolitan area under the jurisdiction of this Commission and to draw out data specific to that group. In addition, federal

data are objective and have been produced by agencies with no interest in the current case.

Q. HOW DO YOU DEFINE LOW-INCOME PHILADELPHIA ELECTRIC RATEPAYERS FOR THE PURPOSES OF YOUR TESTIMONY?

A. They are those electricity consumers residing in Philadelphia and its Pennsylvania suburbs within the metropolitan area who have incomes at or below 150 percent of the federal poverty limits. These customers qualify for low-income home energy assistance (LIHEAP) under the standards of both the federal government and the Commonwealth of Pennsylvania.

Q. WHAT ARE THE FEDERAL POVERTY LIMITS?

A. These limits vary with household size, and are adjusted regularly by the U.S. Office of Management and Budget based on increases in the Consumer Price Index. The current limits at the 150-percent-of-poverty level are shown in my Exhibit GG-2. At current levels, a household of one person (say, an elderly widow living alone) may have an income no higher than $7,875 to qualify. The maximum income rises for larger households, to $13,275 for a family of three and to $26,775 for a family of eight.

Q. SO A SINGLE ELDERLY WIDOW ELIGIBLE FOR LOW-INCOME ENERGY ASSISTANCE HAS AN AVERAGE INCOME OF $7,875, IS THAT CORRECT?

A. No. That is the maximum income she may have and still qualify. Actually, few have incomes as high as the maximum limits. Often they are much lower. It is very important to understand this, because some people confuse the poverty income limits with the incomes actually received by households below those limits. Some assume that all eligible households have incomes this high, while many others think that the average household does. Neither of these things is true.

Q. WHAT IS THE AVERAGE INCOME FOR A SINGLE-PERSON ELECTRIC RATEPAYER HOUSEHOLD UNDER 150 PERCENT OF POVERTY IN THE PHILADELPHIA AREA?

A. It is about $4,641, as shown in my Exhibit GG-2. That is less than three-fifths of the maximum income limit for LIHEAP eligibility.

Q. DO LOW-INCOME ELECTRIC RATEPAYERS OF ALL HOUSEHOLD SIZES HAVE AVERAGE INCOMES LOWER THAN THE FEDERAL MAXIMUM LIMITS FOR ELIGIBILITY?

A. Yes, at every household size the average income is well below the maximum which allows them to qualify. In my Exhibit GG-2, I show the comparison between the maximum level for each household size and the average income received by low-income electric ratepayers of this household size in the Pennsylvania portion of the Philadelphia metropolitan area.

Q. PLEASE GIVE SOME FURTHER EXAMPLES OF THESE LOWER AVERAGE INCOMES.

A. A four-person household can qualify for energy assistance with a maximum income of $15,975. Actually, however, the average income of four-person households under 150 percent of the poverty line is only $10,556. For a six-person household, the maximum is $21,375, but the average is only $14,154.

Q. WHAT PROPORTION OF THE MAXIMUM ELIGIBILITY LEVEL FOR LIHEAP BENEFITS IS THE AVERAGE INCOME OF THESE LOW-INCOME HOUSEHOLDS?

A. Again, this proportion varies with the size of the household, but not in any regular fashion. In most cases, it ranges between roughly three-fifths and about two-thirds of the maximum, as shown in my Exhibit GG-2.

Q. WHY DO YOU PLACE SO MUCH STRESS ON THE RATEPAYER POPULATION BELOW 150 PERCENT OF POVERTY?

A. Because these customers are recognized under the laws of both the United States and the Commonwealth of Pennsylvania as having incomes so low that they require special financial aid from the government if they are to meet their energy bills. I might note that the City of Philadelphia has indicated in its testimony in this case that low-income people will be particularly hard-hit by the job losses that the City expects to result from the proposed

rate increase, if implemented. The thrust of my testimony is to indicate that they will also feel the impact in terms of further strain on budgets that are already severely overloaded by today's high living costs.

Q. IN YOUR OPINION, ARE THESE THE ONLY CUSTOMERS WHO WILL HAVE DIFFICULTY MEETING PHILADELPHIA ELECTRIC'S PROPOSED RATE INCREASE?

A. Not at all. There are many more customers who will be harmed by such an increase, and who will have trouble meeting the additional budgetary burden it imposes. But low-income customers obviously will have particular difficulty, just because their incomes are so low.

Q. HAVE YOU COMPARED THE INCOMES OF LOW-INCOME RATEPAYERS WITH THOSE OF HIGHER-INCOME RATEPAYERS?

A. Yes, and the comparison is shown in my Exhibit GG-3. As is evident from this exhibit, the average incomes of low-income ratepayers are much lower than the average for those above 150% of the poverty level or of the population as a whole.

Q. YOU SPEAK OF "PHILADELPHIA AND ITS PENNSYLVANIA SUBURBS." IS THIS EQUIVALENT TO PHILADELPHIA ELECTRIC'S SERVICE TERRITORY WITHIN PENNSYLVANIA?

A. Not precisely, but it is close enough to provide a reasonably accurate representation of the situation of Philadelphia Electric customers under the jurisdiction of this Commisssion. The Pennsylvania

portion of the Philadelphia metropolitan area, as defined by the U.S. Office of Management and Budget for Census and other purposes, includes the City of Philadelphia plus all of four suburban counties: Bucks, Chester, Delaware and Montgomery. PECo's territory excludes some of the northern portions of this four-county area. But most of this territory is included. Furthermore, the portions missing from PECo's territory are among the less heavily populated. A small part of York County is also included in PECo's service area, although it is not within the metropolitan area. However, the population of this York County portion is not very great. So for practical purposes, the ratepayer population of PECo's service territory within Pennsylvania is quite well represented by the statistics.

Q. HOW DO THE INCOMES OF LOW-INCOME ELECTRIC RATEPAYERS IN THE CITY OF PHILADELPHIA COMPARE WITH THOSE FOR THE ENTIRE PENNSYLVANIA PORTION OF THE METROPOLITAN AREA?

A. They are somewhat lower. The average income for electric ratepayers under 150 percent of poverty in the City of Philadelphia is $7,662. For the entire Pennsylvania portion it is $7,826. Approximately the same differential exists for all household size categories, as shown in my Exhibit GG-4.

Q. YOU SPEAK OF "ELECTRIC RATEPAYERS." IS THIS SHORTHAND FOR THE ENTIRE POPULATION, OR ARE THE CENSUS STATISTICS YOU CITE ACTUALLY PRECISE ENOUGH TO GIVE YOU DATA ON RATEPAYERS AS SUCH?

A. I used Census Bureau computer tapes in my analysis. These tapes allowed me to focus specifically on households that reported in the Census that they paid their own electric bills. It is important to look at this population, because it excludes apartment dwellers whose electric bills are included in their rent. These people's situation may well be different from that of the ratepayer population, even at the same below-150-percent-of-poverty income level.

Q. WHEN WERE YOUR DATA OBTAINED?

A. They are principally from the 1980 Census.

Q. DOES THIS MAKE THEM OUT-OF-DATE?

A. Not to a degree that would affect the validity of my conclusions. There is no reason to believe that the low-income population of metropolitan Philadelphia has decreased since the 1980 Census. In fact, more recent data from the Census Bureau indicate that it probably has increased. In addition, the data on incomes and budgetary burdens which I present for these customers have been adjusted for inflation, and are stated in 1985 dollars.

Q. HOW MANY LOW-INCOME ELECTRIC RATEPAYERS, AS YOU HAVE DEFINED THEM, LIVE IN THE PENNSYLVANIA PORTION OF THE PHILADELPHIA METROPOLITAN AREA?

A. There are about 226,100 ratepayer households--containing nearly 600,000 persons. That is about one-fifth of all PECo customers in this area. In the City of Philadelphia itself, low-income ratepayers are nearly three ratepayers in ten. So when I speak of these low-income customers I am not talking about small numbers. Over two-thirds of low-income ratepayers in the area--some 155,000 households, containing over 400,000 persons--live in the City of Philadelphia. About 71,000 reside in the suburbs. (Exhibit GG-4)

Q. EARLY IN YOUR TESTIMONY YOU SAID THAT LOW-INCOME ELECTRICITY CUSTOMERS "CONSIST LARGELY OF ELDERLY AND HANDICAPPED PERSONS AND SINGLE-PARENT FAMILIES WITH CHILDREN." WOULD YOU PLEASE GO INTO MORE DETAIL ON THIS POINT.

A. Yes. Here I was talking about the population under 150 percent of the federal poverty limits, which as I indicated earlier makes up nearly one-fifth of Philadelphia Electric's ratepayers in the entire Pennsylvania portion of its service area, and nearly 30 percent of electricity customers within the City of Philadelphia. A lot of people have the idea that these are mainly large families with children. In fact, the largest size category is

single persons living alone. They make up nearly two-fifths of the total. One- and two-person households combined make up a three-fifths majority, as shown in my Exhibit GG-5.

Q. YOU HAVE STATED THAT SMALL HOUSEHOLDS OF ONLY ONE OR TWO PERSONS ARE A THREE-FIFTHS MAJORITY OF ALL LOW-INCOME ELECTRIC RATEPAYERS. WHAT PROPORTION OF LOW-INCOME RATEPAYERS CONTAIN SIX PERSONS OR MORE?

A. Only about eight percent are this large. Five-person households make up another eight percent. So, in combination, only about one low-income household in six contains five persons or more.

Q. IS A HOUSEHOLD THE SAME THING AS A FAMILY?

A. No, households include families but not the other way around. A household is all the inhabitants of a housing unit. A family is persons who are related. A household may be a family, or as I have already indicated, a single person living alone. It may also consist of two or more unrelated people sharing living quarters, or occasionally two or more families. As I have indicated, however, most low-income households are quite small.

Q. WHAT CAN YOU SAY ABOUT THE NEARLY TWO-FIFTHS OF LOW-INCOME PECO CUSTOMERS WHOM YOU HAVE INDICATED TO BE SINGLE PEOPLE LIVING ALONE?

A. Among these low-income single ratepayers, almost 49,000 households--nearly 57 percent of the total--

are elderly. Still others are not elderly but are disabled.

Q. IS THERE ANY OTHER IMPORTANT FACT ABOUT LOW-INCOME ELECTRIC CUSTOMERS WHO LIVE ALONE WHICH BEARS ON THEIR VULNERABILITY?

A. Yes. About three-fourths of them (and nearly 85 percent of those aged 65 and older) are women. Most of these women are widowed.

Q. WOULD IT BE CORRECT TO STATE THAT THE MOST TYPICAL LOW-INCOME PECO CUSTOMER IS AN ELDERLY AND/OR DISABLED WOMAN WHO LIVES ALONE?

A. Yes, in thinking of the situation and needs of such a customer, the most accurate image to keep in mind is your elderly mother or grandmother--not a young welfare mother with a lot of children.

Q. EARLIER, HOWEVER, YOU HAD MENTIONED SINGLE-PARENT FAMILIES WITH CHILDREN AS ONE OF THE VULNERABLE GROUPS AMONG RATEPAYERS. IF THEY ARE NOT THE MAJORITY, HOW MANY OF THEM ARE THERE?

A. Just under one-fifth of all low-income ratepayers, about 44,000 in all, are single-parent families with children. Over 90 percent of these families, about 41,000, are headed by women.

Q. AND ARE THESE SINGLE-PARENT FAMILIES WITH CHILDREN PREDOMINANTLY LARGE?

A. No. Most have only one or two children.

Q. RETURNING TO THE SINGLE-PERSON HOUSEHOLDS AMONG THE LOW-INCOME RATEPAYERS, YOU STATED THAT THEIR

INCOMES AVERAGED ONLY ABOUT $4,641 PER YEAR. WHAT DOES THAT AMOUNT TO ON A MONTHLY BASIS?

A. It is an average of $387 per month, and that amount must cover all expenses including the electric bill. This is the average; there are many customers with less.

Q. BUT SINCE THE DATA YOU USE COME FROM THE 1980 CENSUS, AND THERE HAS BEEN CONSIDERABLE INFLATION SINCE, DON'T THEY GREATLY UNDERSTATE THE INCOMES THAT LOW-INCOME RATEPAYERS RECEIVE TODAY?

A. No. I have increased the census income figures based on the change in the Consumer Price Index, or CPI, since the Census was taken. This is a method often used by statisticians to update incomes for inflation in the absence of more recent survey data.

Q. PLEASE DESCRIBE EXACTLY HOW YOU UPDATED THE CENSUS INCOME FIGURES TO TAKE ACCOUNT OF INFLATION.

A. I obtained the CPI for the Philadelphia area for the most recent month for which it was available when this testimony was prepared. That month was November of 1985. I divided it by the annual average CPI for calendar year 1979, which is the year for which persons responding to the 1980 Census were asked to report their incomes. This gave me the inflation factor.

Q. HOW DID YOU APPLY THIS INFLATION FACTOR?

A. I instructed the computer to multiply the income of

every household in the census data tape by this factor. This gave me updated incomes for late 1985, which are the ones I use throughout this testimony. Since inflation is currently low, they can be considered to apply to the present date.

Q. IN YOUR OPINION, DOES THIS METHOD OF UPDATING INCOMES BY THE CONSUMER PRICE INDEX YIELD ACCURATE RESULTS FOR THE LOW-INCOME POPULATION OF THE PHILADELPHIA ELECTRIC COMPANY SERVICE AREA?

A. Probably not as accurate as might be wished, even though the method is an accepted one. I believe that it almost certainly overestimates the growth in incomes since the 1980 Census--especially for low-income households.

Q. ON WHAT DO YOU BASE YOUR BELIEF THAT THE METHOD YOU HAVE USED TO UPDATE INCOMES FOR INFLATION PROBABLY OVERSTATES THE INCOME GROWTH FOR LOW-INCOME HOUSEHOLDS?

A. First, there is a lot of evidence from periodic surveys by the Census Bureau that the incomes of households at the lower end of the income scale have not been increasing in accord with inflation, and that for this reason the poverty population is growing.

Q. BUT THESE ARE NATIONAL STUDIES. DO YOU HAVE ANY EVIDENCE THAT THE INCOMES OF LOW-INCOME HOUSEHOLDS IN THE PHILADELPHIA AREA HAVE NOT BEEN KEEPING UP WITH INFLATION?

A. Yes. I have data on the increase in benefit levels under AFDC--Aid to Families with Dependent Children--between 1980 and 1986. These data indicate that benefit levels have risen by about 10 percent for a two-person family (typically an unwed, divorced or deserted mother with a single child) to about 15 percent for a family of three and about 27 percent for a family of six. This compares with an increase of about 40 percent in the Consumer Price Index for the same period. (Exhibit GG-6)

Q. SO NO AFDC FAMILIES HAVE RECEIVED AN INCREASE IN BENEFITS EQUAL TO INFLATION?

A. That is correct. And smaller families have received smaller increases, much below the inflation rate. I would reiterate that most low-income families are small.

Q. YOU INDICATED THAT YOU ALSO EXAMINED THE BUDGETARY BURDENS PLACED UPON LOW-INCOME ELECTRIC RATEPAYERS BY THE COSTS OF SUCH NECESSITIES AS SHELTER AND FOOD. WOULD YOU PLEASE DISCUSS SHELTER COSTS AS THEY RELATE TO THE INCOMES OF THESE HOUSEHOLDS.

A. Yes. My findings on shelter costs are summarized in my Exhibits GG-7 and GG-8. The first deals with homeowners, the second with renters. All figures are for electric ratepayers.

Q. ARE THESE FIGURES IN UPDATED DOLLARS?

A. Yes, they have been updated by the computer using the Consumer Price Index for the Philadelphia area.

Q. PLEASE DISCUSS THE SHELTER COSTS OF LOW-INCOME HOMEOWNERS.

A. Homeowners are a majority of low-income ratepayers in the Pennsylvania portion of the Philadelphia metropolitan area. For all households combined, these ratepayers have an average income of $673 per month, according to the updated census figures. Monthly owner costs, which include mortgage and tax payments, insurance, fuels and utilities (including electricity), but not maintenance costs, take just over half this amount, or $370 per month. That leaves $303 per month or just about $70 per week for all other expenditures including food, clothing, medical care and other necessary and discretionary items.

Q. PLEASE DISCUSS THE SHELTER COSTS OF LOW-INCOME SINGLE HOMEOWNER-RATEPAYERS LIVING ALONE.

A. Low-income single homeowner-ratepayers of all ages living alone have a much lower monthly income than the average for homeowner households of all sizes. In fact, it is less than three-fifths as great--only $400. Their shelter costs, while lower also, are not sufficiently lower to compensate. They total $286 per month, leaving only $114 per month or about $26 per week for all other living

costs. As I have noted earlier, a majority of single-person low-income households are elderly.

Q. PLEASE DISCUSS THE SHELTER COST SITUATION OF LOW-INCOME RENTERS.

A. While homeowners are a majority, renters are a sizeable minority among the low-income group of ratepayers. There are about three-fourths as many of them as there are of homeowners. They are somewhat worse off than homeowners in most cases. Their incomes are lower overall; and their shelter costs--while lower also in most cases--are higher for small households. Overall, and particularly for single-person households, the combination of low incomes and high shelter costs leaves little remaining for other necessities.

Q. WHAT DO THE DATA SHOW ABOUT RENTER HOUSEHOLDS OF ALL AGES AND SIZES?

A. Their incomes average $625 monthly, about $48 less than owners. Their shelter costs average $350, about $20 lower. This leaves them an average of $275 per month or about $63 per week for all other expenditures.

Q. WHAT ABOUT SINGLE-PERSON RENTER HOUSEHOLDS OF ALL AGES?

A. They are the worst off of all. Their incomes average only about three-fifths as much as the total--$369 monthly. Shelter costs average $297,

leaving them with only $72 per month on average for all other expenses. That is about $17 per week.

Q. DO YOU HAVE DATA ON THESE HOUSEHOLDS' EXPENDITURES FOR OTHER ESSENTIALS?

A. We have data on food expenditures from the 1981 national Consumer Expenditure Survey, conducted on behalf of the U.S. Bureau of Labor Statistics by the U.S. Bureau of the Census.

Q. ARE THESE DATA ALSO SPECIFIC TO THE PHILADELPHIA AREA?

A. No. Only broad regional data are available from the Consumer Expenditure Survey. I obtained the data for the metropolitan areas in the Northeast--which is the region in which Philadelphia is included for Census purposes. This region includes New England as well as the Middle Atlantic states of New York, New Jersey, and Pennsylvania.

Q. AND DID YOU UPDATE THESE FIGURES IN THE SAME FASHION AS ELSEWHERE IN YOUR TESTIMONY?

A. Yes, following the same procedure discussed earlier.

Q. WHAT IS LEFT OF LOW-INCOME HOUSEHOLDS' BUDGETS AFTER BOTH SHELTER AND FOOD COSTS ARE TAKEN OUT?

A. The data bearing on this question are summarized in my Exhibit GG-9. Obviously, low-income single-person renter households fare by far the worst in terms of money remaining. They have a deficit, on average, of $26 or $6 per week. As a

group, however, renter households have somewhat more left than homeowners, largely because they spend less on food. After food and shelter costs, they have $116 monthly remaining, or about $27 per week, to pay for all other expenses. Homeowner households as a group have $52 monthly remaining, or $12 per week. But homeowner households with only a single person have only $2 left per month--pennies per week--which still makes them slightly better off than single renters.

Q. WHICH TYPE OF HOUSEHOLDS HAVE THE LARGEST AMOUNTS REMAINING AFTER SHELTER AND FOOD COSTS?

A. Dollar-wise, the best situation is that of renter households of all sizes, who have an average of $116 remaining which works out to $27 per week. However, it must be understood that some of these people also have dependents whose expenses must be paid, while single-person households must pay only for themselves.

Q. HOW IS IT POSSIBLE FOR LOW-INCOME HOUSEHOLDS TO HAVE INCOME DEFICITS--ACTUALLY SPENDING MORE MONEY TO LIVE THAN THEY RECEIVE?

A. One explanation is that they can and often do fall behind in their bills. Low-income households with members of working age often have irregular incomes from employment. Thus, when they are unemployed they fall behind, and when they are working they

try to catch up. Some of these deficits may be made up in this way.

Q. WHAT DO YOU CONCLUDE OVERALL FROM YOUR EXAMINATION OF BUDETARY BURDENS?

A. I conclude that a large proportion of low-income ratepayers are operating close to or even past the edge of solvency. Any increase in their electric bills must be drawn from budgets which, in most cases, are squeezed to the limit and often beyond the limit by recent years' increases in the costs of such essentials as housing, food, and energy--including electricity itself.

Q. WHAT WILL BE THE BUDGETARY IMPACT OF PECO'S REQUESTED RATE INCREASE, IF GRANTED, ON LOW-INCOME RATEPAYERS?

A. The increase will be extremely serious for many, in light of both the large amount of the increase and their already-overtaxed household budgets. The company has stated in materials supplied to consumers that "the annual cost of service to the average residential user (500 kilowatt-hours per month) would increase from $700 to $910, or by 58 cents per day". To estimate the impact on low-income consumers, I have turned to the figures previously cited from DOE's Residential Energy Consumption Survey. I would first note that the figures given in that survey for average annual electricity consumption is 6.1 thousand (6,100)

KWH. This is very close to the 6,000 KWH obtained by multiplying PECo's 500 KWH per month by 12. Taking the average cited in the Residential Energy Consumption survey of 4.4 thousand (4,400) KWH consumed annually by low-income households, I find that this amount is 72 percent of the average. Applying this ratio to the increase of $210 annually for the average customer stated by the company, I obtain a figure of about $151 annually, or slightly under $13 per month for low-income customers. This is approximate, of course, but will serve to give an idea of the impact of the increase. It can be compared to the following amounts:

- The $2 per month left after shelter and food costs for low-income single person homeowner ratepayers.
- The $26 per month deficit for low-income single person renter ratepayers.
- The $52 per month remaining after food and shelter costs for low-income homeowner ratepayers of all household sizes.
- The $116 per month left after food and shelter costs for low-income renter ratepayers of all household sizes.

These are meagre amounts at best, and PECo's requested rate increase will cut severely into even the largest of them. Under the new rate, if

granted, electricity will cost the average low-income ratepayer about $655 per year. This will be more than eight percent of the total income of the average low-income ratepayer (all household sizes combined); over 14 percent of the total income of the average low-income single person living alone; and 15 percent of the AFDC benefit for a family of three in Philadelphia. These percentages must be evaluated in the context of the fact that these incomes are now strained to the limit, and beyond, by essential living expenses.

Q. AS I UNDERSTAND IT, AIR CONDITIONING IS LARGELY RESPONSIBLE FOR HIGH PEAK LOADS. DO LOW-INCOME HOUSEHOLDS CONTRIBUTE MUCH TO THESE PEAKS?

A. They contribute much less, proportionately, than higher-income ratepayers. Among ratepayers at or below the 150-percent-of-poverty level in PECo's Pennsylvania service territory, only 8.5 percent have central air conditioning. This compares with 20.5 percent among higher-income ratepayers. About half as many in this low-income group, proportionately, have two or more room air conditioners as do higher-income ratepayers. In all, low-income ratepayers with <u>any</u> form of air conditioning are only about one-sixth as numerous as higher-income ratepayers with air conditioning of any type. (Exhibit GG-10)

Q. DO LOW-INCOME HOUSEHOLDS CONTRIBUTE AS MUCH TO DEMAND FOR ELECTRICITY, AND HENCE TO THE NEED FOR NEW GENERATING FACILITIES, AS DO HIGHER-INCOME HOUSEHOLDS?

A. They do not. On average, low-income households use substantially less electricity than those of all income levels combined, and much less than high-income consumers.

Q. WHAT IS YOUR EVIDENCE FOR THIS STATEMENT?

A. It comes from a periodic national survey by the U.S. Department of Energy which is the most complete and detailed source of data on energy consumption in relation to consumer characteristics. This survey is known as the Residential Energy Consumption Survey, and the most recent available data are for the year from April of 1982 through March of 1983.

Q. DOES THE RESIDENTIAL ENERGY CONSUMPTION SURVEY PROVIDE DATA SPECIFICALLY FOR THE PHILADELPHIA AREA?

A. No. However, it does provide figures for the Middle Atlantic Census Division, which consists of the three States of New York, New Jersey and Pennsylvania, as well as for the U.S. as a whole and for a number of other sub-regions.

Q. WHAT DOES THE SURVEY SHOW ABOUT CONSUMPTION RELATED TO INCOMES IN THE MIDDLE ATLANTIC AREA?

A. It shows that consumers with incomes under 125 percent of the poverty line use an average of 4.4 thousand KWH of electricity annually, compared to 6.1 thousand KWH for customers of all income levels. That is less than three-fourths as much as the average. (Exhibit GG-11)

Q. AND HOW DOES THIS CONSUMPTION COMPARE TO THAT OF HIGH-INCOME HOUSEHOLDS IN THE SAME AREA?

A. Consumers with 1981 family incomes of $35,000 or more consume an average of 8.6 thousand KWH annually. That is almost twice as much as the average for consumers with incomes below 125 percent of poverty.

Q. DO YOU HAVE ANY EVIDENCE SPECIFIC TO THE PHILADELPHIA AREA FOR YOUR CONTENTION THAT LOW-INCOME RATEPAYERS USE LESS ELECTRICITY?

A. Yes. It comes from two reports prepared by PECo itself. These are reports of the Company's 1980 Residential Electric Service Load Study. They are Reports Nos. 48482-A and 48482-B, and were obtained under discovery.

Q. WHAT EVIDENCE IS CONTAINED IN THESE REPORTS ON LOW-INCOME HOUSEHOLDS' ELECTRICITY CONSUMPTION?

A. The evidence is partially inferential yet nonetheless strong, and particularly so since it closely confirms the findings of the Residential Energy Consumption Survey. Because the PECo reports themselves contain no data on incomes, I

had to infer income levels from other evidence. The reports do contain information on occupation of the household head, number of persons in the household, number of household members under age 18, and number of rooms in the home.

As will be recalled from my earlier testimony and from my Exhibits GG-2, GG-3 and GG-4, census data show that household size and income are related. Most low-income households are small, containing only one or two persons. The most common size is one person. By the same token, these small households contain few or no children. In fact, most single-person low-income households are elderly. The converse is true as well: most higher-income households are larger than one person, and most of them are not elderly.

With these facts in mind, I compared the data in the Company's survey report No. 48482-A dealing with customers in the lowest and highest consumption classes out of six into which the sample of customers (all in Rate Class R) were divided. The lowest consumption category was 201-300 KWH monthly, and the highest was 1001-1500. These were December usage figures, and December is a month in which air conditioning does not usually play a role in consumption. Note also that space heating (Rate Class RH) and off-peak water heating (Rate Class OP) customers were not included in the

survey. Hence 1001 to 1500 KWH in a December month is indeed high consumption.

Q. WHAT WAS YOUR OVERALL CONCLUSION BASED UPON THE DATA IN THESE REPORTS ON CONSUMPTION AS RELATED TO THE CHARACTERISTICS OF RATEPAYERS?

A. I concluded that the data in these reports demonstrated a strong relationship between consumption and income levels, as the latter could be inferred from occupations and household sizes.

Q. WHAT DID YOU CONCLUDE ABOUT THE INCOME-RELATED CHARACTERISTICS OF RATEPAYERS IN THE LOWEST ELECTRICITY CONSUMPTION CATEGORY?

A. These low-consumption ratepayers were predominantly retired elderly persons and people in low-paid jobs. Most had very small households, and few had children.

Q. PLEASE STATE HOW YOU REACHED THESE CONCLUSIONS.

A. In the lowest consumption class, 201-300 KWH, 39 percent reported the occupation of the head as retired. An additional 14 percent reported it as housewife. All the housewives were single persons living alone. I think it is reasonable to assume that they were usually widowed and in many cases elderly. Only one retired household had more than two persons. I therefore conclude that about half of the sample of customers in the lowest consumption category were probably elderly couples and widowed individuals.

Q. AND THE REST?

A. Many of them reported occupations which generally pay low wages. In all, 17 percent reported that their occupations were such as laborer, porter, house cleaner, maintenance, clerk, and bank teller. Some other reported occupations were less clearly low-income, but homes and apartments were generally small and suggested that most of these people were living modestly.

Q. WHAT DID YOU CONCLUDE ABOUT THE INCOME-RELATED CHARACTERISTICS OF RATEPAYERS AMONG THE HIGHEST CONSUMPTION CATEGORY IN RATE CLASS R?

A. They were predominantly professionals, managers, and members of other highly-paid occupations. The number of people in the household tended to be larger, and the homes they occupied were larger as well.

Q. ON WHAT DO YOU BASE THIS CONCLUSION?

A. In this highest consumption category, with December consumption of 1001 to 1500 KWH, most household heads reported occupations that clearly placed them in the higher-paid professional and managerial categories. More than 10 percent of the sample were doctors; there were also other highly-paid professional categories such as judge, accountant, and engineer. In all, 31 percent were business executives, owners, managers, or supervisors. While many of the other reported occupations were

less clearly high-income, such as salesman and insurance agent, the sizes of the homes they lived in generally suggested that they were economically successful. Most contained ten rooms or more. Not a single household head was either retired or a housewife.

There was only one single-person household in the high-consumption group, and fewer than ten percent contained two persons. All the rest of the households consisted of three persons or more, and over 70 percent contained persons under the age of 18. This figure contrasted with only 11 percent in the lowest consumption category.

Q. WERE THE VERY DIFFERENT DECEMBER CONSUMPTION LEVELS IN THESE TWO CATEGORIES ACCOMPANIED BY DIFFERENT LEVELS OF SUMMER PEAK ELECTRICITY USE?

A. Decidedly. Both the August non-coincident maximum demand and the maximum annual recorded demand for the highest consumption category were more than three times as great as the comparable figures for the lowest usage group.

Q. AND DID THESE DIFFERENT CONSUMPTION LEVELS APPEAR TO BE ASSOCIATED WITH DIFFERENTIAL POSSESSION OF AIR CONDITIONERS?

A. Yes, definitely. In the lowest consumption category, only six percent of the ratepayers had central air conditioning systems, and only 36 percent had room air conditioners. In the great

majority of these cases there was only one room unit. In the highest consumption category, by contrast, 41 percent of the households had central air systems and 44 percent had room units. In such cases there was usually more than one unit, and in several instances as many as four or five.

Q. TAKING INTO ACCOUNT ALL THE EVIDENCE YOU HAVE CITED ON THE RELATIONSHIPS BETWEEN INCOMES, CONSUMPTION LEVELS, AND POSSESSION OF AIR CONDITIONERS, WHAT DO YOU CONCLUDE THAT IS OF RELEVANCE TO THE IMPACT OF THE REQUESTED PECO RATE INCREASE ON LOW-INCOME RATEPAYERS?

A. I conclude that all the evidence indicates that low-income ratepayers contribute little to the large peak demands. These are summer peaks related largely to air conditioning, and especially to use of central air and multiple room-unit systems.

Q. WHAT HAVE YOU CONCLUDED ABOUT THE ADEQUACY OF THE PROGRAMS WHICH ARE NOW IN PLACE TO AID LOW-INCOME RATEPAYERS TO REDUCE OR COPE WITH THEIR ELECTRIC BILLS?

A. My overall conclusion is that these programs, whatever benefits they provide, serve far too few ratepayers to be of much value in reducing the burdens on this group.

Q. PLEASE DESCRIBE THE PROGRAMS OF THIS TYPE OF WHICH YOU ARE AWARE.

A. They are:

(1) The Low-Income Home Energy Assistance Program (otherwise known as LIHEAP). Properly speaking, this is not a PECo program, but a governmental program from which low-income customers of PECo and other energy utilities can get financial assistance. The benefits are paid directly to the company to reduce arrearages.

In the 1984-1985 program year, LIHEAP provided benefits to 10,800 PECo customers. The average grant was $281.

(2) The Utility Emergency Services Fund (UESF). This program is also governmental, and provides benefits only to low-income residents of the city of Philadelphia. Like LIHEAP, it is available to customers of other utilities than PECo. The utilities provide matching funds on a 50-50 basis. The benefits under UESF are available only to customers under 125 percent of the poverty level--unlike other programs which use a more generous (150 percent) cutoff. It also has certain other restrictions. Grants of up to $500 are available only every two years. They are made only if,

with their help, the customer can reduce his or her arrearages to zero. That means that if a customer owes $800, no benefit will be available under UESF unless he can come up with another $300 out of his own pocket.

In 1985, through the date for which figures were made available by the company, this program had provided benefits to 1,326 customers. The average grant was $475.

(3) Project Heat. This program is jointly sponsored by PECo, the United Way of Bucks County, and the Bucks County Government. Naturally, it serves only customers residing in Bucks.

The project was begun in 1985, and through the date of reporting by the company had served 61 customers. The average grant was $213.

(4) Chester County Cares Utility Fund (CCCUF). This project is limited to Chester County residents who have had shutoff notices or whose service has been terminated. Grants, which are limited to $500, must zero out the account, or the customer must enter into a payment

agreement with regard to any remaining deficit.

In 1985, through the date of reporting, this project had served 56 customers. The average grant was $118.

(5) Customer Assistance Program (CAP). This is a PECo project which can aid customers through limiting their electric bills to amounts judged by the company to be within their ability to pay. The exact amount is determined by the company after examination and verification of the customer's income and expenses. The company also requires the customer to engage in certain conservation activities, and may recommend discontinuance of certain appliances judged to be too high in electricity consumption.

This program is presently in a pilot stage and reaches only about 500 customers.

(6) Tighten up - Low Cost Conservation Program (TLC). This conservation project provides low-income customers with an optimal audit to RCS which offers information on expected quick pay-back measures only. (These measures are defined by the company as including such

items as a water heater wrap and thermostat setback, reusable plastic storm windows, weatherstripping and caulking, door sweeps, and "other miscellaneous cost-effective measures".) This assistance, including audit, materials and installation, is currently provided free to eligible low-income customers (mainly LIHEAP recipients). However, a charge for materials used is apparently under consideration.

About 2,100 customers had been served through this program in a period of slightly less than one year ending August 31, 1985. The average cost of a TLC audit and treatment is $165, according to information provided by the company.

Q. HOW MANY CUSTOMERS ARE CURRENTLY SERVED ANNUALLY UNDER THESE PROGRAMS?

A. I could not calculate an exact annual figure because the time intervals for which data are available vary somewhat. However, in total the six programs served approximately 15,000 PECo customers in the latest year or major part of a year for which figures are available. Of this total, however, more than two-thirds is accounted for by LIHEAP, and more than 80 percent by the LIHEAP and UESF programs combined. PECo's own efforts, either

alone or in collaboration with other organizations, have served only a minor fraction of the total number.

Q. AND THIS 15,000 ANNUAL TOTAL OF CUSTOMERS SERVED, OF WHICH MORE THAN TWO-THIRDS ARE ACCOUNTED FOR BY LIHEAP, IS WHAT PERCENTAGE OF ALL LOW-INCOME ELECTRIC RATEPAYERS IN PECO'S PENNSYLVANIA SERVICE TERRITORY?

A. 15,000 customers served out of 226,000 low-income ratepayers is somewhat under seven percent. The number served by PECo's own programs is around one percent of the total number of low-income ratepayers.

Q. IF MORE IS NOT DONE TO ASSIST LOW-INCOME CUSTOMERS IN MEETING INCREASING ELECTRIC BILLS, WHAT WILL BE THE PROBABLE RESULT?

A. There are only two possibilities. Either they will default on their bills in still larger numbers, or they will be unable to pay for essentials of other kinds--including food and shelter.

Q. ARE TERMINATIONS OF SERVICE LIKELY TO INCREASE?

A. That result seems probable, although the amount of the increase is impossible to estimate since I cannot be sure how many low-income customers will elect to do without electric service or without other essentials. They will clearly have to do without something. I would note that residential terminations have been increasing. According to

information furnished by the company under discovery, in response to IR-OCA-11-7, the increase was from 22,855 terminations for the full year 1980 to 31,758 for 1984, the last full year for which data were made available by PECo. For 1985 through September, the total number of terminations was 29,093--already approaching the number for 1984, even though data for the last three months of the year were missing.

Q. HOW WOULD YOU RECOMMEND THAT THE COMMISSION DEAL WITH THE SITUATION OF LOW-INCOME CONSUMERS, IF IT SHOULD GRANT PHILADELPHIA ELECTRIC ITS REQUESTED INCREASE IN WHOLE OR IN PART?

A. The Commission must recognize that low-income customers are particularly vulnerable to further increases in energy costs, which already consume substantial percentages of their budgets. Electricity costs alone are already a burden for many. The Commission should therefore look favorably upon rate design proposals that protect the interests of this category of consumers. Most low-income ratepayers use substantially less electricity than the 500 kwh per month that is the approximate average for all customers. Hence, one way to help protect low-income citizens would be to distribute any downward adjustment in PECo's revenue requirement allocated to the residential class predominantly in the lowest KWH rate block.

This block, if set in the range of 350 to 500 KWH, will encompass most or all electricity use by the majority of low-income ratepayers.

Q. WHAT SHOULD BE DONE TO HELP LOW-INCOME CUSTOMERS WHO USE MORE THAN THE AVERAGE?

A. These customers can best be protected both through low-income energy assistance programs and through stepped-up conservation measures. In many instances, their excessive consumption is due largely to energy-inefficient homes and appliances, and conservation programs can help reduce reduce this consumption.

Q. BUT WOULDN'T THIS BENEFIT SOME HIGH-INCOME LOW-USE CUSTOMERS AS WELL?

A. Yes, no policy instrument is ever perfect. However, this approach would benefit most low-income people, plus many more whose incomes are not much over the 150-percent-of-poverty line. If the Commission should be concerned about a policy that might benefit some who are rich while protecting most of the poor, then one possibility would be to limit the rate to those under 150 percent of poverty. I would point out, however, that this approach would leave out many people whose incomes are just high enough to take them out of the low-income category, but whose budgets are nonetheless under severe strain. In many cases, their effective purchasing power for essentials other than electricity may

well be cut by PECo's increase to less than that of some who are already below the 150 percent limit. In my view, this would be a more serious fault than benefiting some customers who are better off--especially since these customers are conserving more electricity than most, and thus helping to limit the need for additional expensive generating capacity.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Exhibit GG-1

GEORGE GRIER
Principal
The Grier Partnership

Qualifications

Mr. Grier has specialized in statistical analysis of demographic, economic, and housing data and design of data systems, with particular concentration on policy applications. He has been responsible for direction of a number of major studies; has written, published and spoken extensively; and has testified before Congressional committees, courts, and public regulatory commissions.

Principal Staff Experience

1976 to Present--Principal, The Grier Partnership, Bethesda, Maryland

As a partner in this research and consulting organization, Mr. Grier has had responsible roles in the design and direction of several dozen projects for clients in the public, private non-profit, and profit-making sectors. In the energy field, these projects have included:

- Statistical analyses to determine the characteristics and energy expenditures of low-income and elderly households and to assess the budgetary impact of rising energy prices on these households, drawing upon data from the computer tapes of Census Bureau, DOE, and other survey data bases:

  --for the nation as a whole; and

  --in various regions, states and local areas, including New England, Illinois, New Jersey, Pennsylvania, Milwaukee County, and the District of Columbia.

- Assessment of energy burdens for low-income households in all states of the continental U.S. under alternative scenarios as to energy prices, weather, and conservation practices, using specially-designed computer simulation models.

- Analyses of the relationship of energy burdens to benefits provided under LIHEAP and other federal programs at the level of all individual states of the continental U.S. and the District of Columbia.

- Analysis of the amount of subsidy required in each state to keep the energy expenditures of elderly and low-income citizens within specified percentages of their incomes.

- Coordination and analysis of several national surveys of energy prices and utility rates, collecting data from energy suppliers in all parts of the nation for all commonly used fuels.

- Evaluations of several alternative strategies for alleviating energy burdens on low-income households, including:
  - -- "Lifeline" utility rate proposals in Illinois, New Jersey, and Pennsylvania;
  - -- The Illinois SACCC 12-Percent-of-Income Plan;
  - -- The Wisconsin Gas Company's Guaranteed Service Plan;
  - -- The Potomac Electric Power Company's "Residential Aid Rider"

- Analysis of demographic and developmental constraints on efforts to meet energy conservation goals through urban planning and design.

- Preparation and presentation of expert testimony in utility rate cases in several states, including Illinois, New Jersey and Pennsylvania as well as the District of Columbia. Mr. Grier has personally presented the testimony in some of these cases.

In the area of demographic and economic analysis, Mr. Grier has had responsible roles in a number of projects, including:

- Studies of demographic and housing patterns, utilizing data from Census Bureau computer tapes and other sources:
  - -- for the U.S. as a whole and for all major U.S. metropolitan areas, plus special in-depth studies
  - -- for the Baltimore, MD metropolitan area;
  - -- for the Chicago, IL metropolitan area;
  - -- for the Houston, TX metropolitan area;
  - -- for the Philadelphia, PA metropolitan area;
  - -- for the Washington, DC metropolitan area.

- Preparation of a widely-used handbook for local policy makers and planners interested in obtaining up-to-date demographic, economic and housing data on their local areas.

- Specification of data requirements for a major national survey by a federal agency.

- Two national studies of the problem of human displacement resulting from urban revitalization.

- An evaluation of several widely-marketed commercial demographic data systems.

- A number of proprietary market analyses for private clients, including housing and shopping center developers and health care providers.

1967 to 1976--Vice President and Senior Associate, The Washington Center for Metropolitan Studies, Washington, DC

For this non-profit urban studies center, Mr. Grier was responsible for design and direction of several major projects. These projects involved not only written products but also the calling of conferences of various sizes to communicate the results to policy-makers. Mr. Grier often convened and chaired these conferences.

- An area-wide census updating survey for metropolitan Washington, DC. Taken midway between the 1970 and 1980 censuses, this survey brought all major census items, including demographic, economic and housing data, up to date for the metropolitan area, its central city, and its major suburban jurisdictions.

- Studies of the implications of demographic changes for public policy and the planning of housing, public facilities and services in the District of Columbia, the Nation's Capital.

- Design of a prototype manpower information system for the District of Columbia government, and direction of a project to develop manpower information for affirmative action programs in the District.

- Design of improved techniques for estimating population and housing markets.

- A study of the implications of the decline in the birthrate for educational facilities planning at all levels, including public schools in newly-developed areas and institutions of higher education.

- Several studies of emergent population and housing trends in the nation and metropolitan Washington and their policy and program impacts.

1964 to 1967--Director of Social Program Coordination, District of Columbia Government, Washington, DC

In this position, Mr. Grier served as deputy to the District's Director of General Administration. One of his chief duties was to plan new and expanded human resources programs through assembly and analysis of demographic and economic data.

1962 to 1964--Staff Associate, Washington Center for Metropolitan Studies, Washington, DC

Responsible for several policy-focused analyses. On loan for part of this period to design a research program for the United Planning Organization, Washington's federally-funded anti-poverty agency.

1960 to 1962--Senior Staff Member, The Brookings Institution, Washington, DC

One of Mr. Grier's chief responsibilities in this position was to help local public officials in a number of metropolitan areas to achieve an improved understanding of the application of social science techniques to local needs and problems. He convened and chaired two series of community conferences in Cincinnati, Ohio and Lansing, Michigan.

Selected Memberships and Professional Honors

Member, Board of Directors, Lambda Alpha, the international land economics honor society.
Founding Member, Board of Directors, DC Municipal Research Bureau
Member, Economic and Financial Management Advisory Group, U.S. Conference of Mayors
Founding Member, Executive Committee and Board of Directors, Housing Opportunities Council of Metropolitan Washington
Chairman, Committee on Poverty, Society for the Psychological Study of Social Issues
Recipient of two Ford Foundation personal study grants
Received Melvin C. Hazen Award as outstanding young man in District of Columbia Government
Phi Beta Kappa

Education

B.A. with Honors in Psychology, University of Pennsylvania, 1950. Elected to Phi Beta Kappa.
M.A. with Honors in Social Psychology, specialization in survey design and statistics, University of Pennsylvania, 1952.

EXHIBIT GG-2

AVERAGE INCOMES OF LOW-INCOME ELECTRIC RATEPAYERS
COMPARED TO FEDERAL POVERTY LIMITS
PENNSYLVANIA PORTION OF PHILADEPHIA METROPOLITAN AREA

(In November 1985 Dollars)

Persons	150% of Federal Poverty Income Limit	Average Income	Percent Average Income of Limit
1	$ 7,875	$ 4,641	59%
2	$10,575	$ 7,497	71%
3	$13,275	$ 8,216	62%
4	$15,975	$10,556	66%
5	$18,675	$12,047	65%
6	$21,375	$14,154	66%
7	$24,075	$15,061	63%
8	$26,775	$18,602	69%

Source: Average Incomes - 1980 U.S. Census Public Use Microdata Sample File, updated by Consumer Price Index.
Federal poverty limits - U.S. Department of Health and Human Services

Exhibit GG-3

AVERAGE INCOMES OF ELECTRIC RATEPAYERS
BELOW AND ABOVE 150% OF POVERTY,
AND OF ALL ELECTRIC RATEPAYERS,
BY HOUSEHOLD SIZE
PENNSYLVANIA PORTION OF PHILADELPHIA METROPOLITAN AREA

(In November 1985 Dollars)

Persons	Below 150% of Poverty	At or above 150% of Poverty	All Ratepayer Households
1	$ 4,641	$22,011	$15,901
2	$ 7,497	$34,886	$30,932
3	$ 8,216	$40,396	$35,984
4	$10,556	$44,322	$39,766
5	$12,047	$47,470	$41,477
6	$14,154	$49,881	$42,595
7	$15,061	$52,808	$42,075
8 or more	$18,602	$55,516	$42,423
Average - All Sizes	$ 7,826	$37,524	$31,767

Source: 1980 Census Public Use Microdata Sample File, updated by Consumer Price Index.

Exhibit GG-4

AVERAGE INCOMES OF LOW-INCOME ELECTRIC RATEPAYERS
IN THE CITY OF PHILADELPHIA
COMPARED TO ENTIRE PENNSYLVANIA PORTION
OF PHILADELPHIA METROPOLITAN AREA

(In November 1985 Dollars)

	Average Income - Under 150% of Poverty	
Persons	Philadelphia	Pennsylvania Portion of Phila. Metro Area
1	$ 4,546	$ 4,641
2	$ 7,455	$ 7,497
3	$ 8,019	$ 8,216
4	$10,262	$10,556
5	$11,603	$12,047
6	$14,172	$14,154
7	$14,370	$15,061
8 or more	$17,559	$18,602
Average - All Sizes	$ 7,662	$ 7,826
Total No. of Ratepayers	155,140	226,080

Source: 1980 U.S. Census Public Use Microdata Sample File, updated by Consumer Price Index

Exhibit GG-5

SIZE DISTRIBUTION OF LOW-INCOME
ELECTRIC RATEPAYER HOUSEHOLDS
PENNSYLVANIA PORTION OF PHILADELPHIA METROPOLITAN AREA
1980

Persons	Number of Households	Percent of Total
1	86,140	38%
2	50,120	22%
3	28,880	13%
4	24,860	11%
5	17,420	8%
6	9,340	4%
7	6,000	3%
8 or more	3,320	1%
Total	226,080	100%

Source: 1980 U.S. Census Public Use Microdata Sample File.

Exhibit GG-6

AID TO FAMILIES WITH DEPENDENT CHILDREN (AFDC)
BENEFIT LEVELS - 1980 AND 1986
PENNSYLVANIA PORTION OF PHILADELPHIA METROPOLITAN AREA

Philadelphia and Delaware Counties

Family Size	Monthly Benefit Levels Jan. 1, 1980	Jan. 1, 1986	Pct. Change 1980-86
1	$172	$186	8.1%
2	$262	$287	9.5%
3	$318	$365	14.8%
4	$381	$451	18.4
5	$438	$535	22.1%
6	$478	$608	27.2%
Add'l persons	$ 58 each	$ 75 each	29.3%

Bucks, Chester, and Montgomery Counties

Family Size	Monthly Benefit Levels Jan. 1, 1980	Jan. 1, 1986	Pct. Change 1980-86
1	$181	$195	7.7%
2	$273	$299	9.5%
3	$332	$382	15.1%
4	$395	$466	18.0%
5	$451	$551	22.2%
6	$490	$623	27.1%
Add'l persons	$ 58	$ 75	29.3%

Source: Leon Cerullo, Supervisor of Research and Statistics, Pennsylvania Department of Public Welfare (by telephone)

Exhibit GG-7

MONTHLY HOUSEHOLD INCOMES AND OWNER COSTS
FOR LOW-INCOME ELECTRIC RATEPAYER-OWNERS
PENNSYLVANIA PORTION OF THE PHILADELPHIA METROPOLITAN AREA

(In November 1985 Dollars)

Persons	Monthly Household Income	Monthly Owner Costs*	Remainder
1	$ 400	$286	$114
2	$ 614	$329	$285
3	$ 690	$451	$239
4	$ 924	$490	$434
5	$1065	$523	$542
6	$1236	$479	$757
7	$1354	$436	$918
8 or more	$1588	$495	$1093
Average - All Sizes	$ 673	$370	$303

*The sum of payments for real estate taxes, fire and hazard insurance, electricity, gas and other fuels, water, and mortgage. Owner costs as shown here do not include payments for maintenance and repairs.

Source: 1980 Census Public Use Microdata Sample File, updated by Consumer Price Index.

Exhibit GG-8

MONTHLY HOUSEHOLD INCOMES AND GROSS RENTS
FOR LOW-INCOME ELECTRIC RATEPAYER-RENTERS
PENNSYLVANIA PORTION OF THE PHILADELPHIA METROPOLITAN AREA

(In November 1985 Dollars)

Persons	Monthly Household Income	Monthly Gross Rents*	Remainder
1	$ 369	$297	$ 72
2	$ 641	$348	$293
3	$ 681	$374	$307
4	$ 817	$398	$419
5	$ 925	$405	$520
6	$1110	$444	$666
7	$1075	$417	$658
8 or more	$1382	$465	$917
Average - All Sizes	$ 625	$350	$275

*Contract rent plus the estimated average monthly cost of electricity, gas and other fuels, and water, to the extent that these are paid by or on behalf of the renter, in addition to the rent.

Source: 1980 Census Public Use Microdata Sample File, updated by the Consumer Price Index.

Exhibit GG-9

MONTHLY AVERAGE AMOUNT REMAINING
AFTER BOTH SHELTER AND FOOD COSTS FOR
LOW-INCOME ELECTRIC RATEPAYERS
PENNSYLVANIA PORTION OF PHILADELPHIA METROPOLITAN AREA

(In November 1985 Dollars)

	Remainder After Shelter Costs	Food Costs	Remainder After Food and Shelter
All Low-Income Homeowner Ratepayers	$303	$251	$ 52
Single-Person Low-Income Homeowner Ratepayers	$114	$112	$ 2
All Low-Income Renter Ratepayers	$275	$159	$116
Single-Person Low-Income Renter Ratepayers	$ 72	$ 98	- $ 26

Source: Remainder After Shelter Costs - see Exhibits GG-7 and GG-8.
Food Costs - 1981 Consumer Expenditure Survey, U.S. Bureau of Labor Statistics, updated by Consumer Price Index.

Exhibit GG-10

POSSESSION OF AIR CONDITIONING
AMONG ELECTRIC RATEPAYERS ABOVE AND BELOW 150% OF POVERTY
PENNSYLVANIA PORTION OF PHILADELPHIA METROPOLITAN AREA
1980

	Number	Percent
Below 150% of Poverty		
No air conditioning	121,760	53.9%
Central air conditioning	19,280	8.5%
One room unit	55,120	24.4%
Two or more room units	29,920	13.2%
Total Households	226,080	100.0%
150% of Poverty and Above		
No air conditioning	279,360	29.7%
Central air conditioning	193,160	20.5%
One room unit	224,140	23.8%
Two or more room units	243,400	25.9%
Total Households	940,060	100.0%

Source: 1980 U.S. Census Public Use Microdata Sample File.

Average Electricity Consumption and Expenditures

Table 5. (Continued) Census Division: Middle Atlantic

HOUSEHOLD CHARACTERISTICS	ANY ELECTRICITY USED					ELECTRICITY USED AS MAIN HEATING FUEL			
	NUMBER OF HOUSE-HOLDS (MILLIONS)	AVG. AMOUNT CONSUMED PER HOUSEHOLD (THOUSAND KWH)	AVG. AMOUNT CONSUMED PER HOUSEHOLD (MILLION BTU)	AVG. EXPEND-ITURES PER HOUSEHOLD (DOLLARS)	AVG. PRICE (DOLLARS PER MILLION BTU)	NUMBER OF HOUSE-HOLDS (MILLIONS)	AVG. AMOUNT CONSUMED PER HOUSEHOLD (THOUSAND KWH)	AVG. AMOUNT CONSUMED PER HOUSEHOLD (MILLION BTU)	AVG. EXPEND-ITURES PER HOUSEHOLD (DOLLARS)
TOTAL HOUSEHOLDS	13.7	6.1	21	588	28.28	1.0	14.3	49	1109
AREA TYPE									
METROPOLITAN	12.2	5.9	20	596	29.55	.9	14.8	51	1163
CENTRAL CITY	5.1	4.2	14	521	36.42	Q	Q	Q	Q
OUTSIDE CENTRAL CITY	7.1	7.2	24	650	26.63	.8	15.1	51	1222
NON-METROPOLITAN	1.5	7.6	26	526	20.30	Q	Q	Q	Q
ELECTRICITY PAID BY HOUSEHOLD									
YES	12.0	6.3	22	597	27.61	.9	14.9	51	1153
NO	1.8	4.4	15	525	34.71	Q	Q	Q	Q
TYPE OF HOUSING STRUCTURE									
MOBILE HOME	.3	6.4	22	428	19.50	Q	Q	Q	Q
SINGLE FAMILY	8.3	7.5	25	666	26.12	.7	16.9	58	1301
2 OR MORE UNITS	5.2	3.9	13	473	35.54	.3	9.4	32	741
NUMBER OF ROOMS									
1 TO 3	2.3	3.5	12	396	33.01	.3	10.6	36	738
4 TO 5	4.6	5.3	18	523	29.06	.4	12.8	44	1065
6 OR MORE	6.8	7.5	26	697	27.15	.3	19.4	66	1479
MEASURED HEATED SPACE OF RESI-DENCE (IN SQUARE FEET)									
LESS THAN 999	4.8	3.9	13	423	31.73	.4	10.5	36	832
1,000 TO 1,999	5.2	6.6	23	618	27.36	.4	15.7	54	1214
2,000 OR MORE	3.7	8.2	28	759	27.17	.2	18.9	64	1418
YEAR HOUSE BUILT									
BEFORE 1950	7.0	4.9	17	499	29.55	Q	Q	Q	Q
1950 TO 1974	5.6	6.8	23	660	28.40	.5	14.7	50	1197
AFTER 1974	1.2	9.5	32	773	23.93	.4	15.0	51	1064
OWN/RENT									
OWN	8.5	7.2	24	670	27.39	0.5	17.8	61	1412
RENT	5.2	4.3	15	454	30.67	.6	11.6	39	865
1981 FAMILY INCOME									
LESS THAN $10,000	4.4	4.5	16	440	28.34	.4	12.2	42	912
$10,000 TO $19,999	4.2	5.7	20	540	27.67	.3	14.9	51	1155
$20,000 TO $34,999	2.0	6.2	21	612	28.77	Q	Q	Q	Q
$35,000 OR MORE	3.2	8.6	29	837	28.53	.3	17.4	59	1373
TOTAL BELOW 100 PERCENT OF POVERTY LINE	2.0	4.6	16	464	29.57	Q	Q	Q	Q
TOTAL BELOW 125 PERCENT OF POVERTY LINE	3.0	4.4	15	449	29.64	.2	12.4	42	921
AGE OF HOUSEHOLD HEAD									
UNDER 35 YEARS	3.5	6.4	22	601	27.53	.5	13.7	47	1082
35 TO 59 YEARS	5.8	6.9	24	678	28.63	.2	17.5	60	1386
60 YEARS AND OVER	4.4	4.7	16	458	28.41	.3	12.9	44	942
HOUSEHOLD MEMBERS									
ONE PERSON	3.6	3.8	13	362	28.07	.4	10.4	36	739
2 TO 4 PEOPLE	8.3	6.5	22	630	28.21	.6	16.7	57	1362
5 OR MORE PEOPLE	1.8	8.7	30	851	28.70	Q	Q	Q	Q

See footnotes at end of table.

STATEMENT NO. 2

CEPA et al

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Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION V. PHILADELPHIA ELECTRIC COMPANY

DOCKET NO. R-850152

Direct Testimony of

GEORGE J. STERZINGER

on behalf of

Consumers Education and Protective Association,
Action Alliance of Senior Citizens
Association of Community Organizations for Reform Now,
Philadelphia Citizens in Action, and
Mr. Bradshaw

DOCKETED
FEB 6 1986

FOLDE

January 21, 1986

I. QUALIFICATIONS AND PUBLICATIONS

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

A. My name is George J. Sterzinger. My business address is the National Consumer Law Center, 11 Beacon Street, Boston, Massachusetts 02108.

Q. WILL YOU OUTLINE YOUR QUALIFICATIONS AND EXPERIENCE RELEVANT TO THE FIELD OF PUBLIC UTILITIES?

A. I received a B.A. in Economics with Honors from St. Joseph's College in Rennselaer, Indiana, in 1964. By 1968 I completed all the requirements at Purdue University for a doctorate in Economics with the exception of my dissertation. My major field of study was quantitative methods as applied to economic theory. At Purdue University, St. Joseph's College and Dean Junior College in Franklin, Massachusetts, I taught courses in economics ranging from principles, through basic theory, to honors seminars in mathematical economics.

I began work at the National Consumer Law Center in September of 1981.

From 1976 to 1980 I worked with the New England Regional Energy Project. In both places, I have worked on electric and gas rate design, cost allocation, and other regulatory issues. I have testified on electric and gas rate design issues before the regulatory commissions of 21 states: Colorado, Connecticut, Georgia, Illinois, Maine, Maryland, Massachusetts, Michigan, Nevada, New Hampshire, New Jersey, New Mexico, Oklahoma, Pennsylvania, Rhode Island, Texas, Utah, Vermont, Virginia, Washington, and West Virginia. In addition I have served as a consultant on PURPA investigations for the Tennessee Valley Authority.

My article entitled "A Critique of the Peaker Methodology for

Calculating Marginal Costs of Electric Service" appeared in the Sept. 29, 1983 issue of Public Utilities Fortnightly. The July 2, 1981 issue of the same publication carried my article entitled "The Customer Charge and Some Problems of Double Allocation of Distribution System Costs." My paper entitled "Conservation Program Financing: Some Analytic Concerns" was presented at the NARUC Biennial Regulatory Information Conference, and published as part of the Proceedings of the Third Annual Conference. Another paper entitled "Ratemaking, Financing Arrangements, and Diversification: Utility Proposals and Regulatory Responses" was presented at the 1982 Eastern Economic Association Annual Meeting. I have also had published "An Introduction to Statistical and Rate Making Issues Underlying Load Data and Costing Requirements of Sec. 133 of PURPA," "Oil Shale Development and Electric Generation Requirements: Regulatory Policy Reforms," and many other analyses of economic issues that arise in regulating utilities.

II. INTRODUCTION AND SUMMARY OF TESTIMONY

Q. WOULD YOU PLEASE STATE THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to review the cost allocation practices utilized by the Company in this proceeding, to identify incorrect or questionable practices, and where appropriate to suggest remedies to these practices. In addition, my testimony will include a review of some of the information available to the Commission concerning the income and the relationship between income and usage for residential customers on the Philadelphia Electric Company (PECO) system. This review is included in order that the recommended reallocation or reforms to the cost allocation procedures of the Company can be done in such a way as to both reflect policies which are consistent with sound economics and consideration of the effect of the changes on residential consumers', and especially low-income consumers', real income. In addition, to the extent possible, the recommended changes in the allocation of costs will be followed through to suggest reforms or redesign of the residential tariffs.

Q. WOULD YOU BRIEFLY SUMMARIZE YOUR RECOMMENDATIONS?

A. The cost allocation procedures adopted by the Company should be reformed in the following areas:

- Production plant allocation should be changed so that both peak demand and overall energy usage are assigned responsibility for production plant investment in the allocation of these costs;
- The distribution plant classification scheme utilized by the Company should be abandoned, and in its place, the distribution plant from Accounts 360 through 368 should be classified and allocated on a consistent demand basis;

- Income from rental of utility property should be allocated to classes reflecting the nature of the property rented.

The cost allocation policies referred to above have the effect of overcharging residential customers in the residential cost allocation scheme. The approximate overcharging per residential customer is $197 per year. For customers of Philadelphia Electric with incomes at or below 150% of poverty, the overcharge alone represents 2.5% of their real income. In other words, the effect of allowing the highly questionable allocation practices of the Company to continue will be to overcharge residential customers at or below 150% of poverty, an amount equal to 2.5% of their total real income.

With respect to the implication for these changes on rate design, my recommendation is that the customer charge be lowered to approximately $4.00 per month, and that the remaining revenue be collected on a per KWH basis but that the per KWH collection be delayed, depending upon a reassessment of the cost of providing service to the RH class.

III. REVIEW OF COST ALLOCATION AND RATE DESIGN

Q. TURNING TO THE AREA OF COST ALLOCATION AND RATE DESIGN, WOULD YOU BRIEFLY SUMMARIZE THE AREAS OF YOUR CONCERN?

A. There are three areas of concern having to do with the Company-proposed cost of service study. At the present time, the Company uses a coincident peak allocation factor to allocate the total cost of production plant. This method looks at only one of the dimensions that must be considered in order to properly determine the economic level of investment in production plant, and as a result misallocates these costs.

In classifying distribution plant, the Company relies upon a "predominant method" to choose the type of equipment considered to be customer-related. Although no good definition of precisely what is meant by the predominant piece of equipment has been given by the Company, it is obvious that the method as developed charges all customers on a per customer basis for equipment well above the minimum sized employed by the Company. This results directly in a double charging of low-use residential consumers for distribution equipment. Finally, the Company allocates the revenue received from the rental of Company equipment on a production-based allocation factor. Although the precise determination of the equipment rented remains to be supplied by the Company, it is highly likely that the Company's present treatment does not take adequate consideration of the amount of distribution equipment rented and therefore misallocates these revenues.

Q. TURNING FIRST TO THE ALLOCATION OF PRODUCTION PLANT, WOULD YOU BRIEFLY DESCRIBE HOW THE COMPANY AT PRESENT ALLOCATES THAT PLANT, AND OUTLINE

YOUR CONCERN WITH IT?

A. As stated earlier, at the present time the Company allocates all of its investment in production plant on the basis of a coincident peak factor, in this case the average of four summer-month coincident peaks. This factor is applied to the production plant in service, and is subsequently used throughout the Company study in the allocation both of directly related O and M expenses and in a host of other indirectly allocated costs.

Since the level of investment in production facilities depends critically upon both the level of coincident peak and the overall energy use experienced by the Company, the present allocation of costs is inadequate. The overall allocation of production plant in the cost of service study should be altered so that the dual use of both coincident peak and overall energy is reflected in the cost allocation. Moreover, at this time, when the Company is bringing on line and into the rate base a large investment in a nuclear generating facility, the problems raised by the use of the coincident peak allocation factor are greatly aggravated.

Q. WHY DOES THE LEVEL OF INVESTMENT IN PRODUCTION PLANT DEPEND UPON BOTH THE COINCIDENT PEAK AND THE OVERALL ENERGY USE?

A. In order to provide generation to meet the overall load duration curve experienced by the Company, the Company can choose from among a number of investment options. At the two ends of the spectrum of choices available to the Company are peak plants and base plants. A peaking plant is widely recognized as one with the lowest reasonable fixed or capital investment costs but with correspondingly higher energy costs. On the other hand, base plants have relatively large fixed or capital costs, but have lower

operating costs. If the only consideration of the Company was to meet its coincident peak, the economic choice would be to install only peaking plants. Investment in generation facilities above the cost of purchasing or installing a peaking plant is economical only if that investment is undertaken to oobtain lower overall operating or fuel costs. As such, the only economically sound way to treat investment costs undertaken by the Company over and above the cost of peaking units is to treat them on an energy-related basis.

Q. HOW HAS THE COMPANY TREATED THE INVESTMENT IN THE LIMERICK FACILITY IN THIS COST OF SERVICE STUDY?

A. The Company treats the investment in Limerick as it treats all investment in production plant; that is, it allocates it on the basis of four coincident peak hours of use.

Q. DO YOU BELIEVE THIS TREATMENT IS REASONABLE?

A. No I do not. The investment undertaken by the Company in Limerick is first of all substantially above the investment that would have to be undertaken in order simply to provide a KW of capacity. According to figures developed in an earlier part of this proceeding, a reasonable estimate of the cost of bringing a peaking unit on line in 1985 was approximately $267 per KW (Office of Consumer Advocate, testimony of witness Komanoff, page 43). Assuming for purposes of calculation that that investment could be carried with a fixed charge recovery factor of 20%, that would produce yearly costs of a peaking unit of approximately $53 per KW per year. According to figures supplied by the Company in their prefiled statement of reasons, PECO Exhibit No. 3, the yearly cost associated with the Limerick plant is $872 per KW per year. If each KW

of capacity associated with Limerick were to generate electricity for only four hours per year, the cost per KW would be approximately $218 per KWH. (That cost would recover only the fixed costs associated with generation--the fuel and operation and maintenance costs would still have to be added.) It is highly unlikely that any customer would purchase electricity at $218 per KWH. Moreover, it is obvious that the Company has a number of options to produce KWHs much more cheaply if the purpose of the investment is only to provide electricity at the peak hours. The investment in the Limerick unit, to the extent that it is economic, is undertaken in order to provide lowered cost of generation throughout the year. The cost per KW from Limerick, less a credit of $53 for peaking capacity, can produce a KWH at roughly 9.35¢ per KWH if the generation is used year-round.

Q. WHAT CONCLUSIONS FOR COST ALLOCATION DO YOU DRAW FROM THE ABOVE ANALYSIS?

A. Again, to the extent the Limerick investment was economic, it will provide service and benefits to users throughout the year. Since the benefits will be delivered across the year, the only reasonable way to allocate the costs of the plant is to allocate them on an energy basis. It should be noted that in PECO EXHIBIT 3, the Company estimates $207.5 million in energy cost savings anticipated to result from the operation of Limerick I. These savings, which are a direct result of the capital investment undertaken to bring Limerick on line, are flowed through the fuel adjustment clause on a per KWH basis. This simply reinforces the notion that the bulk of the investment in the Limerick nuclear generation station was undertaken to provide year-round service, and should be allocated on that basis.

Q. HAVE YOU CALCULATED THE EFFECT THAT CHANGING THE ALLOCATION SOLELY OF THE LIMERICK PLANT WOULD HAVE ON THE COMPANY CLASSES AND IN PARTICULAR THE RESIDENTIAL R CLASS?

A. That recalculation is shown in Exhibit 1. This exhibit shows how the roughly $920 million associated with bringing Limerick on line would be reallocated if the allocation factor were changed from the present coincident peak to an overall energy basis. The allocation factors were taken from the Company cost of service study. The results show that the greatest differential swing would occur for the residential R tariff where a change in the allocation of Limerick would reduce cost responsibility by roughly $39 million. Compared to the revenue change shown on page 6A of PECO Exhibit WFS-1, making this change would produce roughly a 14.5% reduction in the overall residential rate R revenue responsibility. Additionally, the $38 million reduction would mean a per customer savings of approximately $35 per year.

Thus, at the present time, the misallocation of the investment undertaken in Limerick I results in an overcharging of the average residential customer by approximately $35 per year. As was pointed out in an earlier section of the testimony, this overallocation of costs has to be looked at not only in terms of its effect on the proper assignment of cost responsibility, but also in terms of its effect on people of varying levels of income.

Q. HAVE YOU RECALCULATED AN ALLOCATION FACTOR FOR PRODUCTION FACILITIES WHICH REPRESENTS THE DIMENSIONS OF BOTH PEAK AND ENERGY USAGE IN ALLOCATING THESE COSTS?

A. That calculation is shown also in Exhibit 1 on the line labeled Average and Excess. This factor is developed by allocating production

costs on each class' average demand responsibility and each class' share of the portion of the peak demand minus the average demand where the class share is based upon the class' coincident peak demand. As such, it considers both the overall energy use of the class and the coincident peak use of the class in determining the total class responsibility. The relevant weights given to the average demand and the coincident peak demand depend in turn upon the difference between the coincident peak of the Company and the average demand of the Company. I should add that this factor is not a perfect allocation factor but represents a definite improvement over the present coincident peak method used by the Company. Data and time limitations prevented the calculation of a more precise allocation factor that could be utilized in the determination of production plant responsibility.

Q. TURNING TO THE TREATMENT OF DISTRIBUTION PLANT, WOULD YOU BRIEFLY RECOUNT THE COMPANY TREATMENT OF THAT PLANT AND STATE YOUR RESERVATIONS FOR THAT TREATMENT?

A. The Company treats distribution plant by first classifying the plant from Account 360 through 369 into a demand and customer component. For each of the accounts, or subaccounts, the Company uses the predominant sized piece of equipment to establish the portion that should be classified and allocated on a customer basis. No precise definition of "predominant" is given. Once the customer portion is established, the costs are allocated to classes on the basis of numbers of customers weighted to reflect some voltage considerations. The demand costs, or the costs in the account or subaccount not already collected through the determination of the dominant equipment cost and all costs below that level, are collected on the basis of customer demands. It is important

to note here that the customer demand factors developed consider the demands of all customers, even those who can be served with equipment at or below the predominantly-sized equipment. This is important to note because from it flows a major consequence of the present Company treatment of distribution plant, namely that the cost of the plant is overcollected from low-use customers.

Q. HAVE YOU REVIEWED THE COMPANY DETERMINATION OF THE PREDOMINANT-SIZED EQUIPMENT?

A. To the extent that that is possible from the information made available by the Company, I have made that review. However, it should be noted that no precise definition of predominant-sized equipment is given. Thus, in the work papers provided by the Company in IR-OCA-7-8, it is possible to follow the arithmetic calculations of the Company. However, the two critical determinations, the size and cost of the predominant equipment and the amount of equipment in the subaccount which is of a size greater than the predominant equipment have to be taken as given. No independent work papers showing the development of those two critical figures have been provided. Thus, from its inception the predominant method is essentially subjective. A different determination of the equipment judged to be predominant would produce radically different results. In Account 365, the subportion of that account having to do with aerial primary lines produces in the Company's analysis a classification of only 18.791% of the costs as demand-related. If another conductor size, one smaller than the 4/0 aluminum conductor used by the Company in the study, were to be substituted as the predominant equipment, two factors in the Company's classification study would change: the amount of conductor at a size greater than the predominat size would

increase the amount presently shown, and the cost per foot of conductor would decrease. Both of these factors would tend to produce a greater classification of the plant as demand-related.

Q. WOULD YOU PLEASE EXPLAIN HOW THE COMPANY USE OF THE PREDOMINANT METHOD RESULTS IN AN OVERALLOCATION OF COSTS TO LOW-USE RESIDENTIAL CUSTOMERS?

A. This overallocation flows from the Company classification of a sizable piece of distribution equipment as being the customer-related equipment. Despite the fact that the Company has provided no precise definition of "predominant," it is obvious from the work papers provided by the Company that the piece of equipment they utilized to make the customer classification was at or above the average cost of equipment in the account and subaccounts. This result can be easily seen from looking at the portion of the investment determined to be demand-related. For the major accounts of Overhead Lines--Primary and Secondary, Underground Lines--Primary and Secondary, and Transformers, the Company classifies considerably more than half of the costs in the account as customer-related. In the case of some of the secondary overhead lines, the classification of customer-related is in excess of 99%. Thus the portion of equipment classified as customer is the installed equipment capable of serving average or below-average loads.

In other words, average or below-average users pay for the equipment necessary to serve them through the customer portion of the costs. In addition, the Company develops demand allocation factors to allocate the cost of equipment above the customer-related portion which include the demands of all customers. Thus, the below-average-use customers not only pay for more than the kind of equipment necessary to serve them through the customer charge, they are also required to pay for a portion of the

equipment above the customer-related through the demand-related charges. A more complete development of this critique of a split classification of distribution plant is developed in an article published by me in Public Utilities Fortnightly and attached as Appendix A to this testimony.

Q. HAVE YOU CALCULATED THE OVERALLOCATION OF COSTS TO THE LOW-USE RESIDENTIAL CUSTOMERS THAT RESULTS FROM THE COMPANY'S CLASSIFICATION SCHEME?

A. That overallocation of costs is shown in Exhibit 2. That exhibit compares the customer cost per residential rate R customer as developed from the Company's cost of service study with a recalculated customer cost performed by me based on information provided by the Company to IR-OCA-7-5. Before explaining the results of that exhibit, I should point out that an alternative way of calculating the overallocation of costs that results from the Company's distribution plant classification would be to reclassify the plant on a consistent demand basis, and rerun the cost of service study using that classification. The consistent demand allocation should apply for accounts from 360 to 368.

In addition, my recommendation would be, lacking a more detailed analysis of the investment and services accounts, that 50% of the accounts should be classified as customer-related and 50% as demand-related. The reason for this split is that in the absence of a more complete analysis of the costs, the 50/50 split acts to minimize the potential harm from making either a more exaggerated demand or customer classification.

Turning to Exhibit 2, that shows that in the Company's cost of service study, the costs per residential rate R customer per year are $207.30. In comparison, I have calculated from the information provided by the

Company that the proper customer charge per month should be approximately $4 per customer, which would produce yearly customer costs of $48. Thus, as a result of the improper classification of distribution plant costs, the average residential customer is overcharged $159 per year. (As I stated earlier, this figure of $159 is most likely a slight overstatement of the cost allocation redistribution that would occur if the distribution plant were reclassified as suggested and the entire cost of service study rerun.) Again, referring to my earlier testimony, it is important that this misallocation of costs be considered not only in terms of its effect on the cost allocation and rate design of the Company, but also in terms of its effect on the real income of the customers of Philadelphia Electric.

Q. TURNING TO THE FINAL AREA OF CONCERN WITH THE COST ALLOCATION STUDY, WOULD YOU PLEASE EXPLAIN THE RESERVATIONS YOU HAVE WITH THE COMPANY-PROPOSED METHOD FOR THE TREATMENT OF ACCOUNT 454--RENT FROM ELECTRIC PROPERTY?

A. The present Company treatment is shown on page 7A of WFS-1. That shows that at present the rent from electric property is allocated or distributed to the customer classes on the basis of A1, the production plant allocation factor. That allocation would be proper only if the equipment being rented were production or high voltage transmission plant. If the equipment being rented is distribution level plant, the allocation of the revenue should be based upon an allocation factor reflecting as accurately as possible the kind of distribution plant being rented. In other words, if the equipment being rented is the Company poles, then the allocation of the revenue from that rental should be based upon the allocation of the cost of the poles to the customer

class. The primary problem with allocating revenues obtained from renting distribution plant on the basis of their production level factor is that it allocates a considerable portion of the revenues to the commercial and industrial high tension customer class which has no cost responsibility for distribution plant. In other words, a class that has none of the cost responsibility for the distribution plant owned by the Company would receive roughly 41.5% of all of the revenue obtained by renting that distribution plant.

Clearly this is an improper assignment of the revenue from the distribution plant rental. At the time of preparing this testimony, discovery made on the Company as to the precise breakdown of the equipment rented had not been obtained. As a result, it is impossible to make a recommendation as to exactly how the allocation of the revenues from equipment rental should be made. Nevertheless, a general recommendation, that the allocation of the revenue be based upon the shared cost responsibility for the equipmemt rented can be made. To the extent that the equipment rented is distribution equipment, the allocation of revenues back to customrer classes should reflect that fact.

IV. THE EVALUATION AND CONSIDERATION OF INCOME

Q. HOW DO YOU PROPOSE INTRODUCING THE CONSIDERATION OF INCOME AND THE RELATIONSHIP OF INCOME AND USAGE INTO THE DELIBERATIONS ON COST ALLOCATION AND RATE DESIGN IN THIS PROCEEDING?

A. My proposal is to evaluate the available information having to do with the income of the residential customers of Philadelphia Electric, and the relationship of usage and income among those customers. To the extent that useful information is available on those topics, my testimony is that such information be adopted as an additional evaluation or consideration of policies that are, first of all, based upon sound economic and cost allocation principles.

My testimony should not be taken to preclude specific consideration of the income and relative ability to pay of residential customers over and above cost consideration principles; however, those considerations are not raised at this time. In effect, my testimony is that the available information on the income of residential customers and the information available on the relationship of income to usage should be used in a way which is consistent with economic and costing principles, in order to design rates as sensitive as possible to the needs of low-income customers.

Q. WHAT INFORMATION HAVE YOU REVIEWED CONCERNING THE INCOME OF THE RESIDENTIAL CUSTOMERS AND THE RELATIONSHIP BETWEEN INCOME AND USAGE?

A. I have relied upon the updated census information having to do with the income of customers of Philadelphia Electric developed by George Grier, another witness for CEPA et al in this proceeding. In addition, I have reviewed the studies available to the Company, either developed by

them or at their direction, having to do with the relationship between income and usage. At the time of preparing this testimony, there were outstanding questions having to do with their analysis of income and usage, and as a consequence that information was not available for use in this testimony. However, the information developed from the 1980 census data and subsequently updated having to do with the incomes of residential customers of Philadelphia Electric is useful.

Q. WOULD YOU BRIEFLY DISCUSS THE INFORMATION AND THE TYPE OF RESULTS YOU OBTAINED FROM THIS ANALYSIS?

A. That information is presented in Exhibit 3. That exhibit shows the average income of various household sizes for residential customers below 150% of poverty, and those with incomes at or above 150% of poverty. As expected, the income of those below 150% of poverty is by definition below the income of those above 150% of poverty. The magnitude of the difference, however, is striking. The average income of all households below 150% of poverty is $7,826 per year. By comparison, the average income of households above 150% of poverty is $37,524 per year. Thus, the average income of those above 150% of poverty is nearly five times greater than of all households below 150% of poverty.

Q. WHAT POLICY CONCLUSIONS CAN YOU DRAW FROM THIS TYPE OF DATA?

A. While it is impossible, without more precise information about the relationship that exists between income and usage, to "fine tune" rate design proposals, given the information available from the census data it is possible to conclude that questionable policies which result in the overcharging of residential customers, while they may be acceptable to residential customers on average, have a much more profound effect on

people below poverty status. Specifically, in this case I have identified a number of areas where the residential class is overcharged, and which are discussed in a subsequent part of the testimony. That overcharging costs families above 150% of the poverty level approximately 0.5% of their income on average. For those below 150% of poverty, the effect of the same overcharging is to take 2.5% of their income on average.

The point is not that .5% is affordable or tolerable, but that the 2.5% has a much more serious effect on people's income. My testimony is that this additional consideration, the effect of improper allocation practices on people below 150% of poverty, should be added to the reasons developed in a previous section of the testimony for changing those practices at this time.

	TOTAL COMPANY	COMMERCIAL AND INDUSTRIAL HT	PRIM	RESIDENTIAL SECONDARY	R-H	R
A1	5.391.886	2,235,585	500.698	764.118	211,311	1,489.776
		41.462%	9.286%	14.172%	3.919%	27.630%
C1	3.455.651	1,520.630	280.706	432,405	200.234	808.715
		44.004%	8.123%	12.513%	5.794%	23.403%
VERAGE&EXCESS		2.323.432	460,507	706.801	276.116	1,343,696
		43.091%	8.541%	13.109%	5.121%	24.921%
IFFERENTIAL		2.542%	-1.163%	-1.659%	1.875%	-4.227%

			STREET LIGHTING		OTHER	
	DP	SLP	SLS	OTHER	UTILITIES	INTER
A1	140	249	38	9	80.440	11.714
	0.003%	0.005%	0.001%	.000%	1.495%	0.217%
C1	48.995	11.938	7.541	1.965	52.933	7.529
	1.418%	0.345%	0.218%	0.057%	1.529%	0.218%
AVERAGE&EXCESS	49.046	12.027	7.555	1.968	81.719	11.736
	0.910%	0.223%	0.140%	0.037%	1.516%	0.218%
DIFFERENTIAL	1.415%	0.341%	0.218%	0.057%	0.037%	0.001%

	SEPTA	AMTRAK
A1	41.559	56.249
	0.771%	1.043%
C1	31.533	50.636
	0.913%	1.465%
AVERAGE&EXCESS	46.457	70.835
	0.862%	1.314%
DIFFERENTIAL	0.142%	0.422%

RESIDENTIAL CUSTOMER CHARGE

RATE BASE

ACCT. 369	$41,032,500.00
ACCT. 370	$51,769,000.00
TOTAL	$92,791,500.00
LEVEL ANNUAL CHARGE(16.7%)	$15,496,180.50

EXPENSES

METER O&M	
ACCT. 586	$2,750,000.00
ACCT. 597	$905,000.00
SUBTOTAL	$3,655,000.00
CUSTOMER ACCT.	
ACCT. 902	$10,205,000.00
ACCT. 903	$24,558,000.00
SUBTOTAL	$34,763,000.00
TOTAL EXPENSES	$38,418,000.00
TOTAL CUSTOMER COSTS	$53,914,180.50
NUMBER OF CUSTOMERS	1120500
COST PER CUSTOMER PER YEAR	$48.12
COST PER WFS-1	$207.30

EXHIBIT 3
SERZINGER
Page 1 of 1

INCOME LEVEL BY POVERTY GROUP AND HOUSEHOLD SIZE

HOUSEHOLD SIZE	BELOW 150%	ABOVE 150%
1	$4,641	$23,011
2	$7,497	$34,886
3	$8,216	$40,396
4	$10,555	$44,322
5	$12,047	$47,470
6	$14,154	$49,881
7	$15,061	$52,808
8	$18,602	$55,516
TOTAL	$7,825	$37,534

APPENDIX A

The Customer Charge and Problems Of Double Allocation of Costs

By GEORGE J. STERZINGER

AFTER several years of the "great rate debate" attention finally seems to be turning towards a forgotten part of rate design: the customer charge. Utilities, forced by the Public Utility Regulatory Policies Act to justify or do away with declining energy charges, have begun arguing for cost classification and subsequent rate design with increasingly large customer charges. Recently proposed customer charges seem to be consistently in the $6 to $9 range, accompanied by embedded cost-of-service studies supporting even greater charges.

Consumer and environmental groups concerned about rate design reform (rather than using the customer charge as a place to dump costs, as the utilities do) have seen it as a place to shave costs. Concerned primarily with getting a kilowatt-hour or usage charge to reflect incremental or marginal costs more accurately, these groups have attempted to resolve the problem of the resulting excess revenue by proposing that the customer charge be lowered enough to "lose" the surplus. Negative customer charges or lump sum monthly payments from the utility to consumers have been proposed by more imaginative analysts.[1]

Analyses of the proper customer charge have often yielded contradictory results depending upon whether incremental or embedded costs were used. Incremental analyses often, but not always, support low customer charges, while embedded cost analyses often, but not always, support high customer charges.

The importance of incremental price signals and the need to strike a balance between revenue constraints and proper price signals have produced wide agreement that the customer charge is the least "informative" of all parts of a rate design and should be the last place a utility is allowed to collect revenues if incremental costs are found to be useful in designing rates.

Unfortunately, the debate on the proper definition and use of incremental costs remains unresolved, while traditional practices of embedded cost allocation seem to support very high customer charges. Regulators, forced with making a decision, have found some cost basis to be

This article is a critique of the currently most widely used methodology for classifying a portion of electric utility distribution plant as a customer cost. The author argues that this classification, combined with an allocation of the "above minimum" portion on a demand basis, leads to an overallocation of costs to low-use residential customers of the electric system.

George J. Sterzinger is an economist with the New England Regional Energy Project where he specializes in electric utility rate design testimony. In 1979 he became director of the project. The NEREP provides economic, legal, and technical assistance to low-income groups on regulatory utility issues and other energy policy matters. **Mr. Sterzinger** received a BA degree in economics from St. Joseph College, Rensselaer, Indiana, and has completed all requirements but the dissertation for a PhD degree in economics at Purdue University.

[1] "Customer Charges and the Public Utility Regulatory Policies Act," by Edward F. Renshaw and Perry Renshaw, 104 PUBLIC UTILITIES FORTNIGHTLY 17, August 30, 1979, found high customer charges contrary to the intention of PURPA.

preferable to unresolved speculation, and raised the customer charge based on embedded cost-of-service studies.

Since incremental analyses cannot by themselves support a low customer charge, the embedded cost analyses which support high customer charges must also be closely investigated to determine if they meet current objectives of rate design. An examination of these methodologies reveals the following characteristics:

— Almost all of them rely for their justification on the determination of the cost of a minimum distribution system, and the classification of this system as a customer cost.

— Once the classification has been made, it is an inescapable conclusion of the allocated cost-of-service study that calculated customer costs will be substantial.

— However, an examination of the rationale for the classification and the implications of that classification lead equally inescapably to the conclusion that minimum use residential customers will be overcharged by such cost allocation practices.

— The only reasonable remedy for the problem of overcharging is to classify the entire distribution system on a consistent basis, which would be a demand basis.

— Once this is done, traditional cost-of-service studies no longer provide support for high customer charges.

A national survey of utility practices in classification of distribution system costs determine that the great majority used some form of minimum system to classify costs in the relevant Federal Energy Regulatory Commission accounts. (The survey was conducted by Carolina Power and Light Company, Raleigh, North Carolina.) The survey summarized the results of company practices to determine how much, on average, each distribution plant account was classified as demand. The results by FERC account were as follows:

— Account 364 — Poles and fixtures were separated into primary and secondary; the primary portion was split 50-50 between customer and demand costs, the secondary portion was classified 56.5 per cent customer and 43.5 per cent demand.

— Account 365 — Conductors and devices were also separated into primary and secondary; the primary portion was classified 44.3 per cent customer and 55.7 per cent demand, and the secondary portion was classified 46.4 per cent customer and 53.6 per cent demand.

— Account 368 — Line transformers were classified 34 per cent customer and 66 per cent demand.

— Account 369 — Services were classified 70.8 per cent customer and 29.2 per cent demand.

The difficulties with these methodologies only begin with the minimum distribution system. The concept is very difficult to define and consequently susceptible to widely varying interpretations. No single method exists for calculating the cost of this system; nevertheless, a fairly standard approach is to reconstruct the existing distribution system using some type of minimum equipment. Minimum equipment could be of the type employed by the company, currently purchased by the company, currently used in the industry, or currently required by safety code. The cost of this equipment can be either booked or in current prices. Obviously, with this large a menu of definitions to choose from, a utility analyst can calculate costs for these systems over a wide range.

It should be mentioned here that one other method sometimes used to calculate the cost of a minimum system is the "zero-intercept" method whereby regression equations relating cost to various sizes of equipment are derived, and then solved for the cost of zero-sized or "zero-intercept" equipment. The strongest objections to this methodology arise from the limitations on data, the unreliability of the derived equations, and some fundamental problems that arise from making the statistical inference about the cost of the zero-sized equipment.

A typical utility in the sample discussed earlier, faced with the problem of classifying costs in Account 365 —overhead lines, for example, would determine the cost of the minimum equipment needed to replace all existing lines, calculate that cost as a fraction of the total costs of equipment in the account, and use that fraction to classify customer costs. Thus, a utility with 1,000 miles of overhead lines and two types of line costing $1 per foot and $2 per foot would calculate a minimum system cost of roughly $5.28 million ($1 × 5,280 feet per mile × 1,000 miles). This $5.28 million can, of course, be varied if different types of minimum lines are used, or if for other reasons the cost of $1 per foot is changed.

Beyond problems arising from the indeterminate nature of the minimum system, the appropriateness of classifying these costs as customer costs has been long debated. Strictly speaking, customer costs should be limited to those costs which can be shown to vary exclusively with number of customers. Distribution system costs, both as built and hypothetical minimum system, obviously depend to a great extent on geographical considerations — type of terrain and customer density. Several analysts have argued that the nature of cost causation — in this case at least in part due to geography — does not allow the costs to be neatly fit into either demand or customer cost categories; that the costs are simply unallocable. Recent statistical analyses support this notion.[2]

An additional and more severe problem with this methodology arises from the consequences of classifying distribution system costs into both customer and demand portions. Simply put, this practice leads

[2] "The Economics of Electric Distribution System Costs and Investments," by David J. Lessels, 106 PUBLIC UTILITIES FORTNIGHTLY 37, December 4, 1980, found no statistical justification for the classification of distribution costs as customer related

inevitably to a double allocation and possibly a double collection of these costs from low-use residential customers and a misallocation of costs among customer classes.

To see why this is so, one need only step back for a moment to consider what it is that a cost allocation study attempts to do, and what happens when distribution system costs are split into customer and demand portions and then allocated to individual classes.

An allocation study assigns costs to customers on the basis of usage characteristics; fairness requires that allocated costs follow, as closely as possible, the actual costs of serving customers. Splitting the distribution system into a minimum usage and an above minimum usage portion, and allocating the minimum portion on a customer basis, and the above minimum on a usage basis results in low-use residential customers paying for more of the system than is required to serve them. By splitting the distribution system into two parts, low-use residential consumers are charged twice: once, on a customer basis, for a portion of the system sized to meet their demands; and again on a demand basis for a portion of the system sized to serve demand beyond what would be needed to serve them. The only practical way satisfactorily to assure that low-use customers are charged only once for distribution equipment is to allocate the distribution system costs on a single consistent basis. Of the two considered, customer and demand, it is obvious that only demand can be used to classify and allocate distribution costs on a satisfactory basis.

In order to explain more fully why this method constitutes double charging of low-use customers, we can look more closely at the handling of FERC Accounts 364 and 365 which represent the cost of overhead lines and poles. To illustrate this, suppose the company had only 1,000 miles of overhead lines and 10,000 poles; and in addition it used two types of line — one costing $1 per foot, for 500 miles of overhead, the other costing $2 per foot, for the remainder; and two sizes of pole — 5,000 costing $30 per pole and 5,000 costing $60 per pole. Total cost of this system would be:

a) Line: 500 miles at $1 per foot	$2,640,000	
b) Line: 500 miles at $2 per foot	5,280,000	
Subtotal		$7,920,000
c) Poles: 5,000 poles at $30 per pole	$ 150,000	
d) Poles: 5,000 poles at $60 per pole	300,000	
Subtotal		$ 450,000
Total		$8,370,000

A minimum system in this case would be determined by calculating the cost of the 1,000 miles of overheads if only the minimum-sized line was used, plus the cost of the 10,000 poles if only the minimum-sized pole was used.

Cost of the minimum system is:

a) Line: 1,000 miles at $1 per foot	$5,280,000	
b) Poles: 10,000 poles at $30 per pole	300,000	
Total		$5,580,000

Therefore, the cost of the above minimum (or capacity) system would be the remainder, or $2,780,000.

The minimum system calculated in this fashion could, and actually does, serve a considerable level of usage.

The minimum system is allocated on a customer basis — all customers are charged for an equal share of it. The remainder of the system, the more expensive facilities required to meet loads beyond those handled by minimum-sized equipment, is allocated on some demand basis; noncoincident peak demand is often used. In the calculation of the noncoincident peak demand allocation factors, usage at all levels of the residential and general service customer classes is used to determine allocation factors.

If, for example, the minimum overhead lines, conductors, and poles could supply a demand of two kilowatts per residential customer, that amount of usage would be paid for in the customer charge. In the determination of demand allocation factors, however, each residential customer's demand is calculated and added to determine the portion of the above minimum system costs to be allocated to the residential class and to each customer through the appropriate rates. So a residential customer who has a demand of two kilowatts will have paid for all the distribution costs associated with his load through the customer charge, but will also have his two-kilowatt usage go into the demand allocation factor to allocate distribution costs associated with above minimum usage.

One way to solve the double allocation problem would be to determine, for each piece of minimum equipment, the demand level it would be capable of serving, and then adjusting the demand allocation factors used to allocate the costs of all equipment of that type in order to assure that minimum use customers and the residential class were not charged twice. In many cases this would mean calculating several allocation factors for each FERC distribution account, since more than one type of equipment is used in the account. Even after overcoming all the problems of this approach one is still confronted with the dubious value of charging for equipment on an up-front basis rather than through a per kilowatt-hour charge at a time when conservation is recognized as an important goal of energy policy.

The direct way to assure that problems of overcollection are not built into the methodology used to determine class costs of service is to classify all distribution costs as demand costs. If this methodology is used in embedded cost studies, the studies will produce more equitable estimates of the cost of serving low-use residential customers.

COMMUNITY LEGAL SERVICES, INC.

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January 29, 1986

Mr. Jerry Rich, Secretary
Pennsylvania Public Utility Commission
New Filing Section
Room B-18, North Office Buildng
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Harrisburg, Pennsylvania 17120

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SECRETARY'S OFFICE
Public Utility Commission

RE: PUC v. PECO
Docket No. 8-50152

Dear Secretary Rich:

Enclosed are copies of CEPA, et al. Statements 1 and 2 which are direct testimony on rate structure issues in the above case. These statements were served on all parties in the case and Administratiave Law Judge Matuschak on January 22, 1986 as is indicated by the attached certificate of service.

Sincerely,

John Hanger

John Hanger

/md

EXTRA COPY

CERTIFICATE OF SERVICE

I hereby certify that I am this 22nd day of January serving by first class mail CEPA, et al Statements 1 and 2 upon the following:

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DATED: January 22, 1986

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Attorney for CEPA, et al.

CEPA ET. AL. STATEMENT
R-850152

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Public Utility Commissio

PENNSYLVANIA PUBLIC UTILITY COMMISSION

V.

PHILADEPHIA ELECTRIC CO.

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DIRECT TESTIMONY

OF

GEORGE GRIER

CONCERNING IMPACT OF RATE STRUCTURE

ON LOW-INCOME HOUSEHOLDS

ON BEHALF OF: CONSUMERS EDUCATION AND PROTECTIVE ASSOC.
ACTION ALLIANCE OF SENIOR CITIZENS
PHILADELPHIA CITIZENS IN ACTION
ASSOCIATION OF COMMUNITY ORGANIZATIONS
FOR REFORM NOW
MR. BRADSHAW

January 22, 1986

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS

A. My name is George Grier. My business address is The Grier Partnership, 6532 East Halbert Road, Bethesda, Maryland, 20817.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND QUALIFICATIONS

A. I am a principal in The Grier Partnership, a research and consulting firm which specializes in analysis of policy- and program-related questions in the public and private sectors. The firm's work has been in several areas including energy, demographics, and analysis of social and economic impacts. Recent activities of the firm in which I have been involved include:

- Analyses of patterns of energy use and expenditures by low-income and elderly households, the characteristics of these households, and the implications of both for utility rate structures, need for energy assistance, and implications for weatherization and other conservation measures.
- Development of computerized data systems and computer models for estimating household energy expenditures under varying conditions such as energy prices, climate, principal fuel used, and characteristics of the household, as well as the budgetary impact of these expenditures.

- Preparation of expert testimony for various legal and administrative proceedings concerning the setting of energy price schedules for different classes of consumers.
- Extensive work with Census Bureau and other federal data files, including the computer tape formats of these files, in demographic and economic analyses for public and private clients.

Prior to forming The Grier Partnership in 1976, a principal member of the firm was Research Staff Director for the Washington Center for Metropolitan Studies, a private non-profit "think tank." In that capacity, she directed the 1975 National Survey of Household Energy Use, which was conducted by the Washington Center for Metropolitan Studies for the Federal Energy Administration, a predecessor agency of the U. S. Department of Energy (DOE). That survey, which was known as the WCMS Household Energy Survey, was the prototype for the closely-similar Residential Energy Consumption Surveys now conducted by DOE.

Since that time, the Partnership has conducted a number of analyses of energy price impacts and related matters for a variety of clients in both the public and private sectors. These have included the U.S. Community Services Administration, the Congressional Research Service,

the National Council of Senior Citizens, the National Consumer Law Center, and the New England Regional Energy Project.

My firm has presented testimony in a number of energy price and utility rate cases before the Federal Energy Regulatory Commission, the Illinois Commerce Commission, the New Jersey Board of Public Utilities, the Pennsylvania Public Utility Commission, and the Public Service Commission of the District of Columbia, among others.

In addition, we have presented papers on energy price impacts and related matters before meetings of the National Conference on Optimal Weatherization, the University of Chicago, the University of North Carolina, the Congressional Research Service of the Library of Congress, the U.S. Community Services Administration, and others.

My own professional experience includes nine years as a principal of The Grier Partnership and nine years as a Vice President and Senior Associate of the Washington Center for Metropolitan Studies, plus service with the Brookings Institution, the District of Columbia Government, and the New York State Government. I hold a Master's Degree in Social Psychology from the University of Pennsylvania, with specialization in survey design and statistics.

My background is more fully described in my resume attached hereto as Exhibit GG-1. A list of my reports and publications on energy issues is included in that exhibit.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In my testimony I shall demonstrate the following facts:

1. Low income consumers (i.e., those who qualify for low-income energy assistance) make up a substantial proportion of all Philadelphia Electric Co. ratepayers.

2. The incomes of these PECo ratepayers are very low. They are much lower, on the average, than generally recognized, and considerably lower than the maximum limits for energy assistance.

3. Many of these low-income consumers have little chance of increasing their incomes through their own efforts, since they consist largely of elderly and handicapped persons and single-parent families with children.

4. Most of these customers already have serious and unavoidable budgetary burdens other than their electricity bills--such as housing, food, and other energy bills.

5. Thus, to impose PECo's requested rate increase on them would impose severe

hardship.

6. Relatively few of these low-income electric ratepayers have air conditioners, and hence they do not contribute substantially to high peak loads. In fact, on the average and as a group, they consume considerably less electricity than high-income ratepayers.

Q. WHAT EVIDENCE DO YOU OFFER FOR YOUR CONTENTIONS?

A. My statements are based chiefly on data from federal sources, mainly the U.S. Census Bureau and the Bureau of Labor Statistics. I have supplemented these sources with data from the Company's studies of its own customers. My data sources are specifically referred to in my exhibits.

Q. WHY DO YOU RELY HEAVILY UPON FEDERAL DATA SOURCES?

A. Because these data are specifically applicable to defining the low-income customer population, and to analyzing its characteristics and its economic situation relative to the affordability of the proposed rate increase. Using Census Bureau computer tapes, I was able to focus in particularly upon low-income electricity consumers in the parts of the Philadelphia metropolitan area under the jurisdiction of this Commission and to draw out data specific to that group. In addition, federal

data are objective and have been produced by agencies with no interest in the current case.

Q. HOW DO YOU DEFINE LOW-INCOME PHILADELPHIA ELECTRIC RATEPAYERS FOR THE PURPOSES OF YOUR TESTIMONY?

A. They are those electricity consumers residing in Philadelphia and its Pennsylvania suburbs within the metropolitan area who have incomes at or below 150 percent of the federal poverty limits. These customers qualify for low-income home energy assistance (LIHEAP) under the standards of both the federal government and the Commonwealth of Pennsylvania.

Q. WHAT ARE THE FEDERAL POVERTY LIMITS?

A. These limits vary with household size, and are adjusted regularly by the U.S. Office of Management and Budget based on increases in the Consumer Price Index. The current limits at the 150-percent-of-poverty level are shown in my Exhibit GG-2. At current levels, a household of one person (say, an elderly widow living alone) may have an income no higher than $7,875 to qualify. The maximum income rises for larger households, to $13,275 for a family of three and to $26,775 for a family of eight.

Q. SO A SINGLE ELDERLY WIDOW ELIGIBLE FOR LOW-INCOME ENERGY ASSISTANCE HAS AN AVERAGE INCOME OF $7,875, IS THAT CORRECT?

A. No. That is the maximum income she may have and still qualify. Actually, few have incomes as high as the maximum limits. Often they are much lower. It is very important to understand this, because some people confuse the poverty income limits with the incomes actually received by households below those limits. Some assume that all eligible households have incomes this high, while many others think that the average household does. Neither of these things is true.

Q. WHAT IS THE AVERAGE INCOME FOR A SINGLE-PERSON ELECTRIC RATEPAYER HOUSEHOLD UNDER 150 PERCENT OF POVERTY IN THE PHILADELPHIA AREA?

A. It is about $4,641, as shown in my Exhibit GG-2. That is less than three-fifths of the maximum income limit for LIHEAP eligibility.

Q. DO LOW-INCOME ELECTRIC RATEPAYERS OF ALL HOUSEHOLD SIZES HAVE AVERAGE INCOMES LOWER THAN THE FEDERAL MAXIMUM LIMITS FOR ELIGIBILITY?

A. Yes, at every household size the average income is well below the maximum which allows them to qualify. In my Exhibit GG-2, I show the comparison between the maximum level for each household size and the average income received by low-income electric ratepayers of this household size in the Pennsylvania portion of the Philadelphia metropolitan area.

Q. PLEASE GIVE SOME FURTHER EXAMPLES OF THESE LOWER AVERAGE INCOMES.

A. A four-person household can qualify for energy assistance with a maximum income of $15,975. Actually, however, the average income of four-person households under 150 percent of the poverty line is only $10,556. For a six-person household, the maximum is $21,375, but the average is only $14,154.

Q. WHAT PROPORTION OF THE MAXIMUM ELIGIBILITY LEVEL FOR LIHEAP BENEFITS IS THE AVERAGE INCOME OF THESE LOW-INCOME HOUSEHOLDS?

A. Again, this proportion varies with the size of the household, but not in any regular fashion. In most cases, it ranges between roughly three-fifths and about two-thirds of the maximum, as shown in my Exhibit GG-2.

Q. WHY DO YOU PLACE SO MUCH STRESS ON THE RATEPAYER POPULATION BELOW 150 PERCENT OF POVERTY?

A. Because these customers are recognized under the laws of both the United States and the Commonwealth of Pennsylvania as having incomes so low that they require special financial aid from the government if they are to meet their energy bills. I might note that the City of Philadelphia has indicated in its testimony in this case that low-income people will be particularly hard-hit by the job losses that the City expects to result from the proposed

rate increase, if implemented. The thrust of my testimony is to indicate that they will also feel the impact in terms of further strain on budgets that are already severely overloaded by today's high living costs.

Q. IN YOUR OPINION, ARE THESE THE ONLY CUSTOMERS WHO WILL HAVE DIFFICULTY MEETING PHILADELPHIA ELECTRIC'S PROPOSED RATE INCREASE?

A. Not at all. There are many more customers who will be harmed by such an increase, and who will have trouble meeting the additional budgetary burden it imposes. But low-income customers obviously will have particular difficulty, just because their incomes are so low.

Q. HAVE YOU COMPARED THE INCOMES OF LOW-INCOME RATEPAYERS WITH THOSE OF HIGHER-INCOME RATEPAYERS?

A. Yes, and the comparison is shown in my Exhibit GG-3. As is evident from this exhibit, the average incomes of low-income ratepayers are much lower than the average for those above 150% of the poverty level or of the population as a whole.

Q. YOU SPEAK OF "PHILADELPHIA AND ITS PENNSYLVANIA SUBURBS." IS THIS EQUIVALENT TO PHILADELPHIA ELECTRIC'S SERVICE TERRITORY WITHIN PENNSYLVANIA?

A. Not precisely, but it is close enough to provide a reasonably accurate representation of the situation of Philadelphia Electric customers under the jurisdiction of this Commisssion. The Pennsylvania

portion of the Philadelphia metropolitan area, as defined by the U.S. Office of Management and Budget for Census and other purposes, includes the City of Philadelphia plus all of four suburban counties: Bucks, Chester, Delaware and Montgomery. PECo's territory excludes some of the northern portions of this four-county area. But most of this territory is included. Furthermore, the portions missing from PECo's territory are among the less heavily populated. A small part of York County is also included in PECo's service area, although it is not within the metropolitan area. However, the population of this York County portion is not very great. So for practical purposes, the ratepayer population of PECo's service territory within Pennsylvania is quite well represented by the statistics.

Q. HOW DO THE INCOMES OF LOW-INCOME ELECTRIC RATEPAYERS IN THE CITY OF PHILADELPHIA COMPARE WITH THOSE FOR THE ENTIRE PENNSYLVANIA PORTION OF THE METROPOLITAN AREA?

A. They are somewhat lower. The average income for electric ratepayers under 150 percent of poverty in the City of Philadelphia is $7,662. For the entire Pennsylvania portion it is $7,826. Approximately the same differential exists for all household size categories, as shown in my Exhibit GG-4.

Q. YOU SPEAK OF "ELECTRIC RATEPAYERS." IS THIS SHORTHAND FOR THE ENTIRE POPULATION, OR ARE THE CENSUS STATISTICS YOU CITE ACTUALLY PRECISE ENOUGH TO GIVE YOU DATA ON RATEPAYERS AS SUCH?

A. I used Census Bureau computer tapes in my analysis. These tapes allowed me to focus specifically on households that reported in the Census that they paid their own electric bills. It is important to look at this population, because it excludes apartment dwellers whose electric bills are included in their rent. These people's situation may well be different from that of the ratepayer population, even at the same below-150-percent-of-poverty income level.

Q. WHEN WERE YOUR DATA OBTAINED?

A. They are principally from the 1980 Census.

Q. DOES THIS MAKE THEM OUT-OF-DATE?

A. Not to a degree that would affect the validity of my conclusions. There is no reason to believe that the low-income population of metropolitan Philadelphia has decreased since the 1980 Census. In fact, more recent data from the Census Bureau indicate that it probably has increased. In addition, the data on incomes and budgetary burdens which I present for these customers have been adjusted for inflation, and are stated in 1985 dollars.

Q. HOW MANY LOW-INCOME ELECTRIC RATEPAYERS, AS YOU HAVE DEFINED THEM, LIVE IN THE PENNSYLVANIA PORTION OF THE PHILADELPHIA METROPOLITAN AREA?

A. There are about 226,100 ratepayer households--containing nearly 600,000 persons. That is about one-fifth of all PECo customers in this area. In the City of Philadelphia itself, low-income ratepayers are nearly three ratepayers in ten. So when I speak of these low-income customers I am not talking about small numbers. Over two-thirds of low-income ratepayers in the area--some 155,000 households, containing over 400,000 persons--live in the City of Philadelphia. About 71,000 reside in the suburbs. (Exhibit GG-4)

Q. EARLY IN YOUR TESTIMONY YOU SAID THAT LOW-INCOME ELECTRICITY CUSTOMERS "CONSIST LARGELY OF ELDERLY AND HANDICAPPED PERSONS AND SINGLE-PARENT FAMILIES WITH CHILDREN." WOULD YOU PLEASE GO INTO MORE DETAIL ON THIS POINT.

A. Yes. Here I was talking about the population under 150 percent of the federal poverty limits, which as I indicated earlier makes up nearly one-fifth of Philadelphia Electric's ratepayers in the entire Pennsylvania portion of its service area, and nearly 30 percent of electricity customers within the City of Philadelphia. A lot of people have the idea that these are mainly large families with children. In fact, the largest size category is

single persons living alone. They make up nearly two-fifths of the total. One- and two-person households combined make up a three-fifths majority, as shown in my Exhibit GG-5.

Q. YOU HAVE STATED THAT SMALL HOUSEHOLDS OF ONLY ONE OR TWO PERSONS ARE A THREE-FIFTHS MAJORITY OF ALL LOW-INCOME ELECTRIC RATEPAYERS. WHAT PROPORTION OF LOW-INCOME RATEPAYERS CONTAIN SIX PERSONS OR MORE?

A. Only about eight percent are this large. Five-person households make up another eight percent. So, in combination, only about one low-income household in six contains five persons or more.

Q. IS A HOUSEHOLD THE SAME THING AS A FAMILY?

A. No, households include families but not the other way around. A household is all the inhabitants of a housing unit. A family is persons who are related. A household may be a family, or as I have already indicated, a single person living alone. It may also consist of two or more unrelated people sharing living quarters, or occasionally two or more families. As I have indicated, however, most low-income households are quite small.

Q. WHAT CAN YOU SAY ABOUT THE NEARLY TWO-FIFTHS OF LOW-INCOME PECO CUSTOMERS WHOM YOU HAVE INDICATED TO BE SINGLE PEOPLE LIVING ALONE?

A. Among these low-income single ratepayers, almost 49,000 households--nearly 57 percent of the total--

are elderly. Still others are not elderly but are disabled.

Q. IS THERE ANY OTHER IMPORTANT FACT ABOUT LOW-INCOME ELECTRIC CUSTOMERS WHO LIVE ALONE WHICH BEARS ON THEIR VULNERABILITY?

A. Yes. About three-fourths of them (and nearly 85 percent of those aged 65 and older) are women. Most of these women are widowed.

Q. WOULD IT BE CORRECT TO STATE THAT THE MOST TYPICAL LOW-INCOME PECO CUSTOMER IS AN ELDERLY AND/OR DISABLED WOMAN WHO LIVES ALONE?

A. Yes, in thinking of the situation and needs of such a customer, the most accurate image to keep in mind is your elderly mother or grandmother--not a young welfare mother with a lot of children.

Q. EARLIER, HOWEVER, YOU HAD MENTIONED SINGLE-PARENT FAMILIES WITH CHILDREN AS ONE OF THE VULNERABLE GROUPS AMONG RATEPAYERS. IF THEY ARE NOT THE MAJORITY, HOW MANY OF THEM ARE THERE?

A. Just under one-fifth of all low-income ratepayers, about 44,000 in all, are single-parent families with children. Over 90 percent of these families, about 41,000, are headed by women.

Q. AND ARE THESE SINGLE-PARENT FAMILIES WITH CHILDREN PREDOMINANTLY LARGE?

A. No. Most have only one or two children.

Q. RETURNING TO THE SINGLE-PERSON HOUSEHOLDS AMONG THE LOW-INCOME RATEPAYERS, YOU STATED THAT THEIR

INCOMES AVERAGED ONLY ABOUT $4,641 PER YEAR. WHAT DOES THAT AMOUNT TO ON A MONTHLY BASIS?

A. It is an average of $387 per month, and that amount must cover all expenses including the electric bill. This is the average; there are many customers with less.

Q. BUT SINCE THE DATA YOU USE COME FROM THE 1980 CENSUS, AND THERE HAS BEEN CONSIDERABLE INFLATION SINCE, DON'T THEY GREATLY UNDERSTATE THE INCOMES THAT LOW-INCOME RATEPAYERS RECEIVE TODAY?

A. No. I have increased the census income figures based on the change in the Consumer Price Index, or CPI, since the Census was taken. This is a method often used by statisticians to update incomes for inflation in the absence of more recent survey data.

Q. PLEASE DESCRIBE EXACTLY HOW YOU UPDATED THE CENSUS INCOME FIGURES TO TAKE ACCOUNT OF INFLATION.

A. I obtained the CPI for the Philadelphia area for the most recent month for which it was available when this testimony was prepared. That month was November of 1985. I divided it by the annual average CPI for calendar year 1979, which is the year for which persons responding to the 1980 Census were asked to report their incomes. This gave me the inflation factor.

Q. HOW DID YOU APPLY THIS INFLATION FACTOR?

A. I instructed the computer to multiply the income of

every household in the census data tape by this factor. This gave me updated incomes for late 1985, which are the ones I use throughout this testimony. Since inflation is currently low, they can be considered to apply to the present date.

Q. IN YOUR OPINION, DOES THIS METHOD OF UPDATING INCOMES BY THE CONSUMER PRICE INDEX YIELD ACCURATE RESULTS FOR THE LOW-INCOME POPULATION OF THE PHILADELPHIA ELECTRIC COMPANY SERVICE AREA?

A. Probably not as accurate as might be wished, even though the method is an accepted one. I believe that it almost certainly overestimates the growth in incomes since the 1980 Census--especially for low-income households.

Q. ON WHAT DO YOU BASE YOUR BELIEF THAT THE METHOD YOU HAVE USED TO UPDATE INCOMES FOR INFLATION PROBABLY OVERSTATES THE INCOME GROWTH FOR LOW-INCOME HOUSEHOLDS?

A. First, there is a lot of evidence from periodic surveys by the Census Bureau that the incomes of households at the lower end of the income scale have not been increasing in accord with inflation, and that for this reason the poverty population is growing.

Q. BUT THESE ARE NATIONAL STUDIES. DO YOU HAVE ANY EVIDENCE THAT THE INCOMES OF LOW-INCOME HOUSEHOLDS IN THE PHILADELPHIA AREA HAVE NOT BEEN KEEPING UP WITH INFLATION?

A. Yes. I have data on the increase in benefit levels under AFDC--Aid to Families with Dependent Children--between 1980 and 1986. These data indicate that benefit levels have risen by about 10 percent for a two-person family (typically an unwed, divorced or deserted mother with a single child) to about 15 percent for a family of three and about 27 percent for a family of six. This compares with an increase of about 40 percent in the Consumer Price Index for the same period. (Exhibit GG-6)

Q. SO NO AFDC FAMILIES HAVE RECEIVED AN INCREASE IN BENEFITS EQUAL TO INFLATION?

A. That is correct. And smaller families have received smaller increases, much below the inflation rate. I would reiterate that most low-income families are small.

Q. YOU INDICATED THAT YOU ALSO EXAMINED THE BUDGETARY BURDENS PLACED UPON LOW-INCOME ELECTRIC RATEPAYERS BY THE COSTS OF SUCH NECESSITIES AS SHELTER AND FOOD. WOULD YOU PLEASE DISCUSS SHELTER COSTS AS THEY RELATE TO THE INCOMES OF THESE HOUSEHOLDS.

A. Yes. My findings on shelter costs are summarized in my Exhibits GG-7 and GG-8. The first deals with homeowners, the second with renters. All figures are for electric ratepayers.

Q. ARE THESE FIGURES IN UPDATED DOLLARS?

A. Yes, they have been updated by the computer using the Consumer Price Index for the Philadelphia area.

Q. PLEASE DISCUSS THE SHELTER COSTS OF LOW-INCOME HOMEOWNERS.

A. Homeowners are a majority of low-income ratepayers in the Pennsylvania portion of the Philadelphia metropolitan area. For all households combined, these ratepayers have an average income of $673 per month, according to the updated census figures. Monthly owner costs, which include mortgage and tax payments, insurance, fuels and utilities (including electricity), but not maintenance costs, take just over half this amount, or $370 per month. That leaves $303 per month or just about $70 per week for all other expenditures including food, clothing, medical care and other necessary and discretionary items.

Q. PLEASE DISCUSS THE SHELTER COSTS OF LOW-INCOME SINGLE HOMEOWNER-RATEPAYERS LIVING ALONE.

A. Low-income single homeowner-ratepayers of all ages living alone have a much lower monthly income than the average for homeowner households of all sizes. In fact, it is less than three-fifths as great--only $400. Their shelter costs, while lower also, are not sufficiently lower to compensate. They total $286 per month, leaving only $114 per month or about $26 per week for all other living

costs. As I have noted earlier, a majority of single-person low-income households are elderly.

Q. PLEASE DISCUSS THE SHELTER COST SITUATION OF LOW-INCOME RENTERS.

A. While homeowners are a majority, renters are a sizeable minority among the low-income group of ratepayers. There are about three-fourths as many of them as there are of homeowners. They are somewhat worse off than homeowners in most cases. Their incomes are lower overall; and their shelter costs--while lower also in most cases--are higher for small households. Overall, and particularly for single-person households, the combination of low incomes and high shelter costs leaves little remaining for other necessities.

Q. WHAT DO THE DATA SHOW ABOUT RENTER HOUSEHOLDS OF ALL AGES AND SIZES?

A. Their incomes average $625 monthly, about $48 less than owners. Their shelter costs average $350, about $20 lower. This leaves them an average of $275 per month or about $63 per week for all other expenditures.

Q. WHAT ABOUT SINGLE-PERSON RENTER HOUSEHOLDS OF ALL AGES?

A. They are the worst off of all. Their incomes average only about three-fifths as much as the total--$369 monthly. Shelter costs average $297,

leaving them with only $72 per month on average for all other expenses. That is about $17 per week.

Q. DO YOU HAVE DATA ON THESE HOUSEHOLDS' EXPENDITURES FOR OTHER ESSENTIALS?

A. We have data on food expenditures from the 1981 national Consumer Expenditure Survey, conducted on behalf of the U.S. Bureau of Labor Statistics by the U.S. Bureau of the Census.

Q. ARE THESE DATA ALSO SPECIFIC TO THE PHILADELPHIA AREA?

A. No. Only broad regional data are available from the Consumer Expenditure Survey. I obtained the data for the metropolitan areas in the Northeast--which is the region in which Philadelphia is included for Census purposes. This region includes New England as well as the Middle Atlantic states of New York, New Jersey, and Pennsylvania.

Q. AND DID YOU UPDATE THESE FIGURES IN THE SAME FASHION AS ELSEWHERE IN YOUR TESTIMONY?

A. Yes, following the same procedure discussed earlier.

Q. WHAT IS LEFT OF LOW-INCOME HOUSEHOLDS' BUDGETS AFTER BOTH SHELTER AND FOOD COSTS ARE TAKEN OUT?

A. The data bearing on this question are summarized in my Exhibit GG-9. Obviously, low-income single-person renter households fare by far the worst in terms of money remaining. They have a deficit, on average, of $26 or $6 per week. As a

group, however, renter households have somewhat more left than homeowners, largely because they spend less on food. After food and shelter costs, they have $116 monthly remaining, or about $27 per week, to pay for all other expenses. Homeowner households as a group have $52 monthly remaining, or $12 per week. But homeowner households with only a single person have only $2 left per month--pennies per week--which still makes them slightly better off than single renters.

Q. WHICH TYPE OF HOUSEHOLDS HAVE THE LARGEST AMOUNTS REMAINING AFTER SHELTER AND FOOD COSTS?

A. Dollar-wise, the best situation is that of renter households of all sizes, who have an average of $116 remaining which works out to $27 per week. However, it must be understood that some of these people also have dependents whose expenses must be paid, while single-person households must pay only for themselves.

Q. HOW IS IT POSSIBLE FOR LOW-INCOME HOUSEHOLDS TO HAVE INCOME DEFICITS--ACTUALLY SPENDING MORE MONEY TO LIVE THAN THEY RECEIVE?

A. One explanation is that they can and often do fall behind in their bills. Low-income households with members of working age often have irregular incomes from employment. Thus, when they are unemployed they fall behind, and when they are working they

try to catch up. Some of these deficits may be made up in this way.

Q. WHAT DO YOU CONCLUDE OVERALL FROM YOUR EXAMINATION OF BUDETARY BURDENS?

A. I conclude that a large proportion of low-income ratepayers are operating close to or even past the edge of solvency. Any increase in their electric bills must be drawn from budgets which, in most cases, are squeezed to the limit and often beyond the limit by recent years' increases in the costs of such essentials as housing, food, and energy--including electricity itself.

Q. WHAT WILL BE THE BUDGETARY IMPACT OF PECO'S REQUESTED RATE INCREASE, IF GRANTED, ON LOW-INCOME RATEPAYERS?

A. The increase will be extremely serious for many, in light of both the large amount of the increase and their already-overtaxed household budgets. The company has stated in materials supplied to consumers that "the annual cost of service to the average residential user (500 kilowatt-hours per month) would increase from $700 to $910, or by 58 cents per day". To estimate the impact on low-income consumers, I have turned to the figures previously cited from DOE's Residential Energy Consumption Survey. I would first note that the figures given in that survey for average annual electricity consumption is 6.1 thousand (6,100)

KWH. This is very close to the 6,000 KWH obtained by multiplying PECo's 500 KWH per month by 12. Taking the average cited in the Residential Energy Consumption survey of 4.4 thousand (4,400) KWH consumed annually by low-income households, I find that this amount is 72 percent of the average. Applying this ratio to the increase of $210 annually for the average customer stated by the company, I obtain a figure of about $151 annually, or slightly under $13 per month for low-income customers. This is approximate, of course, but will serve to give an idea of the impact of the increase. It can be compared to the following amounts:

- The $2 per month left after shelter and food costs for low-income single person homeowner ratepayers.
- The $26 per month deficit for low-income single person renter ratepayers.
- The $52 per month remaining after food and shelter costs for low-income homeowner ratepayers of all household sizes.
- The $116 per month left after food and shelter costs for low-income renter ratepayers of all household sizes.

These are meagre amounts at best, and PECo's requested rate increase will cut severely into even the largest of them. Under the new rate, if

granted, electricity will cost the average low-income ratepayer about $655 per year. This will be more than eight percent of the total income of the average low-income ratepayer (all household sizes combined); over 14 percent of the total income of the average low-income single person living alone; and 15 percent of the AFDC benefit for a family of three in Philadelphia. These percentages must be evaluated in the context of the fact that these incomes are now strained to the limit, and beyond, by essential living expenses.

Q. AS I UNDERSTAND IT, AIR CONDITIONING IS LARGELY RESPONSIBLE FOR HIGH PEAK LOADS. DO LOW-INCOME HOUSEHOLDS CONTRIBUTE MUCH TO THESE PEAKS?

A. They contribute much less, proportionately, than higher-income ratepayers. Among ratepayers at or below the 150-percent-of-poverty level in PECo's Pennsylvania service territory, only 8.5 percent have central air conditioning. This compares with 20.5 percent among higher-income ratepayers. About half as many in this low-income group, proportionately, have two or more room air conditioners as do higher-income ratepayers. In all, low-income ratepayers with <u>any</u> form of air conditioning are only about one-sixth as numerous as higher-income ratepayers with air conditioning of any type. (Exhibit GG-10)

Q. DO LOW-INCOME HOUSEHOLDS CONTRIBUTE AS MUCH TO DEMAND FOR ELECTRICITY, AND HENCE TO THE NEED FOR NEW GENERATING FACILITIES, AS DO HIGHER-INCOME HOUSEHOLDS?

A. They do not. On average, low-income households use substantially less electricity than those of all income levels combined, and much less than high-income consumers.

Q. WHAT IS YOUR EVIDENCE FOR THIS STATEMENT?

A. It comes from a periodic national survey by the U.S. Department of Energy which is the most complete and detailed source of data on energy consumption in relation to consumer characteristics. This survey is known as the Residential Energy Consumption Survey, and the most recent available data are for the year from April of 1982 through March of 1983.

Q. DOES THE RESIDENTIAL ENERGY CONSUMPTION SURVEY PROVIDE DATA SPECIFICALLY FOR THE PHILADELPHIA AREA?

A. No. However, it does provide figures for the Middle Atlantic Census Division, which consists of the three States of New York, New Jersey and Pennsylvania, as well as for the U.S. as a whole and for a number of other sub-regions.

Q. WHAT DOES THE SURVEY SHOW ABOUT CONSUMPTION RELATED TO INCOMES IN THE MIDDLE ATLANTIC AREA?

A. It shows that consumers with incomes under 125 percent of the poverty line use an average of 4.4 thousand KWH of electricity annually, compared to 6.1 thousand KWH for customers of all income levels. That is less than three-fourths as much as the average. (Exhibit GG-11)

Q. AND HOW DOES THIS CONSUMPTION COMPARE TO THAT OF HIGH-INCOME HOUSEHOLDS IN THE SAME AREA?

A. Consumers with 1981 family incomes of $35,000 or more consume an average of 8.6 thousand KWH annually. That is almost twice as much as the average for consumers with incomes below 125 percent of poverty.

Q. DO YOU HAVE ANY EVIDENCE SPECIFIC TO THE PHILADELPHIA AREA FOR YOUR CONTENTION THAT LOW-INCOME RATEPAYERS USE LESS ELECTRICITY?

A. Yes. It comes from two reports prepared by PECo itself. These are reports of the Company's 1980 Residential Electric Service Load Study. They are Reports Nos. 48482-A and 48482-B, and were obtained under discovery.

Q. WHAT EVIDENCE IS CONTAINED IN THESE REPORTS ON LOW-INCOME HOUSEHOLDS' ELECTRICITY CONSUMPTION?

A. The evidence is partially inferential yet nonetheless strong, and particularly so since it closely confirms the findings of the Residential Energy Consumption Survey. Because the PECo reports themselves contain no data on incomes, I

had to infer income levels from other evidence. The reports do contain information on occupation of the household head, number of persons in the household, number of household members under age 18, and number of rooms in the home.

As will be recalled from my earlier testimony and from my Exhibits GG-2, GG-3 and GG-4, census data show that household size and income are related. Most low-income households are small, containing only one or two persons. The most common size is one person. By the same token, these small households contain few or no children. In fact, most single-person low-income households are elderly. The converse is true as well: most higher-income households are larger than one person, and most of them are not elderly.

With these facts in mind, I compared the data in the Company's survey report No. 48482-A dealing with customers in the lowest and highest consumption classes out of six into which the sample of customers (all in Rate Class R) were divided. The lowest consumption category was 201-300 KWH monthly, and the highest was 1001-1500. These were December usage figures, and December is a month in which air conditioning does not usually play a role in consumption. Note also that space heating (Rate Class RH) and off-peak water heating (Rate Class OP) customers were not included in the

survey. Hence 1001 to 1500 KWH in a December month is indeed high consumption.

Q. WHAT WAS YOUR OVERALL CONCLUSION BASED UPON THE DATA IN THESE REPORTS ON CONSUMPTION AS RELATED TO THE CHARACTERISTICS OF RATEPAYERS?

A. I concluded that the data in these reports demonstrated a strong relationship between consumption and income levels, as the latter could be inferred from occupations and household sizes.

Q. WHAT DID YOU CONCLUDE ABOUT THE INCOME-RELATED CHARACTERISTICS OF RATEPAYERS IN THE LOWEST ELECTRICITY CONSUMPTION CATEGORY?

A. These low-consumption ratepayers were predominantly retired elderly persons and people in low-paid jobs. Most had very small households, and few had children.

Q. PLEASE STATE HOW YOU REACHED THESE CONCLUSIONS.

A. In the lowest consumption class, 201-300 KWH, 39 percent reported the occupation of the head as retired. An additional 14 percent reported it as housewife. All the housewives were single persons living alone. I think it is reasonable to assume that they were usually widowed and in many cases elderly. Only one retired household had more than two persons. I therefore conclude that about half of the sample of customers in the lowest consumption category were probably elderly couples and widowed individuals.

Q. AND THE REST?

A. Many of them reported occupations which generally pay low wages. In all, 17 percent reported that their occupations were such as laborer, porter, house cleaner, maintenance, clerk, and bank teller. Some other reported occupations were less clearly low-income, but homes and apartments were generally small and suggested that most of these people were living modestly.

Q. WHAT DID YOU CONCLUDE ABOUT THE INCOME-RELATED CHARACTERISTICS OF RATEPAYERS AMONG THE HIGHEST CONSUMPTION CATEGORY IN RATE CLASS R?

A. They were predominantly professionals, managers, and members of other highly-paid occupations. The number of people in the household tended to be larger, and the homes they occupied were larger as well.

Q. ON WHAT DO YOU BASE THIS CONCLUSION?

A. In this highest consumption category, with December consumption of 1001 to 1500 KWH, most household heads reported occupations that clearly placed them in the higher-paid professional and managerial categories. More than 10 percent of the sample were doctors; there were also other highly-paid professional categories such as judge, accountant, and engineer. In all, 31 percent were business executives, owners, managers, or supervisors. While many of the other reported occupations were

less clearly high-income, such as salesman and insurance agent, the sizes of the homes they lived in generally suggested that they were economically successful. Most contained ten rooms or more. Not a single household head was either retired or a housewife.

There was only one single-person household in the high-consumption group, and fewer than ten percent contained two persons. All the rest of the households consisted of three persons or more, and over 70 percent contained persons under the age of 18. This figure contrasted with only 11 percent in the lowest consumption category.

Q. WERE THE VERY DIFFERENT DECEMBER CONSUMPTION LEVELS IN THESE TWO CATEGORIES ACCOMPANIED BY DIFFERENT LEVELS OF SUMMER PEAK ELECTRICITY USE?

A. Decidedly. Both the August non-coincident maximum demand and the maximum annual recorded demand for the highest consumption category were more than three times as great as the comparable figures for the lowest usage group.

Q. AND DID THESE DIFFERENT CONSUMPTION LEVELS APPEAR TO BE ASSOCIATED WITH DIFFERENTIAL POSSESSION OF AIR CONDITIONERS?

A. Yes, definitely. In the lowest consumption category, only six percent of the ratepayers had central air conditioning systems, and only 36 percent had room air conditioners. In the great

majority of these cases there was only one room unit. In the highest consumption category, by contrast, 41 percent of the households had central air systems and 44 percent had room units. In such cases there was usually more than one unit, and in several instances as many as four or five.

Q. TAKING INTO ACCOUNT ALL THE EVIDENCE YOU HAVE CITED ON THE RELATIONSHIPS BETWEEN INCOMES, CONSUMPTION LEVELS, AND POSSESSION OF AIR CONDITIONERS, WHAT DO YOU CONCLUDE THAT IS OF RELEVANCE TO THE IMPACT OF THE REQUESTED PECO RATE INCREASE ON LOW-INCOME RATEPAYERS?

A. I conclude that all the evidence indicates that low-income ratepayers contribute little to the large peak demands. These are summer peaks related largely to air conditioning, and especially to use of central air and multiple room-unit systems.

Q. WHAT HAVE YOU CONCLUDED ABOUT THE ADEQUACY OF THE PROGRAMS WHICH ARE NOW IN PLACE TO AID LOW-INCOME RATEPAYERS TO REDUCE OR COPE WITH THEIR ELECTRIC BILLS?

A. My overall conclusion is that these programs, whatever benefits they provide, serve far too few ratepayers to be of much value in reducing the burdens on this group.

Q. PLEASE DESCRIBE THE PROGRAMS OF THIS TYPE OF WHICH YOU ARE AWARE.

A. They are:

(1) The Low-Income Home Energy Assistance Program (otherwise known as LIHEAP). Properly speaking, this is not a PECo program, but a governmental program from which low-income customers of PECo and other energy utilities can get financial assistance. The benefits are paid directly to the company to reduce arrearages.

In the 1984-1985 program year, LIHEAP provided benefits to 10,800 PECo customers. The average grant was $281.

(2) The Utility Emergency Services Fund (UESF). This program is also governmental, and provides benefits only to low-income residents of the city of Philadelphia. Like LIHEAP, it is available to customers of other utilities than PECo. The utilities provide matching funds on a 50-50 basis. The benefits under UESF are available only to customers under 125 percent of the poverty level--unlike other programs which use a more generous (150 percent) cutoff. It also has certain other restrictions. Grants of up to $500 are available only every two years. They are made only if,

with their help, the customer can reduce his or her arrearages to zero. That means that if a customer owes $800, no benefit will be available under UESF unless he can come up with another $300 out of his own pocket.

In 1985, through the date for which figures were made available by the company, this program had provided benefits to 1,326 customers. The average grant was $475.

(3) Project Heat. This program is jointly sponsored by PECo, the United Way of Bucks County, and the Bucks County Government. Naturally, it serves only customers residing in Bucks.

The project was begun in 1985, and through the date of reporting by the company had served 61 customers. The average grant was $213.

(4) Chester County Cares Utility Fund (CCCUF). This project is limited to Chester County residents who have had shutoff notices or whose service has been terminated. Grants, which are limited to $500, must zero out the account, or the customer must enter into a payment

agreement with regard to any remaining deficit.

In 1985, through the date of reporting, this project had served 56 customers. The average grant was $118.

(5) Customer Assistance Program (CAP). This is a PECo project which can aid customers through limiting their electric bills to amounts judged by the company to be within their ability to pay. The exact amount is determined by the company after examination and verification of the customer's income and expenses. The company also requires the customer to engage in certain conservation activities, and may recommend discontinuance of certain appliances judged to be too high in electricity consumption.

This program is presently in a pilot stage and reaches only about 500 customers.

(6) Tighten up - Low Cost Conservation Program (TLC). This conservation project provides low-income customers with an optimal audit to RCS which offers information on expected quick pay-back measures only. (These measures are defined by the company as including such

items as a water heater wrap and thermostat setback, reusable plastic storm windows, weatherstripping and caulking, door sweeps, and "other miscellaneous cost-effective measures".) This assistance, including audit, materials and installation, is currently provided free to eligible low-income customers (mainly LIHEAP recipients). However, a charge for materials used is apparently under consideration.

About 2,100 customers had been served through this program in a period of slightly less than one year ending August 31, 1985. The average cost of a TLC audit and treatment is $165, according to information provided by the company.

Q. HOW MANY CUSTOMERS ARE CURRENTLY SERVED ANNUALLY UNDER THESE PROGRAMS?

A. I could not calculate an exact annual figure because the time intervals for which data are available vary somewhat. However, in total the six programs served approximately 15,000 PECo customers in the latest year or major part of a year for which figures are available. Of this total, however, more than two-thirds is accounted for by LIHEAP, and more than 80 percent by the LIHEAP and UESF programs combined. PECo's own efforts, either

alone or in collaboration with other organizations, have served only a minor fraction of the total number.

Q. AND THIS 15,000 ANNUAL TOTAL OF CUSTOMERS SERVED, OF WHICH MORE THAN TWO-THIRDS ARE ACCOUNTED FOR BY LIHEAP, IS WHAT PERCENTAGE OF ALL LOW-INCOME ELECTRIC RATEPAYERS IN PECO'S PENNSYLVANIA SERVICE TERRITORY?

A. 15,000 customers served out of 226,000 low-income ratepayers is somewhat under seven percent. The number served by PECo's own programs is around one percent of the total number of low-income ratepayers.

Q. IF MORE IS NOT DONE TO ASSIST LOW-INCOME CUSTOMERS IN MEETING INCREASING ELECTRIC BILLS, WHAT WILL BE THE PROBABLE RESULT?

A. There are only two possibilities. Either they will default on their bills in still larger numbers, or they will be unable to pay for essentials of other kinds--including food and shelter.

Q. ARE TERMINATIONS OF SERVICE LIKELY TO INCREASE?

A. That result seems probable, although the amount of the increase is impossible to estimate since I cannot be sure how many low-income customers will elect to do without electric service or without other essentials. They will clearly have to do without something. I would note that residential terminations have been increasing. According to

information furnished by the company under discovery, in response to IR-OCA-11-7, the increase was from 22,855 terminations for the full year 1980 to 31,758 for 1984, the last full year for which data were made available by PECo. For 1985 through September, the total number of terminations was 29,093--already approaching the number for 1984, even though data for the last three months of the year were missing.

Q. HOW WOULD YOU RECOMMEND THAT THE COMMISSION DEAL WITH THE SITUATION OF LOW-INCOME CONSUMERS, IF IT SHOULD GRANT PHILADELPHIA ELECTRIC ITS REQUESTED INCREASE IN WHOLE OR IN PART?

A. The Commission must recognize that low-income customers are particularly vulnerable to further increases in energy costs, which already consume substantial percentages of their budgets. Electricity costs alone are already a burden for many. The Commission should therefore look favorably upon rate design proposals that protect the interests of this category of consumers. Most low-income ratepayers use substantially less electricity than the 500 kwh per month that is the approximate average for all customers. Hence, one way to help protect low-income citizens would be to distribute any downward adjustment in PECo's revenue requirement allocated to the residential class predominantly in the lowest KWH rate block.

This block, if set in the range of 350 to 500 KWH, will encompass most or all electricity use by the majority of low-income ratepayers.

Q. WHAT SHOULD BE DONE TO HELP LOW-INCOME CUSTOMERS WHO USE MORE THAN THE AVERAGE?

A. These customers can best be protected both through low-income energy assistance programs and through stepped-up conservation measures. In many instances, their excessive consumption is due largely to energy-inefficient homes and appliances, and conservation programs can help reduce reduce this consumption.

Q. BUT WOULDN'T THIS BENEFIT SOME HIGH-INCOME LOW-USE CUSTOMERS AS WELL?

A. Yes, no policy instrument is ever perfect. However, this approach would benefit most low-income people, plus many more whose incomes are not much over the 150-percent-of-poverty line. If the Commission should be concerned about a policy that might benefit some who are rich while protecting most of the poor, then one possibility would be to limit the rate to those under 150 percent of poverty. I would point out, however, that this approach would leave out many people whose incomes are just high enough to take them out of the low-income category, but whose budgets are nonetheless under severe strain. In many cases, their effective purchasing power for essentials other than electricity may

well be cut by PECo's increase to less than that of some who are already below the 150 percent limit. In my view, this would be a more serious fault than benefiting some customers who are better off--especially since these customers are conserving more electricity than most, and thus helping to limit the need for additional expensive generating capacity.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Exhibit GG-1

GEORGE GRIER
Principal
The Grier Partnership

Qualifications

Mr. Grier has specialized in statistical analysis of demographic, economic, and housing data and design of data systems, with particular concentration on policy applications. He has been responsible for direction of a number of major studies; has written, published and spoken extensively; and has testified before Congressional committees, courts, and public regulatory commissions.

Principal Staff Experience

1976 to Present--Principal, The Grier Partnership, Bethesda, Maryland

As a partner in this research and consulting organization, Mr. Grier has had responsible roles in the design and direction of several dozen projects for clients in the public, private non-profit, and profit-making sectors. In the energy field, these projects have included:

- Statistical analyses to determine the characteristics and energy expenditures of low-income and elderly households and to assess the budgetary impact of rising energy prices on these households, drawing upon data from the computer tapes of Census Bureau, DOE, and other survey data bases:
  - --for the nation as a whole; and
  - --in various regions, states and local areas, including New England, Illinois, New Jersey, Pennsylvania, Milwaukee County, and the District of Columbia.
- Assessment of energy burdens for low-income households in all states of the continental U.S. under alternative scenarios as to energy prices, weather, and conservation practices, using specially-designed computer simulation models.
- Analyses of the relationship of energy burdens to benefits provided under LIHEAP and other federal programs at the level of all individual states of the continental U.S. and the District of Columbia.
- Analysis of the amount of subsidy required in each state to keep the energy expenditures of elderly and low-income citizens within specified percentages of their incomes.
- Coordination and analysis of several national surveys of energy prices and utility rates, collecting data from energy suppliers in all parts of the nation for all commonly used fuels.

- Evaluations of several alternative strategies for alleviating energy burdens on low-income households, including:
  - "Lifeline" utility rate proposals in Illinois, New Jersey, and Pennsylvania;
  - The Illinois SACCC 12-Percent-of-Income Plan;
  - The Wisconsin Gas Company's Guaranteed Service Plan;
  - The Potomac Electric Power Company's "Residential Aid Rider"
- Analysis of demographic and developmental constraints on efforts to meet energy conservation goals through urban planning and design.
- Preparation and presentation of expert testimony in utility rate cases in several states, including Illinois, New Jersey and Pennsylvania as well as the District of Columbia. Mr. Grier has personally presented the testimony in some of these cases.

In the area of demographic and economic analysis, Mr. Grier has had responsible roles in a number of projects, including:

- Studies of demographic and housing patterns, utilizing data from Census Bureau computer tapes and other sources:
  - for the U.S. as a whole and for all major U.S. metropolitan areas, plus special in-depth studies
  - for the Baltimore, MD metropolitan area;
  - for the Chicago, IL metropolitan area;
  - for the Houston, TX metropolitan area;
  - for the Philadelphia, PA metropolitan area;
  - for the Washington, DC metropolitan area.
- Preparation of a widely-used handbook for local policy makers and planners interested in obtaining up-to-date demographic, economic and housing data on their local areas.
- Specification of data requirements for a major national survey by a federal agency.
- Two national studies of the problem of human displacement resulting from urban revitalization.
- An evaluation of several widely-marketed commercial demographic data systems.

- A number of proprietary market analyses for private clients, including housing and shopping center developers and health care providers.

1967 to 1976--Vice President and Senior Associate, The Washington Center for Metropolitan Studies, Washington, DC

For this non-profit urban studies center, Mr. Grier was responsible for design and direction of several major projects. These projects involved not only written products but also the calling of conferences of various sizes to communicate the results to policy-makers. Mr. Grier often convened and chaired these conferences.

- An area-wide census updating survey for metropolitan Washington, DC. Taken midway between the 1970 and 1980 censuses, this survey brought all major census items, including demographic, economic and housing data, up to date for the metropolitan area, its central city, and its major suburban jurisdictions.

- Studies of the implications of demographic changes for public policy and the planning of housing, public facilities and services in the District of Columbia, the Nation's Capital.

- Design of a prototype manpower information system for the District of Columbia government, and direction of a project to develop manpower information for affirmative action programs in the District.

- Design of improved techniques for estimating population and housing markets.

- A study of the implications of the decline in the birthrate for educational facilities planning at all levels, including public schools in newly-developed areas and institutions of higher education.

- Several studies of emergent population and housing trends in the nation and metropolitan Washington and their policy and program impacts.

1964 to 1967--Director of Social Program Coordination, District of Columbia Government, Washington, DC

In this position, Mr. Grier served as deputy to the District's Director of General Administration. One of his chief duties was to plan new and expanded human resources programs through assembly and analysis of demographic and economic data.

1962 to 1964--Staff Associate, Washington Center for Metropolitan Studies, Washington, DC

Responsible for several policy-focused analyses. On loan for part of this period to design a research program for the United Planning Organization, Washington's federally-funded anti-poverty agency.

1960 to 1962--Senior Staff Member, The Brookings Institution, Washington, DC

One of Mr. Grier's chief responsibilities in this position was to help local public officials in a number of metropolitan areas to achieve an improved understanding of the application of social science techniques to local needs and problems. He convened and chaired two series of community conferences in Cincinnati, Ohio and Lansing, Michigan.

Selected Memberships and Professional Honors

Member, Board of Directors, Lambda Alpha, the international land economics honor society.
Founding Member, Board of Directors, DC Municipal Research Bureau
Member, Economic and Financial Management Advisory Group, U.S. Conference of Mayors
Founding Member, Executive Committee and Board of Directors, Housing Opportunities Council of Metropolitan Washington
Chairman, Committee on Poverty, Society for the Psychological Study of Social Issues
Recipient of two Ford Foundation personal study grants
Received Melvin C. Hazen Award as outstanding young man in District of Columbia Government
Phi Beta Kappa

Education

B.A. with Honors in Psychology, University of Pennsylvania, 1950. Elected to Phi Beta Kappa.
M.A. with Honors in Social Psychology, specialization in survey design and statistics, University of Pennsylvania, 1952.

EXHIBIT GG-2

AVERAGE INCOMES OF LOW-INCOME ELECTRIC RATEPAYERS
COMPARED TO FEDERAL POVERTY LIMITS
PENNSYLVANIA PORTION OF PHILADEPHIA METROPOLITAN AREA

(In November 1985 Dollars)

Persons	150% of Federal Poverty Income Limit	Average Income	Percent Average Income of Limit
1	$ 7,875	$ 4,641	59%
2	$10,575	$ 7,497	71%
3	$13,275	$ 8,216	62%
4	$15,975	$10,556	66%
5	$18,675	$12,047	65%
6	$21,375	$14,154	66%
7	$24,075	$15,061	63%
8	$26,775	$18,602	69%

Source: Average Incomes - 1980 U.S. Census Public Use Microdata Sample File, updated by Consumer Price Index.
Federal poverty limits - U.S. Department of Health and Human Services

Exhibit GG-3

AVERAGE INCOMES OF ELECTRIC RATEPAYERS
BELOW AND ABOVE 150% OF POVERTY,
AND OF ALL ELECTRIC RATEPAYERS,
BY HOUSEHOLD SIZE
PENNSYLVANIA PORTION OF PHILADELPHIA METROPOLITAN AREA

(In November 1985 Dollars)

Persons	Below 150% of Poverty	At or above 150% of Poverty	All Ratepayer Households
1	$ 4,641	$22,011	$15,901
2	$ 7,497	$34,886	$30,932
3	$ 8,216	$40,396	$35,984
4	$10,556	$44,322	$39,766
5	$12,047	$47,470	$41,477
6	$14,154	$49,881	$42,595
7	$15,061	$52,808	$42,075
8 or more	$18,602	$55,516	$42,423
Average - All Sizes	$ 7,826	$37,524	$31,767

Source: 1980 Census Public Use Microdata Sample File, updated by Consumer Price Index.

Exhibit GG-4

AVERAGE INCOMES OF LOW-INCOME ELECTRIC RATEPAYERS IN THE CITY OF PHILADELPHIA COMPARED TO ENTIRE PENNSYLVANIA PORTION OF PHILADELPHIA METROPOLITAN AREA

(In November 1985 Dollars)

	Average Income - Under 150% of Poverty	
Persons	Philadelphia	Pennsylvania Portion of Phila. Metro Area
1	$ 4,546	$ 4,641
2	$ 7,455	$ 7,497
3	$ 8,019	$ 8,216
4	$10,262	$10,556
5	$11,603	$12,047
6	$14,172	$14,154
7	$14,370	$15,061
8 or more	$17,559	$18,602
Average - All Sizes	$ 7,662	$ 7,826
Total No. of Ratepayers	155,140	226,080

Source: 1980 U.S. Census Public Use Microdata Sample File, updated by Consumer Price Index

Exhibit GG-6

AID TO FAMILIES WITH DEPENDENT CHILDREN (AFDC)
BENEFIT LEVELS - 1980 AND 1986
PENNSYLVANIA PORTION OF PHILADELPHIA METROPOLITAN AREA

Philadelphia and Delaware Counties

Family Size	Monthly Benefit Levels Jan. 1, 1980	Jan. 1, 1986	Pct. Change 1980-86
1	$172	$186	8.1%
2	$262	$287	9.5%
3	$318	$365	14.8%
4	$381	$451	18.4
5	$438	$535	22.1%
6	$478	$608	27.2%
Add'l persons	$ 58 each	$ 75 each	29.3%

Bucks, Chester, and Montgomery Counties

Family Size	Monthly Benefit Levels Jan. 1, 1980	Jan. 1, 1986	Pct. Change 1980-86
1	$181	$195	7.7%
2	$273	$299	9.5%
3	$332	$382	15.1%
4	$395	$466	18.0%
5	$451	$551	22.2%
6	$490	$623	27.1%
Add'l persons	$ 58	$ 75	29.3%

Source: Leon Cerullo, Supervisor of Research and Statistics, Pennsylvania Department of Public Welfare (by telephone)

Exhibit GG-7

MONTHLY HOUSEHOLD INCOMES AND OWNER COSTS
FOR LOW-INCOME ELECTRIC RATEPAYER-OWNERS
PENNSYLVANIA PORTION OF THE PHILADELPHIA METROPOLITAN AREA

(In November 1985 Dollars)

Persons	Monthly Household Income	Monthly Owner Costs*	Remainder
1	$ 400	$286	$114
2	$ 614	$329	$285
3	$ 690	$451	$239
4	$ 924	$490	$434
5	$1065	$523	$542
6	$1236	$479	$757
7	$1354	$436	$918
8 or more	$1588	$495	$1093
Average - All Sizes	$ 673	$370	$303

*The sum of payments for real estate taxes, fire and hazard insurance, electricity, gas and other fuels, water, and mortgage. Owner costs as shown here do not include payments for maintenance and repairs.

Source: 1980 Census Public Use Microdata Sample File, updated by Consumer Price Index.

Exhibit GG-8

MONTHLY HOUSEHOLD INCOMES AND GROSS RENTS
FOR LOW-INCOME ELECTRIC RATEPAYER-RENTERS
PENNSYLVANIA PORTION OF THE PHILADELPHIA METROPOLITAN AREA

(In November 1985 Dollars)

Persons	Monthly Household Income	Monthly Gross Rents*	Remainder
1	$ 369	$297	$ 72
2	$ 641	$348	$293
3	$ 681	$374	$307
4	$ 817	$398	$419
5	$ 925	$405	$520
6	$1110	$444	$666
7	$1075	$417	$658
8 or more	$1382	$465	$917
Average - All Sizes	$ 625	$350	$275

*Contract rent plus the estimated average monthly cost of electricity, gas and other fuels, and water, to the extent that these are paid by or on behalf of the renter, in addition to the rent.

Source: 1980 Census Public Use Microdata Sample File, updated by the Consumer Price Index.

Exhibit GG-9

MONTHLY AVERAGE AMOUNT REMAINING
AFTER BOTH SHELTER AND FOOD COSTS FOR
LOW-INCOME ELECTRIC RATEPAYERS
PENNSYLVANIA PORTION OF PHILADELPHIA METROPOLITAN AREA

(In November 1985 Dollars)

	Remainder After Shelter Costs	Food Costs	Remainder After Food and Shelter
All Low-Income Homeowner Ratepayers	$303	$251	$ 52
Single-Person Low-Income Homeowner Ratepayers	$114	$112	$ 2
All Low-Income Renter Ratepayers	$275	$159	$116
Single-Person Low-Income Renter Ratepayers	$ 72	$ 98	- $ 26

Source: Remainder After Shelter Costs - see Exhibits GG-7 and GG-8.
Food Costs - 1981 Consumer Expenditure Survey, U.S. Bureau of Labor Statistics, updated by Consumer Price Index.

Exhibit GG-10

POSSESSION OF AIR CONDITIONING
AMONG ELECTRIC RATEPAYERS ABOVE AND BELOW 150% OF POVERTY
PENNSYLVANIA PORTION OF PHILADELPHIA METROPOLITAN AREA
1980

	Number	Percent
Below 150% of Poverty		
No air conditioning	121,760	53.9%
Central air conditioning	19,280	8.5%
One room unit	55,120	24.4%
Two or more room units	29,920	13.2%
Total Households	226,080	100.0%
150% of Poverty and Above		
No air conditioning	279,360	29.7%
Central air conditioning	193,160	20.5%
One room unit	224,140	23.8%
Two or more room units	243,400	25.9%
Total Households	940,060	100.0%

Source: 1980 U.S. Census Public Use Microdata Sample File.

Average Electricity Consumption and Expenditures

Table 5. (Continued) Census Division: Middle Atlantic

Household Characteristics	Any Electricity Used					Electricity Used as Main Heating Fuel			
	Number of Households (Millions)	Avg. Amount Consumed per Household (Thousand kWh)	Avg. Amount Consumed per Household (Million Btu)	Avg. Expenditures per Household (Dollars)	Avg. Price (Dollars per Million Btu)	Number of Households (Millions)	Avg. Amount Consumed per Household (Thousand kWh)	Avg. Amount Consumed per Household (Million Btu)	Avg. Expenditures per Household (Dollars)
TOTAL HOUSEHOLDS	13.7	6.1	21	588	28.28	1.0	14.3	49	1109
AREA TYPE									
METROPOLITAN	12.2	5.9	20	596	29.55	.9	14.8	51	1163
CENTRAL CITY	5.1	4.2	14	521	36.42	Q	Q	Q	Q
OUTSIDE CENTRAL CITY	7.1	7.2	24	650	26.63	.8	15.1	51	1222
NON-METROPOLITAN	1.5	7.6	26	526	20.30	Q	Q	Q	Q
ELECTRICITY PAID BY HOUSEHOLD									
YES	12.0	6.3	22	597	27.61	.9	14.9	51	1153
NO	1.8	4.4	15	525	34.71	Q	Q	Q	Q
TYPE OF HOUSING STRUCTURE									
MOBILE HOME	.3	6.4	22	428	19.50	Q	Q	Q	Q
SINGLE FAMILY	8.3	7.5	25	666	26.12	.7	16.9	58	1301
2 OR MORE UNITS	5.2	3.9	13	473	35.54	.3	9.4	32	741
NUMBER OF ROOMS									
1 TO 3	2.3	3.5	12	396	33.01	.3	10.6	36	738
4 TO 5	4.6	5.3	18	523	29.06	.4	12.8	44	1065
6 OR MORE	6.8	7.5	26	697	27.15	.3	19.4	66	1479
MEASURED HEATED SPACE OF RESIDENCE (IN SQUARE FEET)									
LESS THAN 999	4.8	3.9	13	423	31.73	.4	10.5	36	832
1,000 TO 1,999	5.2	6.6	23	618	27.36	.4	15.7	54	1214
2,000 OR MORE	3.7	8.2	28	759	27.17	.2	18.9	64	1418
YEAR HOUSE BUILT									
BEFORE 1950	7.0	4.9	17	499	29.55	Q	Q	Q	Q
1950 TO 1974	5.6	6.8	23	660	28.40	.5	14.7	50	1197
AFTER 1974	1.2	9.5	32	773	23.93	.4	15.0	51	1064
OWN/RENT									
OWN	8.5	7.2	24	670	27.39	0.5	17.8	61	1412
RENT	5.2	4.3	15	454	30.67	.6	11.6	39	865
1981 FAMILY INCOME									
LESS THAN $10,000	4.4	4.5	16	440	28.34	.4	12.2	42	912
$10,000 TO $19,999	4.2	5.7	20	540	27.67	.3	14.9	51	1155
$20,000 TO $34,999	2.0	6.2	21	612	28.77	Q	Q	Q	Q
$35,000 OR MORE	3.2	8.6	29	837	28.53	.3	17.4	59	1373
TOTAL BELOW 100 PERCENT OF POVERTY LINE	2.0	4.6	16	464	29.57	Q	Q	Q	Q
TOTAL BELOW 125 PERCENT OF POVERTY LINE	3.0	4.4	15	449	29.64	.2	12.4	42	921
AGE OF HOUSEHOLD HEAD									
UNDER 35 YEARS	3.5	6.4	22	601	27.53	.5	13.7	47	1082
35 TO 59 YEARS	5.8	6.9	24	678	28.63	.2	17.5	60	1386
60 YEARS AND OVER	4.4	4.7	16	458	28.41	.3	12.9	44	942
HOUSEHOLD MEMBERS									
ONE PERSON	3.6	3.8	13	362	28.07	.4	10.4	36	739
2 TO 4 PEOPLE	8.3	6.5	22	630	28.21	.6	16.7	57	1362
5 OR MORE PEOPLE	1.8	8.7	30	851	28.70	Q	Q	Q	Q

See footnotes at end of table.

STATEMENT NO. 2

CEPA et al

RECEIVED
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Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION V. PHILADELPHIA ELECTRIC COMPANY

DOCKET NO. R-850152

EXTRA COPY

Direct Testimony of

GEORGE J. STERZINGER

on behalf of

Consumers Education and Protective Association,
Action Alliance of Senior Citizens
Association of Community Organizations for Reform Now,
Philadelphia Citizens in Action, and
Mr. Bradshaw

January 21, 1986

I. QUALIFICATIONS AND PUBLICATIONS

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

A. My name is George J. Sterzinger. My business address is the National Consumer Law Center, 11 Beacon Street, Boston, Massachusetts 02108.

Q. WILL YOU OUTLINE YOUR QUALIFICATIONS AND EXPERIENCE RELEVANT TO THE FIELD OF PUBLIC UTILITIES?

A. I received a B.A. in Economics with Honors from St. Joseph's College in Rennselaer, Indiana, in 1964. By 1968 I completed all the requirements at Purdue University for a doctorate in Economics with the exception of my dissertation. My major field of study was quantitative methods as applied to economic theory. At Purdue University, St. Joseph's College and Dean Junior College in Franklin, Massachusetts, I taught courses in economics ranging from principles, through basic theory, to honors seminars in mathematical economics.

I began work at the National Consumer Law Center in September of 1981.

From 1976 to 1980 I worked with the New England Regional Energy Project. In both places, I have worked on electric and gas rate design, cost allocation, and other regulatory issues. I have testified on electric and gas rate design issues before the regulatory commissions of 21 states: Colorado, Connecticut, Georgia, Illinois, Maine, Maryland, Massachusetts, Michigan, Nevada, New Hampshire, New Jersey, New Mexico, Oklahoma, Pennsylvania, Rhode Island, Texas, Utah, Vermont, Virginia, Washington, and West Virginia. In addition I have served as a consultant on PURPA investigations for the Tennessee Valley Authority.

My article entitled "A Critique of the Peaker Methodology for

Calculating Marginal Costs of Electric Service" appeared in the Sept. 29, 1983 issue of Public Utilities Fortnightly. The July 2, 1981 issue of the same publication carried my article entitled "The Customer Charge and Some Problems of Double Allocation of Distribution System Costs." My paper entitled "Conservation Program Financing: Some Analytic Concerns" was presented at the NARUC Biennial Regulatory Information Conference, and published as part of the Proceedings of the Third Annual Conference. Another paper entitled "Ratemaking, Financing Arrangements, and Diversification: Utility Proposals and Regulatory Responses" was presented at the 1982 Eastern Economic Association Annual Meeting. I have also had published "An Introduction to Statistical and Rate Making Issues Underlying Load Data and Costing Requirements of Sec. 133 of PURPA," "Oil Shale Development and Electric Generation Requirements: Regulatory Policy Reforms," and many other analyses of economic issues that arise in regulating utilities.

II. INTRODUCTION AND SUMMARY OF TESTIMONY

Q. WOULD YOU PLEASE STATE THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to review the cost allocation practices utilized by the Company in this proceeding, to identify incorrect or questionable practices, and where appropriate to suggest remedies to these practices. In addition, my testimony will include a review of some of the information available to the Commission concerning the income and the relationship between income and usage for residential customers on the Philadelphia Electric Company (PECO) system. This review is included in order that the recommended reallocation or reforms to the cost allocation procedures of the Company can be done in such a way as to both reflect policies which are consistent with sound economics and consideration of the effect of the changes on residential consumers', and especially low-income consumers', real income. In addition, to the extent possible, the recommended changes in the allocation of costs will be followed through to suggest reforms or redesign of the residential tariffs.

Q. WOULD YOU BRIEFLY SUMMARIZE YOUR RECOMMENDATIONS?

A. The cost allocation procedures adopted by the Company should be reformed in the following areas:

- Production plant allocation should be changed so that both peak demand and overall energy usage are assigned responsibility for production plant investment in the allocation of these costs;
- The distribution plant classification scheme utilized by the Company should be abandoned, and in its place, the distribution plant from Accounts 360 through 368 should be classified and allocated on a consistent demand basis;

- Income from rental of utility property should be allocated to classes reflecting the nature of the property rented.

The cost allocation policies referred to above have the effect of overcharging residential customers in the residential cost allocation scheme. The approximate overcharging per residential customer is $197 per year. For customers of Philadelphia Electric with incomes at or below 150% of poverty, the overcharge alone represents 2.5% of their real income. In other words, the effect of allowing the highly questionable allocation practices of the Company to continue will be to overcharge residential customers at or below 150% of poverty, an amount equal to 2.5% of their total real income.

With respect to the implication for these changes on rate design, my recommendation is that the customer charge be lowered to approximately $4.00 per month, and that the remaining revenue be collected on a per KWH basis but that the per KWH collection be delayed, depending upon a reassessment of the cost of providing service to the RH class.

III. REVIEW OF COST ALLOCATION AND RATE DESIGN

Q. TURNING TO THE AREA OF COST ALLOCATION AND RATE DESIGN, WOULD YOU BRIEFLY SUMMARIZE THE AREAS OF YOUR CONCERN?

A. There are three areas of concern having to do with the Company-proposed cost of service study. At the present time, the Company uses a coincident peak allocation factor to allocate the total cost of production plant. This method looks at only one of the dimensions that must be considered in order to properly determine the economic level of investment in production plant, and as a result misallocates these costs.

In classifying distribution plant, the Company relies upon a "predominant method" to choose the type of equipment considered to be customer-related. Although no good definition of precisely what is meant by the predominant piece of equipment has been given by the Company, it is obvious that the method as developed charges all customers on a per customer basis for equipment well above the minimum sized employed by the Company. This results directly in a double charging of low-use residential consumers for distribution equipment. Finally, the Company allocates the revenue received from the rental of Company equipment on a production-based allocation factor. Although the precise determination of the equipment rented remains to be supplied by the Company, it is highly likely that the Company's present treatment does not take adequate consideration of the amount of distribution equipment rented and therefore misallocates these revenues.

Q. TURNING FIRST TO THE ALLOCATION OF PRODUCTION PLANT, WOULD YOU BRIEFLY DESCRIBE HOW THE COMPANY AT PRESENT ALLOCATES THAT PLANT, AND OUTLINE

YOUR CONCERN WITH IT?

A. As stated earlier, at the present time the Company allocates all of its investment in production plant on the basis of a coincident peak factor, in this case the average of four summer-month coincident peaks. This factor is applied to the production plant in service, and is subsequently used throughout the Company study in the allocation both of directly related O and M expenses and in a host of other indirectly allocated costs.

Since the level of investment in production facilities depends critically upon both the level of coincident peak and the overall energy use experienced by the Company, the present allocation of costs is inadequate. The overall allocation of production plant in the cost of service study should be altered so that the dual use of both coincident peak and overall energy is reflected in the cost allocation. Moreover, at this time, when the Company is bringing on line and into the rate base a large investment in a nuclear generating facility, the problems raised by the use of the coincident peak allocation factor are greatly aggravated.

Q. WHY DOES THE LEVEL OF INVESTMENT IN PRODUCTION PLANT DEPEND UPON BOTH THE COINCIDENT PEAK AND THE OVERALL ENERGY USE?

A. In order to provide generation to meet the overall load duration curve experienced by the Company, the Company can choose from among a number of investment options. At the two ends of the spectrum of choices available to the Company are peak plants and base plants. A peaking plant is widely recognized as one with the lowest reasonable fixed or capital investment costs but with correspondingly higher energy costs. On the other hand, base plants have relatively large fixed or capital costs, but have lower

operating costs. If the only consideration of the Company was to meet its coincident peak, the economic choice would be to install only peaking plants. Investment in generation facilities above the cost of purchasing or installing a peaking plant is economical only if that investment is undertaken to oobtain lower overall operating or fuel costs. As such, the only economically sound way to treat investment costs undertaken by the Company over and above the cost of peaking units is to treat them on an energy-related basis.

Q. HOW HAS THE COMPANY TREATED THE INVESTMENT IN THE LIMERICK FACILITY IN THIS COST OF SERVICE STUDY?

A. The Company treats the investment in Limerick as it treats all investment in production plant; that is, it allocates it on the basis of four coincident peak hours of use.

Q. DO YOU BELIEVE THIS TREATMENT IS REASONABLE?

A. No I do not. The investment undertaken by the Company in Limerick is first of all substantially above the investment that would have to be undertaken in order simply to provide a KW of capacity. According to figures developed in an earlier part of this proceeding, a reasonable estimate of the cost of bringing a peaking unit on line in 1985 was approximately $267 per KW (Office of Consumer Advocate, testimony of witness Komanoff, page 43). Assuming for purposes of calculation that that investment could be carried with a fixed charge recovery factor of 20%, that would produce yearly costs of a peaking unit of approximately $53 per KW per year. According to figures supplied by the Company in their prefiled statement of reasons, PECO Exhibit No. 3, the yearly cost associated with the Limerick plant is $872 per KW per year. If each KW

of capacity associated with Limerick were to generate electricity for only four hours per year, the cost per KW would be approximately $218 per KWH. (That cost would recover only the fixed costs associated with generation--the fuel and operation and maintenance costs would still have to be added.) It is highly unlikely that any customer would purchase electricity at $218 per KWH. Moreover, it is obvious that the Company has a number of options to produce KWHs much more cheaply if the purpose of the investment is only to provide electricity at the peak hours. The investment in the Limerick unit, to the extent that it is economic, is undertaken in order to provide lowered cost of generation throughout the year. The cost per KW from Limerick, less a credit of $53 for peaking capacity, can produce a KWH at roughly 9.35¢ per KWH if the generation is used year-round.

Q. WHAT CONCLUSIONS FOR COST ALLOCATION DO YOU DRAW FROM THE ABOVE ANALYSIS?

A. Again, to the extent the Limerick investment was economic, it will provide service and benefits to users throughout the year. Since the benefits will be delivered across the year, the only reasonable way to allocate the costs of the plant is to allocate them on an energy basis. It should be noted that in PECO EXHIBIT 3, the Company estimates $207.5 million in energy cost savings anticipated to result from the operation of Limerick I. These savings, which are a direct result of the capital investment undertaken to bring Limerick on line, are flowed through the fuel adjustment clause on a per KWH basis. This simply reinforces the notion that the bulk of the investment in the Limerick nuclear generation station was undertaken to provide year-round service, and should be allocated on that basis.

Q. HAVE YOU CALCULATED THE EFFECT THAT CHANGING THE ALLOCATION SOLELY OF THE LIMERICK PLANT WOULD HAVE ON THE COMPANY CLASSES AND IN PARTICULAR THE RESIDENTIAL R CLASS?

A. That recalculation is shown in Exhibit 1. This exhibit shows how the roughly $920 million associated with bringing Limerick on line would be reallocated if the allocation factor were changed from the present coincident peak to an overall energy basis. The allocation factors were taken from the Company cost of service study. The results show that the greatest differential swing would occur for the residential R tariff where a change in the allocation of Limerick would reduce cost responsibility by roughly $39 million. Compared to the revenue change shown on page 6A of PECO Exhibit WFS-1, making this change would produce roughly a 14.5% reduction in the overall residential rate R revenue responsibility. Additionally, the $38 million reduction would mean a per customer savings of approximately $35 per year.

Thus, at the present time, the misallocation of the investment undertaken in Limerick I results in an overcharging of the average residential customer by approximately $35 per year. As was pointed out in an earlier section of the testimony, this overallocation of costs has to be looked at not only in terms of its effect on the proper assignment of cost responsibility, but also in terms of its effect on people of varying levels of income.

Q. HAVE YOU RECALCULATED AN ALLOCATION FACTOR FOR PRODUCTION FACILITIES WHICH REPRESENTS THE DIMENSIONS OF BOTH PEAK AND ENERGY USAGE IN ALLOCATING THESE COSTS?

A. That calculation is shown also in Exhibit 1 on the line labeled Average and Excess. This factor is developed by allocating production

costs on each class' average demand responsibility and each class' share of the portion of the peak demand minus the average demand where the class share is based upon the class' coincident peak demand. As such, it considers both the overall energy use of the class and the coincident peak use of the class in determining the total class responsibility. The relevant weights given to the average demand and the coincident peak demand depend in turn upon the difference between the coincident peak of the Company and the average demand of the Company. I should add that this factor is not a perfect allocation factor but represents a definite improvement over the present coincident peak method used by the Company. Data and time limitations prevented the calculation of a more precise allocation factor that could be utilized in the determination of production plant responsibility.

Q. TURNING TO THE TREATMENT OF DISTRIBUTION PLANT, WOULD YOU BRIEFLY RECOUNT THE COMPANY TREATMENT OF THAT PLANT AND STATE YOUR RESERVATIONS FOR THAT TREATMENT?

A. The Company treats distribution plant by first classifying the plant from Account 360 through 369 into a demand and customer component. For each of the accounts, or subaccounts, the Company uses the predominant sized piece of equipment to establish the portion that should be classified and allocated on a customer basis. No precise definition of "predominant" is given. Once the customer portion is established, the costs are allocated to classes on the basis of numbers of customers weighted to reflect some voltage considerations. The demand costs, or the costs in the account or subaccount not already collected through the determination of the dominant equipment cost and all costs below that level, are collected on the basis of customer demands. It is important

to note here that the customer demand factors developed consider the demands of all customers, even those who can be served with equipment at or below the predominantly-sized equipment. This is important to note because from it flows a major consequence of the present Company treatment of distribution plant, namely that the cost of the plant is overcollected from low-use customers.

Q. HAVE YOU REVIEWED THE COMPANY DETERMINATION OF THE PREDOMINANT-SIZED EQUIPMENT?

A. To the extent that that is possible from the information made available by the Company, I have made that review. However, it should be noted that no precise definition of predominant-sized equipment is given. Thus, in the work papers provided by the Company in IR-OCA-7-8, it is possible to follow the arithmetic calculations of the Company. However, the two critical determinations, the size and cost of the predominant equipment and the amount of equipment in the subaccount which is of a size greater than the predominant equipment have to be taken as given. No independent work papers showing the development of those two critical figures have been provided. Thus, from its inception the predominant method is essentially subjective. A different determination of the equipment judged to be predominant would produce radically different results. In Account 365, the subportion of that account having to do with aerial primary lines produces in the Company's analysis a classification of only 18.791% of the costs as demand-related. If another conductor size, one smaller than the 4/0 aluminum conductor used by the Company in the study, were to be substituted as the predominant equipment, two factors in the Company's classification study would change: the amount of conductor at a size greater than the predominat size would

increase the amount presently shown, and the cost per foot of conductor would decrease. Both of these factors would tend to produce a greater classification of the plant as demand-related.

Q. WOULD YOU PLEASE EXPLAIN HOW THE COMPANY USE OF THE PREDOMINANT METHOD RESULTS IN AN OVERALLOCATION OF COSTS TO LOW-USE RESIDENTIAL CUSTOMERS?

A. This overallocation flows from the Company classification of a sizable piece of distribution equipment as being the customer-related equipment. Despite the fact that the Company has provided no precise definition of "predominant," it is obvious from the work papers provided by the Company that the piece of equipment they utilized to make the customer classification was at or above the average cost of equipment in the account and subaccounts. This result can be easily seen from looking at the portion of the investment determined to be demand-related. For the major accounts of Overhead Lines--Primary and Secondary, Underground Lines--Primary and Secondary, and Transformers, the Company classifies considerably more than half of the costs in the account as customer-related. In the case of some of the secondary overhead lines, the classification of customer-related is in excess of 99%. Thus the portion of equipment classified as customer is the installed equipment capable of serving average or below-average loads.

In other words, average or below-average users pay for the equipment necessary to serve them through the customer portion of the costs. In addition, the Company develops demand allocation factors to allocate the cost of equipment above the customer-related portion which include the demands of all customers. Thus, the below-average-use customers not only pay for more than the kind of equipment necessary to serve them through the customer charge, they are also required to pay for a portion of the

equipment above the customer-related through the demand-related charges. A more complete development of this critique of a split classification of distribution plant is developed in an article published by me in Public Utilities Fortnightly and attached as Appendix A to this testimony.

Q. HAVE YOU CALCULATED THE OVERALLOCATION OF COSTS TO THE LOW-USE RESIDENTIAL CUSTOMERS THAT RESULTS FROM THE COMPANY'S CLASSIFICATION SCHEME?

A. That overallocation of costs is shown in Exhibit 2. That exhibit compares the customer cost per residential rate R customer as developed from the Company's cost of service study with a recalculated customer cost performed by me based on information provided by the Company to IR-OCA-7-5. Before explaining the results of that exhibit, I should point out that an alternative way of calculating the overallocation of costs that results from the Company's distribution plant classification would be to reclassify the plant on a consistent demand basis, and rerun the cost of service study using that classification. The consistent demand allocation should apply for accounts from 360 to 368.

In addition, my recommendation would be, lacking a more detailed analysis of the investment and services accounts, that 50% of the accounts should be classified as customer-related and 50% as demand-related. The reason for this split is that in the absence of a more complete analysis of the costs, the 50/50 split acts to minimize the potential harm from making either a more exaggerated demand or customer classification.

Turning to Exhibit 2, that shows that in the Company's cost of service study, the costs per residential rate R customer per year are $207.30. In comparison, I have calculated from the information provided by the

Company that the proper customer charge per month should be approximately $4 per customer, which would produce yearly customer costs of $48. Thus, as a result of the improper classification of distribution plant costs, the average residential customer is overcharged $159 per year. (As I stated earlier, this figure of $159 is most likely a slight overstatement of the cost allocation redistribution that would occur if the distribution plant were reclassified as suggested and the entire cost of service study rerun.) Again, referring to my earlier testimony, it is important that this misallocation of costs be considered not only in terms of its effect on the cost allocation and rate design of the Company, but also in terms of its effect on the real income of the customers of Philadelphia Electric.

Q. TURNING TO THE FINAL AREA OF CONCERN WITH THE COST ALLOCATION STUDY, WOULD YOU PLEASE EXPLAIN THE RESERVATIONS YOU HAVE WITH THE COMPANY-PROPOSED METHOD FOR THE TREATMENT OF ACCOUNT 454--RENT FROM ELECTRIC PROPERTY?

A. The present Company treatment is shown on page 7A of WFS-1. That shows that at present the rent from electric property is allocated or distributed to the customer classes on the basis of A1, the production plant allocation factor. That allocation would be proper only if the equipment being rented were production or high voltage transmission plant. If the equipment being rented is distribution level plant, the allocation of the revenue should be based upon an allocation factor reflecting as accurately as possible the kind of distribution plant being rented. In other words, if the equipment being rented is the Company poles, then the allocation of the revenue from that rental should be based upon the allocation of the cost of the poles to the customer

class. The primary problem with allocating revenues obtained from renting distribution plant on the basis of their production level factor is that it allocates a considerable portion of the revenues to the commercial and industrial high tension customer class which has no cost responsibility for distribution plant. In other words, a class that has none of the cost responsibility for the distribution plant owned by the Company would receive roughly 41.5% of all of the revenue obtained by renting that distribution plant.

Clearly this is an improper assignment of the revenue from the distribution plant rental. At the time of preparing this testimony, discovery made on the Company as to the precise breakdown of the equipment rented had not been obtained. As a result, it is impossible to make a recommendation as to exactly how the allocation of the revenues from equipment rental should be made. Nevertheless, a general recommendation, that the allocation of the revenue be based upon the shared cost responsibility for the equipmemt rented can be made. To the extent that the equipment rented is distribution equipment, the allocation of revenues back to customrer classes should reflect that fact.

IV. THE EVALUATION AND CONSIDERATION OF INCOME

Q. HOW DO YOU PROPOSE INTRODUCING THE CONSIDERATION OF INCOME AND THE RELATIONSHIP OF INCOME AND USAGE INTO THE DELIBERATIONS ON COST ALLOCATION AND RATE DESIGN IN THIS PROCEEDING?

A. My proposal is to evaluate the available information having to do with the income of the residential customers of Philadelphia Electric, and the relationship of usage and income among those customers. To the extent that useful information is available on those topics, my testimony is that such information be adopted as an additional evaluation or consideration of policies that are, first of all, based upon sound economic and cost allocation principles.

My testimony should not be taken to preclude specific consideration of the income and relative ability to pay of residential customers over and above cost consideration principles; however, those considerations are not raised at this time. In effect, my testimony is that the available information on the income of residential customers and the information available on the relationship of income to usage should be used in a way which is consistent with economic and costing principles, in order to design rates as sensitive as possible to the needs of low-income customers.

Q. WHAT INFORMATION HAVE YOU REVIEWED CONCERNING THE INCOME OF THE RESIDENTIAL CUSTOMERS AND THE RELATIONSHIP BETWEEN INCOME AND USAGE?

A. I have relied upon the updated census information having to do with the income of customers of Philadelphia Electric developed by George Grier, another witness for CEPA et al in this proceeding. In addition, I have reviewed the studies available to the Company, either developed by

them or at their direction, having to do with the relationship between income and usage. At the time of preparing this testimony, there were outstanding questions having to do with their analysis of income and usage, and as a consequence that information was not available for use in this testimony. However, the information developed from the 1980 census data and subsequently updated having to do with the incomes of residential customers of Philadelphia Electric is useful.

Q. WOULD YOU BRIEFLY DISCUSS THE INFORMATION AND THE TYPE OF RESULTS YOU OBTAINED FROM THIS ANALYSIS?

A. That information is presented in Exhibit 3. That exhibit shows the average income of various household sizes for residential customers below 150% of poverty, and those with incomes at or above 150% of poverty. As expected, the income of those below 150% of poverty is by definition below the income of those above 150% of poverty. The magnitude of the difference, however, is striking. The average income of all households below 150% of poverty is $7,826 per year. By comparison, the average income of households above 150% of poverty is $37,524 per year. Thus, the average income of those above 150% of poverty is nearly five times greater than of all households below 150% of poverty.

Q. WHAT POLICY CONCLUSIONS CAN YOU DRAW FROM THIS TYPE OF DATA?

A. While it is impossible, without more precise information about the relationship that exists between income and usage, to "fine tune" rate design proposals, given the information available from the census data it is possible to conclude that questionable policies which result in the overcharging of residential customers, while they may be acceptable to residential customers on average, have a much more profound effect on

people below poverty status. Specifically, in this case I have identified a number of areas where the residential class is overcharged, and which are discussed in a subsequent part of the testimony. That overcharging costs families above 150% of the poverty level approximately 0.5% of their income on average. For those below 150% of poverty, the effect of the same overcharging is to take 2.5% of their income on average.

The point is not that .5% is affordable or tolerable, but that the 2.5% has a much more serious effect on people's income. My testimony is that this additional consideration, the effect of improper allocation practices on people below 150% of poverty, should be added to the reasons developed in a previous section of the testimony for changing those practices at this time.

	TOTAL COMPANY	COMMERCIAL AND INDUSTRIAL HT	PRIM	SECONDARY	RESIDENTIAL R-H	R
A1	5,391,886	2,235,585	500,698	764,118	211,311	1,489,776
		41.462%	9.286%	14.172%	3.919%	27.630%
C1	3,455,651	1,520,630	280,706	432,405	200,234	808,715
		44.004%	8.123%	12.513%	5.794%	23.403%
AVERAGE&EXCESS		2,323,432	460,507	706,801	276,116	1,343,696
		43.091%	8.541%	13.109%	5.121%	24.921%
DIFFERENTIAL		2.542%	-1.163%	-1.659%	1.875%	-4.227%

	OP	SLP	STREET LIGHTING SLS	OTHER	OTHER UTILITIES	INTER
A1	140	249	38	9	80,440	11,714
	0.003%	0.005%	0.001%	.000%	1.492%	0.217%
C1	48,395	11,938	7,541	1,965	52,833	7,529
	1.418%	0.345%	0.219%	0.057%	1.529%	0.218%
AVERAGE&EXCESS	49,046	12,027	7,555	1,968	81,719	11,736
	0.910%	0.223%	0.140%	0.037%	1.516%	0.218%
DIFFERENTIAL	1.415%	0.341%	0.219%	0.057%	0.037%	0.001%

		SEPTA	AMTRAK
	A1	41.559	56.249
		0.771%	1.043%
	C1	31.533	50.636
		0.913%	1.465%
AVERAGE&EXCESS		46.457	70.835
		0.862%	1.314%
DIFFERENTIAL		0.142%	0.422%

RESIDENTIAL CUSTOMER CHARGE

RATE BASE

ACCT. 369	$41,032,500.00
ACCT. 370	$51,758,000.00
TOTAL	$92,791,500.00
LEVEL ANNUAL CHARGE(16.7%)	$15,496,180.50

EXPENSES

METER O&M	
ACCT. 586	$2,750,000.00
ACCT. 597	$905,000.00
SUBTOTAL	$3,655,000.00
CUSTOMER ACCT.	
ACCT. 902	$10,205,000.00
ACCT. 903	$24,558,000.00
SUBTOTAL	$34,763,000.00
TOTAL EXPENSES	$38,418,000.00
TOTAL CUSTOMER COSTS	$53,914,180.50
NUMBER OF CUSTOMERS	120500
COST PER CUSTOMER PER YEAR	$48.12
COST PER MFS-1	$207.30

INCOME LEVEL BY POVERTY GROUP AND HOUSEHOLD SIZE

HOUSEHOLD SIZE	BELOW 150%	ABOVE 150%
1	$4,641	$22,011
2	$7,497	$34,885
3	$8,215	$40,395
4	$10,555	$44,322
5	$12,047	$47,470
6	$14,154	$49,881
7	$15,051	$52,308
8	$18,602	$55,516
TOTAL	$7,825	$37,524

APPENDIX A

The Customer Charge and Problems Of Double Allocation of Costs

By GEORGE J. STERZINGER

AFTER several years of the "great rate debate" attention finally seems to be turning towards a forgotten part of rate design: the customer charge. Utilities, forced by the Public Utility Regulatory Policies Act to justify or do away with declining energy charges, have begun arguing for cost classification and subsequent rate design with increasingly large customer charges. Recently proposed customer charges seem to be consistently in the $6 to $9 range, accompanied by embedded cost-of-service studies supporting even greater charges.

Consumer and environmental groups concerned about rate design reform (rather than using the customer charge as a place to dump costs, as the utilities do) have seen it as a place to shave costs. Concerned primarily with getting a kilowatt-hour or usage charge to reflect incremental or marginal costs more accurately, these groups have attempted to resolve the problem of the resulting excess revenue by proposing that the customer charge be lowered enough to "lose" the surplus. Negative customer charges or lump sum monthly payments from the utility to consumers have been proposed by more imaginative analysts.[1]

Analyses of the proper customer charge have often yielded contradictory results depending upon whether incremental or embedded costs were used. Incremental analyses often, but not always, support low customer charges, while embedded cost analyses often, but not always, support high customer charges.

The importance of incremental price signals and the need to strike a balance between revenue constraints and proper price signals have produced wide agreement that the customer charge is the least "informative" of all parts of a rate design and should be the last place a utility is allowed to collect revenues if incremental costs are found to be useful in designing rates.

Unfortunately, the debate on the proper definition and use of incremental costs remains unresolved, while traditional practices of embedded cost allocation seem to support very high customer charges. Regulators, forced with making a decision, have found some cost basis to be

This article is a critique of the currently most widely used methodology for classifying a portion of electric utility distribution plant as a customer cost. The author argues that this classification, combined with an allocation of the "above minimum" portion on a demand basis, leads to an overallocation of costs to low-use residential customers of the electric system.

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[1]"Customer Charges and the Public Utility Regulatory Policies Act," by Edward F. Renshaw and Perry Renshaw, 104 PUBLIC UTILITIES FORTNIGHTLY 17, August 30, 1979, found high customer charges contrary to the intention of PURPA.

preferable to unresolved speculation, and raised the customer charge based on embedded cost-of-service studies.

Since incremental analyses cannot by themselves support a low customer charge, the embedded cost analyses which support high customer charges must also be closely investigated to determine if they meet current objectives of rate design. An examination of these methodologies reveals the following characteristics:

— Almost all of them rely for their justification on the determination of the cost of a minimum distribution system, and the classification of this system as a customer cost.

— Once the classification has been made, it is an inescapable conclusion of the allocated cost-of-service study that calculated customer costs will be substantial.

— However, an examination of the rationale for the classification and the implications of that classification lead equally inescapably to the conclusion that minimum use residential customers will be overcharged by such cost allocation practices.

— The only reasonable remedy for the problem of overcharging is to classify the entire distribution system on a consistent basis, which would be a demand basis.

— Once this is done, traditional cost-of-service studies no longer provide support for high customer charges.

A national survey of utility practices in classification of distribution system costs determine that the great majority used some form of minimum system to classify costs in the relevant Federal Energy Regulatory Commission accounts. (The survey was conducted by Carolina Power and Light Company, Raleigh, North Carolina.) The survey summarized the results of company practices to determine how much, on average, each distribution plant account was classified as demand. The results by FERC account were as follows:

— Account 364 — Poles and fixtures were separated into primary and secondary; the primary portion was split 50-50 between customer and demand costs, the secondary portion was classified 56.5 per cent customer and 43.5 per cent demand.

— Account 365 — Conductors and devices were also separated into primary and secondary; the primary portion was classified 44.3 per cent customer and 55.7 per cent demand, and the secondary portion was classified 46.4 per cent customer and 53.6 per cent demand.

— Account 368 — Line transformers were classified 34 per cent customer and 66 per cent demand.

— Account 369 — Services were classified 70.8 per cent customer and 29.2 per cent demand.

The difficulties with these methodologies only begin with the minimum distribution system. The concept is very difficult to define and consequently susceptible to widely varying interpretations. No single method exists for calculating the cost of this system; nevertheless, a fairly standard approach is to reconstruct the existing distribution system using some type of minimum equipment. Minimum equipment could be of the type employed by the company, currently purchased by the company, currently used in the industry, or currently required by safety code. The cost of this equipment can be either booked or in current prices. Obviously, with this large a menu of definitions to choose from, a utility analyst can calculate costs for these systems over a wide range.

It should be mentioned here that one other method sometimes used to calculate the cost of a minimum system is the "zero-intercept" method whereby regression equations relating cost to various sizes of equipment are derived, and then solved for the cost of zero-sized or "zero-intercept" equipment. The strongest objections to this methodology arise from the limitations on data, the unreliability of the derived equations, and some fundamental problems that arise from making the statistical inference about the cost of the zero-sized equipment.

A typical utility in the sample discussed earlier, faced with the problem of classifying costs in Account 365 —overhead lines, for example, would determine the cost of the minimum equipment needed to replace all existing lines, calculate that cost as a fraction of the total costs of equipment in the account, and use that fraction to classify customer costs. Thus, a utility with 1,000 miles of overhead lines and two types of line costing $1 per foot and $2 per foot would calculate a minimum system cost of roughly $5.28 million ($1 × 5,280 feet per mile × 1,000 miles). This $5.28 million can, of course, be varied if different types of minimum lines are used, or if for other reasons the cost of $1 per foot is changed.

Beyond problems arising from the indeterminate nature of the minimum system, the appropriateness of classifying these costs as customer costs has been long debated. Strictly speaking, customer costs should be limited to those costs which can be shown to vary exclusively with number of customers. Distribution system costs, both as built and hypothetical minimum system, obviously depend to a great extent on geographical considerations — type of terrain and customer density. Several analysts have argued that the nature of cost causation — in this case at least in part due to geography — does not allow the costs to be neatly fit into either demand or customer cost categories; that the costs are simply unallocable. Recent statistical analyses support this notion.[2]

An additional and more severe problem with this methodology arises from the consequences of classifying distribution system costs into both customer and demand portions. Simply put, this practice leads

[2] "The Economics of Electric Distribution System Costs and Investments," by David J. Lessels, 106 PUBLIC UTILITIES FORTNIGHTLY 37, December 4, 1980, found no statistical justification for the classification of distribution costs as customer related.

inevitably to a double allocation and possibly a double collection of these costs from low-use residential customers and a misallocation of costs among customer classes.

To see why this is so, one need only step back for a moment to consider what it is that a cost allocation study attempts to do, and what happens when distribution system costs are split into customer and demand portions and then allocated to individual classes.

An allocation study assigns costs to customers on the basis of usage characteristics; fairness requires that allocated costs follow, as closely as possible, the actual costs of serving customers. Splitting the distribution system into a minimum usage and an above minimum usage portion, and allocating the minimum portion on a customer basis, and the above minimum on a usage basis results in low-use residential customers paying for more of the system than is required to serve them. By splitting the distribution system into two parts, low-use residential consumers are charged twice: once, on a customer basis, for a portion of the system sized to meet their demands; and again on a demand basis for a portion of the system sized to serve demand beyond what would be needed to serve them. The only practical way satisfactorily to assure that low-use customers are charged only once for distribution equipment is to allocate the distribution system costs on a single consistent basis. Of the two considered, customer and demand, it is obvious that only demand can be used to classify and allocate distribution costs on a satisfactory basis.

In order to explain more fully why this method constitutes double charging of low-use customers, we can look more closely at the handling of FERC Accounts 364 and 365 which represent the cost of overhead lines and poles. To illustrate this, suppose the company had only 1,000 miles of overhead lines and 10,000 poles; and in addition it used two types of line — one costing $1 per foot, for 500 miles of overhead, the other costing $2 per foot, for the remainder; and two sizes of pole — 5,000 costing $30 per pole and 5,000 costing $60 per pole. Total cost of this system would be:

a) Line 500 miles at $1 per foot	$2,640,000	
b) Line 500 miles at $2 per foot	5,280,000	
Subtotal		$7,920,000
c) Poles 5,000 poles at $30 per pole	$ 150,000	
d) Poles 5,000 poles at $60 per pole	300,000	
Subtotal		$ 450,000
Total		$8,370,000

A minimum system in this case would be determined by calculating the cost of the 1,000 miles of overheads if only the minimum-sized line was used, plus the cost of the 10,000 poles if only the minimum-sized pole was used.

Cost of the minimum system is:

a) Line: 1,000 miles at $1 per foot	$5,280,000	
b) Poles: 10,000 poles at $30 per pole	300,000	
Total		$5,580,000

Therefore, the cost of the above minimum (or capacity) system would be the remainder, or $2,780,000.

The minimum system calculated in this fashion could, and actually does, serve a considerable level of usage.

The minimum system is allocated on a customer basis — all customers are charged for an equal share of it. The remainder of the system, the more expensive facilities required to meet loads beyond those handled by minimum-sized equipment, is allocated on some demand basis; noncoincident peak demand is often used. In the calculation of the noncoincident peak demand allocation factors, usage at all levels of the residential and general service customer classes is used to determine allocation factors.

If, for example, the minimum overhead lines, conductors, and poles could supply a demand of two kilowatts per residential customer, that amount of usage would be paid for in the customer charge. In the determination of demand allocation factors, however, each residential customer's demand is calculated and added to determine the portion of the above minimum system costs to be allocated to the residential class and to each customer through the appropriate rates. So a residential customer who has a demand of two kilowatts will have paid for all the distribution costs associated with his load through the customer charge, but will also have his two-kilowatt usage go into the demand allocation factor to allocate distribution costs associated with above minimum usage.

One way to solve the double allocation problem would be to determine, for each piece of minimum equipment, the demand level it would be capable of serving, and then adjusting the demand allocation factors used to allocate the costs of all equipment of that type in order to assure that minimum use customers and the residential class were not charged twice. In many cases this would mean calculating several allocation factors for each FERC distribution account, since more than one type of equipment is used in the account. Even after overcoming all the problems of this approach one is still confronted with the dubious value of charging for equipment on an up-front basis rather than through a per kilowatt-hour charge at a time when conservation is recognized as an important goal of energy policy.

The direct way to assure that problems of overcollection are not built into the methodology used to determine class costs of service is to classify all distribution costs as demand costs. If this methodology is used in embedded cost studies, the studies will produce more equitable estimates of the cost of serving low-use residential customers.

BUCKS COUNTY HOUSING GROUP INC. • 140 E. RICHARDSON AVE. • LANGHORNE, PA 190

February 4, 1986

RECE
FEB1
SECRETARY
Public Utility

Public Utility Commission
Box 3265
Harrisburg, PA 17120

Dear People:

I was scheduled to testify at the hearing Monday night at Delaware Agricultural College but I had to leave.

Please accept this as my testimony and include it in the public re

Sincerely,

Santo Gairo

Santo Gairo, MSW
Executive Director

SG:er

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BUCKS COUNTY HOUSING GROUP INC. • 140 E. RICHARDSON AVE. • LANGHORNE, PA 19047 • (215) 750

My name is Santo Gairo, the Executive Director of the Bucks County Housing Group. We are a private, non-profit organization that provides housing services to people in crisis.

We provide emergency/temporary housing for 16 families at a time at locations in Penndel, Doylestown and Bristol. We provide mortgage counseling under Pennsylvania's Mortgage Assistance Program. We provide counseling for educational services to tenants having rental problems to help reduce evictions, we provide crisis financial help to prevent evictions and to relieve problems with utilities, and we develop affordable housing.

We have seen a dramatic increase in the incidences of homelessness, especiall among families. Homelessness has increased because evictions have increased. Evi tions have increased because costs associated with housing have increased. Utilit costs make up a percent of housing costs. Higher utility costs are passed onto the tenant. The tenants we work with cannot afford to pay higher utility costs and higher housing costs. Surely there income has not and will not increase 28%. Because their income has not and will not increase, and housing costs are increasing, especially utility costs, people are loosing, and a good number will be evicted. We as a small agency cannot respond to this increasing need. We surely cannot go to the government and get a 28% increase, and in fact, housing programs have suffered incredible losses over the past 4 years, with more cuts on the horizon. What are people on a fixed income to do?

In a study conducted by Dr. Harvey Brenner, a professor at John Hopkins Unive sity in Baltimore, a 1% increase in unemployment results in a disproportionate increase in heart attacks, liver ailments, admissions to state hospitals, and abuse.

I suggest that there is a similar increase in evictions with every increase in housing costs.

It is for these reasons that we are against any rate increase.

DOCKETED
FEB 10 1986

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FOLDER

ORIGINAL

COMMONWEALTH OF PENNSYLVANIA
GOVERNOR'S ENERGY COUNCIL
P.O. BOX 8010
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HARRISBURG, PENNSYLVANIA 17105
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February 7, 1986

RECEIVED
FEB 7 1986
SECRETARY'S OFFICE
Public Utility Commission

Jerry Rich, Secretary
Pennsylvania Public Utility Commission
P.O. Box 3265
Harrisburg, Pennsylvania 17120

Re: Pennsylvania Public Utility Commission v. Philadelphia Electric Company Docket No. R-850152

Dear Secretary Rich:

Enclosed please find three copies of GEC Statement No. 1C, the Direct Testimony and Exhibits of Dr. John W. Wilson concerning the Energy Cost Rate issue in the above-captioned proceeding.

Copies of GEC Statement No. 1C are being served upon all parties of record per the attached Certificate of Service.

Very truly yours,

Roger E. Clark

Roger E. Clark
Chief Counsel

DOCUMENT FOLDER

Enclosure

CC: The Honorable Joseph P. Matuschak
All parties of record

CERTIFICATE OF SERVICE

I hereby certify that I have this 7th day of February 1986 served a copy of the foregoing document upon the following by first class mail (postage prepaid), hand delivery or Federal Express:

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Roger E. Clark
Chief Counsel

Dated: February 7, 1986

RECEIVED

FEB 7 1986

SECRETARY'S OFFICE
Public Utility Commission

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-850152
Philadelphia Electric Company	)	

DIRECT TESTIMONY AND EXHIBITS

OF

DR. JOHN W. WILSON

DOCKETED

FEB 10 1986

February 1986

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GEC Statement No. 1C

J. W. WILSON & ASSOCIATES, INC.

ECONOMIC COUNSEL

THIRD FLOOR • WATERGATE OFFICE BUILDING

2600 VIRGINIA AVENUE, N.W. • WASHINGTON, D.C. 20037

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	
	)	Docket No. R-850152
Philadelphia Electric Company	)	
	)	
	)	

DIRECT TESTIMONY

OF

DR. JOHN W. WILSON

February 1986

GEC Statement No. 1C

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-850152
Philadelphia Electric Company	)	

Testimony of Dr. John W. Wilson

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is John W. Wilson. My address is 2600 Virginia Avenue, N.W., Washington, D.C. 20037.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING DEALING WITH PERFORMANCE INCENTIVES AND PHASE-IN ISSUES?

A. Yes; I have.

Q. WERE YOUR QUALIFICATIONS SET FORTH IN YOUR PREVIOUS TESTIMONY?

A. Yes; they were.

I. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF THE TESTIMONY THAT YOU ARE PRESENTING AT THIS TIME?

A. This volume of my testimony deals with PECO's energy cost recovery (ECR) or fuel adjustment clause (FAC). It is organized in two parts. First, I discuss the concept of interim rate adjustment procedures in utility ratemaking, addressing the strengths and weaknesses of such procedures. Second, I explain in detail how the specific ECR approach which the Commission has prescribed for PECO can be integrated with the fuel cost recovery provisions of the nuclear performance incentive mechanism that I discussed in GEC Statement 1A.

II. ECR Design Considerations

Q. WHAT IS AN ENERGY COST RECOVERY OR FUEL ADJUSTMENT CLAUSE?

A. An energy cost recovery (ECR) or fuel adjustment clause (FAC) is a provision in an electric utility's rate schedule which permits the raising or lowering of electric utility rates in response to changes in the fuel (and, frequently, purchased power) cost element of a utility's complete cost of service, without regard to changes in any of the other cost elements. The essence of ECR or FAC procedures is that attention is focused only on those fuel and purchased power costs which the regulatory commission has already determined require interim attention between complete general rate investigations. By adopting such a procedure, regulatory authorities can permit rate adjustments to be made in response to changes in fuel and purchased power costs, without the necessity for a general investigation of all of the cost elements that would normally be considered in a complete rate case.

Purpose of an ECR

Q. WHAT IS THE GENERAL PURPOSE OF AN ENERGY COST RECOVERY OR FUEL ADJUSTMENT CLAUSE?

A. Electric utility rate levels have traditionally been designed to cover the total cost of service. Rate structures have generally been designed to reflect cost structures, but it has not been the usual practice to earmark any type of revenues to cover specific cost items. Viewed in this light, the purpose of interim adjustment procedures is to help the rate level keep pace with costs, whether they are going up or down.

Q. DO MOST STATES HAVE FAC OR ECR CLAUSES?

A. Yes. Fuel costs are now subject to special rate adjustment procedures in most regulatory jurisdictions because they are such a large fraction of the total cost of electric service, and also because they may be very volatile. Moreover, interim rate adjustments for fuel cost changes are easily implemented, because electric utilities maintain detailed records on fuel purchases, including fuel type (oil, coal, etc.), quantity (barrels, tons, etc.), price, heat content

(Btu's per ton, etc.), and on the electricity generated therefrom. Like the other accounting records of electric utilities, these data are maintained monthly, and they are available typically within fifteen to forty-five days after the end of each month for use in the calculation of interim fuel cost changes.

Q. WHY HAVE REGULATORY COMMISSIONS ADOPTED ECR AND FAC INTERIM RATE ADJUSTMENT PROCEDURES?

A. Before approving a utility's request for a rate increase, commissions generally institute an investigation and hearing into the need for higher rates. This process of investigation, known as a general rate case, involves the presentation of testimony and other evidence by the utility company, arguing its need for the higher rates. Supportive or opposing testimony may also be submitted by the staff of the commission and by intervenors, such as the state's consumer advocate or the utility's large customers.

After all the parties to the rate case have been heard and cross-examined, the commission examines the complete record of the proceeding and renders its decision with respect to the proposed rate change. The

commission may accept the proposed rates as filed; reject them entirely, thus continuing the old rates in effect; or, as is usually the case, permit the utility to increase its rates by some part of the total amount originally requested.

Each general rate investigation is a major undertaking for a public utility commission, and it generally extends over a period of at least several months. The substantial effort and time required for a general rate investigation are needed in part to satisfy the procedural requirement that the interested parties (including the company, the commission staff, and any intervenors who wish to participate) all have adequate opportunity to prepare their evidence and arguments and to be heard. Even more important than the procedural requirements are the scope and complexity of the issues that may be considered in a general rate investigation.

Because of the complexity and length of a complete general rate investigation, new rates, once established, are likely to remain in effect for at least a full year before they are superseded by the final decision that may result from the next succeeding rate investigation. In times of rapidly changing electric

utility costs, the time required for a complete general rate investigation can result in "regulatory lag" -- that is, rates which reflect cost circumstances as perceived at the time of the last rate case but out of line with current cost conditions.

In an effort to reduce the potential for regulatory lag resulting from the time and complexity of complete general rate investigations, interim adjustment procedures have been used to change electric utility rates between complete general rate investigations. The purpose of these interim adjustment procedures is to permit prompt changes in electric utility rate levels, in accord with changes in some of the more volatile cost elements, without the necessity of a complete rate investigation.

Q. HOW DO FAC OR ECR CLAUSES TYPICALLY WORK?

A. The use of these interim rate adjustment procedures involves three steps:

(1) Determination of the specific fuel and purchased power cost elements for which interim adjustments are to be made.

(2) From time to time, as changes in these costs occur, determination of the dollar impact of these cost changes on the total cost of service.

(3) Translation of the total cost change into a rate change of an amount sufficient to effect an appropriate revenue change.

Consequences Of An ECR

Q. WHAT ARE THE PRACTICAL CONSEQUENCES OF IMPLEMENTING INTERIM RATE ADJUSTMENT PROCEDURES SUCH AS AN ECR OR FAC?

A. Because they focus on only some of the many elements in the total cost of service for an electric utility, and because they do not involve any consideration of rate structure, these procedures permit prompt and more frequent adjustment of electric utility rate levels, in response to changes in the costs on which they are focused, than is possible in complete rate investigations. This advantage has the following consequences:

- If the costs subject to interim adjustment are moving in the same direction as the total cost of the utility, then the interim adjustment process helps keep the overall rate level in touch with the total cost level of the utility, and therefore it reduces the needed frequency of complete rate investigations.

- If the interim adjustment process permits regulatory resources to be concentrated on those cost elements that are large, highly volatile, or otherwise important, it conserves resources that would otherwise be used for repeated study in complete rate investigations of other cost elements not requiring such frequent regulatory attention.

- ECR or FAC procedures permit prompt rate adjustment at times when extremely large changes in one or another of the factors determining fuel costs make some interim adjustment in the rate level essential.

Q. WHAT IS THE RELEVANCE OF THESE CONSEQUENCES?

A. The first two consequences of using an interim rate adjustment process are simply procedural benefits. They are not glamorous, but they reduce regulatory lag. The third consequence is relevant only in extreme circumstances such as dramatic fuel price increases. In such circumstances, an immediate rate increase may be essential. Of course, fuel cost circumstances are no longer what they were in the 1970's. Recently, fuel costs have declined. Also, as new generating plants with lower fuel costs come on line, fuel costs will tend to fall. From a cost recovery point of view, the need for ECR or FAC procedures have diminished.

Disadvantages Of An ECR

Q. ARE THERE POSSIBLE DISADVANTAGES OF ECR OR FAC PROCEDURES?

A. Yes. Against the possible advantages of ECR or FAC procedures, there are also a number of disadvantages:

- Since interim rate adjustments are based upon consideration of some, but not all, of the costs of an electric utility, it is possible for the rate adjustments to go in one direction while total costs are moving in the other direction. This result is obviously worse than no interim rate adjustment at all.

- Interim adjustment procedures may be biased to register changes in those cost elements that are most subject to increase, without registering the offsetting factors, such as productivity improvement, that reduce total cost increases. (In principle, the opposite bias could also be found, but in fact it has not appeared to be a problem.)

- Interim adjustments may tend to weaken incentives.

- Interim adjustment procedures may distort incentives.

- Interim adjustment procedures, especially automatic ones, have been and may continue to be subject to abuse by the utilities to which they apply.

When a comprehensive fuel and purchased power cost adjustment procedure is used, the rate level is adjusted to reflect the actual total cost of fuel and purchased power per kilowatt-hour of electricity sold. This arrangement insures that an earmarked part of total revenue will equal fuel and purchased power costs; but this is no guarantee that the total revenues, including the base rates not subjected to interim adjustment, will correspond exactly with the total cost of service. Rates subject to comprehensive fuel and purchased power cost adjustments will move in accord with the total cost of service if and only if the changes in fuel costs -- including those resulting from changes in heat rates and in the loss factor, as well as those resulting from changes in fuel prices and the generation mix -- are the dominant factors in total cost changes. In periods when rapidly changing fuel costs have dominated total cost changes, it has been volatile fuel prices that were the dominant factor, rather than the generation mix or other aspects of total fuel costs. This suggests that comprehensive fuel adjustments confer little or no advantage over fuel price adjustments in the most important circumstances.

Q. WHAT IS THE MOST SERIOUS DISADVANTAGE OF A COMPREHENSIVE ECR OR FAC THAT REFLECTS GENERATION MIX CHANGES AS WELL AS FUEL PRICES?

A. The key disadvantage of a comprehensive fuel and purchased power cost adjustment procedure is that it could both weaken and distort the incentives for cost minimization. With this type of fuel adjustment procedure in effect, a utility may have no financial incentive to economize on the use of fuel, when to do so would require the expenditure of money on any other resource. The reason is the obvious one that fuel costs can be recovered immediately and in full; whereas variations in expenditure on other costs cannot be recovered at all, except to the extent that they occur within a period that becomes the test-year for a future general rate investigation. In contrast, an adjustment only for changes in fuel prices, but using the base-period fuel quantities per kilowatt-hour, does not permit the utility to recover the cost of using more fuel or more expensive types of generation in relation to the total kilowatt-hours sold.

Q. WHEN AN ECR IS IMPLEMENTED, COULD THERE BE ANY BENEFIT TO ALLOWING UTILITIES TO ADJUST CUSTOMER BILLS AFTER

THE END OF THE BILLING PERIOD TO COMPENSATE FOR FUEL CLAUSE REVENUE COLLECTIONS THAT EXCEEDED OR FELL SHORT OF ACTUAL FUEL COSTS?

A. Whether or not to allow a true-up after the billing period depends on whether it is deemed more important to equate revenues and cost or to encourage efficiency. Assuming that base-fuel costs are not overstated to begin with, rather than a true-up it is probably more beneficial to institute an ECR or FAC procedure, such as this Commission's prescribed ECR for PECO, that permits only a partial cost change passthrough.

Elements of Fuel and Purchased Power Costs

Q. WHAT ARE THE ELEMENTS OF FUEL AND PURCHASED POWER COST?

A. A utility's total fuel and purchased power expense depends upon four factors:

(1) the prices that it pays for fuel and purchased power;

(2) the quantity of electricity required to be generated;

(3) the quantities of fuel that must be burned in each of the utility's plants to generate one kilowatt-hour of electricity (these quantities are called the "heat rates"); and

(4) the proportions in which the total requirement for electricity is provided by the different generating plants and purchases (called the "generation mix").

The importance of fuel prices and power requirements is obvious, but factors (3) and (4) deserve some brief comment.

Q. WHY ARE HEAT RATES IMPORTANT?

A. Heat rates are important for two reasons. First, the heat rate is the technical efficiency of a generating plant in converting fuel into electric energy. A lower heat rate, meaning less fuel used per kilowatt-hour of electricity, corresponds to greater efficiency and to reduced fuel expense. Second, heat rates are important because they are not the same at all generating plants. Newer plants generally have lower heat rates than older ones, although the environmental policies of the past decade have slowed the rate of improvement. Also, generating units used for peaking purposes, such as gas turbines, generally have higher rates than baseload units, which are more efficient. The existence of

these differences in heat rates is one reason why the generation mix is important.

Q. PLEASE ELABORATE ON THE IMPORTANCE OF GENERATION MIX.

A. If costs were the same for all fuel purchases and if the fuel cost per kilowatt-hour were the same for all generating plants on a utility's system, the total fuel and purchased power cost would not depend upon which plants were used to generate the required total amount of electricity. But the fuel cost per kilowatt-hour is not the same at all plants. Hydroelectric plants have zero fuel cost, though their use is obviously limited by the available water. Nuclear plants have much lower fuel costs per kilowatt-hour than fossil-fuel plants (but much higher capital costs) because current nuclear fuel prices are much lower than fossil-fuel prices for the equivalent amount of heat energy. And even among fossil-fuel plants, fuel costs differ because of differences in fuel prices and heat rates. Prices are different for the different types of fuels -- coal, oil and natural gas -- and also because of differences in transportation cost and sulfur content, among other factors.

Since fuel costs per kilowatt-hour are different at different plants, a utility can reduce its total fuel cost by obtaining more electricity from plants with lower fuel costs per kilowatt-hour, and less electricity from plants with higher fuel costs per kilowatt-hour. In this way, the generation mix can have an important effect on total fuel costs.

Q. WHEN DO FUEL COSTS PER KWH CHANGE?

A. Fuel and purchased power cost per kilowatt-hour changes whenever fuel prices, loads, generation mix or heat rates change.

Fuel prices depend largely upon the fuel markets, and as such they are subject to variability, often unexpected. They may also depend upon the fuel purchasing practices of the utility, because contract terms are different from spot prices. In times of unexpectedly rapid fuel price inflation, fuel prices may also depend upon how aggressively utilities seek to enforce their contractual rights in the face of refusals of suppliers to deliver. Some utilities also purchase fuel from affiliates, and thus they may exercise some control over these prices.

Heat rates are more in the control of the utilities than fuel prices, but the heat rate for a single generating unit usually changes very little, except when modifications to the plant are made for environmental or other reasons.

Q. IS THE GENERATION MIX AN IMPORTANT VARIABLE AFFECTING FUEL COSTS PER KILOWATT HOUR?

A. Yes. Fuel costs range from zero for hydroelectric power up to 5 cents or more per Kwh for fossil generation. Among the factors that affect the generation mix, and through it the average fuel cost per kilowatt-hour, three are extremely important:

(a) hydrologic conditions affecting the availability of water for hydroelectric power;

(b) unavailability or restricted availability of existing nuclear units, owing to refueling, maintenance, or safety requirements; and,

(c) outages, especially for unscheduled maintenance for large, efficient baseload steam generating units.

When more water than usual is available, fuel costs go down; when less water is available, they go up. When nuclear and efficient fossil-fired plants are avail-

ments for those factors most responsible for increasing total costs, such as inflation in the prices of the inputs they purchase; whereas consumer groups are likely to want consideration of those factors that tend to reduce costs or offset inflation, such as improvements in productivity. To make the interim adjustment process work effectively, it would be appropriate for a regulatory commission to establish and enforce a firm policy defining the cost factors that may be considered in this process. If the commission chooses not to do so, interim adjustment proceedings could become complete rate investigations, and they will no longer serve the purpose for which they were designed.

Types Of ECR Rate Adjustments

Q. WHAT TYPES OF FUEL ADJUSTMENT PROCEDURES ARE USUALLY IMPLEMENTED?

A. There are two major types of fuel adjustment procedures that have gained wide acceptance:

- fuel price adjustments, in which rate changes are made to correspond only to the impact of fuel price changes on total fuel costs, disregarding the

impact of the other elements of total fuel costs; and

- fuel cost adjustments, in which rate adjustments are made to correspond to the full amount of the change in total fuel cost per kilowatt-hour of electricity sales, however that fuel cost change may occur.

Q. WHAT IS A FUEL PRICE ADJUSTMENT PROCEDURE?

A. In a typical fuel price adjustment procedure, the price of all electricity sales is adjusted upward or downward by a fixed amount (in mills per kilowatt-hour) for each unit change in the price of fuel (typically measured in cents per million Btu's). For example, a utility may have a retail fuel adjustment clause in which the rate is adjusted by, say, 1/10 mill (.01 cents) per kilowatt-hour for each increase or decrease of 1 cent per million Btu in the cost of fuel to the generating stations that supply it with electricity. The proper size of the fixed adjustment factor in this case depends upon the generating mix, heat rates, and loss factor of the utility in question; and it is ordinarily determined with reference to the base period conditions of these factors, usually those observed in the test year of the rate case in which the fuel adjustment procedure is established.

Q. WHAT IS A FUEL COST ADJUSTMENT PROCEDURE?

A. In a typical fuel cost adjustment procedure, the size of the rate adjustment is simply the change in the total fuel cost per kilowatt-hour of sales from the base level embodied in the base rates to the current period. Fuel cost changes may occur even without fuel price changes -- for example, as a result of changes in generation mix.

Generation Mix Changes

Q. ARE YOU DESCRIBING A NUCLEAR PERFORMANCE STANDARD THAT ELIMINATES AUTOMATIC FUEL COST ADJUSTMENTS IF COST INCREASES ARE ATTRIBUTABLE TO AN UNSATISFACTORY NUCLEAR OPERATING LEVEL?

A. Yes. The advantage of not letting the fuel cost adjustment reflect changes in the generation mix that occur when nuclear plant operation drops to an unreasonably low level is that the incentives for minimizing total short-run operating costs are preserved with the same strength that they have when there is no fuel adjustment at all. Since the adjustment to the utility's rates will not depend upon

the quantities of fossil fuel used to make up for poor nuclear performance, there is no financial incentive for the utility to treat fuel usage decisions differently than it would if there were no fuel adjustment at all. Beyond the established performance band, rates would not be increased on account of increased fuel expenditures due to increased fuel use; and, therefore, the utility gains no financial advantage by substituting fuel outlays for outlays on other inputs to the production of electricity.

Q. ARE FUEL PRICE ADJUSTMENTS OR FUEL COST ADJUSTMENTS MOST CLOSELY ASSOCIATED WITH ACTUAL GENERATING COST CHANGES?

A. Since changes in the generation mix may be the cause of the greatest amount of change in total fuel costs per kilowatt-hour, especially when fuel prices are relatively stable, rate level adjustments that reflect the impact of these changes are likely to be much more closely coordinated with changes in average fuel costs per kilowatt-hour than rate level changes reflecting only adjustments for fuel prices. This matching has a certain philosophical appeal, but closer inspection

suggests several important questions about its validity as a principle of public utility regulation.

Q. PLEASE EXPLAIN.

A. Fuel costs are only one of several cost components for electric utilities, and the merit of changing utility rates in accord with fuel costs changes is therefore dependent upon other costs remaining more-or-less constant, at least with respect to the factors that cause changes in fuel costs. As a practical matter, however, it is not valid to assume that other cost factors will not change. There are numerous opportunities for utility management to make substitutions between fuel and other inputs to the production of electricity. Changes in the quantity and therefore the expenditure on fuel may be inversely related to changes in the use of other productive resources, and it is inappropriate for regulatory policy to reflect the change in fuel expenditure in the rate level without also reflecting the offsetting changes in expenditure on other inputs. In addition to the important equity considerations of this policy, its effects on incentives may be strongly adverse. The utility has no financial incentive to economize on its use of fuel, if

these fuel savings depend upon the expenditure of other resources, because the cost of additional fuel can be passed on immediately to ratepayers, whereas the costs of other resources cannot.

Consider several examples of the reasons why changes in the generation mix occur. First, suppose that these changes are due to changes in the availability of the various plants that a utility can use for generating electricity. If the change in availability is due to scheduled maintenance, or to the normal seasonal variation in hydrologic conditions, it is incorrect to reflect this change in plant availability in rates if, as is usually the case, these normal and expected variations in availability are (as usual) already taken into account in computing base rates. If the change in generation mix is due to the addition or retirement of generating units, then it is also incorrect for the rates to reflect fuel cost differences due to this change in generation mix. The addition of a large new nuclear generating facility will reduce the average fuel cost of power production, because the fuel cost component of nuclear generation is much lower than the fuel cost of fossil-fuel generation. However, it does not necessarily follow that the total cost of nuclear

generation is less than the total cost of fossil-fuel power, and it is therefore incorrect to assume that rates will be lower simply because more nuclear generation is available. If there have been major changes in the utility's plant structure, there may have been major changes in all of the components of the utility's costs. Rate changes should therefore be based upon a full rate investigation, including analysis of the rate base, and not merely on changes in the fuel component of total costs per kilowatt-hour.

Q. WHAT ABOUT CHANGES THAT OCCUR BECAUSE OF UNFORESEEN OUTAGES?

A. Changes in the generation mix can, of course, result from unscheduled plant outages. If these outages are completely beyond the control of the utility's management, and if they have a substantial effect on the utility's fuel cost, then it has been argued that these cost effects should be passed on to ratepayers. However, it is unlikely that plant outages are completely beyond management control. In the competitive sectors of the American economy, each business bears the costs of its own operational failures and difficulties because it cannot include in its prices the

costs of production problems more severe than those experienced by its competitors. There is always a risk of encountering such difficulties, and that is one of the reasons why common equity costs and returns exceed risk-free capital costs. This discipline of competition is one of the most important goals to productive efficiency, and there is no reason why it should not also be applied to public utilities to the maximum extent possible.

If changes in the generation mix are <u>not</u> reflected in the rates, then a utility with unusually severe operational problems must bear the costs of these problems, at least until the next rate case, when it can attempt to convince its regulatory commission that these operational difficulties are a proper part of its cost and therefore its rate level. Conversely, a utility with an unusually good operating record will be able to earn greater profits than one whose track record is less satisfactory. These arrangements may be the best incentives for good operational performance. Thus, the elimination of ECR and FAC procedures entirely is a legitimate regulatory consideration, especially in periods like the present when fuel price

volatility is not expected to cause serious financial difficulties.

Incentive Considerations

Q. IS A PARTIAL FUEL COST RECOVERY MECHANISM PREFERABLE TO A COMPLETE COST RECOVERY?

A. The principal reason for permitting a partial -- but not complete -- inclusion of a fuel price or cost change in an interim adjustment to the rate level is that interim fuel adjustments are neither entirely good nor entirely bad. If a utility is required to exclude some fraction (say 20%) of its calculated fuel cost change from its rates, then most of the benefits that result from interim fuel cost adjustments are still being realized. At the same time, some of the incentives that depend upon the fixity of rates are also present, because some of the additional costs or cost savings that result from changes in fuel expenditures are borne by the utility. For this reason, the allowance of a rate level adjustment equal only to a percentage of the calculated change in fuel costs can be viewed as an incentive factor.

Q. WHY IS AN INCENTIVE FACTOR OF THIS TYPE AN IMPORTANT CONSIDERATION IN DESIGNING AN ECR PROCEDURE?

A. The argument for an incentive factor is based primarily on the proposition that public utility regulation has been and seems likely to remain an art rather than an exact science. Public utilities are far too complex for regulatory agencies to maintain rates at levels exactly equal to what costs currently are, and it is even more difficult for regulatory agencies to ensure continuously that costs are what they should be. Since rates can only be established in a zone of reasonableness, it is unrealistic to argue that monthly rate changes must be made exactly equal to monthly changes in fuel costs. An incentive factor of 80% is likely to provide most of the benefits of a fuel adjustment procedure, namely extension of time during which the divergence between rates and costs is kept within a zone of reasonableness, and it may add an important element to the rate design. Stronger incentives (i.e., lower percentage factors) may also be desirable; but once there is at least a significant incentive factor, it remains for the judgment of the regulatory agency to determine whether the benefits of stronger incentives are or are not outweighed by the possibility that

revenues will fail to keep pace with costs in a time of unsettled fuel prices.

Q. ARE THERE PARTICULAR CIRCUMSTANCES UNDER WHICH A STRONG INCENTIVE FACTOR IS ESPECIALLY IMPORTANT?

A. Yes. The need for a strong incentive factor is greater with a comprehensive fuel and purchased power adjustment procedure than it is with an adjustment procedure based only upon fuel price changes. The reason is that the fuel price adjustment procedure preserves most of the incentives for efficient management of fuel and other resources in the short-run, whereas comprehensive fuel cost adjustment procedures do not. Both approaches can dilute the incentive for the utility to obtain the lowest possible prices for its fuel.

Q. IS IT YOUR TESTIMONY THAT IT CAN BE A STRONG INCENTIVE FOR COST MINIMIZATION IF THE RATES OF A UTILITY ARE FIXED IN A MANNER THAT DOES NOT AUTOMATICALLY TRACK ALL COSTS ACTUALLY INCURRED BY THE UTILITY?

A. Yes. Such an approach could permit the shareholders to obtain some benefit from any cost savings that can be

achieved through improved productivity and efficiency, and it forces them to bear at least some of the consequences of cost overruns. At the same time, this approach could protect ratepayers from some of the cost consequences of managerial failure. Since the ratepayers derive no benefit from cost savings until they are eventually reflected in lower rates, and since an electric utility may be unable to continue to provide adequate service if it is not eventually compensated for its actual costs, periodic rate adjustments in general rate cases should eventually reflect newly attained cost levels and encourage further efficiency. One of the most important areas for informed judgment by regulatory authorities is in achieving an appropriate balance between performance incentives, which are strongest with fixed rates, and the reflection of performance results through changes in the rate level.

Q. IN WHAT WAY COULD ECRS DILUTE EFFICIENCY INCENTIVES?

A. Both fuel adjustment approaches distort the incentives for planning investments to achieve the minimum-cost combination of fuel and capital. However, a utility achieves only a diminution of risks, not an absolute

increase in its profits, by building generating plant with lower capital cost but higher fuel use. The reason is that the consequences of these investment decisions are established at the time the plant is built, and the cost -- both for fuel and for plant -- are reflected in base rates established in complete rate cases. If a utility's investment decisions result in higher fuel costs and lower expenditure for other inputs to the production of electricity, the utility does not need an interim adjustment to recover these higher fuel costs. All interim fuel adjustments do is protect the utility against the risk of unforeseen increases in fuel costs, thus reducing the risk associated with a fuel-intensive investment policy. Correspondly, use of generating plant with lower capital costs reduces the risk associated with regulatory lag in regard to the determination of base rates; but this also reduces the benefits that utilities realize when regulatory lag works in their favor.

Summary

Q. PLEASE SUMMARIZE THE POTENTIAL DRAWBACKS OF FUEL ADJUSTMENT CLAUSES.

A. The first problem with interim adjustment procedures is that they are concerned only with some, but not all, of the total costs of an electric utility; and there is no assurance that the costs for which adjustments are made must necessarily be moving in the same direction as total costs. If the costs for which interim adjustments are made go in one direction, while total costs go in the other, then the interim adjustment process will cause the costs and rate level to diverge faster than they would if there were no interim adjustments. For example, during periods when fuel costs fall but the total costs of electricity supply continue to rise, the operation of interim fuel adjustment procedures exaggerates the lag of the rate level behind rising costs. Thus, interim adjustment procedures are not always helpful in keeping rate levels aligned with total costs.

A second potential problem with interim adjustment procedures is that they may be biased to register changes in those cost elements that are most subject to increase, but not to reflect factors that may tend to make costs decrease. For example, automatic adjustment clauses have in the past been designed to register fuel prices, taxes, and wage rates, but they have given

little attention to productivity or efficiency. So long as there are any improvements at all in productivity and efficiency, average costs will increase less rapidly than the prices of the inputs that a utility buys. An interim adjustment procedure that comprehensively registers inflation in the prices of the inputs bought and used by a utility, but that does not reflect productivity and efficiency gains, will overstate the upward movement of costs. In times when productivity gains and improvements in efficiency come rapidly but the rate of price inflation is relatively slow, as in much of the 1950's and 1960's, unit costs of electricity may actually be falling despite the existence of modest inflation.

The third problem with interim adjustment procedures is that they tend to weaken the incentives for a utility to supply electricity at minimum cost. If the rate level is fixed, then it is the shareholders who stand to gain or lose the full amount of any cost savings or increases, at least until the next rate case, when the rate level is reset to the then prevailing cost level. If, instead, there are interim adjustment procedures to change the rate level quickly in response to cost changes, then these gains and losses are shifted very

quickly to the ratepayers; and management has less incentive to minimize costs than when the benefits go to the shareholders.

Q. PLEASE SUMMARIZE WHY AN INTERIM FUEL PRICE ADJUSTMENT MAY REDUCE THE INCENTIVE FOR A UTILITY TO MINIMIZE THE PRICES THAT IT PAYS FOR FUEL (AND FOR PURCHASED POWER, IF THE PRICE OF PURCHASED POWER IS ALSO ENTERED INTO THE CALCULATION OF THE ADJUSTMENT).

A. When markets for fuel are unsettled, it can be argued that there is considerable scope for aggressive action by utilities to seek lower priced fuel supplies. But if interim fuel price adjustments permit utilities to pass on fuel price increases to ratepayers, and also require utilities to pass on any fuel price savings, then the incentives for management aggressiveness in this regard can be reduced. For example, during the last decade many electric utilities agreed to renegotiation of their long-term contracts for coal and oil, thus allowing fuel prices to increase. Since it is extremely difficult for a regulatory authority to investigate in detail the circumstances of each such renegotiation, to determine whether in fact the electric utility had no practical option but to accept

fuel prices higher than those specified in its existing contract, the need for financial incentives affecting the utility is emphasized. If fuel adjustment clauses did not allow the utilities to pass on the higher fuel prices to the ratepayers promptly (or not at all until the next rate case), then perhaps they might have behaved differently in dealing with their fuel suppliers.

Q. ARE THERE ADDITIONAL DISADVANTAGES OF INTERIM FUEL COST ADJUSTMENT CLAUSES?

A. Yes. The final disadvantage of interim adjustment procedures, especially automatic ones, is that in some instances, the process has been badly designed, yet still received the regulatory approval necessary for its use. In other instances it is possible for a utility to misstate the facts that control the fuel cost adjustment process. With regard to the latter problem, the solution is increased vigilance by the regulatory authority. Especially in instances such as the present, where ECRs are based on forecasted fuel costs, careful regulatory scrutiny is essential. It is now generally recognized that interim adjustment procedures are not a device for abdication of regula-

tory responsibility, as they may sometimes have been in the past, but rather are a device enabling the regulatory authorities to focus their attention on those costs that are changing most rapidly and therefore are most in need of careful review.

II. Integrating the ECR and Nuclear Performance Incentive Standard

Q. CAN THE ECR APPROACH THAT THE COMMISSION HAS PRESCRIBED FOR PECO BE INTEGRATED WITH YOUR NUCLEAR PLANT PERFORMANCE INCENTIVE PROPOSAL?

A. Yes; it can. Because the nuclear operating performance incentive that I have proposed would essentially disallow the recovery of increased fuel or purchased power costs for replacement power if nuclear plant operations fall below the specified operating minimum (and provide for partial fuel savings retention at superior operating levels), my incentive proposal can be readily incorporated into the prescribed ECR method. The end result would be an ECR which provides for no recovery of increased fuel costs that result if nuclear plant operating levels drop below a 60 percent capacity factor and 80 percent recovery of all other fuel cost increases. Conversely, if fuel costs decline because nuclear plants operate at a capacity factor in excess of 70 percent, one half of those cost savings would be retained by the Company as would 20 percent of all other fuel cost reductions. This proposed division of nuclear performance related energy cost over or under

collections between PECO and its customers is portrayed graphically in Exhibit___(J.W.-21). As described more fully below, these reconciliation percentages for nuclear related fuel costs could be combined with other energy cost reconciliations so that:

(1) the Commission's prescribed 80/20 split between customers and the Company applied to energy cost variations attributable to nuclear operating levels within the 60 to 70 percent capacity factor range;

(2) a 50/50 split applied to energy cost reductions attributable to nuclear operating levels above 70 percent;

(3) the Company absorbed all energy cost increases attributable to nuclear operating levels below 60 percent; and

(4) the 80/20 split applied to all other under or over collections.

Q. PLEASE DESCRIBE THE FUNDAMENTAL OPERATION OF THE PRESCRIBED ECR.

A. The prescribed ECR involves a two step process: (1) developing forecasted fuel costs and (2) providing for the appropriate treatment of differences between actual and forecasted fuel costs.

Q. PLEASE DESCRIBE THIS TWO STEP PROCESS AND EXPLAIN HOW IT COULD BE MODIFIED TO ACCOMMODATE YOUR PROPOSED NUCLEAR PERFORMANCE STANDARD.

A. The first step is the development of forecasted fuel costs for a 12 month period. This forecast is based on three considerations:

- Electricity Generation Requirements,
- Generating Plant Mix, and
- Fuel Prices.

In order to forecast fuel costs, I suggest that a target capacity factor be specified by the Commission for nuclear units that PECO have the burden of specifying and justifying the projected output levels of other generation resources as well as fuel prices and total generation requirements. A target capacity factor of 65 percent would appear to be reasonable in this case as it represents the midpoint of the proposed 60-70 percent nuclear operating band. Projected fuel costs per kwh could then be calculated directly from these total output, fuel price and generation mix estimates. This procedure need not be modified to accommodate the proposed nuclear operating efficiency incentive plan.

The second step concerns the regulatory treatment of subsequent differences between forecasted and actual fuel costs. Under the prescribed ECR, 80 percent of net over or under collections would be subject to reconciliation and the remaining 20 percent would either be retained or borne by the Company as an efficiency incentive. To accommodate the proposed nuclear operating efficiency incentive plan, I suggest that this step be modified as described above so that there is no reconciliation for fuel cost increases attributable to nuclear plant capacity factors below 60 percent and only a 50 percent reconciliation for fuel cost reductions attributable to nuclear plant capacity factors above 70 percent. Thus, there would be no modification to the 80/20 split if nuclear plants (as a group) operate in the 60 to 70 percent capacity factor range. However, if nuclear plant performance either exceeds a 70 percent capacity factor or falls below 60 percent, the percentage of total over or under collections to be reconciled would be less than 80 percent.

Q. ARE THERE ANY QUALIFICATIONS OR OTHER CONSIDERATIONS IN THIS REGARD WHICH SHOULD BE CALLED TO THE COMMISSION'S ATTENTION?

A. Yes. It is possible, though perhaps not likely, that the energy cost impact of exceptionally good or bad nuclear performance (e.g., an average annual capacity factor above 70 percent or below 60 percent) may be offset by other factors such as fuel price charges or fossil plant performance to such an extent that the unreconciled under (or over) collection attributable to nuclear performance exceeded the total energy cost under (or over) collection. In that event, the Commission may wish to limit unreconciled energy cost under (or over) collections to no more than the total under (or over) collection. Thus, if nuclear operations fall to 55 percent, resulting in, say, $50 million more fossil fuel costs than would have been required with a 60 percent nuclear capacity factor and $80 million more than at 65 percent, but, at the same time, fossil fuel price reductions saved $100 million, there would be an energy cost over collection despite poor nuclear plant performance. Yet, despite a net over collection of $20 million in this illustration, a $36 million revenue deficiency would be imposed (i.e., $50 million plus 20 percent of $30 million less 20 percent of $100 million) if unreconciled amounts were not limited by total under (or over) collections as suggested above. By establishing the total net under (or over) recovery as a

limit, even if management is confronted with exceptionally poor nuclear operating circumstances, it will still have a strong incentive to attain maximum efficiency in other energy cost areas.

Q. IN WHAT WAY COULD PECO'S ENERGY COST RATE FACTOR BE MODIFIED TO IMPLEMENT THIS INCENTIVE ECR APPROACH?

A. First, the definition of "F" could be amended so as to include the following paragraph:

> The generation mix used to compute estimated energy-related costs should be based on an average annual capacity factor of 65 percent for all nuclear units owned individually or jointly by the Company. The remainder of the forecasted generation mix shall reflect efficient management, operation and dispatch of the Company's generation resources. This non-nuclear generation mix, as well as all forecasted fuel prices and load forecasts used by the Company in computing F must be fully supported and justified by the Company in each ECR filing.

Q. ARE THERE ADDITIONAL MODIFICATIONS THAT COULD BE MADE TO THE ENERGY COST RATE FACTOR?

A. Yes. I recommend that the definition of "E" (i.e., the reconciliation factor) in the ECR formula be amended so as to accommodate both the 80/20 split as prescribed by

the Commission and my proposed nuclear plant performance incentive. I would suggest the following language in this regard:

> Experienced net under or over collections of the cost of energy as of the end of the twelve month period shall (1) be subject to an 80 percent reconciliation, except that (2) any over collections as a result of the Company achieving an annual average nuclear capacity factor of more than 70 percent shall be subject to a 50 percent reconciliation, or (3) any under collections as a result of the Company achieving an annual average nuclear capacity factor of less than 60 percent shall be subject to no reconciliation; provided that the total net unreconciled amount [(1) plus (2) or (1) plus (3)] shall not exceed the total net under or over collection.

In addition to these major amendments, I would also urge the Commission to provide adequate time between an ECR filing and the implementation of rates. In order for the incentive system described above to be effective, the cost forecasts on which the system is based must be reasonable. An adequate period should be established for the Commission Staff and other parties to fully evaluate these forecasts and to present their views and evidence for the Commission's consideration. In my opinion, a period of at least 90 days should be provided for this purpose.

Also, I would urge the Commission to consider replacing the "firm" wholesale sales exclusion in the definitions of F and S_t with a "unit" wholesale sales exclusion. Except for unit sales, which typically involve an entitlement to the output of a specific generating plant, wholesale sales are not generally specifically attributable to particular generating units or to particular levels of system dispatch. As such, if this exclusion were applied to non-unit wholesale sales, it would likely require arbitrary energy cost assignments that could be manipulated to achieve a distorted end result. If there are other overriding considerations which the Commission determines require the exclusion of all firm wholesale sales from this computation, care should be taken in all ECR proceedings to assure that arbitrary wholesale cost assignments do not distort the end result.

Finally I would emphasize that under an ECR approach that is based on projections, it is critically essential for the Commission to assure that the load forecasts, projected fuel prices and assumed generation mix that determine forecasted fuel costs are reasonable and reflect efficient operations. If any of these factors is subject to unreasonable manipulations or

assumptions in developing forecasted fuel costs, the efficiency incentive that is incorporated by providing for only partial reconciliation will be undermined and/or distorted.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY ON THE ECR ISSUES IN THIS CASE?

A. Yes; it does.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-850152
	)	
Philadelphia Electric Company	)	

EXHIBITS ACCOMPANYING THE TESTIMONY

OF

DR. JOHN W. WILSON

February 1986

GEC Statement No. 1C

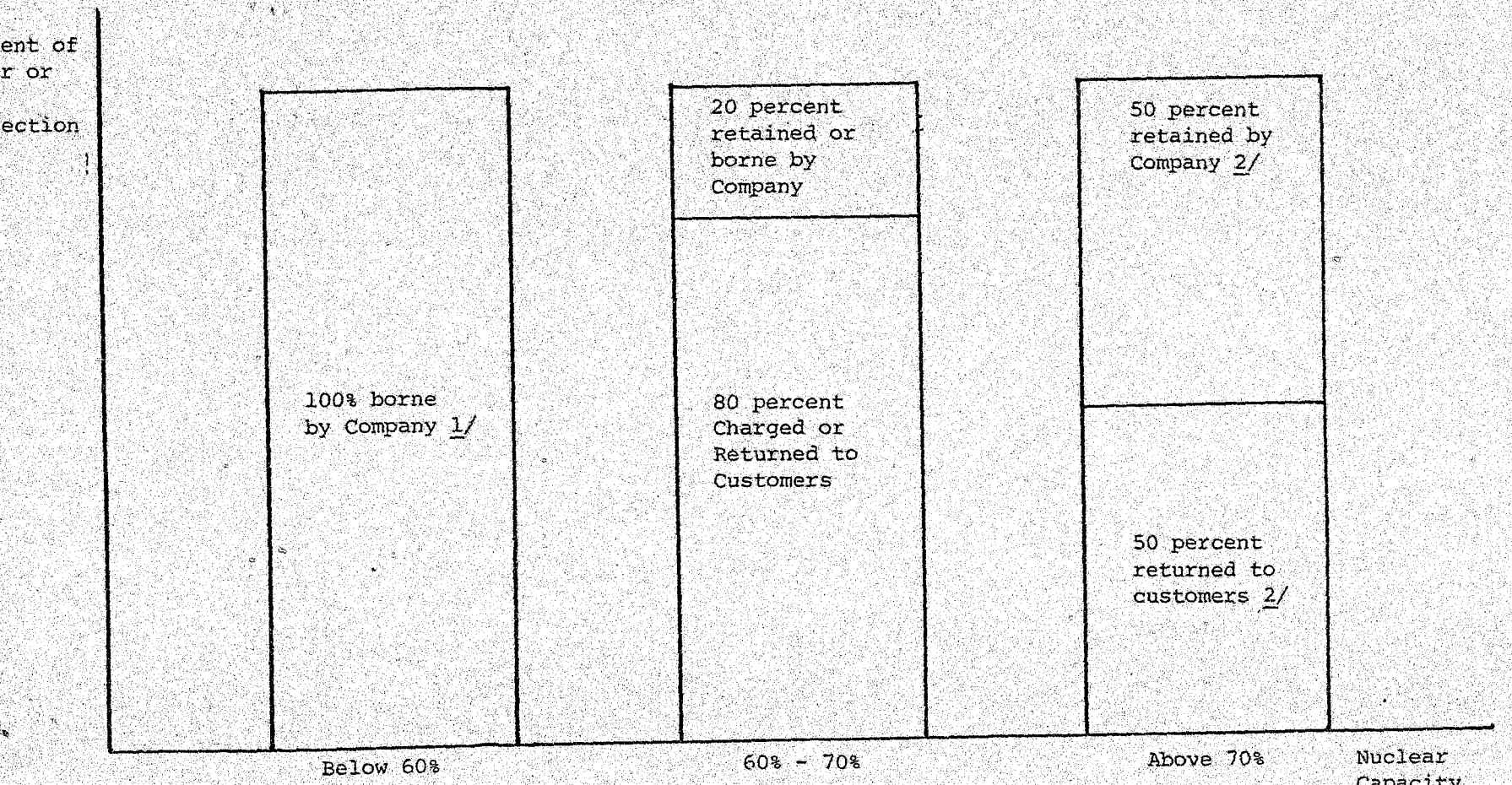
J. W. WILSON & ASSOCIATES, INC.

ECONOMIC COUNSEL

THIRD FLOOR • WATERGATE OFFICE BUILDING

2600 VIRGINIA AVENUE, N.W. • WASHINGTON, D.C. 20037

Division of Nuclear Performance Related Energy
Cost Over or Under Collections Between
Customers and Company



/ 100% applies only to the difference between actual energy costs and what energy cost would have been with a 60 percent nuclear capacity factor.

/ 50% applies only to the difference between actual energy costs and what energy cost would have been with a 70 percent nuclear capacity factor.

Docket No. R-850152
Exhibit ___ (J.W.-21)
Page 1 of 1

CASE NAME PUC, et al. vs. Philadelphia Electric Company

HEARING LOCATION Philadelphia, PA.

HEARING DATE February 4, 1986

ALJ Matuschak

Hearing held YES ✓ NO

Testimony taken YES NO

Hearing concluded YES NO

Further hearing needed YES ✓ NO

Estimated add'l days

RECORD CLOSED YES NO ✓ Date

Briefs to be filed YES the conclusion of case Date

BENCH DECISION YES NO

REMARKS:

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DOCKET MAR 3 1986

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ALJ HEARING REPORT

DOCKET NO. R-850152

CASE NAME PUC, et al. vs. Philadelphia Electric Company

HEARING LOCATION Doylestown, PA.

HEARING DATE February 3, 1986

ALJ Matuschak

CHECK THOSE BLOCKS WHICH APPLY:

Hearing held YES ✓ NO

Testimony taken YES NO

Hearing concluded YES NO

Further hearing needed YES ✓ NO

Estimated add'l days

RECORD CLOSED YES Date NO ✓

Briefs to be filed YES Date NO

at conclusion of case

BENCH DECISION YES NO

REMARKS:

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FEB 7 1986

SECRETARY'S OFFICE
Public Utility Commission

February 5, 1986

Mr. Jerry Rich, Secretary
Pennsylvania Public Utility Commission
North Office Building
Commonwealth and North Streets
Harrisburg, Pennsylvania 17120

RE: Pennsylvania Public Utility Commission
v. Philadelphia Electric Company
Docket No. R-850152

Dear Secretary Rich:

Enclosed for filing with the Commission please find the original and nine copies of Petition of Consumers Education and Protective Association, et al for Commission Review and Answer A Material Question in the above captioned docket.

As shown on the attached Certificate of Service, I have today served copies of this document on all Active Parties.

Sincerely,

John Hanger

John Hanger
Attorney for
Consumers Education and Protective Association, Association of Community Organizations For Reform Now, Action Alliance of Senior Citizens, Philadelphia Citizens In Action, Mr. Bradshaw

DOCUMENT
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JH/md

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FEB 7 1986

SECRETARY'S OFFICE
Public Utility Commission

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION :

v. : DOCKET NO. R-850152

PHILADELPHIA ELECTRIC COMPANY :

PETITION OF CONSUMERS
EDUCATION AND PROTECTIVE ASSOCIATION, et al
FOR COMMISSION REVIEW AND ANSWER A MATERIAL QUESTION

DOCUMENT FOLDER

JOHN HANGER
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CONSUMERS EDUCATION AND
PROTECTIVE ASSOCIATION;
ACTION ALLIANCE OF SENIOR CITIZENS;
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ORGANIZATIONS FOR REFORM NOW;
MR. BRADSHAW

Community Legal Services, Inc.
3638 North Broad Street
Philadelphia, PA. 19140

DOCKETED
FEB 10 1986

NOW COME CONSUMERS EDUCATION AND PROTECTIVE ASSOCIATION, et al (CEPA), pursuant to Section 5.302 of the Commission's Regulations (52 Pa. Code Section 5.302), and Petition your Honorable Commission to interlocutory review and answer a material question. The material question for which this Petition seeks Commission review and answer has arisen as a result of an ALJ ruling denying CEPA, et al's application for a subpoena for Joseph Farrell, Director, Bureau of Consumer Services, Pennsylvania Public Utility Commisson, or his designee to testify with requested documents at the rebuttal phase of the hearings in this case. This ruling denies petitioners access to a witness that, by virtue of his position with the Commission, has unique and essential information which is material to petitioners' case.

The material question for which the Petition seeks Commission review and answer is the following:

> Whether intervenors may compel the production of witnesses, who, by virtue of their positions with the Commission, have unique and essential information that is material and critical to intervenors' case.

Petitioners believe that this question must be answered affirmatively if the record in this case is to be full and complete. Consequently, extraordinary circumstances require that the PUC permit this interlocutory review because:

1. PECO witnesses testified that certain programs protect low-income ratepayers from ability to pay problems and justify not adopting an essential need rate or other rate structure modification to assist low-income ratepayers. Testimony at January 7, 1986, hearing.

2. Without the issuance of a subpoena for Joseph Farrell or his designee, CEPA, et al will be seriously prejudiced, since Joseph Farrell or his designee, by virtue of their positions, have unique and essential knowledge about the effectiveness of PECO's programs to assist low-income ratepayers.

3. The Presiding Officer's ruling raises the critical policy question of whether intervenors may compel the production of witnesses, employed by the Commission, who have exclusive control of evidence material to a case.

Respectfully submitted,

John Hanger

JOHN HANGER
Attorney for CEPA, et al.

CERTIFICATE OF SERVICE

I, hereby certify that I am this fifth day of February 1986 serving by first class mail the attached Petition for Interlocutory Review upon the following:

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Energy Issues In Perspective

Savings to American Consumers from Nuclear Electricity

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SECRETARY'S OFFICE
Public Utility Commission

CONCLUSION

In the face of continuing negative financial news about a variety of new nuclear power plants it may be surprising to find that, overall, nuclear electricity saved American consumers money last year. These savings arise from the fact that the major share of the existing nuclear power plants provide less expensive electricity than either coal- or oil-fired facilities. Even when the more expensive recent additions to the nation's nuclear capacity are included for 1984, the fact that utilities were able to avoid using significant amounts of idle but available oil-fired capacity resulted in overall savings to the consumer.

a) **Nuclear electricity has, since 1973, saved American consumers between $34 and $56 billion due to lower electric rates.**

b) **In 1984, electricity from nuclear generating stations resulted in consumers saving between $1 and $4 billion compared to the costs of providing the same amount of electricity with a mix of coal- and oil-fired generation.**

SUMMARY

Each year the Atomic Industrial Forum (AIF), the commercial nuclear industry's trade association, surveys utilities to determine the average cost of producing electricity from nuclear energy, coal and oil. The surveys provide a comparison of costs for each year for regions of the country in which *all* three types of power plants operate. In every year from 1974 through 1982, nuclear electricity has been cheaper than either coal- or oil-fired electricity. In AIF's 1983 survey, coal and nuclear were found to be equal in costs per kilowatt-hour of electricity produced. And in its most recent survey, nuclear electricity for 1984 was found to be more expensive than coal-fired electricity for the first time. (AIF attributed this to construction stretchouts, high interest rates, inflation and the escalation of regulatory requirements.)

Beginning in 1983, Science Concepts, Inc. (SCI), using AIF data, has calculated the cumulative savings that have accrued to the American consumer because of the operation of nuclear power plants.

The calculations are based on the fact that nuclear electricity would most probably have been produced by a mixture of coal- and oil-fired generation in each year since 1973 if nuclear energy had not been available. (Coal, nuclear and oil accounted for 56%, 13.5% and 5% respectively of electricity produced in 1984.) It is important to note that coal and nuclear capacity is largely utilized, but that the installed oil-fired capacity is largely unused and comprises the major share of the "excess" capacity on the grid.[1]

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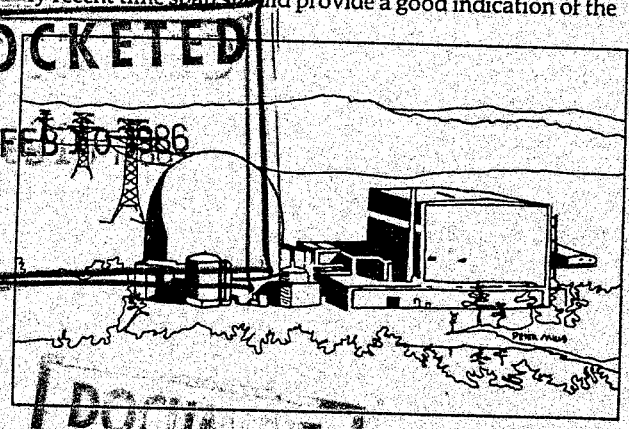

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Considering the practical extent to which coal could replace nuclear-electricity, the range of costs is based on using coal for between 50% and 75% of the replacement power. While historical trends show that utilities have typically provided about 75% of fossil-fuel electricity by burning coal, absent the nuclear option it is likely that more oil capacity would have been used (since it has been available and unused over the past decade), thus increasing oil's share of fossil-fuel generation to replace nuclear to perhaps 50% in any given year. Evidence of the abundance of unused oil-fired capacity can be seen in the fact that the oil share of fossil generation declined from 17% to 8% from 1979 to 1984 (see Table 3). (Only a small portion of this decline was due to conversions of units from oil to coal.)

The costs of replacing nuclear generation each year with a mix of coal/oil capacity have been calculated in 1984$ to take into account the effects of inflation.

METHODOLOGY

In order to determine the magnitude of the net, national financial benefit for consumers from the operation of commercial nuclear plants, it is necessary to know or estimate the following:

—the electricity produced by nuclear energy each year;
—the type of fuel that would have been used if nuclear generating stations were either unavailable or not built;
—the *extra* cost per kilowatt-hour (kwhr) associated with using fuels other than uranium to make the electricity.

There is a paucity of economic data before 1974; therefore, it is necessary to consider the savings from 1974 to 1984 inclusive for the purposes of this estimate. Of all the electricity produced by nuclear generating stations in the U.S., 2,686 billion kwhrs, or 91%, have been generated since 1973.[2] Thus, considering data over this relatively recent time span should provide a good indication of the

Science Concepts, Inc.

October 1985

actual savings throughout the history of commercial nuclear energy.

It is impossible to state with certainty which fuels would have been used if nuclear generating stations had not been available. However, it is possible to make reasonable estimates based on two general scenarios:

a) nuclear plants are shut down and replacement power is needed immediately, or;

b) nuclear plants were never built and utilities had to use some other means of generating electricity.

The first case is one that some anti-nuclear activists have stated as desirable. In this case, the replacement power would have to come from the existing reserve margin, not from new facilities. Given that the construction of adequate replacement power would probably require five to ten years, it is reasonable to assume that only the capacity already installed would have been available to replace nuclear if it had been shut down at any time. The installed and unused generating capacity that would have been available at any given time was largely oil-fired.[3] Thus, the upper bound estimate for consumer savings (because nuclear plants were not shut down) can be arrived at by calculating the additional cost to produce nuclear's share of electricity with oil for each year since 1973.

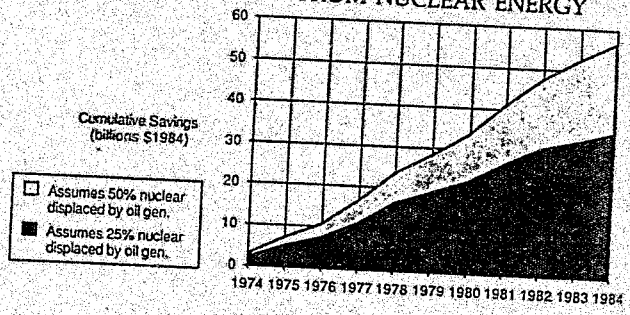
In order to determine the fuel mix for the second scenario, which assumes nuclear generating stations had never been built, one must start with a brief examination of the fuel choices utilities have actually made in the recent past.

Since 1973, the total amount of electricity produced has increased by 1.3 times.[4] During that period, the production of hydro, nuclear, and coal-fired electricity all increased while the use of oil and natural gas-fired electricity declined. Taking into account both the overall additional electricity produced, as well as the replacement power needed to make up for the reduced utilization of oil- and natural gas-fired units, hydro accounted for 3% of all new electrical generation, nuclear 28%, and coal 68%.[5]

Because of the significant absolute and relative growth in the use of coal (a doubling of coal consumption since 1973 in order to maintain about 50% of the nation's generation[6]), it is unlikely that coal would have been used to replace all of the "lost" nuclear capacity. Instead, it is highly probable that the use of oil-fired electricity would not have declined. Thus, for this second scenario, two options are considered: a) utilities would have built enough additional coal capacity to provide one-half of the electricity generated by nuclear energy, with oil providing the other half; b) utilities would have built (at most) enough additional capacity to provide 75% of the electricity generated by nuclear energy, with oil providing 25%.[7]

As a final scenario, one could assume that the ratio of coal-to-oil generation actually used since 1973 is the one utilities would have chosen to maintain in the absence of nuclear electricity. Except for the past two years (when many new coal and nuclear units have come on line, significantly reducing the need to utilize oil capacity), this scenario does not provide results significantly different from a 75/25 mix of coal/oil assumed above (see Table 3). The principal uncertainty with this scenario is that it assumes that utilities could or would have built enough additional coal capacity over this period. If utilities had been unable to finance the construction of nuclear plants over this period, it is unlikely that they could have financed the widespread construction of any significant additional large base-load generating stations (as appears to be the case today).

ECONOMIC SAVINGS FROM NUCLEAR ENERGY



THE SAVINGS

Using the assumptions just described (which provide a conservative lower bound and maximum upper bound), one can calculate the savings that have accrued to American consumers from the 2,686 billion kwhrs that were generated by nuclear since 1973 (rather than the other fuel mixes assumed above). The differences between the cost of nuclear, coal and oil-fired electricity are used for each year of generation, and the current year costs are converted into constant 1984 dollars to compensate for inflation.[8] While natural gas-fired facilities would also be used in some parts of the nation and have generally produced slightly less expensive electricity than oil-fired ones, for the sake of simplicity only oil-fired costs are considered.[9] The fact that the production of natural gas-fired electricity has changed little since 1973 would indicate that oil was the principal fuel implicitly and explicitly replaced by nuclear energy.[10] (It should be noted that coal-fired additions over this period had a large complementary, although far less controversial, role in displacing oil.)

If the 2,686 billion kwhrs of nuclear electricity produced since 1973 were replaced by existing and some new oil-fired units, the extra cost to American consumers would have been an additional $99 billion. If the entire nuclear contribution had been supplied instead by a 50/50 combination of coal- and oil-fired capacity, the extra cost of this electricity for consumers would have been an additional $56 billion. The last scenario, a 75/25 mix of coal/oil replacing nuclear, would have cost consumers an additional $34 billion (see Table 2).

The value of these savings can be placed in perspective when one considers that the nuclear stations producing these savings are generally less than 10 years old and are designed to operate for at least 30 to 40 years. Thus, lifetime savings could well exceed $200 billion.

The annual savings that will be realized by the American consumer because of the electricity produced by nuclear station-generated electricity in 1984 can be calculated in the same fashion as that outlined above. If 1984 nuclear electricity were replaced by a 50/50 mix of coal- and oil-fired capacity, it would have cost an additional $3.7 billion per year; 75/25 coal/oil replacement would yield an additional cost of $0.7 billion; and if all oil-fired capacity were to be used, the additional expense would have been about $10 billion (see Table 2).[11]

Constructing new nuclear and coal generating stations to replace existing oil (and natural gas) capacity has, overall, resulted in significant savings for consumers. However, it has also created the impression that no new capacity is needed. Putting into service new capacity over

the past decade has caused the oil-fired component of the "reserve margin"—that amount of capacity available in excess of what is in use on any given day—to be inflated, since it is oil-fired capacity that a utility will generally choose not to use. (In 1984, only about one-fourth of the installed oil-fired capability was utilized.[12]) This situation has created a need to identify two classifications for reserve margins: reliable and economic. Using excess oil-fired capacity for "peaking" or emergency situations is normal and appropriate. However, if future growth in demand for electricity is *not* met by current plans to build new coal and nuclear generating stations, it is inevitable that significant amounts of the "reserve" oil and natural gas capacity will be used. Since even current "low" oil prices are already unacceptably high for base-load electricity generation, the increased use of the oil "reserve" margin would result in higher short- and long-term costs for consumers.

OTHER ANALYSES

Two other analyses of the economic savings from nuclear energy reach conclusions similar to those contained in this report. The Energy Research Group, Inc. of Boston conducted a comprehensive "bottom up" estimation by examining each nuclear power plant for the years 1974 through 1981 and estimating the likely mix of oil and coal that would have been used in lieu of nuclear. ERG's analysis yielded an overall 75/25 coal/oil mix for replacement and arrived at a cumulative $23.5 billion savings through 1981 inclusive.[13] (This is consistent with Table 2, which shows a savings of $23.1 billion when calculated in the same 1982$, over the same period for the same fuel mix.) Similarly, ERG calculated an oil-only replacement cost of $58.6 million. (Table 2 yields $63.9 billion, in 1982$, over the same period.)

ERG used the same Atomic Industrial Forum data base for generation cost as was used in this analysis. A U.S. Department of Energy analysis used a different data base and arrived at a somewhat different conclusion.[14] The DOE report compared the savings from nuclear over coal-fired generation only, an assumption considered unrealistic for reasons described above, and used cost data different from those reported by the Atomic Industrial Forum. In determining the differences between average coal and nuclear electricity for each year, the AIF considers only those utilities that have at least a 10% interest in at least one nuclear unit.

The DOE figures for average coal and nuclear costs are derived from surveying virtually all nuclear units and coal units larger than 500-megawatts and operating after 1965. This would result in DOE's average coal-fired costs being lower than AIF's due to the fact that there are a number of regions of the country (near large coal mines

TABLE 1
COST DIFFERENCES BETWEEN VARIOUS MEANS OF ELECTRICITY PRODUCTION

Year	Cost to Produce Electricity[1] (¢/kwhr)[2] Nuclear	Coal	Oil	Cost Advantage of Nuclear over... (¢/kwhr)[2] Coal	Oil
1974	1.2*	1.76*	3.35*	0.5	2.1
1975	1.23	1.76	3.35	0.5	2.1
1976	1.5	1.8	3.5	0.3	2.0
1977	1.5	2.0	3.9	0.5	2.4
1978	1.5	2.3	4.0	0.8	2.5
1979	1.9	2.3	4.3	0.4	2.4
1980	2.3	2.5	5.4	0.2	3.1
1981	2.7	3.2	6.9	0.5	4.2
1982	3.1	3.5	7.0	0.4	3.9
1983	3.5	3.5	6.4	0	2.9
1984	4.1	3.4	7.4	−0.7	3.3

1. Average cost figures from Atomic Industrial Forum year end surveys.
2. All costs reported in current year dollars.
*For purposes of this estimate, 1974 costs are assumed to be the same as 1975 since AIF statistics provide fuel costs, not total bus bar costs for 1974. This approximation is consistent with DOE data for 1974 which shows average total nuclear and coal costs of 1.1 and 1.7¢/kwhr respectively.

TABLE 2
ANNUAL SAVINGS TO THE CONSUMER DUE TO THE ECONOMIC ADVANTAGE OF NUCLEAR ELECTRICITY COMPARED TO COAL AND OIL-FIRED ELECTRICITY

Year	Nuclear gen. billion kwhr[1]	Additional cost if nuclear generation replaced with... 100% coal (billions current year$)[2]	100% oil	Additional cost if nuclear generation replaced with... 100% coal (billions constant 1984$)[3]	75/25 coal/oil	50/50 coal/oil	100% oil
1974	114	0.6	2.4	1.2	2.0	2.9	4.7
1975	173	0.9	3.6	1.6	2.8	4.1	6.5
1976	191	0.6	3.8	1.0	2.4	3.7	6.4
1977	251	1.3	6.0	2.0	4.0	5.9	9.7
1978	276	2.2	6.9	3.3	5.1	6.9	10.3
1979	255	1.0	6.1	1.4	3.1	5.0	8.3
1980	251	0.5	7.8	0.6	2.9	5.3	9.8
1981	273	1.4	11.5	1.6	4.5	7.4	13.2
1982	283	1.1	11.0	1.2	3.9	6.6	11.9
1983	294	0	8.5	0	2.2	4.5	8.8
1984	328	−2.3	9.7	−2.3	0.7	3.7	9.7
TOTALS (billions 1984$)				12	34	56	99

1. Annual Energy Review, DOE/EIA-0384, May 1985, Published Aug. 1985.
2. Figure derived using annual differences in generation cost shown in Table 1 and total generation shown in column two above.
3. GNP deflators from 1974 to 1984 inclusive—0.55, 0.60, 0.64, 0.67, 0.72, 0.79, 0.86, 0.94, 1.00, 1.04, 1.08.

TABLE 3

ANNUAL SAVINGS TO THE CONSUMER DUE TO THE ECONOMIC ADVANTAGE OF NUCLEAR ELECTRICITY COMPARED TO COAL AND OIL-FIRED ELECTRICITY

Estimates based on replacing nuclear generation with the same oil/coal fuel mix actually used for each year.

Year	Electricity Generated (billion kwhr)[1] Coal gen.	Oil gen.	Oil/coal mix	Additional cost if nuclear gen. replaced with same oil/coal mix (billions 1984$)[2]
1974	828	301	26/74	2.2
1975	853	289	25/75	2.8
1976	944	320	25/75	2.4
1977	985	358	26/74	4.0
1978	976	365	27/73	5.3
1979	1075	304	22/78	2.9
1980	1162	246	17/83	2.2
1981	1203	206	14/86	3.2
1982	1193	147	12/88	2.5
1983	1259	144	10/90	0.9*
1984	1342	120	8/92	−1.3*
				27.0

1. Ref. 4.
2. Annual coal and oil costs from Table 2.
*Absent nuclear energy, the very low levels of oil utilization would likely have increased, thus calculations of nuclear savings (or losses) for 1983 and 1984 are unrealistically low (high).

for example) where nuclear electricity has never been considered an economically competitive option because coal is readily available and inexpensive. Including these coal costs in the average does not accurately reflect the cost differential between coal and nuclear, since nuclear would not have been built in those regions in any case and since the cheaper coal would not have been available in areas where nuclear plants are located. In order to gain a reasonably accurate assessment of the savings accrued from operating the existing nuclear generating stations, one can only compare the cost of generating electricity from the sources in those regions where nuclear is actually being used. Nonetheless, even under these unfavorable assumptions, for the period 1974 through 1980, the DOE calculations yielded a cumulative $6.2 billion savings in using nuclear energy instead of coal.[15] Over the same period, but using cost comparisons only in regions in which both coal and nuclear operated (the AIF data base used in this paper), one would estimate $11.2 billion savings over coal (see Table 2).

REFERENCES & NOTES

1. See Note 12.
2. "1984 Annual Energy Review," DOE/EIA-0384(84), April 1985; p. 171. 2,939(10⁹) kwhrs nuclear generation 1960 to 1982, 2,686 (10⁹) kwhrs (or 91% of total) from 1974 to 1984 inclusive.
3. That there is sufficient installed but unused oil-fired capacity to replace most nuclear energy is evident in the first order observation that the installed oil capability (excluding the normally idle reserve margin) that is now largely unused could produce at least 245,000 million kwhrs more than it currently does (i.e., the difference between 1978 and 1984 oil-fired electricity production). This is 75% of the entire current 1984 nuclear contribution.
4. Ref. 2, p. 171.
5. Ref. 2, p. 171; differences between 1974 and 1984 generation (in 10⁹ kwhrs) — +20 for hydro, +211 for nuclear, −23 for natural gas, −181 for oil, +513 for coal, +546 overall. Thus between 1974 and 1984 an additional 750(10⁹) kwhrs was generated to both add 546 (10⁹) kwhrs to the grid and make up for 240(10⁹) kwhrs of lost oil- and natural gas-fired generation.
6. Ref. 4, p. 171; coal supplied 47% of nation's electricity in 1970, 56% in 1984 utility coal consumption, 320 million tons in 1970, 664 million tons in 1984 = 2.1 times.
7. Some have observed that absent nuclear energy, PURPA would have provided the incentives for needed power through the construction of large numbers of small, independently-owned power plants. However, it is unlikely that more than 80,000 MW of small power facilities would have been built considering that this did not happen in any case, and the incentives existed with or without nuclear electricity. From a fuel-savings perspective, the use of PURPA-inspired power is somewhat irrelevant since the major share is (and would likely have been) natural gas- and/or oil-fired power. From a consumer perspective, the use of PURPA-inspired power is entirely irrelevant since (under the specifications in the law) it costs the consumer essentially as much as the utilities' most expensive power—utilities are required to buy PURPA power at "avoided" cost, which is generally the cost of its expensive oil-fired capacity.
8. Average oil, coal and nuclear costs from Atomic Industrial Forum annual surveys; GNP deflator to compensation for inflation from Ref. 2.
9. Utilities dependent on natural gas are moving to reduce the use of this fuel as the cost of new gas increases and old, low-priced contracts expire. In any case, the utility cost of natural gas in 1984 at $3.6 per million BTU is only 19% lower than the utility cost of oil at $4.4 per million BTU. In addition, the large unused natural gas-fired capacity (about 30,000 MW) is located primarily in different regions of the country than the idle oil units.
10. Many analyses of the role of nuclear energy in displacing oil are too simplistic (see for example "Questioning Nuclear's Contribution," *Energy Daily*, 10/11/83) seeking only to identify those regions in which oil-fired facilities have actually been shut-down due to nuclear additions. In order to assess the role of nuclear energy in both explicitly and implicitly displacing oil, one must consider three mechanisms: 1) the addition of new non-oil capacity that leads to an oil burner being turned off (explicit replacement); 2) the addition of new non-oil capacity to meet rising demand, although existing oil burners continue to be used (implicit displacement); and 3) the continued operation of existing non-oil capacity instead of utilizing available oil capacity in the "reserve" (implicit displacement). Of these three mechanisms, the latter two are not only the most important in many cases but also the most often ignored by simplistic retrospective analyses.
11. The $6 billion 50/50 coal/oil estimate for 1982 (see Table 2) is consistent with a NERA calculation (April 13, 1983 memorandum to USCEA, "Impacts of a Nuclear Shutdown"), which estimated that a shutdown of nuclear plants would result in an increase in generating costs of $117.7 billion over the 1984 to 2000 time period—an average of about $7 billion per year.
12. "Electric Power Supply & Demand 1985-1994," July 1985. North American Electric Reliability Council, total 1984 installed oil capability of 102,000 MW could produce 538(10⁹) kwhrs @ 60% capacity factor compared to actual 1984 delivery of 108(10⁹) kwhrs amounting to 20% of capability. This assumes 50% of dual-fired capability is oil-fired.
13. "An Approximate Estimate of Historical Cost Savings Resulting From the Use of Nuclear Power," Energy Research Group, Inc., June 1983.
14. D.E. Mathes, Plans and Analysis Division, Office of Nuclear Energy, U.S. Department of Energy, "Federal Subsidies and Incentives For Nuclear Power—A Perspective," Draft, March 1982.
15. Total estimate in the DOE report was given in current year dollars at $3.8 billion. This would be $6.2 billion in constant 1984 dollars.

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FEDERAL SUBSIDIES TO NUCLEAR ELECTRIC UTILITIES

In 1984: $15.66 billion, more than one third of all energy subsidies.

Utility revenues from nuclear power in 1984 were about equal to the subsidies provided.

And nuclear power provided only 1.8 percent of all U.S. energy that year.

From 1948-1980 the federal government spent close to $40 billion subsidizing nuclear power development.

At least $23 billion more in radioactive waste storage expense is expected to be incurred by the year 2000. However, the study producing these figures for the Department of Energy by Joseph Bowring in 1981 did not calculate the cost of the insurance subsidy through the Price-Anderson Act or the costs of health or environmental effects. Also not included were extensive tax subsidies to the nuclear industry for nuclear power plant construction.

Without federal subsidies, electricity from nuclear plants would be 1½ to 2 times more expensive.

Over the next decade the cumulative subsidy to nuclear power will be at least another $40 billion and perhaps as much as $100 billion. For 1986, the subsidy will be $1,211 million.

Figures from The Union of Concerned Scientists
Nuclear Hotline 1986

Electric and Nuclear Utilities

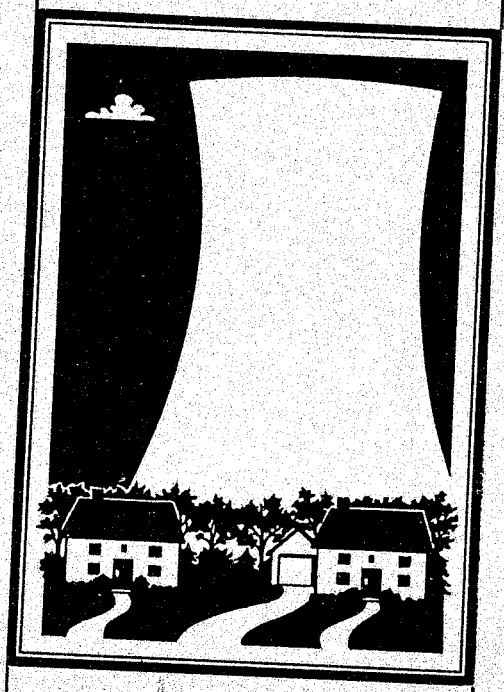
Subsidizing High Costs

Electric Utilities

Although electric utilities provided only 13 percent of the nation's energy in 1984, the industry received nearly two-thirds of federal energy subsidies. Federal support for the electric industry through agency budget outlays, tax breaks and loans in 1984 totalled $28 billion. This subsidy amounted to a "hidden cost" for every American household equivalent to $333—tax money paid each year in addition to monthly bills to support electricity generation. If current policy trends continue, that hidden cost will rise even higher.

While electricity is a versatile and highly valuable form of energy capable of powering a dazzling array of devices from electric lights to telecommunications equipment and life-saving medical scanners, it's also very specialized and expensive. About one-third of the electricity consumed today could be economically replaced by natural gas, a renewable energy source or energy efficient technologies. Heating with electricity priced at 6 cents per kilowatt hour, for example, is the same as heating with natural gas at more than three times its 1985 price. Similarly, new electricity-efficient home appliances can cut electric consumption by more than half, decreasing consumer bills and the need to subsidize more generating plants.

The bulk of federal support for electricity, about $15 billion, is in the form of tax breaks for plant construction. The cost of loans and loan guarantees, also primarily for construction, add up to about $5 billion. Another $7.4 billion not included in the total $28 billion is in the form of "phantom taxes"—money collected from consumers through utility bills in 1984 to cover utility tax payments which were deferred and not paid to the federal government. Companies involved in electricity production also receive a kind of "double-dip" benefit—once from the subsidies for the production of oil, gas, coal and uranium—and on the other side from subsidies for construction of plants to burn these fuels.



The heavy support of electric utilities is tied to a short-term rationale that hiding the costs and providing the illusion of low cost electricity helps to spur manufacturing and production.[23] For the long term, the subsidies are tied to a strategy to electrify the economy.[24]

In the United States, as in most countries, electrification has enjoyed a special place in government priorities. The Edison Electric Institute, an association of the nation's 219 private power companies, promotes a future of mass automation of factories, proliferation of electric cars, and widespread construction of climate-controlled shopping areas and electrically heated homes. [25] Under the assumption that this kind of development will alleviate dependence on fossil fuels and improve the quality of life and U.S. industrial competition in world markets, the federal government has tacitly accepted the electrified vision of the future.

Renewable energy advocates such as Amory Lovins have argued before Congress that energy efficiency and renewable power production with present technologies have the potential to reduce electric demand dramatically and improve the quality of life at a lower cost and with less environmental risk. Doug Bauer of the Edison Electric Institute doesn't agree that efficiency and renewable energy can meet the nation's growth in electricity needs. He and other industry leaders claim that hundreds of new centralized power plants are needed.

In the spring of 1985, Department of Energy officials appeared before a Senate committee predicting the need for as many as 580 new coal and nuclear plants by the year 2000. Cost estimates for such a building program run more than two trillion dollars—an amount larger than the entire national debt.[26] Given the power surpluses of the mid-1980s, the rising bills that would be delivered to consumers and the immense capital that would be needed from

Wall Street, the plan is not likely to progress very far.

The federal commitment to the electrified vision of the future, however, has frozen energy policy-making and is likely to stretch out and deepen the current structure of subsidies. Under the Reagan Administration's "Treasury II" tax reform plan the corporate taxes currently paid by electric utilities would be decreased by half. According to the Energy Information Administration the $66.3 billion tax liability for the period of 1986-1995 would be cut to $33.9 billion.[27]

The result is that electricity will probably continue to receive the largest portion of the federal energy subsidy—distorting competition with more efficient energy sources. As the electrification strategy stalls, it will also create an increasing dependence on fossil fuels, deepening U.S. reliance on foreign energy supplies and raising consumer costs, manufacturing prices and trade deficits.

The questions that surround the electrification strategy and how an annual federal subsidy of $28 billion or $333 per household might be better spent are especially pertinent to nuclear power, which receives more than half of the subsidy for electric utilities.

Federal Subsidies to Electric Utilities
(fiscal year 1984; billions of 1984 dollars)

nuclear electric	$15.56 billion
fossil electric	5.63 billion
fuel subsidy	3.80 billion
hydro electric	2.36 billion
renewable sources	0.65 billion
total	**$28.00 billion**

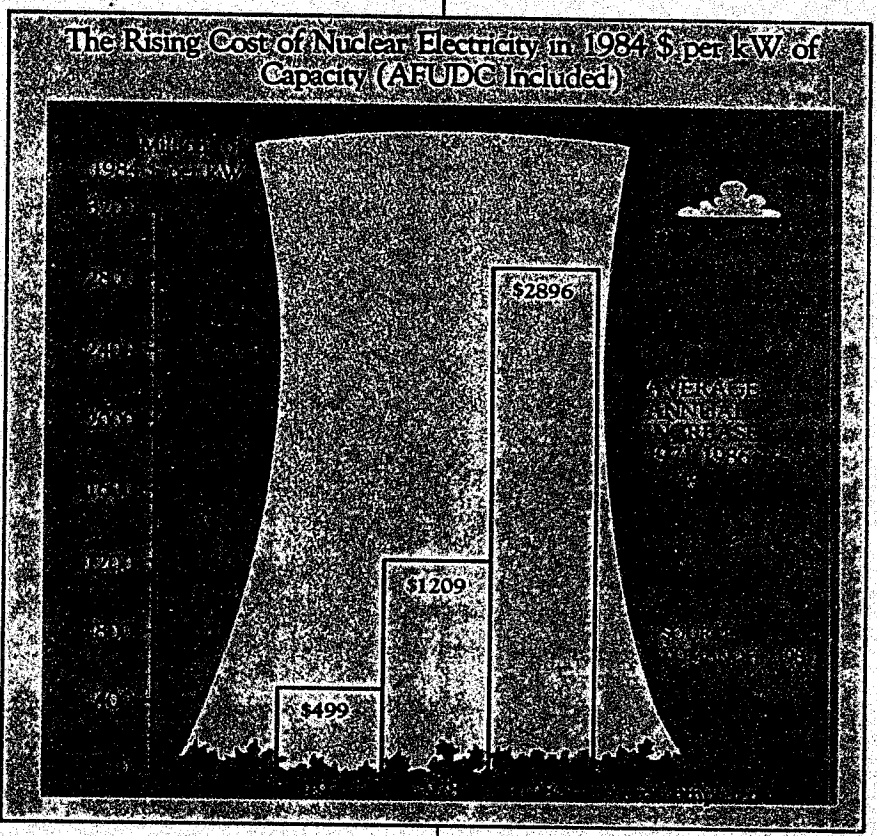
Nuclear

The popular perception is that nuclear power is "dead." It still lives on in the columns of federal balance sheets, however, and has been given a central role in the scheme of replacing oil and electrifying the economy. Taxpayers gave $15.6 billion in nuclear subsidies in 1984, more than one-third of all energy subsidies—an amount equal to $185 per household.[28] Utility revenues from nuclear power in 1984 were about equal to the subsidies provided.[29] The economic collapse of the nuclear industry over the last four years has borne out the charges of critics that boiling water in a nuclear reactor is not an economical method to produce energy.

Energy economist Joseph Bowring conducted a study for the Department of Energy in 1981 which found that from 1948-1980 the federal government had spent close to $40 billion subsidizing nuclear power development.[30] At least $23 billion more in radioactive waste storage expense was expected to be incurred by the year 2000. Bowring made no effort to calculate the cost of the insurance subsidy through the Price-Anderson Act or the costs of health or environmental effects. Nor were extensive tax subsidies to the nuclear industry for nuclear power plant construction included.

Based on the actual dollar allocations, Bowring conservatively concluded that without federal subsidy, electricity from nuclear plants would be one-and-one-half to two times more expensive. More recent estimates calculate electricity from new nuclear plants costing three times as much as the power from oil-fired plants.

The generous subsidies for construction in the 1970s coupled with lax regulation created an atmosphere in which the industry undertook massive nuclear construction projects. Huge power surpluses, cost



overruns and cancellation of partially completed plants resulted. Environmental Action Foundation estimated that the 49 nuclear plants under construction in 1984 would ultimately cost consumers $191 billion more in electric bills than power from other sources.[31] To cover the costs of many of the cancelled plants, consumers are expected to pay rising rates for electricity they will never receive. Additionally, it's assumed that as much as one-third of more than $40 billion of debt for cancelled plants will be written off against federal taxes.[32]

Over the next decade the cumulative subsidy to nuclear power will be at least an additional $40 billion and perhaps as much as $100 billion. Unanswered questions concern the costs of decommissioning, waste transport, and perpetual storage of wastes. These problems will levy an additional hidden cost on consumers.

Although nuclear power received more than $15 billion in annual subsidy in 1984, it produced barely one-third the end-use energy provided by non-hydro renewable energy sources. Hydropower, with one-seventh the money given to nuclear power, provided an equal amount of electricity.[33]

Despite the fact that the economics of nuclear power have soured, federal policy toward nuclear power has not changed. As with expansion of electric utilities in general, an influential core of energy leaders remains committed to nuclear technology, and government subsidy continues intact. At the behest of President Reagan, Department of Energy officials are planning the "second coming" of nuclear power for the 1990s. As part of the forecast for hundreds of new nuclear and coal plants, administration staff are working to streamline licensing and provide advance approval of reactor design to limit opportunities for citizen intervention and speed construction timelines.[34]

Even if only a portion of the forecast for two trillion dollars in new plants is undertaken it will absorb capital which could be used by competing energy sources to produce more energy at less cost and less risk. The construction would also help to freeze the subsidies in place for a longer period of time by extending the commitment to electrification of the economy. As a small indication of the commitment to this policy, for fiscal year 1986, the federal budget outlay for nuclear power will increase.[35]

Federal Subsidies to Nuclear
(fiscal year 1984; billions of 1984 dollars)

ACRS	$3.45 billion
ITC	1.43 billion
Expensing of interest	2.99 billion
Tax-exempt pollution-control bonding	0.73 billion
Tax-exempt publicly-owned utility bonding	1.24 billion
Other tax expenditures	0.11 billion
Agency outlays	2.28 billion
Loans and guarantees	3.32 billion
Total	$15.56 billion

EAF Releases New Phantom Tax Study

Utility Overcharges Mount to $41.5 Billion

Electric utilities overcharged their customers by a record $7.4 billion for federal income taxes last year, boosting the industry's reserve of unpaid, or "phantom," taxes to more than $41 billion. Utilities charged customers $10.6 billion for 1984 federal income taxes, but only reported owing $3.2 billion to the IRS according to EAF's latest study, *Electric Utility Phantom Taxes—1984*.

With the addition of last year's phantom tax charges, utilities are now holding at least $41.5 billion in unpaid income taxes they have collected from ratepayers since 1954. That is the equivalent of almost $500 for every household in the nation. This reserve amount can serve as a "slush fund" for new investments such as power plants.

For the first time, Pacific Gas & Electric led the nation's utilities with a phenomenal tax overcharge of $526 million. PG&E claimed a *refund* of $29 million from the IRS, but charged its customers as if it had paid $497 million in federal income taxes. Southern California Edison followed PG&E with a $435 million tax overcharge. Commonwealth Edison, last year's leader, fell to third place with an overcharge of $402 million.

Commonwealth Edison alone is now holding more than $2 billion in accummulated deferred taxes and tax credits. Eight other utilities each hold more than $1 billion in unpaid taxes.

On a per-customer basis, the utility with the largest reserve of unpaid taxes over the last 30 years is Public Service Co. of Indiana. PSI's unpaid income taxes collected from residential customers alone (about one third of the total) add up to $580 per customer. Other utilities with large per-customer reserves of unpaid taxes are Carolina Power & Light ($448) and Tampa Electric ($382).

Phantom taxes cost the average residential ratepayer more than $100 each year—$34 directly in utility charges, and another $67 indirectly, in higher prices for goods and services charged by industrial and commercial customers who also pay phantom taxes.

The "double charge" of phantom taxes means heavy payments for some ratepayers. Residential customers of Arizona Public Service bear the largest phantom tax burden: approximately $202 last year alone. Alabama Power customers paid $149 for phantom taxes, Toledo Edison's customers shelled out $148, and Public Service Electric & Gas's customers paid $146.

The Phantom Tax 'Top Ten'— 1984

Phantom Taxes

	(millions)
1. Pacific Gas & Electric Co. (Calif.)	$525.5
2. Southern California Edison Co. (Calif.)	435.4
3. Commonwealth Edison Co. (Ill.)	401.5
4. Alabama Power Co. (Ala.)	233.8
5. Public Service Electric & Gas Co. (N.J.)	233.7
6. Florida Power & Light Co. (Fla.)	206.4
7. Philadelphia Electric Co. (Pa.)	198.3
8. Long Island Lighting Co. (N.Y.)	180.9
9. Houston Lighting & Power Co. (Texas)	176.7
10. Pennsylvania Power & Light Co. (Pa.)	171.7

Accumulated Deferred Taxes and Tax Credits

	(millions)
1. Commonwealth Edison Co. (Ill.)	$2,135.7
2. Florida Power & LIght Co. (Fla.)	1,630.8
3. Georgia Power Co. (Ga.)	1,402.3
4. Public Service Electric & Gas Co. (N.J.)	1,355.0
5. Duke Power Co. (N.C., S.C.)	1,292.9
6. Texas Utilities Electric Co. (Texas)	1,121.4
7. Alabama Power Co. (Ala.)	1,075.0
8. Houston Lighting & Power Co. (Texas)	1,033.7
9. Carolina Power & Light Co. (N.C., S.C.)	1,000.9
10. Pacific Gas & Electric Co. (Calif.)	969.2

Phantom Taxes Per Residential Customer

(Direct and Indirect)	
1. Arizona Public Service Co. (Ariz.)	$202.47
2. Alabama Power Co. (Ala.)	149.43
3. Toledo Edison Co. (Ohio)	148.07
4. Public Service Co. of Ind., Inc. (Ind.)	146.16
5. Long Island Lighting Co. (N.Y.)	144.45
6. Kansas Gas & Electric Co. (Kan.)	143.55
7. S.C. Electric & Gas Co. Co. (S.C.)	140.27
8. Ind. & Mich. Electric Co. (Ind., Mich.)	139.50
9. Carolina Power & Light Co. (N.C., S.C.)	138.80
10. Pennsylvania Power & Light Co. (Pa.)	138.71

Accumulated Deferred Taxes and Tax Credits Per Residential Customer

1. Public Service Co. of Ind., Inc. (Ind.)	$580.27
2. Carolina Power & Light Co. (N.C., S.C.)	447.99
3. Tampa Electric & Light Co. (Fla.)	381.60
4. Alabama Power Co. (Ala.)	377.58
5. Florida Power Corp. (Fla.)	375.84
6. Florida Power & Light Co. (Fla.)	374.58
7. Duke Power Co. (N.C., S.C.)	356.32
8. Otter Tail Power Co. (Minn., N.D., S.D.)	351.42
9. South Carolina Electric & Gas Co. (S.C.)	347.72
10. Southwestern Electric Power Co. (Ark., La., Tx.)	340.39

These tax overcharges and consequent phantom taxes result from a clause in the federal tax code that requires utilities to treat taxes using "normalized" accounting procedures; i.e. to receive large federal tax breaks without reflecting these benefits in rates charged to customers. The federal law preempts state regulators' authority to halt tax overcharges. The Reagan administration's Treasury II tax simplification plan would retain both the normalized accounting procedures and most of the utility industry's tax breaks. (See related story, this page.)

Electric Utility Phantom Taxes—1984, *includes an analysis of the impact Treasury II would have on the energy industry, and tax overcharge figures for 125 of the largest electric utilities. Copies are available from EAF, 1525 New Hampshire Ave. N.W., Washington, D.C. 20036 for $5 to citizens and grassroots groups, $10 to publicly-funded institutions, and $25 to businesses.*

ronment Doesn't Live Up to Its Reputation

The New York Times/Tim Knox

the Phoenix
ade Up of Smog

metropolitan area, now about 1.6 million, will jump 55 percent in the next 15 years, to 2.6 million.

Two recent developments have encouraged the continuation of the rapid growth. After years of planning and construction, a multibillion-dollar aqueduct, the Central Arizona Project, began delivering additional water to the city from the Rocky Mountains. Meanwhile, energy costs have begun to decline. They rose so rapidly during the 1970's that they threatened to make air conditioning, so vital to life in the desert, prohibitive.

But there is more and more evidence that Phoenix is paying a high price for its growth. In the view of many urban planners, the city seems to be making many of the same mistakes Los Angeles made decades ago, creating a low density sprawl of freeways and shopping malls that is at once dependent upon and victimized by the automobile. The city has no mass transit system to speak of, and as its borders expand it is becoming increasingly common for residents to drive an hour or more to work on increasingly overloaded highways.

"There's a lot of concern about traffic and congestion," said Eric Anderson, executive vice president of Mountain West Research, a Phoenix company that has studied local growth.

As evidence, he noted that more than 70 percent of the county's voters had recently agreed to increase the local sales tax a half-cent to finance a 20-year highway building program. In time, he said, new roads will help, but for now many retired people are leaving the metropolitan area because it is "too congested, too crowded" and has "too much crime."

A few days ago, in a speech to the Legislature that began his final year in office, Gov. Bruce Babbitt proposed a comprehensive plan to deal with mounting concerns about pollution. "We must recognize," he said, "that the quality of our air is poised to replace the availability of water as the major restraint on our growth."

But his plan drew a quick rebuff from several legislative leaders who saw Mr. Babbitt's proposal as "posturing" for the Eastern press.

That reaction recalled the response to a 1982 opinion survey in which local business leaders expressed the belief that "the quality of life which drew people to Phoenix" was "being threatened by serious environmental problems."

Margaret Hance, who was then Mayor, denounced the study as a "piece of outdated research" by an "Eastern-based research organization which delights in writing negative articles about Phoenix, Arizona, and the Southwest in general."

Despite such resistance, some Phoenix residents have grown increasingly willing to act.

A measure qualified by a citizens' group for the ballot this year would impose strict water quality laws. And neighborhood groups are becoming more aggressive in opposing commercial developments in residential areas.

Others, though, have given up and joined efforts to sell entire neighborhoods to developers. City officials are trying to stop that practice. But residents contend that municipal officials created the problem by allowing commercial developments to rise all around them. One Phoenix woman said recently: "The city — and only the city — destroyed these fine neighborhoods. The least they can do now is let us go."

Steve Sack
Minneapolis Star and Tribune
Tribune Company Syndicate

States and Utilities

Public Power Has Some Bright Lights

By MATTHEW L. WALD

As private utilities struggle to complete over-budget nuclear plants and press for large rate increases, some consumers have again shown an interest in public power.

In Albany, for example, New York State lawmakers are looking closely at a proposal to take over the Long Island Lighting Company, now near bankruptcy because of cost overruns and technical errors in its Shoreham Nuclear Power Station. If the transaction takes place, it will set a record for size, but according to experts in the field it will be otherwise unremarkable. How much is saved in such conversions is a more complicated issue.

Though mergers and acquisitions have caused the number of investor-owned utilities to decline steadily in the last few decades, 86.5 percent of the nation's electricity customers get their power from one of about 200 private companies.

The remaining 13.5 percent, representing a population of about 35 million, is supplied by approximately 2,200 large and small municipal or state systems.

Roughly put, the balance between territory and customers served by private and public systems has been "pretty much a wash over the past 30 years," according to Larry S. Hobart, deputy executive director of the American Public Power Association.

The United States is unusual among the industrialized democracies for the number of entities providing electricity. France and Great Britain, for example, have federalized systems, and Canada has shifted in recent years away from private companies and toward provincial suppliers.

The Association says public power's major advantage is price. Working from Department of Energy statistics, it calculates that in 1983, the last year for which figures are available, investor-owned companies charged 42.5 percent more than public ones for power. The public companies have lower costs for production, distribution, general accounting, administration and customer service, according to Mr. Hobart, losing only in transmission expenses. Many municipal authorities transmit power over lines owned by private companies, paying a toll for the privilege.

A major source of savings, often cited in the Lilco debate, is the cost of financing. Municipal power companies can sell tax-exempt bonds, and because the interest on such instruments is not subject to Federal or, in many instances, state or local tax, purchasers accept rates 2.5 to 3 percentage points lower than those available on other investments. In a capital-intensive business like generating electricity, that difference can be enormous. For a large nuclear plant, interest costs during construction can reach 30 percent of the total bill.

Taxes are another factor. According to Bruce S. Edelston, manager of economic programs at the Edison Electric Institute, the trade association of investor-owned utilities, in 1981 private companies paid 0.59 cents in taxes for each kilowatt-hour sold; government utilities paid 0.12 cents. Also, he said, in most areas the government utilities have first call on cheap supplies of hydroelectric power. Both of these differences, he said, represent a shift of costs between ratepayers and taxpayers or ratepayers of private companies and ratepayers of government utilities, but not an absolute saving.

Another major difference is that public companies are not subject to "rate shock," which can push electric rates up 25 percent or more in a single year. In most states, private utilities set aside all construction costs, plus the interest on them, until a plant is in commercial operation, then factor those costs into their rate structures all at once, generating a sudden price increase.

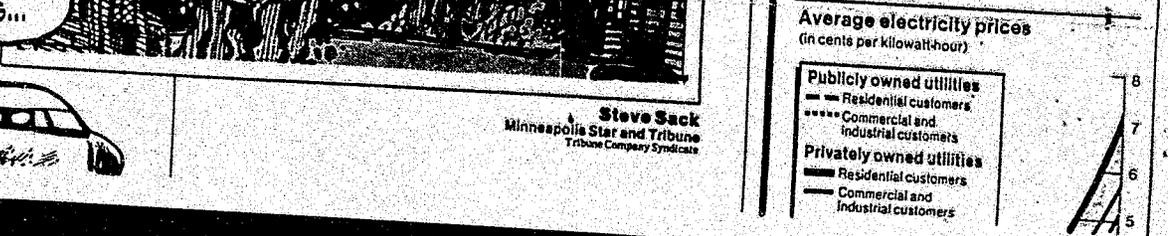
Public companies, from the Tennessee Valley Authority to tiny municipal utilities that own small shares in large generating projects, handle construction costs differently. They factor new investments into their rate structures as the investments are made, so there is no "rate shock" when a plant enters service and the utility enjoys a greater measure of fiscal stability.

Whether the public companies are better at picking sources for power is not clear. In some areas they have access to cheap hydroelectric power, but collectively they show a reliance on oil and nuclear power, two of the most expensive sources, in roughly the same proportion as private utilities. And municipal companies have been among the most enthusiastic participants in some disastrous investments, like Seabrook in New Hampshire.

"I don't think there's any monopoly on brainpower" said Mr. Hobart. "I can't say that leaders of municipals are any smarter than private executives."

The cost of power

Average electricity prices
(in cents per kilowatt-hour)



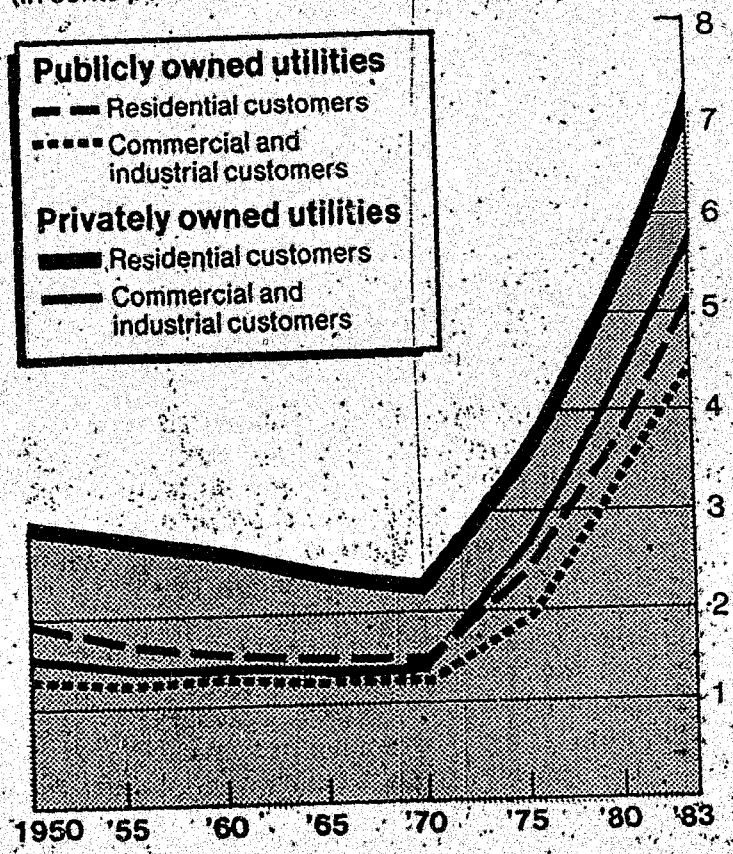
N.Y. Times

Sunday, Jan. 26, 1986

The cost of power

Average electricity prices

(in cents per kilowatt-hour)



Source: American Public Power Association

And who sells it

Type of utility	Number of systems	Meters served (in percent)
Local public systems	2,197	13.6
Private power companies	206	75.4
Rural electric cooperatives	930	11.0
Federal power agencies	12	0.01

Sources: American Public Power Association; Department of Energy; Rural Electrification Administration

CERTIFICATION: This is a true and correct copy of the original Resolution adopted by the Council of the City of Philadelphia on the twenty-ninth day of May, 1980.

President of City Council

ATTEST:

Chief Clerk of the Council

Introduced by
DAVID COHEN

Sponsored by
DAVID COHEN
AUGUSTA A. CLARK
LUCIEN E. BLACKWELL
JOSEPH E. COLEMAN
JOHN F. STREET
JOHN C. ANDERSON
BEATRICE K. CHERNOCK

COUNCIL OF THE CITY OF PHILADELPHIA
OFFICE OF THE CHIEF CLERK
ROOM 402, CITY HALL
PHILADELPHIA

(Resolution No. 169)

RESOLUTION

To cease construction of the Limerick Nuclear Reactors.

WHEREAS, On May 27, 1980, Harold Denton, director of the Office of Reactor Regulations of the Nuclear Regulatory Commission, testified at Congressional hearings in Bucks County Community College that the Limerick plant is too close to Philadelphia and the NRC may "modify or withhold" the operating license for Limerick, and

WHEREAS, The Limerick nuclear reactors under construction since 1971 are only 21 miles from Philadelphia and within a 80-mile radius of 4 million people, and

WHEREAS, Evacuation plans for Philadelphia in case of a major accident at Limerick are not feasible, and

WHEREAS, The Pennsylvania Office of the Consumer Advocate has opposed the continuation of construction of the Limerick nuclear reactors on the grounds of excess generating capacity compared with the need of Philadelphia Electric Company and the high costs, estimated at 5.6 billion dollars rather than 3.2 billion dollars estimated by Philadelphia Electric Co., and

WHEREAS, Philadelphia Electric Co. originally projected completion of Limerick I in May 1976 and Limerick II in May 1977, and now projects completion of Limerick I in 1985 and Limerick II in 1987, while costs continue to escalate, and

WHEREAS, This high cost of construction would be borne by the ratepayers of Philadelphia Electric Co. and the government, in tax investment credits of 10% and accelerated depreciation allowances, and

WHEREAS, Permanent nuclear waste disposal sites have not yet been developed or demonstrated feasible by the utilities or the government, and

WHEREAS, The United States Environmental Protection Agency has termed inadequate the projected supplies of cooling water for Limerick of 40 million gallons per day of Delaware River water, and

WHEREAS, In case of a nuclear accident at Limerick, liability insurance provided by the utilities and federal government is limited to only $560 million, less than 5% of damages estimated possible by government reports, and

WHEREAS, Psychological stress will add to the health problems of residents in Philadelphia and the surrounding areas as demonstrated in the Three Mile Island accident, now

Be It Resolved by the Council of the City of Philadelphia, That all construction cease at the Limerick nuclear reactors plants to protect the health and safety of Philadelphia residents and the ratepayers of Philadelphia Electric Co.

Resolved, Further, that certified copies of this resolution be sent to the President of the United States, the Nuclear Regulatory Commission, the Governor of Pennsylvania, all Philadelphia legislators in Harrisburg, the two U.S. Senators and Philadelphia Congressmen.

Sandia National Laboratories
PUBLIC INFORMATION DIVISION
ALBUQUERQUE, NEW MEXICO 87185
Phone: (505) 844-8065 or 844-7767

News Release

FOR IMMEDIATE RELEASE
December 12, 1985

WORLD'S MOST POWERFUL ACCELERATOR FIRED FOR THE FIRST TIME

ALBUQUERQUE, N.M. -- The world's most powerful particle accelerator -- believed to be the first machine with the potential of igniting a controlled laboratory fusion reaction -- was successfully fired for the first time here Wednesday evening (Dec. 11).

The huge 108-foot diameter machine, named PBFA-II, was designed and built at Sandia National Laboratories, lead laboratory for light ion fusion in the Department of Energy's inertial confinement fusion (ICF) program.

PBFA-II is designed to deliver at least 100 trillion watts of power. However, at least one year of development work is required before power levels of this magnitude can be attempted.

The shot, fired with its capacitor banks charged at 70 percent of capacity, occurred at 8:09 p.m. Mountain Standard Time.

"The world now has the best light-ion accelerator for inertial confinement fusion that can be built," said Pace VanDevender, Sandia Director of Pulsed Power Sciences, following the shot.

The $48 million Particle Beam Fusion Accelerator (PBFA) consists of 36 pulsed power modules that are arranged around a central experimental hub and deliver power to it from all directions.

"PBFA-II is a state of the art accelerator with 1985 technology, even though we've been building it for the past three years." said VanDevender. "We achieved that by fast-tracking the design at the same time we were constructing the accelerator. The successful first shot demonstrated that the risky fast-track process works beautifully."

(In "fast-tracking," accelerator design research continues during the construction process, making it possible to modify yet-uninstalled portions of the machine without impeding the construction process.)

The next steps are to develop a focused lithium ion beam that can deliver more than 100 trillion watts per square centimeter on a pellet a few millimeters in radius. If this proves possible, experiments to implode pea-sized fusion fuel pellets will begin in 1988. Sandia scientists believe it may be possible to achieve ignition of the deuterium-tritium pellet -- sustained release of fusion energy -- during these experiments.

Sandia National Laboratories, with facilities in Albuquerque, New Mexico, and Livermore, California, is operated for the U.S. Department of Energy by AT&T Technologies, Inc.

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encls: PBFA-II backgrounder

d57:12/3/85

The 2nd PBFA II shot was on Jan. 29, 1986

Sandia National Laboratories
PUBLIC INFORMATION DIVISION

News Release

ALBUQUERQUE, NEW MEXICO 87185
Phone: (505) 844-8065 or 844-7767

Backgrounder

PBFA II TO PRODUCE 100 TRILLION WATTS FOR FUSION ENERGY

The Particle Beam Fusion Accelerator II (PBFA II) was built by Sandia National Laboratories for use in the Department of Energy's inertial confinement fusion (ICF) program. The goal of the ICF program is to irradiate small pellets of deuterium and tritium (forms of hydrogen) with intense beams of ions from accelerators such as PBFA II or with beams of light from lasers. Ultimately these very intense beams would compress the hydrogen fuel to about 1,000 times solid density and heat it to about 100 million degrees Celsius, causing the atoms in the elements to fuse. This would produce a small thermonuclear explosion, the heat of which would be used to power a conventional turbogenerator to produce electricity. These microexplosions would be produced at the rate of several per second in a full-scale reactor.

To produce the intense pulses of energy needed to cause the atoms to fuse requires very powerful machines. PBFA II is designed to produce 100 trillion watts of power and 3.5 megajoules of energy in a pulse lasting only 50 billionths of a second. A power gain from a fast-opening switch has been demonstrated that may increase the power to 200 trillion watts. The output power of the accelerator will be several times greater than the instantaneous output of all power plants on earth. Provided the pulse of lithium ions can be sufficiently focused, the pulse is expected to be adequate for pellet ignition studies and may lead to a fusion reaction that produces more energy than has been expended to initiate it — a net energy gain.

PBFA II consists of four layers of nine modules. Each level is arrayed like the spokes of a 108-foot-diameter wheel. The modules — each consisting of a series of capacitors, switches, and transmission lines submerged in oil and water in separate sections of a 20-foot-tall tank — converge on a central hub, which is the vacuum chamber containing the Applied-B diode where the fuel pellet will be placed. Electric current passes through each module simultaneously and into the diode, producing a beam of lithium ions. Eventually this beam will be made to impact on the exterior surface of a pea-sized pellet. The pellet will contain deuterium and tritium fusion fuel.

Ion beams are very efficient, both in the conversion of electromagnetic energy provided by PBFA II to the kinetic energy of ions (80%), and in the absorption of ions by the pellet (nearly 100%).

The $48 million PBFA II was completed within budget in late 1985, more than a month ahead of schedule. Extensive pulsed power testing was conducted before completion. The first year of operation will be devoted to characterization and optimization of the accelerator. In the second year, experiments will concentrate on ion beam formation and focusing. Experiments leading to ignition of a fusion fuel pellet are scheduled to begin in 1988.

PBFA II replaces PBFA I, the "test-bed" accelerator that was capable of producing 30 trillion watts of power in a 40-billionths-of-a-second pulse. PBFA I, which went on line in June 1980, is being converted into the SATURN x-ray machine for simulation of nuclear weapon effects.

-30-

Samples of press coverage

POST
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More Powerful Fusion Reactor Successfully Fired

Major Step Taken Toward Generating Electricity

By Boyce Rensberger
Washington Post Staff Writer

A major step toward the long-sought goal of producing electricity from atomic fusion occurred late Wednesday night when the most powerful fusion reactor ever built was successfully fired at Sandia National Laboratory in New Mexico.

The device contained no nuclear fuel, but the test proved that the newly designed and built machine can perform as intended. About two years of further testing and tuning will be needed before scientists put nuclear fuel into the machine—the Particle Beam Fusion Accelerator II—and try to ignite the first controlled fusion reaction in the laboratory.

The Sandia machine represents one of two main experimental approaches to achieving controlled fusion, called inertial confinement. A rival method, called magnetic confinement and using a device called a tokamak, is under development at Princeton University.

Progress in magnetic confinement has come more slowly than expected while work on Sandia's inertial confinement method has moved faster, overtaking the older magnetic approach.

The theoretical promise of fusion power has long been attractive because, if it works, it could produce electricity using abundant forms of hydrogen as a fuel and create almost no radioactive wastes.

Unlike existing atomic power plants, which rely on the more or less spontaneous splitting, or fission, of radioactive atoms to release heat, fusion reactors would produce energy only after delivering huge pulses of power to pea-sized pellets of hydrogen fuel.

The effect of the pulse is to compress the pellet to a density perhaps a thousand times greater than normal, raising its temperature to about 100 million degrees Celsius. The result is a miniature thermonuclear explosion in which the atoms of hydrogen fuse and convert some of their subatomic particles into energy. A similar reaction occurs in a hydrogen bomb, when the pulse delivered by an atom, or fission, bomb causes the hydrogen explosion.

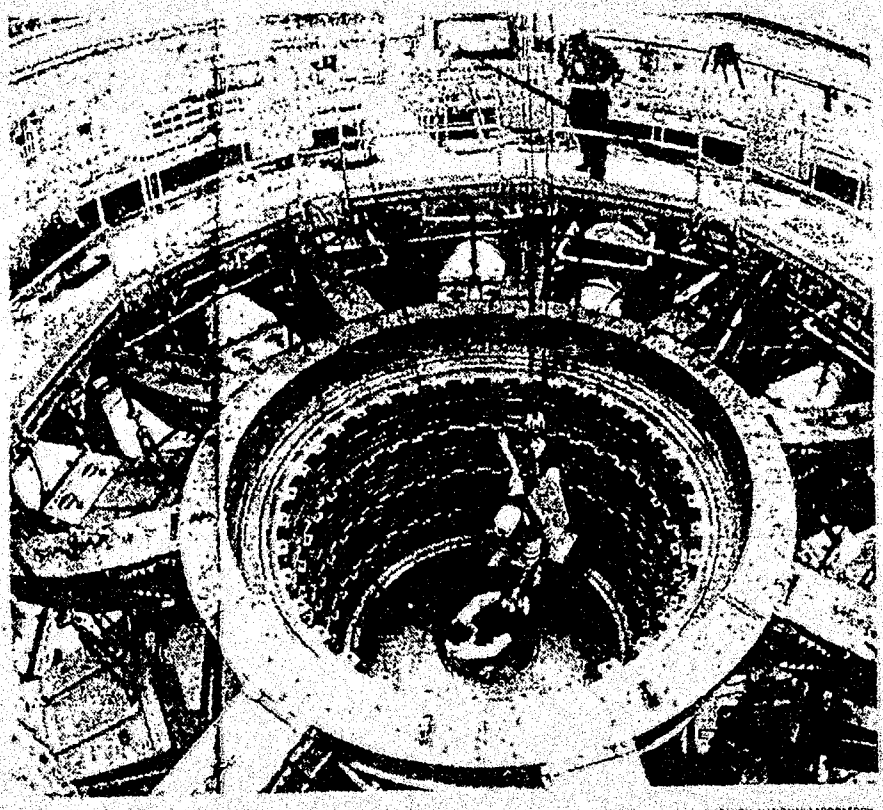
If a practical fusion reactor can be made, it would have to produce enough power to deliver the next pulse of energy to the next pellet and have enough left over to sell. It would explode a series of perhaps 10 pellets a second to sustain the heat output. As with most electrical power plants, the heat would drive steam through turbines connected to generators.

The Sandia machine is a 108-foot diameter wheel in which 36 particle accelerators, situated like spokes, deliver simultaneous pulses that [illegible] brief bursts of electrically charged lithium atoms that slam against anything at the hub. In Wednesday's test the hub was occupied not by a fuel pellet but by instruments that measured the characteristics of the pulses.

When it is fully operational, the device is expected to deliver 100 trillion watts of power at the hub for a pulse lasting about 50 billionths of a second.

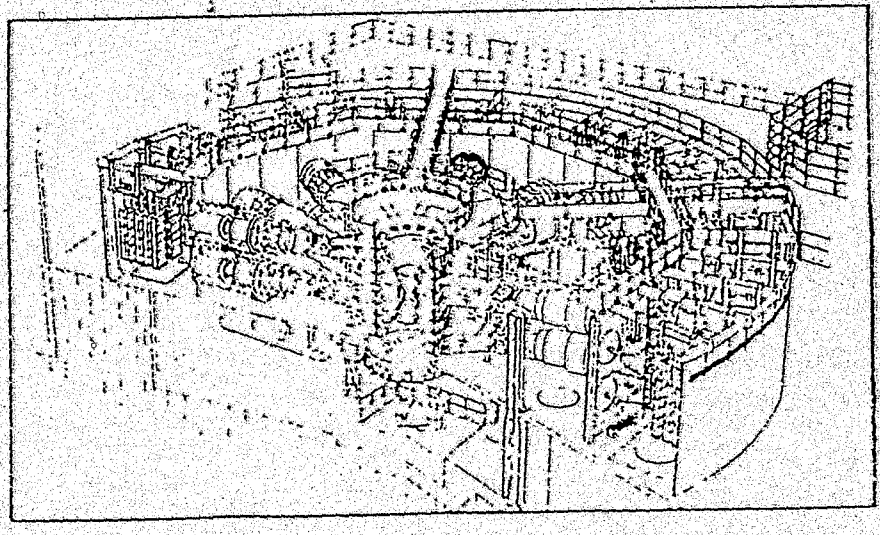
While firing, the pulse will equal 50 times the [illegible] ity. The first test was made at about 70 percent of capacity. If the Sandia reactor meets goals, the next major hurdle will require new versions of reactors that can achieve "break-even," demonstrating that controlled fusion can produce as much energy as it consumes. After that would come reactors that produce surplus energy.

Most experts say it will be decades before fusion power becomes practical. Some, recalling that similar forecasts were made decades ago, say it may never happen.



SANDIA NATIONAL LABORATORY

PBFA-II, due for two more years of testing, is shown under construction above with internal detail below.



ALBUQUERQUE, N. M.

DEC 13 1985

New Mexico Press Clipping Bureau
Albuquerque, N. M.

Fusion Scientists Hail Success Of Sandia Particle-Beam Test

By Byron Spice 292

JOURNAL SCIENCE WRITER

The successful test firing Wednesday of Sandia National Laboratories' Particle Beam Fusion Accelerator 2 doesn't mean nuclear fusion is harnessed, any more than turning on a power saw means that a house has been built.

But scientists in the fusion community have hailed the test as a milestone demonstrating the promise of the new machine.

Federal officials downplay any talk of particle beams being in competition with lasers as the means to spark controlled fusion, but observers maintain continued success with the Sandia machine could quickly make particle beams the lead technology in inertial confinement fusion.

"Certainly nobody knows clearly now which is the best," said Will Happer, a Princeton University physics professor who is chairing a National Academy of Sciences review of the U.S. inertial confinement fusion program. "But if this PBFA machine continues to have success, it could eventually put the lasers out of business."

It will be four or five years, however, before anybody can make such a judgment, Happer cautioned, "and the laser people won't be sitting on their hands either."

The morning after the first test of PBFA-2 found Sandia staff members still elated, but sobered by the thought of how much work remains ahead. The $48 million machine could well be the first to ignite a fusion reaction in a fuel pellet, but "we're a long way from that," said Pace VanDevender, director of pulsed power sciences. "It will be three years before we see if the key physics are adequate."

Fusion is the power source of the sun and thermonuclear weapons and may become a source of commercial power sometime in the next century. Its fuel — hydrogen isotopes — is cheap and abundant. Unlike today's nuclear fission reactors, fusion reactors would pose few waste disposal or radioactive release problems.

One scheme for harnessing fusion is called inertial confinement fusion — using particle beams or lasers to heat and compress a small, hydrogen-filled pellet so that the hydrogen atoms fuse and release energy.

PBFA-2 is a 110-foot diameter machine with 36 modules, each capable of producing a high-power beam of charged lithium atoms. These particle beams converge in the center of the machine and are designed to deliver a 100-trillion-watt jolt to a pea-sized fuel target.

Donald Cook, manager of fusion research, said the next nine months will be spent pushing the machine to peak performance. Researchers then will work at focusing the powerful beams — an effort that could take a year. Only then will fuel target experiments begin.

Sandia's fusion team until now has been concerned primarily with hardware. The advent of target experiments will require an expansion of the fusion program at Sandia, adding expertise in plasma physics and beam/target interactions now lacking at the lab, said Richard Schriever, director of the Department of Energy's Office of Inertial Fusion.

The DOE inertial fusion program also includes the $176 million Nova laser at Lawrence Livermore National Laboratory. Scientists at Los Alamos National Laboratory, who discovered carbon-dioxide lasers were poor drivers for fusion machines, have begun work on a krypton-fluoride laser they believe holds promise. Because inertial fusion could provide insights into the physics of nuclear weapons, DOE's inertial fusion efforts have been located at weapons labs.

Unlike existing laser devices, PBFA-2 may reach "breakeven" — generating more power through fusion than it takes to run the machine. "The machine is certainly scaled to do the job," said Ravi Sudan of the Cornell University Laboratory of Plasma Studies, which is providing technical support for the Sandia program. "A number of bases much be reached before they reach that goal. ... Sandia has a good track record for getting to the bases it projects."

Because particle beams are 10 times cheaper than lasers, many scientists have high hopes for the Sandia program, Sudan said. "It has a chance to be the ultimate system."

For the moment, however, lasers and particle beams are complementary efforts within the same program, emphasized Marshall Sluyter, pulsed power manager for DOE's inertial fusion program.

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My name is Ruth Miner. I live in Philadelphia and I am a working person, but I do not work for the Philadelphia Electric Company, except perhaps to raise money to pay my electric bills.

I am a former stockholder. When I inherited Phila. Electric Co. stock ten years ago I sold it as soon as possible because the company was building nuclear power plants, and I wrote a letter explaining my reason. Recently I telephoned a stockbroker in a well-known Philadelphia firm and asked him about PECO stocks. He said, "No stockbroker in his right mind would recommend buying Philadelphia Electric Company stocks." So nuclear power is not, at least here, considered a prudent investment.

Like other utilities, Phila. Elect. Co. was lured into the Limerick project by the Federal Government's promises of limitless power at little running expense. The government was selling fuel rods at the bargain basement price, I'm told, of $10 per gram and offering attractive subsidies in the form of tax breaks, deferments and depreciation beneffits, while requiring the utility using nuclear power to hold the United States harmless and the Atomic Energy Commission harmless in case of injuries from nuclear power. The insurance companies were not willing to gamble on the safety of nuclear power to the extent of insuring it against major accidents.

This should have made the utilities suspicious. But then Congress went so far as to underwrite the insurance for the ~~electric~~ nuclear utility companies up to a legal cap of no more than $560,000,000 per major accident--too little to cover more than a small fraction of estimated possible damage but still an incredible federal gamble with our tax money, since if a major disaster should occur Congress would probably have to go into session and appropriate more.

All this government subsidizing is being done at our expense That's our money--the taxpayers' money-- being offered to private utility owners to subsidize enterprises too risky to be insured! Think of the insurance rates they would have to be paying if they were insurable and paying for the probable risks! And if we taxpayers and ratepayers weren't providing the insurance through the Price-Anderson Act the nuclear power plants would have to close down.

The nuclear industry has been financed by the federal government to a total of more than $86 billion already. So we are paying twice for nuclear fission power, as taxpayers and as ratepayers. If we weren't subsidizing nuclear power through the federal government our electric rates would be about 1½-2 percent higher than they are. And no referendum was ever placed on our ballots to find out if we wanted to take those physical and financial risks! For 1986 the federal subsidy to nuclear power plants is $1,211 million.

I call it imprudent for the United States government to subsidize expensive nuclear fission energy for electric utilities that need evacuation plans, and I don't think we should throw any more public money, either from taxpayers or ratepayers, after what has been squandered already. I think the Philadelphia Electric Company should pay us back by cutting rates for the unjust profits it makes by charging ratepayers for phantom taxes it doesn't pay. The overcharge amounted to approximately $46.47 per residential customer in

1984 (and if we include estimated cost boosts for other services caused by this padded billing, the phantom tax that should be paid back comes to about $113.76 per residential customer, just for 1984).

Back around 1972, before the ground was broken for the Limerick reactor, there was an Atomic Energy Commission hearing at the Holiday Inn in Pottstown. (You can look it up in the Pottstown Public Library, wherethe records are on file.) At that meeting Philadelphia Electric Company experts testified under oath that even with supplemental water obtained by persuading communities along the river to relinquish their rights to some of their water volume, and even with supplemental water piped in from the Delaware River--even then the reactor would probably have to be shut down during the summer drought season for one or two months.

The PECO experts also admitted that the population density and projected growth in the area around the plant were a little higher than they would have liked.

I submit that it was clear enough at that time that building a boiling water reactor requiring 40 million gallons of river water per day was an imprudent project for the Philadelphia Electric Company to undertake under the circumstances and that we should not now have to suffer rate hikes and safety risks to pay for the company's recklessness.

On May 29, 1980, Philadelphia's City Council passed Resolution #169, stating that all construction should cease at the Limerick nuclear plants, and there were 9 reasons, all still relevant today and all ignored then by the Nuclear Regulatory Commission and the Philadelphia Electric Company:

1. The plants are only 21 miles from Philadelphia, within a 30 mile radius of 4 million people.
2. Evacuation plans for Philadelphia in case of a major accident at Limerick are not feasible.
3. The generating capacity would far exceed the need.
4. The costs of the plants, with the delays, were escalating.
5. The high cost of construction would be borne by ratepayers and the government in tax investment credits of 10 percent and accelerated depreciation allowances.
6. No permanent waste disposal sites were developed or demonstrated feasible (and they still do not exist).
7. The Environmental Protection Agency termed inadequate the projected supplies of cooling water.
8. The $560 million provided in insurance by the utilities and the government would amount to less than 5 percent of damages estimated possible by government reports.

9. Psychological stress would be added to the health problems of Philadelphia citizens.

Our citizens and officials do not want the services and risks of the Limerick power plants and furthermore cannot afford even one of them!

If the Philadelphia Electric Company can't make prudent decisions, maybe we had better look into the possibilities of publicly owned utilities, as New York is doing. The accompanying graph published by the New York Times shows that publicly owned utilities average out cheaper than those run by private companies.

The electric utilities in Great Britain and France are federalized. But even there the nuclear plants have turned out to be too expensive. According to James Harding of Friends of Earth, a study commissioned by Amici della Terra of Italy found that nuclear power is failing market tests in France, England and West Germany, as well as in the United States. Nuclear power is seriously damaging to the economy of France, which next to Brazil and Mexico is the most internationally indebted nation in the Western world. At least one fifth of France's indebtedness can be laid at the feet of its state-run nuclear industry, the study reports.

Nuclear fission power is a clumsy, temporary technology, and the Limerick nuclear plants will be obsolete probably long before they have to be decommissioned, with that enormous expense to be borne again by the ratepayers. There are new alternative sources of energy that will be available before many years have gone by. An Inquirer editorial recently reported that there has been success in converting anthracite slag heaps into clean energy. On January 24, this year, Sandia National Laboratories in Albuquerque, NM, ran a second successful test of its Pulse Beam Fusion Accelerator (PBFA-2), bringing clean nuclear fusion power closer within our reach. Photovoltaic cells are already efficiently converting sunlight into clean energy and there are firms here and abroad that are working to produce commercially viable models.

We don't want costly, obsolete nuclear reactors (of the kind banned in Great Britain because they are too dirty) standing around for an unpredictable number of years threatening the health of present and future children of the earth. Fission power is unsafe, imprudent, passé and an enormous waste of money and human suffering. We don't want it or need it and resent having its expenses foisted upon us.

Ruth Allan Miner

Statement by Ruth Allan Miner
41 West Gravers Lane
Philadelphia, PA 19118

Sources of information:

Union of Concerned Scientists reports
U.S. Goverment documents relating to the Price Anderson Act
Records of Atomic Energy Commission and Nuclear Regulatory Commission hearings

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Mother Earth News (re Amici della Terra report)
The Washington Post
The Philadelphia Inquirer
The New York Times
The Hidden Costs of Energy (published by Center for Renewable Resources,
Suite 638
1001 Connecticut Avenue
Washington, DC 20036)

Sandia National Laboratories, Albuquerque, NM 87185

Ruth Allan Miner

CONSUMERS EDUCATION & CEPA PROTECTIVE ASSOCIATION
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FEB 10 1986
SECRETARY'S OFFICE
Public Utility Commission

Statement at the Public Hearing of the Public Utility Commission
On PECO's Proposed 28% Rate Increase
Philadelphia, Pa., Tuesday, February 4, 1986
by Max Weiner, Educational Director

****

The highly technical arguments for and against this proposed rate increase are being debated at the evidentiary hearings, where CEPA is being represented by John Hanger, Esquire, of the Community Legal Services. I believe the testimony presented by CEPA's expert witnesses and the testimony of the Consumer Advocate are sufficient to show that at this time, PECO is entitled to no rate increase, or at most a small increase of 4 to 5% to account for normal inflation.

I wish to testify as an average pay-the-bill consumer, who feels, as most other residential consumers do, that I am already paying too much for electricity. I strongly object to the proposal of the Company to increase my cost by approximately 28%.

According to the rate card shown below, I am now paying 10.35 cents per kilowatt hour for my electricity.

RATE R RESIDENCE SERVICE
MONTHLY RATE TABLE

Customer Charge: $4.50 Per Month

Energy Charge Prices:

Summer Months (June through September)
10.35¢ Per KWh for the first 500 KWh per dwelling unit.
11.80¢ Per KWh for additional KWh.

Winter Months (October through May)
10.35¢ Per KWh for all KWh per dwelling unit.

The company wants to raise the cost to 13 cents per kilowatt hour, an increase of about 28%. about $20 a month, $240 a year more for me. They claim they need the money because they are bringing Limerick Unit 1. a big, new, modern nuclear plant, on line.

A few blocks from CEPA's office, at Broad Street & Stenton Avenue, there are three gas stations. If one station suddenly increased its price per gallon by 28 cents, the average consumer would buy from the other two stations. The higher-priced station would soon be out of business.

But because we have no choice when we buy electricity, because we must buy from only one company which has a monopoly granted by the state, we are to be forced to pay 28% more for the same energy for which we paid 28% less.

PECO says consumers must pay that higher price because it is running out of generating capacity which produced electricity at the old price, but at the same time we see them closing down some of the so-called "old-fashioned" plants. A coal-fired plant costs much less than a nuclear plant. Predictions that we will run out of oil may or may not come true, but in the meantime, with the cost of oil now cut in half and dropping, (the Oil Minister of Kuwait thinks prices could fall to $10 per barrel by Spring) even an oil-fired plant would cost less than a nuclear plant.

It seems they are creating an artificial shortage in order to justify their argument that they need more capacity.

If we should ask why new plants weren't built in order to produce electricity in the "old-fashioned" way at the cheaper price, we are told that they made the decision that they thought was best for us and even though their decision turned out to be wrong, we, not they, must pay for the error in judgement. I do not think this is fair. The least that should be done is to make PECO supply us with electricity at the same average cost as we have been paying.

Consumers remember when the government and utility companies first talked about nuclear power they said it would be "too cheap to meter." It turns out they were mistaken. Every time another nuclear plant was built our rates kept going up instead of going down. We know it is too late now to hold PECO to the promise of nuclear power "too cheap to meter," but at least PECO should provide electricity at the same average cost of the system prior to bringing Limerick Unit 1 on line. I think if PECO made the mistake of building a nuclear plant that costs more to produce electricity than an ordinary plant, they, and not the consumers should pay for the mistake. If PECO wasted hundreds of millions of dollars in wasteful construction, they should bear the cost, not we.

In fact, there is testimony in the record of these proceedings that the new nuclear plant is not needed, that it will be producing "excess capacity," that will not be "used and useful" in supplying electricity. This is all the more reason why PECO must be prevented from charging consumers more than the average cost of electricity prior to Limerick Unit 1

As consumers, we have to ask why PECO did not pursue an aggressive policy of conservation. There is expert testimony on record that conservation would have produced more kilowatt hours than Limerick #1 will produce - and instead of increasing our rates, would have reduced our rates. If instead of conservation, PECO chose to build a highly expensive nuclear plant why must we be made to pay for their mistaken judgement?

As consumers, we understand that PECO will try to force its rates up, to earn more profit, to pay its stockholders more dividends, to force consumers to pay for the company's mistakes in judgement, in wasteful construction costs, to get the money to push ahead to complete another unnecessary nuclear plant.

But as consumers, we can rely only upon the Public Utility Commission to protect the consumers' interests. If PECO gets this outrageous and unnecessary increase, consumers will not only blame the company but will blame the PUC for letting them get away with it.

In August, 1973, CEPA conducted the first demonstration in the Delaware Valley, expressing the consumers' opposition to the building of any nuclear plants. The occasion was a hearing conducted by Herbert Denenberg, then State Insurance Commissioner, on the danger of nuclear accidents. CEPA said at that time that THE BEST WAY TO PREVENT NUCLEAR ACCIDENTS WAS NOT TO BUILD NUCLEAR PLANTS. (See attached reprint from Consumers Voice.)

In the early days, consumers were intensely concerned with the issue of the safety of nuclear plants. After the near catastrophe at Three Mile Island, in 1979 no new nuclear plants were begun and many under construction were abandoned, partly as a concern for safety and partly as a result of the escalating costs of construction which rendered nuclear power uneconomical.

Suddenly, again, the issue of the safety of nuclear plants has come to the forefront of consumers' concerns. The terrible tragedy of the space shuttle Challenger has compelled us to recall and repeat what we said before, that the safety of a nuclear plant cannot be guaranteed.

We were asssured that space travel is perfectly safe; civilians can now ride in space without any fear; the components of a space shuttle are built in such a way that nothing can possibly go wrong. But something went wrong. In a twinkling of an eye, a $2 billion shuttle exploded, seven heroic men and women were obliterated.

We are given the same assurances as far as nuclear plants. Nothing can possibly go wrong.

But Andrew Cassel, writing in the Philadelphia Inquirer (2/2/86) reminds us that "The simple truth is that complicated systems are prone to error, that the more safeguards and backups that are added, the more likely they are to fail in unpredictable ways."

In 1984, a disaster that could not possibly happen, did happen in Bhopal, India, killing 2,000 people and injuring tens of thousands more. In this morning's news we read of the 12-alarm fire at a "perfectly safe" TRW plant that caused a "state of emergency," making thousands of people in Harrisburg fear for their lives because of toxic emissions.

Will it take a total explosion, a horrible disaster, one that we have been assured over and over again can never happen, to convince our decision makers that nuclear power is inherently unsafe. The consequences of an explosion of a nuclear plant would be a hundred thousand times more disastrous than Bhopal, a TRW plant, Three Mile Island, the Titanic, or the terrible explosion of the Challenger which shocked the nation and the world.

When the biblical king Belshazzar ignored the handwriting on the wall, he was killed and his kingdom destroyed. If we ignore Challenger's flaming message in the sky, we, too, face the possibility of destruction.

No matter how they try, how many safeguards they build in, how strong the assurances that nothing can possibly go wrong, someday, in some plant somewhere, the inevitable fearful accident will occur.

Consumers were not consulted when the decision was made to build the Limerick Nuclear Plants. We don't need those plants. We don't want those plants. We cannot afford to pay for the extra high cost of nuclear plants. But consumers are not only concerned with rising nuclear utility rates. We are concerned with our health, our lives, our survival and the well-being of our loved ones. To our opposition to this latest rate increase which we consider unjust, unnecessary and unwarranted we must add an additional demand: curb the nuclear plants and eventually phase them out of existence. Intensify the search for safe, reliable alternative sources of energy, including the best and cheapest alternative: an aggressive conservation program.

FOR COMPLAINTS

CONSUMERS VOICE

LET THE SELLER BEWARE

CEPA'S MOTTO: "CEPA NEEDS YOU YOU NEED CEPA"

Vol. 8, No. 8 Philadelphia

ISSUED BY: Consumers Education & Protective Association International, Inc. 6048 Ogontz Ave., Phila., Pa. 19141 Contribution 25¢ Subscription $3.00 per year

CEPA Opposes Nuclear Plants

On August 14, CEPA members in Philadelphia leafletted outside City Hall to protest the construction of nuclear power plants near Philadelphia. Dr. Herbert Dennenberg, the Pennsylvania State Insurance Commissioner, was holding hearings in Philadelphia aimed at determining if nuclear insurance coverage under the Price-Anderson Act is adequate, and the potential safety hazards of nuclear power plants.

According to the Insurance Department Newsletter of July 25, 1973, put out by the Consumers' Advisory Committee, "The Price-Anderson Act . . . limits the total liability of utility companies for a nuclear accident to $560 million in damages — a coverage which is clearly inadequate for nuclear mishaps where damage may run into **billions** of dollars. Under the Act, the insurance industry would pay only $95 million; the government the balance. Once this limit has been reached, victims of a nuclear accident may no longer sue to recover their losses."

Two nuclear power plants are in the planning stage in the Philadelphia vicinity. CEPA has taken the position that the Price-Anderson Act is inadequate, but that the real point is that nuclear power plants are unsafe to start with. People are more interested in avoiding a nuclear accident than in collecting insurance after one has occurred, even if the insurance coverage happens to be good.

Ralph Nader, the lead-off witness at the hearings, testified that nuclear power plants are not safe, and should not be built. CEPA agrees. The dangers of such plants are great, and we should not play around with something of that magnitude until we are absolutely certain there will be no holocaust.

In addition to the dangers of a nuclear blast, there is also the problem of radioactive waste-plutonium — which is produced by nuclear plants. Plutonium is extremely dangerous. Even very small quantities will cause cancer. It has a half life of 50,000 years, which means that it takes that long for half of it to deteriorate to something else, and another 50,000 years for half of what remains to deteriorate, and so on. In other words, if 50,000 years ago (48,000 BC), men had been using nuclear power, and storing plutonium, it would have deteriorated to half its level by now. And in that amount of time it still might not be safe. Plutonium we store now would have to be stored until the year 52,000 for half of it to deteriorate. And who knows how much longer after that, until it were safe.

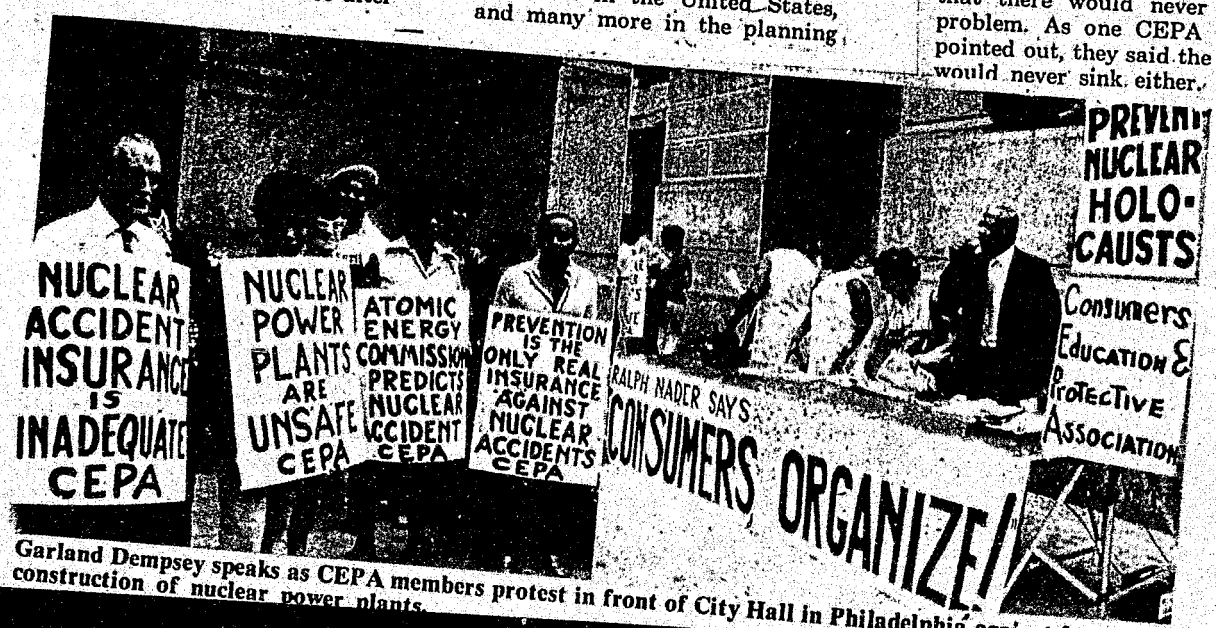
Another problem is that of heat pollution. Nuclear plants produce a great deal of heat. (There are presently 30 nuclear reactors in operation in the United States, and many more in the planning stage). They are cooled by water. Often, water from streams is used to cool the reactors, and is then diverted back into the stream, causing the water temperature of the stream to rise. Even raising the temperature a few degrees can have disastrous effects on the delicate ecology of the stream.

CEPA believes that the only way to insure against these dangers is to PROHIBIT THE CONSTRUCTION OF NUCLEAR POWER PLANTS NOW — not in a generation or two after a nuclear blast occurs, or after the other problems reach a danger level.

Too often our country has reacted only when a crisis is upon us. We have the means to avoid this crisis from ever occurring.

While many of our energy resources are diminishing, there is enough coal in the United States to provide for our energy needs for hundreds of years. Certainly our technology can be adapted to prevent coal from polluting the air. And by using coal, our technology will have enough time to develop efficient ways to tap the energy of the sun, and safe ways to tap the energy of the atom.

The nuclear industry, which has a great deal of money invested in nuclear power plants, insist that the plants are entirely safe, and that there would never be any problem. As one CEPA member pointed out, they said the Titanic would never sink either.



Garland Dempsey speaks as CEPA members protest in front of City Hall in Philadelphia against further construction of nuclear power plants.

1217 Sansom Street, 6th Floor, Philadelphia, Pennsylvania 19107 (215) 592-1774

RECD 1986
SECRETARY'S OFFICE
Public Utility Commission

FEBRUARY 4, 1986

Good evening your Honor, & members of the PUC staff.

MY NAME IS ASHLEY HULSEY, AND I AM SPEAKING ON BEHALF OF THE COALITION ON THE UTILITY CRISIS (CUC). OUR ORGANIZATION WAS FORMED BECAUSE THERE IS A UTILITY CRISIS IN PHILADELPHIA. LOW TO MEDIAN INCOME PERSONS CAN NOT AFFORD BASIC UTILITY COSTS TODAY. IF PECO BURDENS CUSTOMERS WITH THE COST OF LIMERICK, MORE LOW AND EVEM MIDDLE INCOME FAMILIES WILL FACE SHUT-OFF OF UTILITIES NECESSARY FOR SURVIVAL ALL YEAR ROUND. GAS HEAT IS EXORBITANT; OUR CITY"S CITIZENS RELY ON AFFORDABLE ELECTRICITY FOR HEAT, LIGHT, REFRIGERATION. THE HUNDREDS OF CITIZENS PARTICIPATING IN THE COALITION ON THE UTILITY CRISIS OR CUC CLINICS ALREADY HAVE SEVERE UTILITY FINANCING PROBLEMS. ESCALATION OF COSTS FOR BASIC UTILITY COSTS MUST STOP IMMEDIATELY: THE PENNSYLVANIA UTILITY COMMISSION MUST BLOCK THE PECO RATE INCREASE NOW. Thank you.

Ashley Hulsey

TESTIMONY OF LAURIE CAMERON BEFORE PUC ON PROPOSED PECO RATE INCREASE

Public Utility Commission

February 4, 1986

My name is Laurie Cameron; I am the director of Germantown Residents Acting to Conserve Energy, known as GRACE. GRACE serves the Northwest sector of Philadelphia as part of a network of six Neighborhood Energy Centers.

Our center takes applications for all the forms of financial assistance on fuel and utility costs which are available in Philadelphia. We operate both self-help and crew-assisted weatherization programs for low and moderate income households and provide extensive education programs on energy-related topics to the entire community. By the end of this program year we will have served over 3000 households, the vast majority of whom are low income and unable to pay the cost of average utility service or fuel usage.

The effect of a 28 percent increase in the cost of electrical service would be considerable in the neighborhoods served by GRACE. Nearly a quarter of the households in our area might be classified as "working poor" -- that is they earn their income through employment but are eligible for fuel assistance grants. Most such households are marginal at best in their ability to meet basic expenses and pay all utility and fuel bills. A 20 dollar increase in their electric bills will be felt immediately by this group struggling to sustain the American dream in the duly prescribed and approved manner.

The very poor, those on welfare and other low fixed incomes or without income, have already awakened to the reality of shut-offs and long waits in neon lit offices. They accept what they can get and survive. We won't kill them or even get rid of them just by making electricity more expensive or even by shutting them off. In the present climate of budget cuts and supply-side economics they have become accustomed to a decreased grant here or an increased bill there -- they can't pay it anyway and the people they have voted for to represent them havn't been able to do anything about it. More important that the widows and orphans who constitute the vast majority of PECO stockholders get their dividend. If they don't, that's news -- top of the financial page.

This company's rates are already 34 percent above the national average and the full increase would place it 81 percent above the average. Residential rates have risen nearly 50 percent since 1980 while commercial industrial rates rose only 27 percent. You see, PECO had to build this plant so commence and industry would have enough electricity to operate. But the company has to keep the price low so they don't move away or generate their own electricity. They have options. The people in our neighborhood have candles.

Between 1975 and 1983 welfare grants went up 20 percent while the cost of living rose 74 percent and the cost of electric skyrocketed 150 percent. PECO has begun to recognize the plight of people caught in this cost/income vise by launching a pilot bill reduction program for families with a long-term inability to pay. The Customer Assistance Program, as it is called, operates like a welfare program in the sense that participants must reveal all their income and accept the dictates of the company on certain lifestyle matters. Homeowners have been asked to sign documents which were intended to result in liens against their property. In return participants receive sizeable reductions in their bills and a chance to have arrearages forgiven provided they pay their bills.

This raises the question whether company-operated welfare programs are the most fair and appropriate vehicle for reducing the cost of electric service to low and moderate income people. If the argument is accepted that it is o.k. to reduce the bills of certain selected renters without reimbursement, then that same argument could be applied to resurrecting the idea of "life-line" rates for low and moderate income households who keep their average usage below some ceiling -- say 400 kilowatt/hours a month.

A life-line rate would be of especial help to the working poor and to homeowners who would rather reduce their usage than subject their homes to a lien. It would'nt preclude offering a CAP-style program to the very poor for whom usage reduction would not suffice. The total income to PECO from the low and moderate income cohort of the residential sector constitutes only a small percentage of total company income. Perhaps a life-line rate extended to a customer could bring in an automatic payment of Low Income Home Energy Assistance funds to the company.

In any event, I hope and urge that you keep in mind the plight and interests of those who are most vulnerable to rate increases. Thank you.

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COGENERATION

Excerpt from

CHAPTER 3
RESOURCE ENERGY SOURCES

NEW JERSEY ENERGY MASTER PLAN

Draft Edition
March 6, 1985

PLAN ADOPTED 12/85

STATE OF NEW JERSEY
Department of Energy
101 Commerce Street
Newark, New Jersey 07102

THOMAS H. KEAN
Governor

LEONARD S. COLEMAN, JR.
Commissioner

CHAPTER 3

RECOVERABLE ENERGY SOURCES

COGENERATION

History and Recent Trends

It is now clear that New Jersey can improve its economy, enhance energy reliability, raise energy efficiency, reduce energy costs, lower pollution, convert solid waste to fuel and promote and retain jobs by encouraging the growth of a "new" source of electric power: cogeneration and small-power production by non-utility energy entrepreneurs. These are terms for a method for coupling electric power generators to factories and institutions with a high steam load or demand for heat -- whether an oil refiner or a YMCA -- and using the heat to produce electricity that can serve the customer's own needs while selling any excess to the utility.

With cogeneration, consumers who are strapped by New Jersey's high electric rates will find that they can convert this liability into an asset. These high costs will act as a spur to investors eager to assist consumers in the installation of cogeneration equipment. Cogenerated power will then replace much of the high cost electricity formerly generated by utilities, leading to lower costs to all, but especially to those cogenerating. In this way, electric power production statewide will gain new generating capacity without the risks or uncertainties associated with traditional utility power plants.

Cogeneration offers wide-ranging economic benefits statewide as well. Lower energy costs resulting from cogeneration make it more attractive for businesses and industries to locate and to remain in New Jersey. Not only are jobs retained in the state, but a company that is investing in a cogeneration facility is not likely to move to another region.

Encouraging the development of cogenerated power would unlock a huge market for cogeneration equipment and services. According to the New Jersey Department of Labor's Division of Planning and Research, constructing 500 MW of cogeneration would create 7,500 to 10,000 jobs for masons, engineers, electricians, plumbers, carpenters, and planners as well as 9,700 to 10,000 indirect jobs in trucking, manufacturing, and other support services, for a total of 17,000 to 20,000 jobs.

In addition, cogeneration in New Jersey will increase the yearly consumption of natural gas, which will benefit all gas customers by spreading the fixed costs of pipelines and gas companies over greater sales

volumes. Electric consumers, too, will benefit as cogenerated power sold to local electric companies helps to offset the need for large new central power plants and the importation of power from out of state.

To bring this opportunity to fruition, the State must clarify how electric utilities cooperate with this new energy source which also can compete with utility facilities. New rules are needed to harmonize traditional monopoly regulation with the promotion of non-utility power development. Cogeneration and small power production can then fulfill their immense potential for improving the economy and environment of our State.

In the early years of electric power development, cogeneration was widely used in industrial plants. Gradually, however, electric utilities began to grow and absorb non-utility power producers. In part this growth reflected the new technologies of long-distance power transmission which made centralized electric power plants more economic. In part it also reflected actions by utilities with the support of state and federal regulators which would be questioned today as anti-competitive and monopolistic. See, R. Munson, generally, The Power Makers (1985) and C. Wooster,"Cogeneration: Revival Through Legislation," 87 Dickinson L. Rev. 705 (1983), pp. 707-717.

By 1920 about 30 percent of the nation's electricity was still cogenerated; by 1950, 17 percent was cogenerated. At the start of this decade, cogeneration reached its nadir -- 4 percent of national production. It is now sharply on the upswing, however, with over 7 percent of the nation's power generated in this manner and much more on the way.

The re-emergence of cogeneration and other non-utility power sources marks a reemergence of competitive forces in an arena where natural monopolies have reigned supreme. As BPU Commissioner George Barbour described the change: "Competition has entered the markets for many services long regarded as classic natural monopolies," leading to a "partial revolution" that requires regulators to "reexamine policies" grounded on traditional monopoly theories. (G. Barbour, "Public Utilities Regulation: The Opening of a New Era," 116 Pub. Util. Fort., No. 11 (November 28, 1985) at 15.)

Opening the door to cogeneration means rethinking utility regulation. Promoting an entreprenuerial enterprise, such as cogeneration, cannot simply be grafted onto traditional regulation which assumed the necessity for vertically integrated monopolies with exclusive territorial rights (the horizontal monopoly). In this new era of competition regulation must engage in a "step-by-step and balanced approach" in the transition to a more competitive market in electricity and related services. (G. Barbour, Id.) The goal of regulators in 1985 and beyond must be to define where natural monopolies end and competitive forces begin, and then proceed to harmonize the two. This is the regulatory crossroad described by Commissioner Barbour and ushered in by the technological advances and changing economics of electric power production.

Cogeneration is an idea whose time has come again. It is a proven and feasible technology which can be readily employed in New Jersey just as it has in California, Texas and other states where energy businesses have flourished alongside healthy electric utility systems. All that remains is for the State to open up the electricity market and allow investors to compete effectively and fairly with utility power sources. This chapter and the specific policies which follow are intended to produce that result. But in the end the fate of the cogeneration industry will lie with the industry itself and its ability to sell its services to New Jersey businesses and institutions which are eager for a way out of continually rising energy bills. All that the State can and should do is to create conditions favorable for cogeneration to develop at its own pace and on its own merits.

One of the primary reasons for promoting cogeneration is that energy costs have become a critical factor in the ability of states to sustain existing industries and attract new ones. In New Jersey high cost power is an economic concern of the highest priority. Indeed, there appears to be a strong correlation between the level of energy prices in a state and that state's competitive status within the industrial market. The 1983 Alexander Grant Study on General Manufacturing Business Climates of the Forty-Eight Contiguous States of America noted that energy costs in New Jersey remained "unacceptably high," despite the fact that New Jersey rose from 47th place to 30th place in terms of overall business climate.

Ownership Options

The ownership and operation of a cogeneration facility can be structured in many ways, which can be compressed into three basic approaches: industrial, joint industrial/utility, and third party

Industrial Ownership

In this option the cogeneration facilities are built, owned and operated by the same company or entity which receives the cogenerated power. Both the thermal and electrical energies produced by the system are utilized at the site with excess electrical energy sold to the utility. The majority of the State's existing cogeneration plants fall into this category, including all cogeneration systems which produce mechanical shaft horsepower. Hoffman-LaRoche's cogeneration plant at Belvidere, Warren County is an example of this option. Backup service is purchased from the utility in case of breakdown or scheduled maintenance.

Joint Industrial/Utility Ownership

This option refers to a cogeneration facility owned in part by an electric utility and an industrial partner. The role of the utility may also be assumed by a subsidiary of the utility.

An example of joint ownership is Riegel Paper, where the gas turbine is owned by a subsidiary of NUI, the generator by JCP&L and the waste heat boiler by Riegel Paper.

Third-Party Ownership

This ownership option refers to a cogeneration facility which is owned, operated, and otherwise managed by a corporation formed solely for this purpose. Thermal and electrical outputs are sold to another party or parties.

An example of this option is Trenton Integrated Community Energy System (ICES) project, a government-sponsored system owned and operated by the Trenton District Energy Company (TDEC), which is a private concern consisting of Cogeneration Development Corporation of New York City and a number of general partners. Landlords who generate inexpensive cogenerated power for resale to industrial parks or shopping mall tenants also fall into this category.

Financing

Feasibility Studies: The Department has proposed legislation to appropriate funds for site-specific feasibility studies of industrial cogeneration. Coal conversion studies would be funded from this appropriation as well. The Department has already identified more than 2,000 large boilers which are potential targets for cogeneration. Based upon available information from other states with similar programs, site-specific feasibility studies performed by independent licensed engineers range from $700 to $30,000. The Department would pay up to half of the cost of each feasibility study, limited to a maximum of $5,000.

Construction: The New Jersey Economic Development Authority (EDA) was given the legislative mandate to "guarantee up to 90 percent of the amount of a loan to ...an energy improvement system." N.J.S.A. 34:1B-5(r). Thus, cogenerators are eligible for funding at below prevailing market interest rates. Many small- and moderate-sized businesses will find subsidized interest rates a strong incentive to evaluate the potential for cogeneration.

Potential cogenerators in the main can be expected to turn to traditional lending sources for their investment capital. To do so, however, investors must receive sufficient indication of success if they are to proceed with financing. At present, investors are simply unable to gauge the credit-worthiness of projects in this State due to the unpredictable nature of power sales from the cogenerator to the utility (buy-back rates).

Other economic incentives are available through liberal tax treatment of facilities. These include the investment tax credit and accelerated depreciation allowances. With pending federal tax reform, however, these incentives may soon be ended and cogeneration will be forced to compete even more with other investment opportunities. This likely change in the Internal Revenue Code is further justification for a strong State policy in favor of cogeneration if it is ever to have a chance to develop in New Jersey.

As a rule, economic incentives should not continue indefinitely. Their primary purpose is to provide a sound basis for renewing cogeneration as a means of producing energy. After that, cogeneration must compete on its own merits. Incentives, therefore, must be recognized as short-term benefits which can and should be reduced as the proportion of cogenerated electricity increases. Simultaneously, the liberal tax benefits and related incentives available for the central station generation of electricity should also be phased out so that a truly "level playing field" is created. In the meantime, however, special incentives will be necessary for the re-introduction of cogeneration into the New Jersey economy and energy mix.

In the section which follows the Department sets forth in detail the initiatives that it will undertake to advance cogeneration in the State, the problems faced by this new industry, and the particular solutions that must be employed.

How The DOE Will Promote Cogeneration

The Department will promote the fullest possible economic use of cogeneration in New Jersey in five basic ways.

First, the DOE will continue its public education program.

Second, the DOE will establish a special "Cogeneration Center" at the DOE to assist potential users and developers of cogeneration.

Third, the DOE will work for any legislation needed to end the remaining barriers to cogeneration, so that it can compete on a "level playing field" with utility power sources.

Fourth, the DOE will apply its energy conservation and planning regulations to require utilities affirmatively to plan for the incorporation of substantial amounts of cogeneration and other forms of non-utility, alternative technologies into their supply mix.

And fifth, the DOE will implement this chapter of the Master Plan in every arena of importance to cogeneration, notably in proceedings before the BPU and in the policies of the DEP.

Public Education

On May 23, 1985, over 500 representatives of cogeneration developers, banks, businesses, utilities, and government officials crowded into a room at the Gateway Center in Newark to attend the Governor's Forum on Cogeneration in New Jersey, sponsored by the DOE. Among the companies that discussed their successful cogeneration efforts in New Jersey was Hoffman-LaRoche with its 23 MW Belvidere plant. Other speakers described cogeneration's future as a way to conserve energy, lower electricity bills, and substitute for isolated, single-purpose power plants now in use.

On September 10 and 20, 1985, the DOE held hearings on utility policies regarding cogeneration; gas and electric utilities testified on September 10. On September 20, the DOE heard responses from the cogeneration industry, followed by a concluding session on September 24 due to the overflow of witnesses. These hearings are part of the record in this Master Plan. They have proven to be instrumental in its development.

The DOE plans to hold more seminars, conferences, public hearings and, if need be, investigations, to examine the problems and publicize the promise of cogeneration in New Jersey. These educational sessions will be especially helpful in explaining all facets of cogeneration policies to the public and private sectors alike.

The Cogeneration Center at The DOE

The rudiments of a Cogeneration Center at the DOE are already in place. The Commissioner has pinpointed cogeneration as the leading single initiative of the Department. He has named a member of his staff to work as a full-time cogeneration coordinator. Other offices within the Department devote much of their attention to advancing the cause of cogeneration.

More, however, is needed and clearly justified if this environmentally sound, economic and highly reliable approach to energy efficiency is to reach its full potential. Therefore, in keeping with his power to "organize the work of the Department and [to] establish therein such administration subdivisions as he may deem necessary," (N.J.S.A. 52:27F-8), the Commissioner will establish a Cogeneration Center at the DOE. This center will act as a central clearinghouse for cogeneration opportunities; it will mediate problems and disputes; it will cooperate with the Department of Health in its efforts to cogenerate at the many institutions under its jurisdiction; it will assist the DEP in permit procedures; and, perhaps most important, it will be a full-time advocate for cogeneration in the State.

The Center will also contain a registry of cogeneration projects that will enable it to tabulate the growth of cogeneration in the State and to focus attention on projects in need of assistance. In this respect, the center will function much as the Office of Business Advocacy within the Department of Commerce and Economic Development was intended to do -- to serve as a proponent of a technology with immense potential to benefit the entire State.

Legislation and Lobbying

The Legislature has passed and the Governor has enacted a bill, S-2531 (P.L. 1985 C. 359), which exempts all sales of natural gas to cogenerators from the Gross Receipts and Franchise Tax. This tax, initiated decades ago as a substitute for local property taxes, has burgeoned into a 14 percent sales tax on all electricity and natural gas sold by regulated utilities. But gas sold to electric power companies, for use in generating electricity is exempt from the tax. Thus, electric utilities have an immediate 14%

price advantage over cogenerators. By exempting from tax gas sold for cogeneration, the Legislature has helped to level the playing field of competition between potential cogenerators and traditional utility-supplied electricity. In addition, the Legislature has passed and the Governor has enacted another bill, S-2529 (P.L. 1985 C. 266), which exempts cogeneration equipment from sales tax.

The Cogeneration Center will work with legislators and the Governor's office in promoting the best legislation possible. The center will testify, draft bills, organize coalitions, and generally work for the passage of laws needed and justified to further the public interest in a thriving cogeneration industry in New Jersey.

The Energy Conservation and Planning Regulations

Cogeneration and small power production are among the most efficient and dynamic forms of energy conservation yet devised. They include windmills, waste heat recovery, resource recovery and other forms of alternative technologies. Because a cogenerator, in effect, is able to use the same energy twice, cogenerating both heat or steam and making electricity, a cogenerator is also an energy saver of the highest order.

Moreover, as cogeneration replaces the inherently inefficient use of isolated, single-purpose power plants run by utilities -- seldom even half as efficient as cogeneration -- we may see net reductions in the use of certain fossil fuels to make electricity, even if these fuels are used in cogeneration. Recent data show that electric power utilities continue to rely heavily on natural gas or oil to make electricity; yet they waste most of the heat created by the burning of these fuels rather than capturing the heat for dual use, as would a cogenerator. For example:

> More than 34% of Atlantic Electric's in-state generation was derived from oil and gas;
>
> Approximately 94% of JCP&L's native generation was oil- or gas-fired;
>
> Some 58% of PSE&G's in-state generation came from burning the same fuels;
>
> And for New Jersey utilities as a whole, about 60% of power generated within the State was produced by oil- and gas-fired facilities.

Compared to cogenerating the same amount of electricity through oil or gas, these figures suggest that vital fuels are being used wastefully. A shift to cogeneration and other alternative technologies can change this.

In short, cogeneration can substitute for the burning of oil or natural gas by utilities as part of a comprehensive energy conservation and planning effort. Even if all cogenerators use natural gas, the fuel of

choice for cogeneration, there could be a net reduction in fuel used to produce the same quantity of megawatt hours and on-site heat use that would otherwise come from separate utility and on-site heating. In this way we see that promoting cogeneration saves natural gas given the innately more efficient two for one properties of cogenerating heat and electricity.

New Jersey is not the first state to reach this conclusion. The California Energy Commission, for example, has recently published its new energy plan. The Commission counts heavily on cogenerated electricity for much of the State's power needs over the next 10 years. In fact, no new power plants of any kind will be built by utilities in that fast-growing state. See, generally, The 1985 California Electricity Report: Affordable Energy in an Uncertain World, C.E.C., P106-85-001 (May, 1985). The Commission tabulates that some 7,300 MW of cogeneration capacity are under contract with utilities; about 2,000 MW are considered "likely to be available" based upon a historical rate of 28 percent of "all identified projects" coming to fruition (Id., at 60, Table 4-5).

In sum, the Department will interpret its Energy Conservation and Planning Regulations (N.J.A.C. 14A:20-1.1, et seq.) with the above precepts in mind -- namely, that conservation and cogeneration are interrelated. Each electric utility's energy conservation plan will include, inter alia, its evaluation of "programs designed to promote energy conservation through the use of alternative technologies," including cogeneration (Id, at 1.4(a)6). The DOE will then determine if these plans comport with the goals of the regulations and the DOE Act to assure "a secure, stable, and adequate supply of energy at reasonable prices" for the State (N.J.S.A. 52:27F-2). To be approved by the DOE, utility plans must show how they promote cost-effective cogeneration and other forms of energy conservation. Utility plans which do not meet this test will not be approved and will, therefore, be amended. Approved plans, in turn, will be enforced through all measures available by law, including (if need be) judicial injunctions and penalties (N.J.S.A. 52:27F-21).

Implementing This Master Plan

Finally, and perhaps most importantly, this Master Plan provides much-needed guidance for the future of cogeneration in New Jersey. The Master Plan is intended to show other departments and agencies in the State with jurisdiction over cogeneration how to use their power to promote its widespread use without sacrificing other public concerns. How the agencies respond to this plan is, therefore, critical to the success of cogeneration.

Thus, some explanation of the proper role of the Master Plan in the deliberations of other agencies -- notably, but not exclusively, the Board of Public Utilities -- may be helpful. (These comments would also apply to any other section of the Master Plan.)

The Department of Energy Act authorizes the department to adopt a State Energy Master Plan which agencies must implement to the "maximum extent practicable and feasible" (N.J.S.A. 52:27F-15b).

This means that, each "State instrumentality" will abide by the Plan as if it adopted this Plan. The only difference may be that agencies are empowered to relax the Plan's demands when it is clearly necessary to do so, based upon evidence that compliance is not "practicable and feasible."

To assist each instrumentality in complying, the DOE may prepare "such guidelines as the Department determines to be relevant" and helpful (Id.). Guidelines are offered by the DOE wherever the Commissioner finds a need to provide greater direction and specificity to the Plan than the Plan itself conveys. Since the guidelines are merely explanatory of the Plan, they should be honored in the same way as the Plan itself. The Commissioner has determined that the cogeneration policies and the textual explanations therein are sufficiently precise that no guidelines are needed at this time. (See N.J.S.A. 52:27F-15(b) which grants the Commissioner discretion in resorting to guidelines: "...The Department shall prepare...such guidelines as the department determines to be relevant to assist each such instrumentality in conforming with said energy Master Plan...")

Cogeneration: Problems and Remedies

Unless stated otherwise, all references here or in any other part of this Master Plan to cogeneration or small power production shall mean the same as the definition of "qualifying facility" or "cogeneration and small power production" adopted by the Federal Energy Regulatory Commission, 18 CFR 292.101 and .202.

At the September 1985 hearings on cogeneration, the Department considered basic problems or barriers which inhibit the economic use of cogeneration. After careful deliberation, the Department has determined that the major inhibiting factors are as follows:

1. Buy-back rates: The rates offered by electric utilities for the purchase of cogenerated electricity are too low, too variable, and too unpredictable. They also fail to satisfy the requirement of PURPA to offer rates based upon the "full avoided cost" in the long-run of cogeneration as a substitute for power plants owned and operated by electric utilities.

2. Back-up power rates and access: Evidence suggests that electric utilities continue to charge rates for back-up power to cogenerators that appear excessive in light of actual experience to date around the country. Pursuant to the Board of Public Utilities Order in Docket 8010-687 (October 14, 1981), utilities were permitted to charge rates based upon an assumed system outage of 15 percent. Experience shows that the outage rate is closer to 5 percent. Excessive rates discourage investment in otherwise feasible cogeneration systems. Now a decision by the Federal Energy Regulatory Commission (FERC) has raised much doubt as to whether third-party cogenerators will have access to back-up power at any price.

3. Wheeling access and rates: Electric utilities continue to maintain barriers to non-utility power sources gaining access to transmission lines for the sale of their cogenerated power to utilities in

different service territories. These barriers include unpredictable wheeling rates and non-economic restraints which bear little relationship to the burdens and benefits of installing large quantities of cogeneration on the system. In addition, cogenerators serving more than one facility need to engage in "self-wheeling" in order to take full advantage of economies of scale.

4. Unequal bargaining power: Utilities have unfair bargaining advantages over cogenerators due to the monopsony position of the utility (many sellers but one buyer), the greater risk exposure of cogeneration investors, and other factors. Steps must be taken to prevent utilities from taking advantage of their monopsony status, including the use of standard form contracts and incentives/penalties to promote good faith bargaining with cogenerators.

5. Access to natural gas: Natural gas is the principal fuel of cogeneration, largely due to its clean-burning properties, which are critical to the location and operation of cogeneration units in urban and densely populated areas. Unfortunately, prospective cogenerators have had great difficulty in securing adequate supplies at affordable price.

6. Environmental permit procedures: Potential developers have complained of difficulty in gaining necessary air pollution and related permits from the Department of Environmental Protection. They also fear the exaction of unreasonable air pollution requirements that may make cogeneration uneconomic.

7. The future of cogeneration in a power-glutted market: There is a persistent concern that cogeneration may be stifled by the continuing, and in some cases growing, glut of uneconomic but utility-owned electric power generating capacity. This concern arises even though cogeneration can supply large amounts of power at rates that are cheaper than much utility capacity, even though cogeneration can reduce net pollution and net energy use, and even though it promotes a more reliable electric power system. This concern is especially pressing in the case of the PSE&G service territory, where most of the State's cogeneration capacity is found.

8. Miscellaneous Concerns:

   (a) Evidence indicates that some utilities do not always negotiate in good faith. Regulation is needed to assure good faith efforts to conclude contracts.

   (b) To assure least-cost energy for consumers, cogenerators should be allowed to "bid" to displace more expensive power sources, including utility capacity.

   (c) While utilities should be permitted to enter the market for cogeneration development, special safeguards are needed to protect competition.

Buy-back Rates for Cogeneration and Small Power Production

One of the thorniest issues of cogeneration is how to compute the buy-back rates for cogenerated power. Many articles and journals have addressed this question, as has virtually every state regulatory commission in the nation, leading often to varied and creative approaches. (See, e.g., C. Wooster, "Cogeneration: Revival through Legislation?" 87 Dick. L. Rev. 705 (1983); W. Collins, "Electric Utility Rate Regulation: Curing Economic Shortcomings Through Competition," 19 Tulsa L. Jour. 141 (1983); M. Yokell and D. Marcus, "Rate Making for Sales of Power To Electric Utilities," 114 Pub. Util. Fort., No. 3, Aug. 2, 1984, 21-28; J. Schillaci, "The Simultaneous Buy and Sell Provisions of PURPA Section 210 Regulations," 106 8 Pub. Util. Fort. No. 8 at 43-45; S. Silverstone, PURPA Provisions on Cogeneration and Small Power Production (1980); "The Appropriateness and Feasibility of Various Methods of Calculating Avoided Costs," B-141 (1982) (Draft document, National Regulatory Research Institute); R. Lock, "Statewide Purchase Rates Under Sec. 210 of PURPA," 3 Solar L. Rep. 419 (1981); "Calculating Capacity Costs in Cogenerated Rates," 108 Pub. Util. Fort. 57, 58 (Sept. 24, 1981); Stirba, et. al., "Implementing PURPA; the Selection of an Appropriate Methodology," 6 Journal Energy Law and Policy 91 (1985); and Yokell and Porter, "You Can Avoid Pitfalls in the Sale of Cogenerated Power," Cogeneration, 31, Sept.-Oct. 1984. See also, R. Munson, The Power Makers, Rodale Press, 1985, and C. Flavin, Electricity's Future: The Shift to Efficiency and Small-Scale Power, World Watch Paper 61 (1984) for a broader discussion of the future role of cogeneration.)

How much is a utility required or allowed to pay a cogenerator for electricity sold to the utility? The Public Utility Regulatory Policies Act (PURPA), passed in 1978 as part of the National Energy Act, requires utilities to pay cogenerators at a rate no lower than the "full avoided cost" (FAC) of the utility (PURPA, Sec. 210, 16 U.S.C. 824a-3 (1982); and FERC regulations, 18 CFR 292.101(b)(6)(1985). In addition, the purchase rate must be "just and reasonable to the electric consumer...and in the public interest," and "[n]ot discriminate against qualifying cogeneration and small power production facilities" (Id., at (a)(i) and (ii).

The FAC is defined by FERC as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the [cogenerator], such utility would generate itself or purchase from another source" (18 CFR 292.304 (b)(4) (1985). Interpreting these and other regulations has led to a nearly constant stream of litigation, culminating in three United States Supreme Court decisions which appear now to have settled the issue at least enough for development to proceed. These critical decisions are: F.E.R.C. v. Mississippi, 456 U.S. 742 (1982) [Supreme Court upheld the constitutionality of PURPA, in particular the decisional duties imposed on state regulatory commissions]; American Paper Institute v. American Electric Power, 461 U.S. 402 (1982) [Court upheld FERC's "full avoided cost" formula and interconnection rules against challenge by three utilities.]; and Consolidated Edison Co. v. New York Pub. Serv. Com., 53

U.S.L.W. (1985) [Court dismissed Con Edison's challenge to the constitutionality of a minimum purchase rate for cogenerated power of 6¢ per kilowatthour set by legislation which may exceed the true avoided cost, if set pursuant to FERC rules.]

The Draft Energy Master Plan (March 1985) requires the BPU to set rates which "are equal to the fully avoided costs of capacity (present value of new baseload plant) and energy (current average generation expenses of each utility's oil and gas units)" (Draft Energy Master Plan, at 132, 135). This approach has been criticized as combining "apples and oranges" because the cogenerator should receive energy payments based on the energy costs avoided by the baseload power plant also avoided. In the Matter of the Public Hearings In Re: Draft of the 1985 Energy Master Plan, September 10, 1985, Statement of B. Parent, at p. 28 [hereafter "Tr." followed by p. number and date]). Since the DOE believes that the appropriate avoided power plant is a "proxy coal plant," the avoided energy cost should be that of coal, not the more expensive oil or gas. It has also been criticized for deviating from the current policy of the BPU, which is to require utilities to negotiate with each cogenerator the costs of purchasing power from the Pennsylvania-New Jersey-Maryland (PJM) grid plus a 10 percent add-on (commonly referred to as "PJM plus 10") for the energy component, and the PJM capacity deficiency payment for the capacity component. In the matter of the consideration and determination of cogeneration and small power production standards pursuant to the Public Utility Regulatory Policies Act of 1978, Docket No. 8010-687 (October 14, 1981), at 3 (hereafter "Board's Order") ["We further believe that the setting of avoided energy cost at 10 percent above the PJM billing rate will help to adequately promote cogeneration and small power production in New Jersey..."]. (For more background, please see discussion of the PJM system and potential effects on cogeneration on p. 70.)

The DOE believes that a response to these criticisms is in order. It is important to begin by stating the fundamental steps in determining the FAC as contemplated by the DOE.

The Full Avoided Cost is the Sum of the Capacity and Energy Components

Using an incremental, or long-run, approach to FAC requires that we consider the ability of cogeneration to replace or defer the construction of new utility owned and operated power plants. (Yokell and Marcus, "Rate Making for Sales of Power To Electric Utilities," 114 Pub. Util. Fort., No. 3, (August 2, 1984) at 22 (hereafter "Yokell and Marcus"). If cogeneration in the aggregate replaces or delays the construction of a large coal or nuclear power plant, consumers may see a net, long-term reduction in their incremental rates. Rates will be lower than they would have been but for cogeneration, although cogeneration may not reduce rates below their present level.

With cogeneration development total electric power generating capacity will increase without corresponding investments by electric

utilities or their ratepayers. Cogeneration also provides other tangible and intangible benefits which do not always show up in consumers' rates. Also known as "positive externalities," these benefits include improved system reliability and efficiency, reduced air and water pollution, and a shift in risk-taking from utility ratepayers to cogeneration investors. (See Flavin and Wooster, generally, and see also Morris, "The Upcoming Boom in Cogeneration", 115 Pub. Util. Fort. No. 11, 17-19, (May 30, 1985.). These factors help to explain the federal directive that buy-back rates for cogeneration be set on the basis of the "incremental costs" to the utility (18 CFR 292.304.)

The DOE interprets "incremental costs" to mean the capital and energy costs combined of a utility constructing and operating its own new power plant. This view accords with the great majority of jurisdictions and reviewers who have concentrated on this question and resolved it independently, (Wooster, 87 Dick. L. Rev. 705, 735-57, supra, for a state-by-state listing.)

The question, therefore, devolves into two parts: What will be the capital or capacity component and what will be the energy component of the rate to be paid to cogenerators?

Capital or Capacity Component

Two general methods have been identified to this problem: the Differential Revenue Requirement method (DRR) and the "Proxy Unit Approach" (PUA) (Yokell and Marcus, supra, at 23).

The DRR mirrors what a utility would do in calculating the value of a cogenerator's electricity sales. Essentially, it directs the regulatory authority to find the revenues required under a hypothetical "optimum generation expansion plan over a selected period" assuming no contribution by cogenerators. Then perform the same calculation after "forcing the [cogenerators] into the plan at the assumed time" (Id.). Next, subtract the revenues required under step 2 from those required under step 1. This represents the financial value of cogeneration to the utility. Contracts can then be awarded based upon an applicant's share of the capacity allocated to cogeneration in the utility's expansion plan. The DRR has been favored by most utilities.

Practical flaws in applying the DRR approach render it virtually useless to regulators. Foremost among them is the inherent dependence of DRR on a battery of assumptions and data that are often subjective and largely in the utility's sole control. Even if regulatory officials possess the rationale of each utility assertion, it would be burdensome and difficult, to say the least, to test fully the basis and accuracy of each utility calculation on a timely basis. Presumably, the reports filed by utilities under 18 CFR 292.302(b), requiring annual avoided cost reporting "on a cents per kilowatt-hour basis," might reflect the data to be used in a DRR approach; but the task of verifying data is enormous. (See Pub. Serv. Coord. Transp. v. State, 5 N.J. 196, 217-219 (1950) in which the New Jersey Supreme Court admonished the State PUC to probe all

data provided by regulated utilities rather than accepting them as true.) Before this task of verification, probably through the adversarial and public hearing method, could be completed, the data would be rendered stale and the process might have to start anew. Meanwhile, much cogeneration would be left in abeyance awaiting the outcome. The DOE, therefore, rejects the DRR method at the present time due to these practical considerations, despite its obvious appeal as a theoretically more thorough and rigorous approach to determining cost-avoidance.

The Proxy Unit Approach (PUA) avoids many of these pitfalls. It is also so simple that most major "calculations can be performed on a hand calculator by anyone who understands the basic elements of utility operations" (Yokell and Marcus, at 23). The PUA looks simply at a hypothetical power plant -- assumed to be replaced by many cogenerators -- and the costs of financing, building and operating that unit. (Compare this method to the difficulties in examining the entire utility expansion plan over several decades of the DRR.) The PUA allows the regulatory officials to break the question down into the relevant, manageable parts, such as:

-- What is the proxy unit? (e.g., fuel, size, location, operating characteristics, etc.)

-- What is the timing of the proxy unit? (e.g., when would it be needed but for the cogenerators?)

-- How much will the proxy unit cost?

-- How reliably would this proxy unit operate?

-- What is the present value of avoiding this proxy unit which can therefore be awarded to the cogenerators and form the basis for their compensation?

Determining The Proxy Unit

There are at least four ways to decide on the proxy unit. Each has several problems, but one has benefits that ultimately outweigh its difficulties.

The Utility's Most Recently Completed Unit: The obvious benefit of this approach is that it yields objective and specific numbers. All can see the costs actually incurred and passed on to ratepayers in the last power plant built. The problem is that the newest power plants built by New Jersey's electric utilities, except for Rockland Electric, have been nuclear power plants. Hope Creek, at $3.8 billion or higher, is so costly that if it is used as the basis for cogeneration planning, excessive buy-back rates might be produced. No New Jersey utility is likely ever again to spend so much on a single power plant, with or

without cogeneration. More cogeneration than is justified could be stimulated, and ratepayers might pay rates that are unjust.

The Utility's Next Power Plant: The benefit of this proxy unit is that it may actually conform to the facility that cogeneration will displace. This proxy unit has much certainty and realism to it. However, it leaves too much within the discretion, control and judgment of the utility which may have a strong interest in deterring non-utility power sources within its service area. A utility could stifle the growth of cogeneration simply by altering its demand forecasts and resource plans at will. It might publicly plan on no more power plants for the foreseeable future and assign a "zero" value to cogeneration. Then when cogenerator investors are deterred from competition with the utility, it can reverse itself if need be and resume planning for a power plant or power purchases which healthy competition from cogeneration might have avoided. This approach, therefore, suffers from a potential for "bait and switch" manipulation that renders it unfair and unreliable.

The Utility's Next Unit After Certification by the DOE: This approach borrows from the preceding approach, but it has the balancing effect of an outside review by the DOE that will require each utility to submit detailed plans for energy conservation (N.J.A.C. 14A:20-1.4 through 1.8). Once the DOE has reviewed and approved the utility plans, it may then certify them (Id. at 1.9). In this way, a finding may be forthcoming as to what the appropriate avoided power plant will be with respect to each utility. The advantages to this approach are numerous. DOE reviewers can determine on a utility-specific basis what is the optimum plan for that utility. How much conservation investment should the utility plan to accomplish? How much will this defer the need for power generation or purchase, whether from PJM or from cogenerators? Clearly, such a planning process can work. However, it may not be suitable to the singular purpose of identifying a proxy unit and the consequent setting of avoided cost rates to be paid to potential cogenerators. Delays can be expected in the process of preparing, submitting and reviewing of utility plans. These delays could forestall otherwise justified cogeneration development.

More to the point, this planning process is directed primarily toward the promotion of conservation, particularly in the residential sector; it is still the least costly, most environmentally sound form of energy development (Draft Master Plan, at 157, 173). It would be anomalous if promoting residential conservation should serve to bar, even temporarily, the cost-effective development of commercial and industrial cogeneration. Both merit support and devoted attention. And, since much of the conservation initiative will be limited to residential and small commercial ratepayers, it is only fair and proper that cogeneration should proceed at its own legitimate pace, given its strong benefits to industrial and large commercial users who have had to fend for themselves in coping with rising electric rates.

In due course, the DOE believes that it will be able to fine tune the planning process so that the cogeneration and conservation initiatives are effectively merged. The conservation regulations contain many inducements to cogeneration that will directly benefit this effort as well. Nevertheless, until such time, the DOE finds that there is a clearly preferable methodology.

The Hypothetical Statewide Power Unit: The most practical approach to a proxy power plant is to determine the hypothetical power plant on a statewide basis exclusive of statewide conservation developments. Such a pragmatic approach recognizes the statewide regulation and interconnectedness of the investor owned power companies. It also reflects the regulatory simplicity of identifying one unit that would, in fact serve all the users of the State at varying times due to power exchanges and interconnections. Furthermore, it removes the opportunities for a utility to "bait and switch" and eliminates the delays and regulatory expense of engaging in laborious company specific assessments of power plant investment decisions that are still several years away.

What is New Jersey's Statewide Proxy Power Plant?

As stated in the March, 1985 draft Master Plan, the DOE is convinced that the appropriate statewide, proxy unit is a hypothetical baseload coal-burning power plant. When it is needed could be the subject of debate. (See, e.g., the Electric Facility Need Assessment Act, N.J.S.A. 48:7-16, et seq.) Historically, State regulators have had little involvement in formal reviews of the need for new facilities. The related question of timing, i.e., when a power plant justified for billing to consumers and bringing into operation, has received only minimal attention as a rule. Thus, it would seem anomalous to apply a stricter standard to small, non-utility facilities than was applied to large, utility units over the years. Nevertheless, new facilities can be justified and, indeed, are needed whenever they will reduce electricity costs, lower acid rain deposition from State dependence on out-of-state coal plants or generally enhance system reliability.

A review of the existing installed capacity of the New Jersey utilities indicates that as of December 31, 1984, it was 13,278 MW. However, significant amounts of firm capacity purchases are presently being made by ACE and JCP&L. As of December 31, 1984, these firm purchases were about 1,400 MW. Some of these purchase contracts will start expiring in 1992 over a nine-year period. In order to continue providing adequate service, the utilities would, absent massive conservation and cogeneration programs, need to build new facilities. The most likely candidate for this capacity expansion would be a coal-fired plant in the size of 600 MW.

It might be expected that this plant would burn primarily low sulphur coal at 1.5 - 3.5 percent sulphur content in order to conform with New Jersey's strict air pollution control limitations. (See, e.g., N.J.A.C. 7:27-7.1, et seq.; sulphur content; 7:27-10.1, sulphur in coal; 7:27-5.1, general prohibitions, 7:27-8.1, permits and certificates; 7:27-13.4,

ambient air quality standards for sulphur dioxide, and 7:27-3.1, further controls on combustion of fuels.) It would also be equipped with scrubbers and other air emission elimination systems, consistent with the requirements of the "State Implementation Plan" adopted by the DEP. N.J.A.C. 7:27-13.2(a)-(c).

Such a plant could be installed in 1992 at a cost of approximately $1,900 per KW in current dollars. In order to compute the capacity payments for this proxy plant in 1992 to be paid to a cogenerator in 1986, the DOE suggests using the methodology developed by the State of Florida. Under the Florida methodology, monthly capacity costs in dollars per KW are calculated for the proxy unit. The savings associated with deferring this unit for any length of time is then calculated, and this amount is paid out to the cogenerator over the life of the cogeneration contract. With this technique, for the New Jersey proxy plant to be built in 1992, a cogenerator in 1986 would receive a capacity payment of $12.27 per KW per month for a 10-year contract. This translates into approximately 2.4¢ per KWh for a 70 percent capacity factor.

The Energy Component

Logically, it would seem that the energy component of the proxy power plant should serve as the basis for compensating the cogenerator for energy actually delivered. If the cogenerator displaces a unit of coal power plant, then both his capacity and energy payment schedule should be based on the same unit. This reasoning formed the heart of comments by the BPU and PSE&G. They referred to the DOE's proposal that cogenerators be paid for capacity based upon a baseload coal unit and for energy based upon a gas or oil-fired peaking unit as an "apples and oranges" approach.

The DOE remains convinced that there is a sound basis for combining apples and oranges, yielding in this case an energy "salad" for the residents of New Jersey. This is so for the following reasons:

-- As a rule, cogeneration facilities burn oil or natural gas. Since cogenerators must purchase these relatively high-cost fuels, they deserve to be paid for their efforts just as a utility "passes through" its fuel costs (In the matter of Redi-Flo Corp., 76 N.J. 21 (1978). Also, if they are ever to compete "on a level playing field" with utility power plants, they may require temporary incentives. This incentive factor both compensates for incentives routinely given to utilities and recognizes the many intangible benefits of cogeneration. Indeed, in the BPU's original orders of 1981 in Docket No. 8010-687 regarding the buy-back rates for cogeneration, the Board added a premium of 10 percent to the PJM billing rate -- hence, PJM plus 10 -- expressly due to these external benefits. ("[W]e are of the opinion that there is intrinsic value to smaller, decentralized cogeneration and small power production facilities." Board's Order, at 4.) Since 1981 the public has come to appreciate that these benefits far exceed their previous estimates. They include burning alternative fuels; using energy more efficiently; enhancing reliability for electricity supply; reducing consumption of oil or natural gas by electric utilities; increasing economic security for industrial and commercial

ratepayers; lowering acid rain in the State; and the secondary benefits of having a thriving "emerging technologies" industry in the State (See J. Cannon, Acid Rain and Energy: A Challenge for New Jersey, [Inform, Inc., 1984]. For a report on one state's efforts in this regard, see The 1985 California Electricity Report: Affordable Electricity in an Uncertain World, Cal. Energy Comm., P106-85-001, at 143.

-- New cogeneration facilities replace both peaking and baseload units. Given the short lead-time for constructing and installing cogeneration facilities, they offer the promise of substituting for high cost power generation of all types in a very short period. For the next few years, cogeneration investors can quickly displace otherwise uneconomic power generation and purchases. In so doing, the current price of oil and natural gas is the appropriate avoidance standard for compensating these investors, especially given the continued dependence of utilities on natural gas and oil as fuel sources at power plants in-state. Eliminating these inefficient and uneconomic uses of prime fossil fuels should be a leading objective of the State.

The Department recognizes that setting the avoided cost rate must also take into consideration the interests of non-cogenerating ratepayers. If cogeneration can be stimulated at a lower rate, then all public interests are better served. This balancing factor is well recognized (See e.g., 18 CFR 292.304(a)1). ("Rates for purchase shall...[b]e just and reasonable to the electric consumer of the electric utility and in the public interest.") Consequently, the Department has determined that the energy component shall be that of the most efficient baseload oil- or gas-fired steam units.

The Department agrees, however, that the energy component should be reduced to the avoided energy of a baseload proxy unit as of the date when that power plant theoretically would be needed. In other words, if the coal unit is assumed to be needed, but for cogeneration, in 1992, then as of 1992 the energy component should be based on a coal plant in that same year.

In this way the DOE has created a kind of "two-tier" pricing policy. In the first tier are cogenerators who respond swiftly to this Master Plan, sign contracts, and otherwise serve as pioneers for those who will follow. (Pennsylvania calls this a pioneer rate). Being among the first should merit special consideration. Those who follow will reap the benefits of their successes. They will find an easier regulatory path, assuming their product is competitively priced. Accordingly, those who invest after 1992 should receive an energy rate equal to avoided coal-fuel costs in the same year. Non-utility power producers in operation before that year will receive the premium rates based upon oil or natural gas steam units until that same year.

An Alternative: Locked-in PJM Rates

The electric power utilities, as stated, continue to support retention of the Board's pricing policy announced five years ago. This policy reflects a spot-market approach which has slowed cogeneration investment in the State. It may be, however, that one of the most basic flaws in this approach -- its unpredictability -- can be corrected. Since utilities routinely project future trends in the PJM billing rate, as central to their planning for new facilities, there is no reason why cogenerators should not also enjoy the benefits of that forecasting. The trend lines for the PJM billing rate could serve as the trend line for cogeneration buy-back rates. This would alleviate much of the unpredictability in the 1981 BPU order. A cogenerator should be able to choose a locked-in trend in the projected PJM billing rate, just as a utility relies on this information to foreshadow its investment decisions.

Accordingly, cogenerators may select a contract for back-up power rates using the "ramped-up" PJM billing rate for the energy component as the formula for their compensation. Whether the 10 percent premium should be increased, as seems likely, is another question. Such an option may be simpler than the proxy unit method; it also may be faster than the PUA. It will, in any event, be up to the cogenerator to choose.

Summary

The State must alter its pricing policies to attract and retain cogeneration investment. Therefore, the DOE adopts a two-tier pricing plan, using the proxy coal unit for capacity costs together with the energy cost of a baseload oil or gas unit until 1992, when it will shift to the avoided energy cost of the same coal unit. Alternatively, a cogenerator may choose to use the PJM billing rate (plus some appropriate premium, 10 percent under the BPU's 1981 orders) that is locked in to a projection of the future PJM billing rate. This rate will be likely to escalate in keeping with rising PJM billing rates; therefore, it is also a ramped up rate that will guarantee an increasing revenue stream to a cogenerator, provided it performs to expectations.

In fashioning these rates, the State must be careful to provide incentives only where cogeneration actually takes place. The Department therefore proposes that the rates described in this plan apply only to power supplied by cogenerators to utilities beyond a cogenerator's own needs. cogenerated electricity must be based upon the principles of thermal dispatch of power. Naturally, any rates established under these criteria must be fair to existing customers, include a consideration of the long-term reliability of the QF and cover the cost of any transmission enhancements required to interconnection.

Back-up Power Rates and Access

Few industries would invest in cogeneration without the availability of the utility's electricity when the cogenerator needs repair. Historically,

refusal to deal with cogenerators enabled the utility industry to drive them out of business (Wooster, 87 Dick L. Rev., supra, at 712-14). PURPA and the regulations of FERC now guarantee that utilities must not discriminate against cogenerators in the sale of back-up, maintenance, supplemental or interruptible power (16 U.S.C. 824 a-3(b), and 18 CFR 292.305). Of special note, FERC regulations and the BPU's orders prohibit utilities from projecting that all cogenerators will be off-line at the same time, a technique used in the past to charge them an excessive demand charge (based on the fiction that the utility will reserve capacity for their use at all times, even when not needed) (18 CFR 290. 305 (c) (1).).

The BPU's 1981 orders authorized a demand charge predicated on the assumption that cogenerators as a group would be off-line 15 percent of the time. (See p. 6 of the October 14, 1981 order which describes the Board's "assumption of diversity" of 15 percent at the generation level.) More current experience, however, shows that even this rate is too high. Nationally cogenerators have a group outage rate closer to 5 percent. Therefore, barring any experience to the contrary unique to New Jersey, the State should use this lower figure in calculating back-up power rates. Doing so also conforms with the caveat in the BPU's original order that "such charges and their underlying assumptions should be reviewed as soon as more data is available." (Board's Order, p. 6.)

Unfortunately, a recent decision by FERC undercuts this protection for many cogenerators. In the Alcon decision, FERC ruled that the utility must supply back-up power only to the actual owner and operator of the cogeneration equipment, but not to the industrial customer of the cogenerator (In the matter of P.R.E.P.A (Alcon), FERC Docket No. QF 84-147 (1985). Over a third of all cogeneration is the product of third-party financing and operation where cogeneration specialists, taking advantage of tax incentives, operate the facility for the industrial purchaser of the steam and electricity. The Alcon decision could stifle third-party investment.

There is a simple way to avoid the harsh and restrictive nature of the Alcon case. State regulatory officials can order utilities under state law to provide full back-up, supplemental and maintenance power at affordable rates to third-party cogeneration (See, e.g., N.J.S.A. 48:2-13, -16, -23, -24, and -27). Utilities in New Jersey must provide such nondiscriminatory service at fair rates to all cogeneration facilities, regardless of who in fact owns title to the hardware or operates the equipment.

Besides the rates to be charged for cogeneration back-up, there is much concern over the non-economic aspects of gaining access to the utility system. The industry complains of long delays by utilities, indecisive and unresponsive negotiations, refusals to interconnect with the utility's network, high costs to interconnect, unreasonable and repetitious demands for safety and compatibility assurances, and other forms of apparent passive resistance (See, e.g., Transcript of September 20, 1985, statements of J. McNair, pp. 127-28; R. Topper, p. 147; J. Barnes, p. 161, 162). These problems can be as discouraging to investors as the economic difficulties described above.

Accordingly, the Department and the BPU will order utilities to cease and desist from any behavior that unreasonably delays or frustrates a cogenerator's request for access. The BPU will assist in the identification and prevention of any form of stalling tactics, recalcitrance or anti-competitive behavior. Much of this problem, it is expected, will be resolved in the standard offer contracts which a cogenerator will be entitled to sign and enforce against the utility, and in other protections against bad faith bargaining.

Wheeling Access and Rates

Control over transmission lines has helped electric power utilities to eliminate competition by public or municipal systems. (Indeed, a crucial development in the history of the electric utility was the invention of long-distance transmission. See, e.g., R. Munson, The Power Makers, 50-52.) Such concerns motivated the U.S. Supreme Court in United States v. Otter Tail Power Co. to order a private utility to allow a municipal utility to transport power across its franchise area using its transmission network, even though the two were de facto competitors (410 U.S. 366, 377 (1973). (The Supreme Court relied upon the finding that "Otter Tail has a 'strategic dominance in the transmission of power in most of its service area' and that it used this dominance to foreclose potential entrants into the retail area from obtaining electric power from outside sources of supply." (See discussion of Otter Tail as a classic example of the "bottleneck monopoly" in "Refusals to Deal by Vertically Integrated Monopolists", 87 Harv. L. Rev. 1720 (1974).)

In the same way, utilities have a long history of using transmission line monopoly to stem the entry of potential non-utility competitors -- namely, cogeneration and small power production -- into their service area (R. Munson, supra, 55-71). Some journal writers now believe that the only "natural monopoly" remaining in electric power lies in the long-distance transmission of electricity at high voltage (Cohen, "Efficiency and Competition in the Electric-Power Industry, 88 Yale L. Jour. 1511, 14-18, citing numerous authorities, which recognizes the continuing "economies of scale in bulk-power supply," as contrasted with the increasing diseconomies in large-scale central station power generation.) Typically, the situation arises where an industrial firm seeks to generate its own power and sell the excess to the local utility; when this request is denied, the factory may try to sell the output to another utility or to buyers outside the service territory. Typically, as well, this request to wheel the cogenerated power has been denied or subjected to onerous conditions and uncertain rates.

PURPA and implementing FERC regulations, however, show that Congress intends for cogenerators to be able to sell their power to other utilities through fair access to wheeling services (18 CFR 292. 303 (b), (c) and (d).). But much discretion remains in FERC and at the state level as to what the wheeling charges may be and how to resolve other wheeling controversies. At least one state, Texas, has assumed complete control over intrastate wheeling (Cogen Rept., Oct. 11, 1985 at 5). In New Jersey and most states, however, wheeling rates may be subject to FERC regulation.

Often as important as wheeling charges is whether the wheeling utility may assume line losses in the wheeling contract. In the typical utility-to-utility wheeling, power is brought in from afar and some line loss might be expected as the local utility picks up the power at its border and transmits it elsewhere.

Since cogenerators export rather than import power, the situation is reversed. In most states which have considered the issue, it is recognized that cogeneration results in negative line losses. That is, the additional increments of non-utility power added to the lines help to offset line losses otherwise experienced by the utility. Cogenerated power is generally produced at a location which is closer to the load than the utility's power plants. When cogenerated power is wheeled, electrons are not transmitted to the far-away purchasing utility. Instead, they are fed into the grid, and power is delivered to the purchasing utility. If the cogenerator is located close to major load usage in the transmitting utility's service territory -- usually the case, especially in densely populated and heavily developed New Jersey -- the added power will reduce overall line losses as if it were sold to and used by the host utility.

The line loss issue is often crucial. A utility can experience a 5 percent line loss in transporting power from its border to another utility; but if a comparable level of cogeneration is near a large load, the utility should expect a savings of approximately 5 percent. Instead of being charged for line losses, therefore, cogenerators in this situation should receive a credit.

Two New Jersey-based utilities, PSE&G and JCP&L, have expressed a willingness to wheel on certain conditions. ACE however, and to a lesser extent JCP&L, have raised the contention that the State should not require wheeling by a utility on a long-term or firm basis. ACE argues that its transmission system was built for and paid for by its franchise customers and they must have first priority. ACE also argues that its transmission lines are already loaded at 98 percent of its capacity on a year-round basis. If so, then it appears certain that ACE, located in a fast-growing area, will need to expand its transmission capacity in any event. Cogenerators as a class can reduce loading on bulk power transmission lines if they export power or engage in simultaneous buy-sell transactions in which no power is exported to the grid. Thus, a transmission capacity credit would seem particularly appropriate on ACE's system.

ACE's argument that its transmission capacity was built for and is being paid for by its franchise customers misses the point of wheeling services to cogenerators, also among their customers. Wheeling can reduce the costs of transmission services otherwise absorbed by other ratepayers because cogenerators should pay their fair share of transmission capacity. In this respect, if ACE or any other company fails to provide wheeling services when capacity is available, it imposes unnecessary costs on its other customers.

Furthermore, it appears incongruous to deny wheeling services to cogenerators that will provide power efficiently, reliably and within the State while providing such services to out-of-state utilities -- which is

routinely done through PJM interaction. JCP&L imports 70 percent of its power requirements and ACE has contracted for large power imports from Pennsylvania Power & Light; much of this power could be provided in-state through efficient cogeneration that also may reduce acid rain from Pennsylvania coal plants. In-state cogeneration that can wheel from one utility to the next will help right these imbalances.

Setting wheeling rates may be the province of FERC, but there is every indication that the federal regulators will defer to proposals by the states. The methods employed in Texas are noteworthy and may be applied in New Jersey. Two approaches that were debated were a boundary method and a megawatt mile approach. Reportedly, the Texas PUC arrived at a hybrid method that will provide some compensation to all affected utilities and at the same time provide for a stable, easy-to-calculate and verifiable approach.

The New Jersey BPU will be called upon to adopt without delay a similarly definite and fair method of determining wheeling rates and terms of service. (In its 1981 order the Board directed that "[a] Phase II proceeding be established to consider the issue of wheeling within the State of New Jersey." Id., p. 11. On November 13, 1985, the BPU called together various electric utilities for a conference to begin discussion of a BPU wheeling policy.) The goal must be to establish a statewide market for cogenerated power that allows it to be used where it is most needed. In addition, cogenerators should be permitted and encouraged to engage in self-wheeling in which they wheel power from one or more facilities to multiple customers. In this way the most optimally-sized cogeneration system can be constructed and put into operation without running the risk of being charged excessive wheeling rates or being declared a public utility.

Unequal Bargaining Power and Standard Offer Contracts

An electric power utility is both a monopoly and a monopsony. It is a monopoly because it is the only company authorized by law to generate and sell electricity to other customers within a designated service territory. It is a monopsony because by law all non-utility power providers are limited to selling all their excess power to the same utility or risk being declared a public utility (Hamilton and Bros, "The Need for Standard Contracts and Prices for Small Power Producers, "115 Pub. Util. Fort., No. 11, May 30, 1985, 24-32).

Such a position of power -- as the sole buyer and seller -- creates an unequal bargaining situation which can frustrate and stifle the entire cogeneration effort. The monopsonist utility can raise entry barriers through subtle exactions, called transaction costs. It can, for example, discourage cogeneration by engaging in drawn-out contract negotiations requiring time and expensive expert assistance; the utility's time and costs will be passed on to ratepayers, but the cogenerator must bear its own. The utility can say it is eager for cogeneration, but it can rotate negotiators, so that each one must start the process anew; or it can send

negotiators who lack expertise or the authority to close a deal. By imposing unfavorable take-it-or-leave it contract terms, the utility can simply dictate its own bottom line all too often.

Such monopsony abuses are not merely theoretical; they are actual and historical. They were at the heart of the Otter Tail decision, discussed earlier, which found the utility's practices to be in violation of federal anti-trust laws. They were also singled out repeatedly and frequently by cogeneration witnesses in hearings before the DOE as characteristic of their own experiences (See, e.g., Tr. statement of P. Maistro, p. 213). Thus, it is imperative that clear, enforceable and definite measures be in place if we are to even the bargaining positions of the utility and the would-be cogenerator and reduce transactional barriers to a minimum.

The best approach to correcting these problems is to establish standard offer contracts. This approach is used in California with unprecedented success; it is also the approach favored by journal writers and by the cogeneration industry (Hamilton and Bros, supra.) And, while it is opposed by New Jersey's electric power utilities, they have failed to bring forth reasons to support their opposition, other than the simple truism that each cogenerator is different.

The standard offer contract is a uniform contract with the essential terms already filled in and approved by the State. (Logically, a variety of standard offers may be approved by the State, depending on such variables as whether the cogenerator will use renewable fuels or burn solid waste, the size of the cogenerator, and other factors.) The contract empowers the cogenerator to sign the contract "as is" or negotiate any condition it wishes. But the utility cannot refuse the contract as signed. Once the cogenerator has signed it, the contract is an enforceable legal instrument (Id.) In this way, bargaining positions are more nearly equalized, and if negotiations flag, the cogenerator always has the option of fixing his signature to the bottom of the page.

The outline of such a contract at a minimum should include the following:

Part I. Business Relationship to the Utility

A. Status with FERC as a qualifying facility.

B. Purchase price for power and method of payment to the non-utility producer.

C. Price for back-up power and method of payment to the utility.

D. Cost of interconnection and method of payment.

E. Liability.

F. Liability insurance.

G. Access to producer's facilities.

H. Conditions for interruption of

1. power to the facility, or
2. power from the facility.

I. Notice requirements for interruption.

J. Penalty clause for nonperformance of any provisions in the contract.

K. Dispute resolution and arbitration.

Part II. Technical Relationship with the Utility (including safety features)

A. Conformance to applicable laws, codes, regulations and ordinances.

B. Technical requirements for

1. interconnection and
2. operation.

The most important single element in this contract is the price for power: How much can the potential investors expect in the revenue stream from this facility? Since New Jersey will adopt a statewide proxy unit method of calculating buy-back rates, together with a pioneer rate for energy, this will be filled in at the conclusion of that process of determination. Alternatively, for those eager to proceed in the interim, the locked-in projection of the PJM billing rate -- together with a premium for the environmental and social benefits of cogeneration -- may also serve as one contract rate. (The Legislature could even establish a "floor rate" as it did in New York; this rate would then be the minimum for the benefit of a cogenerator.)

Access to Natural Gas

Cogeneration facilities can use almost any combustible matter as their fuel. Some units burn almond shells, corn husks, sawdust, and other forms of waste, including municipal solid waste (resource recovery). Others are not cogenerators at all, but are wind-powered forms of small-power production. Still others will use coal. Most, however, rely on the cleanest burning fuel possible, natural gas. With the end of the gas crisis of the 1970s, natural gas is in abundant supply; but a combination of factors has made it difficult for this gas glut to translate into low prices for all users, including cogenerators. Yet gas is clearly the best fuel, particularly because of air quality standards in New Jersey. As a

result, no cogeneration policy is comprehensive without making provision for access to natural gas.

Until very recently, many industries were turning to direct purchases of gas from producers far from New Jersey as one way to beat the high cost of gas delivered by Local Distribution Companies (LDC's or gas utilities). However, a court order in Maryland Peoples' Counsel v. FERC, 761 F. 2d 768 (D.C. Cir, 1985), and 761 F. 2d 780, and the rising tide of competition in gas transportation services have led FERC radically to alter the rules of gas transportation in Order No. 436.

Interstate pipelines historically purchased gas from the well-head producers, then sold it in bulk to the LDC's which re-sold it retail to the public. The new FERC policy gives pipelines a fundamental choice: Either they can transport all gas on a nondiscriminatory policy or they may not transport at all. They no longer may transport gas to some customers and not for others or charge what FERC labels as discriminatory or preferential rates. (They can of course, continue to transport and sell their own gas.) While a policy against discrimination appears basic to fairness, it may not lead to the result sought by FERC -- more competition in the interstate natural gas market. When the pipelines are glutted with their own high-priced gas which they cannot sell, they are naturally reluctant to transport cheaper gas through their pipelines to cogenerators buying gas from others.

As this transition to the new FERC rules evolves, cogenerators have three choices on fuels: First, they can choose to use non-traditional fuels, such as solid waste or even coal. Second, they can choose to burn natural gas. Or, third, they can choose to burn oil.

The first is highly desirable, where it can be accomplished safely and without harm to the environment. Indeed, it is State policy to encourage or compel counties to plan for the ultimate disposition of municipal solid waste in resource recovery facilities that will generate electricity (N.J.S.A. 13:1E-6(b)(1) and 1E-93, and 48:13A-1, et seq.). See also, Part One, Chapter 2 of this Master Plan. However, siting waste-to-energy plants will prove difficult and controversial, as with landfills.

If a firm can burn low-sulphur coal or coal in a fluidized bed or otherwise comply with air quality standards, it should be encouraged to do so. Coal, however, has not yet proven itself as an attractive fuel for urban cogeneration projects, especially smaller ones.

This leaves natural gas or oil for most users. The former is clean to burn, which makes it highly desirable in urban settings where so many cogeneration projects can be expected. The latter is not nearly so clean and comes primarily from foreign imports. But at least there are oil dealers from which to choose.

The DOE believes that natural gas is by far the preferred choice. Without transportation gas, utilities must provide gas to these users on a reliable and affordable basis. (If not, some companies may be forced to

construct their own connections to interstate pipelines, by-passing the LDC entirely.) Many gas utilities seem eager to provide all the gas they can. They recognize that gas for cogeneration will be an excellent load leveler: It will help to balance the gas company's (winter) heating-peak season with the electric utility's (summer) cooling-peak season. By selling large quantities of gas in the summer to a cogenerator, which in turn sells power to a utility straining to meet peak demands, both utilities appear to benefit along with the cogenerator.

Environmental Permit Procedures

Siting cogeneration units in a densely populated, heavily industrialized state can be difficult. The DEP routinely requires a variety of permits for any industrial, fuel-burning installation. Cogeneration is no exception. Of special concern to the industry is how long it takes to receive permit approval. (Tr. statements of R. Toppe, at 146; B. Trobaugh at 196, P. Maistro at 211, and H. Kociencki at 220, September 20, 1985.) In addition, investors worry that costly selective catalytic converters will be required on all new installation, should California's Air Resources Board adopt such a rule and other states, including New Jersey, follow suit.

The DOE believes that the DEP should recognize the positive environmental externalities conferred by cogeneration, including reducing acid pollution from western coal plants. The latter is the cause of almost all the acid rain that now harms so much of the country, especially the East Coast (J.S. Cannon, Acid Rain and Energy: A Challenge for New Jersey [Inform, Inc., 1984], at 2.). Acid rain, in particular, is produced by large coal-burning power plants that supply New Jersey with much of its energy.

Therefore, the DOE calls upon the DEP to establish a rapid, one-stop permitting process for cogenerators that will lessen out-of-state energy dependence. The environmental agency should be vigorous in seeking out ways to offset the pollution generated at the facility (pollution offsets). Giving the facilities explicit credit for their contribution to New Jersey's acid rain efforts is clearly justified.

Cogeneration in a Power-Glutted Market

California has led the nation in promoting a successful cogeneration industry. In less than five years installed cogeneration capacity has jumped from 300 MW to about 2,000 MW with still more under negotiation (The 1985 California Electricity Report, supra.) The California Energy Commission and the PUC are now facing the problem which the utilities had told them could never happen: too much cogeneration capacity.

Some commentators fear that a cogeneration glut could lead to a death spiral in electric utilities. As more customers generate their own power and sell back to the utility, which is obligated to buy, fewer customers

will be left to pay the fixed costs of the utility. The utility will then raise rates to the remaining customers, which will lead to still more customers leaving the system, cogenerating their own power, or simply increasing their conservation. This concern is especially troubling for utilities which are just finishing costly nuclear power plants. Such utilities may call for caps to be placed on new cogeneration capacity. Alternatively, they may do all in their power to discourage cogeneration through whatever legal means are at their disposal.

Restricting the amount of new capacity from these other sources is at best a short-term solution that would impose substantial hidden costs on the public. The public will pay more than it should if potential cogenerators are denied the opportunity to supply the public with lower cost energy. Setting a limit on cogeneration is roughly akin to tariffs, import quotas and other trade restrictions that may protect certain interests but only by transferring hidden costs to the public. At the same time, the existing utility network must be maintained. Accordingly, some method must be found for encouraging constant innovation and competition but without undermining the basic infrastructure in electricity that is the hallmark of the utility industry.

The DOE believes that there are several approaches to this problem. No utility power plants should be exempt from the competitive forces of non-utility power. Nor should non-utility sources be shielded against the winnowing effects of market forces. The best solution is one which follows the least-cost principle of promoting economic dispatch of power sources, whether they are owned and operated by utilities or by non-utilities.

Placing all power generators on a level playing field is the logical next step in the revolution in electric power regulation and development unleashed by PURPA. There is no need to place an arbitrary lid on new power, if each new increment survives a rigorous test of the marketplace. Simply put, there is no glut of power if adding more capacity means lowering production costs, reducing consumer bills, or reducing the pollution caused by single-purpose power plants. This new, decidedly more open system would resemble the growth era of the 1950s and 60s when each new utility project capitalized on economies of scale and reduced cost and rates to all. The major difference here is that the test of need for new capacity would be based upon market forces. Also, much of the new capacity would be non-utility units that displace utility units; just as new utility capacity in those years often drove non-utility sources out of operation.

In such a competitive setting, if "new" power sources replace the "old" sources, the latter could then be written off (perhaps mothballed, placed under new management, or sold off). If found to be obsolete, the uneconomic units would no longer be "used and useful" to consumers. Therefore, they would not be charged to ratepayers. This approach avoids the "Catch-22" that competition will lead to higher rates even when the competitors will supply electricity at lower rates, because utilities may charge ratepayers for economically obsolete capacity. If a facility -- whether it is a cogenerator or a utility unit -- cannot compete, then the State must not tolerate its forced subsidization by the public. Such a

process might be characterized as one which focuses on the fully avoidable cost to the consumer, not to the utility, although in the long-run the result should be the same.

Change and innovation would substitute for the static concept that utility facilities, once approved, stay in the rate base until they are too old to operate or until they are replaced by new utility units. With de facto and de jure competition ushered in by cogeneration and other non-utility power sources, the power supply industry might resemble the automobile retail market: new vehicles replace existing cars even if they retain some useful life (as evidenced by the used car trade), not because the current stock of cars is determined by some authority to be inadequate in number or seating capacity, but because the new entries offer consumers a choice of lower cost, more reliability, greater safety, or other perceived attractions. Regulation, in an atmosphere of competition, will have to adjust to facilitate a healthy mix of embedded utility capacity, notably in the transmission and distribution area, and emerging non-utility sources that can bid against each other to serve consumers in the lowest cost, most efficient and environmentally sound manner. In this light, there can never be a glut of ways to improve service, improve air quality, and reduce consumers' bills.

New Jersey does not have to begin today to confront a saturated market for non-utility power sources, but the time for doing so could come even faster than in California, which has served the nation so well as a kind of energy laboratory. As a result, the BPU and the DOE, aided by the active participation of the emerging cogeneration industry and the existing utilities, must begin immediately to prepare for a regulatory regime which accurately mirrors the competitive forces now gathering. Therefore, no lid needs to be considered at this time and no moratorium on new cogeneration appears justifiable in the future, if we proceed to plan and prepare for a smooth transition to market-based energy policies in this vital area.

Miscellaneous Concerns

The duty to negotiate in good faith: While the provision of standard offer contracts and firm buy-back rates will do much to promote good faith bargaining by utilities, more protection may still be in order. Utilities may devise tactics or demands which discourage cogeneration. For example, JCP&L's demand that cogenerators sign a recapture clause would deny a cogeneration investor the current use of contracted for payments. (See Statement of Scott Spiewak at Tr. 55-56, September 20.) As such, it can only be described as a bad faith negotiating position. Other bad faith demands can be expected to be identified. To prevent these from holding up the contract process, the BPU and the DOE must maintain an open door policy for resolution of contract disputes. In particular, the BPU should have an expedited appeal process available to all cogenerators. This process would entitle any aggrieved party to petition the BPU for expedited disposition of a contract claim or an argument that a bargaining position is in bad faith. A list of such bad faith demands should be maintained and updated. Whenever a utility has been found to have negotiated in such a

manner, penalties should be imposed on the utility and rewards allocated to the cogenerator which brought them to the attention of the BPU.

Maintaining Data on Cogeneration Development: Every cogenerator should file a registration statement with the DOE and the BPU simultaneous with its request for contract negotiations with a utility. The registration statement will require that the applicant identify the fuels to be used, and the size of the facility, as well as provide other relevant and potentially helpful information. With this process, it will be possible to monitor negotiations, review the milestones in each project, and determine whether any facility should lose its place in line for failure to proceed, while pushing other projects forward. A final registry of facilities will also help energy planners account for the full impact of cogeneration in the State, as it progresses from project inception to on-line facilities.

Utility Entry Into Cogeneration Marketing: With the growth in cogeneration, it is understandable that electric utilities should become interested in this source of power production. The risks to permitting such diversification are obvious. Utility-owned subsidiaries might receive more favorable treatment from their parent utilities, such as higher buy-back rates, easier negotiating, better credit and billing terms, and more favorable cancellation provisions. These fears have been realized in some states. In California, for example, San Diego Gas & Electric has been charged with agreeing to an energy-pricing formula for its subsidiary which exceeds the avoided cost offered to other cogenerators (Cogen. Rept., November 8, 1985, p. 5). Clear conflicts of interest have been found where Southern California Edison personnel hold important positions in its wholly-owned cogeneration-subsidiary (Id.)

PURPA limits utility ownership in any qualifying facility to less than 50 percent of the equity in the project (18 CFR 206). By implication, a utility, therefore, may invest up to that amount and still qualify as a cogenerator entitled to all the guarantees of a non-utility cogenerator. This policy creates incentives for utility management to favor their own subsidiaries, however arms-length the transactions might appear.

On the other hand, if utility shareholders can enjoy some of the benefits of a healthy cogeneration industry, their management will be more receptive to the concept in general and to specific projects in particular. Also, utility investment capital, customer relations and engineering abilities can be helpful in promoting the growth of this vital industry.

The Department believes that the State should offer conditional encouragement to the trend of utilities entering the cogeneration market. (PSE&G and JCP&L have already established such subsidiaries which are actively signing up projects.) Mindful of the risk of anti-competitive actions, however, the State must impose a higher level of scrutiny and special safeguards to all utility-subsidiary projects, at least until the independent cogeneration industry in the State has grown sufficiently to compete equally with utility-owned units. Thus, all contracts for large increments of cogeneration from utility-subsidiaries should be subject to a

period of review by the BPU. Similarly, a policy of notice and protest should be offered in all such contracts, such that independents can protest to the BPU if they believe that they were squeezed out of a bid or were otherwise unfairly disadvantaged in efforts to sign up a customer. Should no problems develop in New Jersey over a reasonable period, then such procedures might be discontinued. But at least in the early going, New Jersey must profit from the experience in other states and take steps to see that this nascent industry is given the chance to flourish, while permitting proper opportunities for utilities to advance in this worthwhile direction.

Setting Cogeneration Quotas or Goals: One way to promote utility use of cogenerated power is to set quotas. Failure to achieve these goals could lead to penalties. The California PUC imposed a 1/7 of 1 percent penalty at the conclusion of its OII-26 investigation on the rate of return of PG&E for its failure to promote alternative energy contracts. The utility's response was dramatic, with PG&E soon emerging as a national leader in the promotion of alternative and small-power energy sources (G. Maneatis, "The Nation's Leading Alternative Energy Utility: PG&E", 114 Pub. Util. Fort., No. 13, Dec. 20, 1984, 18-22. For a history of this seminal case, see D. Roe, Dynamos and Virgins, Random House, 1985). New Jersey may need to have the option of imposing penalties for utility failure to promote cogeneration, to bargain in good faith, or otherwise to develop its full potential.

Incentives for small-power production: Many small cogeneration projects, namely units of 100 kilowatts or less, find it difficult to obtain needed financing due to the marginal economics of all small facilities. These include: capital costs which are high relative to labor, interconnection costs, fuel costs, and stand-by charges. Yet these small units offer great benefits to users and, in the aggregate, to society through their contribution to system reliability and economic development. They are most apt to be used by financially strapped customers, such as non-profit hospitals, YMCA's, schools, and other small to medium-size institutions. By reducing their costs of energy, small power production can enable them to provide greater services at lower costs to their clients and the community.

Accordingly, in order to facilitate their widespread use, the Department believes that units with a capacity of 100 kw or less should have the option of running their load meter backwards, rather than require them to sell their excess output to the utility. Any electricity sold to a utility would first be offset by a credit for purchases from the utility in a simultaneous "buy-sell" transaction, at the customer's request. All net energy sold to the utility would be billed at the retail rate applicable to the user.

SUMMARY AND RECOMMENDATIONS
ISSUES AND PROBLEMS
ACTIONS AND STRATEGIES

1. A STANDARD METHOD OF CALCULATING FAIR UTILITY BUY-BACK RATES IS NEEDED TO ENCOURAGE THE DEVELOPMENT OF COGENERATION.

[The rates offered by electric utilities for the purchase of cogenerated electricity are too low, too variable, and too unpredictable. In addition, these rates fail to satisfy the PURPA requirement to offer rates based upon the "full avoided cost" of cogeneration as a substitute for utility-owned and -operated power plants.]

THE BPU SHALL COMMENCE A PROCEEDING TO ESTABLISH RATES FOR COGENERATION BUY-BACK. THIS PROCEEDING SHALL BEGIN NOT LATER THAN 90 DAYS AFTER THE ADOPTION OF THIS PLAN AND SHALL CONCLUDE AS EXPEDITIOUSLY AS POSSIBLE, BUT IN NO CASE SHALL THE PROCEEDING LAST MORE THAN SIX MONTHS BEFORE A FINAL ORDER IS ISSUED. PROGRESS REPORTS SHALL BE PREPARED AND MADE PUBLIC EVERY 30 DAYS TO DETAIL ALL CRITICAL PATHS AND PROGRESS, ANY IMPEDIMENTS TO MAINTAINING THE HEARING SCHEDULE, AND SUCH OTHER INFORMATION AS THE DOE MAY REQUEST.

THIS PROCEEDING SHALL DETERMINE ALL ISSUES RELATING TO THE APPROPRIATE BUY-BACK RATE. FOR THE CAPACITY COMPONENT OF THE RATE, THE BPU WILL USE THE PROXY UNIT METHOD OF ANALYSIS, ASSUMING THE NEED FOR A NEW BASELOAD COAL-FIRED POWER PLANT, AS DESCRIBED HEREIN, BY 1992. FOR THE ENERGY COMPONENT, THE BPU SHALL DETERMINE THE RATE BASED UPON THE CURRENT RATE FOR OIL- OR GAS-GENERATED ELECTRICITY AT A BASELOAD FACILITY. THIS RATE SHALL APPLY FOR THE PERIOD OF 1986-1992, AT WHICH TIME THE PROXY UNIT'S FUEL COST WILL BE THE ENERGY COMPONENT INSTEAD.

THE BPU SHALL MAKE AVAILABLE FOR COGENERATORS RATES BASED UPON LONG-TERM, LEVELIZED PJM COST PROJECTIONS.

THE ELECTRIC UTILITIES SHALL FILE WITH THE DOE AND MAKE PUBLIC THEIR ESTIMATES OF PROJECTED PJM PURCHASE POWER RATES FOR THE NEXT 5-, 10- AND 15-YEAR PERIODS. A COGENERATOR SHALL HAVE THE OPTION OF SIGNING A CONTRACT WITH A UTILITY USING THESE ESTIMATES. HOWEVER, A COGENERATOR OR ANY OTHER PERSON MAY OBJECT TO THE ESTIMATES. THE BPU SHALL THEN COMMENCE A HEARING, WHICH SHALL BEGIN AND CONCLUDE AS EXPEDITIOUSLY AS POSSIBLE, BUT IN NO CASE SHALL LAST LONGER THAN 30 DAYS.

2. BACK-UP POWER RATES AND LACK OF ACCESS TO BACK-UP POWER DISCOURAGE INVESTMENT IN OTHERWISE FEASIBLE COGENERATION SYSTEMS.

[A 1981 BPU order allows the utilities to base their charges upon an assumed system outage rate of 15 percent, while experience indicates that the outage rate is closer to 5 percent. Gaining access to the utility system often involves problems such as long delays, lack of cooperation, unreasonable demands, and high costs to interconnect. In addition, a FERC decision has raised much doubt as to whether third-party cogenerators will have access to back-up power at any price.]

UPON REQUEST OF A COGENERATOR, EACH ELECTRIC UTILITY SHALL PROVIDE ALL NECESSARY FORMS OF BACK-UP POWER, INCLUDING BUT NOT LIMITED TO SUPPLEMENTARY POWER, BACK-UP POWER, MAINTENANCE POWER, AND INTERRUPTIBLE POWER. NO UTILITY MAY LIMIT THE OFFER OF OR ACCESS TO BACK-UP POWER TO ANY COGENERATOR OR ITS CUSTOMERS ON THE BASIS OF OWNERSHIP INTEREST OR FINANCING BASIS OF THE COGENERATION UNIT.

EACH UTILITY SHALL PUBLISH A GENERIC LIST OF COMPONENTS FOR INTERCONNECTION, WHICH SHALL APPLY IN ALL CASES EXCEPT WHERE THE APPLICANT PRESENTS A CLEARLY DISTINCT PROPOSAL THAT MERITS INDIVIDUALIZED ATTENTION AND NEGOTIATION. THIS LIST SHALL BE SUBMITTED TO THE BPU WITHIN 30 DAYS OF THE ADOPTION OF THIS MASTER PLAN AND, UNLESS OBJECTED TO, SHALL CONSTITUTE THE STEPS REQUIRED FOR SUCCESSFUL INTERCONNECTION. IF OBJECTED TO, THE BPU SHALL PROMPTLY SCHEDULE AND COMPLETE A HEARING AND ISSUE A DETERMINATION NO LATER THAN 30 DAYS AFTER THE CONCLUSION OF THE HEARING. IF ANY UTILITY UNREASONABLY DELAYS OR OBSTRUCTS A COGENERATOR IN ITS EFFORTS TO OBTAIN INTERCONNECTION, THE BPU SHALL IMPOSE FINANCIAL PENALTIES TO BE AWARED IN PART TO THE COGENERATOR BRINGING THE COMPLAINT.

THE RATES FOR SALES OF BACK-UP POWER SHALL NOT BE BASED UPON THE ASSUMPTION THAT FORCED OUTAGES OR OTHER REDUCTIONS IN ELECTRIC OUTPUT BY ALL COGENERATION FACILITIES ON AN ELECTRIC UTILITY'S SYSTEM WILL OCCUR SIMULTANEOUSLY, OR DURING THE SYSTEM PEAK, OR BOTH; AND SHALL TAKE INTO ACCOUNT THE EXTENT TO WHICH SCHEDULED OUTAGES OF THE COGENERATION FACILITIES CAN BE USEFULLY COORDINATED WITH SCHEDULED OUTAGES OF THE UTILITY'S FACILITIES. THE BPU SHALL REQUIRE UTILITIES TO SUBMIT STANDARD BACK-UP POWER RATES AS PART OF THE REQUIREMENT TO SUBMIT AND MAINTAIN STANDARD OFFER CONTRACTS.

EACH COGENERATION FACILITY SHALL BE OBLIGATED TO PAY ANY REASONABLE INTERCONNECTION COSTS WHICH THE BPU AUTHORIZES THE UTILITY TO CHARGE. NO RATE MY EXCEED THE ACTUAL AND REASONABLE COST OF COMPLETING THE INTERCONNECTION, UNLESS A RETURN ON SAME IS AUTHORIZED BY THE BPU ON SIMILAR INTERCONNECTIONS FOR NON-COGENERATING CUSTOMERS. NO INTERCONNECTION FEE SHALL BE REQUIRED TO BE PAID IN ADVANCE. EACH COGENERATION FACILITY SHALL HAVE THE OPTION OF PAYING ITS INTERCONNECTION COSTS AS PART OF ITS REGULAR BILLING OR AS A DEDUCTION FROM BUY-BACK RATES. STANDARD BUY-BACK RATES AND TERMS SHALL BE INCLUDED IN EACH STANDARD OFFER CONTRACT.

3. COGENERATORS MUST HAVE ACCESS TO TRANSMISSION LINES TO WHEEL EXCESS ELECTRICITY AT REASONABLE RATES.

[Electric utilities maintain barriers, including unpredictable wheeling rates and non-economic restraints, to non-utility power sources who wish to gain access to transmission lines for the sale of cogenerated power to utilities in different service territories. In addition, cogenerators serving more than one facility need to engage in self-wheeling to take full advantage of economies of scale.]

IF A COGENERATION FACILITY AGREES, AN ELECTRIC UTILITY SERVING THE AREA WHEREIN THE FACILITY IS LOCATED SHALL TRANSMIT THE ENERGY OR CAPACITY OR BOTH TO ANY OTHER ELECTRIC UTILITY. IF THE UTILITY FAILS TO DO SO, UPON REQUEST THE UTILITY SHALL BE OBLIGATED TO PURCHASE THE POWER FOR USE IN ITS OWN SYSTEM AND SHALL PAY THE COGENERATION FACILITY AS IF IT HAD PERFORMED AS REQUESTED, UNLESS THE UTILITY SHOWS GOOD CAUSE FOR ITS REFUSAL TO WHEEL. GOOD CAUSE SHALL MEAN THE PHYSICAL OR ENGINEERING INABILITY TO TRANSMIT THE POWER DUE TO LACK OF TRANSMISSION CAPACITY, NOT INCLUDING A LACK OF CAPACITY CAUSED BY THE RESERVATION OF CAPACITY FOR UTILITY-GENERATED POWER NOT ON THE SYSTEM, TRANSMISSION OF POWER FROM OTHER UTILITIES OR WHEN A LACK OF CAPACITY SHOULD HAVE BEEN FORESEEN BY THE UTILITY DUE TO GROWTH ON THE SYSTEM.

WHERE UTILITY TRANSMISSION CAPACITY HAS BEEN FOUND BY THE BPU TO BE SATURATED, THE BPU SHALL ORDER THE UTILITY TO DEVELOP PLANS FOR THE EXPANSION OF CAPACITY IN THE MOST ENVIRONMENTALLY SOUND AND FISCALLY PRUDENT MANNER, BUT THE UTILITY SHALL NOT CHARGE COGENERATION FACILITIES MORE THAN THEIR FAIR SHARE OF NEW CAPACITY ON THE BASIS OF AN AUCTION AND BID SYSTEM IN WHICH UTILITY-SUPPLIED POWER SHALL HAVE NO ADVANTAGE OR PREFERENCE OVER POWER TO BE GENERATED BY A COGENERATION FACILITY.

ANY UTILITY TO WHICH SUCH ENERGY OR CAPACITY IS TRANSMITTED SHALL PURCHASE SAME AS IF THE COGENERATION FACILITY WERE SUPPLYING ENERGY OR CAPACITY DIRECTLY TO SUCH ELECTRIC UTILITY, EXCEPT THAT THE RATE FOR PURCHASE BY THE ELECTRIC UTILITY SHALL BE ADJUSTED UP OR DOWN TO REFLECT LINE LOSSES AND SHALL NOT INCLUDE ANY CHARGES FOR TRANSMISSION.

NO UTILITY SHALL CHARGE FOR LINE LOSSES DUE TO TRANSMISSION UNLESS THE UTILITY DEMONSTRATES THE ACTUAL INCIDENCE OF SAID LINE LOSSES ATTRIBUTED TO THE SPECIFIC COGENERATION FACILITY IN QUESTION.

NO UTILITY SHALL CHARGE FOR LINE LOSSES DUE TO TRANSMISSION IF THE COGENERATION FACILITY IS LOCATED WITHIN REASONABLE PROXIMITY OF LARGE LOAD DEMANDS ON THE UTILITY SYSTEM, DUE TO THE NEGATIVE NATURE OF SUCH LINE LOSSES.

NO UTILITY MAY CHARGE FOR LINE LOSSES UNLESS THE BPU APPROVES SAID CHARGES, AND IN NO CASE SHALL A COGENERATION FACILITY BE REQUIRED TO PAY FOR SUCH LOSSES IN ADVANCE OR WITHOUT THE OPTION TO PAY OVER A MUTUALLY AGREED PERIOD.

THE BPU SHALL ESTABLISH UNIFORM, STATEWIDE RATES FOR TRANSMISSION SERVICES WHICH SHALL BE INCLUDED IN THESE STANDARD OFFER CONTRACT AT THE OPTION OF THE COGENERATION FACILITY. SUCH RATES SHALL BE NON-DISCRIMINATORY AND NO GREATER THAN THE ACTUAL COST OF TRANSMISSION, TOGETHER WITH SUCH RETURN ON INVESTMENT AS THE BPU AUTHORIZES.

UPON REQUEST, EACH COGENERATION FACILITY SHALL BE ENTITLED TO TRANSMIT ITS POWER GENERATION OR ANY PORTION THEREOF TO AND AMONG ITS CUSTOMERS ON A NON-DISCRIMINATORY BASIS AT A RATE TO BE DETERMINED BY THE BPU.

4. THE USE OF STANDARD OFFER CONTRACTS CAN HELP TO EQUALIZE THE BARGAINING POWER OF UTILITIES AND COGENERATORS.

[Many factors contribute to the unfair bargaining advantages of utilities over cogenerators, including the monopsony position of the utility and the greater risk exposure of cogeneration investors. Steps must be taken to prevent utilities from taking advantage of their monopsony status.]

THE BPU SHALL REQUIRE EACH ELECTRIC UTILITY TO PREPARE STANDARD OFFER CONTRACTS WITHIN 30 DAYS OF THE ADOPTION OF THIS MASTER PLAN. EACH CONTRACT SHALL ADDRESS AT A MINIMUM ALL THE REQUIREMENTS PRESENTED IN THIS PLAN AS SUITABLE FOR CONTRACT OFFERS AND SUCH OTHER REQUIREMENTS AS THE BPU OR THE DOE SHALL, FROM TIME TO TIME, REQUIRE TO BE INCLUDED.

A STANDARD OFFER CONTRACT IS AN OFFER TO ENTER INTO A CONTRACT WITH ANY QUALIFIED COGENERATION FACILITY. IT SHALL INCLUDE ALL ESSENTIAL TERMS REQUIRED OF THE UTILITY AND THE COGENERATION FACILITY AND ENTITLES THE FACILITY TO ACCEPT THE TERMS OF THE CONTRACT ON ITS FACE OR TO NEGOTIATE ANY CHANGES, ADDITIONS, OR DELETIONS IT WISHES. UPON SIGNING THE CONTRACT AND FILING A CERTIFIED COPY WITH THE UTILITY, THE BPU AND THE DOE, THE CONTRACT SHALL BE BINDING ON THE SIGNATORY AND THE UTILITY.

ANY COGENERATION FACILITY SHALL BE ENTITLED TO ACCEPT THE STANDARD OFFER CONTRACT PRESENTED TO THE BPU OR IT MAY PROTEST THE TERMS, CONDITIONS OR ANY LANGUAGE IN THE CONTRACT OFFER AND REQUEST A HEARING WITH THE BPU, WHICH THE BPU SHALL COMMENCE AND COMPLETE AS SOON AS POSSIBLE, NOT TO EXCEED SIX MONTHS. AT THE CONCLUSION OF THIS HEARING, THE BPU SHALL REQUIRE WHATEVER CHANGES, ADDITIONS OR DELETIONS NECESSARY TO ACHIEVE THE PURPOSES OF THIS MASTER PLAN. THE STANDARD OFFER AS APPROVED OR MODIFIED SHALL THEN OPERATE AS A BINDING LEGAL INSTRUMENT IN THE SAME MANNER AS A STANDARD OFFER CONTRACT SUBMITTED BY THE UILITY AND SUBJECT TO ACCEPTANCE BY AN QUALIFIED COGENERATION FACILITY.

5. COGENERATORS NEED ACCESS TO ADEQUATE, AFFORDABLE SUPPLIES OF NATURAL GAS.

[Natural gas is the principal fuel of cogeneration and, due to its clean-burning properties, the fuel of choice in urban and densely populated areas. Prospective cogenerators often have difficulty in securing supplies at affordable prices.]

THE BPU SHALL REQUIRE EACH NATURAL GAS UTILITY (LOCAL DISTRIBUTION COMPANY OR LDC) TO OFFER TO PROVIDE NATURAL GAS TO ANY COGENERATION FACILITY AS THE PRIMARY FUEL FOR THE FACILITY IN SUCH QUANTITIES AND QUALITY NECESSARY FOR SUCCESSFUL COGENERATION. WITHIN 30 DAYS OF THE ADOPTION OF THIS PLAN, EACH LDC SHALL ALSO PREPARE AND SUBMIT PLANS TO THE BPU AND THE DOE WHICH SHALL DETAIL THE AMOUNTS, QUALITY AND RATES TO BE CHARGED FOR NATURAL GAS FOR COGENERATION, ANY SERVICE EXTENSIONS NECESSARY, AND ANY RESTRICTION OR CONDITIONS ON THE RECEIPT OF SUCH SERVICES.

RATES FOR TARIFFS FOR NATURAL GAS FOR COGENERATION SHALL BE NO HIGHER THAN THOSE FOR NATURAL GAS SOLD BY THE LDC TO SIMILARLY SITUATED CUSTOMERS, EXCEPT THAT SOME CREDIT SHOULD BE ACCORDED COGENERATORS IN LIGHT OF THE EXTERNAL BENEFITS CONFERRED BY COGENERATION.

6. IN ORDER TO ENCOURAGE COGENERATION, THE PROCESS OF OBTAINING ENVIRONMENTAL PERMITS MUST BE EXPEDITED.

[Cogeneration developers have had difficulty in gaining the necessary environmental permits from the Department of Environmental Protection. They also fear the exaction of unreasonable air pollution requirements that may make cogeneration uneconomic.]

THE DEP SHALL ESTABLISH A PROCEDURE FOR THE PROMPT AND FAIR RESOLUTION OF ALL PERMIT REQUIREMENTS FOR COGENERATION APPLICANTS WITHIN A SINGLE OR INTEGRATED PERMIT PROCESS.

DUE TO THE POTENTIAL NET REDUCTIONS IN VARIOUS AIR POLLUTANTS IN NEW JERSEY FROM THE WIDESPREAD USE OF COGENERATION TO SUBSTITUTE FOR UTILITY POWER GENERATION AND PURCHASES, THE DEP SHALL DEVISE AN OFFSETS STRATEGY WHEREBY POLLUTANTS EMITTED AT THE LOCAL LEVEL FROM A COGENERATION FACILITY MAY BE OFFSET FROM NET REDUCTIONS IN POLLUTANTS ENTERING THE SAME GENERAL AREA.

THE DEP SHALL DEVISE AND EMPLOY METHODS FOR DETERMINING THE AGGREGATE AIR QUALITY IMPACTS OF VARIOUS LEVELS AND TYPES OF COGENERATION USAGE AS AN ALTERNATIVE OR SUPPLEMENT, IN WHOLE OR IN PART, TO REQUIRING INDIVIDUALIZED AIR QUALITY REVIEWS FOR EACH COGENERATION APPLICANT.

7. THE GROWTH OF COGENERATION MAY BE STIFLED BY THE CONTINUING AND, IN SOME CASES, GROWING GLUT OF UNECONOMIC BUT UTILITY-OWNED ELECTRIC POWER GENERATING CAPACITY.

[As more customers generate their own power and sell back to the utility, fewer customers will be left to pay the fixed costs of the utility. The utility will then raise rates to remaining customers, leading to still more customers leaving the system, cogenerating their own power, or simply increasing conservation. Restricting the amount of new capacity from other sources is at best a short-term solution that would impose substantial hidden costs on the public.]

EACH COGENERATION SPONSOR SHALL FILE WITH THE DOE A CONFORMING COPY OF ITS APPLICATION TO BE CERTIFIED AS A QUALIFYING FACILITY PURSUANT TO FERC REGULATIONS, 18 C.F.R. 292.203 AND .207 AT THE SAME TIME THAT IT FILES FOR SAME WITH FERC. THE DOE SHALL THEN MAINTAIN AN OPEN REGISTER OF "QF" APPLICATIONS AND ALL UPDATES AS PROVIDED BELOW. EACH COGENERATOR SHALL THEN FILE WITH THE DOE AT LEAST ONCE EVERY SIX MONTHS, OR MORE OFTEN IF SO ORDERED, A REPORT SETTING FORTH THE FOLLOWING:

A. A LIST OF CRITICAL MILESTONES IN THE DEVELOPMENT OF THE COGENERATION PROJECT, ESTIMATED DATES FOR ACHIEVING THOSE CRITICAL POINTS AND ANY IMPEDIMENTS AND PLANS FOR MEETING SAME;

B. THE STATUS OF THE COGENERATION PROJECT IN MEETING THE MILESTONES IDENTIFIED IN ITS PRIOR REPORT OR AS THEY MAY BECOME KNOWN;

C. THE STATUS OF THE PROJECT WITH THE DEP AND ANY OTHER FEDERAL, STATE OR LOCAL AGENCY WHICH REQUIRES PERMITS TO CONSTRUCT OR OPERATE THE FACILITY;

D. THE STATUS OF THE COGENERATION PROJECT IN ITS CONTRACT DEALING WITH ANY ELECTRIC UTILITY REGARDING BUY-BACK RATES, INTERCONNECTION, BACK-UP POWER, WHEELING, NATURAL GAS, OR ANY OTHER RELEVANT NEGOTIATION ISSUE INVOLVING REGULATED UTILITIES IN NEW JERSEY;

E. A CONFORMING COPY OF THE CONTRACT(S) WITH THE ELECTRIC UTILITY(IES) AT THE TIME IT IS SIGNED AND FINALIZED;

F. A NOTARIZED STATEMENT FROM THE PROJECT SPONSOR WITHIN 24 HOURS OF THE DATE THAT (1) CONSTRUCTION HAS BEGUN ON THE FACILITY, (2) WHEN CONSTRUCTION HAS BEEN COMPLETED, AND (3) WHEN THE FACILITY HAS BEEN BROUGHT INTO OPERATION;

G. A REPORT OF THE FACILITY'S OPERATING RECORD AT THE CONCLUSION OF EACH CALENDAR YEAR, NOTING ANY CHANGES IN HEAT RATE, FUEL USE, SIZE, EFFICIENCY, OUTAGES, OR OTHER RELEVANT INFORMATION.

AT LEAST ANNUALLY THE DOE SHALL PUBLISH A STATUS REPORT ON COGENERATION IN NEW JERSEY WHICH SHALL INCLUDE, BUT NEED NOT BE LIMITED TO, A SUMMARY OF THE PRIOR DATA AND SHALL PROMINENTLY SET FORTH A STATEMENT AS TO THE AMOUNTS OF COGENERATION PLANNED, CERTIFIED WITH FERC, UNDER CONTRACT, UNDER CONSTRUCTION, AND IN OPERATION.

ANY COGENERATION PROJECT OF 100 MW OR LARGER SHALL BE DESIGNATED AND CONSIDERED TO BE AN "ENERGY FACILITY" PURSUANT TO THE DEPARTMENT OF ENERGY ACT, N.J.S.A. 52:27F-15(c), AND THEREFORE SHALL REQUIRE A FINDING OF NEED AND CONFORMANCE WITH THE APPROVED ENERGY FORECAST AND RESOURCE PLAN OF THE AFFECTED UTILITY(IES), PURSUANT TO THE REQUIREMENTS OF N.J.A.C. 14A:20-1.1, ET SEQ., AND THE ENERGY FACILITY REVIEW POLICIES OF THE DEPARTMENT.

WITHIN SIX MONTHS OF THE ADOPTION OF THIS MASTER PLAN, EACH ELECTRIC POWER UTILITY SHALL SUBMIT A PLAN TO THE DOE AND TO THE BPU FOR ACHIEVING A REALISTIC MARKET FOR POWER COMPETITION BETWEEN AND AMONG UTILITY FACILITIES AND NON-UTILITY FACILITIES, INCLUDING METHODS FOR COMPARING THE DIRECT AND INDIRECT COSTS OF POWER GENERATION, SYSTEM EFFICIENCY AND RELIABILITY AND ENVIRONMENTAL IMPACTS. THE PLAN WILL DESCRIBE METHODS FOR AUCTIONING RIGHTS TO SELL POWER TO THE UTILITY ON A NON-DISCRIMINATORY BASIS. UTILITY FACILITIES AND NON-UTILITY SOURCES WILL HAVE EQUAL OPPORTUNITY TO COMPETE FOR THE OPPORTUNITY TO GENERATE AND MARKET ELECTRICITY, IN ORDER TO FURTHER THE GOALS OF A LEAST-COST ENERGY STRATEGY FOR RATEPAYERS. WITHIN 30 DAYS OF RECEIPT OF THE PLANS, THE DOE AND THE BPU SHALL SET FORTH DATES FOR HEARINGS TO CONSIDER SUCH PLANS AND DETERMINE HOW BEST TO PROMOTE COMPETITION AND LEAST-COST DELIVERY OF RELIABLE, ENVIRONMENTALLY SOUND SERVICE. THESE HEARINGS SHALL BE COMPLETED WITH AN ORDER ISSUED SETTING FORTH SUCH STRUCTURE OF A MARKET FOR POWER SOURCES WITHIN ONE YEAR OF THE ADOPTION OF THIS PLAN.

8. COGENERATORS MUST BE PROTECTED FROM BAD FAITH DEMANDS AND BARGAINING.

[Evidence indicates that utilities do not always bargain in good faith. While standard offer contracts and firm buy-back rates will promote good faith bargaining, more protection may be needed.]

NO UTILITY MAY REQUIRE AS A CONDITION OF ANY CONTRACT THAT THE COGENERATION FACILITY AGREE TO A RECAPTURE CLAUSE OR ANY OTHER ARRANGEMENT WHICH WILL DENY TO THE FACILITY AND ITS INVESTORS THE IMMEDIATE USE OF ALL PAYMENTS FOR THE SALE OF CAPACITY OR ENERGY.

EACH UTILITY SHALL NEGOTIATE IN GOOD FAITH AT ALL TIMES WITH ANY COGENERATION OWNER, OPERATOR OR SPONSOR AND SHALL ENDEAVOR TO REACH AN AGREEMENT IN THE SHORTEST POSSIBLE TIME.

THE BPU SHALL ESTABLISH AN ABBREVIATED PROCESS FOR THE HEARING OF COMPLAINTS, PROTESTS OR PETITIONS FOR DECLARATORY RULINGS ON BAD FAITH ACTIVITIES OR NEGOTIATING POSITIONS. UPON SUCH A FIND, THE BPU SHALL ORDER THE UTILITY TO CEASE AND DESIST FROM SUCH BAD FAITH ACTION, AND IT SHALL ORDER THE UTILITY TO PAY OR CREDIT TO THE COGENERATION PROJECT A SUM EQUAL TO ALL COSTS ATTRIBUTABLE, DIRECTLY OR INDIRECTLY, TO SUCH BAD FAITH ACTIONS.

THE BPU SHALL DEVISE, DEVELOP AND MAINTAIN A CURRENT LIST OF BAD FAITH PRACTICES, WHETHER PRESUMPTIVELY OR PER SE BAD FAITH, AND IT

SHALL ENTERTAIN PETITION FOR DECLARATORY RULINGS WITH RESPECT TO ANY PRACTICE WHICH THE PETITIONER BELIEVES SHOULD BE ADDED TO OR REMOVED FROM THE LIST. SUCH PRACTICES SHALL INCLUDE, BUT NOT BE LIMITED TO, INJECTING BAD FAITH DEMANDS INTO THE NEGOTIATION PROCESS, HABITUALLY OR REPEATEDLY FAILING TO MEET REASONABLE REQUESTS FROM A POTENTIAL COGENERATOR FOR MEETINGS, ANSWERS OR DECISIONS, OR FAILING TO BRING TO MEETINGS REPRESENTATIVES KNOWLEDGEABLE ABOUT THE PARTICULARS OF THE COGENERATION PROJECT AND QUALIFIED TO RENDER DECISIONS THAT BIND THE UTILITY IN THE MANNER OF A BUSINESS AGENT. A UTILITY DEEMED TO BE ENGAGING IN SUCH BAD FAITH NEGOTIATION SHALL BE LIABLE TO THE COGENERATOR FOR ALL COSTS PROXIMATELY CAUSED BY SUCH BAD FAITH NEGOTIATION OR DEMANDS, AS DETERMINED BY THE BPU.

9. COGENERATOR MUST HAVE THE OPPORTUNITY TO PROVIDE LEAST-COST ENERGY FOR CONSUMERS.

[Cogenerators have not in the past been able to displace utility-generated capacity, even though the power generated from these sources is more expensive.]

IF A UTILITY REFUSES TO CONTRACT FOR CAPACITY OR ENERGY OR BOTH FROM AN OTHERWISE QUALIFIED COGENERATION FACILITY DUE TO A LACK OF NEED FOR THE POWER, AND IF NO OTHER PURCHASER OF THE POWER IS FOUND BY THE UTILITY WHICH WILL PURCHASE POWER TRANSMITTED TO IT, THE COGENERATION FACILITY MAY BID AGAINST POWER SUPPLIED BY UTILITY-OWNED AND -OPERATED FACILITIES OR OTHER NON-UTILITY PROJECTS. THE UTILITY SHALL SELECT THE POWER SOURCE WHICH AVOIDS THE GREATEST COST OTHERWISE INCURRED BY THE RATEPAYERS OF THE UTILITY. IF THE COGENERATOR IS AGGRIEVED BY THE DECISION OF THE UTILITY, IT MAY PETITION THE BPU FOR A DECLARATORY RULING THAT THE UTILITY SHOULD PURCHASE THE POWER OFFERED BY THE COGENERATOR UPON A FINDING THAT (1) THE POWER THAT WOULD BE DISPLACED COSTS MORE TO PRODUCE OR SUPPLY THAN THE POWER FROM THE COGENERATOR, WHETHER CAPACITY OR ENERGY OR BOTH; AND (2) THE COGENERATOR OFFERS NON-ECONOMIC BENEFITS, SUCH AS ENHANCED SYSTEM RELIABILITY, THE BURNING OF ALTERNATIVE FUELS, THE REDUCTION OF AIR OR WATER POLLUTION OR OTHER ADVANTAGES SUPERIOR TO THOSE FROM THE UTILITY FACILITY OR OTHER NON-UTILITY FACILITIES ON THE SYSTEM.

THE BPU AND THE DOE SHALL REQUIRE TO PURCHASE POWER, CAPACITY OR ENERGY OR BOTH, FROM COGENERATION WHICH IS LESS COSTLY TO RATEPAYERS THAN UTILITY-OWNED OR -OPERATED CAPACITY EXCESS, REGARDLESS OF WHETHER SUCH UTILITY CAPACITY IS IN RATE BASE, WHENEVER THE NON-UTILITY SOURCE WOULD CONFORM TO OR OTHERWISE PROMOTE A LEAST-COST ENERGY STRATEGY. IN MAKING THIS FINDING, THE BPU SHALL FIND THAT THE NON-UTILITY SOURCES PROMOTE A LEAST-COST ENERGY STRATEGY WHENEVER SAID COGENERATION FACILITIES OR INCREMENTS CAN DISPLACE COSTLIER UTILITY FACILITIES. THE BPU SHALL THEN PROCEED TO DETERMINE WHETHER SAID CAPACITY WHICH IS DISPLACED SHOULD BE REMOVED FROM RATE BASE AS NO LONGER USED AND USEFUL.

10. SMALL COGENERATION FACILITIES MUST BE PROTECTED FROM UNFAIR COMPETITION FORM UTILITIES THAT ENTER THE COGENERATION MARKET.

[Utilities are beginning to enter the market for cogeneration development; however, special safeguards are needed to protect competition.]

ANY COGENERATION FACILITY OF 100 KW OR LESS SHALL BE CONSIDERED A "SMALL POWER PRODUCTION FACILITY."

THE BPU SHALL REVISE ITS COGENERATION AND SMALL POWER PRODUCTION TARIFF/RIDER QFS (MARCH 21, 1985, DOCKET NO. 8412-1239) TO IMPLEMENT THE OPTION OF NET ENERGY BILLING AT A RATE EQUAL TO THE UTILITY'S EFFECTIVE RETAIL RATE FOR THE CUSTOMER, WHICH SHALL APPLY FOR ANY SMALL POWER PRODUCTION FACILITY.

THE BPU SHALL REVIEW EACH CONTRACT FOR CAPACITY, ENERGY OR BOTH FOR ANY COGENERATION FACILITY OF 1 MW OR GREATER THAT IS FINANCED OR OWNED IN PART BY THE SUBSIDIARY OF AN ELECTRIC UTILITY. THE BPU SHALL DETERMINE WHETHER THE UTILITY OFFERED ANY PREFERENCE TO THE PROJECT THAT IS NOT AVAILABLE TO NON-UTILITY UNITS, AND SHALL, IF IT SO FINDS, DISAPPROVE OF SAME OR IMPOSE SUCH NEW STANDARDS AS IT FINDS APPROPRIATE.

THE BPU SHALL PROVIDE 30 DAYS FOR ANY PERSON TO PROTEST THE AWARDING OF ANY CONTRACT TO ANY COGENERATION FACILITY THAT IS FINANCED OR CONSTRUCTED IN WHOLE OR PART BY A UTILITY SUBSIDIARY.

Thomas H. Kean
Governor

NEW JERSEY DEPARTMENT OF ENERGY
101 Commerce Street
Newark, New Jersey 07102

Leonard S. Coleman, Jr.
Commissioner

COGENERATION LEGISLATION ENACTED

S-2529 signed into law by Governor Kean August 1985. P.L. 1985, C. 266 exempts cogeneration equipment from sales tax.

S-2531 signed into law by Governor Kean November 1985. P.L. 1985, C. 359 exempts natural gas used for cogeneration systems from the Gross Receipts and Franchise Taxes (approximately 13.5%).

PENDING COGENERATION LEGISLATION

A-2773 exempts cogeneration facilities from property tax for five years. Pending in the Assembly Revenue, Finance and Appropriations Committee.

A-2717 is a supplemental appropriation of $500,000 for individual cogeneration feasibility studies. Pending in the Assembly Revenue, Finance and Appropriations Committee.

For a copy of the above laws or bills, call the New Jersey Bill Room at (609) 292- 6395.

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SECRETARY'S OFFICE
Public Utility Commission

LIMERICK 1 RATES

Feb. 4, 1986

This paper was prepared in regards to the electrical rate increase for Limerick 1, the 1,050 megawatt nuclear powerplant. This plant cost between $2.2 billion and $3.8 billion. The staff of the PUC (Public Utilities Commission) claims that $1.6 billion was added to the original cost of $2.2 billion by construction delays in 1976 and 1978. The PE (Piggydelphia Electric) budget should be split into two parts, namely a capital budget and an operating budget. For example, SEPTA (Southeastern Pennsylvania Transportation Authority) has a capital budget and an operating budget.

The capital budget would cover the cost of air pollution controls for coal-burning power plants, such as Eddystone and Cromby; repairs to the Peach Bottom boiling water nuclear reactors, and the cost of another boiling water nuclear plant Limerick 1. Somebody ought to determine if PE will continue to operate coal-burning plants, such as Cromby and Eddystone, now that Limerick 1 is in full operation.

The operating budget would cover such matters, as salary increases. A strong suspicion exists that once a given project is paid for, Piggydelphia Electric transfers the raise in rates for project completion into a salary increase. There seems to be no budget planning. Piggydelphia Electric needs to use the Gramm-Rudman federal budget planning technique.

For example, Piggydelphia Electric asked for a rate increase of $228 million on Feb. 23, 1983. The PUC granted a rate increase of $143.5 million on Nov. 22, 1983. This

increase consisted mostly of raising the rate per KWH (Kilowatt Hour). $65 million of this increase was used to install and operate air pollution control equipment at the coal-fired Eddystone and Cromby plants. Now an interesting question arises. Does this $65 million still support air pollution equipment or is it used to pay salaries at Piggydelphia Electric Co.? In short consumers should pay for repairs to existing equipment, new facilities, and new nuclear power plants, but not for salary increases and other non-essentials. Salaries and other non-essentials should be frozen.

The consumers do have a voice in the OCA (Office of Consumer Advocate) with Consumer Advocate David M. Barash. But I don't think there is a close relationship between the consumers and the OCA.

Is the per cent raise to the householder, who uses 200 to 1000 KWH, the same as the per cent raise for large industrial users? At one time Piggydelphia Electric was increasing rates more for small customers than for large customers.

In the July 23, 1981 defunct Bulletin the Piggydelphia Electric Propaganda Minister Ronald Harper is quoted as saying, "During these times of inflation, if you don't come back once a year, you've got something super going for you". Then, there are three other Piggydelphia officials involved with inflation. They are Joseph H. Paquette; vice president in charge of finances and accounting; Clifford Brenner; vice president of propaganda; and Neil McDermott; who is the Poo Bah of Piggydelphia Electric. Poo Bah was the character in the Gilbert and Sullivan light opera, "The Mikado", who was Lord High Everything Else.

These four upper level "Piggydelphia streetpersons" from the Energy Castle at 23 & Market come around and seek handouts from everybody. They differ from the Center City "Streetpersons" in that they don't actually suffer from economic need. These four "Energy Castle streetpersons" are "dollar addicts", who are hooked on a "dollar habit". Ever since Piggydelphia Electric moved from the Edison Bldg. at 9 & Sansom to the Energy Castle, this company has gone off on an economic binge.

Why does nuclear power cost so much? You can still have nuclear power at reasonable rates to the consumer and give the stockholders a return of 14 to 17%, if you can control the cost of nuclear power.

As I said in a Oct. 15, 1984 protest letter about rate increases, there seems to be very little information available to me in regards to salaries. Last year, Philadelphia City employees got a salary increase of 8%. Does that occur in Piggydelphia Electric? I can't help but wonder if Piggydelphia Electric doesn't grant higher salaries and wages, and then ask for a higher rate to pay for these higher salaries and wages. Maybe it should get the rate increase, first, if any: and then pay higher salaries and wages, second. To return to 1983, in the worst depression in fifty years, Piggydelphia Electric whined for a rate increase. I imagine if Piggydelphia Electric could get the energy for free, as from a waterfall; it would still claim it needs a rate increase.

There is still another peculiar fact about nuclear power plants, namely that they self-destruct in 25 years. There were articles in the Sept. 4, 1984 Inquirer and the Nov. 12, 1984

U. S. News and World Report that the first nuclear plant in the U. S. at Shippingsport; 25 miles from Pittsburgh, Pa.; was to be torn down by the federal government, after operating for 25 years since 1958.

There are two reasons for this eventual failure, both caused by neutron bombardment from the Uranium 235 of the nuclear core. First, the neutron bombardment destroys the crystalline structure of the metal and produces metal fatigue. The metal parts become brittle and break very easily. This especially affects the pressure vessel and the pipes.

Second, after 25 years of neutron bombardment, the metal parts become artificially radioactive. Even if the Uranium 235 and its neutrons are removed, the metal parts still emit nuclear radiation, which seems to consist of charged helium atoms or alpha particles, and high speed electrons or beta particles. It is not known whether this secondary radiation includes gamma rays, also known as X-rays, and secondary neutrons.

Hence, this neutron destruction of nuclear plants in 25 years should result in large depreciation losses on federal income taxes. The larger neutron depreciation loss should reduce the electric rate charge to the consumers.

Recently, a dispute arose between Arie Schinnar, a Wharton School economist from Pennsylvania University, who is a consultant to the City of Philadelphia in its fight on the rate change and Clifford Brenner. This is described in the Jan. 15, 1986 and Jan. 20, 1986 issues of the Inquirer on Arie Schinnar. Brenner's reply is in the Jan. 30, 1986 Inquirer. Effectively,

Schinnar uses a computer model, called Starloc, to attack the electrical rate increase. In his reply Brenner asks if the city used Starloc to predict what the effect on the economy would be when the city proposed a 32% water rate increase in 1985.

As one who was involved in the water rate hearings in 1981, 1983, and 1985, I can provide a partial answer to Brenner's question on city water rates. On Fri.; Aug. 16, 1985 Deputy Water Commissioner Ronald L. Coy estimated a 12.5% increase in 1986 for electrical rates and a 10% increase in 1987. He stated that estimates are difficult in electrical rates.

On Fri.; Aug. 23, 1985 Coy raised his estimates on the rise in electrical rates to 24%. Thomas Canuteson, a consultant to the Consumer Party and the CLS (Community Legal Services) also said it is difficult to forecast water rates because one doesn't know what the electrical rate increase will be.

Just as Philadelphia Electric is bringing Limerick 1 boiling water nuclear reactor into operation, so the City is bringing three new sewage treatment plants into operation within a year or two. They are the Northeast, Southwest, and Southeast. I might add I am not a member of the Consumer Party.

Actually, there are three electrical rates; namely the Bill Fee, alias Customer Charge; the KWH charge, and ECR (Energy Cost Rate). In New Jersey, there is a law which says commercial legal forms must be written in plain English. If Pennsylvania had such a law, electrical bills would identify the Customer Charge as the Bill Fee.

The Bill Fee began in June, 1982. In Feb., 1983 I wrote a letter to three Piggydelphia Electric officials; namely Paquette, McDermott, and Harper; and sent copies to the five PUC Commissioners. In it I said that if PE bills didn't contain the KWH charge and the State Tax Adjustment Charge within one year, the Bill Fee should be cut from $3.50 to $1. Instead, after three years the Bill Fee has risen from $3.50 to $4.50 and the bills still do not contain the KWH charge or State Tax Adjustment Charge. The bills should also identify the Bill Fee as a separate charge, instead of merging it as part of the KWH charge. The reason for this concealment is to avoid rate shock. The Pennsylvania legislature should overrule the PUC and pass a law to bring about these reforms.

It is true that one can obtain auxiliary documents from PE, which will identify the Bill Fee and give the KWH rate. From time to time the bills are accompanied by small calculation sheets, which indirectly give the State Tax Adjustment Charge. All three figures should be on the bill.

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Photocopies of the following articles are included:--

1. PE Seeking Another Rate Increase; July 23, 1981 Bulletin.
2. First Nuclear Plant Dismantles After 25 Years;
   Sept. 4, 1984 Inquirer.
3. Atomic Power's New Woe: How to Bury Old Plants;
   Nov. 12, 1984 U. S. News & World Report.
4. Economist: PE Rate Hike Could Cut Jobs;
   Jan. 15, 1986 Inquirer.
5. PE Executive Replies: Rate-Hike Concerns Unfounded;
   Jan. 30, 1986 Inquirer.

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SECRETARY'S OFFICE
Public Utility Commission

PE seeking another rate increase

By GUNTER DAVID
Of The Bulletin Staff

Philadelphia Electric Co. (PE), which received a record $187.6 million electricity rate increase in April, will seek another boost next Wednesday.

Mayor Green disclosed the company's plans yesterday at a press conference, saying he learned about the impending rate request at a meeting with company officials.

Green declined to elaborate, and Clifford Brenner, PE vice president for communication, said the company will release no information until the request is filed with the Pennsylvania Public Utility Commission (PUC).

On April 24, the PUC granted Philadelphia Electric an 11-percent rate increase. But Brenner noted the boost had been requested nine months earlier and that it was far less than the $304 million the company had sought.

At the time the increase was granted, spokesman Ron Harper predicted the company would ask for another one soon. "During these times of inflation, if you don't come back once a year, you've got something super going for you," Harper said.

PE's electricity charges rank seventh among 11 major eastern utilities, according to information released by the company.

Customers using 500 kilowatt hours per month are charged $42.93 by PE, $46.59 by Atlantic City Electric, $44.98 by Delmarva Power (Delaware) and $43.86 by Public Service Electric & Gas Co. (New Jersey). Pennsylvania Power and Light charges $29.36 a month.

PE has 1.2 million customers in Philadelphia and the four suburban counties.

After quarter-century, U.S. is dismantling its first nuclear plant

Boston Globe

The first nuclear power plant in the United States now stands silent, nestled against a hillside overlooking the Ohio River near the small western Pennsylvania town of Shippingport, about 25 miles from Pittsburgh.

Its dedication in 1958, attended by President Dwight D. Eisenhower, was a high point in the nation's "Atoms for Peace" initiative under which the atom was harnessed to light people's homes. Its retirement two years ago, after 25 years of service, passed with little public notice.

Now, after a two-year wait, the uranium fuel inside the reactor core has cooled and been removed, and this first commercially operated nuclear plant is about to be the first to be torn down in a $79.7 million project the U.S. Energy Department hopes will demonstrate to the public that reactors can be retired safely.

Compared with the attention given to financing, building and operating reactors, little has been said about what happens when "old age" sets in at a plant, accompanied by levels of radioactivity that make further maintenance and operation impractical.

The chief cause of old age is metal fatigue, caused by nuclear fission inside the reactor that heats metals throughout the plant and also causes them to develop radioactive properties of their own. Many critical parts of the plant deteriorate over time and eventually cannot be serviced because they are so highly radioactive that mechanics cannot work on them long enough to fix them.

"Decommissioning," as it is called — by entombment in concrete, mothballing under tight security or dismantlement as at Shippingport — is a fate facing all the world's 300 operating reactors before the year 2025. In the United States, 20 of the more than 80 licensed commercial reactors will be candidates for decommissioning over the next 15 years, according to the Energy Department.

At Shippingport, which was built and operated by the federal government on a site provided by a private utility, the plan is to tear the plant down to the ground — piece by piece.

Edward G. DeLaney, the Energy Department's project manager, says this work will be made easier by the fact that, as a "first child," the Shippingport plant received special care and has reached the end of its life much less radioactive than its younger but bigger cousins.

Officially, the work at Shippingport begins this month, with the federal government picking up the tab. At other commercial plants, the utility company that owns the reactor will bear the cost of decommissioning. At many utilities, trust funds are being established for that purpose. The money for the trust funds comes from a small charge in the consumer's monthly electric bill.

The parts of a nuclear power plant that get most radioactive and require the most careful handling are the reactor vessel, the piping leading into and out of the vessel, the pumps that move the cooling water out of the reactor to the steam generator and the steam generator itself.

Chemical sprays will be used to decontaminate the interior of the plant. That alone should reduce radiation by as much as 90 percent before hundreds of welders and other craftsmen begin their work, DeLaney said.

Throughout most of 1986 and into 1987, this crew, with saws and torches, some of which can be operated at a distance, will be cutting up hundreds of feet of irradiated pipes and huge pieces of steel shielding into bits small enough for shipment.

Then comes the 35-foot-high, 10-foot-diameter steel reactor vessel — a virtual replica of the vessel that powered the USS Nautilus, the world's first nuclear submarine, also now retired.

The uranium the Shippingport reactor vessel held is gone, but its 7-inch-thick walls still emit radiation at unacceptable levels and will continue to do so for two centuries or more and, in the case of some stainless-steel parts, for up to 10,000 years.

To reduce the risk to workers, the Energy Department plans to encase this steel in three feet of concrete and then lift this 770-ton hulk, in one piece, with a specially built crane onto a waiting track transporter. Finally, the reactor vessel is to be floated away.

Plans call for the vessel to be taken sometime in late 1987 or 1988 down the Ohio and Mississippi Rivers, through the Gulf of Mexico and the Panama Canal, and up the Pacific Coast to the Columbia River.

Its final resting place will be deep beneath the desert sands surrounding some of the nation's most secret atomic energy facilities near the Hanford Reservation in Washington state. Over time, its radioactivity will decay to a point where, DeLaney says, "after 100 to 200 years, you could excavate that entire area safely." The rest of the radioactive material from the plant will be trucked to the site and also will be buried. The uranium fuel will be taken by rail to a government nuclear laboratory in Idaho.

Traditional critics of nuclear energy say that at first glance the procedures to be employed to take apart the plant on its present seven-acre site are as safe as can be expected in what is acknowledged to be an infant technology.

The Union of Concerned Scientists, long a voice against aspects of nuclear technology it considers unsafe, sees decommissioning "as a very low-risk thing" compared with other nuclear-energy concerns, spokeswoman Jane Seegal said.

But Sally Hindman, a researcher for the Critical Mass Energy Project, an organization led by consumer advocate Ralph Nader, says floating all the debris by barge through populated areas and across Panama is another matter.

"I think there is going to be a big outcry," she said. "People are going to question the potentiality of accidents and what it might mean for their community."

TIMOTHY A. MURPHY—USN&WR

Dismantling of old nuclear structures is industry's next big task.

Atomic Power's New Woe: How to Bury Old Plants

Reactors that have outlived usefulness are a growing and costly problem. The challenge: Getting rid of them safely.

Hard on the heels of many problems that have plagued the nuclear-energy industry, another nightmare is developing: How to dispose of a growing inventory of aging power plants.

Of mounting concern is the fate of as many as 20 outworn reactors that may be shut down by the end of the next decade and could pose health hazards far into the future. Even with uranium fuel rods removed, the concrete-and-steel hulks will remain dangerously radioactive for thousands of years.

Dismantling the huge reactors, say industry officials as well as critics of nuclear power, could add to consumers' utility bills or create a public-health threat if radiation is allowed to escape.

"Giving old nuclear reactors a decent burial is going to be a difficult task," concedes Daniel Williams, an Arkansas Power & Light Company engineer and chairman of an industry-backed task force on dismantling. "We have the technology available to do the job, but we haven't put it to the test yet."

Long before the first kilowatt of commercial U.S. nuclear power was produced in 1958, it was known that reactors eventually would have to be decommissioned—an industry term for razing them and disposing of the debris.

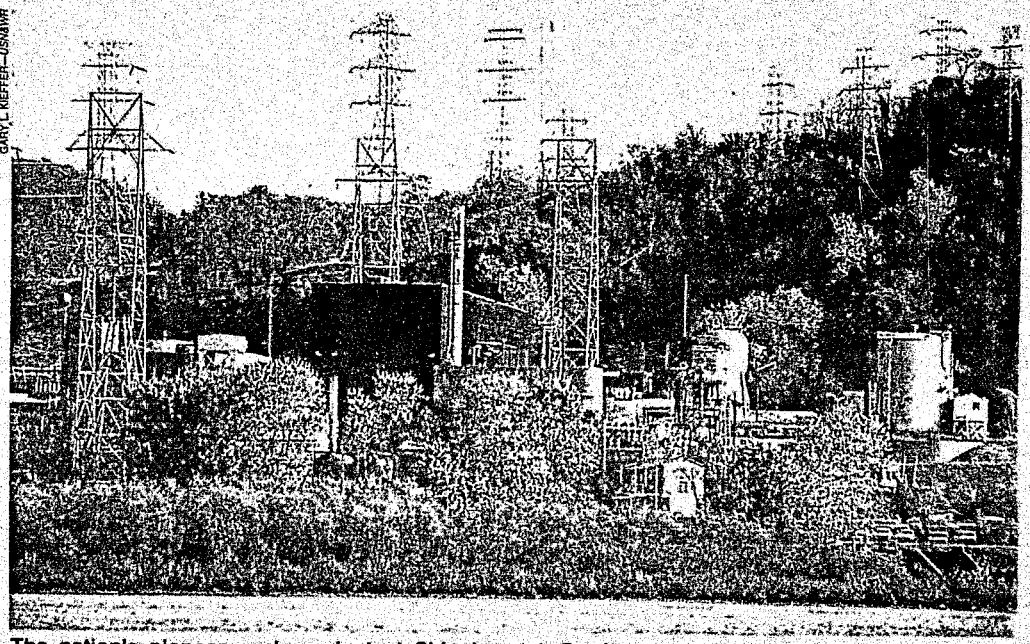
"Like any other piece of heavy industrial equipment, nuclear plants wear out," says Lynn Wallis, a General Electric engineer and an American Nuclear Society spokesman. "Pumps, valves and pipes are subject to corrosion and leaks. Eventually, it becomes more economical to shut a plant down rather than try to maintain it in good condition."

Of 86 operating reactors in the U.S., four already have shut down permanently and are candidates for demolition: Humboldt Bay in California, the Dresden plant near Chicago, Indian Point in New York and Shippingport in Pennsylvania. In addition, the Three Mile Island reactor in Pennsylvania that was crippled in a major accident in 1979 is still being cleaned up and may not reopen.

Some congressional analysts and experts at the Nuclear Regulatory Commission suggest that closed reactors could number 20 or more in the next few years. They cite maintenance and structural problems, such as cracks in pipes or brittle reactor walls, as the kinds of defects that will shorten the plants' projected lifespans.

Who pays? By any measure, decommissioning commercial reactors will be costly. The Atomic Industrial Forum, a nuclear-power advocate in Washington, forecasts demolition costs of large plants averaging 77 million per unit in 1984 dollars. Though some utilities have reserves to cover part of the decommissioning process, others will have to pass costs to consumers in higher rates.

"The industry underestimates how massive this job is going to be," says Michael Totten of the Critical Mass Energy Project, which backs alternatives to nuclear power. "Taking apart a highly radioactive vessel weighing hundreds of tons isn't an everyday engineering prob-



GARY L. KIEFFER—USN&WR

The nation's pioneer nuclear plant at Shippingport, Pa. Its reactor will be the first commercial one to be taken apart and buried.

Life Inside a "Hot" Reactor

MIDDLETOWN, Pa.

Five years after the nuclear accident at Three Mile Island, red and yellow signs inside the damaged power plant proclaiming "Danger: Contaminated Area" still serve as reminders of the event.

Radiation-control technician Donald Knaby recalls the first time he suited up to go into the affected area. "It was real scary," says the ex-steelworker. "You were going someplace where you weren't real sure what was going to happen."

Since then, Knaby, 35, has entered the radioactively "hot" building a dozen times for his employer, General Public Utilities (GPU), which is doing cleanup work. About 800 people are involved in defueling the TMI plant.

Across the United States, thousands of employes function daily in and around nuclear reactors. An estimated 5,000 unskilled workers are hired by the industry each year as "jumpers" or "glowboys" to repair steam-turbine generators. They do manual jobs in which a few minutes of exposure puts them at the upper end of radiation limits set by the U.S. Nuclear Regulatory Agency.

GPU does not hire these so-called radiation sponges, maintaining that it does not need them.

As the industry begins to dismantle its older reactors, thousands more workers will get their first major exposure to alpha and beta rays emitted by nuclear materials—rays that in large amounts can be extremely dangerous.

Whether these people eventually will have higher cancer rates than those in other occupations remains to be seen.

Why they work. Considering the negative publicity surrounding TMI, why would anyone accept employment inside the plant? "I like it," answers Greg Hoek, a 27-year-old auxiliary operator. "Working for a power company on electric lines would be more dangerous."

To find such workers, the nuclear industry often turns to such firms as Catalytic, Inc., of Philadelphia, which recruits and psychologically screens prospects. "We try to weed out the abnormal and those who might go off the deep end," says Pete Kopyscianski, manager of Catalytic's power-projects division.

Technician works on cleanup operation at Three Mile Island.

Workers are well paid but not rich. There is no hazardous-duty increment. At TMI, the company pays union wages ranging from $13 an hour for painters to $15 for journeyman electricians. An agreement with the state prevents strikes and walkouts.

For the employes, life inside a nuclear plant is carefully controlled. Sensors monitor individual radiation doses constantly. The doses are tabulated in a computer as each person leaves the area. As personal dosage levels rise, the workers must get renewed permission to enter reactor buildings. Closed-circuit-TV cameras monitor work.

Layers of protection. Technicians in a hot building are sheathed in layers of protective clothing to keep contaminated dust and fluids off their skin. In addition to street clothes, a typical worker wears three layers of plastic boots, a yellow plastic work suit sealed with tape at all openings, several layers of gloves, a surgeon's cap, a respirator, an air purifier and a dosimeter to measure radiation exposure.

Despite such efforts, workers sometimes do get contaminated. "I had a friend who got some radiation contamination," says Hoek, "and he picked up a half-hour of overtime for taking a shower."

James Renshaw, a GPU manager, agrees that mistakes do happen, "but we clean the guy up, and we try to prevent it from happening as much as possible."

By RON SCHERER

lem." Antinuclear groups also argue that decommissioning poses serious health risks. They note that radioactive chemicals and building materials will be carried by boat and truck and that landfill sites may leak hazardous runoff into public water supplies.

Several methods have been devised for getting rid of plants after their uranium fuel has been removed. Some will simply be mothballed—fenced off, guarded and monitored for a period of years. Another approach is entombment, in which a reactor vessel is encased in concrete until radiation inside subsides enough for disassembly.

A third method is being tried at Shippingport, a generating plant near Pittsburgh that is about to become the first commercial reactor to be disassembled and buried. Department of Energy supervisors of the four-year project guess that dismantling Shippingport's relatively small reactor will cost 80 million.

The job will require heavy protective shielding for workers because one day's exposure to the reactor would contaminate a person with a lethal dose of radiation. Used tools will have to be buried as radioactive waste. Water will be sprayed continuously over the demolition site to keep radioactive dust from spreading.

When the reactor vessel itself is exposed, it will be encased in concrete. The 770-ton structure will then be carried by barge down the Ohio and Mississippi rivers and through the Panama Canal for ultimate burial at a federal facility in Washington State.

Ed DeLaney, head of the Department of Energy decommissioning staff that is managing the Shippingport work, believes the job can be done with minimum risk to the public. "What we learn at Shippingport will determine the best way to dismantle other plants," he says.

Massive bills. What worries officials at the NRC as well as consumer advocates is whether the industry will be able to afford the costs of decommissioning plants that are 10 to 20 times larger than Shippingport.

The NRC has proposed that utilities be required to set up funds to finance decommissioning so that users of a reactor's electricity also pay those costs.

"You can't guarantee that a power company will even be around in 40 or 50 years," says an NRC official. "It's important that utilities provide for future costs of dismantlement now." □

By STANLEY N. WELLBORN

Economist: PE rate hike could cut jobs

By Andrew Cassel
Inquirer Staff Writer

The Philadelphia region could lose 19,000 jobs by 1989 if Philadelphia Electric Co. gets the electric-rate increase it has requested in order to pay for its Limerick 1 nuclear plant, a consultant to the city said yesterday.

Arie Schinnar, a Wharton School economist, said employment growth in the city alone would be reduced by 8,000 jobs if PE's proposed $671 million rate increase is approved.

In testimony submitted for the city to the state Public Utility Commission, which is now considering PE's rate request, Schinnar says the PE rate increase would cost the city government an additional $16 million a year by 1989. More than a third of that would result from lower tax revenues, he says.

The city is among nearly a dozen government agencies and consumer groups challenging PE's plan to raise electric rates beginning beginning in June, mostly to pay for Limerick 1. The giant, 1,050-megawatt power plant, which was completed a year

(See LIMERICK on 8-A)

Inquirer

JAN 15 1986

Economist: Limerick rate increase could cost region 19,000 jobs by '89

LIMERICK, from 1-A

ago, is being readied for commercial use beginning next month.

In the testimony submitted yesterday, PE's opponents assailed the Limerick plant, saying it was unneeded and too expensive and asking the PUC to shrink the proposed increase by as much as two-thirds.

PE spokesman Neil McDermott said the company would answer its challengers in the PUC hearings. But he added that there is "absolutely no substantiation" for the idea that higher electric rates cost jobs.

PE has put the cost of its newest nuclear plant at $3.8 billion — a total that includes the price of facilities designed to be shared by both Limerick 1 and its still-unfinished twin, Limerick 2. The company has asked to begin recovering its costs, plus a profit, on the plant beginning this June.

If granted in full by the PUC, that would mean an average increase of 9.4 percent in electric rates each year for three successive years. By 1988, PE says it would be getting an extra $671 million in revenues.

The proposed increase would bring the typical Philadelphia-area homeowner's electric bill to more than $76 a month. The highest current average bills in the nation, paid by customers of New York's Consolidated Edison, are about $73 a month. Con Ed does not have a rate-increase request pending.

Utility rates in Philadelphia were cited as among the highest in the nation in a recent quarterly survey by the American Chamber of Commerce Researchers Association, which compares living costs among U.S. cities. The survey, using figures supplied by PE, reported the monthly bill for a typical 1,800-square-foot all-electric home as $182.91, behind only New York City.

Schinnar, in his testimony to the PUC, says that the company's plan to further increase rates would slow growth in nearly all sectors of the region's economy, by forcing consumers to spend about 16 percent more of their income on electricity even after inflation.

He said that under PE's plan, the region's economy would have about 1,400 fewer jobs in manufacturing, about 5,200 fewer in services and about 5,180 fewer in wholesaling and retailing.

The numbers were generated by a computer model of the region's economy, which Schinnar and his colleagues have been developing over the last 18 months, he said.

As a result of the Schinnar study and others, the city is asking the PUC to stretch out PE's rate request so that prices for electricity rise only about 4 percent each year for seven years, instead of 9.4 percent each year for three.

In separate testimony submitted to the utility commission yesterday, the PUC's own staff recommended reducing the allowable cost of Limerick 1 to about $2.2 billion, a move that by itself would shrink the rate increase by about two-thirds.

The PUC staff contends that company-ordered construction delays in the mid-'70s added an extra $1.6 billion to Limerick 1's cost. The delays came during periods of high interest rates, which sharply increased the cost of financing the project.

In 1981, after a preliminary investigation of Limerick's cost, the PUC ruled that PE had acted imprudently in delaying construction. But the commission did not say how much the action would reduce PE's rate increase for the plant. When PE filed its rate-increase request in September, the utility argued again that it should not be penalized for the delays.

PUC staff attorneys protested, arguing that the issue had already been decided. All that remained was to determine the appropriate size of the penalty, they said. Administrative Law Judge Joseph P. Matuschak, who is presiding over the current rate-increase hearings, agreed. But the company appealed to the full commission.

Whether or not PE is penalized for the delays, the Limerick plant is simply too expensive to justify adding it to PE's rate base, a group of commercial users said yesterday.

According to a consultant for the University of Pennsylvania and other large customers, Limerick 1's costs, which will be paid beginning this year, far outweigh its benefits, which won't be seen for decades.

"It is doubtful that the entire cost of Limerick 1 will ever be justified by its operating savings for customers," Boston consultant Paul Chernick told the commission. Chernick said PE should be allowed to collect no more than $187 million for Limerick 1 this year, an amount more than 80 percent below what PE says it needs to begin paying for the plant.

Chernick also criticized PE for retiring several small oil-fired power plants, which the company says it will not need now that Limerick is becoming operational.

Hearings on the rate-increase proposal began last month and are expected to continue through March, after which Matuschak will make a recommendation to the full PUC.

Four special hearing sessions at which members of the public are invited to testify have been scheduled for this month and next. The sessions are:

- Thursday, Jan. 23, at 1:30 p.m. at the Delaware County Council meeting rooms, Second and Orange Streets, Media.
- Monday, Feb. 3, at 6:30 p.m. at the Student Center, Delaware Valley College, Route 202, Doylestown;
- Tuesday, Feb. 4, at 1:30 and 6:30 p.m. at Arch Street United Methodist Church, Broad and Arch Streets, Philadelphia.

JAN 15 1986

Inquirer

PE executive replies

Rate-hike concerns unfounded

To the Editor:

The Inquirer's editorial credibility, already substantially eroded, suffered yet another drop by a shameful rush to judgment on the Limerick Unit 1 rate case. A Jan. 21 editorial uncritically accepts as gospel the arguments and positions set forth by intervenors in the case, without having the journalistic decency to wait for either a response or cross-examination.

Working from a computer model, a Wharton professor hired by the city testified that the city and the region would suffer a reduction in the potential growth of jobs if the Limerick 1 rate increase were granted. A similiar attempt at this kind of academic analysis was made in the Limerick 2 show-cause hearings by yet another "expert," Leonard Rodberg. In less than two minutes of cross-examination, Mr. Rodberg's initial testimony that 840 jobs would be lost to the area for every 1 percent increase in electric rates was consigned to the ash heap.

I quote Mr. Rodberg's pathetic response: "It is very difficult to extract from the overall employment change in a region the effect of a factor such as a change in electric rates, and to my knowledge no one anywhere succeeded in doing that kind of disaggregation. . . . I did not claim, and I don't think anybody could claim, that you could look at the actual employment change in a region and see the effect of, in most cases, see the effect of the change in energy prices because there are so many other things going on in an economy that affect the level of employment, movement of industry, people, etc."

Perhaps Arie Schinnar of the Wharton School will be able to defend his computerized conclusions next month better than Mr. Rodberg did his. In the meantime, his claim, just like Mr. Rodberg's claim before it, has been given by The Inquirer a currency and credibility it simply does not deserve.

The Inquirer speaks of "economic damage" in founding its editorial on the Schinnar testimony. Perhaps The Inquirer would like to run its own price increases through the Schinnar computer model. In 1970, a column-inch of advertising in the daily Inquirer was priced at $28.70. In 1985, the same column-inch was $163.59, an increase of 470 percent. For the same years, the increase for the Sunday Inquirer runs 552 percent. Perhaps the Schinnar computer model would show that advertisers in The Inquirer and their customers have been so impacted by these price increases that they have been unable to sustain their buying power and other job-creating economic activity. Could it be that The Inquirer contributed substantially to the city's depressed economic conditions of those years by its own rate increases?

And one wonders, since Mr. Schinnar is the city government's consultant, whether the city ran its proposed 32 percent water increase through his computer model to determine its impact on jobs and the economy.

It should also be noted that in the Limerick 2 show-cause hearings last year another Wharton professor, the well-known and highly respected Anita A. Summers, testified on behalf of PE to the effect that the company's estimates of regional economic growth were too conservative. That is to say, her testimony *supported* restarting construction of Limerick 2.

Did the editorial take that into account in its baseless refutation of the need for Limerick 2? Did the editorial take into account that the administrative law judge's decision in the Limerick 2 matter stated that additional capacity would be needed in the 1990s? Yet, the editorial regurgitates uncritically an unnamed consultant's assertion that, let alone Limerick 2, Limerick 1 is not "cost-justified for decades."

Even before it goes into commercial operation next month, Limerick 1 has already generated over 1.3 billion kilowatt hours, the savings from which will be passed on to Philadelphia Electric customers. Last summer, when our company exceeded the peak load its opponents said would not be reached until the 1990s, Limerick 1 — still in testing — provided the kilowatt hours needed to meet that peak. Limerick 1 has made it possible to retire 963 megawatts of aged and expensive oil-burning capacity, reducing this area's (and the nation's) dependence on foreign oil.

The editorial goes on to rave about "a new technology . . . able to convert the mountains of culm slag . . . into cheap electric powers." We see here again an editorial grasping for pie-in-the-sky technologies to replace the need for Limerick. This time, it is not solar or wind power; it is culm-fired generators. In fact, there has yet to be a commercial-size application in this country of this not-new-at-all technology that will provide reliable electric power. I doubt seriously that The Inquirer would want to depend on culm-fired generators to deliver the electric power to run its word processors and presses five years from now.

Finally, commenting on the PUC's decision to permit the completion of Limerick 2, the editorial asserts that the cost cap to which the company has agreed is "unenforceable." No basis for making that statement is given; one can attribute it only to editorial arrogance. The sad fact is that much of the editorial smacks of the same.

Clifford Brenner
Philadelphia Electric Co.
Philadelphia.

Inquirer

JAN 30 1986

FEB 20 1986
SECRETARY'S OFFICE
Public Utility Commission

TESTIMONY OF LAURIE CAMERON BEFORE PUC ON PROPOSED PECO INCREASE

February 4, 1986

My name is Laurie Cameron; I am the director of Germantown Residents Acting to Conserve Energy, known as GRACE. GRACE serves the Northwest sector of Philadelphia as part of a network of six Neighborhood Energy Centers.

Our center takes applications for all the forms of financial assistance on fuel and utility costs which are available in Philadelphia. We operate both self-help and crew-assisted weatherization programs for low and moderate income households and provide extensive education programs on energy-related topics to the entire community. By the end of this program year we will have served over 3000 households, the vast majority of whom are low income and unable to pay the cost of average utility service or fuel usage.

The effect of a 28 percent increase in the cost of electrical service would be considerable in the neighborhoods served by GRACE. Nearly a quarter of the households in our area might be classified as "working poor" -- that is they earn their income through employment but are eligible for fuel assistance grants. Most such households are marginal at best in their ability to meet basic expenses and pay all utility and fuel bills. A 20 dollar increase in their electric bills will be felt immediately by this group struggling to sustain the American dream in the duly prescribed and approved manner.

The very poor, those on welfare and other low fixed incomes or without income, have already awakened to the reality of shut-offs and long waits in neon lit offices. They accept what they can get and survive. We won't kill them or even get rid of them just by making electricity more expensive or even by shutting them off. In the present climate of budget cuts and supply-side economics they have become accustomed to a decreased grant here or an increased bill there -- they can't pay it anyway and the people they have voted for ~~the~~ to represent them havn't been able to do anything about it. More important that the widows and orphans who constitute the vast majority of PECO stockholders get their dividend. If they don't, that's news -- top of the financial page.

This company's rates are already 34 percent above the national average and the full increase would place it 81 percent above the average. Residential rates have risen nearly 50 percent since 1980 while commercial industrial rates rose only 27 percent. You see, PECO had to build this plant so commerce and industry would have enough electricity to operate. But the company has to keep the price low so they don't move away or generate their own electricity. They have options. The people in our neighborhood have candles.

Between 1975 and 1983 welfare grants in Pa. went up 20 percent while the cost of living rose 74 percent and the cost of electric skyrocketed 150 percent. PECO has begun to recognize the plight of people caught in this cost/income vise by launching a pilot bill reduction program for families with a long-term inability to pay. The Customer Assistance Program, as it is called, operates like a welfare program in the sense that participants must reveal all their income and accept the dictates of the company on certain lifestyle matters. Homeowners have been asked to sign documents which were intended to result in liens against their property. In return participants receive sizeable reductions in their bills and a chance to have arrearages forgiven provided they pay their bills.

This raises the question whether company-operated welfare programs are the most fair and appropriate vehicle for reducing the cost of electric service to low and moderate income people. If the argument is accepted that it is o.k. to reduce the bills of certain selected renters without reimbursement, then that same argument could be applied to resurrecting the idea of "life-line" rates for low and moderate income households who keep their average usage below some ceiling -- say 400 kilowatt/hours a month.

A life-line rate would be of especial help to the working poor and to homeowners who would rather reduce their usage than subject their homes to a lien. It would'nt preclude offering a CAP-style program to the very poor for whom usage reduction would not suffice. The total income to PECO from the low and moderate income cohort of the residential sector constitutes only a small percentage of total company income. Perhaps a life-line rate extended to a customer could bring in an automatic payment of Low Income Home Energy Assistance funds to the company.

In any event, I hope and urge that you keep in mind the plight and interests of those who are most vulnerable to rate increases. Thank you.

R-850152
Roc

INTERHOUSE CORRESPONDENCE

TO Judge Robert A. Christianson - C/o PUC - Harrisburg 17120

DATE 2/6/86 SUBJECT Making Utility Companies reduce their requests for money

I wrote to you on 8/29/85 complimenting you on the effort you made to reduce the Bell Atlantic rate request to 12% of the amount they were asking. I now hope you will aid the rate payers in reducing the 671 million rate request by Phila. Electric Co which I believe is 28% increases over the next few years. It seems that the mistakes and mismanagement of P.E are always charged to rate payers, but the stockholders receive their splendid dividends very regularly, regardless of costs at Limerick construction errors. I doubt if we need all the power P.E. claims will be required and hope you check carefully.

SIGNED _____ DEPT: _____

REPLY:

If rates continue to increase, many poorer families will have difficulty in keeping warm enough to stay healthy in cold weather, and the new Balance the Budget law passed by Congress means more reductions in costs of everything including welfare.

Copy to Janice M. Liddell - PUC - Harrisburg 17120

Thank you for your efforts also Mrs. Salafferio good deeds.

RECEIVED
FEB 10 1986
Office of A. L. J.
Harrisburg

DOCUMENT FOLDER

DOCKETED
FEB 10 1986

M. J. QUINN
740 ARLINGTON RD
NARBERTH PA
19072

DATE 2/6/86 SIGNED M. J. Quinn

COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION
P. O. BOX 3265, HARRISBURG, Pa. 17120

February 11, 1986

IN REPLY PLEASE
REFER TO OUR FILE

Jerry Rich, Secretary
Pennsylvania Public Utility Commission
New Filing Section
P.O. Box 3265
Harrisburg, PA 17120

RECEIVED
FEB11 1986
SECRETARY'S OFFICE
Public Utility Commission

In re: Pennsylvania Public Utility Commission

v.

Philadelphia Electric Company

Docket No. R-850152

Dear Mr. Rich:

Enclosed for filing please find an original and nine copies of the Trial Staff's Answer to the Respondent's Motion for Certification for filing in the above-captioned matter.

Very truly yours,

Daniel P. Delaney
Deputy Chief Counsel

Enclosures

cc: Honorable Joseph P. Matuschak
Service List

RECEIVED
FEB 11 1986
SECRETARY'S OFFICE
Public Utility Commission

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION :
:
v. :
: Docket No. R-850152
PHILADELPHIA ELECTRIC COMPANY :

DOCKETED
FEB 12 1986

TRIAL STAFF'S ANSWER TO RESPONDENT'S MOTION FOR CERTIFICATION

AND NOW, this 11th day of February, 1986, comes the TRIAL STAFF of the Pennsylvania Public Utility Commission (Trial Staff) and answers the motion of the Philadelphia Electric Company (PECO) for certification of interlocutory order in the following manner:

1. On January 21, 1986, the Commission entered an order affirming the ruling of presiding Administrative Law Judge Matuschak granting the Trial Staff's Motion in Limine and holding that the issue of the Company's prudency in delaying Limerick construction in 1976 and 1978 could not be relitigated in the instant proceeding.

2. On January 31, 1986, PECO filed a motion requesting the Commission to amend its January 21 order to include the language required by Section 702(b) of the Judicial Code, 42 Pa. C.S. §702(b), so that an interlocutory appeal with permission could be taken to the Commonwealth Court.

FOLDER

3. Section 702(b) of the Judicial Code provides:

> When a court or other government unit, in making an interlocutory order in a matter in which its final order would be within the jurisdiction of an appellate court, shall be of the opinion that such order involves a controlling question of law as to which there is substantial ground for difference of opinion and that an immediate appeal from the order may materially advance the ultimate termination of the matter, it shall so state in such order. The appellate court may thereupon, in its discretion, permit an appeal to be taken from such interlocutory order.

4. The Trial Staff opposes the Company's request for certification of the January 21 order for the following reasons:

a. Section 702(b) requires a statement that an immediate appeal would materially advance the ultimate termination of the matter. An appeal at this time of the prior order will do nothing to advance this case, whose litigation at this point is approximately half completed. Indeed the prosecution of an appeal at this time, as indicated below, raises a substantial issue of the Commission's jurisdiction to complete the case while the matter is before the Commonwealth Court.

b. The legal issues advanced in its motion by the Company have all been addressed and rejected by both the Presiding Officer and the Commission in the course of ruling on the Trial Staff's Motion in Limine. Their resurrection at this point provides no basis to amend the prior order.

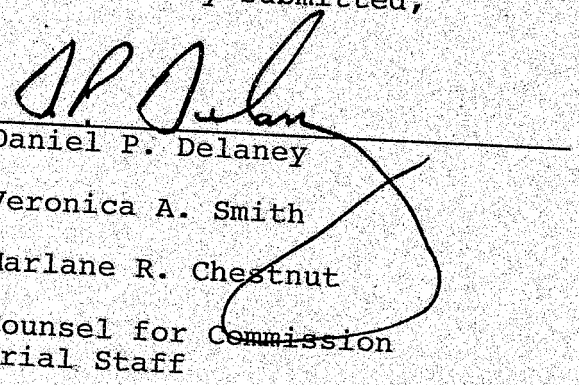
c. Rule of Appellate Procedure 1701 limits the Commission's jurisdiction to continue proceedings in a matter when an appeal has been taken. The Company's

prosecution of an appeal of a Commission order at this docket at this time raises a significant issue of the Commission's jurisdiction to continue proceedings while that matter is before the Commonwealth Court. Indeed in the opinion of Trial Staff, the Company's prosecution of an appeal at this time, whether certified or not, could legitimately be considered by the Commission as a waiver by the Company of the statutory suspension provisions of Section 1308 of the Public Utility Code, 66 Pa. C.S. §1308.

5. The Trial Staff submits that the Company has failed to advance any compelling reason why the Commission's January 21 order should be certified for interlocutory appeal. The Company's motion must therefore be denied.

WHEREFORE, the Trial Staff respectfully requests this Honorable Commission to deny the Company's motion for certification of interlocutory appeal.

Respectfully submitted,



Daniel P. Delaney

Veronica A. Smith

Marlane R. Chestnut

Counsel for Commission
Trial Staff

G-28 North Office Building
Harrisburg, PA 17120
(717) 783-3190

CERTIFICATE OF SERVICE

I hereby certify that I am, this day, serving the foregoing document(s), either by messenger or by first class mail, upon the persons addressed below:

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Deputy Chief Counsel
Pennsylvania Public Utility Commission

Dated: February 11, 1986

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February 10, 1986

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FEB 11 1986

SECRETARY'S OFFICE
Public Utility Commission

VIA FEDERAL EXPRESS

Secretary
Pennsylvania Public Utility
Commission
New Filing Section
Secretary's Bureau
Room B-18
North Office Building
Commonwealth & North Streets
Harrisburg, Pennsylvania 17120

Re: **Pennsylvania Public Utility Commission v. Philadelphia Electric Company**
Docket No. R-850152

Dear Sir:

Enclosed for filing in the above-captioned proceeding please find four copies of a document entitled "Corrected Testimony of James A. Ross." Also enclosed for filing please find the original plus three copies of a document entitled "Errata Sheet re Testimony of James A. Ross."

Also enclosed please find an additional copy of each of these documents. We would appreciate it if your office would time-stamp these copies and return them to us in the enclosed self-addressed, stamped envelope for our files.

Sincerely,

Earle H. O'Donnell

Earle H. O'Donnell

Attorney for
Occidental Chemical Corporation

Enclosures

cc: All Parties w/o attachments

DOCUMENT FOLDER

RECEIVED
FEB 11 1986
SECRETARY'S OFFICE
Public Utility Commission

Before the
Pennsylvania Public Utility Commission
Docket No. R-850152

PHILADELPHIA ELECTRIC COMPANY

Corrected Testimony
of
JAMES A. ROSS

DOCKETED
FEB 11 1986

On behalf of
Occidental Chemical Corporation

DOCUMENT FOLDER

February, 1986
Project 4066

Drazen-Brubaker & Associates, Inc.
St. Louis, Missouri 63141-0110

Before the

Pennsylvania Public Utility Commission

Docket No. R-850152

PHILADELPHIA ELECTRIC COMPANY

Summary of Testimony of James A. Ross

Q PLEASE SUMMARIZE YOUR TESTIMONY.

A The testimony which I present addresses the appropriate prices and provisions for providing supplementary power, back-up power and maintenance power to PECO customers. In my testimony, I discuss the basic principles and practices which should be employed in the determination of rates to be paid by PECO for these types of service. Furthermore, the testimony presents specific tariff schedules detailing the appropriate prices and provisions for providing these types of service. I have discussed both the appropriate service provisions and the appropriate rates for each of these types of service.

Conclusions and Recommendations

Q WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS?

A My conclusions and recommendations regarding service provisions are as follows:

1. PECO customers whose electric requirements may be provided by non-utility generation facilities including cogeneration and small power production facilities (collectively referred to as "cogeneration") have a potential need for supplementary power, back-up power and maintenance power. PECO should provide these types of service on a nondiscriminatory basis which reflects the cost of providing each type of service.

2. The tariff language setting forth the provisions under which these types of service are provided should clearly reflect the intent of the provisions. Based upon my understanding of Mr. Sundermier's testimony, I agree with PECO's policies regarding written permission for parallel operation and customer cost responsibility for additional distribution facilities. In order to clarify these policies in the tariff language, I recommend that the parallel operation provision be as follows:

> The customer shall not begin initial operation of any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. Written permission is not required for re-establishing parallel operation occasioned by outages subsequent to the initial parallel operation. The Company shall have the right to inspect the customers installation in accordance with Tariff Rule 9.3.

With regard to additional distribution facility cost responsibility, I recommend the following:

> Investment in additions or changes to Company distribution facilities required to provide this service, that is over and above the investment that is normally incurred to provide service to such a customer assuming the customer were to obtain its full requirements from the Company in accordance with the rules and regulations, will be paid by customer.

3. I urge this Commission to modify the availability provisions associated with the supply of supplementary power, back-up power and maintenance power to read as follows, so that all customers receiving cogenerated power have access to these services:

Availability.

To any customer whose electrical requirements or any part thereof are regularly provided by facilities other than those of the Company, including qualified small power production or cogeneration facilities (qualifying facilities).

4. The Commission should eliminate the "Control of Supply Provision" as set forth in the Auxiliary Service Rider (and Scott Exhibit No. 1) and adopt the Excess Supply provision shown in Schedule 8 of Exhibit JAR-1 ( ). The provision presented in Schedule 8 addresses the PECO concern pertaining to electrical power consumption in excess of contract amount without requiring devices to physically limit the sale of power.

5. Maintenance power should be made available on a firm basis. Although the currently-effective Auxiliary Service Rider does not provide for firm maintenance power, the revised version of the Rider as shown in Scott Exhibit No. 1 (Revised Rider) clearly indicates a willingness on the part of PECO to provide maintenance power on a firm basis. Further, consistent with the Revised Rider, I recommend that the 1,000 kW minimum capacity requirement and the limitation on the duration and frequency of maintenance power be eliminated.

6. I recommend that the Commission review the Liability Provision in the Auxiliary Service Rider to determine whether it is discriminatory and imposes excessive risks on cogenerators. If similar liability requirements are not imposed on others operating in parallel with PECO, the current provision should be deleted and replaced by an even-handed provision. Such a provision could read as follows:

> Each party shall reimburse or hold harmless the other for all losses to the other party or third parties; for all damage to the facilities of the other party; or for all liabilities to third parties as a result of such parties negligent operation or use of electrical facilities used in connection with the provisions of this service.

Q WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY WITH REGARD TO THE APPROPRIATE RATES THAT SHOULD BE PAID FOR SUPPLEMENTARY, BACK-UP AND MAINTENANCE POWER?

A To summarize:

1. I agree with PECO's position that the normal service rate and applicable riders is an appropriate basis for pricing supplementary power. However, it is not appropriate to bill supplementary power in combination with back-up power as required by the Auxiliary Service Rider (and the Revised Rider). This combination billing practice should be prohibited.

2. The application of the "normal service rate and applicable riders" for back-up power as prescribed by the PECO Auxiliary Service Rider (and Revised Rider) is inappropriate and ignores the capacity supplied by cogeneration facilities. The effect of the back-up power provision in both the effective Auxiliary Service Rider and the Revised Rider is to assess excessive charges for back-up power and to potentially discourage cogeneration development.

3. Analyses to demonstrate that the PECO Auxiliary Service Rider reflects the probability that back-up service will or will not contribute to the need for and the use of utility capacity as required by the FERC have not been performed by PECO (see Occidental Chemical Exhibit No. 1 and Company testimony Tr. 1679). Further, as demonstrated by Schedule 3 of Exhibit JAR-1 ( ), there is an inherent simultaneous outage assumption in both the Auxiliary Service Rider and the Revised Rider--an assumption which is inconsistent with the FERC and PUC rules.

4. Back-up power charges under the PECO Riders can vary significantly for customers purchasing the same amount of power. Schedule 4 of Exhibit JAR-1 ( ) illustrates that the difference in charges could be over 85%.

5. Back-up power rate based upon the daily proration (of the otherwise applicable) firm rate is reasonable, provides protection to the other PECO ratepayers and should be adopted as the basis for pricing back-up service when taken by a cogenerator. The appropriate rate should contain a minimum payment provision which, if based on PECO's full requested revenue level, is the monthly rate

of $3.35 per kW times the contract capacity for back-up power. Schedule 5 of Exhibit JAR-1 ( ), shows the development of the $3.35 per kW charge. (If the approved rate level is less than requested, this charge should be appropriately reduced to reflect the approved rate level.)

6. Scheduled Maintenance Power should be provided during the off-peak nonsummer months and should be priced at the (otherwise applicable) daily prorated firm rate that incorporates a 0.50 Scheduling Provision Factor to reflect the cost to provide this off-peak type service. Schedule 6 of Exhibit JAR-1 ( ) illustrates the calculation of the scheduled maintenance power payment under the appropriate rate for Scheduled Maintenance Power. This schedule also illustrates the method of proration that would apply to both scheduled maintenance power and back-up power under my proposal.

7. I recommend that PECO be required to provide interruptible back-up and maintenance service on an "as-available" basis, in order to recognize the varying service needs of cogenerators and to encourage the development of qualifying facilities. The appropriate rate for this type of service is the Company's hourly PJM billing rate plus a 10% adder.

8. I recommend that the Commission implement the specific rate schedules presented in Schedules 7, 8, 9 and 10 of Exhibit JAR-1 ( ), which incorporate my recommendations regarding the appropriate prices and provisions for providing service on both a firm and interruptible basis.

Testimony to supplement that which is provided in this direct testimony may be necessary upon receipt of information which has been requested from PECO.

Before the

Pennsylvania Public Utility Commission

Docket No. R-850152

PHILADELPHIA ELECTRIC COMPANY

Testimony of James A. Ross

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James A. Ross, 605 Old Ballas Road, St. Louis, Missouri.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation with the firm of Drazen-Brubaker & Associates, Inc., utility rate and economic consultants.

Q WOULD YOU PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE?

A This is set forth in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Occidental Chemical Corporation.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of my testimony is to address the various aspects of the Philadelphia Electric Company (PECO) tariff pertaining to the

supply of supplementary power, back-up power and maintenance power to PECO customers. My testimony also sets forth the basic principles and practices which should be employed in the determination of rates to be paid by PECO customers for supplementary power, back-up power and maintenance power. I shall discuss some of the more fundamental, theoretical and practical considerations attendant to the determination of the appropriate prices and provisions for these types of service. Furthermore, the testimony presents specific tariff schedules detailing the appropriate prices and provisions for providing these types of service.

Failure to specifically address an aspect of the PECO rates, rules and regulations pertaining to these types of service should not be construed as an endorsement of that aspect.

Supplementary, Back-up, and Maintenance Power

Q WHAT TYPES OF SERVICE DOES A PARTIAL REQUIREMENTS CUSTOMER NEED FROM THE UTILITY?

A Utility customers whose electric requirements may be provided by non-utility generation including cogeneration and small power production facilities (collectively referred to hereafter as "cogeneration") have a potential need for at least three types of service from the utility. The FERC regulations (18 CFR, Part 292) identify these services as supplementary power, back-up power, and maintenance power.

Q WHAT IS SUPPLEMENTARY POWER?

A Supplementary power is power supplied by the utility to the customer in addition to that which is supplied by cogeneration. For example, a customer with a total requirement of 60,000 kW may satisfy 40,000 kW with cogeneration and purchase the remaining 20,000 kW from the utility as supplementary power. Supplementary power is typically used consistently throughout the year.

Q WOULD THE CHARACTERISTICS OF A SUPPLEMENTARY POWER CUSTOMER BE SIMILAR TO THE CHARACTERISTICS OF A REGULAR TOTAL REQUIREMENTS CUSTOMER?

A Yes. Both customers require a continuous firm supply of power. Further, the load imposed upon the utility system for both of these customers is a function of the electrical consumption requirements of the customer.

Q WHAT IS MAINTENANCE POWER?

A Maintenance power is power supplied by the utility to replace the generation from cogeneration facilities when those facilities are scheduled out of service for maintenance. This type of power would normally be provided on a pre-arranged schedule basis to allow equipment to be taken out of service for routine inspections and preventive maintenance.

Two important characteristics of maintenance power are that the service is only required for short durations (typically not

more than a month) and the time at which load is imposed on the utility system is controllable. This means that supply of maintenance power can be arranged at a time when the utility has idle capacity available. As will be discussed later, this is an important cost-causative characteristic which should be reflected in the rate paid for this power.

Q WHAT IS BACK-UP POWER?

A Back-up power is power that is supplied by the utility to replace generation ordinarily provided by cogeneration equipment during periods of unscheduled outage.

Unlike supplementary power, the need for back-up power is a function of random equipment outages associated with generation facilities (and the time required to return the equipment to service). Further, back-up power differs from maintenance power in that back-up power cannot be scheduled.

Q IS THE NEED FOR BACK-UP POWER UNIQUE TO COGENERATION?

A Absolutely not. Utility generation equipment sustains forced and partial outages as a routine course of operation. Such outages require that the utility maintain sufficient reserves in order to accommodate these regular occurrences. The supply of back-up power to a cogenerator requires the use of reserves in the same manner as the reserves back-up a utility generating resource during an unscheduled outage. The utility outage and the

cogeneration outage both occur randomly and are directly related to the performance of generating equipment.

Q HOW DO THESE TYPES OF SERVICE DIFFER FROM REGULAR UTILITY SERVICE?

A Usually, a customer requiring electricity purchases all of his or her requirements from the utility ("total requirements customer"). The service required by a customer receiving power from cogeneration may differ from regular utility service in several ways.

First, cogeneration might not provide all of a customer's electrical power requirements ("partial requirements customer"). This customer, therefore, requires supplementary power from the utility on a continual basis.

Second, there will be periods when the cogenerating equipment has to be taken out of service for maintenance. Unless the partial requirements customer reduces his use of electricity, the utility will be called upon to provide maintenance power. In this case, the utility will be supplying all, or part, of the load on an intermittent basis for a period which normally has been previously scheduled with the utility.

Finally, all generating equipment is subject to being taken out of service due to equipment failures. Such failures occur on a random basis and occasion the need for back-up power to be provided by the utility.

Q HAS THE FERC AND THE PENNSYLVANIA PUBLIC UTILITY COMMISSION (PUC)

ESTABLISHED SPECIFIC CRITERIA FOR DEVELOPING RATES FOR BACK-UP AND MAINTENANCE POWER?

A Yes. In addition to stating that back-up and maintenance power rates shall be nondiscriminatory and provided upon request, the FERC rules in Section 292.305(c) also state:

> (c) Rates for sales of backup and maintenance power. The rate for sales of backup power or maintenance power:
>
> (1) shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and
>
> (2) shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

The PUC rules state in Section 59.35(c) and (d) that:

> (c) A utility's rate for sales of back-up power to qualifying facilities shall not be based upon an assumption that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously or during the system peak, or both, unless supported by factual data.
>
> (d) A utility's rate for sales of maintenance power to qualifying facilities shall include all energy costs and a demand or capacity charge not in excess of a charge required to recover the appropriate transmission plant and full distribution plant costs. When the scheduled outages of a qualifying facility cannot be scheduled during other than utility peak periods, the demand or capacity charge shall be the full charge stated in the utility's filed tariff under which the qualifying facility receives such service.

Service Provisions

Q HAVE YOU REVIEWED PECO'S AUXILIARY SERVICE RIDER?

A Yes, I have. The Auxiliary Service Rider, effective September 25, 1984, is presented in Schedule 1 of Exhibit JAR-1 ( ). In addition to the September 25, 1984 Auxiliary Service Rider, I have reviewed the revised version of this Rider (Revised Rider) filed with this Commission on December 27, 1985. The Revised Rider was entered into the record in this proceeding as Scott Exhibit No. 1 and is presented in Schedule 2 of Exhibit JAR-1 ( ).

Q HAVE YOU ALSO REVIEWED THE TESTIMONY OF PECO WITNESS WILLIAM SUNDERMIER?

A Yes, I have. Although Mr. Sundermier has provided testimony in this proceeding clarifying certain of PECO's policies addressed in both the Auxiliary Service Rider and the Revised Rider, the actual language implementing such policies is ambiguous in both riders.

Q SHOULD THE TARIFF LANGUAGE CLEARLY REFLECT THE STATED PECO POLICIES?

A Yes, it should. PECO has stated that the tariff contains the only written statement of PECO's policy regarding the supply of supplementary, back-up or maintenance power (Tr. 1690-91). Thus, unambiguous tariff language is essential to customer understanding of these PECO policies.

Q. WHAT ARE YOUR RECOMMENDATIONS WITH REGARD TO CLARIFYING THE TARIFF LANGUAGE?

A. On cross-examination, Mr. Sundermier explained PECO's policies regarding written permission for parallel operation and customer cost responsibility for additional distribution facilities. Based on my understanding of his testimony, I concur with the stated PECO policies. However, the tariff language does not clearly reflect the Company intent as explained by Mr. Sundermier. I therefore recommend that the tariff language related to parallel operation be as follows:

> The Customer shall not begin initial operation of any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. Written permission is not required for re-establishing parallel operation occasioned by outages subsequent to the initial parallel operation. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

With regard to additional distribution facility cost responsibility, the following language is recommended:

> Investments in additions or changes to Company distribution facilities required to provide this service, that is over and above the investment normally incurred to provide service to such a customer assuming the customer were to obtain its full requirements from the Company in accordance with the Rules and Regulations, will be paid by customer.

Mr. Sundermier's testimony (Tr. 1670-1671) indicates that this language more clearly sets forth PECO's policy regarding distribution facilities.

Q HAVE YOU INCLUDED IN YOUR PROPOSED RATE SCHEDULES THE RECOMMENDED LANGUAGE REGARDING PARALLEL OPERATION AND DISTRIBUTION FACILITY COST?

A Yes, I have. I have also included in my proposed rate schedule language which more clearly states the PECO policy, expressed by Mr. Sundermier during the hearing (Tr. 1628-29), that supplementary power, back-up power, and maintenance power is available to all cogenerators regardless of qualifying status under PURPA. (As with the other policies discussed above, PECO's policy on the availability of this service is not embodied in any other written document available to prospective cogenerators.)

Q ARE THERE CERTAIN PECO POLICIES SET FORTH IN THE AUXILIARY SERVICE RIDER WHICH, IF ALLOWED TO CONTINUE, CAN DISCOURAGE THE DEVELOPMENT OF QUALIFYING FACILITIES?

A Yes, there are. Foremost among such policies is PECO's stated refusal to supply supplementary power, back-up power or maintenance power to a customer receiving power from an on-site cogeneration facility not owned by that customer.

Such a policy can be especially onerous to a PECO customer, such as the hospital discussed by Mr. Sundermier (Tr. 1629-1632) that is attempting to minimize operating costs so that it can continue to provide a service and maintain employment in the state of Pennsylvania. Moreover, once the cogeneration unit is operating, from a PECO cost, operations or rate standpoint, there is no

difference between supplying a customer that owns generation facilities and a customer that does not own such facilities. Unless PECO is informed of the different ownership, it could not distinguish between the two facilities from a service perspective.

Q WHAT DO YOU RECOMMEND?

A I urge the Commission to prohibit this practice by adopting the following language regarding the availability of supplementary, back-up and maintenance power:

> Availability.
> To any customer whose electrical requirements or any part thereof are regularly provided by facilities other than those of the Company, including qualified small power production or cogeneration facilities (qualifying facilities).

Q DOES THE AUXILIARY SERVICE RIDER HAVE A CONTROL OF SUPPLY PROVISION?

A Yes, it does. The tariff language is as follows:

> In case the number of kilowatts contracted for is less than customer's maximum demand as estimated by the Company, the Company may require the customer to limit his demand to the load in kilowatts contracted for by means of a circuit breaker or fuses, of types provided by the Company, to be furnished, installed, connected and maintained by the customer at his expense. The fuse size or the setting of the circuit breaker and its adjustment shall be under the sole control of the Company.

Q DO THE OTHER SERVICE RATE SCHEDULES OF PECO CONTAIN A CONTROL OF SUPPLY PROVISION AS SET FORTH IN THE AUXILIARY SERVICE RIDER?

A According to Company testimony, they do not. This provision is

unique to the service provided to cogenerators.

Q GIVEN THE AMOUNT OF POWER AVAILABLE TO PECO, IS IT LOGICAL THAT PECO SHOULD NEED OR DESIRE TO LIMIT SALES?

A No, it is not. Nevertheless, PECO has included such a provision in the Auxiliary Service Rider. This provision permits PECO, at its discretion, physically to limit the amount of power a supplementary power customer can purchase whereas a total requirements customer has no such limitation. Such a provision is discriminatory, may discourage cogeneration and should be eliminated.

Q WHAT IS AN APPROPRIATE WAY TO HANDLE POWER CONSUMPTION IN EXCESS OF CONTRACT AMOUNTS?

A An appropriate way to handle this situation is through an adjustment of the contract amount as described by Mr. Sundermier (Tr. 1633).

The back-up power rate which I have proposed contains such a provision for adjusting the contract in the case of electrical power consumption in excess of contract amounts.

Q CAN A CUSTOMER PURCHASE MAINTENANCE POWER ON A FIRM BASIS UNDER THE PROVISION OF THE EFFECTIVE AUXILIARY SERVICE RIDER?

A No. Maintenance power is only available on a non-firm basis. The rider clearly states that maintenance power will be subject to interruption at the sole discretion of the Company.

Q ARE THE MAINTENANCE POWER PROVISIONS OF THE EFFECTIVE AUXILIARY SERVICE RIDER CONSISTENT WITH THE FERC REGULATIONS?

A No, they are not. The FERC and PUC regulations require that maintenance power be available on a firm basis.

Q HAVE YOU ANY INDICATION THAT PECO IS WILLING TO PROVIDE MAINTENANCE POWER ON A FIRM BASIS?

A Yes, the Revised Rider indicates such a willingness. Schedule 2 of Exhibit JAR-1 ( ) presents the revised version of the Auxiliary Service Rider filed by PECO on December 27, 1985 with this Commission. The Firm Supply provision shown in Schedule 2 clearly indicates that PECO is proposing to provide maintenance power on a firm basis.

Further, the Revised Rider eliminates the 1,000 kW minimum capacity requirement and the limitations on the duration and frequency of maintenance power presently in effect.

Q DO YOU CONCUR THAT MAINTENANCE POWER SHOULD BE PROVIDED ON A FIRM BASIS AND WITHOUT THE LIMITATIONS SPECIFIED IN THE PRESENT AUXILIARY SERVICE RIDER?

A Yes, I do. My recommendations set forth in this testimony address the appropriate provisions of both firm and interruptible maintenance power.

Q HAVE YOU REVIEWED THE LIABILITY SECTION OF THE AUXILIARY SERVICE

RIDER?

A Yes, I have. The current liability provision reads as follows:

> LIABILITY. The Customer shall reimburse or hold harmless the Company for all losses to Company, Customer or third parties; for all damage to Company or Customer facilities; or for all liabilities to third parties as a result of Customer's operation or use of non-Company owned generating facilities under the provisions of this rider.

The Revised Rider filed on December 27, 1985 (Scott Exh. 1) reads somewhat differently:

> LIABILITY. The Customer shall hold the Company harmless from all losses and damages to the Customer. The Customer shall reimburse the Company or third parties for all losses and damages to the Company or third parties resulting from the Customer's operation or use of non-Company owned generating facilities under the provisions of this rider.

While the precise language differs in some respects between the two riders, several features seem to be common to both. First, there is no reference in either to liability on the part of the Company. Second, there is no expressed statement in either that indicates that the Customer's liability is limited to instances in which it is at fault.

Q DO YOU HAVE ANY COMMENTS ON THE LIABILITY PROVISION?

A I believe that the liability sections should be subject to the same general standards that guide the Commission in reviewing other terms and conditions set forth in the Auxiliary Service Rider. As I have previously mentioned, this includes the requirement that the tariff be non-discriminatory.

Q ARE THE FULL REQUIREMENTS RETAIL CUSTOMERS SUBJECTED TO THE SAME LIABILITY PROVISIONS?

A According to Mr. Sundermier, no. (Tr. 1647)

Q IS THE LIABILITY PROVISION CONSISTENT WITH THE LIABILITY PROVISIONS IN PECO INTERCHANGE AGREEMENTS WITH OTHER UTILITY SYSTEMS OPERATING IN PARALLEL WITH THE PECO SYSTEM?

A Based on the Company's response to Occidental's data request, the answer is no. Occidental asked the Company to furnish copies of all interchange agreements (IR-CHEM 44). These agreements govern transactions between PECO and companies which operate generation equipment in parallel with PECO. PECO can sell power to or purchase power from these entities. Similar arrangements for parallel operation and purchase and sale of power are common between utilities and cogenerators. I have reviewed each of these interchange agreements furnished by PECO. The liability provisions in these agreements are quite different from those contained in the rider. For instance, such agreements provide for liability by both the Company and the other parties to the Agreement.

Q WHAT IS YOUR RECOMMENDATION WITH REGARD TO THE INCLUSION OF A LIABILITY PROVISION IN THE PECO TARIFF?

A I recommend that the Commission review the liability provision in the rider to determine whether it imposes discriminatory or excessive risks on cogenerators. If similar liability requirements are

not imposed on others who operate in parallel with PECO, the current provisions should be deleted and replaced by an even-handed provision. Such a provision could read as follows:

> Each party shall reimburse or hold harmless the other for all losses to the other party or third parties; for all damage to the facilities of the other party; or for all liabilities to third parties as a result of such party's negligent operation or use of electrical facilities used in connection with the provisions of this service.

Rates for Service

Q DO YOU AGREE WITH THE PECO POSITION THAT THE NORMAL SERVICE RATE AND APPLICABLE RIDERS IS AN APPROPRIATE BASIS FOR PRICING SUPPLEMENTARY AND BACK-UP POWER?

A To supplementary power, yes, but not to back-up power. Supplementary power should be billed in accordance with the PECO service schedule and applicable riders for which the service would otherwise be available to a customer not receiving a portion of its electrical requirements from cogeneration, because supplementary power is used to meet requirements in addition to those that can be supplied from cogeneration facilities. Thus, usage by supplementary power customers is akin to normal firm rate service.

For reasons discussed later, back-up power customers can be expected to impose different costs on the system than full requirements customers. Thus, rates for back-up service should not be identical to the rates applicable to full requirements customers.

Finally, it is not appropriate to bill supplementary power in combination with back-up power as required by the PECO Auxiliary Service Rider (and the Revised Rider). These types of service are distinct and have totally different load and cost characteristics. Thus, as I will discuss later, the PECO provision that requires the combining of back-up service with supplementary service for billing purposes, is inappropriate.

Q YOU STATED EARLIER IN YOUR TESTIMONY THAT BACK-UP POWER IS BASED UPON THE PRINCIPLE THAT THE UTILITY IS PROVIDING RESERVE CAPACITY, IS THIS "RESERVE" PRINCIPLE CONSISTENT WITH HOW A UTILITY PROVIDES SERVICE TO ITS REGULAR FIRM CUSTOMERS?

A Yes, it is. For example, a utility with 3,000 MW of firm load and a 25% reserve margin requirement would install 3,750 MW of capacity. Mr. Sundermier stated that this is precisely how PECO provides to service its firm customers (Tr. 1640). Thus, a nongenerating firm customer with a load of 100 kW would pay the utility for 125 kW of capacity (100 kW associated with the load and 25 KW associated with the reserve).

Similarly, a 100 kW customer supplied by a cogeneration facility of 100 kW should only pay the utility for the reserve capacity, because the cogeneration facility is providing the 100 kW of capacity to serve the customer's load. The utility is merely responsible for the reserve. However, both are entitled to call upon this reserve whenever needed.

Q IS THE LEVEL OF RESERVE A FUNCTION OF GENERATING RESOURCE RELIABILITY?

A Yes, it is. This means that cogeneration with reliability greater than utility-controlled resources may require reserves lower than the utility average. In fact, the PJM Pool specifically recognizes the relationship between resource reliability and reserve requirement. A PJM member having more reliable capacity has a smaller Pool obligation, all other things being equal. In the long-run, the level of necessary reserve for cogeneration can be determined by the observed performance of the cogeneration facilities.

Q DO BACK-UP SERVICE AND MAINTENANCE SERVICE IMPOSE THE SAME COSTS ON THE UTILITY?

A No, they do not. Back-up service and maintenance service are two distinct types of service which differ from regular utility service and from one another. It is important that the rates reflect this cost differential. Further, in the interest of encouraging qualifying facility (QF) development, these services should be provided in the most flexible manner possible.

The rates for back-up service should reflect the probability that back-up power will or will not contribute to the need for and the use of utility capacity. Maintenance service rates (for maintenance scheduled with the utility) should reflect the off-peak nature of this service.

Q HOW IS BACK-UP SERVICE PRICED WITH THE THE PECO AUXILIARY SERVICE RIDER?

A The PECO Auxiliary Service Rider requires a customer (including customers who are qualifying facilities) to pay for back-up service under the provisions of the "normal service rate and applicable riders."

However, the FERC requirements are that:

> A qualifying facility is entitled to purchase back-up or standby power at a nondiscriminatory rate which reflects the probability that the qualifying facility will or will not contribute to the need for and the use of utility capacity. (Section-by-section analysis of Section 292.305).

Thus, an important question is whether the "normal service rate" is appropriate, given the characteristics of back-up service.

Q HAVE YOU REVIEWED THE ANALYSES PECO PERFORMED TO DEMONSTRATE THAT THE AUXILIARY SERVICE RIDER REFLECTS THE PROBABILITY THAT BACK-UP SERVICE WILL OR WILL NOT CONTRIBUTE TO THE NEED FOR AND THE USE OF UTILITY CAPACITY?

A No, I have not made such a review because PECO did not perform any analyses. PECO has stated, in response to data requests and in testimony, that such analyses were not performed. Occidental Chemical Exhibit No. 1 is a copy of the PECO response to data requests inquiring about such analyses. Further, Mr. Sundermier testified that PECO did not develop separate load characteristics data for the services provided under the Auxiliary Service Rider

(Tr. 1679).

Thus, it is clear that the Auxiliary Service Rider is not based upon an analysis which supports that the rate for back-up service is consistent with the FERC and PUC rules and regulations.

Q IN GENERAL, HOW ARE THE MONTHLY BACK-UP SERVICE CHARGES COMPUTED UNDER PECO'S AUXILIARY SERVICE RIDER?

A The Rider states that the monthly billing for back-up power will be under the provisions of the normal service rate and applicable riders for full requirement customers.

For example, a 10,000 kW demand measured customer taking service on the currently-effective Rate HT would pay approximately $61,090 in monthly charges if the facility was forced out of service and required back-up power for 10 hours in a given summer month (10,000 x 10 x .0739 + 10,000 x 5.37 = $61,090). The same customer would pay approximately $42,960 a month during the period of October through May if he did not use any additional back-up power due to the ratchet provision of Rate HT (10,000 x .8 x 5.37 = 42,960).

Q IS THE SERVICE RIDER CONCEPT, AS IMPLEMENTED BY PECO'S AUXILIARY SERVICE RIDER, APPROPRIATE FOR DETERMINING BACK-UP SERVICE CHARGES?

A No, it is not. The rates applied to back-up power customers under the Auxiliary Service Rider (and the Revised Rider) are developed

using the characteristics of customers who are predominantly full requirement customers of PECO. There is a fundamental difference in the cost characteristics of a back-up customer and the cost characteristics of the majority of the customers who form the basis for the normal service rates.

For full requirement customers, PECO must install the capacity to supply the customer load plus the reserve capacity needed to assure that the load is reliably served. On the other hand, the cogeneration facility is supplying the load carrying capacity of a back-up power customer and PECO is only responsible for the reserve capacity. To apply the "normal service rate and applicable riders" as prescribed by the PECO Auxiliary Service Riders is to ignore the capacity supplied by the cogeneration facility.

The effect of the back-up power provisions in both PECO Riders is to assess excessive charges for back-up power and to potentially discourage cogeneration development.

Q UNDER WHAT CONDITIONS COULD THE COST CHARACTERISTICS OF BACK-UP POWER CUSTOMERS CORRESPOND TO THE COST CHARACTERISTICS OF FULL REQUIREMENTS CUSTOMERS ON THE PECO SYSTEM?

A This could occur if the electric output of all generating equipment supplying partial requirement customers sustained outages simultaneous with PECO peaks. This assumption, unless supported by factual data, is clearly prohibited by both the FERC rules and the Pennsylvania Public Utility Commission rules implementing

PURPA.

Q PLEASE ILLUSTRATE THE SIMULTANEOUS OUTAGE ASSUMPTION FOR COGENERATORS INHERENT IN THE PECO AUXILIARY SERVICE RIDER.

A This inherent simultaneous outage assumption in both the Auxiliary Service Rider and the Revised Rider is illustrated in Schedule 3 of Exhibit JAR-1 ( ). The three customers shown in Schedule 3 are assumed to be full requirement customers with cost responsibility of 10% as shown on Line 9.

Schedule 3 shows these same customers assuming they have installed cogeneration facilities and are purchasing back-up power (with equipment outages occurring on a random basis), Lines 10 through 16. The cost responsibility under the random outage scenario is about 2% (Line 17).

Obviously, a rate designed to recover the cost of full requirement customers is not appropriate for cogenerators because of the difference in the cost to provide service (compare Line 9 to Line 17). The application of a normal service rate to back-up power inherently ignores the cogeneration capacity and thus assumes simultaneous outages on the cogeneration facilities at time of peak. This is illustrated on Schedule 3, where the back-up power customer cost responsibility (10%) is identical to that of the full requirements customers (10%) (Lines 18 through 24).

Q ASIDE FROM THE INAPPROPRIATENESS OF THE RATES, CAN THE

AUXILIARY SERVICE RIDER RESULT IN SIGNIFICANTLY DIFFERENT BACK-UP POWER CHARGES TO CUSTOMERS REQUIRING THE SAME AMOUNT OF BACK-UP POWER?

A Yes, it can. In effect, a customer requiring both supplementary and back-up power can be penalized vis-a-vis a customer taking the same amount of back-up power on a stand-alone basis.

Q WOULD YOU PLEASE ILLUSTRATE HOW THIS CAN OCCUR?

A Schedule 4 of Exhibit JAR-1 ( ) illustrates the difference in back-up power charges that can result from the Auxiliary Service Rider billing provisions. In the example, one customer purchases only back-up power. Another customer purchases the identical amount of back-up power in conjunction with supplementary power. As shown in Schedule 4, the customer purchasing back-up power on a stand-alone basis pays $80,304 (Line 13). By contrast, the customer (who normally purchase $354,734 of monthly supplementary power as shown on Line 10) pays $148,686 for the same back-up power merely because supplementary power is also taken. This represents over an 85% difference in charges for the identical service. This illustration clearly shows that the Auxiliary Service Rider produces inappropriate and unreasonable charges for back-up power.

Alternate Rate Proposal for Back-Up Service and Maintenance Service

Q IN YOUR OPINION, WHAT SHOULD BE THE BASIS FOR BACK-UP SERVICE AND

MAINTENANCE SERVICE CHARGES?

A Fundamentally, cost of service should be the basis for determining the rates for back-up service and maintenance service. Although factors, such as simplicity and ease of administration may also be appropriately considered, the fundamental starting point and guideline should be that of the cost of providing service.

Q HAVE YOU DEVELOPED A PROPOSED BACK-UP SERVICE RATE THAT RECOGNIZES THE RELATIONSHIP BETWEEN COST AND COGENERATION UNIT RELIABILITY?

A Yes, I have.

Q PLEASE BRIEFLY DESCRIBE YOUR PROPOSAL.

A Under my proposed for back-up service, a customer would be obligated to pay PECO a minimum monthly payment directly related to the cost of PECO-owned production and transmission plant. When back-up service is actually taken by a cogenerator, the charges paid to PECO would be based on a proration of the service rate which would otherwise be applicable.

Q HOW DOES YOUR PROPOSAL REFLECT DIFFERENT RESERVE COSTS FOR DIFFERENT NON-UTILITY GENERATING UNIT RELIABILITIES.

A Whenever a customer takes back-up service, the monthly demand charge (of the otherwise applicable firm rate) would be applied on a prorated basis. The more back-up service required by a customer, the higher the back-up service payment. This would reflect

the higher probability that the back-up power will be taken coincident with the PECO system peaks.

Another important feature is that, while other ratepayers are protected from subsidizing a back-up power customer, this customer would never pay more than the rate this Commission has deemed appropriate for a regular firm customer of PECO. This is a much more reasonable rate for back-up service than the PECO Auxiliary Service Rider, which does not even attempt to reflect the unique characteristics of back-up service (and can also charge vastly different amounts for the same service).

Q WHAT ARE YOU PROPOSING AS THE APPROPRIATE RATE FOR ESTABLISHING THE MINIMUM BACK-UP SERVICE PAYMENT?

A A monthly rate of $3.35 per kilowatt based on PECO's full requested revenue level. (If the approved rate level is less than requested, this charge should be appropriately reduced to reflect the approved rate level.)

Q HOW WAS THE $3.35 PER KILOWATT DEMAND CHARGE DEVELOPED?

A Schedule 5 of Exhibit JAR-1 ( ) shows the development of the $3.35 per kilowatt demand charge. This charge represents the monthly cost associated with the reserve component of PECO's production and transmission plant. Column 1 of Schedule 5 shows the total plant in-service investment (Line 3), the total accumulated depreciation (Line 6), and the net plant associated with

production and transmission plant (Line 7). Column 2 shows the annual cost (based on Company-sponsored Exhibits in this docket) associated with the requested return on plant, depreciation expense, and income taxes. Line 11 shows that the total annual cost of these elements is approximately $1,435 million. Column 3 shows that the per-unit cost associated with production and transmission plant on a $/kW of total installed capability basis. Line 13 of Schedule 5 shows the annual reserve cost for production and transmission at a 22% planning reserve margin. Line 17 shows the development of the monthly minimum cost of $3.35/kW.

Q UNDER YOUR PROPOSAL, WHAT WOULD BE THE MINIMUM MONTHLY PAYMENT FOR A CUSTOMER WHO CONTRACTS FOR 10,000 KILOWATTS OF BACK-UP SERVICE?

A A customer who contracts for 10,000 kW of back-up service would be obligated to make a minimum monthly payment of $33,500 per month (10,000 x 3.35 = 33,500). Of course, when the back-up power is actually taken, the total payment would be a function of the amount of back-up service taken. But in no event, would the payment made by a customer in any month be less than the $33,500 figure. Furthermore, a customer would be obligated to enter into a contract with PECO for back-up service covering not less than 12 calendar months. This would result in a minimum annual payment of $402,000. Note that this is approximately $100,000 more than the 40% minimum contract demand payment requirement of Rate HT (9.44 x 10,000 x .4 x 8 = 302,080).

Q WOULD THE $33,500 FIGURE IN YOUR PREVIOUS EXAMPLE BE IN ADDITION TO THE CHARGES COMPUTED FOR BACK-UP SERVICE ACTUALLY TAKEN DURING A MONTH?

A No. The $33,500 represents a minimum monthly payment and is not an additional charge. For example, in a month when the charge for actual service taken was $20,000, a customer would pay $33,500. However, in a month when the actual charges were $46,000, the customer would pay $46,000.

Q IN YOUR OPINION, SHOULD THE UTILITY BE COMPENSATED DIFFERENTLY FOR BACK-UP POWER DELIVERED IN EXCESS OF THE BACK-UP CONTRACT CAPACITY?

A Yes. I recommend that the utility be compensated for the excess power at the service rate set forth in the back-up power contract <u>without</u> proration for that month. In other words, the excess power delivered by the utility would be priced at the full monthly firm rate for the initial month. Furthermore, the Back-Up Contract Capacity should be increased to the "delivered" amount for the ensuing 12 months.

Q SHOULD THE CUSTOMER BE ALLOWED TO REDUCE THE REVISED BACK-UP CONTRACT CAPACITY AT THE END OF THE 12-MONTH PERIOD?

A Yes. However, I believe this is best left to negotiation.

Q DO YOU HAVE AN ALTERNATE PROPOSAL REGARDING MAINTENANCE SERVICE?

A Yes, I do.

Q HOW DOES YOUR ALTERNATE PROPOSAL FOR MAINTENANCE SERVICE DIFFER FROM THAT OF PECO'S?

A With regard to the effective Auxiliary Service Rider, my proposal differs as follows:

1. Scheduled Maintenance Power under my proposal would be on a firm basis whereas the PECO rider only provides maintenance power on an unscheduled basis.

2. Under my proposal, Maintenance Power would be available to all customers whereas PECO's rider excludes customers with loads less than 1,000 kW.

3. The scheduling notification period under my proposal is not less than 12 calendar months, whereas the PECO rider has a notification period of at least 30 days.

4. My proposal requires the customer to notify the Company when maintenance power is no longer required whereas the PECO rider suggests that the customer can return to service without notifying the Company.

With regard to the revised rider filed on December 27, 1985, my maintenance power proposal differs in two major respects. The first area pertains to the scheduling of maintenance power. My proposal requires the customer to provide not less than 12 months written notification that maintenance power is required of the Company (PECO's notification period is 30 days). Further, maintenance power under my proposal is restricted to the off-peak period of October through May, whereas the PECO revised rider has no such restriction. The PECO revised rider requires approval from the Company for scheduled maintenance to be performed. My

proposal, with its extended notification and restricted period available for maintenance, allows the customer to select the period during which maintenance is to be performed.

The other major difference is that my proposal provides a rate which reflects the off-peak nature of maintenance service, whereas the PECO revised rider does not reflect the cost-causative nature of maintenance service and would charge an inappropriately high rate for this service.

Q BRIEFLY DESCRIBE YOUR PROPOSAL REGARDING SCHEDULED MAINTENANCE SERVICE?

A Scheduled Maintenance Service would be provided to a customer who provides PECO with not less than 12 months advance written notice that scheduled maintenance is to be performed. Further, the period during which scheduled maintenance can be performed is restricted to the off-peak period of October through May. These two factors would assure PECO that maintenance service would not contribute to system peak requirements.

As with both the effective Auxiliary Service Rider and the Revised Rider (Tr. 1662-64), my proposal is also based upon a proration of the otherwise applicable firm rate. However, my proposal for scheduled maintenance takes into account the reduced system cost associated with supplying scheduled maintenance power.

Q HOW DOES PECO ALLOCATE PRODUCTION AND TRANSMISSION PLANT AND

RELATED EXPENSES TO CLASSES OF SERVICE?

A PECO allocates these costs on the basis of the average contribution of each class to hourly system peaks in each of the four summer months (June through September). As stated in Mr. Sundermier's direct prefiled testimony on Page 6 at Line 19:

> Production and transmission plant must be designed to meet the maximum demand requirements imposed on the system by the customers; therefore, it is appropriate that these costs should be allocated on the basis of contribution to those peak demands.

Q UNDER THE COMPANY'S ALLOCATION METHOD, HOW MUCH PRODUCTION AND TRANSMISSION PLANT AND RELATED EXPENSES SHOULD BE ALLOCATED TO CUSTOMERS RECEIVING SERVICE UNDER YOUR SCHEDULED MAINTENANCE PROPOSAL?

A My scheduled maintenance proposal is designed to assure PECO that additional production and transmission plant and related expenses will not be imposed upon the PECO system. Thus, to be consistent with the PECO allocation method, the scheduled maintenance service customers should not be allocated any production and transmission plant or related expenses.

Q HOW HAVE YOU REFLECTED THE REDUCED COSTS WHICH WOULD BE IMPOSED ON PECO BY CUSTOMERS RECEIVING SERVICE UNDER YOUR SCHEDULED MAINTENANCE POWER PROPOSAL?

A This cost reduction is reflected by way of a Scheduling Provision Factor of 0.05 which would be applied to the normal billing demand.

Q HOW WOULD THE BILLING DEMAND FOR SCHEDULED MAINTENANCE BE COMPUTED UNDER YOUR PROPOSAL?

A The customer scheduling his maintenance power requirements with PECO under the provisions of my scheduled maintenance service would have his normal billing demand reduced by 50%. This scheduling provision factor reflects the off-peak type of service that is being provided and the corresponding costs.

Q WHAT WOULD BE THE BILLING DEMAND FOR A CUSTOMER WHO SCHEDULED 10,000 KILOWATTS OF MAINTENANCE POWER UNDER YOUR PROPOSAL?

A Schedule 6 of Exhibit JAR-1 ( ) illustrates the calculation of the billing demand and the resulting scheduled maintenance power payment under my proposal. Line 6 shows that the billing demand would be the product of the 10,000 kW and the 0.50 scheduling provision factor. Thus, the billing demand for a customer who schedules 10,000 kW of demand would be 5,000 kW.

Q DOES THE PRORATION METHOD SET FORTH IN SCHEDULE 6 OF EXHIBIT JAR-1 ( ) REFLECT THE METHOD OF PRORATION THAT WOULD APPLY TO BOTH SCHEDULED MAINTENANCE POWER AND BACK-UP POWER UNDER YOUR PROPOSAL?

A Yes, it would. The ratio of the days of power use to the days in the month would be applied to the capacity charge calculation and the hours' use blocking in the energy charge.

Q HAVE YOU PREPARED SPECIFIC RATE SCHEDULES FOR SUPPLEMENTARY POWER,

BACK-UP POWER AND MAINTENANCE POWER WHICH IMPLEMENTS YOUR RECOMMENDATIONS?

A Yes, I have. Schedule 7 of Exhibit JAR-1 ( ) is a rate schedule which incorporate my recommendations regarding supplementary power. Schedules 8 and 9 incorporate my recommendations with regard to back-up power and maintenance power, respectively.

Q IN ORDER TO RECOGNIZE THE VARYING SERVICE NEEDS AND TO ENCOURAGE THE DEVELOPMENT OF QUALIFYING FACILITIES, SHOULD BACK-UP AND MAINTENANCE SERVICE ALSO BE PROVIDED AND PRICED ON AN "AS-AVAILABLE" BASIS?

A Yes, it should. Under an "as-available" method, the customer would not pay for any monthly capacity charges. However, at the time the customer desires service, he would pay a rate based upon the additional energy charges incurred by the utility, plus a mark-up.

Although the customer would not be obligated to pay capacity payments, the utility would not be obligated to ensure that the capacity would be available at all times.

Q WHAT IS THE APPROPRIATE RATE FOR "AS-AVAILABLE" BACK-UP AND MAINTENANCE SERVICE?

A The appropriate rate for this type of service is the Company's hourly PJM billing rate plus a 10% adder. Thus, PECO would have complete control with regard to supplying the service and also

would be assured of receiving full compensation for all costs associated with power supplied, plus a mark-up.

Q IS PECO A PARTY TO AGREEMENTS THAT PROVIDE FOR TRANSACTIONS SIMILAR TO YOUR "AS-AVAILABLE" BACK-UP AND MAINTENANCE POWER PROPOSAL?

A Yes, it is. PECO is a party to a number of agreements where energy is scheduled to another party when the other party cannot supply the energy with its own resources. Further, the agreements call for the costing of such energy supplied based upon the cost of generating the energy plus an adder which ranges from $1.40 per megawatthour to $2.60 per megawatthour. Based upon the projected PJM hourly billing rates, the 10% adder that I have recommended should be more than adequate when compared to these transactions.

Q HAVE YOU PREPARED A SPECIFIC RATE SCHEDULE FOR AS-AVAILABLE POWER?

A Yes, I have. Schedule 10 of Exhibit JAR-1 ( ) is a rate schedule which would implement the as-available back-up and maintenance service proposal. Note that the $24 per kW figure appearing in the Penalty For Failure to Curtail section shown in Schedule 10 is based on PECO's full requested revenue level. Thus, if the approved rate level is less than requested, this charge should be appropriately reduced.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does. However, supplemental testimony may be necessary upon receipt of information which has been requested from PECO.

Qualifications of James A. Ross

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James A. Ross, 605 Old Ballas Road, St. Louis, Missouri.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation with the firm of Drazen-Brubaker & Associates, Inc., utility rate and economic consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I am a graduate of the University of Missouri, with the degrees of Bachelor of Science in Electrical Engineering and Master of Science in Engineering Management.

After graduation in 1971, I was employed by Union Electric Company, a utility which provides service to Metropolitan St. Louis, Missouri, and surrounding areas. While assigned to the Power Operation Function, I was responsible for system operation-related engineering evaluations which included long-range and intermediate planning studies, various economic studies and computer simulation of system operations. I was later assigned to the Corporate Planning Function with responsibilities in capacity planning coordination activities and special studies. Subsequent to my ten-year employment with Union Electric Company, I joined the firm of Drazen-Brubaker & Associates, Inc.

Q DURING YOUR EMPLOYMENT WITH UNION ELECTRIC COMPANY, DID YOU PARTICIPATE IN ANY CAPACITY PLANNING EVALUATIONS?

A Yes, I was responsible for assisting in all facets of Union Electric's ten-year capacity addition studies. My responsibilities included computer simulation of system operations, development of capacity addition strategies and engineering economic evaluation of alternatives. Additionally, I was assigned to the System Studies Group of the Compressed Air Energy Storage research project sponsored by the Department of Energy and the Electric Power Research Institute. My responsibilities included participation in the overall capacity planning evaluation of compressed air energy storage as a viable capacity alternative and authoring portions of the Project's report on utility system planning.

Also, while assigned to the Corporate Planning Function, I was assigned to a Union Electric oversight committee regarding a power plant siting study being performed by an outside consultant.

Q WHAT REGULATORY COMMISSIONS HAVE YOU TESTIFIED BEFORE?

A I have testified on electric rates and related matters before the regulatory commissions of Alabama, Colorado, Idaho, Louisiana, Massachusetts, Michigan, New York, South Carolina, Texas, Utah and Wyoming.

Before the

Pennsylvania Public Utility Commission

Docket No. R-850152

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Public Utility Commission

PHILADELPHIA ELECTRIC COMPANY

Corrected Exhibit

of

JAMES A. ROSS

DOCKETED
FEB 11 1986

On behalf of

Occidental Chemical Corporation

February, 1986
Project 4066

Drazen-Brubaker & Associates, Inc.
St. Louis, Missouri 63141-0110

Philadelphia Electric Company

SUPPLEMENT NO. 6 TO
ELECTRIC-PA. P.U.C. NO. 26
FIRST REVISED PAGE NO. 52
Superseding Original Page No. 52

STANDARD RIDERS-Continued

Applicable to rates as indicated in Applicability Index of Riders

AUXILIARY SERVICE RIDER

APPLICABILITY. Service to customers, including qualified small power production or cogeneration facilities (qualifying facilities) operating in parallel with the Company, any part of whose electric requirements are regularly provided by facilities owned by that Customer, and where the Company supply can be substituted for that of the Customer, will be supplied only under the provisions of this rider.

EXTENT OF SUPPLY. The maximum firm supply available from the Company will be defined by contract except for customers served on Rates R, R-H and GS-without demand measurement.

CONTROL OF SUPPLY. In case the number of kilowatts contracted for is less than the Customer's maximum demand as estimated by the Company, the Company may require the Customer to limit his demand to the load in kilowatts contracted for by means of a circuit breaker or fuses, of types approved by the Company, to be furnished, installed, connected and maintained by the Customer at his expense. The fuse size or the setting of the circuit breaker and its adjustment shall be under the sole control of the Company.

PARALLEL OPERATION. The Customer shall not at any instant operate any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

TYPE OF SUPPLY. The following types of power supply are available:

Back-up Power supply is available to replace the Customer's own generating capacity whenever it may be interrupted on an unscheduled basis.

Supplementary Power supply is available to add to the Customer's own generating capacity on a continuing firm supply basis.

Maintenance Power supply is available to customers whose total load exceeds 1,000 kilowatts to replace part or all of the Customer's own generating capacity. The supply of maintenance power will be on a scheduled basis that is acceptable to the Company, with at least thirty days advance written notice required, and will be subject to interruption at the sole discretion of the Company. Maintenance periods will be limited to a maximum of three months duration and two occurrences per year which must be separated by at least thirty days. The supply of maintenance power will be terminated when the Customer's generating capacity is returned to operation as indicated by the recorded demands on the Company's metering equipment or upon notification to the Company by the Customer, whichever occurs first.

RATE AND BILLING.

Back-up or Supplementary Power will be available to the Customer under a contract that will specify the total maximum capacity that the Company could be required to serve at any time. The monthly billing for Back-up or Supplementary Power will be under the provisions of the normal service rate and applicable riders. (C)

Maintenance Power will be billed under the provisions of the normal service rate, except that charges will be prorated for periods of less than one month's supply. The minimum contract demand and the summer month ratchet of the normal service rate will not be applicable. Qualifying facilities will be billed under the provisions of the night service rider corresponding to the appropriate rate schedule.

DISTRIBUTION FACILITIES. Any investment in additions or changes to Company distribution facilities required to provide back-up power, supplementary power or maintenance power will be paid by the Customer before the interconnection of Company and Customer facilities.

LIABILITY. The Customer shall reimburse or hold harmless the Company for all losses to Company, Customer, or third parties; for all damage to Company or Customer facilities; or for all liabilities to third parties as a result of Customer's operation or use of non-Company owned generating facilities under the provisions of this rider.

TERM.

Annual, except where otherwise specified by the firm rate.

(C) Indicates change.

STANDARD RIDERS-Continued

Applicable to rates as indicated in Applicability Index of Riders

AUXILIARY SERVICE RIDER (C)

APPLICABILITY. Service to those customers, including qualifying facilities of small power producers and cogenerators as defined in the Public Utility Regulatory Policies Act, operating in parallel with the Company, any part of whose electric requirements are regularly provided by facilities owned by that Customer, and where the Company supply can be substituted for that of the Customer, will be supplied only under the provisions of this rider.

EXTENT OF SUPPLY. The maximum demand requirement and, when applicable, the firm capacity demand (see Paragraph on Curtailable Supply) available from the Company will be defined by contract except for customers served on Rates R, R-H and GS-without demand measurement.

CONTROL OF SUPPLY. In case the number of kilowatts contracted for is less than the Customer's maximum demand as estimated by the Company, the Company may require the Customer to limit his demand to the load in kilowatts contracted for by means of a circuit breaker or fuses, of types approved by the Company, to be furnished, installed, connected and maintained by the Customer at his expense. The fuse size or the setting of the circuit breaker and its adjustment shall be under the sole control of the Company.

PARALLEL OPERATION. The Customer shall not at any instant operate any source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

TYPES OF AUXILIARY SERVICES. The following types of auxiliary service are available:

BACK-UP POWER supply is available to replace the energy used by the Customer whenever the Customer's own generating capacity is interrupted on an unscheduled basis.

SUPPLEMENTARY POWER supply is available to add to the Customer's own generating capacity.

MAINTENANCE POWER supply is available to replace the Customer's own generating capacity during periods of scheduled maintenance. The supply of maintenance power will be on a scheduled basis that is acceptable to the Company with at least thirty days' advance written approval from the Company required. The supply of maintenance power will be terminated when the Customer's generating capacity is returned to normal operation as indicated by the recorded demands on the Company's metering equipment or upon notification to the Company by the Customer, whichever occurs first.

FIRM SUPPLY. Auxiliary service will be billed under the provisions of the rate applicable to the voltage of the service supply from the Company and applicable riders except that charges for maintenance power will be prorated in accordance with the number of days that the service is supplied during the billing month.

DEFINITION OF PEAK HOURS. On-Peak Hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight Saving Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the on-peak hours will end at 4:00 pm on Fridays. Off-Peak Hours are defined as the hours other than those specified as on-peak hours.

(Continued)

(C) Indicates change.

Philadelphia Electric Company

STANDARD RIDERS-Continued

Applicable to rates as indicated in Applicability Index of Riders

AUXILIARY SERVICE RIDER-Continued

CURTAILABLE SUPPLY. Customers may agree to curtail their demand during on-peak hours to a value specified in the contract. This demand value is the firm capacity demand required by the Customer and shall provide for a minimum of 1,000 kilowatts of curtailable demand during on-peak hours. The Customer shall reduce demand to the firm capacity value after a minimum of 30 minutes prior notice by the Company when, in the sole judgment of the Company, any capacity limitations exist. Customers with curtailable load will be billed under the provisions of the normal service rate and applicable riders except that during the eight months of October through May the billing demand will not be less than 40% of the firm capacity nor less than 80% of the highest billing demand in the preceding months of June through September, but in no case shall the minimum billing demand be greater than 80% of the firm capacity demand, except as indicated under the paragraph on Penalty For Failure to Curtail. Curtailable load will be prorated in accordance with the number of days that the maximum registered demand exceeds the firm capacity demand. There shall be a monthly transmission reservation charge of $2.16 per kilowatt of curtailable load plus, when applicable, a distribution reservation charge of $0.98 per kilowatt of curtailable load. The State Tax Adjustment Clause shall be applicable to these charges. These charges will apply in all months; however, in any month in which the Customer's on-peak billing demand exceeds the firm capacity demand, there will be a credit determined by multiplying the transmission charge and, when applicable, the distribution charge by the demand in excess of the firm capacity demand. If the Customer does not elect to reserve transmission and distribution capacity, the reservation charge will be waived; however, the Customer will be at risk for additional curtailment as a result of the unavailability of transmission and distribution capacity. If a Customer does not elect to reserve transmission and distribution capacity and subsequently wants to reserve such capacity, the Customer must pay for any additional costs that the Company incurs to provide such capacity. When a Customer elects to pay the reservation charge, the option to waive this charge will no longer be available.

PENALTY FOR FAILURE TO CURTAIL. The first time that the Customer is notified by the Company to curtail to the firm capacity demand and the Customer fails to curtail to this demand, a penalty of $24 per kilowatt shall be applicable to each kilowatt of maximum registered demand that is in excess of the Customer's firm capacity demand during the curtailment period. In addition, if the failure to curtail occurs in a summer month the minimum billing demand in the following months of October through May shall not be less than 80% of the maximum measured demand during the period in which the Customer failed to curtail. The second time that the Customer fails to curtail, the same penalty shall be applicable and curtailable supply will not be available to the Customer for a period of three years.

DISTRIBUTION FACILITIES. Any investment in additions or changes to Company distribution facilities required to provide auxiliary service will be paid by the Customer before the interconnection of Company and Customer facilities. In addition, when required by the Company, the cost of communication equipment, such as telemetering or telephone, will be paid by the Customer.

LIABILITY. The Customer shall hold the Company harmless from all losses and damages to the Customer. The Customer shall reimburse the Company or third parties for all losses and damages to the Company or third parties resulting from the Customer's operation or use of non-Company owned generating facilities under the provisions of this rider.

TERM. In accordance with the applicable rate schedule, except that customers with curtailable load shall notify the Company at least three years prior to termination of curtailable supply under the provisions of this rider.

(C) Indicates change.

PHILADELPHIA ELECTRIC COMPANY

Illustration of Simultaneous Outage Assumptions Inherent in PECO Auxiliary Service Rider

Line	Description	Jun. (MW) (1)	Jul. (MW) (2)	Aug. (MW) (3)	Sept. (MW) (4)	4-Month Average (5)	Percent of System (6)
1	System	2,000	2,000	2,000	2,000	2,000	
	Full Requirements Customers						
2	Customer 1 - Contract Capacity	100	100	100	100	100	
3	Coincident Peak Demand	80	80	80	80	80	
4	Customer 2 - Contract Capacity	50	50	50	50	50	
5	Coincident Peak Demand	40	40	40	40	40	
6	Customer 3 - Contract Capacity	100	100	100	100	100	
7	Coincident Peak Demand	80	80	80	80	80	
8	Total Contribution to System Peak	200	200	200	200	200	
9	Full Requirements Customer Cost Responsibility as a Percent of System Peak						10%
	Backup Power Customers with Random Outages						
10	Customer 1 - Contract Capacity	100	100	100	100	100	
11	Coincident Peak Demand	0	0	0	0	0	
12	Customer 2 - Contract Capacity	50	50	50	50	50	
13	Coincident Peak Demand	50	0	0	50	25	
14	Customer 3 - Contract Capacity	100	100	100	100	100	
15	Coincident Peak Demand	0	0	80	0	20	
16	Total Contribution to System Peak	50	0	80	50	45	
17	Backup Power Customer Cost Responsibility as a Percent of System Peak						2%
	Backup Power Customers with Simultaneous Outages at Time of Peak						
18	Customer 1 - Contract Capacity	100	100	100	100	100	
19	Coincident Peak Demand	80	80	80	80	80	
20	Customer 2 - Contract Capacity	50	50	50	50	50	
21	Coincident Peak Demand	40	40	40	40	40	
22	Customer 3 - Contract Capacity	100	100	100	100	100	
23	Coincident Peak Demand	80	80	80	80	80	
24	Total Contribution to System Peak	200	200	200	200	200	
25	Backup Power Customer Cost Responsibility as a Percent of System Peak						10%

PHILADELPHIA ELECTRIC COMPANY

Illustration of Inconsistent Backup Power
Billing on PECO
Auxiliary Service Rider

Line	Description	Amount
	Supplementary Power Monthly Requirements:	
1	Billing Demand - kW	10,000
2	Energy Use - kWh	5,840,000
	Backup Power Monthly Requirements:	
3	Billing Demand - kW	10,000
4	Energy Use - kWh	360,000
	Rate HT Base Rate Power Cost (Excluding TOU Adjustment)	
5	Supplementary Power: Capacity Charge (10,000 @ 5.37)	$ 53,700
6	Energy Charge:	
7	First 150 Hours' Use (1,500,000 @ .0739)	110,850
8	Next 150 Hours' Use (1,500,000 @ .0556)	83,400
9	All Additional kWh (2,840,000 @ .0376)	106,784
10	Total Energy Charge	301,034
	Total (Line 5 + Line 9)	$ 354,734
11	Backup Power	
12	Capacity Charge (10,000 @ 5.37)	$ 53,700
13	Energy Charge (360,000 @ .0739)	26,604
	Total	$ 80,304
14	Charges for Supplementary Power and Backup Power (Line 10 + Line 13)	$435,038
15	Auxiliary Service Rider Combined Billing Capacity Charge (20,000 kW @ 5.37)	$107,400
16	Energy Charge:	
17	First 150 Hours' Use (3,000,000 @ .0739)	221,700
18	Next 150 Hours' Use (3,000,000 @ .0556)	166,800
19	All Additional kWh (200,000 @ .0376)	7,520
20	Total Energy Charge	396,020
	Total (Line 15 + Line 19)	503,420
21	Total Backup Power Charges Under Auxiliary Service Rider Provision (Line 20 - Line 10)	$148,686
22	Increase in Backup Charge Due to Combined Billing Provision Assuming No Change in Supplementary Charge (Percent Line 21 Exceeds Line 13)	85.2%

PHILADELPHIA ELECTRIC COMPANY

Development of
Minimum Monthly Backup Contract Capacity Rate

Line	Description	Plant Investment (000) (1)	Annual Cost (000) (2)	Per Unit Cost ($/kW) (3)
	Plant in Service			
1	Production	$6,585,483		
2	Transmission	636,683		
3	Total	7,222,166		
	Less: Accumulated Depreciation			
4	Production	900,583		
5	Transmission	195,169		
6	Total	$1,095,752		
7	Net Plant (Line 3 - Line 6)	$6,126,414		
8	Return on Total @ 12.70%		$ 778,055	
9	Production and Transmission Depreciation Expense		222,362	
10	Income Taxes		434,155	
11	Total Annual Cost		$1,434,572	
12	Per Unit Cost @ 7,858,000 kW of Installed Capability			$182.56
13	Annual Reserve Cost @ 22%			$ 40.16
14	Monthly Minimum Cost (Line 13 ÷ 12)			$ 3.35

Sources: Company Exhibit WFS-1 and PECO Statement No. 14.

PHILADELPHIA ELECTRIC COMPANY

Illustration of
Proposed Scheduled Maintenance Charges

Line	Description	Amount
	Maintenance Power Requirement	
1	Days in Month	30
2	Days of Power Use	15
3	Measured Demand - kW	10,000
4	Energy Use - kWh	2,880,000
5	Scheduling Provision Factor	0.50
	Determination of Billing Demand	
6	kW of Billing Demand (10,000 x 0.50)	5,000
	Proration of Rate HT To Calculate Monthly Charge	
7	Capacity Charge (5,000 x (15/30) x 5.37)	$ 13,425.00
	Energy Charge	
	First 150 Hours' Use:	
8	(5,000 x 150 x (15/30) x .0739)	27,712.50
	Next 150 Hours Use:	
9	(5,000 x 150 x (15/30) x .0556)	20,850.00
	All Additional kWh:	
10	(2,130,000 @ .0376)	80,088.00
11	Total Energy Charge	$128,650.50
12	Total Scheduled Maintenance Power Payment	$142,075.50

PHILADELPHIA ELECTRIC COMPANY

Rate SP - Supplementary Power

Availability.

To any customer whose electrical requirements or any part thereof are regularly provided by facilities other than those of the Company, including qualified small power production or cogeneration facilities (qualifying facilities).

Conditions of Supply.

The maximum firm supply available from the Company will be defined by contract except for customers served on Rates R, R-H and GS--without demand measurement. Supplementary Power is available to add to the generating capacity from facilities other than those of the Company that regularly provide a part of customer's electrical requirements.

Parallel Operation.

The Customer shall not begin initial operation of any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. Written permission is not required for re-establishing parallel operation occasioned by outages subsequent to the initial parallel operation. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

Rate and Billing.

The monthly billing for Supplementary Power will be under the provision of the service rate and applicable riders identified in the Contract.

Liability.

Each party shall reimburse or hold harmless the other for all losses to the other party or third parties; for all damage to the facilities of the other party; or for all liabilities to third parties as a result of such party's negligent operation or use of electrical facilities used in connection with the provisions of this service.

Term.

Annual, except where otherwise specified by the firm rate.

PHILADELPHIA ELECTRIC COMPANY

Rate BP - Back-Up Power

Availability.

To any customer whose electrical requirements or any part thereof are regularly provided by facilities other than those of the Company, including qualified small power production or cogeneration facilities (qualifying facilities).

Conditions of Supply.

The maximum supply to be made available from the Company will be defined by contract (hereinafter referred to as "Back-Up Contact Capacity). Back-up power is available to replace generating capacity from facilities other than those of the Company, whenever such capacity may be interrupted on an unscheduled basis.

Parallel Operation.

The Customer shall not begin initial operation of any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. Written permission is not required for re-establishing parallel operation occasioned by outages subsequent to the initial parallel operation. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

Rate and Billing.

The monthly billing for the Back-up Power will be in accordance with the Monthly Rate Table including applicable adjustments of the service rate identified in the Contract, except that the capacity and energy charge shall be prorated on a daily basis for periods of less than one month's supply. The minimum contract demand and summer month ratchet of the normal service rate will not be applicable nor will the minimum charge.

Determination of Billing Demand.

The billing demand will be the maximum measured demand, adjusted for power factor in accordance with the Rules and Regulations, occurring during any unscheduled outage period of the month less the Supplementary Power billing demand; less the Scheduled Maintenance Power Capacity for the month if one or both of these additional services are provided at the time of the maximum measured demand.

Minimum Charge.

The monthly minimum charge shall be the customer charge of the service rate identified in the Contract, plus $3.35 per kW of Back-Up Contract Capacity.

Distribution Facilities.

Investments in additions or changes to Company distribution facilities required to provide this service, that is over and above the investment normally incurred to provide service to such a customer assuming the customer were to obtain its full requirements from the Company in accordance with the Rules and Regulations, will be paid by customer.

Excess Supply.

Back-up power billing demand in excess of Back-Up Contract Capacity will be billed in accordance with Rate and Billing provision of this Rate BP without proration. The Back-Up Contract Capacity shall be increased to the level established by measurement and the contract term extended for the ensuing 12 calendar months.

Liability.

Each party shall reimburse or hold harmless the other for all losses to the other party or third parties; for all damage to the facilities of the other party; or for all liabilities to third parties as a result of such party's negligent operation or use of electrical facilities used in connection with the provisions of this service.

Term of the Contract.

Annual, continuing thereafter unless cancelled upon 12 months' prior notice.

PHILADELPHIA ELECTRIC COMPANY

Rate SMP - Scheduled Maintenance Power

Availability.

To any customer whose electrical requirements or any part thereof are regularly provided by facilities other than those of the Company, including qualified small power production or cogeneration facilities (qualifying facilities).

Conditions of Supply.

The maximum supply to be made available from the Company will be defined by contract. Scheduled Maintenance Power is available to replace generating capacity from facilities other than those of the Company, whenever such capacity is scheduled out of service during the period October through May, on not less than 12 months advanced written notice. The supply of Scheduled Maintenance Power shall be terminated upon notification to the Company by the Customer.

Parallel Operation.

The Customer shall not begin initial operation of any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. Written permission is not required for re-establishing parallel operation occasioned by outages subsequent to the initial parallel operation. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

Rate and Billing.

The monthly billing for the Scheduled Maintenance Power will be in accordance with the Monthly Rate Table including applicable adjustments of the service rate identified in the Contract, except that the capacity and energy charge shall be prorated on a daily basis for periods of less than one month's supply. The minimum contract demand and summer month ratchet of the normal service rate will not be applicable nor will the minimum charge.

Determination of Billing Demand.

The billing demand will be the product of the amount of capacity scheduled with the Company, adjusted for power factor, and the Scheduling Provision Factor of 0.50.

Minimum Charge.

The monthly minimum charge shall be the customer charge of the service rate identified in the Contract.

Distribution Facilities.

Investments in additions or changes to Company distribution facilities required to provide this service, that is over and above the investment normally incurred to provide service to such a customer assuming the customer were to obtain its full requirements from the Company in accordance with the Rules and Regulations, will be paid by customer.

Liability.

Each party shall reimburse or hold harmless the other for all losses to the other party or third parties; for all damage to the facilities of the other party; or for all liabilities to third parties as a result of such party's negligent operation or use of electrical facilities used in connection with the provisions of this service.

Term.

Annual, continuing thereafter unless cancelled upon 12 months' prior notice.

PHILADELPHIA ELECTRIC COMPANY

Rate AP - As-Available Power

Availability.

To any customer whose electrical requirements or any part thereof are regularly provided by facilities other than those of the Company, including qualified small power production or cogeneration facilities (qualifying facilities).

Parallel Operation.

The Customer shall not begin initial operation of any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. Written permission is not required for re-establishing parallel operation occasioned by outages subsequent to the initial parallel operation. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

Conditions of Supply.

The load supplied by this service must be completely interruptible on notice of at least one-half hour when, in the sole judgment of the Company, any capacity limitations exist. As-Available Power is available to replace generating capacity from facilities other than those of the Company, whenever such capacity is out of service.

Rate and Billing.

Service will be billed at the Company's hourly PJM Billing Rate, plus 10% of that hourly rate. The measured demand of the load supplied by this service will not be included in the calculation of billing demand for other service provided by Company. The PJM dispatch rate will be made available to the Customer on request, in order to estimate the Company's PJM Billing Rate. If the Customer fails to Interrupt the load at the time designated by the Company, the Penalty for Failure to Curtail will be applicable for the monthly billing without modification.

The Energy Cost Rate, State Tax Adjustment and Rate HT Time-of-Use Adjustment are not applicable to this service.

Penalty for Failure to Curtail.

The first time that the Customer is notified by the Company to curtail the Customer fails to curtail a penalty of $24 per kilowatt shall be applicable to each kilowatt of maximum registered demand that is associated with its service during the curtailment period. In addition, if the failure to curtail occurs in a summer month the minimum billing demand in the following months of October through May shall not be less than 80% of the demand during the period in which the Customer failed to curtail. The second time that the Customer fails to curtail within a 12 calendar-month period, the same penalty shall be applicable and curtailable supply will not be available to the Customer for a period of one year.

Liability.

Each party shall reimburse or hold harmless the other for all losses to the other party or third parties; for all damage to the facilities of the other party; or for all liabilities to third parties as a result of such party's negligent operation or use of electrical facilities used in connection with the provisions of this service.

Minimum Charge.

The monthly minimum charge shall be the customers charge of the service rate identified in the Contract.

Term.

Annual, continuing thereafter unless cancelled upon 12 months' prior notice.

Before the

Pennsylvania Public Utility Commission

Docket No. R-850152

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SECRETARY'S OFFICE
Public Utility Commission

PHILADELPHIA ELECTRIC COMPANY

Corrected Testimony

of

JAMES A. ROSS

DOCUMENT FOLDER

On behalf of

Occidental Chemical Corporation

DOCKETED

FEB 11 1986

February, 1986
Project 4066

Drazen-Brubaker & Associates, Inc.
St. Louis, Missouri 63141-0110

Before the

Pennsylvania Public Utility Commission

Docket No. R-850152

PHILADELPHIA ELECTRIC COMPANY

Summary of Testimony of James A. Ross

Q PLEASE SUMMARIZE YOUR TESTIMONY.

A The testimony which I present addresses the appropriate prices and provisions for providing supplementary power, back-up power and maintenance power to PECO customers. In my testimony, I discuss the basic principles and practices which should be employed in the determination of rates to be paid by PECO for these types of service. Furthermore, the testimony presents specific tariff schedules detailing the appropriate prices and provisions for providing these types of service. I have discussed both the appropriate service provisions and the appropriate rates for each of these types of service.

Conclusions and Recommendations

Q WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS?

A My conclusions and recommendations regarding service provisions are as follows:

1. PECO customers whose electric requirements may be provided by non-utility generation facilities including cogeneration and small power production facilities (collectively referred to as "cogeneration") have a potential need for supplementary power, back-up power and maintenance power. PECO should provide these types of service on a nondiscriminatory basis which reflects the cost of providing each type of service.

2. The tariff language setting forth the provisions under which these types of service are provided should clearly reflect the intent of the provisions. Based upon my understanding of Mr. Sundermier's testimony, I agree with PECO's policies regarding written permission for parallel operation and customer cost responsibility for additional distribution facilities. In order to clarify these policies in the tariff language, I recommend that the parallel operation provision be as follows:

> The customer shall not begin initial operation of any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. Written permission is not required for re-establishing parallel operation occasioned by outages subsequent to the initial parallel operation. The Company shall have the right to inspect the customers installation in accordance with Tariff Rule 9.3.

With regard to additional distribution facility cost responsibility, I recommend the following:

> Investment in additions or changes to Company distribution facilities required to provide this service, that is over and above the investment that is normally incurred to provide service to such a customer assuming the customer were to obtain its full requirements from the Company in accordance with the rules and regulations, will be paid by customer.

3. I urge this Commission to modify the availability provisions associated with the supply of supplementary power, back-up power and maintenance power to read as follows, so that all customers receiving cogenerated power have access to these services:

Availability.

To any customer whose electrical requirements or any part thereof are regularly provided by facilities other than those of the Company, including qualified small power production or cogeneration facilities (qualifying facilities).

4. The Commission should eliminate the "Control of Supply Provision" as set forth in the Auxiliary Service Rider (and Scott Exhibit No. 1) and adopt the Excess Supply provision shown in Schedule 8 of Exhibit JAR-1 ( ). The provision presented in Schedule 8 addresses the PECO concern pertaining to electrical power consumption in excess of contract amount without requiring devices to physically limit the sale of power.

5. Maintenance power should be made available on a firm basis. Although the currently-effective Auxiliary Service Rider does not provide for firm maintenance power, the revised version of the Rider as shown in Scott Exhibit No. 1 (Revised Rider) clearly indicates a willingness on the part of PECO to provide maintenance power on a firm basis. Further, consistent with the Revised Rider, I recommend that the 1,000 kW minimum capacity requirement and the limitation on the duration and frequency of maintenance power be eliminated.

6. I recommend that the Commission review the Liability Provision in the Auxiliary Service Rider to determine whether it is discriminatory and imposes excessive risks on cogenerators. If similar liability requirements are not imposed on others operating in parallel with PECO, the current provision should be deleted and replaced by an even-handed provision. Such a provision could read as follows:

> Each party shall reimburse or hold harmless the other for all losses to the other party or third parties; for all damage to the facilities of the other party; or for all liabilities to third parties as a result of such parties negligent operation or use of electrical facilities used in connection with the provisions of this service.

Q WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY WITH REGARD TO THE APPROPRIATE RATES THAT SHOULD BE PAID FOR SUPPLEMENTARY, BACK-UP AND MAINTENANCE POWER?

A To summarize:

1. I agree with PECO's position that the normal service rate and applicable riders is an appropriate basis for pricing supplementary power. However, it is not appropriate to bill supplementary power in combination with back-up power as required by the Auxiliary Service Rider (and the Revised Rider). This combination billing practice should be prohibited.

2. The application of the "normal service rate and applicable riders" for back-up power as prescribed by the PECO Auxiliary Service Rider (and Revised Rider) is inappropriate and ignores the capacity supplied by cogeneration facilities. The effect of the back-up power provision in both the effective Auxiliary Service Rider and the Revised Rider is to assess excessive charges for back-up power and to potentially discourage cogeneration development.

3. Analyses to demonstrate that the PECO Auxiliary Service Rider reflects the probability that back-up service will or will not contribute to the need for and the use of utility capacity as required by the FERC have not been performed by PECO (see Occidental Chemical Exhibit No. 1 and Company testimony Tr. 1679). Further, as demonstrated by Schedule 3 of Exhibit JAR-1 ( ), there is an inherent simultaneous outage assumption in both the Auxiliary Service Rider and the Revised Rider--an assumption which is inconsistent with the FERC and PUC rules.

4. Back-up power charges under the PECO Riders can vary significantly for customers purchasing the same amount of power. Schedule 4 of Exhibit JAR-1 ( ) illustrates that the difference in charges could be over 85%.

5. Back-up power rate based upon the daily proration (of the otherwise applicable) firm rate is reasonable, provides protection to the other PECO ratepayers and should be adopted as the basis for pricing back-up service when taken by a cogenerator. The appropriate rate should contain a minimum payment provision which, if based on PECO's full requested revenue level, is the monthly rate

of $3.35 per kW times the contract capacity for back-up power. Schedule 5 of Exhibit JAR-1 ( ), shows the development of the $3.35 per kW charge. (If the approved rate level is less than requested, this charge should be appropriately reduced to reflect the approved rate level.)

6. Scheduled Maintenance Power should be provided during the off-peak nonsummer months and should be priced at the (otherwise applicable) daily prorated firm rate that incorporates a 0.50 Scheduling Provision Factor to reflect the cost to provide this off-peak type service. Schedule 6 of Exhibit JAR-1 ( ) illustrates the calculation of the scheduled maintenance power payment under the appropriate rate for Scheduled Maintenance Power. This schedule also illustrates the method of proration that would apply to both scheduled maintenance power and back-up power under my proposal.

7. I recommend that PECO be required to provide interruptible back-up and maintenance service on an "as-available" basis, in order to recognize the varying service needs of cogenerators and to encourage the development of qualifying facilities. The appropriate rate for this type of service is the Company's hourly PJM billing rate plus a 10% adder.

8. I recommend that the Commission implement the specific rate schedules presented in Schedules 7, 8, 9 and 10 of Exhibit JAR-1 ( ), which incorporate my recommendations regarding the appropriate prices and provisions for providing service on both a firm and interruptible basis.

Testimony to supplement that which is provided in this direct testimony may be necessary upon receipt of information which has been requested from PECO.

Before the

Pennsylvania Public Utility Commission

Docket No. R-850152

PHILADELPHIA ELECTRIC COMPANY

Testimony of James A. Ross

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James A. Ross, 605 Old Ballas Road, St. Louis, Missouri.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation with the firm of Drazen-Brubaker & Associates, Inc., utility rate and economic consultants.

Q WOULD YOU PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE?

A This is set forth in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Occidental Chemical Corporation.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of my testimony is to address the various aspects of the Philadelphia Electric Company (PECO) tariff pertaining to the

supply of supplementary power, back-up power and maintenance power to PECO customers. My testimony also sets forth the basic principles and practices which should be employed in the determination of rates to be paid by PECO customers for supplementary power, back-up power and maintenance power. I shall discuss some of the more fundamental, theoretical and practical considerations attendant to the determination of the appropriate prices and provisions for these types of service. Furthermore, the testimony presents specific tariff schedules detailing the appropriate prices and provisions for providing these types of service.

Failure to specifically address an aspect of the PECO rates, rules and regulations pertaining to these types of service should not be construed as an endorsement of that aspect.

Supplementary, Back-up, and Maintenance Power

Q WHAT TYPES OF SERVICE DOES A PARTIAL REQUIREMENTS CUSTOMER NEED FROM THE UTILITY?

A Utility customers whose electric requirements may be provided by non-utility generation including cogeneration and small power production facilities (collectively referred to hereafter as "cogeneration") have a potential need for at least three types of service from the utility. The FERC regulations (18 CFR, Part 292) identify these services as supplementary power, back-up power, and maintenance power.

Q WHAT IS SUPPLEMENTARY POWER?

A Supplementary power is power supplied by the utility to the customer in addition to that which is supplied by cogeneration. For example, a customer with a total requirement of 60,000 kW may satisfy 40,000 kW with cogeneration and purchase the remaining 20,000 kW from the utility as supplementary power. Supplementary power is typically used consistently throughout the year.

Q WOULD THE CHARACTERISTICS OF A SUPPLEMENTARY POWER CUSTOMER BE SIMILAR TO THE CHARACTERISTICS OF A REGULAR TOTAL REQUIREMENTS CUSTOMER?

A Yes. Both customers require a continuous firm supply of power. Further, the load imposed upon the utility system for both of these customers is a function of the electrical consumption requirements of the customer.

Q WHAT IS MAINTENANCE POWER?

A Maintenance power is power supplied by the utility to replace the generation from cogeneration facilities when those facilities are scheduled out of service for maintenance. This type of power would normally be provided on a pre-arranged schedule basis to allow equipment to be taken out of service for routine inspections and preventive maintenance.

Two important characteristics of maintenance power are that the service is only required for short durations (typically not

more than a month) and the time at which load is imposed on the utility system is controllable. This means that supply of maintenance power can be arranged at a time when the utility has idle capacity available. As will be discussed later, this is an important cost-causative characteristic which should be reflected in the rate paid for this power.

Q WHAT IS BACK-UP POWER?

A Back-up power is power that is supplied by the utility to replace generation ordinarily provided by cogeneration equipment during periods of unscheduled outage.

Unlike supplementary power, the need for back-up power is a function of random equipment outages associated with generation facilities (and the time required to return the equipment to service). Further, back-up power differs from maintenance power in that back-up power cannot be scheduled.

Q IS THE NEED FOR BACK-UP POWER UNIQUE TO COGENERATION?

A Absolutely not. Utility generation equipment sustains forced and partial outages as a routine course of operation. Such outages require that the utility maintain sufficient reserves in order to accommodate these regular occurrences. The supply of back-up power to a cogenerator requires the use of reserves in the same manner as the reserves back-up a utility generating resource during an unscheduled outage. The utility outage and the

cogeneration outage both occur randomly and are directly related to the performance of generating equipment.

Q HOW DO THESE TYPES OF SERVICE DIFFER FROM REGULAR UTILITY SERVICE?

A Usually, a customer requiring electricity purchases all of his or her requirements from the utility ("total requirements customer"). The service required by a customer receiving power from cogeneration may differ from regular utility service in several ways.

First, cogeneration might not provide all of a customer's electrical power requirements ("partial requirements customer"). This customer, therefore, requires supplementary power from the utility on a continual basis.

Second, there will be periods when the cogenerating equipment has to be taken out of service for maintenance. Unless the partial requirements customer reduces his use of electricity, the utility will be called upon to provide maintenance power. In this case, the utility will be supplying all, or part, of the load on an intermittent basis for a period which normally has been previously scheduled with the utility.

Finally, all generating equipment is subject to being taken out of service due to equipment failures. Such failures occur on a random basis and occasion the need for back-up power to be provided by the utility.

Q HAS THE FERC AND THE PENNSYLVANIA PUBLIC UTILITY COMMISSION (PUC)

ESTABLISHED SPECIFIC CRITERIA FOR DEVELOPING RATES FOR BACK-UP AND MAINTENANCE POWER?

A Yes. In addition to stating that back-up and maintenance power rates shall be nondiscriminatory and provided upon request, the FERC rules in Section 292.305(c) also state:

> (c) Rates for sales of backup and maintenance power. The rate for sales of backup power or maintenance power:
>
> (1) shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and
>
> (2) shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

The PUC rules state in Section 59.35(c) and (d) that:

> (c) A utility's rate for sales of back-up power to qualifying facilities shall not be based upon an assumption that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously or during the system peak, or both, unless supported by factual data.
>
> (d) A utility's rate for sales of maintenance power to qualifying facilities shall include all energy costs and a demand or capacity charge not in excess of a charge required to recover the appropriate transmission plant and full distribution plant costs. When the scheduled outages of a qualifying facility cannot be scheduled during other than utility peak periods, the demand or capacity charge shall be the full charge stated in the utility's filed tariff under which the qualifying facility receives such service.

Service Provisions

Q HAVE YOU REVIEWED PECO'S AUXILIARY SERVICE RIDER?

A Yes, I have. The Auxiliary Service Rider, effective September 25, 1984, is presented in Schedule 1 of Exhibit JAR-1 ( ). In addition to the September 25, 1984 Auxiliary Service Rider, I have reviewed the revised version of this Rider (Revised Rider) filed with this Commission on December 27, 1985. The Revised Rider was entered into the record in this proceeding as Scott Exhibit No. 1 and is presented in Schedule 2 of Exhibit JAR-1 ( ).

Q HAVE YOU ALSO REVIEWED THE TESTIMONY OF PECO WITNESS WILLIAM SUNDERMIER?

A Yes, I have. Although Mr. Sundermier has provided testimony in this proceeding clarifying certain of PECO's policies addressed in both the Auxiliary Service Rider and the Revised Rider, the actual language implementing such policies is ambiguous in both riders.

Q SHOULD THE TARIFF LANGUAGE CLEARLY REFLECT THE STATED PECO POLICIES?

A Yes, it should. PECO has stated that the tariff contains the only written statement of PECO's policy regarding the supply of supplementary, back-up or maintenance power (Tr. 1690-91). Thus, ambiguous tariff language is essential to customer understanding of these PECO policies.

Q WHAT ARE YOUR RECOMMENDATIONS WITH REGARD TO CLARIFYING THE TARIFF LANGUAGE?

A On cross-examination, Mr. Sundermier explained PECO's policies regarding written permission for parallel operation and customer cost responsibility for additional distribution facilities. Based on my understanding of his testimony, I concur with the stated PECO policies. However, the tariff language does not clearly reflect the Company intent as explained by Mr. Sundermier. I therefore recommend that the tariff language related to parallel operation be as follows:

> The Customer shall not begin initial operation of any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. Written permission is not required for re-establishing parallel operation occasioned by outages subsequent to the initial parallel operation. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

With regard to additional distribution facility cost responsibility, the following language is recommended:

> Investments in additions or changes to Company distribution facilities required to provide this service, that is over and above the investment normally incurred to provide service to such a customer assuming the customer were to obtain its full requirements from the Company in accordance with the Rules and Regulations, will be paid by customer.

Mr. Sundermier's testimony (Tr. 1670-1671) indicates that this language more clearly sets forth PECO's policy regarding distribution facilities.

Q HAVE YOU INCLUDED IN YOUR PROPOSED RATE SCHEDULES THE RECOMMENDED LANGUAGE REGARDING PARALLEL OPERATION AND DISTRIBUTION FACILITY COST?

A Yes, I have. I have also included in my proposed rate schedule language which more clearly states the PECO policy, expressed by Mr. Sundermier during the hearing (Tr. 1628-29), that supplementary power, back-up power, and maintenance power is available to all cogenerators regardless of qualifying status under PURPA. (As with the other policies discussed above, PECO's policy on the availability of this service is not embodied in any other written document available to prospective cogenerators.)

Q ARE THERE CERTAIN PECO POLICIES SET FORTH IN THE AUXILIARY SERVICE RIDER WHICH, IF ALLOWED TO CONTINUE, CAN DISCOURAGE THE DEVELOPMENT OF QUALIFYING FACILITIES?

A Yes, there are. Foremost among such policies is PECO's stated refusal to supply supplementary power, back-up power or maintenance power to a customer receiving power from an on-site cogeneration facility not owned by that customer.

Such a policy can be especially onerous to a PECO customer, such as the hospital discussed by Mr. Sundermier (Tr. 1629-1632) that is attempting to minimize operating costs so that it can continue to provide a service and maintain employment in the state of Pennsylvania. Moreover, once the cogeneration unit is operating, from a PECO cost, operations or rate standpoint, there is no

difference between supplying a customer that owns generation facilities and a customer that does not own such facilities. Unless PECO is informed of the different ownership, it could not distinguish between the two facilities from a service perspective.

Q WHAT DO YOU RECOMMEND?

A I urge the Commission to prohibit this practice by adopting the following language regarding the availability of supplementary, back-up and maintenance power:

> Availability.
>
> To any customer whose electrical requirements or any part thereof are regularly provided by facilities other than those of the Company, including qualified small power production or cogeneration facilities (qualifying facilities).

Q DOES THE AUXILIARY SERVICE RIDER HAVE A CONTROL OF SUPPLY PROVISION?

A Yes, it does. The tariff language is as follows:

> In case the number of kilowatts contracted for is less than customer's maximum demand as estimated by the Company, the Company may require the customer to limit his demand to the load in kilowatts contracted for by means of a circuit breaker or fuses, of types provided by the Company, to be furnished, installed, connected and maintained by the customer at his expense. The fuse size or the setting of the circuit breaker and its adjustment shall be under the sole control of the Company.

Q DO THE OTHER SERVICE RATE SCHEDULES OF PECO CONTAIN A CONTROL OF SUPPLY PROVISION AS SET FORTH IN THE AUXILIARY SERVICE RIDER?

A According to Company testimony, they do not. This provision is

unique to the service provided to cogenerators.

Q GIVEN THE AMOUNT OF POWER AVAILABLE TO PECO, IS IT LOGICAL THAT PECO SHOULD NEED OR DESIRE TO LIMIT SALES?

A No, it is not. Nevertheless, PECO has included such a provision in the Auxiliary Service Rider. This provision permits PECO, at its discretion, physically to limit the amount of power a supplementary power customer can purchase whereas a total requirements customer has no such limitation. Such a provision is discriminatory, may discourage cogeneration and should be eliminated.

Q WHAT IS AN APPROPRIATE WAY TO HANDLE POWER CONSUMPTION IN EXCESS OF CONTRACT AMOUNTS?

A An appropriate way to handle this situation is through an adjustment of the contract amount as described by Mr. Sundermier (Tr. 1633).

The back-up power rate which I have proposed contains such a provision for adjusting the contract in the case of electrical power consumption in excess of contract amounts.

Q CAN A CUSTOMER PURCHASE MAINTENANCE POWER ON A FIRM BASIS UNDER THE PROVISION OF THE EFFECTIVE AUXILIARY SERVICE RIDER?

A No. Maintenance power is only available on a non-firm basis. The rider clearly states that maintenance power will be subject to interruption at the sole discretion of the Company.

Q ARE THE MAINTENANCE POWER PROVISIONS OF THE EFFECTIVE AUXILIARY SERVICE RIDER CONSISTENT WITH THE FERC REGULATIONS?

A No, they are not. The FERC and PUC regulations require that maintenance power be available on a firm basis.

Q HAVE YOU ANY INDICATION THAT PECO IS WILLING TO PROVIDE MAINTENANCE POWER ON A FIRM BASIS?

A Yes, the Revised Rider indicates such a willingness. Schedule 2 of Exhibit JAR-1 ( ) presents the revised version of the Auxiliary Service Rider filed by PECO on December 27, 1985 with this Commission. The Firm Supply provision shown in Schedule 2 clearly indicates that PECO is proposing to provide maintenance power on a firm basis.

Further, the Revised Rider eliminates the 1,000 kW minimum capacity requirement and the limitations on the duration and frequency of maintenance power presently in effect.

Q DO YOU CONCUR THAT MAINTENANCE POWER SHOULD BE PROVIDED ON A FIRM BASIS AND WITHOUT THE LIMITATIONS SPECIFIED IN THE PRESENT AUXILIARY SERVICE RIDER?

A Yes, I do. My recommendations set forth in this testimony address the appropriate provisions of both firm and interruptible maintenance power.

Q HAVE YOU REVIEWED THE LIABILITY SECTION OF THE AUXILIARY SERVICE

RIDER?

A Yes, I have. The current liability provision reads as follows:

> LIABILITY. The Customer shall reimburse or hold harmless the Company for all losses to Company, Customer or third parties; for all damage to Company or Customer facilities; or for all liabilities to third parties as a result of Customer's operation or use of non-Company owned generating facilities under the provisions of this rider.

The Revised Rider filed on December 27, 1985 (Scott Exh. 1) reads somewhat differently:

> LIABILITY. The Customer shall hold the Company harmless from all losses and damages to the Customer. The Customer shall reimburse the Company or third parties for all losses and damages to the Company or third parties resulting from the Customer's operation or use of non-Company owned generating facilities under the provisions of this rider.

While the precise language differs in some respects between the two riders, several features seem to be common to both. First, there is no reference in either to liability on the part of the Company. Second, there is no expressed statement in either that indicates that the Customer's liability is limited to instances in which it is at fault.

Q DO YOU HAVE ANY COMMENTS ON THE LIABILITY PROVISION?

A I believe that the liability sections should be subject to the same general standards that guide the Commission in reviewing other terms and conditions set forth in the Auxiliary Service Rider. As I have previously mentioned, this includes the requirement that the tariff be non-discriminatory.

Q ARE THE FULL REQUIREMENTS RETAIL CUSTOMERS SUBJECTED TO THE SAME LIABILITY PROVISIONS?

A According to Mr. Sundermier, no. (Tr. 1647)

Q IS THE LIABILITY PROVISION CONSISTENT WITH THE LIABILITY PROVISIONS IN PECO INTERCHANGE AGREEMENTS WITH OTHER UTILITY SYSTEMS OPERATING IN PARALLEL WITH THE PECO SYSTEM?

A Based on the Company's response to Occidental's data request, the answer is no. Occidental asked the Company to furnish copies of all interchange agreements (IR-CHEM 44). These agreements govern transactions between PECO and companies which operate generation equipment in parallel with PECO. PECO can sell power to or purchase power from these entities. Similar arrangements for parallel operation and purchase and sale of power are common between utilities and cogenerators. I have reviewed each of these interchange agreements furnished by PECO. The liability provisions in these agreements are quite different from those contained in the rider. For instance, such agreements provide for liability by <u>both</u> the Company and the other parties to the Agreement.

Q WHAT IS YOUR RECOMMENDATION WITH REGARD TO THE INCLUSION OF A LIABILITY PROVISION IN THE PECO TARIFF?

A I recommend that the Commission review the liability provision in the rider to determine whether it imposes discriminatory or excessive risks on cogenerators. If similar liability requirements are

not imposed on others who operate in parallel with PECO, the current provisions should be deleted and replaced by an even-handed provision. Such a provision could read as follows:

> Each party shall reimburse or hold harmless the other for all losses to the other party or third parties; for all damage to the facilities of the other party; or for all liabilities to third parties as a result of such party's negligent operation or use of electrical facilities used in connection with the provisions of this service.

Rates for Service

Q DO YOU AGREE WITH THE PECO POSITION THAT THE NORMAL SERVICE RATE AND APPLICABLE RIDERS IS AN APPROPRIATE BASIS FOR PRICING SUPPLEMENTARY AND BACK-UP POWER?

A To supplementary power, yes, but not to back-up power. Supplementary power should be billed in accordance with the PECO service schedule and applicable riders for which the service would otherwise be available to a customer not receiving a portion of its electrical requirements from cogeneration, because supplementary power is used to meet requirements in addition to those that can be supplied from cogeneration facilities. Thus, usage by supplementary power customers is akin to normal firm rate service.

For reasons discussed later, back-up power customers can be expected to impose different costs on the system than full requirements customers. Thus, rates for back-up service should not be identical to the rates applicable to full requirements customers.

Finally, it is not appropriate to bill supplementary power in combination with back-up power as required by the PECO Auxiliary Service Rider (and the Revised Rider). These types of service are distinct and have totally different load and cost characteristics. Thus, as I will discuss later, the PECO provision that requires the combining of back-up service with supplementary service for billing purposes, is inappropriate.

Q YOU STATED EARLIER IN YOUR TESTIMONY THAT BACK-UP POWER IS BASED UPON THE PRINCIPLE THAT THE UTILITY IS PROVIDING RESERVE CAPACITY, IS THIS "RESERVE" PRINCIPLE CONSISTENT WITH HOW A UTILITY PROVIDES SERVICE TO ITS REGULAR FIRM CUSTOMERS?

A Yes, it is. For example, a utility with 3,000 MW of firm load and a 25% reserve margin requirement would install 3,750 MW of capacity. Mr. Sundermier stated that this is precisely how PECO provides to service its firm customers (Tr. 1640). Thus, a nongenerating firm customer with a load of 100 kW would pay the utility for 125 kW of capacity (100 kW associated with the load and 25 KW associated with the reserve).

Similarly, a 100 kW customer supplied by a cogeneration facility of 100 kW should only pay the utility for the reserve capacity, because the cogeneration facility is providing the 100 kW of capacity to serve the customer's load. The utility is merely responsible for the reserve. However, both are entitled to call upon this reserve whenever needed.

Q IS THE LEVEL OF RESERVE A FUNCTION OF GENERATING RESOURCE RELIABILITY?

A Yes, it is. This means that cogeneration with reliability greater than utility-controlled resources may require reserves lower than the utility average. In fact, the PJM Pool specifically recognizes the relationship between resource reliability and reserve requirement. A PJM member having more reliable capacity has a smaller Pool obligation, all other things being equal. In the long-run, the level of necessary reserve for cogeneration can be determined by the observed performance of the cogeneration facilities.

Q DO BACK-UP SERVICE AND MAINTENANCE SERVICE IMPOSE THE SAME COSTS ON THE UTILITY?

A No, they do not. Back-up service and maintenance service are two distinct types of service which differ from regular utility service and from one another. It is important that the rates reflect this cost differential. Further, in the interest of encouraging qualifying facility (QF) development, these services should be provided in the most flexible manner possible.

The rates for back-up service should reflect the probability that back-up power will or will not contribute to the need for and the use of utility capacity. Maintenance service rates (for maintenance scheduled with the utility) should reflect the off-peak nature of this service.

Q HOW IS BACK-UP SERVICE PRICED WITH THE THE PECO AUXILIARY SERVICE RIDER?

A The PECO Auxiliary Service Rider requires a customer (including customers who are qualifying facilities) to pay for back-up service under the provisions of the "normal service rate and applicable riders."

However, the FERC requirements are that:

> A qualifying facility is entitled to purchase back-up or standby power at a nondiscriminatory rate which reflects the probability that the qualifying facility will or will not contribute to the need for and the use of utility capacity. (Section-by-section analysis of Section 292.305).

Thus, an important question is whether the "normal service rate" is appropriate, given the characteristics of back-up service.

Q HAVE YOU REVIEWED THE ANALYSES PECO PERFORMED TO DEMONSTRATE THAT THE AUXILIARY SERVICE RIDER REFLECTS THE PROBABILITY THAT BACK-UP SERVICE WILL OR WILL NOT CONTRIBUTE TO THE NEED FOR AND THE USE OF UTILITY CAPACITY?

A No, I have not made such a review because PECO did not perform any analyses. PECO has stated, in response to data requests and in testimony, that such analyses were not performed. Occidental Chemical Exhibit No. 1 is a copy of the PECO response to data requests inquiring about such analyses. Further, Mr. Sundermier testified that PECO did not develop separate load characteristics data for the services provided under the Auxiliary Service Rider

(Tr. 1679).

Thus, it is clear that the Auxiliary Service Rider is not based upon an analysis which supports that the rate for back-up service is consistent with the FERC and PUC rules and regulations.

Q IN GENERAL, HOW ARE THE MONTHLY BACK-UP SERVICE CHARGES COMPUTED UNDER PECO'S AUXILIARY SERVICE RIDER?

A The Rider states that the monthly billing for back-up power will be under the provisions of the normal service rate and applicable riders for full requirement customers.

For example, a 10,000 kW demand measured customer taking service on the currently-effective Rate HT would pay approximately $61,090 in monthly charges if the facility was forced out of service and required back-up power for 10 hours in a given summer month (10,000 x 10 x .0739 + 10,000 x 5.37 = $61,090). The same customer would pay approximately $42,960 a month during the period of October through May if he did not use any additional back-up power due to the ratchet provision of Rate HT (10,000 x .8 x 5.37 = 42,960).

Q IS THE SERVICE RIDER CONCEPT, AS IMPLEMENTED BY PECO'S AUXILIARY SERVICE RIDER, APPROPRIATE FOR DETERMINING BACK-UP SERVICE CHARGES?

A No, it is not. The rates applied to back-up power customers under the Auxiliary Service Rider (and the Revised Rider) are developed

using the characteristics of customers who are predominantly full requirement customers of PECO. There is a fundamental difference in the cost characteristics of a back-up customer and the cost characteristics of the majority of the customers who form the basis for the normal service rates.

For full requirement customers, PECO must install the capacity to supply the customer load plus the reserve capacity needed to assure that the load is reliably served. On the other hand, the cogeneration facility is supplying the load carrying capacity of a back-up power customer and PECO is only responsible for the reserve capacity. To apply the "normal service rate and applicable riders" as prescribed by the PECO Auxiliary Service Riders is to ignore the capacity supplied by the cogeneration facility.

The effect of the back-up power provisions in both PECO Riders is to assess excessive charges for back-up power and to potentially discourage cogeneration development.

Q UNDER WHAT CONDITIONS COULD THE COST CHARACTERISTICS OF BACK-UP POWER CUSTOMERS CORRESPOND TO THE COST CHARACTERISTICS OF FULL REQUIREMENTS CUSTOMERS ON THE PECO SYSTEM?

A This could occur if the electric output of all generating equipment supplying partial requirement customers sustained outages simultaneous with PECO peaks. This assumption, unless supported by factual data, is clearly prohibited by both the FERC rules and the Pennsylvania Public Utility Commission rules implementing

PURPA.

Q PLEASE ILLUSTRATE THE SIMULTANEOUS OUTAGE ASSUMPTION FOR COGENERATORS INHERENT IN THE PECO AUXILIARY SERVICE RIDER.

A This inherent simultaneous outage assumption in both the Auxiliary Service Rider and the Revised Rider is illustrated in Schedule 3 of Exhibit JAR-1 ( ). The three customers shown in Schedule 3 are assumed to be full requirement customers with cost responsibility of 10% as shown on Line 9.

Schedule 3 shows these same customers assuming they have installed cogeneration facilities and are purchasing back-up power (with equipment outages occurring on a random basis), Lines 10 through 16. The cost responsibility under the random outage scenario is about 2% (Line 17).

Obviously, a rate designed to recover the cost of full requirement customers is not appropriate for cogenerators because of the difference in the cost to provide service (compare Line 9 to Line 17). The application of a normal service rate to back-up power inherently ignores the cogeneration capacity and thus assumes simultaneous outages on the cogeneration facilities at time of peak. This is illustrated on Schedule 3, where the back-up power customer cost responsibility (10%) is identical to that of the full requirements customers (10%) (Lines 18 through 24).

Q ASIDE FROM THE INAPPROPRIATENESS OF THE RATES, CAN THE

AUXILIARY SERVICE RIDER RESULT IN SIGNIFICANTLY DIFFERENT BACK-UP POWER CHARGES TO CUSTOMERS REQUIRING THE SAME AMOUNT OF BACK-UP POWER?

A Yes, it can. In effect, a customer requiring both supplementary and back-up power can be penalized vis-a-vis a customer taking the same amount of back-up power on a stand-alone basis.

Q WOULD YOU PLEASE ILLUSTRATE HOW THIS CAN OCCUR?

A Schedule 4 of Exhibit JAR-1 ( ) illustrates the difference in back-up power charges that can result from the Auxiliary Service Rider billing provisions. In the example, one customer purchases only back-up power. Another customer purchases the identical amount of back-up power in conjunction with supplementary power. As shown in Schedule 4, the customer purchasing back-up power on a stand-alone basis pays $80,304 (Line 13). By contrast, the customer (who normally purchase $354,734 of monthly supplementary power as shown on Line 10) pays $148,686 for the same back-up power merely because supplementary power is also taken. This represents over an 85% difference in charges for the identical service. This illustration clearly shows that the Auxiliary Service Rider produces inappropriate and unreasonable charges for back-up power.

Alternate Rate Proposal for Back-Up Service and Maintenance Service

Q IN YOUR OPINION, WHAT SHOULD BE THE BASIS FOR BACK-UP SERVICE AND

MAINTENANCE SERVICE CHARGES?

A Fundamentally, cost of service should be the basis for determining the rates for back-up service and maintenance service. Although factors, such as simplicity and ease of administration may also be appropriately considered, the fundamental starting point and guideline should be that of the cost of providing service.

Q HAVE YOU DEVELOPED A PROPOSED BACK-UP SERVICE RATE THAT RECOGNIZES THE RELATIONSHIP BETWEEN COST AND COGENERATION UNIT RELIABILITY?

A Yes, I have.

Q PLEASE BRIEFLY DESCRIBE YOUR PROPOSAL.

A Under my proposed for back-up service, a customer would be obligated to pay PECO a minimum monthly payment directly related to the cost of PECO-owned production and transmission plant. When back-up service is actually taken by a cogenerator, the charges paid to PECO would be based on a proration of the service rate which would otherwise be applicable.

Q HOW DOES YOUR PROPOSAL REFLECT DIFFERENT RESERVE COSTS FOR DIFFERENT NON-UTILITY GENERATING UNIT RELIABILITIES.

A Whenever a customer takes back-up service, the monthly demand charge (of the otherwise applicable firm rate) would be applied on a prorated basis. The more back-up service required by a customer, the higher the back-up service payment. This would reflect

the higher probability that the back-up power will be taken coincident with the PECO system peaks.

Another important feature is that, while other ratepayers are protected from subsidizing a back-up power customer, this customer would never pay more than the rate this Commission has deemed appropriate for a regular firm customer of PECO. This is a much more reasonable rate for back-up service than the PECO Auxiliary Service Rider, which does not even attempt to reflect the unique characteristics of back-up service (and can also charge vastly different amounts for the same service).

Q WHAT ARE YOU PROPOSING AS THE APPROPRIATE RATE FOR ESTABLISHING THE MINIMUM BACK-UP SERVICE PAYMENT?

A A monthly rate of $3.35 per kilowatt based on PECO's full requested revenue level. (If the approved rate level is less than requested, this charge should be appropriately reduced to reflect the approved rate level.)

Q HOW WAS THE $3.35 PER KILOWATT DEMAND CHARGE DEVELOPED?

A Schedule 5 of Exhibit JAR-1 ( ) shows the development of the $3.35 per kilowatt demand charge. This charge represents the monthly cost associated with the reserve component of PECO's production and transmission plant. Column 1 of Schedule 5 shows the total plant in-service investment (Line 3), the total accumulated depreciation (Line 6), and the net plant associated with

production and transmission plant (Line 7). Column 2 shows the annual cost (based on Company-sponsored Exhibits in this docket) associated with the requested return on plant, depreciation expense, and income taxes. Line 11 shows that the total annual cost of these elements is approximately $1,435 million. Column 3 shows that the per-unit cost associated with production and transmission plant on a $/kW of total installed capability basis. Line 13 of Schedule 5 shows the annual reserve cost for production and transmission at a 22% planning reserve margin. Line 17 shows the development of the monthly minimum cost of $3.35/kW.

Q UNDER YOUR PROPOSAL, WHAT WOULD BE THE MINIMUM MONTHLY PAYMENT FOR A CUSTOMER WHO CONTRACTS FOR 10,000 KILOWATTS OF BACK-UP SERVICE?

A A customer who contracts for 10,000 kW of back-up service would be obligated to make a minimum monthly payment of $33,500 per month (10,000 x 3.35 = 33,500). Of course, when the back-up power is actually taken, the total payment would be a function of the amount of back-up service taken. But in no event, would the payment made by a customer in any month be less than the $33,500 figure. Furthermore, a customer would be obligated to enter into a contract with PECO for back-up service covering not less than 12 calendar months. This would result in a minimum annual payment of $402,000. Note that this is approximately $100,000 more than the 40% minimum contract demand payment requirement of Rate HT (9.44 x 10,000 x .4 x 8 = 302,080).

Q WOULD THE $33,500 FIGURE IN YOUR PREVIOUS EXAMPLE BE IN ADDITION TO THE CHARGES COMPUTED FOR BACK-UP SERVICE ACTUALLY TAKEN DURING A MONTH?

A No. The $33,500 represents a minimum monthly payment and is not an additional charge. For example, in a month when the charge for actual service taken was $20,000, a customer would pay $33,500. However, in a month when the actual charges were $46,000, the customer would pay $46,000.

Q IN YOUR OPINION, SHOULD THE UTILITY BE COMPENSATED DIFFERENTLY FOR BACK-UP POWER DELIVERED IN EXCESS OF THE BACK-UP CONTRACT CAPACITY?

A Yes. I recommend that the utility be compensated for the excess power at the service rate set forth in the back-up power contract <u>without</u> proration for that month. In other words, the excess power delivered by the utility would be priced at the full monthly firm rate for the initial month. Furthermore, the Back-Up Contract Capacity should be increased to the "delivered" amount for the ensuing 12 months.

Q SHOULD THE CUSTOMER BE ALLOWED TO REDUCE THE REVISED BACK-UP CONTRACT CAPACITY AT THE END OF THE 12-MONTH PERIOD?

A Yes. However, I believe this is best left to negotiation.

Q DO YOU HAVE AN ALTERNATE PROPOSAL REGARDING MAINTENANCE SERVICE?

A Yes, I do.

Q HOW DOES YOUR ALTERNATE PROPOSAL FOR MAINTENANCE SERVICE DIFFER FROM THAT OF PECO'S?

A With regard to the effective Auxiliary Service Rider, my proposal differs as follows:

1. Scheduled Maintenance Power under my proposal would be on a firm basis whereas the PECO rider only provides maintenance power on an unscheduled basis.

2. Under my proposal, Maintenance Power would be available to all customers whereas PECO's rider excludes customers with loads less than 1,000 kW.

3. The scheduling notification period under my proposal is not less than 12 calendar months, whereas the PECO rider has a notification period of at least 30 days.

4. My proposal requires the customer to notify the Company when maintenance power is no longer required whereas the PECO rider suggests that the customer can return to service without notifying the Company.

With regard to the revised rider filed on December 27, 1985, my maintenance power proposal differs in two major respects. The first area pertains to the scheduling of maintenance power. My proposal requires the customer to provide not less than 12 months written notification that maintenance power is required of the Company (PECO's notification period is 30 days). Further, maintenance power under my proposal is restricted to the off-peak period of October through May, whereas the PECO revised rider has no such restriction. The PECO revised rider requires approval from the Company for scheduled maintenance to be performed. My

proposal, with its extended notification and restricted period available for maintenance, allows the customer to select the period during which maintenance is to be performed.

The other major difference is that my proposal provides a rate which reflects the off-peak nature of maintenance service, whereas the PECO revised rider does not reflect the cost-causative nature of maintenance service and would charge an inappropriately high rate for this service.

Q BRIEFLY DESCRIBE YOUR PROPOSAL REGARDING SCHEDULED MAINTENANCE SERVICE?

A Scheduled Maintenance Service would be provided to a customer who provides PECO with not less than 12 months advance written notice that scheduled maintenance is to be performed. Further, the period during which scheduled maintenance can be performed is restricted to the off-peak period of October through May. These two factors would assure PECO that maintenance service would not contribute to system peak requirements.

As with both the effective Auxiliary Service Rider and the Revised Rider (Tr. 1662-64), my proposal is also based upon a proration of the otherwise applicable firm rate. However, my proposal for scheduled maintenance takes into account the reduced system cost associated with supplying scheduled maintenance power.

Q HOW DOES PECO ALLOCATE PRODUCTION AND TRANSMISSION PLANT AND

RELATED EXPENSES TO CLASSES OF SERVICE?

A PECO allocates these costs on the basis of the average contribution of each class to hourly system peaks in each of the four summer months (June through September). As stated in Mr. Sundermier's direct prefiled testimony on Page 6 at Line 19:

> Production and transmission plant must be designed to meet the maximum demand requirements imposed on the system by the customers; therefore, it is appropriate that these costs should be allocated on the basis of contribution to those peak demands.

Q UNDER THE COMPANY'S ALLOCATION METHOD, HOW MUCH PRODUCTION AND TRANSMISSION PLANT AND RELATED EXPENSES SHOULD BE ALLOCATED TO CUSTOMERS RECEIVING SERVICE UNDER YOUR SCHEDULED MAINTENANCE PROPOSAL?

A My scheduled maintenance proposal is designed to assure PECO that additional production and transmission plant and related expenses will not be imposed upon the PECO system. Thus, to be consistent with the PECO allocation method, the scheduled maintenance service customers should not be allocated any production and transmission plant or related expenses.

Q HOW HAVE YOU REFLECTED THE REDUCED COSTS WHICH WOULD BE IMPOSED ON PECO BY CUSTOMERS RECEIVING SERVICE UNDER YOUR SCHEDULED MAINTENANCE POWER PROPOSAL?

A This cost reduction is reflected by way of a Scheduling Provision Factor of 0.05 which would be applied to the normal billing demand.

Q HOW WOULD THE BILLING DEMAND FOR SCHEDULED MAINTENANCE BE COMPUTED UNDER YOUR PROPOSAL?

A The customer scheduling his maintenance power requirements with PECO under the provisions of my scheduled maintenance service would have his normal billing demand reduced by 50%. This scheduling provision factor reflects the off-peak type of service that is being provided and the corresponding costs.

Q WHAT WOULD BE THE BILLING DEMAND FOR A CUSTOMER WHO SCHEDULED 10,000 KILOWATTS OF MAINTENANCE POWER UNDER YOUR PROPOSAL?

A Schedule 6 of Exhibit JAR-1 ( ) illustrates the calculation of the billing demand and the resulting scheduled maintenance power payment under my proposal. Line 6 shows that the billing demand would be the product of the 10,000 kW and the 0.50 scheduling provision factor. Thus, the billing demand for a customer who schedules 10,000 kW of demand would be 5,000 kW.

Q DOES THE PRORATION METHOD SET FORTH IN SCHEDULE 6 OF EXHIBIT JAR-1 ( ) REFLECT THE METHOD OF PRORATION THAT WOULD APPLY TO BOTH SCHEDULED MAINTENANCE POWER AND BACK-UP POWER UNDER YOUR PROPOSAL?

A Yes, it would. The ratio of the days of power use to the days in the month would be applied to the capacity charge calculation and the hours' use blocking in the energy charge.

Q HAVE YOU PREPARED SPECIFIC RATE SCHEDULES FOR SUPPLEMENTARY POWER,

BACK-UP POWER AND MAINTENANCE POWER WHICH IMPLEMENTS YOUR RECOMMENDATIONS?

A Yes, I have. Schedule 7 of Exhibit JAR-1 ( ) is a rate schedule which incorporate my recommendations regarding supplementary power. Schedules 8 and 9 incorporate my recommendations with regard to back-up power and maintenance power, respectively.

Q IN ORDER TO RECOGNIZE THE VARYING SERVICE NEEDS AND TO ENCOURAGE THE DEVELOPMENT OF QUALIFYING FACILITIES, SHOULD BACK-UP AND MAINTENANCE SERVICE ALSO BE PROVIDED AND PRICED ON AN "AS-AVAILABLE" BASIS?

A Yes, it should. Under an "as-available" method, the customer would not pay for any monthly capacity charges. However, at the time the customer desires service, he would pay a rate based upon the additional energy charges incurred by the utility, plus a mark-up.

Although the customer would not be obligated to pay capacity payments, the utility would not be obligated to ensure that the capacity would be available at all times.

Q WHAT IS THE APPROPRIATE RATE FOR "AS-AVAILABLE" BACK-UP AND MAINTENANCE SERVICE?

A The appropriate rate for this type of service is the Company's hourly PJM billing rate plus a 10% adder. Thus, PECO would have complete control with regard to supplying the service and also

would be assured of receiving full compensation for all costs associated with power supplied, plus a mark-up.

Q IS PECO A PARTY TO AGREEMENTS THAT PROVIDE FOR TRANSACTIONS SIMILAR TO YOUR "AS-AVAILABLE" BACK-UP AND MAINTENANCE POWER PROPOSAL?

A Yes, it is. PECO is a party to a number of agreements where energy is scheduled to another party when the other party cannot supply the energy with its own resources. Further, the agreements call for the costing of such energy supplied based upon the cost of generating the energy plus an adder which ranges from $1.40 per megawatthour to $2.60 per megawatthour. Based upon the projected PJM hourly billing rates, the 10% adder that I have recommended should be more than adequate when compared to these transactions.

Q HAVE YOU PREPARED A SPECIFIC RATE SCHEDULE FOR AS-AVAILABLE POWER?

A Yes, I have. Schedule 10 of Exhibit JAR-1 ( ) is a rate schedule which would implement the as-available back-up and maintenance service proposal. Note that the $24 per kW figure appearing in the Penalty For Failure to Curtail section shown in Schedule 10 is based on PECO's full requested revenue level. Thus, if the approved rate level is less than requested, this charge should be appropriately reduced.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does. However, supplemental testimony may be necessary upon receipt of information which has been requested from PECO.

Qualifications of James A. Ross

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James A. Ross, 605 Old Ballas Road, St. Louis, Missouri.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation with the firm of Drazen-Brubaker & Associates, Inc., utility rate and economic consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I am a graduate of the University of Missouri, with the degrees of Bachelor of Science in Electrical Engineering and Master of Science in Engineering Management.

After graduation in 1971, I was employed by Union Electric Company, a utility which provides service to Metropolitan St. Louis, Missouri, and surrounding areas. While assigned to the Power Operation Function, I was responsible for system operation-related engineering evaluations which included long-range and intermediate planning studies, various economic studies and computer simulation of system operations. I was later assigned to the Corporate Planning Function with responsibilities in capacity planning coordination activities and special studies. Subsequent to my ten-year employment with Union Electric Company, I joined the firm of Drazen-Brubaker & Associates, Inc.

Q DURING YOUR EMPLOYMENT WITH UNION ELECTRIC COMPANY, DID YOU PARTICIPATE IN ANY CAPACITY PLANNING EVALUATIONS?

A Yes, I was responsible for assisting in all facets of Union Electric's ten-year capacity addition studies. My responsibilities included computer simulation of system operations, development of capacity addition strategies and engineering economic evaluation of alternatives. Additionally, I was assigned to the System Studies Group of the Compressed Air Energy Storage research project sponsored by the Department of Energy and the Electric Power Research Institute. My responsibilities included participation in the overall capacity planning evaluation of compressed air energy storage as a viable capacity alternative and authoring portions of the Project's report on utility system planning.

Also, while assigned to the Corporate Planning Function, I was assigned to a Union Electric oversight committee regarding a power plant siting study being performed by an outside consultant.

Q WHAT REGULATORY COMMISSIONS HAVE YOU TESTIFIED BEFORE?

A I have testified on electric rates and related matters before the regulatory commissions of Alabama, Colorado, Idaho, Louisiana, Massachusetts, Michigan, New York, South Carolina, Texas, Utah and Wyoming.

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Public Utility Commission

Before the

Pennsylvania Public Utility Commission

Docket No. R-850152

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FEB 11 1986

PHILADELPHIA ELECTRIC COMPANY

Corrected Exhibit

of

JAMES A. ROSS

On behalf of

Occidental Chemical Corporation

February, 1986
Project 4066

Drazen-Brubaker & Associates, Inc.
St. Louis, Missouri 63141-0110

SUPPLEMENT NO. 6 TO
ELECTRIC-PA. P.U.C. NO. 26
FIRST REVISED PAGE NO. 52
Superseding Original Page No. 52

STANDARD RIDERS-Continued

Applicable to rates as indicated in Applicability Index of Riders

AUXILIARY SERVICE RIDER

APPLICABILITY. Service to customers, including qualified small power production or cogeneration facilities (qualifying facilities) operating in parallel with the Company, any part of whose electric requirements are regularly provided by facilities owned by that Customer, and where the Company supply can be substituted for that of the Customer, will be supplied only under the provisions of this rider.

EXTENT OF SUPPLY. The maximum firm supply available from the Company will be defined by contract except for customers served on Rates R, R-H and GS-without demand measurement.

CONTROL OF SUPPLY. In case the number of kilowatts contracted for is less than the Customer's maximum demand as estimated by the Company, the Company may require the Customer to limit his demand to the load in kilowatts contracted for by means of a circuit breaker or fuses, of types approved by the Company, to be furnished, installed, connected and maintained by the Customer at his expense. The fuse size or the setting of the circuit breaker and its adjustment shall be under the sole control of the Company.

PARALLEL OPERATION. The Customer shall not at any instant operate any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

TYPE OF SUPPLY. The following types of power supply are available:

Back-up Power supply is available to replace the Customer's own generating capacity whenever it may be interrupted on an unscheduled basis.

Supplementary Power supply is available to add to the Customer's own generating capacity on a continuing firm supply basis.

Maintenance Power supply is available to customers whose total load exceeds 1,000 kilowatts to replace part or all of the Customer's own generating capacity. The supply of maintenance power will be on a scheduled basis that is acceptable to the Company, with at least thirty days advance written notice required, and will be subject to interruption at the sole discretion of the Company. Maintenance periods will be limited to a maximum of three months duration and two occurrences per year which must be separated by at least thirty days. The supply of maintenance power will be terminated when the Customer's generating capacity is returned to operation as indicated by the recorded demands on the Company's metering equipment or upon notification to the Company by the Customer, whichever occurs first.

RATE AND BILLING.

Back-up or Supplementary Power will be available to the Customer under a contract that will specify the total maximum capacity that the Company could be required to serve at any time. The monthly billing for Back-up or Supplementary Power will be under the provisions of the normal service rate and applicable riders. (C)

Maintenance Power will be billed under the provisions of the normal service rate, except that charges will be prorated for periods of less than one month's supply. The minimum contract demand and the summer month ratchet of the normal service rate will not be applicable. Qualifying facilities will be billed under the provisions of the night service rider corresponding to the appropriate rate schedule.

DISTRIBUTION FACILITIES. Any investment in additions or changes to Company distribution facilities required to provide back-up power, supplementary power or maintenance power will be paid by the Customer before the interconnection of Company and Customer facilities.

LIABILITY. The Customer shall reimburse or hold harmless the Company for all losses to Company, Customer, or third parties; for all damage to Company or Customer facilities; or for all liabilities to third parties as a result of Customer's operation or use of non-Company owned generating facilities under the provisions of this rider.

TERM.

Annual, except where otherwise specified by the firm rate.

(C) Indicates change.

Philadelphia Electric Company

STANDARD RIDERS-Continued

Applicable to rates as indicated in Applicability Index of Riders

AUXILIARY SERVICE RIDER (C)

APPLICABILITY. Service to those customers, including qualifying facilities of small power producers and cogenerators as defined in the Public Utility Regulatory Policies Act, operating in parallel with the Company, any part of whose electric requirements are regularly provided by facilities owned by that Customer, and where the Company supply can be substituted for that of the Customer, will be supplied only under the provisions of this rider.

EXTENT OF SUPPLY. The maximum demand requirement and, when applicable, the firm capacity demand (see Paragraph on Curtailable Supply) available from the Company will be defined by contract except for customers served on Rates R, R-H and GS-without demand measurement.

CONTROL OF SUPPLY. In case the number of kilowatts contracted for is less than the Customer's maximum demand as estimated by the Company, the Company may require the Customer to limit his demand to the load in kilowatts contracted for by means of a circuit breaker or fuses, of types approved by the Company, to be furnished, installed, connected and maintained by the Customer at his expense. The fuse size or the setting of the circuit breaker and its adjustment shall be under the sole control of the Company.

PARALLEL OPERATION. The Customer shall not at any instant operate any source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

TYPES OF AUXILIARY SERVICES. The following types of auxiliary service are available:

BACK-UP POWER supply is available to replace the energy used by the Customer whenever the Customer's own generating capacity is interrupted on an unscheduled basis.

SUPPLEMENTARY POWER supply is available to add to the Customer's own generating capacity.

MAINTENANCE POWER supply is available to replace the Customer's own generating capacity during periods of scheduled maintenance. The supply of maintenance power will be on a scheduled basis that is acceptable to the Company with at least thirty days' advance written approval from the Company required. The supply of maintenance power will be terminated when the Customer's generating capacity is returned to normal operation as indicated by the recorded demands on the Company's metering equipment or upon notification to the Company by the Customer, whichever occurs first.

FIRM SUPPLY. Auxiliary service will be billed under the provisions of the rate applicable to the voltage of the service supply from the Company and applicable riders except that charges for maintenance power will be prorated in accordance with the number of days that the service is supplied during the billing month.

DEFINITION OF PEAK HOURS. On-Peak Hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight Saving Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the on-peak hours will end at 4:00 pm on Fridays. Off-Peak Hours are defined as the hours other than those specified as on-peak hours.

(Continued)

(C) Indicates change.

Philadelphia Electric Company

STANDARD RIDERS-Continued

Applicable to rates as indicated in Applicability Index of Riders

AUXILIARY SERVICE RIDER-Continued

CURTAILABLE SUPPLY. Customers may agree to curtail their demand during on-peak hours to a value specified in the contract. This demand value is the firm capacity demand required by the Customer and shall provide for a minimum of 1,000 kilowatts of curtailable demand during on-peak hours. The Customer shall reduce demand to the firm capacity value after a minimum of 30 minutes prior notice by the Company when, in the sole judgment of the Company, any capacity limitations exist. Customers with curtailable load will be billed under the provisions of the normal service rate and applicable riders except that during the eight months of October through May the billing demand will not be less than 40% of the firm capacity nor less than 80% of the highest billing demand in the preceding months of June through September, but in no case shall the minimum billing demand be greater than 80% of the firm capacity demand, except as indicated under the paragraph on Penalty For Failure to Curtail. Curtailable load will be prorated in accordance with the number of days that the maximum registered demand exceeds the firm capacity demand. There shall be a monthly transmission reservation charge of $2.16 per kilowatt of curtailable load plus, when applicable, a distribution reservation charge of $0.98 per kilowatt of curtailable load. The State Tax Adjustment Clause shall be applicable to these charges. These charges will apply in all months; however, in any month in which the Customer's on-peak billing demand exceeds the firm capacity demand, there will be a credit determined by multiplying the transmission charge and, when applicable, the distribution charge by the demand in excess of the firm capacity demand. If the Customer does not elect to reserve transmission and distribution capacity, the reservation charge will be waived; however, the Customer will be at risk for additional curtailment as a result of the unavailability of transmission and distribution capacity. If a Customer does not elect to reserve transmission and distribution capacity and subsequently wants to reserve such capacity, the Customer must pay for any additional costs that the Company incurs to provide such capacity. When a Customer elects to pay the reservation charge, the option to waive this charge will no longer be available.

PENALTY FOR FAILURE TO CURTAIL. The first time that the Customer is notified by the Company to curtail to the firm capacity demand and the Customer fails to curtail to this demand, a penalty of $24 per kilowatt shall be applicable to each kilowatt of maximum registered demand that is in excess of the Customer's firm capacity demand during the curtailment period. In addition, if the failure to curtail occurs in a summer month the minimum billing demand in the following months of October through May shall not be less than 80% of the maximum measured demand during the period in which the Customer failed to curtail. The second time that the Customer fails to curtail, the same penalty shall be applicable and curtailable supply will not be available to the Customer for a period of three years.

DISTRIBUTION FACILITIES. Any investment in additions or changes to Company distribution facilities required to provide auxiliary service will be paid by the Customer before the interconnection of Company and Customer facilities. In addition, when required by the Company, the cost of communication equipment, such as telemetering or telephone, will be paid by the Customer.

LIABILITY. The Customer shall hold the Company harmless from all losses and damages to the Customer. The Customer shall reimburse the Company or third parties for all losses and damages to the Company or third parties resulting from the Customer's operation or use of non-Company owned generating facilities under the provisions of this rider.

TERM. In accordance with the applicable rate schedule, except that customers with curtailable load shall notify the Company at least three years prior to termination of curtailable supply under the provisions of this rider.

(C) Indicates change.

PHILADELPHIA ELECTRIC COMPANY

Illustration of Simultaneous Outage Assumptions Inherent in PECO Auxiliary Service Rider

Line	Description	Jun. (MW) (1)	Jul. (MW) (2)	Aug. (MW) (3)	Sept. (MW) (4)	4-Month Average (5)	Percent of System (6)
1	System	2,000	2,000	2,000	2,000	2,000	
	Full Requirements Customers						
2	Customer 1 - Contract Capacity	100	100	100	100	100	
3	Coincident Peak Demand	80	80	80	80	80	
4	Customer 2 - Contract Capacity	50	50	50	50	50	
5	Coincident Peak Demand	40	40	40	40	40	
6	Customer 3 - Contract Capacity	100	100	100	100	100	
7	Coincident Peak Demand	80	80	80	80	80	
8	Total Contribution to System Peak	200	200	200	200	200	
9	Full Requirements Customer Cost Responsibility as a Percent of System Peak						10%
	Backup Power Customers with Random Outages						
10	Customer 1 - Contract Capacity	100	100	100	100	100	
11	Coincident Peak Demand	0	0	0	0	0	
12	Customer 2 - Contract Capacity	50	50	50	50	50	
13	Coincident Peak Demand	50	0	0	50	25	
14	Customer 3 - Contract Capacity	100	100	100	100	100	
15	Coincident Peak Demand	0	0	80	0	20	
16	Total Contribution to System Peak	50	0	80	50	45	
17	Backup Power Customer Cost Responsibility as a Percent of System Peak						2%
	Backup Power Customers with Simultaneous Outages at Time of Peak						
18	Customer 1 - Contract Capacity	100	100	100	100	100	
19	Coincident Peak Demand	80	80	80	80	80	
20	Customer 2 - Contract Capacity	50	50	50	50	50	
21	Coincident Peak Demand	40	40	40	40	40	
22	Customer 3 - Contract Capacity	100	100	100	100	100	
23	Coincident Peak Demand	80	80	80	80	80	
24	Total Contribution to System Peak	200	200	200	200	200	
25	Backup Power Customer Cost Responsibility as a Percent of System Peak						10%

PHILADELPHIA ELECTRIC COMPANY

Illustration of Inconsistent Backup Power
Billing on PECO
Auxiliary Service Rider

Line	Description	Amount
	Supplementary Power Monthly Requirements:	
1	Billing Demand - kW	10,000
2	Energy Use - kWh	5,840,000
	Backup Power Monthly Requirements:	
3	Billing Demand - kW	10,000
4	Energy Use - kWh	360,000
	Rate HT Base Rate Power Cost (Excluding TOU Adjustment)	
	Supplementary Power:	
5	Capacity Charge (10,000 @ 5.37)	$ 53,700
	Energy Charge:	
6	First 150 Hours' Use (1,500,000 @ .0739)	110,850
7	Next 150 Hours' Use (1,500,000 @ .0556)	83,400
8	All Additional kWh (2,840,000 @ .0376)	106,784
9	Total Energy Charge	301,034
10	Total (Line 5 + Line 9)	$ 354,734
	Backup Power	
11	Capacity Charge (10,000 @ 5.37)	$ 53,700
12	Energy Charge (360,000 @ .0739)	26,604
13	Total	$ 80,304
	Charges for Supplementary Power and Backup	
14	Power (Line 10 + Line 13)	$435,038
	Auxiliary Service Rider Combined Billing	
15	Capacity Charge (20,000 kW @ 5.37)	$107,400
	Energy Charge:	
16	First 150 Hours' Use (3,000,000 @ .0739)	221,700
17	Next 150 Hours' Use (3,000,000 @ .0556)	166,800
18	All Additional kWh (200,000 @ .0376)	7,520
19	Total Energy Charge	396,020
20	Total (Line 15 + Line 19)	503,420
	Total Backup Power Charges Under Auxiliary Service Rider Provision	
21	(Line 20 - Line 10)	$148,686
	Increase in Backup Charge Due to Combined Billing Provision Assuming No Change in Supplementary Charge (Percent Line 21	
22	Exceeds Line 13)	85.2%

PHILADELPHIA ELECTRIC COMPANY

Development of
Minimum Monthly Backup Contract Capacity Rate

Line	Description	Plant Investment (000) (1)	Annual Cost (000) (2)	Per Unit Cost ($/kW) (3)
	Plant in Service			
1	Production	$6,585,483		
2	Transmission	636,683		
3	Total	7,222,166		
	Less: Accumulated Depreciation			
4	Production	900,583		
5	Transmission	195,169		
6	Total	$1,095,752		
7	Net Plant (Line 3 - Line 6)	$6,126,414		
8	Return on Total @ 12.70%		$ 778,055	
	Production and Transmission			
9	Depreciation Expense		222,362	
10	Income Taxes		434,155	
11	Total Annual Cost		$1,434,572	
	Per Unit Cost @ 7,858,000 kW			
12	of Installed Capability			$182.56
13	Annual Reserve Cost @ 22%			$ 40.16
	Monthly Minimum Cost			
14	(Line 13 ÷ 12)			$ 3.35

Sources: Company Exhibit WFS-1 and PECO Statement No. 14.

PHILADELPHIA ELECTRIC COMPANY

Illustration of
Proposed Scheduled Maintenance Charges

Line	Description	Amount
	Maintenance Power Requirement	
1	Days in Month	30
2	Days of Power Use	15
3	Measured Demand - kW	10,000
4	Energy Use - kWh	2,880,000
5	Scheduling Provision Factor	0.50
	Determination of Billing Demand	
6	kW of Billing Demand (10,000 x 0.50)	5,000
	Proration of Rate HT To Calculate Monthly Charge	
7	Capacity Charge (5,000 x (15/30) x 5.37)	$ 13,425.00
	Energy Charge	
	First 150 Hours' Use:	
8	(5,000 x 150 x (15/30) x .0739)	27,712.50
	Next 150 Hours Use:	
9	(5,000 x 150 x (15/30) x .0556)	20,850.00
	All Additional kWh:	
10	(2,130,000 @ .0376)	80,088.00
11	Total Energy Charge	$128,650.50
12	Total Scheduled Maintenance Power Payment	$142,075.50

PHILADELPHIA ELECTRIC COMPANY

Rate SP - Supplementary Power

Availability.

To any customer whose electrical requirements or any part thereof are regularly provided by facilities other than those of the Company, including qualified small power production or cogeneration facilities (qualifying facilities).

Conditions of Supply.

The maximum firm supply available from the Company will be defined by contract except for customers served on Rates R, R-H and GS--without demand measurement. Supplementary Power is available to add to the generating capacity from facilities other than those of the Company that regularly provide a part of customer's electrical requirements.

Parallel Operation.

The Customer shall not begin initial operation of any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. Written permission is not required for re-establishing parallel operation occasioned by outages subsequent to the initial parallel operation. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

Rate and Billing.

The monthly billing for Supplementary Power will be under the provision of the service rate and applicable riders identified in the Contract.

Liability.

Each party shall reimburse or hold harmless the other for all losses to the other party or third parties; for all damage to the facilities of the other party; or for all liabilities to third parties as a result of such party's negligent operation or use of electrical facilities used in connection with the provisions of this service.

Term.

Annual, except where otherwise specified by the firm rate.

PHILADELPHIA ELECTRIC COMPANY

Rate BP - Back-Up Power

Availability.

To any customer whose electrical requirements or any part thereof are regularly provided by facilities other than those of the Company, including qualified small power production or cogeneration facilities (qualifying facilities).

Conditions of Supply.

The maximum supply to be made available from the Company will be defined by contract (hereinafter referred to as "Back-Up Contact Capacity). Back-up power is available to replace generating capacity from facilities other than those of the Company, whenever such capacity may be interrupted on an unscheduled basis.

Parallel Operation.

The Customer shall not begin initial operation of any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. Written permission is not required for re-establishing parallel operation occasioned by outages subsequent to the initial parallel operation. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

Rate and Billing.

The monthly billing for the Back-up Power will be in accordance with the Monthly Rate Table including applicable adjustments of the service rate identified in the Contract, except that the capacity and energy charge shall be prorated on a daily basis for periods of less than one month's supply. The minimum contract demand and summer month ratchet of the normal service rate will not be applicable nor will the minimum charge.

Determination of Billing Demand.

The billing demand will be the maximum measured demand, adjusted for power factor in accordance with the Rules and Regulations, occurring during any unscheduled outage period of the month less the Supplementary Power billing demand; less the Scheduled Maintenance Power Capacity for the month if one or both of these additional services are provided at the time of the maximum measured demand.

Minimum Charge.

The monthly minimum charge shall be the customer charge of the service rate identified in the Contract, plus $3.35 per kW of Back-Up Contract Capacity.

Distribution Facilities.

Investments in additions or changes to Company distribution facilities required to provide this service, that is over and above the investment normally incurred to provide service to such a customer assuming the customer were to obtain its full requirements from the Company in accordance with the Rules and Regulations, will be paid by customer.

Excess Supply.

Back-up power billing demand in excess of Back-Up Contract Capacity will be billed in accordance with Rate and Billing provision of this Rate BP without proration. The Back-Up Contract Capacity shall be increased to the level established by measurement and the contract term extended for the ensuing 12 calendar months.

Liability.

Each party shall reimburse or hold harmless the other for all losses to the other party or third parties; for all damage to the facilities of the other party; or for all liabilities to third parties as a result of such party's negligent operation or use of electrical facilities used in connection with the provisions of this service.

Term of the Contract.

Annual, continuing thereafter unless cancelled upon 12 months' prior notice.

PHILADELPHIA ELECTRIC COMPANY

Rate SMP - Scheduled Maintenance Power

Availability.

To any customer whose electrical requirements or any part thereof are regularly provided by facilities other than those of the Company, including qualified small power production or cogeneration facilities (qualifying facilities).

Conditions of Supply.

The maximum supply to be made available from the Company will be defined by contract. Scheduled Maintenance Power is available to replace generating capacity from facilities other than those of the Company, whenever such capacity is scheduled out of service during the period October through May, on not less than 12 months advanced written notice. The supply of Scheduled Maintenance Power shall be terminated upon notification to the Company by the Customer.

Parallel Operation.

The Customer shall not begin initial operation of any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. Written permission is not required for re-establishing parallel operation occasioned by outages subsequent to the initial parallel operation. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

Rate and Billing.

The monthly billing for the Scheduled Maintenance Power will be in accordance with the Monthly Rate Table including applicable adjustments of the service rate identified in the Contract, except that the capacity and energy charge shall be prorated on a daily basis for periods of less than one month's supply. The minimum contract demand and summer month ratchet of the normal service rate will not be applicable nor will the minimum charge.

Determination of Billing Demand.

The billing demand will be the product of the amount of capacity scheduled with the Company, adjusted for power factor, and the Scheduling Provision Factor of 0.50.

Minimum Charge.

The monthly minimum charge shall be the customer charge of the service rate identified in the Contract.

Distribution Facilities.

Investments in additions or changes to Company distribution facilities required to provide this service, that is over and above the investment normally incurred to provide service to such a customer assuming the customer were to obtain its full requirements from the Company in accordance with the Rules and Regulations, will be paid by customer.

Liability.

Each party shall reimburse or hold harmless the other for all losses to the other party or third parties; for all damage to the facilities of the other party; or for all liabilities to third parties as a result of such party's negligent operation or use of electrical facilities used in connection with the provisions of this service.

Term.

Annual, continuing thereafter unless cancelled upon 12 months' prior notice.

PHILADELPHIA ELECTRIC COMPANY

Rate AP - As-Available Power

Availability.

To any customer whose electrical requirements or any part thereof are regularly provided by facilities other than those of the Company, including qualified small power production or cogeneration facilities (qualifying facilities).

Parallel Operation.

The Customer shall not begin initial operation of any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. Written permission is not required for re-establishing parallel operation occasioned by outages subsequent to the initial parallel operation. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

Conditions of Supply.

The load supplied by this service must be completely interruptible on notice of at least one-half hour when, in the sole judgment of the Company, any capacity limitations exist. As-Available Power is available to replace generating capacity from facilities other than those of the Company, whenever such capacity is out of service.

Rate and Billing.

Service will be billed at the Company's hourly PJM Billing Rate, plus 10% of that hourly rate. The measured demand of the load supplied by this service will not be included in the calculation of billing demand for other service provided by Company. The PJM dispatch rate will be made available to the Customer on request, in order to estimate the Company's PJM Billing Rate. If the Customer fails to Interrupt the load at the time designated by the Company, the Penalty for Failure to Curtail will be applicable for the monthly billing without modification.

The Energy Cost Rate, State Tax Adjustment and Rate HT Time-of-Use Adjustment are not applicable to this service.

Penalty for Failure to Curtail.

The first time that the Customer is notified by the Company to curtail the Customer fails to curtail a penalty of $24 per kilowatt shall be applicable to each kilowatt of maximum registered demand that is associated with its service during the curtailment period. In addition, if the failure to curtail occurs in a summer month the minimum billing demand in the following months of October through May shall not be less than 80% of the demand during the period in which the Customer failed to curtail. The second time that the Customer fails to curtail within a 12 calendar-month period, the same penalty shall be applicable and curtailable supply will not be available to the Customer for a period of one year.

Liability.

Each party shall reimburse or hold harmless the other for all losses to the other party or third parties; for all damage to the facilities of the other party; or for all liabilities to third parties as a result of such party's negligent operation or use of electrical facilities used in connection with the provisions of this service.

Minimum Charge.

The monthly minimum charge shall be the customers charge of the service rate identified in the Contract.

Term.

Annual, continuing thereafter unless cancelled upon 12 months' prior notice.

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FEB 11 1986
SECRETARY'S OFFICE
Public Utility Commission

PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

Errata Sheet re Testimony of James A. Ross

Page No.	Line No.	Comments
Testimony of James A. Ross		
3	3	cogeneration and [should be] cogeneration.
3	4	power production resources. For [should be] For
4	6	characteristics [should be] characteristic
4	25	generating resources [should be] generating resource
5	10	First, the cogeneration [should be] First, cogeneration
9	4	schedules [should be] schedule
9	21	(Tr. 1629-1632), [should be] (Tr. 1629-1632)
16	7	bill purposes, [should be] billing purposes,
16	24	the 25 MW reserve. [should be] the reserve.
21	17	(compared [should be] (compare
22	19	a 85% [should be] an 85%
24	4	for [should be] from
28	23	associated supplying [should be] associated with supplying
30	15	Thus the [should be] Thus, the
31	15	plus a [should be] plus a
31	16	mark-up. [should be] mark-up.
32	2	supplied. [should be] supplied, plus a mark-up.

DOCKETED
FEB 11 1986

DOCUMENT FOLDER

PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

Errata Sheet re Testimony of James A. Ross

Page No.	Line No.	Comments
Exhibit of James A. Ross		
Schedule 6	7	(15/30 x 5.73) [should be] (15/30) x 5.37)
6	7	$ 14,325.00 [should be] $ 13,425.00
6	12	$142,975.50 [should be] $142,075.50
7		Liability. 4 lines down, "negilgent" [should be] negligent
8	1 of 2	Parallel Operation. 5 lines down, occasioned outages [should be] occasioned by outages
8	2 of 2	Liability. 4 lines down, "negilgent" [should be] negligent
9	2 of 2	Liability. 4 lines down, "negilgent" [should be] negligent
10	2 of 2	Liability. 4 lines down, "negilgent" [should be] negligent

PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

Errata Sheet re Testimony of James A. Ross

Page No.	Line No.	Comments
Summary of Testimony of James A. Ross		
1	23	RECOMMENDATIONS: [should be] RECOMMENDATIONS?
2	2	by a non-utility [should be] by non-utility
2	13	occassioned [should be] occasioned
2	24	follows so [should be] follows, so
2	25	power has [should be] power have
4	16	Occidential [should be] Occidental
4	21	power . [should be] power.
5	3	appropriate [should be] appropriately
5	7	( ), [should be] ( )

COMMUNITY LEGAL SERVICES, INC.

LAW CENTER NORTH CENTRAL
3638 NORTH BROAD STREET
PHILADELPHIA, PA. 19140
215-227-2400

ORIGINAL

February 11, 1986

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FEB 11 1986

SECRETARY'S OFFICE
Public Utility Commission

Mr. Jerry Rich, Secretary
Pennsylvania Public Utility Commission
North Office Building
Commonwealth & North Streets
Harrisburg, Pennsylvania 17120

RE: Pennsylvania Public Utility Commission
v. Philadelphia Electric Company
Docket No. R-850152

Dear Secretary Rich:

Enclosed please find for filing with the Commission CEPA, et al's Brief and nine copies. I have also attached the Postal Service Form 3817 certificate of mailing to the cover of the original. Consequently, this brief should be deemed filed on February 11, 1986.

As the Certificate of Service shows this brief has been served on all parties of record.

Sincerely,

John Hanger

John Hanger
Counsel for
CEPA, AASC, ACORN
PICA, and Mr. Bradshaw

JH/md

Enclosure

cc: All Parties of Record
Honorable Linda C. Taliaferro, Chairman
Commissioner Frank Fischl
Commissioner William Shane

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

FEB 11 1986

SECRETARY'S OFFICE
Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	DOCKET NO. R-850152
PHILADELPHIA ELECTRIC COMPANY	:	

BRIEF OF CONSUMERS EDUCATION AND PROTECTIVE ASSOCIATION, ACTION ALLIANCE OF SENIOR CITIZENS, PHILADELPHIA CITIZENS IN ACTION, ASSOCIATION OF COMMUNITY ORGANIZATIONS FOR REFORM NOW, AND MR. BRADSHAW

Brief in Support of a Petition for Interlocutory Review Pursuant to Section 5.302 of the Commission's Rules of Proceedure, 52 Pa. Code § 5.302.

DOCKETED

FEB 13 1986

JOHN HANGER
Counsel for CEPA, AASC, PCIA, ACORN, and Mr. Bradshaw

COMMUNITY LEGAL SERVICES, INC.
Law Center North Central
3638 N. Broad Street
Philadelphia, PA. 19140

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I. ALJ MATUSCHAK'S DECISION DENYING CEPA, et al's REQUEST TO SUBPOENA JOSEPH FARRELL OR HIS DESIGNEE VIOLATES THE PUBLIC UTILITY CODE AND SHOULD BE REVERSED BY THE COMMISSION . . .	3
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EXHIBITS

1. CEPA, et al's Application for Subpoena of Joseph Farrell or his Designee

STATEMENT OF THE CASE

This interlocutory appeal is before the Commission as a result of a Petition for Commission Review and Answer to a Material Question filed by CEPA, et al, pursuant to 52 Pa. Code § 5.302.

CEPA, et al seeks such review, because Administrative Law Judge Matuschak denied on Thursday, January 30, 1986 CEPA, et al's application for a subpoena of Joseph Farrell, Director, Bureau of Consumer Services, or his designee and certain documents (See CEPA's Application for Subpoena of Joseph Farrell or his designee which is marked as Exhibit 1, attached hereto, and incorporated by reference). CEPA's Application for Subpoena of Joseph Farrell or his designee was made on January 23, 1986.

CEPA sought to subpoena Joseph Farrell or his designee to attend the rate structure rebuttal phase of this case which begins on February 26, 1986. Given the press of time, if this matter is not resolved before February 26, 1986, CEPA would accept the issuance of a subpoena for Joseph Farrell or his designee to attend the sur-rebuttal hearing scheduled for March 5, 1986.

CEPA believes Mr. Farrell solely possesses unique evidence about the Philadelphia Electric Company's programs and efforts to ameliorate the ability-to-pay problem experienced by many low-income ratepayers of PECO. A PECO witness, Mr. Raymond Williams, had pointed to these programs (weatherization, Customer Assistance

Program, energy assistance grants etc.) as an adequate to the payment problems of low-income families. More importantly, Mr. Williams implied that the existence of these programs removed the need for the ALJ and this Commission to look at rate structure initiatives (like a cost-based essential need rate) that might help low-income ratepayers maintian necessary electric service.

Given that CEPA, AASC, PCIA, ACORN, and Mr. Bradshaw favor the adoption of cost-based essential need rate in this case, a central issue for them is whether or not PECO's programs for low-income ratepayers adequately insure poor families access to electricity. In order to guarantee that Joseph Farrell or his designee would address this issue, CEPA applied for a subpoena for Mr. Farrell or his designee. That application was denied by the ALJ, and the denial is now the subject of this Petition for Review.

ARGUMENT

I. ALJ MATUSCHAK'S DECISION DENYING CEPA, et al's REQUEST TO SUBPOENA JOSEPH FARRELL OR HIS DESIGNEE VIOLATES THE PUBLIC UTILITY CODE AND SHOULD BE REVERSED BY THE COMMISSION

66 Pa. C.S.A. § 308(f) states in relevant part the following:

> Members of the staff of the Commission shall appear and present testimony in any proceeding before the Commission when called by the Commission or any of the parties to the proceeding.
>
> (Underlining Added)

Petitioners who are parties to this proceeding which involves consideration of the largest utility rate increase in the history of Pennsylvania merely seek to call Joseph Farrell, Director, Bureau of Consumer Services, or his designee to testify in this case. Plainly, the Public Utility Code not only gives petitioners the right to have Mr. Farrell or his designee testify but also creates a duty for the staff of the Commission "to appear and present testimony" when requested by a party to a proceeding before the Commission.

Petitioners to insure that Joseph Farrell or his designee fulfilled his statutory duty to testify in this case, given petitioner's request that he do so, followed accepted procedure and applied for a subpoena. Remarkably, that subponea was denied, and

the Law Bureau of the Pennsylvania Public Utility Commission has indicated that Mr. Farrell or his designee will not testify unless he is subpoenaed. (Transcript of January 30, 1986 Hearing).

A few words should be said about the importance and relevance of Mr. Farrell or his designee's testimony to petitioners' case. Petitioners support the adoption of a cost-based essential needs rate, since petitioners maintain such a rate structure initiative is essential if PECO electric service is to remain accessible to low-income families. During testimony on January 7, 1986, Mr. Raymond Williams, a witness for PECO, made repeated references to various programs (weatherization, budget billing, energy assistance grants, customer assistance program etc.) available to low-income families that PECO believes protects poor ratepayers' access to service. (Tr. 1774-1775, January 7, 1986) Given such programs, Mr. Williams left no doubt that rate structure initiatives, like cost-based essential needs to assist low-income ratepayers, are unnecessary (Tr. 1994-1997, January 8, 1986).

When considering the wisdom and necessity of cost-based essential needs, a critical issue, therefore, is the effectiveness of PECO's programs designed to remedy the ability-to-pay problem of poor ratepayers. It is on that issue of the effectiveness of PECO's programs that Joseph Farrell possesses unique and irreplaceable information. Petitioners, therefore, sought his testimony but were informed by the Law Bureau that Mr. Farrell or his designee would not testify unless he was subpoenaed.

It also should be noted that PECO's filing in this case includes a claim to fund particular PECO conservation and weatherization programs available to low-income families. In the light of these claims for revenue, the relevancy and materiality of Mr. Farrell's testimony about the worth of these programs is beyond dispute.

Petitioners recognize the Law Bureau's concern about interruption of staff's work that results from the request to testify. But petitioners also note that, in accordance with 66 Pa. C.S.A. 308(f), only parties to a proceeding may secure the testimony of staff. Additionally, any testimony that parties to a proceeding seek to obtain from staff must conform to the rules of evidence. Parties, therefore, cannot go on irrelevant fishing expeditions that abuse the Commission staff's time.

The Legislature, nonetheless, established the "bottom line" by enacting 66 Pa. C.S.A. 308(f). It obviously determined that any interruption to staff's other work caused by the duty to testify at the request of parties was outweighed by the need to create fair proceedings. Such fairness could not be achieved unless parties access to staff testimony, that often is unique and irreplaceable, was guaranteed by state law. Given the Law Bureau's position in this matter that, intentionally or not, is insensitive to the rights of petitioners and other "public" parties, the Legislature's enactment of 66 Pa. C.S.A. 308(f) was well-advised.

Moreover, any effort by the Law Bureau to use 66 Pa. C.S.A. 308(b) to subvert 66 Pa. C.S.A. 308(f) should be soundly rejected

by this Commission as a matter of policy and certainly in this particular petition. First and foremost, 66 Pa. C.S.A. 308(f) and parties access to evidence possessed by Commission staff which it guarantees is not in conflict with 66 Pa. C.S.A. 308(b). To the extent that Mr. Farrell or his designee by giving testimony at the request of petitioners would be reclassified as "prosecutory" and not "advisory," such action would leave numerous people in the Bureau of Consumer Services (including Joseph Farrell if his designee testified) to advise the Commission on this case. So, petitioners can have the testimony of staff, as is required by 66 Pa. C.S.A. 308(f), and the Commission, if it desires, can receive the advice of all members of the Bureau of Consumer Services but for the one person who testifies. Additionally, the Law Bureau knows that changing the status of a staff person from advisory to prosecutory happens often and poses no real barrier. It can occur one more time so that petitioners' rights under 66 Pa. C.S.A. 308(f) are honored.

Despite the critical nature of Mr. Farrell or his designee's testimony to petitioners' case, and despite the clear mandate of 66 Pa. C.S.A. 308(f), the ALJ denied petitioners subpoena and the Law Bureau has refused to insure that Mr. Farrell will testify in the rebuttal or sur-rebuttal phases of this case. Consequently to avoid a gross miscarrage of justice and an obvious violation of state law, this Commission should reverse the ALJ and issue a subpoena for Mr. Farrell to attend the rate structure rebuttal phase of this hearing which begins on February 26, 1986 or the sur-rebuttal phase which begins on March 5, 1986.

Alternatively, the Commission could instruct Mr. Farrell or his designee to attend the February 26, 1986 rebuttal hearing (assuming the Commission rules on this petition before February 26, 1986) or the March 5, 1986 sur-rebuttal hearing.

Given the importance of this matter to petitioners and the on-going proceeding, petitioners request that the Commission rule on their petition before February 26, 1986 but no later than March 3, 1986.

Finally, unless the Commission reverses the ALJ and order him to issue the subpoena that petitioners requested on January 23, 1986 (see Exhibit 1) or just orders Mr. Farrell or his designee to attend either the February 26, 1986 or March 5, 1986 hearings, petitioners will suffer irreparable prejudice and the record in this very important case will not be complete and fair.

CONCLUSION

For all the foregoing reasons, petitioners ask that the Commission reverse the January 30, 1986 ALJ decision not to subpoena Joseph Farrell or his designee and order him to issue a subpoena for Joseph Farrell or his designee to testify either at the February 26, 1986 hearing, if the Commission rules on this petition before that hearing, or the March 5, 1986 sur-rebuttal hearing if the Commission cannot rule before February 26, 1986. Alternatively, the Commission could forego the procedural step of ordering that the ALJ issue a subpoena for Mr. Farrell or his designee and just order Mr. Farrell or his designee to attend the February 26, 1986 hearing

or the March 5, 1986 hearing.

Respectfully submitted,

John Hanger

JOHN HANGER
Attorney for
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Action Alliance of Senior Citizens
Philadelphia Citizens in Action
Association of Community Organizations
For Reform Now
Mr. Bradshaw

Community Legal Services, Inc.
Law Center North Central
3638 North Broad Street
Philadelphia, Pennsylvania 19140

(215) 227-2400

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	DOCKET NO. R-850152
PHILADELPHIA ELECTRIC COMPANY	:	

APPLICATION FOR SUBPOENA OF
JOSEPH FARRELL OR HIS DESIGNEE
TO ATTEND THE REBUTTAL PHASE
OF THE HEARINGS IN THE ABOVE CASE

NOW COME CONSUMERS EDUCATION AND PROTECTIVE ASSOCIATION, et al (CEPA), pursuant to Section 5.421 of the Commission's Regulations (52 Pa. Code Section 5.421), to apply for a subpoena of Mr. Joseph Farrell, Director, Bureau of Consumer Services, Pennsylvania Public Utility Commission, or his designee to attend with requested documents the rebuttal phase of the hearings in this case.

Mr. Farrell or his designee is requested to bring with him and have available at the hearing the following:

(a) A summary of all citations for violation of 52 Pa Code Chapter 56 issued to the Philadelphia Electric Company (PECO) for the last 2 years or other evidence of PECO's violation of 52 Pa Code Chapter 56 during the last 2 years;

EXHIBIT 1

(b) Any memoranda or other documents regarding PECO's compliance with 52 Pa Code Chapter 56 or with programs benefiting ratepayers with incomes at or below 150% of the Office of Management and Budget (OMB) poverty line;

(c) Any memoranda or documents concerning the effectiveness of PECO's programs in eliminating or ameliorating the ability-to-pay problem of PECO ratepayers at or below 150% of the poverty line;

(d) Any evidence, memoranda, or documents evaluating PECO's implementation of 52 Pa Code Chapter 56.

CEPA et al's request for the issuance of a subpoena for Mr. Farrell or his designee should be granted because:

1. Mr. Farrell wil testify about PECO's implementation of 52 Pa Code Chapter 56 which establishes the rights and responsibilities of ratepayers regarding billings, collection, and termination and which particularly impacts low-income ratepayers' ability to pay PECO's proposed rates.

2. Mr. Farrell will testify about the effectiveness of PECO's programs to remedy the ability-to-pay problem experienced by many PECO ratepayers and particulary low-income PECO ratepayers and clarify whether these programs by themselves, without rate design changes, will protect low-income ratepayers.

3. Mr. Farrell will comment on the testimony of PECO witness Raymond Williams (Tr. 1994-1997; January 8, 1986) concerning the alleged effectiveness of PECO's response to the ability-to-pay problem of low-income ratepayers.

4. The documents that CEPA, et al request Mr. Farrell bring with him to the hearing pertain directly to PECO's response to the ability-to-pay problems of low-income ratepayers which will worsen if PECO's rate request in this proceeding is not severely slashed and if PECO's rate design is not altered.

5. The filing contains a claim for revenue to fund various PECO conservation and weatherization programs for low-income customers, including tighten-up Low-Cost Conservation Program (TLC), Utility Emergency Services Fund (UESF) and others, as set forth in PECO's response to IR-OCA 11-12.

6. Consequently, the funding level and cost effectiveness of these programs are issues in this proceeding and questions on which Mr. Farrell or his designee can comment.

WHEREFORE, for all the foregoing reasons, CEPA, et al pray that your Honor issue a subpoena for Mr. Farrell or his designee.

Respectfully submitted,

John Hanger

JOHN HANGER
Attorney for CEPA, AASC, ACORN, PCIA and Mr. Bradshaw

Community Legal Services,
3638 North Broad Street
Philadelphia, PA. 19140
(215) 227-2400

DATED: January 23, 1986

NOTICE TO PARTIES CONCERNING DATE
BY WHICH RESPONSE TO
APPLICATION FOR SUBPOENA IS DUE

All parties are, hereby, notified that, pursuant to 52 Pa Code 5.421(b), all parties wishing to respond to the foregoing application for a subpoena must do so by January 29, 1986.

John Hanger

JOHN HANGER

Community Legal Services, Inc.
3638 North Broad Street
Philadelphia, PA. 19140
(215) 227-2400

DATED: January 23, 1986

CERTIFICATE OF SERVICE

I, hereby, certify that I am serving this eleventh day of February, 1986 the attached Brief In Support of CEPA, et al's Petition For Interlocutory Review by first class mail upon the following:

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John Hanger
JOHN HANGER

DATED: February 11, 1986

COMMONWEALTH OF PENNSYLVANIA

OFFICE OF CONSUMER ADVOCATE
1425 Strawberry Square
Harrisburg, Pennsylvania 17120

DAVID M. BARASCH
Consumer Advocate

(717) 783-5048

February 12, 1986

RECEIVED

FEB 12 1986

SECRETARY'S OFFICE
Public Utility Commission

Jerry Rich, Secretary
Pennsylvania Public Utility
Commission
P.O. Box 3265
Harrisburg, PA 17120

Re: Pennsylvania Public Utility
Commission v. Philadelphia
Electric Company,
Docket No. R-850152

Dear Secretary Rich:

Enclosed please find the original and one copy of a Protective Agreement entered into between the Philadelphia Electric Company and the Office of Consumer Advocate. This Agreement concerns certain data provided to the Company by Komanoff Energy Associates, a consultant retained by this Office.

Sincerely,

Scott J. Rubin
Assistant Consumer Advocate

Enclosure
2729P

cc: Frederick H. Knight, Esq. (w/enclosure)
Hon. Joseph Matuschak (w/enclosure)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

FEB 12 1986

SECRETARY'S OFFICE
Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION :
:
v. : Docket No. R-850152
:
PHILADELPHIA ELECTRIC COMPANY :

FOLDER

DOCKETED
FEB 13 1986

PROTECTIVE AGREEMENT

The Pennsylvania Office of Consumer Advocate ("OCA") and its consultants Komanoff Energy Associates ("KEA"), and Philadelphia Electric Company ("PECO") and its consultants National Economic Research Associates ("NERA") and Putnam, Hayes & Bartlett ("PHB") hereby agree that the information and data listed below are considered by KEA to be confidential and proprietary. KEA is willing to provide this material to PECO and its consultants, NERA and PHB, in the above-docketed proceeding subject to certain conditions necessary to preserve its confidential and proprietary nature. The information and data are the workpapers of KEA which were used in the preparation of OCA Statement 6 and are being provided on two floppy diskettes, readable by an IBM PC.

PECO, NERA, and PHB agree that their employees, agents, contractors and representatives will utilize the information and data produced pursuant to this Agreement for the sole purpose of analyzing the position of OCA in the above-docketed proceeding. PECO, NERA, and PHB agree that they will not make copies in any form, use in any other proceeding, disclose to any other person, including other parties to this

proceeding, use or make publicly or privately available to any third party, the information and data produced pursuant to this Agreement, with the exception that PECO may copy the diskettes for distribution to NERA and PHB. PECO, NERA, and PHB further agree that they will not include any information or data produced pursuant to this Agreement in the direct testimony of PECO witnesses in the subject proceeding without the specific written consent of KEA having been first obtained and will not enter the information and data subject to this Agreement or any part thereof into the public record without first obtaining such consent. PECO, NERA, and PHB also agree that they will return all copies of the information and data described herein, and any analyses prepared utilizing such information and data, to OCA within thirty (30) days after the close of the record in this proceeding.

Intending to be legal bound hereby, the parties have executed this Agreement, this 14th day of January, 1986.

Scott J. Rubin, Esq. for
Office of Consumer Advocate

Charles Komanoff, for
Komanoff Energy Associates

Frederick H. Knight, Esq. for
Philadelphia Electric Company

Lewis J. Perl
National Economic Research
Associates

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Putnam, Hayes & Bartlett

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SAMUEL A. SCHRECKENGAUST, JR.

February 12, 1986

Re: Pennsylvania Public Utility Commission, et al.,
v. Philadelphia Electric Company
Docket No. R-850152

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Reed, Smith, Shaw & McClay
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Philadelphia, PA 19107-4616

RECEIVED
FEB 13 1986
SECRETARY'S OFFICE
Public Utility Commission

Dear Mr. Morris:

Enclosed please find the response of Philadelphia Area Industrial Energy Users Group (PAIEUG) to the data requests of SEPTA/AMTRAK, Set I, Nos. 3 and 4.

All parties of record to this proceeding have been supplied with copies as evidenced by the attached Certificate of Service.

Very truly yours,

McNEES, WALLACE & NURICK

By David M. Kleppinger
David M. Kleppinger

DMK/jf
Enclosure

cc: All Parties of Record (w/encl.)

DOCUMENT FOLDER

CERTIFICATE OF SERVICE

Pennsylvania Public Utility Commission, et al., :
v. : Docket No. R-850152
Philadelphia Electric Company :

I hereby certify that I have served a copy of the foregoing document on all known parties of record to this proceeding; all by first class mail (unless otherwise indicated) properly addressed as follows:

Administrative Law Judge
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Harrisburg, PA 17102

David M. Kleppinger

David M. Kleppinger

Dated this 12th day of FEBRUARY, 1986, at Harrisburg, PA.

FEB 13 1986
SECRETARY'S OFFICE
Public Utility Commission

3. Why did Jeffry Pollock select the cost study prepared by Melvin Bloom which used the 1985 EDH normalization adjustment as opposed to the 1980-83 EDH normalization adjustment, or the 213 EDH normalization adjustment? (Pollock)

Response

As stated on Page 8 of the direct testimony, the 1985 EDH normalization cost-of-service study "yields the lowest rate of return for the high tension class relative to the other weather adjusted cost studies." Mr. Pollock chose this particular study because the results were the most conservative from the high tension class's perspective.

4. Provide workpapers to show how Jeffry Pollock calculated the revenue increases applied to all classes as shown in Schedule 5 of Exhibit JP-1. Indicate where and why you deviated from a revenue increase spread among the classes relative to nonfuel revenues as discussed on Page 18 of the testimony of Jeffry Pollock. (Pollock)

Response

The workpapers are supplied in Attachment IR - SEPTA/AMTRAK-4.

The reasons for deviating from an equal percent nonfuel increase for particular classes are described on Pages 18 and 19 of the direct testimony. Specifically, the increase was adjusted in order to: (1) maintain the interclass revenue subsidy at the present level and (2) keep the index of return from exceeding 140% of the system average return. Referring to Exhibit JP-1 ( ), Schedule 6, the first constraint was applied to the primary, secondary, residential heating, Rate OP, SEPTA and AMTRAK classes. The second constraint was applied to the street lighting class.

DOCUMENT FOLDER

DOCKETED
FEB 13 1986

PECO COSIA FINAL

ATTACHMENT IR - SEPTA/AMTRAK-4

PHILADELPHIA ELECTRIC COMPANY

Summary of PAIEUG et al Revised Cost-of-Service Study Results
at Present, Proposed and Recommended Rates
Four Coincident Peak Method
1985 EDH Study
Year Ending June 30, 1986

Line	Customer Class	Rate Base (000)	Present Operating Income (000)	Present Operating Revenues (000)	Electric Sales (000)	PROPOSED REVENUE INCREASE Growth (000)	Other Revenue (000)	Total Increase (000)
1	High Tension	2,323,751.000	146,641.000	795,616.000	350,372.000	6,898.000	19.000	357,289.000
2	Primary	532,969.000	39,643.000	181,052.000	73,448.000	1,611.000	70.000	75,129.000
3	Secondary	966,894.000	77,558.000	332,684.000	128,033.000	1,703.000	0.000	129,736.000
	Residential:							
4	Heating	364,832.000	21,653.000	123,816.000	44,585.000	2,205.000	0.000	46,790.000
5	Regular	2,443,984.000	126,691.000	715,109.000	267,733.000	2,314.000	0.000	270,047.000
6	Rate OP	15,952.000	3,559.000	24,342.000	2,940.000	27.000	0.000	2,967.000
7	Total Residential	2,824,768.000	151,903.000	863,267.000	315,258.000	4,546.000	0.000	319,804.000
	Street Lighting:							
8	Rate SLP	30,349.000	3,398.000	13,464.000	736.000	0.000	0.000	736.000
9	Rate SLS	40,261.000	5,306.000	17,742.000	457.000	0.000	0.000	457.000
10	All Other	3,370.000	645.000	2,328.000	108.000	0.000	0.000	108.000
11	Total Street Lighting	73,980.000	9,349.000	33,534.000	1,301.000	0.000	0.000	1,301.000
12	Other Utilities	109,398.000	7,994.000	29,933.000	3.000	0.000	0.000	3.000
13	Interdepartmental	12,228.000	1,550.000	4,836.000	0.000	0.000	0.000	0.000
14	SEPTA	52,102.000	3,956.000	18,451.000	5,003.000	0.000	0.000	5,003.000
15	AMTRAK	67,443.000	6,187.000	31,407.000	4,709.000	0.000	0.000	4,709.000
16	Total Company	6,963,533.000	444,781.000	2,290,780.000	878,127.000	14,758.000	89.000	892,974.000
						14,758.000		

PHILADELPHIA ELECTRIC COMPANY

Summary of PAIEUG et al Revised Cost-of-Service Study Results
at Present, Proposed and Recommended Rates
Four Coincident Peak Method
1985 EDH Study
Year Ending June 30, 1986

Line	Customer Class	Electric Sales (000)	RECOMMENDED REVENUE INCREASE Growth (000)	Other Revenue (000)	Total Increase (000)	Proposed Operating Income (000)	Recommended Operating Income (000)
1	High Tension	295,796.394	5,779.986	19.000	301,595.380	322,525.132	295,108.604
2	Primary	66,957.241	1,318.194	70.000	68,345.435	76,627.063	73,287.689
3	Secondary	122,037.274	1,952.827	0.000	123,990.101	141,423.677	138,595.119
	Residential:						
4	Heating	45,639.031	1,145.019	0.000	46,784.049	44,686.507	44,683.577
5	Regular	310,723.131	4,508.932	0.000	315,232.062	259,628.152	281,871.590
6	Rate OP	1,992.645	53.043	0.000	2,045.688	5,019.577	4,566.039
7	Total Residential	358,354.806	5,706.993	0.000	364,061.800	309,334.236	331,121.206
	Street Lighting:						
8	Rate SLP	3,315.666	0.000	0.000	3,315.666	3,760.314	5,030.217
9	Rate SLS	4,083.244	0.000	0.000	4,083.244	5,530.969	7,316.076
10	All Other	262.484	0.000	0.000	262.484	698.166	774.214
11	Total Street Lighting	7,661.395	0.000	0.000	7,661.395	9,989.449	13,120.506
12	Other Utilities	11,984.280	0.000	0.000	11,984.280	7,995.477	13,893.551
13	Interdepartmental	6.006	0.000	0.000	6.006	1,550.000	1,552.957
14	SEPTA	6,681.436	0.000	0.000	6,681.436	6,418.847	7,245.098
15	AMTRAK	8,648.178	0.000	0.000	8,648.178	8,505.119	10,444.274
16	Total Company	878,127.010	14,758.000	89.000	892,974.010	884,369.000	884,369.005

PHILADELPHIA ELECTRIC COMPANY

Summary of PAIEUG et al Revised Cost-of-Service Study Results
at Present, Proposed and Recommended Rates
Four Coincident Peak Method
1985 EDH Study
Year Ending June 30, 1986

Line	Customer Class	Proposed Operating Revenues (000)	Recommended Operating Revenues (000)	Net To Gross	Required Operating Revenues Amount (000)	Percent
1	High Tension	1,152,905.000	1,097,211.380	2.0313885	1,097,227.380	34.463%
2	Primary	256,181.000	249,397.435	2.0313885	238,020.435	7.476%
3	Secondary	462,420.000	456,674.101	2.0313885	424,579.101	13.336%
	Residential:					
4	Heating	170,606.000	170,600.049	2.0313885	173,952.049	5.464%
5	Regular	985,156.000	1,030,341.062	2.0313885	1,088,265.062	34.182%
6	Rate OP	27,309.000	26,387.688	2.0313885	21,227.688	0.667%
7	Total Residential	1,183,071.000	1,227,328.800		1,283,444.800	40.312%
	Street Lighting:					
8	Rate SLP	14,200.000	16,779.666	2.0313885	14,390.972	0.452%
9	Rate SLS	18,199.000	21,825.244	2.0313885	17,350.244	0.545%
10	All Other	2,436.000	2,590.484	2.0313885	1,887.169	0.059%
11	Total Street Lighting	34,835.000	41,195.395		33,628.385	1.056%
12	Other Utilities	29,936.000	41,917.280	2.0313885	41,917.280	1.317%
13	Interdepartmental	4,836.000	4,842.006	2.0313885	4,842.006	0.152%
14	SEPTA	23,454.000	25,132.436	2.0313885	23,856.436	0.749%
15	AMTRAK	36,116.000	40,055.178	2.0313885	36,238.178	1.138%
16	Total Company	3,183,754.000	3,183,754.010	2.031389481	3,183,754.000	100.000%

PHILADELPHIA ELECTRIC COMPANY

Summary of PAIEUG et al Revised Cost-of-Service Study Results
at Present, Proposed and Recommended Rates
Four Coincident Peak Method
1985 EDH Study
Year Ending June 30, 1986

Line	Customer Class	ENERGY SALES Per Budget (GWh)	Growth (GWh)	Total Proforma (GWh)	INCREASE DUE TO GROWTH Fuel Savings (000)	Other (000)
1	High Tension	12,696.300	251.125	12,947.425	1,884.693	3,895.293
2	Primary	2,241.000	58.137	2,299.137	436.318	881.875
3	Secondary	3,441.537	46.811	3,488.348	351.317	1,601.510
	Residential:					
4	Heating	1,543.300	72.05	1,615.350	540.735	604.283
5	Regular	6,465.900	58.262	6,524.162	437.256	4,071.675
6	Rate OP	391.723	3.547	395.270	26.620	26.423
7	Total Residential	8,400.923	133.859	8,534.782	1,004.612	4,702.382
	Street Lighting:					
8	Rate SLP	96.618	0.000	96.618	0.000	0.000
9	Rate SLS	60.840	0.000	60.840	0.000	0.000
10	All Other	15.850	0.000	15.850	0.000	0.000
11	Total Street Lighting	173.308	0.000	173.308	0.000	0.000
12	Other Utilities	449.862	0.000	449.862	0.000	0.000
13	Interdepartmental	63.400	0.000	63.400	0.000	0.000
14	SEPTA	268.500	0.000	268.500	0.000	0.000
15	AMTRAK	431.500	0.000	431.500	0.000	0.000
16	Total Company	28,166.330	489.932	28,656.262	3,676.940	11,081.060
		27,653.068				11,081.060

PHILADELPHIA ELECTRIC COMPANY

Summary of PAIEUG et al Revised Cost-of-Service Study Results
at Present, Proposed and Recommended Rates
Four Coincident Peak Method
1985 EDH Study
Year Ending June 30, 1986

Line	Customer Class	Nonfuel Growth Revenue (000)	Percent	Present Base Revenue With ECR Roll-out (000)	ECR Roll-out (000)
1	High Tension	10,495.403	35.2%	785,557.000	97,170.425
2	Primary	2,479.387	8.0%	178,729.000	17,255.023
3	Secondary	3,254.043	14.5%	328,244.000	26,180.052
	Residential:				
4	Heating	3,849.346	5.5%	121,780.000	12,123.202
5	Regular	4,341.793	36.7%	699,286.000	48,963.836
6	Rate OP	264.013	0.2%	23,392.000	2,966.501
7	Total Residential	8,455.152		844,458.000	64,053.539
	Street Lighting:				
8	Rate SLP	0.000	ERR	13,431.000	725.118
9	Rate SLS	0.000	ERR	17,722.000	456.604
10	All Other	0.000	ERR	2,300.000	118.954
11	Total Street Lighting	0.000	ERR	33,453.000	1,300.677
12	Other Utilities	0.000	ERR	29,633.000	0.000
13	Interdepartmental	0.000	ERR	4,803.000	0.000
14	SEPTA	0.000	ERR	18,244.000	2,015.093
15	AMTRAK	0.000	ERR	28,696.000	3,238.408
16	Total Company	24,683.985	100.00%	2,251,817.000	211,213.215
					0.785

OVERSIZE

Documents

PHILADELPHIA ELECTRIC COMPANY

Summary of PAIEUG et al Revised Cost-of-Service Study Results
at Present, Proposed and Recommended Rates
Four Coincident Peak Method
1985 EDH Study
Year Ending June 30, 1986

Line	Customer Class	Rate of Return		Index of Return		Interclass Subsidy	
		Present Rates	Proposed Rates	Present Rates	Proposed Rates	Present Rates (000)	Proposed Rates (000)
		(1)	(2)	(3)	(4)	(5)	(6)
1	High Tension	6.31%	13.88%	99	109	($3,623)	$55,678
2	Primary	7.44	14.38	116	113	11,377	18,161
3	Secondary	8.02	14.63	126	115	32,095	37,841
	Residential:						
4	Heating	5.94	12.25	93	96	(3,352)	(3,346)
5	Regular	5.18	10.62	81	84	(59,750)	(103,109)
6	Rate OP	22.31	31.47	349	248	5,160	6,081
7	Total Residential	5.38	10.95	84	86	(57,942)	(100,374)
	Street Lighting:						
8	Rate SLP	11.20	12.39	175	98	2,965	(191)
9	Rate SLS	13.18	13.74	206	108	5,555	849
10	All Other	19.14	20.72	300	163	873	549
11	Total Street Lighting	12.64	13.50	198	106	9,392	1,207
12	Other Utilities	7.31	7.31	114	58	2,044	(11,981)
13	Interdepartmental	12.68	12.68	198	100	1,562	(6)
14	SEPTA	7.59	12.32	119	97	1,276	(402)
15	AMTRAK	9.17	12.61	144	99	3,817	(122)
16	Total Company	6.39%	12.70%	100	100	$0	($0)

20-Jan-86

PHILADELPHIA ELECTRIC COMPANY

Derivation of Nonfuel Revenue
Year Ending June 30, 1986

Line	Rate Schedule	Energy Sold (MWh)	Present Base Revenue (000)	Embedded Energy Costs (000)	Proforma Nonfuel Revenue (000)
				28.753	
1	R	6,465,900	$739,467	$185,914	$553,553
2	RH	1,543,300	127,424	44,375	83,049
3	OP	393,600	25,989	11,317	14,672
4	POL	8,320	1,527	239	1,288
5	GS	3,406,780	344,838	97,955	246,883
6	PD	2,241,000	191,010	64,435	126,575
7	HT	12,696,300	860,983	365,057	495,926
8	EPA	431,500	31,683	12,407	19,276
9	EPS	268,500	20,100	7,720	12,380
10	SLP	104,148	14,993	2,995	11,998
11	SLS	60,840	18,129	1,749	16,380
12	TL	32,880	3,486	945	2,541
13	BLI	62	7	2	5
14	TRR	0	306	0	306
15	Subtotal	27,653,130	$2,379,942	$795,110	$1,584,832
16	Other Elec Operations	489,932	122,051	14,087	107,964
17	Total Company	28,143,062	$2,501,993	$809,197	$1,692,796

20-Jan-86

PHILADELPHIA ELECTRIC COMPANY

PAIEUG et al Recommended
Distribution of Proposed Nonfuel Revenue Increase
Relative to Present Nonfuel Revenue
Year Ending June 30, 1986

Line	Rate Schedule	Proforma Nonfuel Revenue (000)	Recommended Nonfuel Revenue Increase Amount (000)	Percent	Index
1	R	$553,553	$310,723	56.1%	103
2	RH	83,049	45,639	55.0%	101
3	OP	14,672	2,007	13.7%	25
4	POL	1,288	62	4.8%	9
5	GS	246,883	121,776	49.3%	90
6	PD	126,575	66,957	52.9%	97
7	HT	495,926	295,796	59.6%	109
8	EPA	19,276	8,648	44.9%	82
9	EPS	12,380	6,681	54.0%	99
10	SLP	11,998	3,516	29.3%	54
11	SLS	16,380	4,083	24.9%	46
12	TL	2,541	247	9.7%	18
13	BLI	5	2	38.3%	70
14	TRR	306	89	29.1%	53
15	Subtotal	$1,584,832	$866,228	54.7%	100
16	Other Elec Operations	107,964	26,745	24.8%	45
17	Total Company	$1,692,796	$892,973	52.8%	

20-Jan-86

PHILADELPHIA ELECTRIC COMPANY

PAIEUG et al Recommended
Distribution of Proposed Net Revenue Increase
Relative to Present Base Revenue
Year Ending June 30, 1986

Line	Rate Schedule	Proforma Base Revenue (000)	Net Revenue Increase Amount (000)	Percent	Index
1	R	$739,467	$262,197	35.5%	128
2	RH	127,424	34,057	26.7%	97
3	OP	25,989	(947)	-3.6%	-13
4	POL	1,527	(0)	.0%	0
5	GS	344,838	96,208	27.9%	101
6	PD	191,010	50,139	26.2%	95
7	HT	860,983	200,511	23.3%	84
8	EPA	31,683	5,410	17.1%	62
9	EPS	20,100	4,666	23.2%	84
10	SLP	14,993	2,735	18.2%	66
11	SLS	18,129	3,627	20.0%	72
12	TL	3,486	0	.0%	0
13	BLI	7	2	21.9%	79
14	TRR	306	89	29.1%	105
15	Subtotal	$2,379,942	$658,691	27.7%	100
16	Other Elec Operations	122,051	23,068	18.9%	
17	Total Company	$2,501,993	$681,760	27.2%	

PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
1985 EDH STUDY
FOUR PEAK METHOD
TWELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

RATE BASE	TOTAL	HIGH TENSION	PRIMARY	SECONDARY	RATE RH	RATE R	RATE OP
ELECTRIC PLANT IN SERVICE	16,893,834	32,871,155	$ 672,201	11,226,341	$ 475,210	$3,207,112	$ 22,435
ACCUMULATED PROVISION FOR DEPREC	1,665,850	475,777	118,983	220,181	97,058	654,595	8,334
NET PLANT IN SERVICE	7,227,984	2,395,378	553,218	1,006,160	378,151	2,552,517	14,101
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	272,153	100,401	20,252	34,666	15,492	85,594	3,279
DEDUCTIONS							
ACCELERATED AMORTIZATION	2,323	868	190	331	112	732	0
LIBERALIZED DEPRECIATION	526,166	170,534	39,928	72,644	28,068	188,773	1,311
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	6,963,532	2,323,751	532,969	966,894	364,832	2,443,984	15,952
REVENUE							
SALES	2,251,817	785,557	178,729	328,244	121,780	699,286	23,392
OTHER	38,962	10,059	2,323	4,940	2,036	15,823	950
TOTAL REVENUE	2,290,779	795,616	181,052	332,684	123,816	715,109	24,342
EXPENSES							
OPERATION AND MAINT EXP	1,440,907	518,688	105,468	184,426	82,048	471,542	16,764
DEPRECIATION AND AMORT	264,877	88,379	20,451	36,242	13,796	92,410	870
TAXES OTH THN INCOME TAX	82,178	26,993	6,239	11,619	4,497	26,783	701
INCOME TAXES	34,032	26,199	8,030	17,026	1,471	-30,941	4,384
PROV FOR DEFERRED INC TAX	41,011	-5,145	2,587	8,215	1,193	32,172	-1,925
INC TX DEF IN PRIOR YR	-13,606	-5,037	-1,109	-1,932	-662	-4,329	-2
INVESTMENT TAX CREDIT	-3,401	-1,102	-258	-470	-181	-1,220	-8
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	1,845,998	648,975	141,409	255,126	102,162	588,418	20,782
NET OPERATING INCOME	444,781	146,641	39,643	77,558	21,653	126,691	3,559
RATE OF RETURN	6.39%	6.31%	7.44%	8.02%	5.94%	5.18%	22.31%
INDEX OF RETURN	100	99	116	126	93	81	349
DEVIATION	.00	-.08	1.05	1.63	-.45	-1.20	15.93
REVENUE SUBSIDY	0	-3,624	11,378	32,095	-3,351	-59,750	5,161
PROPOSED OPERATING INCOME	$ 684,369	$ 322,508	$ 76,628	$ 141,436	$ 44,687	$ 259,631	$ 5,020
PROPOSED RATE OF RETURN	12.70%	13.88%	14.38%	14.63%	12.25%	10.62%	31.47%
PROPOSED INDEX OF RETURN	100	109	113	115	96	84	248
PROPOSED DEVIATION	.00	1.18	1.68	1.93	-.45	-2.08	18.77
PROPOSED REVENUE SUBSIDY	0	55,643	18,162	37,866	-3,344	-103,102	6,062

Exhibit MPB-3 ( )
Schedule 2
Page 1 of 2

01/16/86 15:45

Exhibit MPB-3 ( )
Schedule 2
Page 2 of 2

PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
1985 EDH STUDY
FOUR PEAK METHOD
TWELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

	RATE SLP	RATE SLS	OTH SL	OTHER UTILITIES	INTER DEPARTMT	SEPTA	AMTRAK
RATE BASE							
ELECTRIC PLANT IN SERVICE	$ 47,797	$ 66,424	$ 5,392	$ 135,753	$ 15,216	$ 65,436	$ 83,364
ACCUMULATED PROVISION FOR DEPREC	15,580	23,073	1,862	21,873	2,555	11,502	14,477
NET PLANT IN SERVICE	32,217	43,350	3,530	113,880	12,661	53,934	68,887
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	1,223	1,208	168	3,633	474	2,111	3,551
DEDUCTIONS							
ACCELERATED AMORTIZATION	0	0	0	42	5	18	25
LIBERALIZED DEPRECIATION	2,839	3,945	319	8,072	903	3,886	4,942
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	30,349	40,261	3,370	109,398	12,228	52,102	67,443
REVENUE							
SALES	13,431	17,722	2,300	29,633	4,803	18,244	28,696
OTHER	33	20	26	300	33	207	2,711
TOTAL REVENUE	13,464	17,742	2,328	29,933	4,836	18,451	31,407
EXPENSES							
OPERATION AND MAINT EXP	6,591	6,821	1,012	15,242	1,918	10,931	19,455
DEPRECIATION AND AMORT	1,080	2,302	171	4,209	466	1,958	2,542
TAXES OTH THN INCOME TAX	483	635	74	530	60	614	950
INCOME TAXES	1,761	2,051	437	-969	521	1,129	2,933
PROV FOR DEFERRED INC TAX	175	660	-9	3,223	354	-5	-485
INC TX DEF IN PRIOR YR	-6	-7	-1	-244	-26	-107	-143
INVESTMENT TAX CREDIT	-18	-26	-2	-52	-6	-25	-32
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	10,066	12,436	1,683	21,939	3,287	14,495	25,220
NET OPERATING INCOME	3,398	5,306	645	7,994	1,550	3,956	6,187
RATE OF RETURN	11.20%	13.18%	19.14%	7.31%	12.67%	7.59%	9.17%
INDEX OF RETURN	175	206	300	114	198	119	144
DEVIATION	4.81	6.79	12.75	.92	6.29	1.21	2.79
REVENUE SUBSIDY	2,964	5,555	873	2,044	1,561	1,275	3,818
PROPOSED OPERATING INCOME	$ 3,760	$ 5,531	$ 698	$ 7,995	$ 1,550	$ 6,419	$ 8,505
PROPOSED RATE OF RETURN	12.39%	13.74%	20.72%	7.31%	12.67%	12.32%	12.61%
PROPOSED INDEX OF RETURN	98	108	163	58	100	97	99
PROPOSED DEVIATION	-.31	1.04	8.02	-5.39	-.03	-.38	-.09
PROPOSED REVENUE SUBSIDY	-192	849	549	-11,982	-7	-403	-122

Exhibit MPB-3 ( )
Schedule 2
Page 2 of 2

Docket R-850152

PENNSYLVANIA PUBLIC UTILITY COMMISSION
COMMONWEALTH OF PENNSYLVANIA
HARRISBURG, PENNSYLVANIA

LINDA C. TALIAFERRO
CHAIRMAN

TELEPHONE
(717) 787-4301

January 31, 1986

The Honorable James L. Wright, Jr.
Member, House of Representatives
Room 248 Main Capitol Building
Harrisburg, Pennsylvania 17120

Dear Representative Wright:

Thank you for your letter dated January 28, 1986 concerning Philadelphia Electric Company's recent request for a rate increase.

As you know, while this matter is pending before the Commission, I am legally prohibited from discussing this matter on its merits. However, pursuant to your request, I will have your letter and its attachment placed with the record in this matter.

Again, thank you for writing. If I may be of any assistance in the future, please do not hesitate to contact my office.

Sincerely,

Linda C. Taliaferro

Linda C. Taliaferro
Chairman

DOCUMENT FOLDER

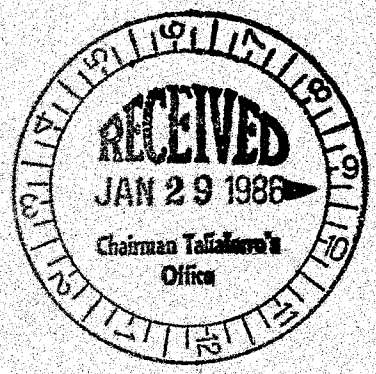
JAMES L. WRIGHT, JR. MEMBER
116 HOLLOW ROAD
LEVITTOWN, PENNSYLVANIA 19056
PHONE: (215) 946-7175

ROOM 248, MAIN CAPITOL BUILDING
HOUSE OF REPRESENTATIVES
HARRISBURG, PENNSYLVANIA 17120-0028
PHONE: (717) 787-8581

COMMITTEES
MINES & ENERGY MANAGEMENT, MINORITY CHAIRMAN
BUSINESS & COMMERCE

HISTORICAL & MUSEUEM COMMISSION
ENERGY DEVELOPMENT AUTHORITY
GOVERNOR'S ENERGY COUNCIL

HOUSE OF REPRESENTATIVES
COMMONWEALTH OF PENNSYLVANIA
HARRISBURG



January 28, 1986

Honorable Linda Taliaferro
Chairman
Public Utility Commission
Room 104 North Office Building
Harrisburg, PA 17120

Dear Chairman Taliaferro:

Attached is a letter addressed to me by SAGE, the lead senior citizen group in Bucks County.

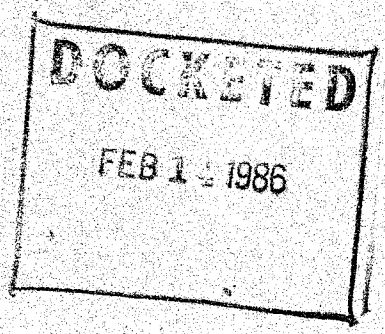
I agree with their observation that Limerick is not needed. As the Minority Chairman of the House Mines and Energy Committee, I am aware of the excess capacity that exists in the PJM grid.

I cannot attend the local hearing, as the House is in session. I do hope you can add my letter to your files and consider both SAGE and my opinions as you make your decision.

Sincerely,

James L. Wright, Jr.

JLW:ml
cc: Sylvia Harris, President
SAGE
30 East Oakland Avenue
Doylestown, PA 18901



SAGE — SENIOR ACTION GROUP ENDEAVOR
30 E. Oakland Avenue
Doylestown, Pa. 18901

January 22, 1986

The Honorable James L. Wright
House P.O. Box
Harrisburg, PA 17120

Dear Representative Wright:

SAGE, Senior Action Group Endeavor, is an organization of senior citizens who are interested in legislative and administrative matters which affect older adults. Each member of SAGE is a delegate from an independent senior citizens' group.

SAGE is writing to you today to ask your help in a matter which affects individuals, businesses, municipal governments, school boards--any person or entity which pays electrical bills. As you may know, the Philadelphia Electric Company has asked the Pennsylvania Public Utility Commission for permission to increase our electric rates by 28% so that they can make their Limerick #1 plant operational. SAGE believes that the Delaware Valley region does not need this nuclear plant to fill its energy needs and SAGE knows that seniors and others on limited and even middle class budgets will be devastated by a 28% increase in their monthly electric bills and the resulting increase in local taxes and consumer costs that will follow an increase in the electric bills of local governments and businesses.

SAGE is planning to give testimony at the Public Hearing to be held at Delaware Valley College All Purpose Room in the Student Center, Doylestown, at 6:30 P.M. on February 3, 1986. SAGE will tell the Public Utility Commission that senior citizens in Bucks County cannot afford a 28% increase in electric rates which are already the highest in the state. SAGE invites you to join them in testifying at the February 3 Public Hearing at Delaware Valley College on this matter.

Thank you for your concern for Bucks County's senior citizens.

Sincerely,

Sylvia Harris/ns/

Sylvia Harris,
SAGE President

DOCUMENT FOLDER

SH:NS:esd

COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION
P. O. BOX 3265, HARRISBURG, Pa. 17120

February 13, 1986

IN REPLY PLEASE
REFER TO OUR FILE

R-850152

To: All Interested Parties
(see 1/9/86 notice)

Pennsylvania Public Utility Commission, et al.
vs.
Philadelphia Electric Company

N O T I C E

This is to advise that further hearing in the captioned proceeding scheduled for Tuesday, February 18, 1986, at Philadelphia, is cancelled. Further hearing will be held, as previously scheduled, Wednesday, Thursday and Friday, February 19, 20 and 21, 1986, at 10:00 a.m., in Room 1306, Philadelphia State Office Building, Broad and Spring Garden Streets, Philadelphia.

With the exception of the above, future hearings will be held in accordance with our notices dated January 9 and 14, 1986.

Please mark your records accordingly.

DOCKETED
FEB 14 1986

ccs:
Judge Matuschak
Law Bureau
Bureau of Rates
Mr. Bramson
Ms. Dickson
Ms. Crouse
File

DOCUMENT
FOLDER