ENVIRONMENTALISTS' STATEMENT 1

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BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PENNSYLVANIA POWER AND LIGHT COMPANY FOR APPROVAL OF ITS RESTRUCTURING PLAN UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE

DOCKET NO. R-00973954

PREPARED TESTIMONY AND
EXHIBITS OF
DAVID SCHOENGOLD

TABLE OF CONTENTS

Q. Please state your name and business address.

A. My name is David Schoengold. My business address is MSB Energy Associates, 7507 Hubbard Avenue, Middleton, WI 53562.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Environmentalists.

Q. Please describe your background and experience in electric utility issues.

A. I have worked in the electric utility field since 1974, first at the Wisconsin Public Service Commission, and then as a consultant. I spent sixteen years at the Wisconsin Public Service Commission, including nine years as the Director of the Systems Analysis Bureau which was responsible for electricity forecasting, generation and transmission planning, demand-side analysis, system modeling, fuel costs, renewable and alternative energy resources, natural gas planning, and emission reduction strategies. At the Wisconsin Commission I was, among other things, responsible for the studies which convinced the Commission to order the utilities to avoid a massive commitment to nuclear power and the problems which so many utilities which went that direction found themselves in. As a consultant I have analyzed the impact of restructuring in a number of states. I have also provided technical expertise to planning collaboratives, reviewed utility integrated resource plans and supply-side plans, developed independent integrated resource plans, analyzed sales promotion practices, reviewed and developed avoided costs, analyzed the impact of resource alternatives on emissions of pollutants, reviewed utility transmission planning studies, and developed alternative transmission plans including distributed resources as an option. I have served clients in 25 states and testified in ten. I helped to lead the development of an EPA-funded study of integrated planning for the PJM system. I drafted the Environmentalist's comments on Pennsylvania utility competition pilot programs earlier this year, and have submitted testimony for the Environmentalists in the PECO restructuring case, R 00973953. A complete copy of my vita is attached as Exhibit DS-1.

Q. What is the purpose of your testimony today?

A. I will present the Environmentalists' perspective on a number of issues related to the Pennsylvania Power and Light Company (PP&L) restructuring proposal. My testimony should be considered in conjunction with that of Bruce Biewald and of Peter Bradford who are presenting the Environmentalists' perspective on other issues in this docket.

EXECUTIVE SUMMARY AND CONCLUSIONS

Q. Please summarize your testimony and present your conclusions.

A. The following is my summary, conclusions, and recommendations.

- The market price of power used by PP&L in calculating the net stranded generating assets is both too low and highly unlikely to be accurate.
- The Commission would be better off using a *pro forma* market price designed to encourage the formation of a robust market, with true ups to

correct the CTC collection if the *pro forma* market price turns out to be incorrect.

- The Commission should give the power market several years to develop, and then should determine the true market value of the PP&L production plant by having the company auction it off to the highest bidders (taking care to avoid selling all the generation to a single or a small number of entities in order to prevent the development of a concentration of market power) in an open auction. After the open auction has determined the true market value of the generating plants, the PP&L CTC can be adjusted to true up the collection of allowed stranded costs.
- PP&L is allocating too high a fraction of stranded asset costs to retail customers. The Commission should use the current allocation fraction which is 80 percent.
- PP&L stockholders have already received a substantial return on their bad investment in stranded generating assets. Providing for 100 percent recovery of both investment and future return on that investment is unfair to the customers, since it puts the entire responsibility for the bad investment on their shoulders.
- Allowing a 42.7 percent recovery of stranded generating assets will provide enough revenue to fully pay off the debt holders without decreasing the return the stockholders have already earned. This would be a reasonable allowed level of recovery for stranded generating assets.

- The Commission should not approve the proposed depreciation reserve transfer from T&D to generation because of the cost shifting and environmental implications of such a shift.
- The T&D portion of the utility should be required to utilize targeted area planning in order to minimize the cost and environmental impacts of providing T&D services. As part of this process PP&L should begin to collect the information discussed in my testimony which will enable it to do targeted area planning.
- PP&L's proposed change in rate structure to collect a large portion of the CTC on a fixed charge basis will have serious environmental implications and impacts as well on low-usage customers and many low-income customers. The Commission should not allow PP&L to use such a CTC collection strategy.
- The PP&L proposal to collect the usage-related portion of the CTC using a declining block approach will lead promote sales, hurt low-usage and many low-income customers and have environmental impacts. The Commission should order the use of a flat rate to collect the usage-related portion of the CTC.
- The Commission should require that all power sold in Pennsylvania come from power plants which, at a minimum, meet the emission standards for new power plants.

INTRODUCTION

Q. Is there a theme to your testimony?

A. Yes. The Environmentalists have adopted a Vision for the New Electricity Marketplace which I consulted in developing my testimony. I provided input to the Vision Statement as the Environmentalists group developed it. I attach it as Exhibit DS-2 in order to inform the Commission of an important consideration in my views. I advise the Commission to require changes to the restructuring plan which will make it fit in more closely with the Vision.

Q. What areas will you cover in your testimony?

A. I will address the following issues:

- Stranded generating assets
- Market price of power
- Jurisdictional allocation of stranded asset costs
- Allowed recovery of stranded generating assets
- Transfer of depreciation reserves from transmission and distribution to generation
- Competitive Transition Charge (CTC) allocation and structure
- Securitization of stranded asset costs
- Regulation of the transmission and distribution functions
- Environmental implications of the restructuring proposal
- Unbundling of prices

My recent work on restructuring issues in a number of states including the impact of restructuring on different customer classes, transmission and distribution regulation, and stranded costs, plus my familiarity with the PJM system from previous studies has gone into my understanding of the situation for PP&L.

STRANDED GENERATING ASSETS

Q. You stated initially that you will be addressing the issue of stranded generating assets. There are a number of other elements which PP&L proposes to include in the CTC such as regulatory assets, decommissioning expenses, and non-utility generator (NUG) contract costs. Do you intend to address these elements of the CTC in your testimony?

A. No. I will focus my attention on stranded generating assets.

Q. Does that mean you are supporting the PP&L determination of regulatory assets, decommissioning expenses, and NUG contracts?

A. No. I just have not reviewed those costs. Bruce Biewald will be reviewing decommissioning costs on behalf of the Environmentalists. The other transition costs are not being addressed by the Environmentalists at this time.

Q. PP&L uses an approach to calculating net stranded generating assets which compares the revenues produced by the system as a result of selling at market prices to the cost of running the system. What is your view of the PP&L approach?

A. In theory it makes sense. However, in practice it has major problems. The key problem is its sensitivity to the input parameters. While this might not be so much of a problem if the method is used in a way that allows for regular corrections, PP&L is proposing a one-time use of the method to arrive at a CTC, with no mechanism for adjusting the CTC if conditions change. A small difference in the estimate of market price can make a big difference in the level of assumed stranded generating assets for which PP&L's customers are being asked to pay. Since PP&L presented only a single estimate of market price, we cannot determine directly the impact of small changes in market price on the level of stranded costs and the CTC. However, we do have the example of PECO which presented three market price estimates in its restructuring docket.[1] These estimates varied (on a levelized basis) by only about 10%, or 0.4 cents per kWh. Yet what appeared on the face to be a small difference in estimated market price led to a difference in stranded asset estimates of $788 million. Apart from market price, the method used by PP&L for calculating stranded costs is also extremely sensitive to assumptions regarding key input variables such as the cost of future environmental regulations, future fuel price, and nuclear plant performance. The impact of the decisions made in this case is too large to be based on a method which has such wide variability, and which rests so heavily on assumptions of conditions over 30 years into the future. PP&L Witness Jones

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[1] PECO Energy Statement No. 1, Direct Testimony and Exhibits of Thomas P. Hill, Exhibit TPH-1.

in his testimony notes the difficulty of being able to rely on the accuracy of long-range forecasts.[2] If we could successfully rely on long-range forecasts, we would not have the problem we have today of stranded generating assets.

Q. Has it not always been necessary to predict input variables far into the future while making long-range utility plans?

A. Yes it has. And the difficulty in accurately predicting the future is one of the reasons that many utilities are in difficult positions today with respect to stranded assets. However, it has always been important in planning to focus on the impact of variability in important inputs. Successful planning values most highly those plans which are amenable to adjustment to meet changing conditions. For example, some states with long-range planning processes were able to recognize changes in the need for new plants and the cost of building them in the 1970s and 1980s, and to cancel and/or defer plants. The savings from being able to adjust plans were large. In contrast, the PP&L method of calculating stranded asset costs relies on detailed long-range projections without allowing for adjustments necessary to reflect changed conditions.

Q. How would you propose dealing with the sensitivity of stranded asset costs to difficult to predict inputs?

A. I will set forth my proposal in the next section of my testimony when I discuss market price. However, I would mention here that the inadvisability of the

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[2] PP&L Statment No. 7, Direct Testimony of Scott T. Jones, PH.D, page 37.

Commission buying into 30-year assumptions counsels an on-going Commission-led planning process that will satisfy at least two important regulatory needs -- validating CTC collection levels and insuring against system reliability problems.

MARKET PRICE OF POWER

Q. Why is the market price of power important in this case?

A. Under the PP&L method for calculating stranded generating asset costs, the market price of power determines the value of the existing generating system. A higher market price means that the existing system is more valuable, while a lower market price means the opposite. Since the long-run market value of the existing generating system (as determined by the revenues for power sales) is subtracted from the net book value of the plant to determine the level of stranded generating assets in the PP&L method, a higher market price means lower stranded generating assets, and vice versa. As I explained above, the level of stranded asset costs is very sensitive to the market price assumed.

Q. What is the likelihood that the Jones estimate of the market price of power is accurate?

A. The likelihood that the Jones market price estimate is accurate is very low. In the near-term (when one might expect more accurate forecasts), the problem is that the basis for making projections is undergoing extreme changes. Most current market price estimates are based on the transactions in the limited marketplace that exists. These transactions are currently a fairly small segment of the power being generated and sold, and represent the use of the excess plant on the system at this time. As a result, there is a natural tendency for these transactions to be priced low, since the utilities are not relying on market revenues to pay the full costs of the plants, but rather using market revenues as extra income source. While the amount of excess capacity on the system may be large compared to the low level of transactions taking place, this will not be the case when all (or most of) the power sells through the retail market. For example, Wisconsin Electric Power Company (WEPCO) is currently selling some of its excess power to customers in Illinois at a price less than 2 cents per kWh (for firm power). But, when estimating the cost of purchasing power in the wholesale marketplace to replace the failing Point Beach 2 Nuclear Plant (a much larger transaction than the sale to the Illinois customers), WEPCO estimated market prices at over 4 cents per kWh. The point of this comparison is not that the market price should be 2 cents or that it should be 4 cents, but rather the extreme variability as estimated by the same company when looking at the same market.

In other words, there is not now an existing large scale market, and nobody really knows how the market will behave as it develops. PP&L witness Jones says as much when he states at page 10 of his testimony that the market will undergo structural changes in response to the increase in wholesale and retail competition.

Over the long-term one might expect some of the uncertainties to balance against each other giving a more predictable market price. However, there are some very important uncertainties which make predictions difficult. Of key importance is the uncertainty of air regulations. The EPA has now sent to the White House regulations concerning NO_x, VOC's, and fine particulates, the impact of which is not yet known. There is also a reasonable probability that the federal government will promulgate CO_2 regulations which will affect market prices.

Q. How good are track records when it comes to estimating electricity market prices?

A. There are not really any historical estimates of market prices, since there have not been power markets of any significant size. However, it is to a large extent serious mis-estimates of the cost of new power plants and the need for those plants that have led us to the current problems with stranded generating assets. These failures of projections suggest that present market price estimates will not prove accurate.

If we look back 30 to 40 years to the 1950's-60's (the same 30 to 40 years that the PP&L is looking forward in time), we find utilities forecasting that nuclear power plants will be the providers of low cost power for the future.

Q. Are you suggesting that relying on the Jones market price estimate will likely lead to an over-estimate of the level of stranded generating assets?

A. Yes. The result will be subsidization of PP&L's own power plants and a serious undercutting of the development of the competitive market.

Q. *Do you have a specific recommendation as to what the PUC should do to deal with the problem of estimating market price?*

A. I think there are several possible approaches the PUC could use. One approach would be to develop a better market price estimate than the one used by PP&L. However, *any* market price estimate will suffer from the problems I discussed above -- the market is not well enough developed to accurately estimate the near-term market price, and that the uncertainties in future fuel prices and technology render a long-term forecast very unlikely to be accurate. Therefore, I am proposing two alternative approaches which will minimize the need to forecast market prices.

Q. Please describe these approaches.

A. The first approach is for the PUC to accept that an administratively determined market price is neither meaningful nor likely to be accurate, and to instead allow the marketplace to determine its own estimate of the market price. Under this approach, the utilities would sell their generation under an open auction to the highest bidders. The resulting sale prices for the plants would be, by definition, the market value of the power plants. The Commission could then net that market-determined capital value of the plants against the book value of the plants in order to determine the stranded asset cost. This approach has the advantage that the PUC does not have to try to administratively determine a market price. Since the purpose of estimating the market price is to determine the value of the existing plants, use of an auction to determine the actual market value of the power plants renders the administratively determined market price superfluous.

Q. Are there any problems with this approach?

A. There are several. One is the potential for the utilities themselves to dominate the auction of the power plants and artificially depress the prices. However, this problem should be mitigated through the use of an open auction in which a large number of potential buyers are allowed to participate. A bigger problem is that the newness of the marketplace for power may cause potential buyers the same problem as faced by the Commission in trying to determine the market prices, and thus the value of the plants. Given the uncertainties surrounding the market (how it will be organized, who if anyone will run the market, how it will interface with the ISO, etc), I expect there is a good chance that buyers will bid less than the true value of the plants because of perceived risks.

Q. How would you suggest dealing with the latter problem?

A. I think the best approach would to delay the sale of the plants in an open auction for several years until the marketplace has a chance to develop and potential buyers have the opportunity to observe how market prices actually behave. At that time potential buyers would be able to bid on the power plants with a much better knowledge of the likely value of those plants.

Q. Under this alternative approach, would there not still be a stranded asset cost problem prior to the sale of the power plants which would require some sort of estimate of market price?

A. Yes. I am not suggesting that the Commission wait several years before taking any steps to address the stranded generating asset cost problem. I would suggest that the Commission address the problem now by adopting an administratively determined market price which is recognized to be a temporary, *pro forma* estimate for short-term use only. Rather than try to achieve a precise market price (since that will be done by the auction later on), the Commission would essentially adopt an approximate, short-term *pro forma* place holder. The CTC would be developed based on the *pro forma* market price. Since this price would be acknowledged to be temporary and of limited accuracy, a tracking account would be developed to monitor shortfalls or overcollections of revenue by the utility resulting from the actual market price being below or above the *pro forma* value. Then, when the plants are finally sold at the open auction, a final CTC will be determined which reflects the difference between the sale price and the book value and also the tracking account balance.

Q. Are you proposing a schedule for selling the plants at this time?

A. The schedule should be keyed to the development of the power market which is best indicated by the amount of transactions actually taking place. A schedule for selling the plants should be related to the percentage of power in the open market.

Q. Under the Competition Act does the Commission have the authority to order PP&L to sell its generating plants?

A. While I am not a lawyer and thus do not render a legal opinion, I do not believe the Act *specifically* grants the Commission this authority. However, the Act does allow for commission discretion on the development and application of the CTC. I believe it would be relatively straightforward for the Commission to give the utility the option of choosing several alternative approaches, one of which might include divestiture of generating plants.

Q. You suggest the use of a tracking account to adjust for the situation of the actual market price being different than the estimated market price. Could such an approach work on its own -- that is, without the open auction of the power plants to determine a final market value of those plants?

A. Yes. If the Commission does not want to include an auction sale of power plants in its approach to restructuring, it could consider an approach that combines a *pro forma* estimate of the market price with a tracking account and without the required sale of the generating plants.

Q. Under any of the approaches which utilize a *pro forma* market price for power, the Commission would still have to adopt such a value. Do you have a recommendation as to the *pro forma* market price which the Commission should adopt?

A. Yes. First I want to make clear that under my proposal the selection of a *pro forma* market price will not have a long-term financial impact on PP&L because the use of the tracking account will make it whole for any mis-estimation in that market price. However, the selection of the market price *will* affect the development of the market. A *pro forma* market price which is too low will artificially boost the CTC, allowing the utility to sell power to the wholesale market at an artificially low price. This will happen because the retail T&D customers paying the CTC would, in effect, subsidize the wholesale and retail market customers. It will undercut other providers and hinder the development of a robust and thriving market. A *pro forma* market price which is on the high side will reduce the fraction of the costs which the utility collects through the CTC and require it to use a more realistic price in its market sales. Therefore, I would recommend that the Commission select a *pro forma* market price on the higher rather than lower side. This is the approach the Commission adopted in its draft orders in the Pilot Program dockets. As the Commission noted in those orders, this approach will serve to encourage the development of the wholesale power market.

To reiterate, the impact of using too high or too low an estimate of market price is not symmetrical. Using too low a market price estimate will lead to a CTC which is too high, subsidizing existing generation and squelching the development of the market. Using too high a market price estimate will encourage the development of the market, but will not hurt the utility financially since it will be able to recover shortfalls in stranded cost recovery through true-ups.

Q. Won't using too high a market price estimate lead to customers paying too high prices for power?

A. No. The customers will, in the end, pay a price based on what the actual market price turns out to be. The use of a higher market price estimate for calculating the CTC, by encouraging the development of the market, may lead to lower customer prices in the end.

Q. Given these considerations, do you have a recommended market price estimate for the Commission to use?

A. Yes. Given all of these considerations, I would recommend that the Commission adopt a *pro forma* market price of 3.25 Cents per kwh beginning in 1998, that amount to be increased at the rate of inflation (using the GDP price deflator for all goods and services). This is based on my review of the probable new sources of power into the PJM market which lead me to the conclusion that natural gas-fired combined cycle plant will make up the bulk of new generation and can thus be expected to have a major influence on the market price.

JURISDICTIONAL ALLOCATION OF STRANDED GENERATING ASSET COSTS

Q. What is the jurisdictional allocation of stranded generating asset costs used by PP&L?

A. PP&L appears to use different allocation factors for different assets. The tables in Exhibit JRS-1 are broken out into different asset categories, and inspection of the tables indicates that PP&L is using a higher retail allocation factor for fossil plants than for nuclear. Also, Exhibit JRS-1 shows the retail allocation of stranded asset costs going up from values in the low 80 percent range in 1997 to values in the high 90 percent range in the 2000-2002 time period. No explanation is given for this increase. The only reference is to the Exhibits of Joseph M. Kleha. The Kleha exhibits look only at 1995 and do not look out into the future.

Q. Is it appropriate for PP&L to use an increasing retail allocation factor for future years?

A. No. This has the effect of causing retail customers to subsidize PP&L's wholesale business. The recovery of stranded costs should reflect the responsibility for those stranded costs. Since stranded costs are being dealt with now, the allocation factors should reflect the current responsibility for generating plant. It appears that the best retail allocation estimate to use is the 80 percent factor developed in Exhibit JMK-1 at pages 11 and 33. This factor should be used for all years through the end of the period during which the stranded asset costs are calculated.

STRANDED GENERATING ASSET RECOVERY FRACTION

Q. PP&L is calling for 100 percent recovery of stranded generating asset costs. Is this appropriate?

A. No. The amount of stranded generating assets represents a huge economic loss. There are billions of wasted dollars which will not produce anything of value, but must be dealt with. I do not believe it is correct to hold the customers entirely responsible for this loss. To do so would be to treat the PP&L stockholders as if there were no economic loss at all. I believe a sharing of the economic loss is appropriate.

Q. How should the economic loss be shared?

A. I recommend a 42.7% customer/57.3% shareholder split (the details of the split are developed later). The first thing to remember is that the customers have been paying returns to PP&L's stockholders for many years already. The stockholders have already received a fairly decent return on their investment in the generating assets, even though much of that investment has turned out to be valueless to the customers. It is necessary to take this into consideration when determining how to share the economic loss.

Q. How much money have the PP&L stockholders already received in payment for their investment in the stranded assets?

A. This question is difficult to answer precisely, since a detailed answer would require an extremely intensive review of PP&L's books over the past decades. However, we can approximate the answer in a fairly straightforward way.

The first point is that PP&L's stockholders have already received a significant portion of their investment back through already booked depreciation. Out of a $2.83 billion investment in generating plant ($6.25 billion of production plant times an equity fraction of 45.2%), the stockholders have already collected $0.93 billion in depreciation (45.2% of the difference between the $6.25 billion invested and the $4.20 billion of remaining unamortized production plant). This is 32.8% of their initial investment. In addition, PP&L stockholders have earned returns on their investment since it was put into the rate base.

Q. How much have the stockholders been authorized to receive in return for their investment in production plant?

A. I have developed a model to estimate their returns. This is shown in Exhibit DS-3. This model looks at the depreciation, remaining rate base, and returns on rate base year by year. Exhibit DS-3 shows that by the time accumulated depreciation has reached 32.8% of the initial investment, the returns on investment authorized to the stockholders have totaled 104.8% of their initial investment. In this case 104.8% of the stockholders' initial investment is $2.96 billion. (This is a slight underestimate, since it ignores the last partial year needed to bring accumulated depreciation up to 32.8%. We will ignore this slight difference.) Thus the stockholders have been allowed a total recovery (returns plus depreciation) of $3.89 billion on an initial investment of $2.83 billion, or 137.6% of investment. As Exhibit DS-4 shows, the stockholder internal rate of return on their investment to date has been approximately 7.0%.

Q. Does this mean that, even if the Commission allows no recovery of stranded generating asset costs, the stockholders will end up with a return on their investment of 7.0%, the return they have earned to date?

A. No. It is important to remember that the debt holders will receive their full debt amortization and interest, no matter what fraction of stranded generating asset costs the Commission allows to be recovered. If the Commission allows no recovery from ratepayers, the stockholders will have to generate the money to pay off the debt holders. Thus, if the Commission allows for zero recovery, the stockholders overall return, rather than holding constant at 7.0%, will go down.

Q. How does the stockholder return on investment vary with different levels of allowed stranded generating asset cost recovery?

A. The following table shows the impact on stockholders of various levels of allowed recovery of stranded generating asset costs. The details of the calculations are shown in Exhibit DS-5, Schedules 1-9. The values in the table are calculated using the PP&L estimate of the market revenue for PP&L power. A higher market revenue will increase the stockholder return for partial recovery cases, since the market revenues go directly to the stockholders.

PP&L Stockholder Return on Investment

Allowed Recovery Fraction	Total Dollars Recovered and to be Recovered by Stockholders	Future Dollars to be Recovered by Stockholders	Return on Stockholder Investment
100%	$6.10 billion	$2.22 billion	11.5 percent
75%	$5.14 billion	$1.25 billion	9.9 percent
50%	$4.17 billion	$0.28 billion	7.8 percent
42.7%[3]	$3.89 billion	$0	7.0 percent
25%	$3.20 billion	($0.68 billion)	4.2 percent

[3] This is the recovery fraction which leaves the stockholders unchanged from their current level of cost recovery.

In this table, *Total Dollars Recovered and to be Recovered by Stockholders* includes.depreciation and returns already collected, depreciation and returns to be collected through the CTC, and the market revenue from power sold from the existing system. *Future Dollars to be Recovered by Stockholders* is the amount of those dollars not yet collected -- in other words, the amount to be collected through the CTC plus the market revenue.

Q. So the Commission does not have to allow 100 percent recovery of stranded generating asset costs for the stockholders to both recoup their money back and earn a return on their overall investment?

A. That is correct. Even if the Commission allows only 25% recovery, the stockholders will end up recouping all their money plus some return on their overall investment. This is so, even though there is approximately $1.90 billion of stockholder share of unrecovered depreciation at this time.

Q. You speak in your testimony of returns that the stockholders have been authorized to earn. Have the stockholders actually earned the authorized return over the years?

A. Whether or not the stockholders have earned the authorized return is not relevant, and I have therefore not investigated whether or not they have. It is not relevant because the Commission does not guarantee a rate of return. Rather, it sets tariffs in rate cases under which the utility and its stockholders have the opportunity to earn the authorized return if the management runs the company properly. If the management does not run the company properly, the stockholders may not earn the authorized return. That, however, is not the fault of the Commission and the customers, and they should bear no responsibility for such mismanagement.

Q. Is it not the case that only 100 percent recovery will provide the stockholders with the full authorized return on their investment?

A. Yes. However, as I explained earlier, I believe that in a situation such as PP&L's where there is a multi-billion dollar economic loss to address, it is not appropriate for the customers to have to bear the full responsibility for that loss and for the stockholders to receive a full return *on* their investment as well as return *of* their investment. Declaring 100 percent recovery of the stranded generating asset costs puts 100 percent of the responsibility for the economic losses on the customers and 0 percent on the stockholders.

Q. What level of stranded generating asset cost recovery are you recommending?

A. I believe that the 42.7% recovery is a reasonable level which maintains the stockholders currently achieved return on investment. The stockholders will end up having made a reasonable return, but will not have to generate their own funds to pay the debt holders. Two key results of this level of stranded generating asset cost recovery are, 1) customers will have the opportunity to see real reductions in their cost of electricity, and 2) the opportunity of PP&L to use stranded asset recovery to subsidize its plants in the marketplace will be minimized, allowing for the development of a robust wholesale power market.

SHIFT OF DEPRECIATION RESERVES FROM TRANSMISSION AND DISTRIBUTION TO GENERATION

Q. PP&L has proposed transferring depreciation reserves from transmission and distribution (T&D) to generation as a means of mitigating stranded generating assets. What are the implications of such a transfer?

A. I will focus on the proposed transfer of distribution depreciation reserves since transfer of transmission depreciation involves FERC and is thus much more complicated procedurally. Since the depreciation reserve allocated to an asset category is subtracted from the plant-in-service for that category to yield the rate base allocated to that asset category, transferring depreciation reserves from distribution to generation will decrease the generation rate base and increase the distribution rate base. Industrial and wholesale customers are allocated only a small portion of distribution costs -- much less than their share of generation costs. The end result of the transfer is to increase the overall allocation of costs to the residential and commercial classes and reduce the overall allocation of costs to the industrial and wholesale classes. This goes counter to the intention of the Competition Act that cost shifting not occur.

Q. What are the environmental implications of the PP&L proposal?

A. Since residential and commercial customers are allocated a higher fraction of the T&D investment, the result will be higher residential and commercial rates and lower industrial rates. Industrial customers are generally believed to have a higher price elasticity for electricity than residential and commercial customers.

As a result, the depreciation reserve transfer will probably lead to greater load growth, with concomitant environmental impacts.

Q. Does PP&L claim that the reason for the transfer is to adjust for incorrect depreciation balances?

A. PP&L does make that claim, but also states that one purpose of the transfer is to serve as a mitigation measure. While I have not reviewed the depreciation studies in detail, I would ask the Commission to study them carefully and consider very carefully the cost shifting which appears to result from the change. I believe the Commission should not approve the transfer because of the cost shifting it entails.

COMPETITIVE TRANSITION CHARGE (CTC) ALLOCATION AND STRUCTURE

Q. How does PP&L intend to allocate the CTC to different customer classes?

A. PP&L intends to allocate that portion of the CTC which represents stranded capacity costs in the same way that capacity costs are currently allocated. That portion which represents stranded energy costs will be allocated in the same way that energy costs are now allocated. Since the overwhelming portion of the stranded costs are capacity related, the CTC will be mostly allocated on a capacity basis.

Q. Is this an appropriate way to allocate the CTC?

A. I do not believe that it is. Capacity costs are allocated in a way which is supposed to reflect the way different customer classes are responsible for the need for that capacity. While the CTC comes mostly from stranded *capital* investments, one can no longer say that they represent *capacity* costs. The CTC represents economic losses, not real capacity. These economic losses have, by definition, no value. If they had value, they would not be in the stranded asset cost category. The CTC represents money, not capacity. Therefore, there is no inherent reason to allocate the CTC in the same way as capacity costs are allocated. Since there is no sound basis for allocating the CTC as if it were capacity, it is useful to step back and determine an independent, reasonable basis for allocation. Since, for the most part, the stranded generating asset costs come from large base load plants which were built to provide inexpensive energy to the system at the trade-off of expensive capacity, I would recommend allocating the CTC on an energy basis. Indeed, my recommended allocation matches the use of the expensive-in-fact base load plants to provide base load capacity and energy to the high load factor users, the industrial customers. Exacerbating the problem are such programs as PP&L's Demand Free Days program.[4] Under this program which excused (and continues to excuse) large customers from demand responsibility for load on three of the five weekdays, the customers on the program had the ability to avoid financial responsibility for the capacity costs of generating plants which they were using. Since the proposed

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[4] PP&L Statement No. 11, Direct Testimony of Oliver G. Kasper, page 10.

PP&L CTC allocation is based on prior responsibility for capacity costs, these customers will continue to avoid responsibility for stranded asset costs. I understand that the Competition Act is quite clear on how the CTC should be allocated to different rate classes, calling for allocation which matches the allocation of production plant determined in the most recent base rate case. Nevertheless, I believe that the most appropriate way to allocate the CTC costs would be on an energy basis. The Commission should reject the use of special programs like the industrial load promotion programs in applying its allocation.

Q. Is PP&L proposing to collect a portion of the CTC as a fixed charge?

A. Yes. PP&L is proposing a rate design under which half of the CTC will be charged on a per kWh basis and half on a fixed basis. This rate will be optional for residential customers but mandatory for all other customers.

Q. Is this an appropriate way to collect the CTC?

A. No. The CTC should be collected based on customer usage, not as a fixed charge.

Q. Why?

A. Collecting all or part of the CTC on a fixed basis will artificially reduce the variable cost of electricity to customers, acting as an incentive to the customers to buy more electricity wastefully, and as a disincentive for energy efficiency. This will lead to negative environmental impacts. Also, shifting costs from a variable to a fixed basis will most likely lead to increases in costs for low-usage and many low-income customers.

Q. Wouldn't collecting all of the CTC on a variable basis itself create an incentive for PP&L to promote sales, which would also result in negative environmental implications?

A. No. Under the Competition Act the CTC recovery will be reconciled for higher or lower sales volumes. This reconciliation should eliminate one incentive to boost sales.

Q. Is PP&L proposing to use a declining block structure to collect the variable portion of the CTC?

A. Yes. The CTC per kWh goes down as the kWh usage goes up. In fact, according to Witness Krall's Exhibit DAK-1, the tail block for the LP-6 (Customized) rate is actually *negative*. The more the customer uses, the less that customer will pay -- *not just per kWh, but in total as well.*

Q. What is the impact of a declining block structure for the variable portion of the CTC?

A. There are several. It exacerbates the problems discussed above of shifting some of the CTC collection to a fixed basis. There will be even stronger sales promotion incentives. Another result is that low-usage customers and many low-income customers will be forced to carry a larger share of the responsibility for stranded asset costs. I recommend that the Commission reject such a distortion, requiring assessment of the CTC on a constant per kWh basis.

SECURITIZATION OF STRANDED ASSET COSTS

Q. Is securitization of stranded asset costs an issue in this case?

A. It is not clear whether the Commission will be treating securitization as an issue in this case or not. While securitization is not specifically being proposed at this time, it is discussed in the utility testimony. I assume that before the Commission adopts a securitization program it will need to have another case to approve the Qualified Rate Orders. Just what type of case will be held is not clear at this time. Therefore, I will address a number of issues related to securitization in this testimony.

Q. Is securitization related to restructuring?

A. No. Securitization is a financial strategy to reduce financing costs by replacing the current capital structure (for whatever portion of plant which is being securitized) with guaranteed debt. While it has been proposed as a way to reduce the cost of stranded assets, it is not inherently related to stranded assets or any other element of restructuring.

Q. Whether or not securitization is related to restructuring, is it a good method for reducing costs?

A. That needs to be examined closely. In the near-term (the first few years), securitization will most likely reduce rates slightly. However, securitization replaces a decreasing cost stream (under traditional regulation the revenue requirement goes down as depreciation reduces the rate base on which a return is being paid) with a level debt amortization payment. At some future point it is highly likely that the securitization payments will be higher than the revenue requirement under traditional regulation.

Q. What affects the timing of the crossover point?

A. The timing of the crossover point is very sensitive to the relationship between the interest rate on securitization bonds and the cost of capital which is being replaced. Also, the cost of setting up the securitization refinancing is a major factor in determining the overall cost-effectiveness of the approach. All of these elements will need to be investigated closely at the time when a specific securitization proposal is brought to the Commission.

Q. Are there ways to improve the cost-effectiveness of securitization?

A. Yes. The PP&L capital structure is made up of a mixture of debt and equity. The cost of equity to the customers is significantly higher than the cost of debt. If the proceeds of the sale of securitization bonds were used to retire equity rather than a mix of debt and equity, it is likely that the result would be more savings. Focusing on the most expensive bonds rather than the average cost bonds would also produce more savings.

Q. Is there any reason why securitization should be used only for reducing the cost of stranded assets?

A. Purely on a financial basis it might make sense to securitize all capital investment (assuming that analysis of the interest rate and securitization terms turns out to be favorable). However, a negative consideration is that the irrevocable nature of the securitization approach eliminates the possibility of future Commission oversight.

REGULATION OF THE TRANSMISSION AND DISTRIBUTION UTILITIES

Q. Will transmission and distribution (T&D) remain a regulated monopoly after restructuring?

A. Yes. These functions will remain as natural monopolies best served by single suppliers under continued regulation.

Q. Most of the attention in this docket seems to be on the generation side of PP&L's business. Are there important aspects of T&D which should be addressed here?

A. Yes. I will address two T&D issues; one, the need for an integrated approach to T&D planning to minimize the cost of providing T&D services; and two, the appropriate way to recover T&D costs from customers.

Q. With respect to the first issue, what is an integrated approach to T&D planning?

A. An integrated approach to T&D planning means focusing on finding the least expensive solution to T&D problems (including all costs and using life cycle costing), whether that solution is a reinforcement of the T&D system, localized generation, demand-side management approaches, or renewable resources. The principle behind targeted area planning is that an automatic assumption that T&D reinforcement is the appropriate solution to T&D problems may well lead to higher costs to the customers plus the negative environmental impacts of increased T&D construction.

Q. How can localized generation, demand-side management, and renewable resources reduce the need for T&D investments?

A. The level of required T&D capability is what is needed to reliably bring needed power to an area from outside that area. The localized resources reduce the need for outside power supplies (by increasing the locally supplied total) and thus *reduce the overall need for T&D capability to that area.*

Q. Are localized resources less expensive than T&D reinforcements?

A. Sometimes they are, and sometimes they aren't. It is not possible to prejudge the situation. That is why it is necessary to use a planning approach which investigates the full range of options rather than just assuming the T&D solution is best. Similarly, while localized resources are more likely to create more local jobs, the planning spproach should also include an economic impact analysis to determine the jobs effects of the various options.

Q. What will be required for PP&L to do targeted area planning?

A. Targeted area planning requires that the utility collect local load data, detailed information on the condition and capability of local feeders, profiles of likely energy resources, economic and demographic data, solid information on alternatives to tradidional system reinforcement straegies, and other technical information. It also requires that PP&L develop area specific avoided costs. If these things are not now being done, PP&L will need to begin them soon. I urge the Commission to require the Company to begin the data collection and T&D planning process now, in partnership with the stakeholders in its service territory.

Q. What about the second issue, the appropriate way to collect T&D costs?

A. As part of the move towards restructuring, many utilities have begun to talk about collecting more of the distribution costs on a fixed basis through customer charges. Fixed costs would go up, and variable costs go down. There are negative impacts of this change in pricing structure, including likely cost increases for low-income and low-usage customers, improper incentives for additional sales and disincentives for energy conservation, and the negative environmental impacts of those additional, unnecessary sales.

Q. Is PP&L recommending such a change at this time?

A. No. However, I believe it is still an important issue since it may arise in the future, and thus I am addressing it here. The Competition Act calls for the development of unbundled rates. While PP&L is not proposing a shift of T&D costs from variable to fixed at this time, there are other parties in this case, and we do not know if any of them will come forward with such a proposal. The Environmentalists are opposed to such a shift no matter who may propose it.

Q. What are the negative impacts of a shift to higher fixed costs and lower variable costs?

A. There are both environmental and socioeconomic impacts. The environmental impacts come from the fact that reducing variable costs will tend to encourage unnecessary sales growth and discourage investment in local energy efficiency.

The result will be greater levels of air pollution and more construction of unnecessary facilities with their concomitant environmental impacts. The tendency of the sales is also to lower the growth in local jobs, moving local dollars out of the local economy to pay for remotely-generated electricity. The socioeconomic impacts relate to low-usage and many low-income customers. These customers will most likely see an increase in their cost of power under this approach.

Q. Will collecting T&D costs on a variable basis (as is now done) cause PP&L to promote sales in order to increase profits from the monopoly side of its business?

A. There is some potential for this, and it would all-in-all be better if the T&D utilities were regulated in a way that allowed for trueing-up for sales variability. However, it does not appear that the use of true-ups in this manner would be allowed under the Competition Act. On balance, there is more danger of improper sales promotions by charging customers for T&D costs on a fixed-cost basis than on a variable basis.

ENVIRONMENTAL IMPLICATIONS OF THE PP&L RESTRUCTURING PROPOSAL

Q. Are there environmental implications of the PP&L restructuring proposal?

A. Yes. There are a number of negative environmental implications of the PP&L proposal as it has been presented. First, and most important, if the CTC is calculated as proposed by PP&L, with PP&L's assumptions with respect to market price, there will be little opportunity for customers to obtain any savings by purchasing from other power suppliers. This will slow down the introduction of new, clean generating options (both fossil fueled options such as high efficiency natural gas technologies and renewable resource options). Such a CTC will indirectly subsidize existing generation (both PP&L's and other utilities', both in and out of Pennsylvania) including older inefficient, polluting units. The PP&L proposed CTC will also directly subsidize PP&L's existing generating plants.

Also very important is the environmental impact of the sales promotion incentives inherent in PP&L's use of a fixed charge to collect half of the CTC and the use of a declining block structure for collecting the variable portion. Such promotional structures would lead to unnecessary air pollution from facilities within the Commonwealth and from ramped-up generating facilities to the west and south which produce emissions carried into Pennsylvania by the winds.

Q. Please describe PP&L's strategy regarding plant refurbishment.

A. The pattern of expenditures in Exhibit JRS-1 suggests that some plant refurbishment will be undertaken during the analysis period.

Q. What are the air pollution implications of the implementation of these life extension plans?

A. The PP&L life extensions will lead to increases in the emissions of NO_x, SO_2, CO_2, and other pollutants compared to emissions if these older plants were retired at their original retirement dates and replaced with combined cycle natural gas fired combustion turbines or some other advanced combustion turbine based technology.

Q. Why should the Commission be concerned about air pollution effects?

A. Higher emissions will make it more difficult to maintain air quality at levels sufficient to protect human health and property. This may impose restrictions on economic development, constraining the siting of manufacturing operations or competitive power producers in Pennsylvania.

These impacts could be mitigated by requiring more stringent emission controls at the dirtier plants, and in fact may be required by federal or state environmental regulators.

Q. Has PP&L included any significant improvement of environmental performance of existing plants in its system plans?

A. I found no mention of any such proposed improvement. The lack of strategic plans to bring PP&L's plants up to the current environmental standards allows these plants to compete unfairly in the power market. Builders of new power plants are required to invest money to meet very stringent emission standards.

Q. Are only PP&L's plants given this market advantage resulting from differential environmental regulations?

A. No. All existing power plants have this market advantage.

Q. What do you propose to do about this problem?

A. I propose two measures. First, adopting my proposal for dealing with stranded generating asset costs would both reduce the subsidy of PP&L's plants and, by encouraging the development of the competitive market, provide a greater opportunity for customers to save money by purchasing power from newer, cleaner plants. Second, I propose that the Commission adopt a plan under which all power purchased in Pennsylvania would have to come from plants meeting the latest environmental standards. This would level the environmental playing field and result in cleaner air in Pennsylvania. The Competition Act at Section 2802 (21) notes the problems related to uneven environmental standards.

I would definitely *not* propose easing the environmental standards on new plants. While some have raised questions as to whether the Commerce Clause of the U.S. Constitution would allow Pennsylvania to regulate the environmental standards for power bought and sold in an interstate marketplace, other states have enacted similar regulations based on their right to protect the health and welfare of their citizens.

UNBUNDLING OF PRICES

Q. Have you examined the proposed unbundling of PP&L rates?

A. Yes. PP&L's approach to unbundling involves a major shift of costs from variable (based on usage) to fixed. As I stated before, this approach has serious promotional and environmental impacts which I oppose. It also is likely to have negative impacts on low-income customers. We oppose this major change in rate structure.

Q. Will the unbundled prices need to be recalculated to reflect the recommendations you have made on dealing with stranded generating asset costs?

A. Yes. However, I have not recalculated the CTC and the resulting unbundled rates at this time.

CONCLUSIONS

Q. Can you summarize your conclusions and recommendations?

A. Yes. I have reached the following conclusions:

- The market price of power used by PP&L in calculating the net stranded generating assets is both too low and highly unlikely to be accurate.
- The Commission would be better off using a *pro forma* market price designed to encourage the formation of a robust market, with true ups to correct the CTC collection if the *pro forma* market price turns out to be incorrect.
- The Commission should give the power market several years to develop, and then should determine the true market value of the PP&L production plant by having the company auction it off to the highest bidders (taking care to avoid selling all the generation to a single or a small number of entities in order to prevent the development of market power) in an open auction. After the open auction has determined the true market value of

the generating plants, the PP&L CTC can be adjusted to true up the collection of allowed stranded costs.

- PP&L is allocating too high a fraction of stranded asset costs to retail customers. The Commission should use the current allocation fraction which is 80 percent.
- PP&L stockholders have already received a substantial return on their bad investment in stranded generating assets. Providing for 100 percent recovery of both investment and future return on that investment is unfair to the customers, since it puts the entire responsibility for the bad investment on their shoulders.
- Allowing a 42.7 percent recovery of stranded generating assets will provide enough revenue to fully pay off the debt holders without decreasing the return the stockholders have already earned. This would be a reasonable allowed level of recovery for stranded generating assets.
- The Commission should not approve the proposed depreciation reserve transfer from T&D to generation because of the cost shifting and environmental implications of such a shift.
- The T&D portion of the utility should be required to utilize targeted area planning in order to minimize the cost and environmental impacts of providing T&D services. As part of this process PP&L should begin to collect the information discussed in my testimony which will enable it to do targeted area planning.

- PP&L's proposed change in rate structure to collect a large portion of the CTC on a fixed charge basis will have negative environmental implications and impacts as well on low-usage customers and many low-income customers. The Commission should not allow PP&L to use such a CTC collection straegy.
- The PP&L proposal to collect the usage-related portion of the CTC using a declining block approach will lead promote sales, hurt low-usage and many low-income customers and have negative environmental impacts. The Commission should order the use of a flat rate to collect the usage-related portion of the CTC.
- The Commission should require that all power sold in Pennsylvania come from power plants which, at a minimum, meet the emission standards for new power plants.

Q. Does this complete your testimony?

A. Yes.

Exhibit DS-1

to Environmentalists' Statement No. 1

Resume of David Schoengold

Docket No. R-00973954

Application of
Pennsylvania Power and Light Company
for Approval of its Restructuring Plan
under Section 2806 of the Public Utility Code

DAVID SCHOENGOLD
Principal
MSB Energy Associates

EXPERIENCE

MSB Energy Associates, 1988 to present.
Consultant to the Government of Tunisia, 1985.
Wisconsin Public Service Commission, 1974 to 1990.
University of Wisconsin, Institute for Environmental Studies, 1973 to 1974.
United States Peace Corps, Philippines, 1970 to 1972.
Argonne National Laboratories, Applied Mathematics Division, 1968 to 1970.

EDUCATION

BA in Physics, Rutgers University, 1966.
Graduate Study in Physics and Computer Science, University of Chicago, 1966-68.

UTILITY PLANNING AND REGULATORY EXPERIENCE

David Schoengold co-founded MSB Energy Associates in 1988 to provide planning and analytical services to public utility commissions, state energy offices, public interest groups, and others with an interest in public utility policy. Since co-founding MSB Energy Associates Mr. Schoengold has served clients in Arizona, California, Connecticut, the District of Columbia, Georgia, Hawaii, Illinois, Indiana, Iowa, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, South Carolina, Texas, Vermont, West Virginia, and Wisconsin. Recently he has analyzed the impact of utility restructuring proposals in California, Illinois, Iowa, Michigan, New York, and Ohio. He has provided technical expertise to planning collaboratives, reviewed utility integrated resource plans and supply-side plans, developed independent integrated resource plans, analyzed sales promotion practices, reviewed and developed avoided costs, analyzed the impact of resource alternatives on emissions of pollutants, reviewed utility transmission planning studies, and developed alternative transmission plans including distributed resources as an option. He has presented testimony in the District of Columbia, Georgia, Illinois, Iowa, Michigan, Minnesota, New York, Ohio, West Virginia, and Wisconsin. In addition he has presented workshops and seminars on various aspects of utility planning for numerous groups.

Mr. Schoengold has testified in cases involving rates, resource planning, facility certification, administrative rules, externalities, independent power projects, public policy, and civil damages. He has testified on the need for, alternatives to, and system planning implications of utility plans and proposals, rate design, buy-back rates for cogenerators, energy forecasts, fuel costs, planning budgets, and power plant prudence.

Mr. Schoengold has been involved in utility planning and regulation since 1974 when he joined the Wisconsin Public Service Commission staff. He spent sixteen years at the Wisconsin Commission, including nine years as the Director of the Systems Analysis Bureau which was responsible for electricity forecasting, generation and transmission planning, demand-side analysis, system modeling, fuel costs, renewable and alternative energy resources, natural gas planning, and emission reduction strategies. At the Wisconsin Commission Mr. Schoengold played a major role in the development of the Wisconsin advance planning process, integrated resource planning, statewide integrated transmission planning and access, and the inclusion of externalities in resource planning. He directed one of the first studies of conservation and renewable resources as least-cost alternatives to traditional utility generation. He performed the analytical work which resulted in Wisconsin abandoning its plans for a heavily nuclear dependent future, enabling the state to avoid the nuclear financial problems common to many states.

TESTIMONY

- New York State Public Service Commission (1997)
  Dockets 96-E-0909, 96-E-0897, 96-E-0891, 96-E-0900, 96-E-0898
  Regulatory principles for distribution utilities under restructuring for five major New York utilities

- Michigan Public Service Commission (1997)
  Docket U-11290
  Testimony before the Commission on the impact of different restructuring approaches on electricity utility customers. Comments on staff restructuring report.

- Public Service Commission of Wisconsin (1996)
  Docket 6630-UR-109
  Appropriate rates for industrial interruptible customers

- Public Service Commission of Wisconsin (1996)
  Docket 6690-UR-110
  Appropriate buyback rates for power from a small hydroelectric facility

- Minnesota Legislature (1996)
  Testimony before the Senate Taxation Committee
  Cost and environmental impacts of a proposed cogeneration facility

- Public Service Commission of Wisconsin (1996)
  Dockets 6630-CE-197/209 (Point Beach Projects)
  Cost-benefit analysis of nuclear plant steam generator repairs

- Minnesota Legislature (1995)

Testimony before the House Energy Committee
Cost and environmental impacts of a proposed cogeneration facility

- Public Service Commission of Wisconsin (1995)
  Docket 05-EP-7 (Advance Plans for Electric Utilities)
  Cost-benefit analysis of nuclear plant repairs

- Public Service Commission of Wisconsin (1994)
  Docket 6690-UR-109
  Appropriate buyback rates for power from a small hydroelectric facility

- Illinois Commerce Commission (1994)
  Docket 92-0121
  Need for and alternatives to a proposed 138 kV transmission line

- Illinois Commerce Commission (1993, 1994)
  Docket 92-0221
  Need for and alternatives to a proposed 138 kV transmission line

- Public Service Commission of Wisconsin (1992, 1993)
  Docket 05-EP-6 (Advance Plans for Electric Utilities)
  Cogeneration policies, buy-back rates, and avoided cost methods

- Minnesota Legislature (1992)
  Testimony before the Joint Energy Committee
  Savings from joint or shared planning among Minnesota utilities

- Georgia Public Service Commission (1992)
  Dockets 4031-U and 4034-U
  Review of the integrated resource plans of Georgia Power and Savannah Electric Power and development of alternative long-range expansion plans

- Georgia Public Service Commission (1991)
  Docket 4047-U
  Rules for the preparation and filing of integrated resource plans

- Civil Court, Iron County, Michigan (1991)
  AGA Connor Forest Products vs Indeck Energy
  Civil damages related to a canceled cogeneration plant

- Minnesota Public Service Commission (1991)
  Docket E-002/CN-91-19
  Economics analysis of dry-cask storage for spent nuclear fuel at the Prairie Island Nuclear Power Plant and alternative power sources

- District of Columbia Public Service Commission (1991)
  Case 905
  Cost allocation for a large customer of Potomac Electric Power Company

- Public Service Commission of Wisconsin (1990)
  Docket 9990-EP-100
  Load management practices of Wisconsin utilities

- Illinois Commerce Commission (1990)
  Docket 90-0041
  Review of the least-cost plans and planning policies of Central Illinois Light Company

- Illinois Commerce Commission (1990)
  Docket 88-0139
  Proper use of economic dispatch on the Commonwealth Edison system in the face of complex coal contracts. Testimony, while prepared, was not given due to a settlement in the case.

- West Virginia Public Service Commission (1990)
  Docket 89-239-G-PW, et al
  Analysis of the conditions under which sales promotion activities should be allowed for gas and electric utilities

- Public Utilities Commission of Ohio (1990)
  Dockets 90-659-EL-FOR and 90-660-EL-FOR
  Analysis of forecasts and long range plans for Ohio Power and Columbus Southern, including alternative long-range expansion plans for the companies. Testimony, while prepared, was not given due to a settlement of the case.

Mr. Schoengold also testified in numerous cases as a senior staff witness at the Wisconsin Public Service Commission.

- Advance Plans 1 through 5 (Dockets 05-EP-1 through 05-EP-5 -- on numerous occasions between 1977 and 1990)
  A wide variety of planning issues including forecasts, nuclear vs coal power, alternative energy, load management, transmission planning, demand-side management resources, cost allocation, cogeneration, avoided costs, demand-side vs supply-side resources, principles and methods of integrated resource planning, and principles and impacts of sales promotion

- Rate Cases (numerous occasions between 1975 and 1990)
  - Wisconsin Electric Power
  - Wisconsin Power and Light
  - Madison Gas and Electric

Wisconsin Public Service
Northern States Power
Proctor and Gamble Cogeneration Buyback rates

Fuel costs, cost allocations, sales promotion, demand-side management, time-of-use pricing, avoided costs, and incentive regulation

- Construction Cases

  Germantown Combustion Turbines (1976-1977)
  Pleasant Prairie Power Plant (1978)
  Tyrone Nuclear Power Plant (1978)
  Weston 3 (1979)
  Edgewater 5 (1980)
  Prairie Island -- Eau Claire Transmission Line (1981-1982)
  Point Beach Nuclear Plant Steam Generator Replacement (1982)

  Need for power, appropriateness of the utility proposals, and the comparative economics of alternatives

- Generic Investigations

  Time-of-Use Rates (1978)
  Load Management (1980)
  Avoided Cost Methodology (1980)
  Electric Sales Promotion (1983)
  Interruptible Rates (1988)

  Costs and benefits of various proposals, system planning impacts of load management, and the impacts of resource alternatives

SELECTED REPORTS AND MANUSCRIPTS

"Electric Industry Restructuring in Iowa: Residential and Low Income Customer Impacts," 1996.

"Integrating Clean Air Policy to Improve Air Quality and Reduce Pollution Control Costs for the Electric Power Industry," Report to the Boston Edison DSM Settlement Board, 1996 (co-author).

"Regulation of Distribution Monopolies," Report from the California Regulatory Research Project of the Center for Energy Efficiency and Renewable Technologies, August 1996 (co-author).

"Major Tax Subsidies to Investor-Owned Electric Utilities and the Cost to the U.S. Treasury -- 1994," Report to the American Public Power Association, 1996.

"Explaining Public Power's Low Rates: A Critical Review of the EEI-Sponsored Report: 'Subsidies and Unfair Competitive Advantages Available to Publicly Owned and Cooperative Utilities'," Report to the American Public Power Association, 1996.

"Application of the Distributed Utility Concept to the Boston Edison Company: Creating Additional Value for the Customer," 1995.

"Major Tax Subsidies to Investor-Owned Electric Utilities and the Cost to the U.S. Treasury," Report to the American Public Power Association, 1995.

"The Impact of Nuclear Retirements on Commonwealth Edison and the Eastern Wisconsin Utilities," Report to the Environmental Law and Policy Center of the Midwest, 1995.

"Allocating the Cost of Generating Capacity -- a Discussion Paper of Interclass Subsidies," 1994.

"Energy Efficiency and Renewable Energy -- Opportunities from Title IV of the Clean Air Act," United States Environmental Protection Agency, 1994.

"Planning for Environmental Constraints on the PJM System," 1993.

"Avoided Costs for Electric Utilities -- a Theoretical and Practical Handbook," 1993.

"Spare the Stick and Spoil the Carrot: Why DSM Incentives for Shareholders Aren't Necessary," invited chapter in, Regulatory Incentives for Demand-Side Management, Steven Nadel, Michael Reid, and David Walcott, editors, American Council for an Energy Efficient Economy, 1992 (with Steven Kihm and Paul Newman).

"Final Report on the New Orleans Integrated Resource Planning Project," 1992.

"Assessment of Tradeable Sulfur Dioxide Allowances Generated by Selected Energy Conservation Initiatives," 1991.

"Tertiary Sector Energy Use Model for the Tunisian Energy Planning Project," Resource Management Associates, 1985.

"Alternative Electric Power Supply Study -- Update 1985," Wisconsin Public Service Commission, 1985.

"Alternative Electric Power Supply Study for the Year 2000," Wisconsin Public Service Commission, 1982.

PRESENTATIONS

"Distributed Generation on the Boston Edison System," presentation to the Boston Edison Settlement Board Distributed Utility Workshop, 1995.

"Major Tax Subsidies to Investor-Owned Electric Utilities," presentation to the American Public Power Association, 1995.

"Planning in the Face of Environmental Constraints," presentation to the Public Utilities Institute of the University of Wisconsin, 1994.

"Avoided Cost Methods," presentation to the Pennsylvania Public Utility Commission, 1993.

"Avoided Cost Methods," presentation to the Public Utilities Institute of the University of Wisconsin, 1993.

"Modeling Methods for Least-Cost Planning," presentation at the NARUC Least-Cost Planning Training Seminars, 1990.

"Principles of Electric Utility Planning," presentation at the University of Wisconsin -- Eau Claire, 1985.

Exhibit DS-2

to Environmentalists' Statement No. 1

Environmentalists'

Vision for the
New Electricity Marketplace

Docket No. R-00973954

Application of
Pennsylvania Power and Light Company
for Approval of its Restructuring Plan
under Section 2806 of the Public Utility Code

The Environmentalists' Vision for the New Electricity Marketplace

Fundamental Goal

The fundamental goal of restructuring is to provide a marketplace where consumers have access to adequate, safe, clean, reliable and efficient energy services at fair and reasonable prices at the lowest long-term cost to society.

Public Interest

The marketplace will provide energy services which minimize the long term cost to society rather than maximize the short term monetary gain. The marketplace will not simply be a frenzy for the next cheap kilowatthour, but will also promote public interest concerns such as the environment, public health, universal service, energy security, local economic development, etc. An industry that continues to shift environmental costs to the public is not efficient. Structural changes will be encouraged when they result in improved economic efficiency and serve the broader public interest. Barriers to utilizing life cycle economic analysis will be minimized. Industry/community partnerships will be strengthened to promote such things as energy efficiency in housing and community development.

The public benefits of energy efficiency, renewable resource technologies and research and development should be maintained through existing and new mechanisms. Energy efficiency, renewable resource technologies and research and development provide significant economic and other benefits for Pennsylvania and are critical to achieving a long-term sustainable and efficient electricity future.

Robust Market

The potential for competition to improve economic efficiency and to reduce long-term costs rests on having robust competition in the marketplace. Robust competition requires multiple service providers in the marketplace in order that customers have real choice.

All power generation will face full and fair competition. The utilities will not enjoy competitive advantage, either through massive stranded cost war chests or other anti-competitive actions. There will be no unreasonable barriers to entry into the marketplace. Market development will be guided in a way that increases the role of competition among energy service providers and the role of choice for customers. The concentration of ownership of generating capacity in the marketplace will be limited in order to minimize opportunities for abuse of market power.

Shared Benefits

Electric industry restructuring is done in a way that benefits all customer classes fairly and does not unduly disadvantage any customer class nor preserve any undue cross-class subsidy. Mechanisms will be developed which enable small users to enjoy the same benefits of the marketplace as large users.

Consumer Choice

Consumers will have the opportunity to make informed choice among electricity providers and services. The marketplace will provide power choices equitably among consumers and customer classes. Similar choices should be available to all consumers under similar terms and costs. There will be no captive customers, either as a result of institutional arrangements or on a *de facto* basis as a result of lack of interest on the part of suppliers to serve certain consumers or groups of consumers.

Consumer Information and Education

Consumers are provided with information concerning their energy purchases that is factual, objective, and understandable, so they can make informed choices. This information includes objective data on the mix of generation sources as well as air and water emissions and other waste generation. This information is in all promotional materials and billing statements in an easy-to-understand label.

Consumer Protection

Consumers are protected from anti-competitive behavior, undue discrimination, poor service and unfair billing and disconnection practices. The marketplace is obligated to connect and provide service to customers on reasonable terms available to all customers.

Universal Service

Because electricity is vital for health, safety and economic opportunity, universal energy services will be available at just, reasonable and affordable rates to all households needing assistance. Appropriate assistance will be flexible and targeted to include energy conservation, bill payment assistance, budget counseling, energy education, renewable energy and other tools to enable all Pennsylvanians to afford a reasonable level of energy services. Permanent energy assistance in the form of energy conservation will be a strong part of the universal service strategy. Universal service programs will be credited with the savings they cause in collection costs and bad debt write-offs.

In order to leverage additional resources and to maximize their effectiveness, universal service programs will be offered in a broader context of human services through community-based providers.

Network Integrity

The safety, reliability, quality and sustainability of electric service will be maintained or improved in a restructured electric industry. Market-based decisions, driven by economics and competition alone, could jeopardize critical safety and reliability of long-term strategic resource and facility planning. Public policy should ensure the integrity of the electric grid and encourage prudent long-term resource planning, acquisition and utilization.

There will be open interconnection access with the grid in a transparent and user-friendly process. The utilization of distributed energy systems will be facilitated through such strategies such as net metering for small-scale renewable and clean energy systems. The grid will be operated by a truly Independent System Operator (ISO), providing open access to the transmission system to support a vigorous and competitive power market.

The distribution system will use integrated targeted area resource planning to determine the least cost strategies to upgrade the distribution system. Building more lines will be the option of choice only when it is cheaper than the other alternatives. Parties implementing conservation or distributed energy which benefits power flows on the distribution system and avoids or postpones upgrades will receive some of the savings they have made possible. The same will be true for the transmission system.

Stranded Costs

The consideration of stranded costs will seek to balance the ratepayers' expectations of access to the benefits of restructuring and competitive energy supplies and services with the shareholders' reasonable expectations of an economic return. The analysis will involve a three step process of (1) the identification and quantification of the stranded cost claim, (2) the review of the adequacy of each utility's efforts to mitigate its stranded costs, and (3) the appropriate sharing of the stranded costs between ratepayers and shareholders.

Decommissioning costs will be adequately funded in a manner that is fair and efficient. Nuclear plant operators will be responsible for some portion of the decommissioning costs and will have an interest in controlling those costs.

Dated: June 18, 1997

Exhibit DS-3

to Environmentalists' Statement No. 1

Return on Investment to-Date
for Stockholders

Docket No. R-00973954

Application of
Pennsylvania Power and Light Company
for Approval of its Restructuring Plan
under Section 2806 of the Public Utility Code

Exhibit DS-3

Table 1. Simple Return Model
(per unit of investment)

Plant Life = 35
Return on Equity = 11.5%

	Accumulated Depreciation	Rate Base	Return	Cumulative Return
1	0.029	0.971	0.112	0.112
2	0.057	0.943	0.108	0.220
3	0.086	0.914	0.105	0.325
4	0.114	0.886	0.102	0.427
5	0.143	0.857	0.099	0.526
6	0.171	0.829	0.095	0.621
7	0.200	0.800	0.092	0.713
8	0.229	0.771	0.089	0.802
9	0.257	0.743	0.085	0.887
10	0.286	0.714	0.082	0.969
11	0.314	0.686	0.079	1.048
12	0.343	0.657	0.076	1.124
13	0.371	0.629	0.072	1.196
14	0.400	0.600	0.069	1.265
15	0.429	0.571	0.066	1.331
16	0.457	0.543	0.062	1.393
17	0.486	0.514	0.059	1.452
18	0.514	0.486	0.056	1.508
19	0.543	0.457	0.053	1.561
20	0.571	0.429	0.049	1.610
21	0.600	0.400	0.046	1.656
22	0.629	0.371	0.043	1.699
23	0.657	0.343	0.039	1.738
24	0.686	0.314	0.036	1.774
25	0.714	0.286	0.033	1.807
26	0.743	0.257	0.030	1.837
27	0.771	0.229	0.026	1.863
28	0.800	0.200	0.023	1.886
29	0.829	0.171	0.020	1.906
30	0.857	0.143	0.016	1.922
31	0.886	0.114	0.013	1.935
32	0.914	0.086	0.010	1.945
33	0.943	0.057	0.007	1.952
34	0.971	0.029	0.003	1.955
35	1.000	-0.000	-0.000	1.955

Exhibit DS-4

to Environmentalists' Statement No. 1

Total Return to-Date for Stockholders

Docket No. R-00973954

Application of
Pennsylvania Power and Light Company
for Approval of its Restructuring Plan
under Section 2806 of the Public Utility Code

Table 1. Internal Rate of Return to-Date
(costs in $billions)

Year	Initial Investment	Depreciation	Cumulative Depreciation	Rate Base	Return	Return Plus Depreciation	Total To-Date	Equity Holders Cash Flow	
1	-2.825	0.081	0.081	2.745	0.158	0.239	0.239	-2.587	IRR To-Date
2		0.081	0.161	2.664	0.306	0.387	0.626	0.387	7.0%
3		0.081	0.242	2.583	0.297	0.378	1.003	0.378	
4		0.081	0.323	2.503	0.288	0.369	1.372	0.369	
5		0.081	0.404	2.422	0.279	0.359	1.731	0.359	
6		0.081	0.484	2.341	0.269	0.350	2.081	0.350	
7		0.081	0.565	2.260	0.260	0.341	2.422	0.341	
8		0.081	0.646	2.180	0.251	0.331	2.753	0.331	
9		0.081	0.727	2.099	0.241	0.322	3.075	0.322	
10		0.081	0.807	2.018	0.232	0.313	3.388	0.313	
11		0.081	0.888	1.937	0.223	0.304	3.692	0.304	
12		0.038	0.926	1.899	0.218	0.256	3.948	0.256	

Exhibit DS-5

to Environmentalists' Statement No. 1

**Total Return of and on Investment
for Stockholders
Through End of Transition Period**

Docket No. R-00973954

Application of
Pennsylvania Power and Light Company
for Approval of its Restructuring Plan
under Section 2806 of the Public Utility Code

Exhibit DS-5
Schedule 1

Table 1. Total Return of and on Investment to PP&L Stockholders
Allowed Recovery Fraction: **100.0%**

Costs in Billions	
Production plant in service (1)	6.251
Equity fraction (2)	45.2%
Equity cost (3)	2.825
Debt fraction (includes pref) (4)	54.8%
Depreciation fraction (to date) (5)	32.8%
Depreciation to-date (6)	2.048
Equity share to-date (7)	0.926
Net Production Plant (current) (8)	4.203
Market value (current) (9)	1.190
Net stranded cost (current) (10)	3.013
Cumulative return to-date fraction (11)	104.8%
Cumulative return to-date (12)	2.961
Total to equity holders to date (13)	3.887
Fraction returned to date (14)	137.6%
Equity holder IRR to-date (15)	7.0%
Stranded asset allowed fraction (16)	100.0%
Allowed future depreciation (17)	3.013
Allowed future return on capital (18)	0.855
Total to be collected in the CTC (19)	3.868
Total CTC collection plus market value (20)	5.058
To be paid to retire debt principal (21)	2.303
To be paid to interest (22)	0.537
Total to be paid to debt holders (23)	2.841
Residual for equity holders (24)	2.217
Overall total to equity holders (25)	6.105
Total recovery fraction (26)	216.1%
Equity holder IRR after transition (27)	**11.5%**

Exhibit DS-5
Schedule 2

Table 2. Total Return of and on Investment to PP&L Stockholders
Allowed Recovery Fraction: **75.0%**

Costs in Billions	
Production plant in service (1)	6.251
Equity fraction (2)	45.2%
Equity cost (3)	2.825
Debt fraction (includes pref) (4)	54.8%
Depreciation fraction (to date) (5)	32.8%
Depreciation to-date (6)	2.048
Equity share to-date (7)	0.926
Net Production Plant (current) (8)	4.203
Market value (current) (9)	1.190
Net stranded cost (current) (10)	3.013
Cumulative return to-date fraction (11)	104.8%
Cumulative return to-date (12)	2.961
Total to equity holders to date (13)	3.887
Fraction returned to date (14)	137.6%
Equity holder IRR to-date (15)	7.0%
Stranded asset allowed fraction (16)	75.0%
Allowed future depreciation (17)	2.260
Allowed future return on capital (18)	0.641
Total to be collected in the CTC (19)	2.901
Total CTC collection plus market value (20)	4.091
To be paid to retire debt principal (21)	2.303
To be paid to interest (22)	0.537
Total to be paid to debt holders (23)	2.841
Residual for equity holders (24)	1.250
Overall total to equity holders (25)	5.138
Total recovery fraction (26)	181.8%
Equity holder IRR after transition (27)	**9.9%**

Table 3. Total Return of and on Investment to PP&L Stockholders
Allowed Recovery Fraction: **50.0%**

Costs in Billions	
Production plant in service (1)	6.251
Equity fraction (2)	45.2%
Equity cost (3)	2.825
Debt fraction (includes pref) (4)	54.8%
Depreciation fraction (to date) (5)	32.8%
Depreciation to-date (6)	2.048
Equity share to-date (7)	0.926
Net Production Plant (current) (8)	4.203
Market value (current) (9)	1.190
Net stranded cost (current) (10)	3.013
Cumulative return to-date fraction (11)	104.8%
Cumulative return to-date (12)	2.961
Total to equity holders to date (13)	3.887
Fraction returned to date (14)	137.6%
Equity holder IRR to-date (15)	7.0%
Stranded asset allowed fraction (16)	50.0%
Allowed future depreciation (17)	1.507
Allowed future return on capital (18)	0.428
Total to be collected in the CTC (19)	1.934
Total CTC collection plus market value (20)	3.124
To be paid to retire debt principal (21)	2.303
To be paid to interest (22)	0.537
Total to be paid to debt holders (23)	2.841
Residual for equity holders (24)	0.283
Overall total to equity holders (25)	4.171
Total recovery fraction (26)	147.6%
Equity holder IRR after transition (27)	**7.8%**

Exhibit DS-5
Schedule 4

Table 4. Total Return of and on Investment to PP&L Stockholders
Allowed Recovery Fraction: **42.7%**

Costs in Billions	
Production plant in service (1)	6.251
Equity fraction (2)	45.2%
Equity cost (3)	2.825
Debt fraction (includes pref) (4)	54.8%
Depreciation fraction (to date) (5)	32.8%
Depreciation to-date (6)	2.048
Equity share to-date (7)	0.926
Net Production Plant (current) (8)	4.203
Market value (current) (9)	1.190
Net stranded cost (current) (10)	3.013
Cumulative return to-date fraction (11)	104.8%
Cumulative return to-date (12)	2.961
Total to equity holders to date (13)	3.887
Fraction returned to date (14)	137.6%
Equity holder IRR to-date (15)	7.0%
Stranded asset allowed fraction (16)	42.7%
Allowed future depreciation (17)	1.286
Allowed future return on capital (18)	0.365
Total to be collected in the CTC (19)	1.651
Total CTC collection plus market value (20)	2.841
To be paid to retire debt principal (21)	2.303
To be paid to interest (22)	0.537
Total to be paid to debt holders (23)	2.841
Residual for equity holders (24)	0.000
Overall total to equity holders (25)	3.887
Total recovery fraction (26)	137.6%
Equity holder IRR after transition (27)	**7.0%**

Exhibit DS-5
Schedule 5

Table 5. Total Return of and on Investment to PP&L Stockholders
Allowed Recovery Fraction: **25.0%**

Costs in Billions	
Production plant in service (1)	6.251
Equity fraction (2)	45.2%
Equity cost (3)	2.825
Debt fraction (includes pref) (4)	54.8%
Depreciation fraction (to date) (5)	32.8%
Depreciation to-date (6)	2.048
Equity share to-date (7)	0.926
Net Production Plant (current) (8)	4.203
Market value (current) (9)	1.190
Net stranded cost (current) (10)	3.013
Cumulative return to-date fraction (11)	104.8%
Cumulative return to-date (12)	2.961
Total to equity holders to date (13)	3.887
Fraction returned to date (14)	137.6%
Equity holder IRR to-date (15)	7.0%
Stranded asset allowed fraction (16)	25.0%
Allowed future depreciation (17)	0.753
Allowed future return on capital (18)	0.214
Total to be collected in the CTC (19)	0.967
Total CTC collection plus market value (20)	2.157
To be paid to retire debt principal (21)	2.303
To be paid to interest (22)	0.537
Total to be paid to debt holders (23)	2.841
Residual for equity holders (24)	-0.684
Overall total to equity holders (25)	3.204
Total recovery fraction (26)	113.4%
Equity holder IRR after transition (27)	**4.2%**

Exhibit DS-5
Schedule 6

Definition of Entries in Tables 1-5.

(1) 6.251 from EIA Financial Statistics of Major U.S Investor -Owned Electric Utilities, 1995, page 450. Exhibit JMK-1, Part-1 shows a value of 6.284. A higher value would indicate greater collection of depreciation to-date. Therefore we used the lower number to be conservative.
(2) from Exhibit JRS-1, Attachment 1
(3) (1)*(2)
(4) 1.0 - (2)
(5) [(1)-(8)]/(1)
(6) (5)*(1)
(7) (6)*(2)
(8) from Exhibit JRS-1; 50/117
(9) calculated from Exhibit JRS-1
(10) (8)-(9)
(11) From depreciation tables -- Exhibit DS-2
(12) (11)*(3)
(13) (12)+(7)
(14) (13)/(3)
(15) From Exhibit DS-3
(16) Assumption
(17) (10)+(16)
(18) From 7 year depreciation schedule @ WCC, Schedule 7, WCC based on 7.78 % debt and preferred (Exhibit JRS-1/Attachment 1)
11.5% equity (Exhibit JRS-1/Attachment 1)
(19) (17)+(18)
(20) (19)+(9)
(21) (8)*(4)
(22) From 7 year depreciation schedule at debt cost, Exhibit DS-4/Schedule 8
(23) (21)+(22)
(24) (20)-(23)
(25) (24)+(13)
(26) (25)/(3)
(27) From Table 9, Exhibit DS-4/Schedule 9

Exhibit DS-5
Schedule 7

Table 7. Allowed Return at Weighted Cost of Capital
Costs in Billions of Dollars
Life of CTC = 7 Years
Weighted Cost of Capital = 9.46%
100 Percent Recovery (lesser allowed recovery leads to a directly proportionally reduction in the dollar figure)

	Accumulated Depreciation	Rate Base	Return	Cumulative Return	Total
1	0.430	2.583	0.244	0.244	0.675
2	0.861	2.152	0.204	0.448	1.309
3	1.291	1.722	0.163	0.611	1.902
4	1.722	1.291	0.122	0.733	2.455
5	2.152	0.861	0.081	0.814	2.967
6	2.583	0.430	0.041	0.855	3.438
7	3.013	0.000	0.000	0.855	3.868

Exhibit DS-5
Schedule 8

Table 8. Payments to Debt and Preferred Holders
Costs in Billions of Dollars
Life of CTC = 7 Years
Cost of Debt = 7.78%

	Cumulative Amortization	Balance	Interest	Cumulative Interest	Total
1	0.329	1.974	0.154	0.154	0.483
2	0.658	1.645	0.128	0.281	0.940
3	0.987	1.316	0.102	0.384	1.371
4	1.316	0.987	0.077	0.461	1.777
5	1.645	0.658	0.051	0.512	2.157
6	1.974	0.329	0.026	0.537	2.512
7	2.303	0.000	0.000	0.537	2.841

Table 9. Internal Rate of Return (costs in billions of dollars) Through End of Transition Period

Year	Initial Investment	Depreciation	Cumulative Depreciation	Rate Base	11.5% Return	Return Plus Depreciation	Future Return Plus Depreciation	Equity Holders Cash Flow	
1	-2.825	0.081	0.081	2.745	0.158	0.239	0	-2.587	Total IRR
2		0.081	0.161	2.664	0.306	0.387	0	0.387	11.5%
3		0.081	0.242	2.583	0.297	0.378	0	0.378	
4		0.081	0.323	2.503	0.288	0.369	0	0.369	IRR To-Date
5		0.081	0.404	2.422	0.279	0.359	0	0.359	7.0%
6		0.081	0.484	2.341	0.269	0.350	0	0.350	
7		0.081	0.565	2.260	0.260	0.341	0	0.341	
8		0.081	0.646	2.180	0.251	0.331	0	0.331	
9		0.081	0.727	2.099	0.241	0.322	0	0.322	
10		0.081	0.807	2.018	0.232	0.313	0	0.313	
11		0.081	0.888	1.937	0.223	0.304	0	0.304	
12		0.038	0.926	1.899	0.218	0.256	0.168	0.425	
13							0.317	0.317	
14							0.317	0.317	
15							0.317	0.317	
16							0.317	0.317	
17							0.317	0.317	
18							0.317	0.317	
19							0.149	0.149	
20							0.000	0.000	

Environmentalist Statement 1-SR

8/27/97
Hearing
wj H

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PENNSYLVANIA POWER AND LIGHT
COMPANY FOR
APPROVAL OF ITS RESTRUCTURING PLAN
UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE

DOCKET NO. R-00973954

SURREBUTTAL TESTIMONY
OF
DAVID SCHOENGOLD

Q. Please state your name and business address.

A. My name is David Schoengold. My business address is 7507 Hubbard Avenue, Middleton, Wisconsin 53562

Q. Have you submitted direct testimony in this docket?

A. Yes.

Q. What is the purpose of your surrebuttal testimony today?

A. I will respond to rebuttal testimony submitted by Dr. Susan Tierney, Douglas Krall, Dr. Joseph Kalt, Joseph Kleha, and Dr. Scott Jones.

Surrebuttal to Dr. Susan Tierney

Q. Please respond to Dr. Tierney's comments on your testimony concerning the allocation of the CTC.

A. Dr. Tierney suggests that the Competition Act would not allow the Commission to follow my suggestion and allocate the CTC according to energy use rather than based on demand. I will leave to the Commission the decision as to what its authority is under the Act. However, Dr. Tierney raises no objection to my main point which is that stranded costs are of no value and thus are no longer capacity related. Therefore, they need not be allocated in the same way as capacity related costs are allocated.

Q. Please respond to Dr. Tierney's comments concerning periodic adjustment of the CTC.

A. Dr. Tierney appears to be suggesting in her rebuttal testimony that I have objected to a fixed CTC in light of the fact that market prices will be changing during the transition period. This is a misunderstanding of my point. If we could know with certainty the market price trajectory over time, a fixed CTC would be perfectly reasonable (assuming it were set to yield the proper net present value of stranded costs). My point is that the trajectory of the market prices is not knowable at this time, and fixing a CTC based on PP&L's current projection is likely to lead to overcollection or undercollection of stranded asset costs.

Q. Please respond to Dr. Tierney's comments on unbundling the declining block rate structure.

A. Dr. Tierney interprets my testimony as recommending that each and every rate element retain the declining block structure inherent in current rates. Again, I have not stated this, nor can such a proposition by reasonably inferred from my direct testimony. Nonetheless, I must say that I find odd her view that a rate structure in which every customer has a different mix of fixed and usage sensitive prices meets her stated goal of rate simplicity.

Surrebuttal to Douglas Krall

Q. Please respond to Mr. Krall's comment that, under the new rate structures, customers will still have an incentive to conserve energy.

A. It is true that as long as the variable cost of electricity is greater than zero there will be some incentive to conserve energy. However, under the proposed new rate structure, customers will have a greatly reduced incentive to conserve energy. In fact, they will have a greatly increased incentive to use more electricity.

Q. Please respond to Mr. Krall's comments on the regulation of transmission and distribution companies.

A. Mr. Krall acknowledges that it is a laudable goal to try to reduce the cost of providing transmission and distribution (T&D) services through implementation of cost-effective renewables, energy efficiency and distributed generation alternatives. Having recognized the merits of my proposal, Mr. Krall essentially throws up his hands at the idea of trying to coordinate the benefits among the generation company, transmission company, and distribution company. While implementing the approach I have recommended is certainly more difficult under a structure which lacks vertical integration, throwing up one's hands and saying it cannot be done is not especially useful.

Indeed, there are a number of approaches which could be used to recognize and capture the generation and distribution related benefits, including the offering of credits by the distribution and/or transmission company to providers who build generation sited to reduce T&D expenditures, allowing the distribution company to build and/or own generation under the limited conditions when it solves distribution problems, and the like.

Furthermore, Mr. Krall suggests that it is "premature" to adopt the T&D planning approach I have recommended. He offers no guidance as to when the approach will become timely. Thus his suggestions are not very useful.

Q. Please respond to Mr. Krall's comments with respect to the lack of environmental comparability between existing PP&L plants and new power plants.

A. First I am glad to see that PP&L does plan to improve the environmental performance of its plants. This was not clear from the filing.

Nevertheless, Mr. Krall does imply that the plants will not be brought up to the environmental performance level of new plants. Therefore, the issue of fairness which I raised still remains. Mr. Krall suggests that it is not a matter of fairness, but rather one of law. However, the Clean Air Act assumed continued regulation of generation and also assumed retirement of older plants after a typical utility plant life. Neither of these assumptions are borne out by current realities. Therefore, to fall back on the excuse that plant owners are simply following the law in complying with disparate environmental regulations does not address the problem. My proposed solution does address the problem. Nor does the Clean Air Act inhibit the Pennsylvania PUC from taking the steps I recommend in my direct testimony to address the problem of environmental comparability.

Indeed, my statement of the problem, and the recommendations I make, bear a striking similarity to statements offered by PP&L witness Tierney in recent testimony before the New Jersey Board on the environmental implications of restructuring. (Pre-filed Testimony of Susan F. Tierney, Ph.D. on Behalf of Intercontinental Energy Corporation, New Jersey Board of Public Utilities, Docket No. EX94120585Y, July 26, 1996, provided pursuant to PP&L Response to Set #2 Of Environmentalists Data Requests, Number 110, attached hereto as Exhibit DS-6) There, Dr. Tierney remarked on the "pervasive, significant differences between the environmental impacts of modern gas-fired generation facilities..and oil and coal units, especially those built more than a decade ago." (Id. at p. 2) As envisaged by Dr. Tierney:

"A gross distortion in the present market is the subsidy enjoyed by older plants in New Jersey and elsewhere in the region that have been grandfathered from the full effect of clean air laws. Newer generating plants...operate according to much more stringent standards. Many older plants have been sheltered from modern environmental standards, under the expectation that these plants would be retired before long, and would be replaced over time by a fleet of cleaner plants. This assumption no longer is valid as we stand on the eve of a more competitive electricity market. We not expect that many existing plants, because of their economics and their insulation from clean air laws, will continue to operate well beyond their original retirement dates. Without an incentive to induce electric generators to operate under comparable emissions standards, those generators that are subject to less stringent environmental standards will have an undue advantage in the competitive generation market -- an advantage that we think the Board should remove." (Id at p. 7).

Surrebuttal to Dr. Joseph Kalt

Q. Please respond to Dr. Kalt's comment that I provide no rationale or principle for a sharing of stranded asset costs between customers and stockholders.

A. Dr. Kalt is wrong. I made my rationale for sharing very clear. Stranded asset costs represent a bad investment on the part of the utility and an economic loss. A sharing of the responsibility for bad investments seems to be a reasonable approach to the problem.

Q. Please respond to Dr. Kalt's comments on keeping environmental and economic policies separate.

A. Dr. Kalt seems to believe that it is possible to keep environmental and economic policy separate. In fact, environmental and economic policy are very thoroughly intertwined, especially insofar as related to the production and delivery of electric energy. For Dr. Kalt to suggest that they can be separated is a simplistic view of things. Rather than pretend to be able to separate them, it is better to recognize the intertwined nature and make use of it to better meet public policy goals in both areas.

Surrebuttal to Joseph Kleha

Q. Please respond to Mr. Kleha's comments on the jurisdictional allocation of stranded costs.

A. Mr. Kleha claims that if not for restructuring and competition, the retail responsibility fraction for the generating assets would be increasing over time, and therefore the responsibility for stranded costs should also be increasing over time. This position ignores the important point that stranded costs are not generating assets, but rather economic losses of no value. Therefore, it makes much more sense to make a jurisdictional allocation of those costs based on the last point at which they did represent generating assets -- that is, the point in time at which the decision was made to end the generation monopoly, restructure the utilities, and move towards competition. This argues for fixing the jurisdictional allocation fractions at the current levels rather than changing them over time.

Q. Please respond to Mr. Kleha's comment that a CTC reconciliation process based on adjustment for future deviations form estimated market prices would be too complex.

A. Mr. Kleha made this comment in response to testimony of Mr. Boonin. However, the comment could be taken to apply to my recommendation for CTC reconciliation as well, so I have chosen to respond to his comment. I have two points to make in response. The first is that the electric utility restructuring process is by its very nature complex, and to try to pretend that it can be made simple is specious. The second is that developing a reconciliation process is not especially complex. All it requires is the actual market price (as reported after the fact) and a time profile of the utility's power production. From these two sets of data it is reasonably straightforward to determine the company's actual market revenue to compare to the assumed market revenue used in determining the CTC. A reconciliation is then straightforward.

Q. Please respond to Mr. Kleha's comments on the allocation of the CTC to rate classes.

A. In general Mr. Kleha is making the same argument that Dr. Tierney made in her rebuttal testimony, and the same response would apply. Mr. Kleha, however, goes on to say that PP&L's current rate design allocates generating capacity costs based on customer demand. I would suggest that, given PP&L's "Demand Free Days" program which excuses the largest customers from paying for demand which may well occur during monthly and even annual peak days, the current rates do not allocate generating capacity costs based on demand.

Surrebuttal to Dr. Scott Jones

Q. Please respond to Dr. Jones' comments on the use of an auction sale to determine the actual value of PP&L's plants.

A. Dr. Jones appears to be suggesting that we can get a better determination of the value of the PP&L plants through an administrative process than through the use of a market approach such as an auction. This view appears to be in conflict with both the Competition Act which sets forth markets as better determinants of cost and value than regulation and with the views of other PP&L witnesses such as Dr. Kalt which favor the use of markets and competition rather than administrative regulation.

In addition, Dr. Jones suggests that an auction will set an unreasonably low value for the plants. In fact, it is my understanding that in places such as New England where utility generation has been put up for sale, prices for that generation have been quite reasonable, and in some cases, above book value for the units.

Finally, Dr. Jones suggests that a delayed auction such as I have recommended will delay the determination of the market value of the plants and make it difficult to move forward with competition. He misunderstands my proposal. I do not call for a delay in any determination of the market value of the PP&L plants. Rather, I have suggested developing an interim determination of the market value with a reconciliation of that market value as more information becomes available. Competition and restructuring can move forward just as quickly as with the company's proposal.

Q. Does that complete your surrebuttal?

A. Yes

Environmentalists' Statement No. 2

8/27/97

Before the

Pennsylvania Public Utility Commission

Pennsylvania Power & Light Company
Restructuring Plan

R- 973954

Testimony and Exhibits of

Bruce Edward Biewald

Synapse Energy Economics, Inc.
101 Chilton Street, Cambridge, MA 02138

June 30, 1997

Table of Contents

1. Qualifications

Q: State your name, occupation and business address.

A: My name is Bruce Edward Biewald. My address is Synapse Energy Economics, Inc., 101 Chilton Street, Cambridge, Massachusetts, 01238.

Q. Please describe your current employment.

A. I am President of Synapse Energy Economics, Inc., a consulting company specializing in economic and policy analysis of electricity restructuring, particularly issues of consumer protection, market power, stranded costs, renewables, efficiency, environmental quality, and nuclear power.

Q. What are your qualifications with regard to energy policy?

A. I graduated from the Massachusetts Institute of Technology in 1981, where I studied energy use in buildings. I was employed for 15 years at the Tellus Institute, where I was Manager of the Electricity Program, responsible for studies of electric system operation and planning, regulatory policy and industry restructuring, stranded costs, system benefits, market power, nuclear and fossil power plant costs and performance, renewable resources, power supply contracts and performance standards, nuclear plant decommissioning and radioactive waste issues, climate change policy, environmental externalities valuation, energy conservation and demand-side management, rates and fuel adjustment clause analysis, electric power system reliability, avoided costs, fuel prices, purchased power availability and cost, production costing modeling, economic analysis of power plants and resource plans, and risk analysis.

I have testified on these issues in more than thirty five cases in regulatory proceedings in eighteen states and two Canadian provinces.

I have co-authored approximately 80 reports including studies for the Electric Power Research Institute, the U.S. Department of Energy, U.S. Environmental Protection Agency, the Office of Technology Assessment, the New England Governors' Conference, the New England Conference of Public Utility Commissioners, and the National Association of Regulatory Utility Commissioners. My papers have been published in the Electricity Journal, Energy Journal, Energy Policy, Public Utilities Fortnightly and numerous conference proceedings, and I have made presentations on the economic and environmental dimensions of energy throughout the U.S. and internationally. My resume is provided here as Exhibit BEB-1.

Q. What is your experience with regard to environmental disclosure for electricity?

A. I have analyzed the issue on behalf of the Vermont Department of Public Service and the Regulatory Assistance Project. The paper that I coauthored for RAP on environmental disclosure is provided here as Exhibit BEB-3. I have also made presentations on this issue at workshops sponsored by the Center for Clean Air Policy, the Energy Foundation, and the American Wind Energy Association.

Q. What was your role in preparing the report provided as Exhibit BEB-3?

A. Synapse Energy Economics worked as a contractor to the Regulatory Assistance Project. I was involved in conceptualizing the issues, preparing drafts, editing the entire report, and finalizing it. I am prepared to answer questions about any aspect of the report.

Q. What is your experience with regard to market power?

A. I have analyzed electricity market power issues in New York and New England. I testified on market power in the New Hampshire restructuring docket on behalf of the Consumer Advocate, and in the Vermont restructuring docket on behalf of the Department of Public Service. I also testified on market power in Consolidated Edison's restructuring case on behalf of the City of New York. I have conducted a study of market power in the New England Power Pool for the New England Conference of Public Utility Commissioners.

Q. What is your experience specifically with regard to nuclear decommissioning costs?

A. I have investigated, studied and testified on the topic of nuclear power plant economics and decommissioning costs since 1982. I have testified on the projected costs and funding of nuclear plant decommissioning in state regulatory proceedings in Arizona, California, New Hampshire, and Wisconsin. I have been invited to speak on decommissioning by the National Association of State Utility Consumer Advocates (NASUCA), and my papers on the subject have been published in the Energy Journal and Public Utilities Fortnightly. I have compiled and analyzed a database of nuclear plant decommissioning cost estimates that were prepared by TLG Engineering, PP&L's decommissioning consultant in this case. A graph of that data is presented in Exhibit BEB-2.

Q. Has your testimony served as the basis for regulatory commission decisions?

A. Yes. The Michigan Public Service Commission has adjusted Consumers Power Company and Detroit Edison Company projections of power costs based upon my projections of fuel costs, purchased power costs and sales revenues. The Massachusetts Department of Public Utilities adopted the set of monetary values for air pollutants recommended in my testimony. The California Public Utilities Commission adjusted a

TLG Engineering, Inc. estimate of nuclear decommissioning costs by approximately $100 million, based upon my testimony. In addition, my recommendations have been reflected in several settlement agreements in cases on excess capacity, avoided costs and power plant performance.

2. Summary and Recommendations

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

A. I was retained by the parties to this case collectively known as "The Environmentalists" to comment on (1) environmental disclosure for electricity, (2) PJM market issues, (3) nuclear plant decommissioning costs, and (4) rate design for stranded cost recovery. What the Environmentalists envision for the market is that:

- customers will be well informed of their generation options, including price, risk and environmental attributes,
- "clean electricity" options in which customers can make a real and positive change to the region's resource mix will be developed and marketed effectively,
- a robust wholesale market will develop in which smaller companies will compete on fair terms with larger companies, and all customers will have an opportunity to benefit,
- nuclear plant decommissioning will be adequately funded to provide assurance of the availability of funds for eventual plant dismantlements,
- nuclear plant decommissioning costs will be managed carefully and shared equitably,
- any stranded cost recovery that is allowed should be recovered fairly, with all customers bearing their share of the burden.

My testimony should also be considered in conjunction with that of David Schoengold and Peter Bradford who are presenting the Environmentalists' perspective on other issues in this docket.

Q. Please summarize your conclusions and recommendations with regard to environmental disclosure for electricity and consumer education.

A. The Commission should require all retail electricity suppliers selling in Pennsylvania to disclose their fuel mix and key air and other waste emissions to consumers in a standard and easy to comprehend label. Disclosure should be mandatory for all suppliers. The tracking of transactions to support disclosure and labeling should be done by the Independent System Operator. These requirements should apply to PP&L.

I recommend that a set of objectives be adopted to guide the design and implementation of a fuel mix and environmental disclosure system. Specifically, the system should be effective, accurate, comprehensive, flexible, simple, expandable, inclusive and credible. It is essential that the system be created in such a way that customers who pay more for clean electricity actually make a difference to the resource mix.

A comprehensive program of consumer education on the environmental effects of electricity production and use should be implemented to complement disclosure. The Company and the Commission should include the Environmentalists and other interested parties in the process of developing and reviewing consumer education plans and materials.

Disclosure and consumer education issues are discussed in Section 3 of my testimony, below.

Q. Please summarize your conclusions and recommendations with regard to PJM issues.

A. Undue vertical and horizontal market power can be obstacles to the development of competitive electricity markets. Vertical market power can best be addressed by establishing a strong and independent system operator for the transmission system, and by separating the distribution function as much as possible from generation. Horizontal market power in wholesale electricity markets may require limits on the ownership of capacity in the region. I recommend that the Commission take a strong position on these issues, and coordinate with the other PJM states. PJM market issues are discussed in Section 4 of my testimony.

Q. Please summarize your conclusions and recommendations with regard to nuclear decommissioning costs.

A. My key points on the treatment of nuclear decommissioning costs in this case are the following:

- The currently approved annual cost amount for PP&L's nuclear decommissioning obligations is about $9.5 million per year (Kleha direct testimony, page 15).
- PP&L has suggested that nuclear decommissioning costs be collected in the CTC and that the CTC be extended "beyond the nine-year window provided by the Act to permit recovery of its nuclear decommissioning costs over the remaining life of the Susquehanna generating plant" (Kleha direct testimony, page 14).
- PP&L has not demonstrated mitigation of the nuclear decommissioning portion of its stranded costs.
- PP&L's nuclear decommissioning cost obligation is currently estimated by the Company to be $724 million in 1993 dollars (PP&L Response to Interrogatories of the Environmentalists, Set 3, Attachment 1, page 4). This amount is large, very uncertain, and to some extent within the control of the plant owner.
- PP&L's nuclear decommissioning consultant, Mr. Tom LaGuardia, has been estimating decommissioning costs for 20 years. Even after adjusting for inflation, his recent estimates are roughly six times his 1976 cost estimate for dismantling a large pressurized water reactor, and the average annual rate of escalation in his estimates has out paced inflation by about 10 percent per year over the past two decades (see Exhibit BEB-2).
- Costs can, to some extent, spill over between nuclear decommissioning and the costs

of operation and the costs of spent fuel disposal.

- There are currently important uncertainties about nuclear decommissioning related to the policies of the Internal Revenue Service and the Nuclear Regulatory Commission.
- It is difficult to make a specific plan now for nuclear decommissioning costs are so uncertain and they will be incurred so far in the future.
- The principles that should guide sound nuclear decommissioning policy are: (1) ***assurance*** that adequate funds will be available to decommission the plants in a safe and timely manner, (2) ***equity*** between customers and shareholders, and across generations, and (3) ***efficiency***, primarily provided by creating a framework in which the plant operator has an appropriate incentive to control the costs of the decommissioning project.

I recommend the following with regard to nuclear decommissioning costs:

- PP&L should be required to update its 1993 nuclear decommissioning cost study.
- For any additional costs for decommissioning that PP&L is allowed to recover through the CTC or to include in its stranded cost calculations, PP&L should be required to demonstrate that it will -- and has -- placed the funds into its external decommissioning fund.
- The Commission should require an adequate plan from PP&L for the mitigation of its decommissioning costs.
- Procedures should be put in place to ensure that the plant is operated in such a way that the decommissioning cost obligation is not increased.
- PP&L should be responsible for some portion of any decommissioning costs in excess of current projections, and responsible for all excess costs not demonstrated to be prudently incurred.
- In the event that decommissioning costs less than expected, customers should receive an appropriate refund.
- The Commission should address the complicated technical and policy issues of nuclear decommissioning in a generic case, in which limited regulatory resources can be used efficiently and a consistent policy can be developed that does not unfairly disadvantage one company relative to another.
- The Commission should carefully weigh the costs, benefits, and risks before assigning nuclear decommissioning to the wires business. It should consider the problems that occurred in the past when cost-based regulation was applied to the large, complex, expensive, and uncertain project of nuclear plant construction. It should consider the benefits of an incentive framework for nuclear decommissioning costs, in which the risks are shared between the Company and its customers. The Commission should not, at this point, extend the cost recovery for decommissioning beyond nine years.

With regard to spent nuclear fuel storage and disposal, my findings are the following:

- PP&L has been collecting and paying to the Department of Energy the one mill per kWh fee for nuclear spent fuel disposal.
- PP&L's filing includes the ongoing one mill per kWh fee in its projections of nuclear fuel costs (Exhibit JRS-1, Tab A, page 3) and hence these costs for spent nuclear fuel disposal have been reflected in the calculation of the market value of PP&L's nuclear units.
- The U.S. Department of Energy has been slow to accept responsibility for spent nuclear fuel from commercial nuclear power plants.

I recommend the following with respect to spent nuclear fuel:

- PP&L and the U.S. DOE should bear the responsibility for storage and disposal of spent nuclear fuel, not captive customers paying through a wires charge.
- PP&L should recover the funds for spent nuclear fuel storage and disposal in the market through the revenue from the sales of energy from the nuclear plants.
- Spent nuclear fuel storage and disposal costs should be handled separately from decommissioning, with money set aside for both in separate funds, with different policies with regard to sharing the costs and risks.

Nuclear decommissioning and spent fuel storage issues are discussed in Section 5 of my testimony.

Q. Please summarize your conclusions and recommendations with regard to rate design for stranded costs.

A. I find that the customized rate design is unnecessarily complex, unfair, and does not promote true efficiency or the development of competitive markets. I recommend that the Commission adopt a simple, non-bypassable, volumetric charge for any stranded cost recovery that is allowed.

Rate design for stranded cost recovery is discussed in Section 6 of my testimony.

3. Environmental Disclosure for Electricity

Q. What is disclosure and how would it apply in the case of electricity and its environmental attributes?

A. Disclosure is the process in which consumers are informed about their electricity suppliers' sources of electricity. With environmental disclosure requirements for electricity, retail suppliers in the state would report their resource mix and key environmental attributes of their resource portfolio to their customers. Customer education is also very important -- and should be coordinated with disclosure so that consumers have the information they need to make decisions and the knowledge to understand that information.

Q. Why is environmental disclosure for electricity sound public policy?

A. First, electricity generation has extraordinary impacts on the environment. In the U.S. electricity generation is responsible for roughly two thirds of the total SO_2 emissions, nearly one third of total NO_x emissions, and more than one third of total CO_2 emissions. Fossil fueled electricity generating plants also emit heavy metals, and fine particulates, and have a number of impacts associated with mining and the creation of waste in the fuel cycle. Nuclear plants present different environmental and health risks, associated with accidents, nuclear fuel mining, fabrication and enrichment, spent nuclear fuel transportation and storage, and decommissioning. Land and water use of power plants can be substantial.

These and other impacts of electric power have been well studied. For example, I managed a large project for the Boston Edison Company Settlement Board that surveyed these impacts and quantified them where possible, for power plants in New England (*Non-Price Benefits of BECo Demand-Side Management Programs*). I also participated in a major study of the environmental externalities of electric power plants in New York (*New York State Environmental Externalities Cost Study*, for the Empire State Electric Energy Research Corporation and the New York State Energy Research and Development Authority). The U.S. Department of Energy conducted a major study of the environmental damages from electricity generation (*Estimating Fuel Cycle Externalities: Analytical Methods and Issues, Report Number 2 on the External Costs and Benefits of Fuel Cycles: A Study by the U.S. Department of Energy and the Commission of the European Communities*). In addition to such overview studies, many specific research projects have focused on particular impacts of power generation.

The second reason to implement disclosure for electricity is that many consumers are interested in the environmental implications of their purchasing decisions. Surveys repeatedly show a high degree of public support for and interest in clean energy sources. For example, a 1996 report by Farhar and Houston reviews data from more than 700 polls and concludes that the public supports renewable energy, backed by a willingness to pay $6 to $25 per month more for electricity from less harmful sources by 76 percent of those surveyed. The Sustainable Energy Coalition survey revealed bipartisan support for renewables, stating that 57 percent of the 1200 registered voters surveyed would like congress to require a renewable portfolio standard. National consumer surveys conducted for the Edison Electric Institute concluded that 77 percent of consumers surveyed in 1993 stated that they make "changes in daily consumer behavior because of environmental concerns."

Third, many electricity suppliers are interested in marketing a "clean product" or portraying themselves as a "green company." For example, in the New Hampshire pilot program, many suppliers used environmental language in their marketing. A list of the environmental claims made by suppliers in the Massachusetts and New Hampshire pilot programs is provided in Table 1 on page 6 of Exhibit BEB-3. These range from specific information about the power supply sources (e.g., "more than 90 percent of the electricity in Green Mountain Energy Partners' supply comes from hydropower sources") to general statements (e.g., "its the beginning of our long-term commitment to you and the earth").

Forth, with competition in electricity customers have an opportunity to choose their supplier. In order for this choice to be most meaningful the customers should have basic information about the suppliers in a standardized, easy-to-understand format. Fuel mix and environmental information can be disclosed along with standardized information on price and price volatility.

Q. Are regulators in other states requiring disclosure for electricity suppliers?

A. Yes. State regulatory commissions in Massachusetts and Vermont have included a mandatory disclosure provision as an element in their December 1996 electric industry restructuring orders. Maine's May 1997 restructuring act includes a mandatory disclosure.

The National Association of Regulatory Utility Commissioners recently passed a "resolution in support of customer 'right-to-know' and product labeling standards for retail marketing of electricity." NARUC "urges states adopting retail direct access programs to include enforceable standards of disclosure and labeling that would allow retail consumers easily to compare the price, price variability, resource mix, and environmental characteristics of their electricity purchases." NARUC's resolution is provided in full in Appendix A on page 26 of the report provided as Exhibit BEB-3. On June 3, 1997, the New England Governors' Conference adopted a similar "resolution in support of customer 'right-to-know' and product labeling standards for the retail marketing of electricity in New England."

Q. What should the objectives of an environmental disclosure system be?

A. I recommend that the following set of objectives be used in designing an environmental disclosure and tracking system for PP&L:

- Effective: it should make a difference in the actual mix of electricity resources.
- Accurate: It should provide consumers good, objective, and quantitative information about their supplier's sources of electricity.
- Comprehensive: It should allow for the disclosure of a wide range of environmental impacts, and fuel-type information.
- Flexible: It should encourage innovation in technology, contracting and marketing.
- Simple: It should be straightforward and readily understandable.
- Expandable: It should be adaptable to various scales so that it can start small and grow geographically.
- Inclusive: It should provide opportunities for both existing utilities and new players to offer renewable resources.
- Credible: It must be trustworthy both initially and over time. To the extent that the system embodies subjective value judgments, they must be made by an independent entity with individuals who have a proven track record for objectivity.

These criteria depend on each other and in some ways conflict with each other. They should be seen as design objectives for the system, and the inevitable tradeoffs among them should be made carefully.

Q. Which of the objectives do you consider to be most important?

A. In my view the first and the last objectives listed are the most important. If the system is not effective at "making a difference" then it is a waste of time or worse. That is, if a customer pays more for "clean electricity" thinking that this is influencing the resource mix then the transaction should actually influence the resource mix in a manner that is reasonably similar to what the customer believes to be the case.

The objective of "credibility" is related to this. The system must be credible in order to work. It must "make a difference" in order to be credible.

Q. Why should environmental disclosure be mandatory?

A. Some believe that disclosure should be optional. That is, that only suppliers who wish to make affirmative environmental claims need to disclose information about their resource mix. I disagree with this view. Certainly, some suppliers will voluntarily make specific environmental claims. These claims will likely range from credible statements to dubious assertions, and perhaps even fraudulent claims. In this environment a standardized system of mandatory disclosure has several important functions:

- verification of claims about the resource mix,

- disclosure of information to consumers about the "dirtier" suppliers, and
- standardization of information for ease of comparison.

Accurate claims about "cleanness" of the resource mix will be supported by the information on the standard label. Vague claims that are inaccurate will be discouraged.

This is analogous to food labeling: the front of the box typically has claims such as "low fat" while the back of the box has the standard mandatory label with ingredients and nutritional information. For electricity we will need to address both. The voluntary claims ("front of the box") will need some rules and guidelines. The mandatory and comprehensive information ("back of the box") is what disclosure addresses.

Q. What should be disclosed?

A. In general, and for PP&L specifically, the basic information that should be disclosed is the fuel mix and key air emissions. Specifically, the supply portfolio should, at a minimum, be reported by "fuel mix" -- coal, oil, gas, nuclear, hydro, and non-hydro renewables. In addition, key air emissions should be reported; including carbon dioxide, sulphur dioxide, nitrogen oxides, and fine particulates. To the extent that other major environmental impacts, such as waste creation, can be quantified, these should be included as well. A standardized point of comparison, such as the regional average level of pollution per kWh, should be indicated for reference.

Q. What vehicles should be used for communicating information to consumers?

A. The information can be disclosed in various formats and through various channels. The format for disclosure should probably follow the example of nutritional labeling: a straightforward standardized layout using percentages and relating technical information to commonly understood benchmarks. Research is currently underway to determine what information electricity consumers will want and be able to process. This is funded by the National Council on Competition and the Electric Industry, and is being coordinated by the Regulatory Assistance Project.

A sample label for electricity is provided on page 9 of Exhibit BEB-3. This is provided as a suggestion of what information might be included and how it might be presented. The specific design, format, and content should be developed with some input from Pennsylvania consumers. The label must balance the desire of some consumers for a great deal of detailed information with the desire of many for simple and quick summary information. The appropriate level of detail would also vary with the different communication vehicles. For example, the information disclosed on a bill might differ from the information required to be disclosed in marketing materials. It would also be appropriate to have a very detailed set of information provided to regulators on a periodic basis, to help in verifying claims, and to provide to those consumers and consumer agencies that request detailed information.

The vehicle for disclosure should include the bills that are sent to customers and the promotional materials that suppliers develop for marketing. The roles for industry, government and others need to be worked out. At one extreme, a disclosure system could conceivably be entirely voluntary, designed and implemented by the market participants. At the other extreme, government agencies could undertake the bulk of the activities themselves -- collecting data, calculating attributes, verifying and enforcing the system. Another model would rely upon independent parties to rate suppliers -- along the lines of "Consumer Reports."

The most successful approaches will probably draw upon all of these actors. The minimum role for suppliers would involve making the essential data (primarily quantities of energy transactions) available. Independent third-party rating systems are likely to develop in one form or another on their own accord. Government can take the role of outlining information requirements for industry to comply with, and then to spot check on disclosure accuracy.

Q. What time scales should a tracking and disclosure system work on?

A. There is first the issue of how frequently the information should be put in front of the customer. This issue should be researched along with the design of electricity labels.

A separate issue is the matter of time period for doing any calculations. For example, a system that tracks transactions on an hourly basis will give a different result than one based on annual averages. It may be that quarterly estimates provide the right balance between accuracy and burden.

Finally, there is the timing issue of prospective versus retrospective information. A disclosure system might base information on recent history, adjusted for major expected changes such as the expiration of a contract or a major plant outage. Utility rate cases often use actual data for a "test year," and then adjust it for "known and measurable changes." Perhaps an analogous approach could be developed for electricity disclosure. Alternatively, it may be preferable to use an approach with true-ups, where the information reported would be reconciled with actuals over time.

Q. Is the tracking of transactions to support disclosure feasible?

A. Yes. Electricity markets already involve numerous transactions among numerous market participants. These numbers and the overall complexity of the market are increasing. Nonetheless, it is entirely possible to track these transactions. Indeed, tracking is and must be done in order to settle the financial obligations. The fuel mix and environmental attributes can be tracked using a system that builds upon the existing information systems.

Q. How would a system of tracking and disclosure work in an electricity market with a spot market or power exchange?

A. Electric power pools have system agreements, approved by FERC, that lay out protocols for dispatching power plants and for billing. A typical arrangement has the actual dispatch optimized on a combined basis, that is, all of the available generators are used in a least-cost manner to serve total pool hourly loads. Then, for accounting purposes, each company is assigned its own units first toward its own load. The result will be that some companies generate more than their own load and some companies generate less. Energy transactions are then assumed in order to balance the system, and buyers compensate sellers according to the pricing provisions in the system agreement (marginal cost plus ten percent and "split-savings" are two pricing schemes). The pooling agreement and accounting systems could be modified for disclosure/tracking system to unambiguously allocate generation from each company's owned units either to its own load or to sales. In situations where a number of companies sell in the pool, perhaps to several buyers, the sources of generation would be known, and attributed to the buyers, perhaps on a pro rata basis. With restructuring, much of this will remain the same, but dispatch will in many cases be based on bids rather than costs.

In effect, the tracking system can work by following the dollars. For any time period, there is a known amount of electricity generated, and a known amount of electricity consumed. These should be equal, after accounting for losses in the transmission and distribution systems. Retail buyers compensate the generators, perhaps in some cases with several intermediaries. By following the contracts and the flow of money from retail consumers to generators one can develop a reasonable measure of accountability.

Q. Is there a single approach that is theoretically superior to all others for tracking the attributes of generation to the point of retail sale?

A. No, there is no single unambiguously preferable approach. There are, however, several approaches to tracking, each with its strengths and weaknesses. The most important thing may be simply to agree on one system that can be applied consistently. Ideally the system would be applied at least on the scale of the PJM system, and perhaps even coordinated with neighboring systems. The Commission in Pennsylvania should simultaneously (1) establish the disclosure requirement for retail sellers in the State, and (2) work with other states and PJM to implement a tracking system for PJM as a whole. It should unambiguously express its intention to do so when it issues the order in this case, providing that PP&L conform its public information to that requirement.

Q. What approach to disclosure and tracking do you recommend?

A. I recommend that the state and the region adopt a company-based tracking system in which wholesale sales are allocated before retail sales. I believe that this is the most readily implementable approach.

Q. Why do you recommend a company approach?

A. A system that requires disclosure of provider companies is preferable to one that discloses individual "products" (or contracts). First, the company approach will be easier to implement. It will have a smaller number of "entities" for which information must be tracked, and hence a more manageable amount of data and computation requirements.

More importantly, company-based disclosure is more meaningful than product disclosure. A statement that the supplier has a certain resource mix is meaningful and reasonably straightforward. With product-based disclosure suppliers can simply allocate on paper their clean generation to a "clean product" and their dirty generation to a "cheap product." Customers paying more for the clean product may be just receiving reallocated existing resources, and hence are not making a difference (objective number 1, above).

Q. What do mean by a tracking system that allocates wholesale sales first?

A. There are a variety of ways to approach the treatment of transactions in an environmental disclosure system for electricity. The most straightforward, and ultimately perhaps the best, approach is described below -- a company-based system with generation allocated to wholesale sales first. With this system each company would allocate its generation to its wholesale sales, and then allocate its remaining resource mix (generation and wholesale purchases) to its retail sales.

This simple system divides electric companies into their production and retail functions. Wholesale sales are assumed to be from producer's own generation, unless the producer sells more at wholesale than it produces. If wholesale sales exceed own generation, then the extra is assumed to come proportionately from the companies the producer purchases from. This approach allows the complex web of electricity transactions to be dealt with in a straightforward manner, avoiding the difficulties and ambiguities of tracing power transactions back through several companies.

By separating the production and retail functions, this simple system shows great flexibility for representing the many types of entities and transactions that will occur in the market. Transactions from outside of the system might be treated differently than transactions within the system. For example, it may be appropriate to attribute marginal emissions and fuel mix to imports.

Q. Are there other systems that could be used for tracking transactions?

A. The "wholesale transactions first" approach is the most straightforward way to account for transactions, but other approaches that account for the web of transactions in a more subtle way are conceivable. For example, a retail sales first convention might be adopted. Or alternatively, each company might be seen as selling a slice of its own generation and its purchases -- both to its wholesale customers and its own retail customers. However, because the transactions comprise a complex web, and not a unidirectional chain, these approaches are more complex. They can involve working back through sometimes many companies to find the mix for a single buying company. The implementation of some of these approaches would require sophisticated mathematical tools (e.g., linear programming) to implement.

Q. You mentioned that consistency is important in a tracking system. Why is that?

A. Without a consistent tracking system, it might happen that some of the power generated from dirtier sources is not disclosed or that the same clean power might be sold more than once. Consistency over the largest possible area helps to reduce the possibilities for gaming the system. Ideally, the PJM and neighboring systems (or their ISO equivalents) will adopt tracking systems that are the same, or at least reasonably consistent.

Q. What data are required to implement a tracking system?

A. The essential data for a disclosure system include generation by plant, and the buyer, seller and quantity of energy for each transaction. These data are, in general, currently made available to government agencies. There are, however, some gaps in what is reported, and there is an unacceptably long time lag before some data are publicly available.

Moreover, electricity market participants are becoming increasingly sensitive about making information available. Procedures should be implemented that respect the legitimate confidentiality concerns of market participants while ensuring that sufficient data are available to implement an environmental tracking system -- and to allow regulatory oversight of market power and electric system reliability.

Relevant data are currently provided to the Energy Information Administration, the Environmental Protection Agency, the Federal Energy Regulatory Commission, and various state agencies. Data sources and issues are discussed in Exhibit BEB-3 on pages 17 to 19, and Appendix C.

Q. Who should be responsible for implementing the tracking sytem to support disclosure?

A. The Independent System Operator should play the key role in implementing the tracking aspect of environmental disclosure. ISO's have the technical expertise, the necessary information on generation and transactions, procedures for handling sensitive data appropriately, and the independent status for credibility. It is important that Pennsylvania utilities and the Pennsylvania Public Utilities Commission encourage that the tracking function be included in the mandate of the PJM ISO, and that provisions for tracking fuel mix and key environmental attributes be included in current PJM software upgrades. If the Commission can clearly and satisfactorily delegate the tracking and reporting function to the ISO it can assure that good information flows essentially automatically to retail sellers and aggregators, who would report the information to customers..

Q. Do you agree with Ms. Lennon that a customer education program is needed?

A. Absolutely. Ms. Lennon points out that "In a competitive electric generation market, it will be critical for all consumers to have access to up-to-date information about a variety of topics..." and that "This information will be particularly important in an evolving market that will include new, non-traditional sellers" (Lennon direct testimony, page 3). A customer education program that presents clear and unbiased information to consumers is essential for meaningful choice.

Q. What requirements in the Act relate to disclosure and consumer education?

A. The Act includes several requirements that should be addressed through an education program. First, the Act requires

> each distribution company, electricity supplier, marketer, aggregator and broker to provide adequate and accurate customer information to enable customers to make informed choices regarding the purchase of all electricity services offered by that provider. *Information shall be provided to consumers* in an understandable format that enables consumers to compare prices and services on a uniform basis. (Section 2807 (d) (2))

Second, energy conservation services must be available in all distribution service territories (Section 2804 (9)). Third, customers must be informed of the changes in the electric industry (Section 2807 (d)(3)).

Q. What criteria should the Commission use to evaluate the appropriateness of PP&L's education program?

A. In order to be worthy of Commission approval, an education program must be effective, accurate, accessible, comprehensive and unbiased. Therefore, PP&L's education program should cover a broad range of options and issues, from pricing, billing and metering options to consumer protection and environmental impact information. In addition, the program should make educational materials accessible to all consumers, which will require information in multiple languages. Finally, the information that PP&L uses for consumer education must not include language that could inappropriately influence customers to choose to remain with their incumbent utility. I recommend that the Commission take strong leadership in this area, setting precise protocols and content requirements to prevent PP&L, and other utilities, from charging captive customers for tens of millions of dollars of "customer information" that may turn out to be little more than marketing.

Q. How does consumer education relate to disclosure for electricity?

A. Pennsylvania consumers will, for the first time, be presented with a choice of electricity supplier, and -- through a disclosure requirement -- be presented with information about the fuel mix and environmental impacts of electricity generation. A comprehensive program of consumer education should be developed to assist buyers in comprehending electricity restructuring, comparing offers, and understanding the environmental impacts of their choices. The consumer education initiative should be coordinated with and complementary to the disclosure and labeling requirement.

Q. Does PP&L plan to include environmental information in its "customer choice education materials?"

A. Yes. While the April 10 draft of PP&L's "Customer Choice Handbook"makes no mention of environmental issues (Attachment 1 to PP&L Response to Interrogatories of the Office of Consumer Advocate, Set IV, Question 2) and Ms. Lennon makes no mention of environmental and health issues in her direct testimony, PP&L has indicated that its customer choice education materials "will include discussion of the fuel mix and the 'green' energy issue" (PP&L Response to Interrogatories of the Office of Consumer Advocate, Set IV, Question 10). PP&L states that it will form a "Customer Choice Education Advisory Committee of representatives from community-based organizations which will work in partnership with the Company to develop approaches to presenting such information" (PP&L Response to Interrogatories of the Office of Consumer Advocate, Set IV, Question 10).

My clients in this case -- the Environmentalists -- should be included in PP&L's Customer Choice Education Advisory Committee, since their perspective and expertise on environmental issues and communication will be valuable. The key customer education materials developed by PP&L should be subject to Commission review, including a process for parties to comment, prior to their release. If an appropriately representative P&L Advisory Committee does not approve the Company's materials, the Commission should prohibit their issuance with customer dollars or bearing any Commission imprimatur.

Q. Is environmental disclosure for electricity a substitute for other environmental policies?

A. Absolutely not. Environmental disclosure for electricity is an important policy that can provide useful information to consumers about their electricity purchasing decisions. Other regulations, such as portfolio standards and emission caps, are necessary and appropriate, and in no way in conflict with disclosure specifically or electricity markets generally. Restructuring of the electricity industry can and should be implemented in a way that improves Pennsylvania's environmental quality.

4. PJM Market Issues

A Competitive Electricity Marketplace

Q. What do the Environmentalists envision for the future electricity markets?

A. The Environmentalists envision a robust market:

> The potential for competition to improve economic efficiency and to reduce long-term costs rests on having robust competition in the marketplace. Robust competition requires multiple service providers in the marketplace in order that customers have real choice.
>
> All power generation will face full and fair competition. The utilities will not enjoy competitive advantage, either through massive stranded cost war chests or other anti-competitive actions. There will be no unreasonable barriers to entry into the marketplace. Market development will be guided in a way that increases the role of competition among energy service providers and the role of choice for customers.
>
> The concentration of ownership of generating capacity in the marketplace will be limited in order to minimize opportunities for abuse of market power. The ISO will play a role in monitoring and mitigating market power problems in the generation markets. The ISO governance will include public interest representation and will not be dominated by the current utility companies.

While I subscribe to these views, and I advised the Environmentalists as they drafted this statement, I am quoting from the Environmentalists' Vision for the New Electricity Marketplace.

Market Power Problems

Q. What sort of problems can arise in the functioning of a market?

A. There are various types of market power problems that can keep a market from functioning competitively. These include problems of undue vertical market power and horizontal market power.

Q. What is vertical market power?

A. Vertical integration provides opportunities for the following types of anti-competitive behavior:

- favoring affiliates in purchasing decisions;
- providing affiliates with preferential service;
- timing and siting transmission upgrades in a way that favors affiliated generators;
- cross-subsidizing unregulated affiliates; and
- providing affiliates with proprietary market data.

The Federal Energy Regulatory Commission has catalogued in detail the propensity of vertically integrated utilities to abuse their market power (70 FERC 61,357 [1995, 65-85]). FERC's observations include the following:

> In the past, transmission-owning utilities have discriminated against others seeking transmission access. Transmission-owning utilities have denied access by outright refusals to deal.... More often, however, discrimination is likely to be manifested more subtly and indirectly. One such way would be [delaying negotiations until]....the window for the customer's trade opportunity has closed. Another way of frustrating access is to substantially change the terms of negotiated agreements through protracted delay including filings with regulatory agencies. Another way...is to allow access but only on noncomparable or unsupportable terms and conditions that are inferior to the conditions [available to]...the transmission owners themselves [such as refusing network services, denying postage stamp rates, denying priority service, insisting on long scheduling lead times, denying flexibility in the use of firm transmission capacity, providing inferior ancillary services, requiring onerous deposits, and requiring double payments in lieu of reciprocity].... Finally, an additional way for transmission-owning utilities to frustrate access and competition is by granting each other superior rights and lower rates, in pools, interconnection agreements and other protocols.

(Pages 71-78; citations omitted)

FERC describes similar past vertical market power abuses in the gas industry, when pipelines discriminated in favor of their own gas, and concludes:

> Our experience in the gas area influences our decision that, at a minimum, functional unbundling of wholesale services is necessary in order to contain non-discriminatory open access and to avoid anticompetitive behavior in wholesale electricity markets.

(page 85)

With direct-access competition, market power at retail may also be a problem. Incumbent utilities have a considerable advantage in providing retail service as a result of their current relationships with customers, detailed and valuable information about customers, and in some cases contracts with customers. Barriers to entry in the retail-services market may be particularly severe, given the working relationships that have built up over time between customers and their incumbent utilities.

Q. What is horizontal market power?

Horizontal market power in electricity arises from horizontal concentration in generation. A key mechanism for exploiting horizontal market power is for a large firm to raise market prices by withholding capacity from the market, raising the market price and thereby increasing profits over competitive-market levels.

Q. Is horizontal market power a concern in the PJM system?

Preliminary examination of market concentration in the PJM electricity market suggests that there may be opportunities for abuse of market power in generation if restructuring moves forward. These concerns arise mainly in situations where capacity is tight, for example during hours with high levels of demand or multiple large unit forced or scheduled outages.

Q. How does market concentration influence price and how is it measured?

A. An oligopoly is a market structure in which a few firms dominate the supply of a commodity. Its occurrence is quite common. Economic theory tells us that in oligopolistic markets prices can be expected to fall between the extremes of a perfectly competitive market at the low end and an unregulated monopoly market at the high end. It is impossible to say with confidence how a particular market will behave within the two tractable extremes.

The two most common measures of market concentration are the Herfindahl index, and the "concentration ratio." The Herfindahl index is the sum of the squares of individual firm's market shares. The higher the index number the greater the level of concentration, and the more likely that market power will be a problem. For example, the Herfindahl index would be 1000, for an industry with ten equal size firms. "Concentration ratios" are specified for a particular number of firms. For example, the three-firm concentration ratio (CR3) for that same industry would be 30 percent. No single metric can capture the complexities of the cost structures and relationships in a real market, but the Herfindahl and concentration ratio are both useful measures that can serve as starting points in analyses of market power.

Different oligopoly theories point to different measures of concentration as the most appropriate for explaining how significantly prices might deviate from marginal costs. Similarly, empirical explorations of concentration and price data in various industries are inconclusive in establishing a generally preferred measure of concentration for accurately predicting pricing behavior. At one theoretical extreme, oligopoly firms may act competitively, or "quasi-competitively," resulting in reasonable market prices. At the other extreme, the firms may collude perfectly, with results much like an unregulated monopoly.

Theoretical models may offer some insight as to the behavior of a market in electricity generation. However, even for markets that have existed for years and have been studied in detail, there are likely to be differences of opinion about how the market has behaved. It is simply impossible to say with confidence how a complex market will work before it exists, and with many aspects of its regulation and structure unresolved. The most we can do is to study the current market structure and cost functions, and to identify areas of concern and potential solutions.

Q. What is the level of market concentration in PJM?

A. Based upon current ownership, the capacity shares of the six largest companies in PJM, including the NUG capacity they control by contract, are as follows:

PSE&G	20%
GPU	18%
PECO	16%
PP&L	15%
BG&E	12%
PEPCO	12%

The concentration ratio for the three largest companies (CR3) is about 54%, and the concentration for the five largest companies is 81%. The proposed merger of BG&E and PEPCO would create the new largest company in PJM and would increase the CR3 to about 62%.

The Herfindahl (or "HHI") index is about 1550. The pending BG&E-PEPCO merger would increase the HHI by roughly 300 points to about 1850. This is undesirable from a market concentration point of view. According to the Department Justice's April 2, 1992 "Horizontal Merger Guidelines" used by FERC in evaluating market power impacts of mergers (see FERC's Policy Statement Order No. 592, Docket No. RM96-6-000, issued December 18, 1996), markets with an HHI index of about 1000 are "moderately concentrated," and mergers that raise the HHI be more than 100 points "potentially raise significant competitive concerns." The guidelines also indicate that, at a Herfindahl above 1800, the market is "highly concentrated" and adverse effects are "presumed." In such concentrated markets, there are significant concerns of market power, although whether and to what extent there is a problem depends upon a variety of other factors, for example, barriers to market entry.

Q. Dr. Jones has described a "future competitive generation market" in which suppliers bid their generation at its marginal cost, and receive payment for electricity that they generate at a market clearing price. Do you share this view of the future?

A. In many respects I agree with the view of the future electricity markets articulated by Dr. Jones on pages 5 through 7 of his direct testimony. I believe that it is likely that PJM will move to a bid-based dispatch in the near future, and that such a system can produce benefits. However, it is by no means certain that suppliers will bid at their marginal (or variable) cost. In order to ensure that they do, and that the market is appropriately competitive, it is important to conduct an analysis of the opportunities for suppliers in the market to add to their profits by raising prices. If the market is competitive, then strategies of withholding capacity or bidding above variable cost will not be profitable.

Q. Is it possible to analyze market power in PJM?

A. Yes. First, it is possible to calculate measures of market concentration, such as the HHI, for various product markets (e.g., generating capacity) in PJM. This has been done. It is useful but only a first step. After examining the measures of market concentration it is important to apply a model that can reflect some of the details of the market, such as which suppliers own capacity at various points along the supply curve, and how this intersects with the demand for the product. In electricity markets it is possible to use simulation models to directly inquire whether and to what extent anti-competitive strategies will be profitable to sellers in the market. I have applied such a model to the New England power pool and found that market power is likely to be a problem. A similar analysis should be done of the PJM electricity market before declaring that it is, or is not, adequately competitive. I urge the Commission to require PP&L to undertake such an analysis, using its dispatch modeling capability and inputs which stakeholders and the Commission staff agree upon.

Q. What are the factors that mitigate against the opportunities for abuse of horizontal market power?

A. There are several important mitigating factors, including market entrants (imports or new facilities), demand elasticity (the tendency of consumers to buy less of a product when the price increases), and antitrust regulation. These all play an important role in checking the magnitude of market power problems to the extent that they exist.

Q. How do vertical and horizontal market power relate to each other?

A. One way in which vertical and horizontal market power relate is that control of the transmission system can be used to limit the effective scope of the generation market. For example, creating a limitation on transmission capability into an area can lead to a situation in which an owner of capacity in that area has an increased ability to raise prices profitably within that area. It is also important to recognize that such transmission limits can be created indirectly, by decisions about generators, since the configuration of generation on the system influences the amount of capacity that can be carried over various interties.

Vertical and horizontal market power are also related in terms of the solutions. Divestiture of generating capacity, if done appropriately, can be an effective way to address both types of market power -- vertical, in that the ownership interest in the wires is separate from the ownership interest in energy generations, and horizontal, in that the larger blocks of capacity can be split.

Market Power Solutions

Q. What do you recommend for removing or mitigating the potential exercise of market power?

A. The following policies may be necessary in order to prevent market power from undermining competition in electricity markets:

- First, a strong and independent system operator should be established to coordinate the dispatch, ensure system reliability, to implement open access to the transmission system, to conduct transmission system planning, and to identify market power problems.
- Second, the distribution function ("poles and wires") should be separated as much as possible form the generation function, in order to minimize problems of vertical market power. While the Commission may not be able to require divestiture, it should encourage divestiture in its restructuring and ratemaking policies.
- Third, limits on the concentration of ownership of generating capacity should be established for participants in PJM.
- Fourth, detailed modeling studies should be conducted, in which strategic behavior is analyzed in the context of real markets with generation ownership patterns, transmission constraints, and opportunities for new entrants.

Q. What influence should the Pennsylvania Public Utilities Commission exert over these PJM issues?

A. Many of these issues are primarily to be resolved by FERC. There are, however, important ways in which the PUC can influence that process. First, the PUC can make it clear to the utilities what it would like to see in terms of market power protections. Second, the PUC should comment to the FERC on these issues in every possible forum. Third, the PUC should conduct or require analysis of market power. This analysis should include simulation modeling of the opportunities for large companies in the PJM system to influence the market price through strategic behavior in their bidding or by strategically withholding resources from the market. Fourth, the Commission should condition the exercise of its discretion in this and other restructuring cases on the Applicant utility's complying with the Commission's concerns — if a utility like PP&L wants favorable treatment in the stranded costs, rates and terms areas of the Commission's discretion, it must enthusiastically demonstrate compliance with Commission market concerns.

Now that PP&L has filed for certification as competitive provider of electricity it has placed itself squarely in the middle of the analysis that looks for self-dealing, cross-subsidy and favoritism for affiliates. I do not claim that PP&L has undertaken such undesirable activities, or that it necessarily will. But its newly acquired status sets up favorable conditions. An additional factor, not yet evident in this case, but present with PECO Energy's securitization, is the existence of a suddenly acquired fund of billions of dollars with which to enable market distortions. The Commission should require particular, focused behaviors I describe above from Pennsylvania utilities that put themselves in situations that permit market abuse.

5. Nuclear Decommissioning Costs

Findings and recommendations with regard to nuclear decommissioning costs

Q. What are your key points with regard to nuclear decommissioning costs?

A. The Environmentalists' vision is that decommissioning costs will be adequately funded in a manner that is fair and efficient -- nuclear plant operators will be responsible for some portion of the decommissioning costs and will have an interest in controlling those costs.

My findings on the treatment of nuclear decommissioning costs in this case are the following:

- The currently approved annual cost amount for PP&L's nuclear decommissioning obligations is about $9.5 million per year (Kleha direct testimony, page 15).
- PP&L has suggested that nuclear decommissioning costs be collected in the CTC and that the CTC be extended "beyond the nine-year window provided by the Act to permit recovery of its nuclear decommissioning costs over the remaining life of the Susquehanna generating plant" (Kleha direct testimony, page 14).
- PP&L has not demonstrated mitigation of the nuclear decommissioning portion of its stranded costs.
- Mitigation is difficult to do or to demonstrate at this point in time for nuclear decommissioning costs, since the key activities will occur so far in the future.

My key points on nuclear decommissioning costs more generally are the following:

- PP&L's nuclear decommissioning cost obligation is currently estimated by the Company to be $724 million in 1993 dollars (PP&L Response to Interrogatories of the Environmentalists, Set 3, Attachment 1, page 4). This amount is large, very uncertain, and to some extent within the control of the plant owner.
- PP&L's nuclear decommissioning consultant, Mr. Tom LaGuardia, has been estimating decommissioning costs for 20 years. Even after adjusting for inflation, his recent estimates are roughly six times his 1976 cost estimate for dismantling a large pressurized water reactor, and the average annual rate of escalation in his estimates has out paced inflation by about 10 percent per year over the past two decades (see Exhibit BEB-2).
- Costs can, to some extent, spill over between nuclear decommissioning and the costs of operation and the costs of spent fuel disposal.
- Some decommissioning costs are the result of continued operation of the facilities.
- There are currently important uncertainties about nuclear decommissioning related to the policies of the Internal Revenue Service and the Nuclear Regulatory Commission.
- It is difficult to make a specific plan now for nuclear decommissioning costs are so

uncertain and they will be incurred so far in the future.

- The principles that should guide sound nuclear decommissioning policy are: (1) ***assurance*** that adequate funds will be available to decommission the plants in a safe and timely manner, (2) ***equity*** between customers and shareholders, and across generations, and (3) ***efficiency***, primarily provided by creating a framework in which the plant operator has an appropriate incentive to control the costs of the decommissioning project.

Q. Please summarize your recommendations with regard to nuclear decommissioning costs.

A. I recommend the following:

- PP&L should be required to update its 1993 nuclear decommissioning cost study.
- For any additional costs for decommissioning that PP&L is allowed to recover through the CTC or to include in its stranded cost calculations, PP&L should be required to demonstrate that it will -- and has -- placed the funds into its external decommissioning fund.
- The Commission should require an adequate plan from PP&L for the mitigation of its decommissioning costs.
- Procedures should be put in place to ensure that the plant is operated in such a way that the decommissioning cost obligation is not increased.
- PP&L should be responsible for some portion of any decommissioning costs in excess of current projections, and responsible for all excess costs not demonstrated to be prudently incurred.
- In the event that decommissioning costs less than expected, customers should be receive an appropriate refund.
- The Commission should address the complicated technical and policy issues of nuclear decommissioning in a generic case, in which limited regulatory resources can be used efficiently and a consistent policy can be developed that does not unfairly disadvantage one company relative to another.
- The Commission should carefully weigh the costs, benefits, and risks before assigning nuclear decommissioning to the wires business. It should consider the problems that occurred in the past when cost-based regulation was applied to the large, complex, expensive, and uncertain project of nuclear plant construction. It should consider the benefits of an incentive framework for nuclear decommissioning costs, in which the risks are shared between the Company and its customers. The Commission should not, at this point, extend the cost recovery for decommissioning beyond nine years.

Q. What are your findings and recommendations with regard to spent nuclear fuel storage and disposal costs?

A. My findings are:

- The spent nuclear fuel from operation of a nuclear power plant is much more radioactive than the plant components themselves.
- PP&L has been collecting and paying to the Department of Energy the one mill per kWh fee for nuclear spent fuel disposal.
- PP&L's filing includes the ongoing one mill per kWh fee in its projections of nuclear fuel costs (Exhibit JRS-1, Tab A, page 3) and hence these costs for spent nuclear fuel disposal have been reflected in the calculation of the market value of PP&L's nuclear units.
- The U.S. Department of Energy has been slow to accept responsibility for spent nuclear fuel from commercial nuclear power plants.

I recommend the following with respect to spent nuclear fuel:

- PP&L and the U.S. DOE should bear the responsibility for storage and disposal of spent nuclear fuel, not captive customers paying through a wires charge.
- PP&L should recover the funds for spent nuclear fuel storage and disposal in the market through the revenue from the sales of energy from the nuclear plants.
- Spent nuclear fuel storage and disposal costs should be handled separately from decommissioning, with money set aside for both in separate funds, with different policies with regard to sharing the costs and risks.

Treatment of nuclear decommissioning in PP&L's stranded cost calculation

Q. How does PP&L treat nuclear decommissioning costs in its estimate of stranded costs?

A. PP&L includes an annual amount of $117 million for nuclear decommissioning in its stranded cost calculations (see Exhibit JRS 1, page 14). The amount included in jurisdiction rates is about $9.5 million per year (Kleha direct testimony, page 15).

Q. Does PP&L believe that this is adequate to cover its share of the decommissioning expense for Susquehanna?

A. No. PP&L explains in its "Decommissioning Funding" document provided in response to Environmentalists Set 3, Question 139, that with its recommended assumptions for decommissioning cost and after-tax return on the fund balance that "the estimated cost of decommissioning the Susquehanna plant would exceed the projected value of the trust fund in the year 2022 for Unit No. 1 and 2024 for Unit No. 2 by about $852 million (page 5).

Q. Do you agree with PP&'s assessment of the decommissioning fund adequacy?

A. I do not necessarily agree with the specifics of PP&L's assessment. I do, however, concur with the general conclusion that the annual funding amount appears to be inadequate. Moreover, PP&L's decommissioning cost study upon which the funding amount is based is dated. It was done in 1993, and decommissioning cost estimates can change dramatically over a three-and-one-half year period.

Nuclear decommissioning costs and stranded cost mitigation

Q. What is the estimated magnitude of PP&L's nuclear decommissioning costs?

A. PP&L has estimated its nuclear decommissioning cost obligation to be $724 million in 1993 dollars (PP&L response to Interrogatories of the Environmentalists, Set 3, Attachment 1, page 4).

Q. Do you believe this to be an accurate estimate of nuclear decommissioning cost?

A. No. PP&L's nuclear units have operating licenses that expire between the years 2014 and 2029. Dismantling a large, highly radioactive nuclear unit is a large, complex undertaking for which experience is currently quite limited, and regulations continue to evolve. It is not possible now to produce an accurate estimate at for the cost of decommissioning PP&L's nuclear units. Even if PP&L were to update its 1993 cost study (which I recommend be done) the new estimate will be subject to considerable uncertainty -- technical, economic, and regulatory.

Q. Please describe the basis for this conclusion.

A. I have reviewed many engineering estimates of nuclear decommissioning cost over the past 15 years. While the state of the art of nuclear decommissioning cost estimation has improved over the past 15 years, there are still important deficiencies. I have found that even the more recent cost estimates are inherently based upon a number of uncertain or unsupported assumptions. For example, it is typical to assume a hypothetical facility will be available for the acceptance of low level radioactive waste. Transportation costs are then estimated based upon an assumed distance to the non-existent facility. Disposal fees for the non-existent facility are typically based upon either the current fees at existing facilities unlikely to accept the waste from the nuclear power plant at issue, or the results of studies that estimate the prices that the un-sited, non-existent facility will charge for radioactive waste disposal.

The method and timing of decommissioning are also major sources of uncertainty. Even if one could say for certain that Limerick will operate to the end of its current license expiration date in 2029, it is not possible to say with confidence whether the plant will be dismantled five years or fifty years after that date.

The dismantlement process itself involves considerable uncertainty, as experience dismantling commercial nuclear reactors is limited to smaller units or special cases such as the Shoreham unit in Long.Island, which operated only at low power for a short period of time. Dismantling a full-scale nuclear unit that has operated for many years will present new challenges.

Q. Have U.S. utility industry nuclear decommissioning cost estimates been accurate in the past?

A. No. Engineering estimates of nuclear power plant decommissioning costs emanating from American utilities have a poor track record. The Company's decommissioning consultant, on whose judgment they rely for their estimates of nuclear decommissioning costs, is Mr. Tom LaGuardia, of TLG Engineering. Mr. LaGuardia has prepared dozens of nuclear power plant decommissioning cost estimates over the past 20 years.

Q. How do Mr. LaGuardia's estimates from 20 years ago compare with his estimates today?

a. Mr. LaGuardia's current decommissioning cost estimates are in the range of 15 times greater than his 1976 estimate for dismantling a large pressurized water reactor. Adjusted for inflation, the recent cost estimates are approximately 6 times higher than the older estimate. This is an escalation in cost of 600 percent.

The 1976 study that I refer to is an engineering analysis of the decommissioning cost of a large nuclear power plant for the Atomic Industrial Forum (*An Engineering Evaluation of Nuclear Power Reactor Decommissioning Alternatives*, AIF/NESP-009) in which Mr. LaGuardia estimated the cost to be $26.9 million (in 1975 dollars for immediate dismantlement of a generic 1160 MW pressurized water reactor). In today's dollars that would amount to about $70 million. In contrast, Mr. LaGuardia's recent site-specific estimates filed by PP&L in this case average about $400 million.

Q. What has the trend been in Mr. LaGuardia's estimates between 1976 and the present?

a. The trend is for continually increasing decommissioning cost estimates, at an alarming rate of escalation. I have compiled a database of about 180 of Mr. LaGuardia's site-specific estimates done between 1977 and 1995, all for the "immediate dismantlement" method of decommissioning. I have adjusted these for inflation, and have plotted them in Exhibit BEB-2. As the graph shows, the engineering estimates have been increasing rapidly over time. The two lines in the graph are linear and log-linear fits to the data. The average annual rate of increase is roughly 10% faster than inflation over this period.

This amounts to a doubling of the estimates every 7 or 8 years.

Q. Why is the growth in Mr. LaGuardia's estimates relevant to his current decommissioning cost estimates for PP&L's nuclear capacity?

A. The escalation in Mr. LaGuardia's estimates is important for at least two reasons. First, it shows that decommissioning cost estimation is not a mature, stable undertaking. While progress has been made over the last 20 years, and decommissioning estimates are now generally presented in a standardized format, the alarming rate of change in the estimates indicates considerable uncertainty in the current estimates. Second, the decommissioning cost estimates do not simply show volatility -- there has been a clear upward trend. Decommissioning policy and stranded cost policy should not ignore this trend. A head-in-the-sand approach will not be productive. Rather, understanding the past trends, the driving factors, and the implications for the future decommissioning costs is essential to making sound policy decisions.

Q. So, can the Commission simply adjust Mr. LaGuardia's PP&L estimate by a 10% increase and proceed with the balance of its stranded cost review?

A. This would not be adequate. A 10% increase (the historical rate of increase) would account for only one year of cost escalation. Moreover, while the past rates of increase must be considered, it is not reasonable to simply state that decommissioning cost estimates will continue to increase at the rate that they have in the past. What is needed is the establishment of a framework for decommissioning that ensures that the needed funds will be available in a timely manner, that provides for customers and shareholders to bear their fair share of the costs over time, and that provides incentives for the plant owner to control the magnitude of decommissioning costs.

Q. Are there other considerations that point to the possibility of further increases in the nuclear decommissioning cost estimates?

A. I believe that some of the factors that have driven past increases in the decommissioning cost estimates will continue to influence nuclear decommissioning costs in the future. For example, the cost of low-level radioactive waste disposal has increased rapidly over the past two-decades, and could continue to do so. A substantial portion of the increases in decommissioning cost estimates has been the related to spent nuclear fuel. While the cost of transportation and long-term storage of spent fuel is generally not included in the decommissioning cost estimates, the delays in the Department of Energy's schedule for accepting spent fuel from commercial nuclear reactors have driven decommissioning cost estimates upward due to the on-site implications of spent fuel handling and storage upon the scope and timing of decommissioning activities.

In addition, there is a general pattern of cost underestimation for large, complex projects; particularly those that involve institutional uncertainties. This phenomenon was evident in the case of nuclear power plant construction costs. The trends to date for nuclear decommissioning cost estimates suggest a similar, albeit somewhat different, set of factors at work. As large, fully radioactive nuclear power plants begin to be decommissioned, regulations and technology will evolve together... in most cases leading to higher costs.

Q. In addition to escalation of the cost estimates, are there other reasons to be concerned about the adequacy of nuclear decommissioning funding?

A. Yes. The possibility of nuclear plant shutdown prior to the license termination date is a major concern. Several units have shut down already, and further shutdowns are likely as nuclear plants are increasingly subjected to market forces. I have analyzed the operating economics of nuclear power plants in many regulatory proceedings over the last fifteen years. While on average, capacity factors have improved, the low market prices for electricity render some existing power plants uneconomic on an operating cost basis. This is true particularly for some nuclear plants. In a paper authored for the January/February 1997 *Electricity Journal,* I concluded that there are about ten nuclear plants in the U.S. that may be uneconomical to operate, based upon 1995 data. Other observers of the utility industry have reported similar conclusions. For example, a 1995 report by Moody's Investors Service stated that "there are at least 10 nuclear plants (out of 109 in the U.S.) that might be closed in the event of deregulation." (*Stranded Costs Will Threaten Credit Quality of U.S. Electrics*, August, 1995). More recently, Moody's found that "The propensity for certain nuclear plants to require expensive capital additions to comply with the standards of their Nuclear Regulatory Commission (NRC) operating license increases the likelihood that the number of early shutdowns might be even greater than those 10 originally identified." (*Moody's Assesses Nuclear Power Risks in A More Competitive Market*, November, 1996). Similarly, a report by the INGAA Foundation found that 40 percent of the nation's nuclear capacity is "vulnerable to shutdown" with increasing competition in the electric industry. (*Nuclear Power Plants and Implications of Early Shutdown for Future Natural Gas Demand*, 1997).

With decommissioning funding based upon the full license period, if a nuclear unit is retired prior to the license termination date, there will be a funding deficiency, in some cases of considerable magnitude. In particular, if PP&L's units shut down early there will be a net deficit in the funding available to decommission the units. PP&L estimate of the "current shortfall" in 1996 is $596 million, based upon its 1993 cost estimate for decommissioning (PP&L's Response to Interrogatories of the Environmentalists, Set 3, Question 139).

Q. Is it conceivable that a nuclear plant operator might find itself bankrupt or otherwise unable to carry out decommissioning for lack of funds?

A. It is possible that a nuclear plant owner could, after the shutdown of the plant, find that the funds set aside for decommissioning are inadequate for the task -- as a result of premature shutdown and/or higher than expected decommissioning cost. This may come at a time when the Company is financially stressed as a result of the loss of generating capacity and the associated income stream. The Nuclear Regulatory Commission has taken this possibility seriously, and has set up external funding requirements to avoid such a situation. The NRC is also currently considering the implications of electric industry restructuring upon the adequacy of nuclear decommissioning funding.

Q. Does PP&L have an obligation to mitigate with regard to its nuclear decommissioning costs?

A. As a regulatory technical person, I read the Act to say "Yes." The legal interpretation is properly left to the Commission and the lawyers who argue this case. Even independently, as a matter of regulatory policy, the Commission should require as a precondition to providing stranded cost recovery, that the utility has taken all reasonable and prudent measures to mitigate its stranded costs. Nuclear decommissioning represents a large portion of stranded costs. I assume that the Commission will look to the Pennsylvania's Electricity Generation Customer Choice and Competition Act, "transition or stranded costs" definition in Section 2808. It defines stranded costs as those "...which the commission determines will remain following mitigation by the electric utility." Nuclear decommissioning should not be an exception -- if stranded cost recovery is to be allowed then these costs should be aggressively mitigated.

Q. How might PP&L mitigate its stranded costs as they relate to nuclear decommissioning?

A. One way to mitigate the decommissioning portion of stranded costs is to contribute shareholder dollars to the fund, reducing the deficiency. Accelerating decommissioning funding in order to reduce the fund deficiency is another approach.

Since decommissioning is a process that hasn't taken place yet, there are additional opportunities for mitigation that are not possible for uneconomic plant construction costs. For example, good planning and cost control measures for the decommissioning process that reduce the total cost exposure for decommissioning would translate into stranded cost reductions. I have not seen evidence of a comprehensive PP&L program to minimize the cost of this de-construction program. This would be hands-on mitigation, not just shifting costs in time or among the various parties.

Q. What do you conclude regarding stranded cost mitigation and nuclear decommissioning?

A. I believe that PP&L has not addressed the issue of stranded cost mitigation as it relates to nuclear decommissioning, and that the Commission should require a plan for and evidence of such mitigation prior to approving CTC recovery of stranded costs. PP&L's decommissioning obligation as currently forecast by the Company is large. It could be larger still, with further increases in nuclear decommissioning cost estimates and further requirements for spent fuel storage and disposal. Therefore, I recommend that the Commission require of PP&L that it take clear and significant efforts to mitigate its future nuclear stranded investment. PP&L's shareholders funding the decommissioning provides an opportunity to demonstrate the Company's good faith and to protect citizens and the environment.

Responsibility for nuclear obligations

Q. Are you recommending that PP&L's customers pay additional amounts to the cover nuclear decommissioning costs?

A. No. This is exactly what I am concerned about. Providing assurance of adequate funding for safe and timely nuclear decommissioning is imperative. At the same time, customers should not be saddled with an open-ended obligation to bear these costs. I am concerned that PP&L's customers will be asked in the future to pay for additional, as-yet-unfunded nuclear decommissioning costs. I am also concerned that the Commission avoid enabling the same kind of cost-plus de-construction that plagued the nuclear power industry's construction efforts, contributing to the high costs of nuclear capacity.

Q. Is it efficient for PP&L to bear responsibility for the cost of decommissioning its nuclear capacity?

A. Yes, it is efficient in several different ways. First, there is the fuzzy line between operating costs and decommissioning costs.

It is possible to run the Susquehanna plant in a very clean manner, with somewhat higher operating costs but lower decommissioning costs. For example, by thoroughly decontaminating equipment and by removing radioactive wastes from the site during the plant's operating life, decommissioning costs will be lower. Conversely, if operating costs are kept low by only doing essential decontamination and by storing radioactive wastes at the plant site, decommissioning costs will be higher. Unfortunately, the competitive market that Susquehanna's operators are entering will tend to encourage the operators toward shifting such costs into the future.

If operating costs and decommissioning costs are treated differently (e.g., the former recovered in market prices and the latter recovered in a wires charge, like the CTC) then inefficient decisions may result. Certainly, it would be an important, if somewhat burdensome, regulatory necessity to watch the boundary between operation and decommissioning.

Also, an efficient incentive structure would have the nuclear plant owner responsible for at least some of the decommissioning costs. Cost-based regulation is arguably responsible for the nuclear plant construction cost debacle. Electricity restructuring is motivated in large measure by a desire to move away from a system in which a utility's cost recovery is based entirely on what it spends. By allocating substantial decommissioning costs to operators instead of to customers, the Commission would help ameliorate some of the pressures toward higher decommissioning costs.

We should not rely on the cost-plus, customer-pays system for a cost as large and important as nuclear plant decommissioning. Rather, the nuclear plant owner should bear its rightful responsibility for the costs of decommissioning, in a sensible, fair and efficient framework, in which there are reasonable incentives to control decommissioning costs.

A further concern is the reorganization of the electricity industry, including what we presently know as PP&L. For instance, PP&L may in the future spin its nuclear assets off into generating companies that lack the solid funding of the T&D monopoly. As the formerly PP&L nuclear units ended their useful lives, we could find the nuclear generating companies undercapitalized, unable to handle the true cost of decommissioning and waste storage/disposal. It is safer, and more equitable, if society now invests in the decommissioning of the nuclear plants, rather than saddling our children with the cost responsibility. This investment should be fairly shared.

The worst case scenario is a future in which "hot" shut-down nuclear plants remain in place, for lack of funds to properly dismantle them and store the radioactive waste. Pennsylvania cannot afford the burden of untended nuclear derelicts in the 21st century; and the state will not have the option of letting them sit relatively unattended, as it has with many old non-radioactive steel-making facilities. As a component of a restructuring plan, requiring the present nuclear owner and operator to "mitigate" by reducing unfunded obligations with shareholder funds is a reasonable expectation.

Q. PP&L proposes that the Commission extend the CTC "beyond the nine-year window provided by the Act to permit recovery of its nuclear decommissioning costs of the remaining life of the Susquehanna generating plant" (Kleha direct testimony, page 14). Do you agree with this proposal?

a. I agree with PP&L's proposal in part. It may be reasonable to have a "wires charge" for a portion of the decommissioning funding.

It is not reasonable, however, to have the wires charge be the sole means for funding the Company's nuclear decommissioning obligations. This would, in effect, provide a subsidy to the continued operation of the plant. It would also relieve the plant operator from the burden of controlling decommissioning costs.

The Commission should develop a decommissioning policy in which the obligation to pay for nuclear decommissioning costs is shared in an equitable and efficient manner between the customers (in a wires charge) and the generation portion of the company (which could attempt to recover these costs in the market prices charged for electricity). In this way, the operator of the nuclear units would have a direct financial interest in managing the magnitude of the decommissioning cost. With any system, all of the costs that are collected for decommissioning -- those from the wires charge and those from the plant operator -- should be placed in one or more external funds to ensure that they are available for plant decommissioning when needed. The Commission should not, at this point in time, extend the CTC.

Q. Does your proposal create a risk that decommissioning will not be adequately funded?

A. A policy that the nuclear plant owner will be responsible for a share of the decommissioning costs might, if implemented irresponsibly, create significant added risk of fund inadequacy. However, I believe that if the sharing mechanism is well designed, and the Company acts responsibly, then there is little added risk.

In my view there is some substantial benefit to having the owner "involved" in the funding, making decommissioning a central concern of management rather than a diversion of attention with costs that will be passed directly through to captive customers in a wires charge. Moreover, the utility's share of the decommissioning obligation can and should be placed into the external fund, in order to provide added assurance of the availability of funds. I understand that the Nuclear Regulatory Commission, which has an important role in assuring that decommissioning funding is in place, would not have a problem with such a proposal.

Q. How should the Commission go about developing a policy to address this difficult situation?

A. I recommend that the Commission undertake a process to establish this policy, ideally on a generic basis, for all of the utilities in the state with nuclear investments. Fortunately, the PP&L and PECO restructuring orders will issue at the same time, in January 1998, allowing the Commission to effectively set a generic policy with two of the state's larger nuclear owners. The following information should be collected from the companies and considered in developing the specific approach:

- estimation of the amount of decommissioning cost that is dependent upon continued operation of the plants,
- analysis of the degree of uncertainty in the current decommissioning estimates,

- identification of the activities and costs that are in the "grey area" between nuclear decommissioning and plant operations and the development of protocols for ensuring that costs that should be a part of ongoing plant operation do not slip into decommissioning,
- examination of the implications of national spent fuel disposal policy upon decommissioning timing and cost,
- analysis of the tax implications of a shared funding approach, and
- analysis of the funding assurance implications, including the connection with any NRC decisions on decommissioning funding for utilities in a restructured environment.

Q. What about the obligation to dispose of spent nuclear fuel?

A. Currently, nuclear plant owners pay a one mill per kWh charge to the Department of Energy to cover the costs of the high-level radioactive waste disposal program. The nature of the DOE's obligations to accept nuclear waste, most importantly the timing of that acceptance, is currently a disputed matter, and subject to considerable uncertainty.

In PP&L's filing, these costs of spent nuclear fuel disposal are included in the nuclear fuel cost projections (Exhibit JRS 1, Tab A, page 3) and hence have been reflected in the calculation of the market value of PP&L's nuclear units. The same is true for "costs associated with supplemental on-site spent fuel storage" (Exhibit JRS 1, Tab A, page 3). If these costs are understated then PP&L should, in the future, bear responsibility for the under-funding of the fuel disposal obligation.

Q. What do you recommend with regard to the responsibility for nuclear obligations, such as spent fuel and nuclear decommissioning?

A. My recommendations are presented in the beginning of Section 5, above.

6. Rate Design for Stranded Cost Recovery

Q. How does PP&L propose recovering its stranded cost?

A. PP&L has proposed a "customized rate design" for the CTC through which the company will recover stranded costs. Rather than having a per kWh charge for the CTC, the proposal is to move one half of the charge to a fixed payment, based upon the customer's kWh consumption in calendar year 1996. The remaining half would be based upon actual kWh usage as it evolves over time. (Tierney direct testimony, page 5)

Q. Would all of PP&L's customers be on the "customized rate design?"

A. No. PP&L proposes that this would be mandatory for commercial and industrial customers, and optional for residential customers (Tierney direct testimony, page 21). Presumably, to the extent that they have full information and are make rational choices, residential customers with increasing usage will opt onto the customized rate, while those with decreasing usage will not. Customers of any class who are on the rate have an added incentive to increase consumption relative to a scenario in which they face a volumetric price structure.

Q. What reasons does the Company give for proposing the customized rate?

A. Dr. Tierney lists three reasons for believing that the rate is desirable (quoted from Tierney direct testimony, pages 20 and 21):

- It is socially efficient: consumers making consumption decisions on the margin should not be influenced by transition costs.
- It speeds the transition to the competitive world, by reducing the influence of transition charge recovery on prices in emerging competitive markets.
- And it fosters economic development as commercial and industrial customers "see" prices that more accurately reflect the cost to serve.

Q. Do you agree with the Company?

A. No. I believe that "social efficiency" is a term that necessarily includes all of the costs of electricity production and use, even those that are not directly included in current market costs. For example, in thinking about social efficiency it is important to consider the health and environmental costs of air pollution from power plants.

These "externalities" can be large. For example, one set of calculations of the health and environmental damages of existing coal generation estimate the external costs to be between 2 cents per kWh and 7 cents per kWh depending upon the assumptions used. These are "damage cost" estimates for a hypothetical 300 MW unit with typical existing coal plant emissions factors, located on the lower Hudson in New York State. They were calculated using "EXMOD," a computer model for estimating power plant human health and environmental damages developed for the "Empire State Electric Energy Research Corporation."

Using the "marginal cost of control" values adopted by Dr. Tierney when she served as a Department of Public Utilities Commissioner in Massachusetts (see DPU order 89-239, August 31, 1990), the social costs of an existing coal unit for air emissions alone can be well in excess of 10 cents per kWh. Any policy claiming to be "socially efficient" must recognize these costs.

Q. Do you agree that the customized rate design "speeds the transition to the competitive world?"

A. I do not. Policies that promote open access and provide opportunities for entry to the market by new competitors speed the transition to competition. Providing customers with declining block rates or other creative rate structures for the stranded cost portion of their electricity bill does not hasten real competition in any meaningful way.

Q. Will the customized rate design "foster economic development" among commercial and industrial customers?

A. Perhaps. Some large customers, with a portion of their bill "fixed" based upon 1996 levels of electricity consumption, will proceed to consume more electricity in the future than they would have otherwise. However, electricity consumption is not synonymous with economic development. Promoting inefficient use of electricity in the name of economic development is not sound policy. The state should encourage clean and efficient economic development through other policies -- not by giving large and growing existing customers a break on their share of whatever stranded costs the Commission decides should be recovered.

Q. In your view is the customized rate design a fair way to recover stranded costs?

A. No. If any stranded costs are to be recovered, the rate design should be a simple volumetric charge that is non-bypassable. All customers at a particular time should pay the same amount per kWh.

Dr. Tierney has argued that the customized rate design is "fair because it more closely matches historical usage of generation and related costs to stranded cost recovery than does a pure usage-based charge" (PP&L Response to Interrogatories of the Office of Consumer Advocate, Set III, Question 33). According to PP&L's estimate, $2.9 billion out of $4.6 billion total stranded costs is associated with the Susquehanna plant (Exhibit JRS 1, Tab B, page 1). To the extent that one takes the view (consistent with Dr. Kalt's direct testimony on behalf of PP&L) that the stranded nuclear assets were built to serve growing load, that load included forecast increasing sales to existing commercial and industrial customers as well as new customers moving into the service territory. Moreover, because the plant was and is a baseload unit, then the high load factor customers, like the industrials, have a particularly large responsibility for it. They should pay their share of the Susquehanna costs, rather than secure the discount that the Company proposal would provide them.

In fact, the stranded portion of power supply assets is by definition uneconomic -- and not "used and useful" in serving anyone. It makes no sense to construct a complex, non-standard design for recovering such costs, and justifying it on the basis of fairness. For costs of this sort a simple allocation based upon kWh sales seems appropriate and fair.

Q. What is the cost of implementing the customized rate design?

A. The Company does not know. The Environmentalists inquired about the cost of implementing the customized rate design and PP&L responded that "The Company has not conducted any analysis that addresses the activities or costs of implementing the customized rate design option" (PP&L Response to Interrogatories of the Environmentalists. Set 2, Question 108).

I believe it will be unnecessarily expensive. While I cannot say what the cost would be, it is clear that the customized rate design option will add a layer of complexity and cost to PP&L's billing activities. Each individual customer's usage in 1996 must be kept and used to figure subsequent bills. Issues will surely arise as to whether certain customers are "new" or had some anomaly in their 1996 metered usage. There is also the unnecessary, added complexity for the customers -- who will already be inundated with complex, but important and necessary, information about electricity restructuring, unbundled bills, and competing electricity service offers.

Q. Please summarize your findings and recommendations with regard to PP&L's customized rate redesign.

A. I find that the customized rate design is unnecessarily complex, unfair, and does not promote true efficiency or the development of competitive markets. I recommend that the Commission adopt a simple, non-bypassable, volumetric charge for any stranded cost recovery that is allowed.

Q. Does this conclude your testimony?

A. Yes.

Environmentalists' Statement No. 2-SR

8/27/97
Hearing
w/ 14

Before the

Pennsylvania Public Utility Commission

Pennsylvania Power & Light Company
Restructuring Plan

R-973954

Surrebuttal Testimony of

Bruce Edward Biewald

Synapse Energy Economics, Inc.
101 Chilton Street, Cambridge, MA 02138

August 15, 1997

INTRODUCTION

Q. Please state your name and business address.

A. My name is Bruce Edward Biewald. My business address is Synapse Energy Economics, Inc., 101 Chilton Street, Cambridge, Massachusetts 02138.

Q. Have you provided testimony previously in this proceeding?

A. Yes. I provided written direct testimony on June 17, 1997 on behalf of the Environmentalists in a statement designated as Environmentalists' Statement No. 3. In my direct testimony I addressed three sets of issues: (1) environmental disclosure for electricity, (2) market power issues, (3) nuclear decommissioning, and (4) rate design for stranded costs.

Q. What is the purpose of this surrebuttal testimony?

A. In this surrebuttal testimony I address the rebuttal testimony of Pennsylvania Power & Light Company witnesses Douglas A. Krall, Joseph P. Kalt, Scott T. Jones, and Joseph M. Kleha. These are the four PP&L rebuttal witnesses who addressed my direct testimony in this case.

FUEL MIX AND ENVIRONMENTAL DISCLOSURE

Q. Mr. Krall takes issue with your recommendation for mandatory disclosure of fuel mix and key environmental impacts. What is your understanding of Mr. Krall's concerns?

A. Mr. Krall (rebuttal testimony, page 19) articulates two problems with the tracking aspect of disclosure. Specifically, he believes that (1) "all load servers will take a significant portion of their supply from the spot market" and (2) "the company is uncertain as to how specific plants and their fuel mixes can be segregated to the accounts of individual customers."

Q. Please address Mr. Krall's concern regarding the spot market.

A. I agree with Mr. Krall that it is likely that the spot market will play an important function in the future electricity market. This does not, however, pose a problem for environmental disclosure. The system for tracking can be designed so that suppliers who buy from the spot market are assigned the mix of what was sold into the spot market during a particular period. With this approach, if a particular supplier wishes to claim to use 100 percent renewables resources, for example, then it will not be able to rely on the spot market. This is not a problem. It simply reflects the reality of the situation. Suppliers can still claim to use 50 percent renewable generation, for example, and make use of the spot market. Moreover, the calculations for tracking can be done on any time scale determined to be appropriate – e.g., hourly, weekly, or monthly.

Q. Please address Mr. Krall's concern about the segregating generation to individual customers.

A. In my view generation from various sources should not be segregated to the accounts of individual customers. Rather, the companies selling at retail should be required to disclose their full resource mix to all of their customers, and in marketing materials to prospective customers.

Q. How do your recommendations in this case relate to the Pennsylvania Commission's policy on this matter as articulated in its recent order?

A. The Pennsylvania Commission articulated an interim policy on disclosure in its July 10, 1997 "Interim Requirements for Customer Information" (Docket No. M-00960890F0008). This policy includes mandatory disclosure of the supply mix (page 43) and verification of specific environmental claims. I believe this is an excellent start. This requirement will ensure that customers receive basic information about the sources of their supplier's electricity. The fuel mix disclosure requirement will require a system of tracking transactions to attribute generation at power plants to sales at retail. My recommendation on this topic -- in my direct testimony in this case filed on June 30, 1997 -- was for fuel mix *and* environmental disclosure (Biewald direct testimony, page 5).

I continue to believe that the mandatory disclosure policy should extend beyond fuel mix to key environmental attributes. At the same time, I commend the Commission for adopting the basic system of mandatory disclosure as part of its consumer information policy. Moreover, I point out here that it is a relatively simple matter to extent the fuel mix disclosure system to key environmental attributes, since the basic protocols for tracking will be in place. The Environmentalists believe that the mandatory disclosure requirement can and should be extended to include key impacts of fossil, nuclear, and hydro generation, and are available to assist the Commission in expanding the disclosure system at an appropriate time. We hope that this will be done soon.

Moreover, with a mandatory fuel mix disclosure requirement that does not include mandatory disclosure of environmental attributes the role of consumer education on the environmental impacts of generation from various fuel types becomes increasingly important. The Environmentalists are available and interested in contributing to the consumer education efforts on this topic at the state and utility-specific levels.

Q. How do Mr. Krall's concerns in this case relate to the Pennsylvania Commission's policy on this matter as articulated in its recent order?

A. I am puzzled by this. On the one hand, Mr. Krall points to the Pennsylvania Commission's July 10 Interim Requirements for Customer Information as a "more workable system [than the one that I recommend] which satisfies the needs of responsible disclosure" (Krall rebuttal testimony, page 20). At the same time, Mr. Krall's criticisms of my recommended disclosure system are on the issues of the role of the spot market and the difficulty of segregating the supply mix (pages 19 and 20). Both of these supposed problems would apply to the Commissions' requirement for fuel mix disclosure.

Q. With regard to the environmental aspect of disclosure, would the mandatory disclosure that you recommend conflict with a requirement for suppliers to back up specific claims?

A. Absolutely not. The two policy approaches are entirely consistent, indeed complementary. A requirement that suppliers back up specific environmental claims that they choose to make is important. Existing rules and guidelines go a good way toward providing such "truth-in-advertising." In addition, an electricity market in which informed customers can make real choices calls for mandatory disclosure of basic environmental information – even from suppliers who are not making specific environmental claims.

MARKET POWER ISSUES

Q. Dr. Jones takes issue with your testimony on market power. What is your understanding of his position?

A. Dr. Jones discusses the Federal Energy Regulatory Commission's recent order regarding PP&L's application for authorization to sell electric energy and capacity at market-based rates (Jones rebuttal, starting at page 86). Dr. Jones seems to imply that the FERC's decision in that case (ER97-3055-000) conditionally accepting market-based rates for PP&L implies that FERC has considered market power issues and found that they should not concern the Pennsylvania Commission to the extent indicated in my direct testimony in this case.

Q. Do you agree with Dr. Jones' rebuttal testimony?

A. No. It is important to acknowledge what FERC did and did not consider in the case that Dr. Jones cites. The products considered in that case were non-firm energy sales, short-term capacity and long-term capacity sales. These were analyzed by Dr. Jones in the context of current conditions – i.e., without retail access. FERC made its decision with regard to limited competition for these products with wholesale competition. This is a different matter from the retail competition that is the subject of this and other cases before the Pennsylvania Commission.

Q. Does FERC generally consider the potential for market power abuse as it relates to retail electricity competition?

A. No. FERC's policy is to defer to the state commissions with regard to market power related to retail access. For example, in its order authorizing the proposed merger of Baltimore Gas and Electric Company and Potomac Electric Power Company the FERC noted that "The record in the instant proceeding includes evidence that the proposed merger may have impacts on retail competition" and added that "We believe that these concerns merit consideration." (page 15) Nonetheless, FERC decided in that case to leave consideration of retail market issues to the DC and Maryland Commissions.

Q. What do you recommend to the Pennsylvania Commission?

A. I recommend that the Commission conduct detailed studies of market power and take appropriate corresponding steps such as those listed on pages 25 and 26 of my direct testimony.

NUCLEAR DECOMMISSIONING

Q. Mr. Kleha claims to rebut your testimony on "the appropriateness of 'delivery' charge recovery of nuclear decommissioning costs." Please summarize Mr. Kleha's rebuttal.

A. Mr. Kleha states that he has reviewed my "recommendation that the Commission not permit recovery of nuclear decommissioning costs over the remaining life of the Susquehanna generating plant" and finds it to be "short-sighted and contrary to the public interest" (Kleha rebuttal testimony, pages 29 and 30). He implies that my testimony in some way would discontinue PUC oversight of the decommissioning funds.

Q. Has Mr. Kleha accurately represented your testimony and recommendations?

A. No. On page 28 of my direct testimony I make eight recommendations with regard to nuclear decommissioning policy. The last of these recommendations is that the "Commission should not, at this point, extend the cost recovery for decommissioning beyond nine years." I recommended that the Commission instead "carefully weigh the costs, benefits, and risks before assigning nuclear decommissioning to the wires business" and that it "should consider the benefits of an incentive framework for nuclear decommissioning costs, in which risks are shared between the Company and its customers." I submit that my recommendations are not short-sighted and do not imply the end of PUC oversight of decommissioning costs. Quite the contrary. I view nuclear decommissioning as a very important public health and safety issue over the long-term, and believe that additional PUC oversight is needed – both in the near-term and the long-term. That is why I recommended a generic case to examine these issues and to consider them carefully. Mr. Kleha's simple fix -- to put recover all decommissioning costs in a wires charge – is not in the interests of the citizens of the State.

Q. Does Mr. Kleha take issue with any of your other recommendations with regard to nuclear decommissioning and spent nuclear fuel?

A. No. Mr. Kleha only mentions the one recommendation that he mischaracterized.

STRANDED COST RATE STRUCTURE AND ENVIRONMENTAL POLICY

Q. Dr. Kalt characterizes the Environmentalists' position on rate design stranded cost recovery as aiming to "maximally discourage electricity use and, thereby, environmental pollution associated with the generation, transmission, and distribution of electric power" (Kalt rebuttal, page 68). Do you agree with this statement?

A. No. This is not our goal.

Q. Do you agree with Dr. Kalt's approach to energy and environmental policy?

A. No. Dr. Kalt points out that if we "utilize reform of the economics of the electric power sector to pursue … environmental policy goals" then "rational consideration of all dimensions of the problem" is not permitted (page 68). He believes that environmental policy is a separate matter from electricity pricing (page 68) and expresses concern that if an electricity-use tax were the proper environmental policy then we would have "erred in … pushing all CTC charges into volumetric rates" (page 69, lines 15 to 17). In my view, Dr. Kalt's approach to policy is over-simplified, perhaps appropriate in an idealized world that exists only in textbooks. As a practical matter, our electricity restructuring policy decisions will have impacts upon consumers, shareholders, and the quality of our environment. It is simply not possible – nor is it desirable – to pretend otherwise. In the context of actual electricity restructuring in Pennsylvania we should consider the implications of our actions and aim to create a system that is socially efficient. We cannot duck responsibility by hypothesizing an ideal process for the separate deliberation and development of environmental regulations.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

Environmentalist DS-6

STATE OF NEW JERSEY

BOARD OF PUBLIC UTILITIES

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8/27/97
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In the Matter of the Energy Master Plan Phase I Proceeding to Investigate the Future Structure of the Electric Power Industry	No. EX94120585Y

PRE-FILED TESTIMONY

BY

SUSAN F. TIERNEY, PH.D., OF

THE ECONOMICS RESOURCE GROUP, INC.

ON BEHALF OF

INTERCONTINENTAL ENERGY CORPORATION

DOCKETED
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July 26, 1996

My name is Susan Tierney. I am appearing this morning on behalf of Intercontinental Energy Corporation of Hingham, Massachusetts. I am a Managing Consultant at The Economics Resource Group, Inc., in Cambridge, Massachusetts. I am pleased to join Ellen Roy of IEC to offer testimony on the Phase II Energy Master Plan proceeding being conducted by this Board.

I'm here today to talk about the environmental implications of electric industry restructuring. In her testimony, Ms. Roy describes "environmental comparability" as one of the four essential preconditions for creation of an efficient generation market in New Jersey. I'd like to talk about what is meant by environmental comparability, why it is so important to include it as an element of a more competitive industry structure, and what the Board might do to help ensure that the move towards a competitive electricity market helps enhance rather than undermine New Jersey's environmental goals.

Much has been said already about New Jersey's air pollution problems. In recent months, policy makers in the Northeast and Mid-Atlantic states have pointed to power plants in upwind states as major sources of the air pollution here. Indeed, the members of the New Jersey Phase II Proceeding's Working Group #3 recommended that the Board address pollution from old dirty upwind power plants as part of a final decision on restructuring.

Clearly, reducing pollution from upwind sources will require a regional if not a national solution. We hope that New Jersey policy makers, including this Board, will continue to work politically with other stakeholders to help address and solve the problem of excessive levels of pollution being transported into this region from upwind states.

But we're here today to talk about what can be done locally. Older fossil fuel plants in this state emit substantial levels of air pollution. The Board should do what it can to address these local sources of pollution, so that restructuring of the electric industry in New Jersey does not make the environmental situation worse.

IEC believes that restructuring and open electricity markets can help, not hinder, the objectives of both efficient energy production and use and environmental protection, if the right policies are adopted. For example, as IEC noted in its initial comments in this proceeding filed on September 15, 1995, the introduction of independent power facilities and demand-side management in New Jersey over the last decade has enabled the state to reduce not only the costs of electricity, but also the emissions associated with generating it. In particular, the growth in low-environmental-impact IPPs and DSM programs has placed New Jersey and the region in a far better position to meet the requirements of the Clean Air Act Amendments of 1990.

There are pervasive, significant differences between the environmental impacts of modern gas-fired generation facilities, such as those built by IEC, and oil and coal generating units, especially those built more than a decade ago. Some examples of these differences are:

- Air Emissions. A natural gas-fired combined-cycle plant, such as IEC's South River facility, has extremely low SO_2 emissions and, with appropriate controls, very low NO_x emissions as well. The allowed emissions rates for IEC's South River plant are below 0.15 lbs/mmBtu for NO_x, and approximately 0.002 lbs/mmBtu for SO_2.

By contrast, similarly sized oil or coal facilities have greater SO_2 and NO_x emissions by an order of magnitude. The difference is still greater for oil and coal plants built several decades ago. For example, large coal- and oil-fired plants in New Jersey have much higher emissions rates, even after the recent introduction of controls on some of the older stations. According to a recent report issued by the U.S. Environmental Protection Agency, several major fossil steam power plants in New Jersey have NO_x emissions rates as high as 1.3 lbs/mmBtu, or nearly ten times the allowed level for a recently constructed plant like IEC's South River facility.[1]

Another, more dramatic way to make this comparison is to contrast actual NO_x emissions for New Jersey power plants. In 1995, South River's NO_x emissions were approximately 655 tons. By contrast, several New Jersey fossil plants put out significant levels of NO_x -- a reflection of the combined effects of differences in fuel, technology, more lax pollution requirements, and much less efficient heat rates. According to the EPA Report, PSEG's Hudson Station (unit 1 is oil, unit 2 is

[1] United States Environmental Protection Agency, Phase II NOx Controls for the MARAMA and NESCAUM Regions, Final Report No. EPA -453/R-96-002 (Nov. 1995).

coal, for a total size of 1,115 MW) has combined NO_x emissions of 10, 622 tons per year; Atlantic City's BL England station (units 1 and 2 are coal, unit 3 is oil) has total NO_x emissions of 8,345 tons per year; PSEG's Mercer Station (coal-fired, 652 MW) has total emissions of 6,350 tons of NO_x per year; and PSEG's Bergen station (oil fired, 650 MW) has total emissions of 5,616 tons of NO_x per year.

- Ash and Solid Wastes. IEC's 300-MW South River facility is essentially a "zero discharge" facility for particulate emissions, with an average rate for particulate emissions of 0.15 per day.

By contrast, a similarly-sized coal-fired facility can generate as much as 500 tons per day of fly ash, which requires removal, transport and landfilling. This represents more than a 3000-fold increase in solid waste, together with the associated problems of fugitive dust and the need to purchase and fill large tracts of land with ash.

- Water Usage and Waste Water. IEC's South River plant has limited discharges of waste water to local wastewater treatment facilities. This waste water is neutralized at South River before it is discharged to the local system. The plant uses approximately 0.5 million gallons of water per day.

By contrast, a similarly-sized oil- or coal-fired facility with cooling towers would use approximately five million gallons of water per day, a ten-fold increase, plus would generate "blow down" waste water from the cooling towers. A similar oil- or coal-fired plant without cooling towers would need approximately 150 million gallons per day for once-through cooling, an additional 30-fold increase. Furthermore, use of this method of cooling leads to thermal and trace metal pollution which has harmful effects on fish and other marine life.

- Fuel Storage. Natural gas, the primary fuel used at the South River plant, is delivered by transcontinental pipeline. It eliminates the major risks of fuel storage associated with coal (large storage areas, fugitive dusting, and rainwater runoff) and oil (fuel oil leaks or spills on land or in water during unloading or transfer operations).

Modern generating plants, such as those build by IEC, were constructed in an era of greater environmental concern and under much more stringent standards than those that continue to be applied to older and less efficient fossil fuel plants. Older power plants in New Jersey and in upwind states have failed to bear the costs of meeting more current environmental standards -- costs that IEC and other modern competitors have incurred already. In this respect, some New Jersey utilities are subject to the very same criticism that they direct at "upwind" competitors who operate under less stringent environmental regulations: comparing power costs is deceptive when the producers are not playing by the same rules.

Power from older plants is deceptively "cheap" because it externalizes the costs of increased pollution, which are "paid" by everyone in the form of a degraded environment and associated health and other costs. If economic efficiency is the main objective of industry restructuring, and if environment progress is to continue, all market competitors should be forced to internalize more of the costs of pollution. Without such internalization, restructuring of the electric industry will result in stranding the benefits associated with investments in cleaner technologies, and yield artificially low prices for electricity at the expense of the environment and the rest of the New Jersey economy.

While the Board may not have direct authority over environmental problems, the Board should not lose sight of the potential for industry restructuring to foster a cleaner environment. The Board should create explicit incentives for the use of cleaner generation, incentives that allow utilities to return to ratepayers what are essentially "stranded benefits" associated with cleaner generating sources. Utilities also should be encouraged to make good business decisions about whether to continue to operate their power plants, or to shut them down should prudent business and environmental practices dictate.

Here are two of the kinds of incentives the Board should adopt. First, the Board should recognize the benefits of low-emissions facilities by tying stranded cost recovery to an asset's environmental performance. The Board should create a stranded cost recovery "carrot" for the costs associated with low-emission generating facilities. For example, depending upon the maximum length of the stranded cost recovery period eventually adopted by the Board as appropriate for a transition to a competitive electric industry, the Board should extend that cost recovery period for generation assets that are "low-emissions facilities," in order to match the length of stranded cost recovery to the "stranded benefits" associated with clean facilities.

A second approach – a modification of our first proposal – would also use stranded cost recovery as an incentive for implementing clean power generation strategies. In this approach, a utility that improved the overall average emissions rates for its portfolio of generation assets by a certain future date would be allowed a longer cost-recovery period for all of its generation assets. A "snapshot" of each utility's average system emissions could be calculated for a historical year, such as the year that the Board issues its restructuring principles. Then, any utility that brought its average emissions rates up to modern standards could have an extended cost recovery period for those assets. This snapshot could be calculated on an emissions-per-kilowatt-hour basis for all of the utility's generation assets. The utilities could bring their generation portfolios into compliance with the modern standards by a number of methods, such as fuel switching, emissions offsets or trading, plant closure, renewable resources, addition of pollution control technologies, and/or repowering.

Finally, let me comment on why we are offering these recommendations.

The Board's adoption of the kinds of incentives we have proposed will help make the electric generation market operate efficiently by reducing price distortions. A gross distortion in the present market is the subsidy enjoyed by older plants in New Jersey and elsewhere in the region that have been grandfathered from the full effect of clean air laws. Newer generating plants, including those built by IEC, operate according to much more stringent standards. Many older plants have been sheltered from modern environmental standards, under the expectation that these plants would be retired before long, and would be replaced over time by a fleet of cleaner plants. This assumption no longer is valid as we stand on the eve of a more competitive electricity market. We now expect that many existing plants, because of their economics and their insulation from clean air laws, will continue to operate well beyond their original retirement dates. Without an incentive to induce electric generators to operate under comparable emissions standards, those generators that are subject to less stringent environmental standards will have an undue advantage in the competitive generation market -- an advantage that we think the Board should remove.

If, as we believe, the Board's objective for a restructured industry is economic efficiency -- rather than cost shifting -- along with continued environmental progress, then all market competitors should face the same environmental standards. Otherwise, the restructuring of the electric industry will result in stranding the benefits associated with past investment in cleaner technologies. Left to itself, the market will yield artificially low prices for electricity, subsidized at the expense of the environment, and will shift pollution control costs to other sectors of the economy.

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Exhibit BEB-1 to BEB-3

to Environmentalists' Statement No. 2

8/27/97

Resume of Bruce Edward Biewald

Docket No. R-00973954

Pennsylvania Power & Light Company
Restructuring Plan

Bruce Edward Biewald

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA
President, 1996 to present:
Consulting on issues of energy economics, environmental impacts, and utility regulatory policy, including electric industry restructuring, electric power system planning, performance-based regulation, stranded costs, system benefits, market power, nuclear and fossil power plant costs and performance, renewable resources, power supply contracts and performance standards, green marketing of electricity, environmental disclosure, nuclear plant decommissioning and radioactive waste issues, climate change policy, environmental externalities valuation, energy conservation and demand-side management, electric power system reliability, avoided costs, fuel prices, purchased power availability and cost, dispatch modeling, economic analysis of power plants and resource plans, and risk analysis.

Tellus Institute, Boston, MA
Senior Scientist and Manager of the Electricity Program, 1989 to 1996:
Responsible for research and consulting on all aspects of electric system planning, regulation, and restructuring.
Research Associate, later Associate Scientist, 1980 to 1988.

EDUCATION

Massachusetts Institute of Technology
BS 1981, Architecture, Building Technology, Energy Use in Buildings.

Harvard University Extension School
1989/90, Graduate courses in micro and macroeconomics.

SUMMARY OF TESTIMONY, PUBLICATIONS, AND PRESENTATIONS

Expert testimony on energy, economic, and environmental issues in 37 regulatory proceedings in 18 different states and 2 Canadian provinces.

Co-author of approximately 80 reports, including studies for the Electric Power Research Institute, the U.S. Department of Energy, the U.S. Environmental Protection Agency, the Office of Technology Assessment, the New England Governors' Conference, and the National Association of Regulatory Utility Commissioners.

Papers published in the Electricity Journal, the Energy Journal, Energy Policy, Public Utilities Fortnightly, and numerous conference proceedings.

Invited to speak by American Society of Mechanical Engineers, International Atomic Energy Agency, National Association of Regulatory Utility Commissioners, National Association of State Utility Consumer Advocates, National Consumer Law Center, the Latin American Energy Association (OLADE), the Swedish Environmental Protection Agency (SNV), the U.S. Environmental Protection Agency, and others.

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Environmental externalities valuation, emissions effects and global warming.

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Integrated energy planning, power plant emissions, and nuclear plant performance.

Pennsylvania Public Utilities Commission (R-891364) – October 1989
Generating capacity requirements of the Philadelphia Electric Company and the Pennsylvania-New Jersey-Maryland Interconnection.

Maryland Public Service Commission (8199) – October 1989
Performance standards for coal, oil, and nuclear power plants.

Michigan Public Service Commission (U-9172) – April 1989
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Pennsylvania Public Utility Commission (P-870216, P-880283, P-880284, and P-880286) – March 1989
Allegheny Power System planning and avoided costs.

Michigan Public Service Commission (U-8880) – February 1988
Detroit Edison Company power supply costs, economics of Fermi "buy-back" purchase, nuclear fuel expense, oil costs, and power transactions.

Michigan Public Service Commission (U-8866) – December 1987
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"Modelling Fuel Cycle and Site-Dependent Environmental Impacts in Electric Resource Planning," Stephen Bernow and Bruce Biewald, invited paper at OECD-IEA Expert Workshop on Life-Cycle Analysis of Energy Systems, Paris, France, May 18 and 19, 1992. Proceedings published OECD/IEA Paris, 1993.

"Computer Model Use in Energy Conservation Planning," presented at the Latin American Energy Organization (OLADE) Seminar on Power Systems Computer Modelling in Quito, Ecuador, September 23-25, 1991.

"Environmental Externalities Measurement: Quantification, Valuation and Monetization," Bernow, Biewald and Marron, in External Environmental Costs of Electric Power, proceedings of a German-American workshop, Ladenburg, FRG, October 23-25, 1991. Edited by Olav Hohmeyer and Richard Ottinger, published by Springer-Verlag (Berlin, Heidelberg, New York).

"Some Microcomputer Tools for Least Cost Integrated Energy Planning: ECO, LEAP and EDB," Bruce Biewald and Harvey Salgo, presented at workshop on Energy Pricing and Planning, Bratislava, Czechoslovakia, May 21-22, 1991.

"Confronting Uncertainty: Contingency Planning for Decommissioning," Bruce Biewald and Stephen Bernow, Chapter 18 of "Nuclear Decommissioning Economics," a special issue of *The Energy Journal* of the International Association for Energy Economics, Volume 12, March 1991.

"Avoided Emissions and Environmental Dispatch," Stephen Bernow and Bruce Biewald, presented at the Conference on "Demand-Side Management and the Global Environment," Arlington, Virginia, April 22-23, 1991.

"Environmental Benefits of DSM in New York: Long Island Case Study," Bruce Biewald and Stephen Bernow, presented at the Conference on "Demand-Side Management and the Global Environment," Arlington, Virginia, April 22-23, 1991.

"Full Cost Dispatch: Incorporating Environmental Externalities in Electric System Operation," Stephen Bernow, Bruce Biewald and Donald Marron, the *Electricity Journal*, March 1991.

"EDB: A Flexible Database System for Energy-Environmental Analysis," Bruce Biewald, Michael Lazarus, and David Von Hippel, presented at International Atomic Energy Agency (IAEA) Technical Committee Meeting on "Development of a Database for Comparative Health and Environmental Impacts of Various Energy Systems," in Vienna, Austria, October 15-19, 1990.

"Full Cost Economic Dispatch: Recognizing Environmental Externalities in Electric Utility System Operation," Stephen Bernow, Bruce Biewald, and Donald Marron, presented at NARUC Conference on Externalities, Jackson Hole, Wyoming, October 1990.

"An Assessment of Demand-Side Management Models and Their Use and Applicability in Canadian Utilities," Martin Adelaar and Bruce Biewald, in the proceedings of the Canadian Electrical Association Demand-Side Management Conference, Halifax, Nova Scotia, September 1990.

"Avoided Cost Contracts Can Undermine Least Cost Planning," Stephen Bernow, Bruce Biewald, and Donald Marron, Energy Policy, September 1990.

"Environmental Externalities Measurement: Quantification, Valuation, and Monetization," Stephen Bernow, Bruce Biewald, and Donald Marron, in the proceedings of the Seventh NARUC Biennial Regulatory Information Conference, September 1990.

"Do We Really Need Nuclear Generating Companies?," Public Utilities Fortnightly, June 7, 1990.

"Nuclear Power Economics: Construction, Operation and Disposal," Bruce Biewald and Donald Marron, March 1989.

"Electric Utility System Reliability Analysis: Determining the Need for Generating Capacity," Stephen Bernow and Bruce Biewald, in the proceedings of the Sixth NARUC Biennial Regulatory Information Conference, September 1988.

"Nuclear Power Plant Decommissioning: Cost Estimation for Power Planning and Ratemaking," Stephen Bernow and Bruce Biewald, Public Utilities Fortnightly, October 29, 1987.

"Cost and Performance of Boiling Water Reactors," Stephen Bernow, Bruce Biewald and Tim Woolf, Public Utilities Fortnightly, August 1987.

PRESENTATIONS

(Note: Presentations that were accompanied by a written paper are listed in the section for "papers," above.)

Presentation on "State Initiatives and Regional Issues," New England Governors' Conference Workshop on Restructuring and Environmentally Sustainable Technologies, Warwick, Rhode Island, March 25, 1997.

Invited speaker on stranded costs, National Association of State Utility Consumer Advocates, meeting in San Francisco, November 1996.

Presentation on "Nuclear Power Plant Decommissioning Costs and Electricity Restructuring," Nuclear Decommissioning Trusts conference, New York City, November 18, 1996.

Invited speaker on stranded costs, Indiana Utilities Regulatory Commission Forum, Indianapolis, November 1, 1996.

Presentation on "Small Customers in a Restructured Electricity Industry: Transaction Costs, Advanced Metering Technologies and Aggregation Options" to the Consumers' Energy Conference, South Portland, Maine, July 1996.

Presentation on "Electric Generation Market Power in New England" to New England Conference of Public Utility Commissioners, Manchester Village, Vermont, May 1996.

Presentation on "Advanced Metering for Residential Customers on Electricity Restructuring" to National Consumer Law Center's 10th Annual Conference in Washington, DC, February 1996.

Presentations on "Market Power," "Environmental Aspects of Restructuring" and "Market Access for Small Customers" to Vermont Public Service Board workshops on electricity restructuring, January and February 1996.

Presentation on "Environmental Impacts of Energy: Sustainability and Social Costing" to British Columbia Utilities Commission Workshop, Vancouver, BC, March 1995.

Presentation on "Competition and Economic Efficiency" to the National Council on Competition and the Electric Industry, December 1995.

Presentation on "Compliance Planning Under Regulatory Uncertainty," to EPA "Opportunities Conference: Energy Efficiency and Renewable Energy," Washington, DC, June 1993.

Presentation on "Energy and Sustainability" to Hydro-Quebec Conference, Hampshire College, Amherst, Massachusetts, April 1993.

Invited Speaker on environmental externalities, ASME "ECO World" conference in Washington, DC, June 1992.

Invited Speaker, Association of Energy Engineers, Boston, Massachusetts, February 1992.

Presentation of Acid Rain Abatement Optimization Model to the Swedish Environmental Protection Agency, Solna, Sweden, November 1991.

Presentation on Integrated Resource Planning to Boston Gas Company, July 1990.

Training on Methods for Calculating Electric System Avoided Costs, provided to energy planners and policy makers from five Southeast Asian countries sponsored by U.S. Agency for International Development and administered by the Institute of International Education, May 1990.

Invited Speaker, National Association of State Utility Consumer Advocates (NASUCA) Mid-Year Meeting, Annapolis, Maryland, and June 1988.

Invited Speaker, Conference on New Developments in Nuclear Decommissioning Costs and Funding Methods, sponsored by the Northeast Center for Professional Education, Washington, DC, April 1988.

Exhibit BEB-2

to Environmentalists' Statement No. 2

Graph of TLG Decommissioning Estimates: 1977 to 1995

Docket No. R-00973954

Pennsylvania Power & Light Company
Restructuring Plan

Exhibit BEB-2

TLG Decommissioning Estimates (1995 $/kW)

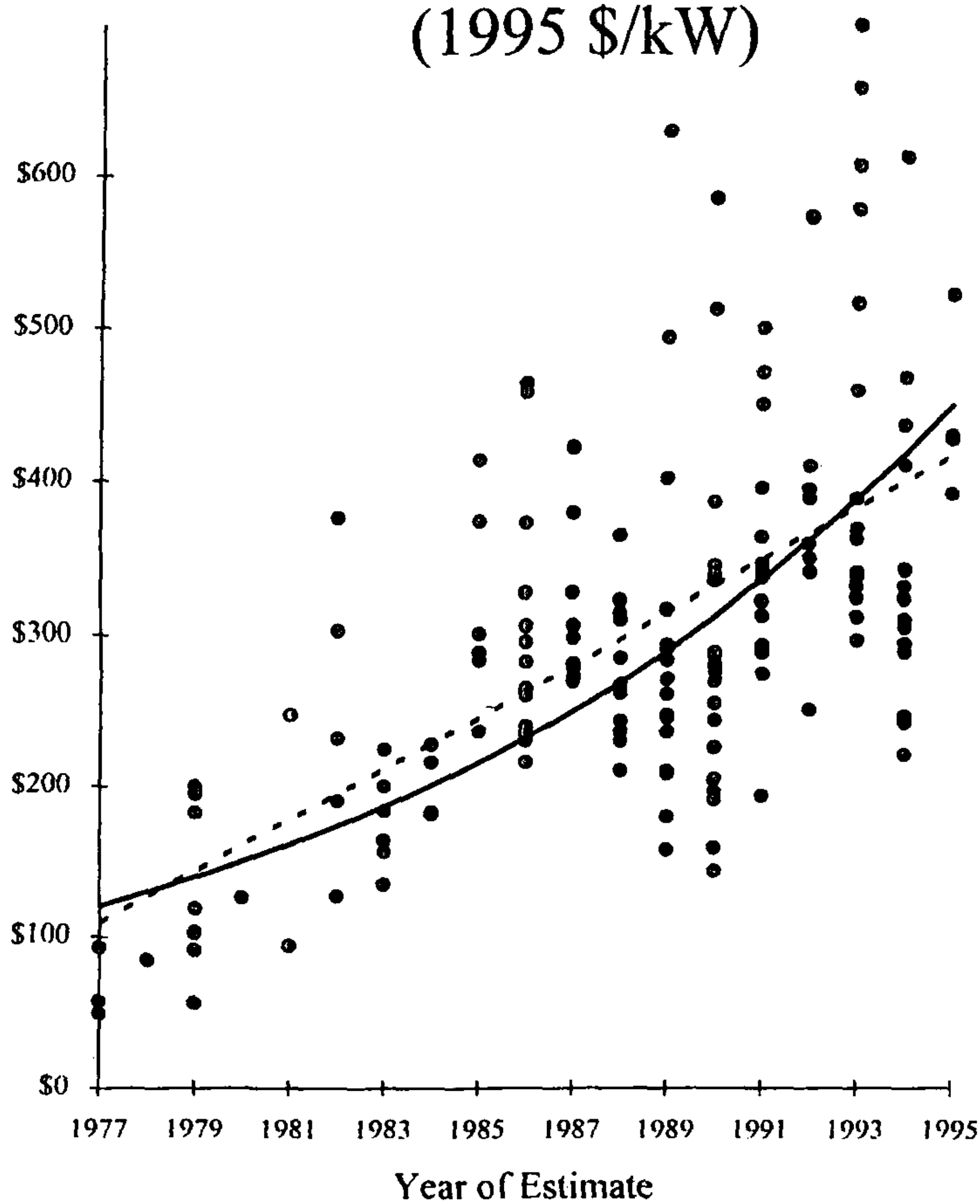

Exhibit BEB-3

to Environmentalists' Statement No. 2

Full Environmental Disclosure for Electricity: Tracking and Reporting Key Information

Docket No. R-00973954

Pennsylvania Power & Light Company
Restructuring Plan

Full Environmental Disclosure for Electricity: Tracking and Reporting Key Information

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Table of Contents

1. Introduction and Summary

Customer choice is happening quickly. In 1998 millions of retail customers in half a dozen or more states will, for the first time, choose their own suppliers of electricity. The hope is that competitive markets and customer choice will outdo traditional regulatory oversight in lowering costs, allocating risks and choosing new and clean resources. For this to happen, electricity customers — like customers in any competitive market — must be well informed. Lessons from other markets and early experience from pilot retail competition projects have shown that giving customers reliable information, preferably in a standardized format, is critical. Reflecting this, the National Association of Regulatory Utility Commissioners (NARUC) recently passed a resolution calling for the uniform disclosure standards including price, price variability, resource mix and the environmental characteristics of electricity purchases.[1] The resolution's conclusion

> ***The National Association of Regulatory Utility Commissioners (NARUC), ... believes that the electric industry should facilitate informed customer choice that will promote efficient markets, resource diversity, and environmental quality; and***
>
> ***NARUC supports initiatives leading to minimum, enforceable, uniform standards for the form and content of disclosure and labeling that would allow retail and wholesale consumers easily to compare price, price variability, resource mix, and environmental characteristics of their electricity purchases; and***
>
> ***NARUC urges states adopting retail direct access programs to include enforceable standards of disclosure and labeling that would allow retail consumers easily to compare the price, price variability, resource mix, and environmental characteristics of their electricity purchases.***

The full resolution can be found in Appendix A.

The limited retail choice pilot programs to date have featured a wide array of environmental claims by marketers (see Table 1). Power marketers often stress the environmental advantages of their product for one reason — many customers prefer environmentally benign power sources. Publicly available independent customer surveys (and presumably the marketers' own research) show that many customers prefer clean power sources and are sometimes willing to spend more to get them. As a result, environmental claims for electricity products may become a fixture of the competitive landscape.

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[1]Disclosure is factual and objective. For example a particular purchase might be 40 percent coal, 30 percent gas and 30 percent geothermal power. It does not address subjective claims, such as whether a particular purchase is good or bad, clean or dirty.

A *uniform disclosure mechanism* would give customers an accurate, objective basis for comparing the environmental (and other) claims of competitive suppliers. On the other hand, without the common language of uniform disclosure, customers must continue to sift through the vague, unverifiable, and often misleading claims that have been common in the pilots. Customer focus groups conducted with pilot program participants in New Hampshire and Massachusetts confirm consumer dissatisfaction with the "apples to oranges" comparisons they have been asked to make.
An environmental disclosure policy is desirable for many reasons. Besides giving customers an objective basis by which to compare products, it protects suppliers from unfair trade practices claims by setting clear rules of the road. It protects against customer backlash aimed at environmentally-benign resources by helping to insure that customers get what they pay for. Depending on the level of customer demand, it can result in cleaner resources and less pollution.

The main purpose of this paper is to describe how a retail electricity seller's resource mix and environmental characteristics can be tracked and disclosed to consumers. Its main conclusions are:

1) A uniform mechanism for disclosing emissions and fuel mix is feasible.

2) The long established methods of measuring generation, demand and contract rights were developed to track dollar flows and associated fuel mix and emission characteristics. These same methods can be easily adapted to provide the basis for disclosure. While many of the electric utility industry's existing institutions and market structures will change, the basic building blocks of existing settlement processes will remain and can be used for disclosure purposes.[2]

3) All of the necessary generation, fuel use and emission information needed to support disclosure is already collected. With very few exceptions the information is publicly available through federal and state agencies. For a number of reasons, we suggest that existing data and definitions be used but that new market structures or institutions, such as POOLS or ISOs collect and disseminate the information.

There are clearly a number of important tasks remaining to be done:

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[2]While developing a credible disclosure protocol is not conceptually difficult, it does require making choices and resolving many details. To add concreteness to the discussion, the report is based on some initial opinions about what might work best. For example, our discussion of tracking assumes a label like the increasingly familiar and well researched "Nutrition Facts" affixed to food provides would be used to disclose the fuel mix and environmental emissions associated with electricity purchases. See Table 2. In other instances, the choices and issues are described, and resolution is left to await the results of other ongoing research sponsored by the National Council on Competition in the Electric Industry.

1) The National Council on Competition in the Electric Utility Industry (National Council) is taking a leadership role developing disclosure standards and guidelines. A multi-part disclosure related research effort coordinated by the National Council is underway. The research is being aided by a DOE-convened interagency task force consisting of representatives from DOE, FERC, EIA, EPA, FTC and FDA. Reports will be widely disseminated as work is completed.

2) State commissions, particularly those considering retail competition, should articulate the need for full consumer disclosure to facilitate the efficient operation of a competitive market. Commissions should initiate state or regional efforts to identify options and issues and implement disclosure requirements in a timely manner. Input should be gathered from a broad cross section of stakeholders.

3) Federal and state commissions should carefully assess the extent to which the public interest in full disclosure outweighs requests for trade secret status.

4) Federal and state commissions should recognize that the formative stage of new market institutions, such as power pools and ISOs, is the best time to examine how operations can efficiently improve consumer access to key information.

2. Disclosure

2.1. What is Special about Electricity?

Why require uniform disclosure of electricity instead of relying on marketing by sellers and existing federal and state advertising laws to inform consumers? There are several answers. Uniform consumer-friendly labeling or disclosure is required in many areas. Some of most common of which are food, appliance and automobile labels and standard disclosure for consumer loans. In each case, the history (or likelihood) or customer confusion combined with societal interest in having an informed public to produce uniform disclosure.

There are several reasons that consumer protection requires full disclosure of key attributes of competitive electricity sales. Shopping for electricity is a new experience for consumers. The intangible nature of the commodity and the inability to distinguish one kWh from another will make it nearly impossible for individuals to independently determine the source of the power or to verify whether claims are true. Complex price structures make it very difficult to even compare the price of competing offers.[3] Finally, experience with the pilot programs shows a high

[3] We believe uniform labels should include a common measure of price, combining customer charges, demand charges, complex time-of-use charges and sign-up bonuses to something like an average price for typical residential consumer. Because this part of a label does not require any form of tracking (even if it does require clear standards for calculation), it is not discussed more in this report.

level of consumer confusion.

Giving consumers the information is important from a societal perspective as well. The scale of the industry's environmental impacts are far reaching, ranging from very small impacts for most renewables and new gas-fired technologies to much larger impacts for older coal-fired facilities. If electricity restructuring is to give retail customers the opportunity to make meaningful choices regarding the source or environmental nature of their electricity purchases, customers will need reliable and consistently developed information based on some sort of tracking and verification system. Likewise, to abide by state and federal truth in advertising laws, generators or marketers of electricity will need a tracking and reporting system to substantiate any environmental claims.

The challenge is to develop a workable system of environmental disclosure so that customers can make informed choices. To be workable, disclosure should provide a common standard that facilitates comparisons between suppliers in a way that balances simplicity and accuracy.

2.2. Types of Environmental Claims

It is clear from early experience with retail competition pilot programs that environmental or green marketing may be a primary tool to attract customers.[4] Retail competition pilot programs are now underway, and the promotional literature is quite useful in providing a sense of the types of claims that companies will make. Many competitors are making environmental claims presumably because they believe environmental considerations are an important factor to customers when they shop for electricity.

A list of environmental claims made by competitors in the New Hampshire and Massachusetts pilot programs, sorted by type of claim, is provided in Table 1.

This paper deals primarily with the first group of claims — those directly related to power supply, some of which can be misleading. For example, the claim that a particular supplier has no coal, nuclear or Hydro Quebec in its mix is dubious and undocumented. The implied claim that pumped storage hydro is 100 percent hydropower is probably false, given that pumped

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[4]In addition to the pilot programs, a number of "green pricing" programs are underway, prior to the introduction of retail choice of supplier. For example, Wisconsin Electric's "Energy for Tomorrow Renewable Energy Program" offers customers an opportunity to "purchase electricity generated by renewable resources" with an option allowing 25 percent, 50 percent or 100 percent of "the electricity used in your home will be displaced by renewable energy." Many of the same disclosure issues apply to either case (green marketing in a retail choice context or green pricing in a monopoly context), but the problems are somewhat more complex in a market environment due to the increased number of suppliers and aggregators, the new types of transactions (spot market, futures, etc.) and the wider array of green offerings.

storage facilities require energy from other power plants for pumping.[5]

2.3. What to Disclose?

The most fundamental questions are what to disclose generally and what to disclose in the form of a simple label. Ongoing research and decisions by regulators have begun to identify a long list of information that will be required to be disclosed to consumers (Alexander 1996). This may include consumer rights, complaint process and disconnection and payment policies. With effort, a standard one or two page document might be prepared to help consumers understand and compare key terms.

Our focus, however, is on a uniform label which, like food labels, conveys key but very limited amounts of information. Our experience suggests that a useful label (Table 2) might convey information about price, resource mix and certain environmental characteristics. This is supported by recent regulatory decisions in Vermont, Massachusetts and Maine and the recent NARUC resolution referenced earlier.

3. Tracking Transactions

3.1. Feasibility: What is it Possible to Track?

Is it possible to know where electricity at a customer's meter came from? This simple question has a complex answer because electricity follows the laws of physics, not the computations of accountants. With an interconnected grid, the power flow over the transmission system is ambiguous. About the best one can say is that power is put into the grid at certain points and taken out at other points. Which generator produced the power that went through a particular customer's meter is, in a physical sense, indeterminate, except in certain unrealistic cases.

The fact that electrons cannot be traced from a customer back to a source has not impaired the ability of power producers and power suppliers to plan their systems, choose what to build and what to buy, inform consumers and others of the supplier's fuel mix or emissions, or most important, transact hundreds of billions of dollars of transactions. For market purposes, it is sufficient to know which firms were selling into the grid, which were buying from it and where losses were occurring.

Long before "restructuring" entered the lexicon, to assure a smoothly functioning market, utilities developed mechanisms and settlements processes to track who generates, who consumes

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[5]The New Hampshire ad from Northfield Energy was one of this year's winners of the Center for Science in the Public Interests Harlan Page Hubbard Lemon award for deceptive advertizing.

and who buys. While the details vary from place to place, they all share a common basic design. For each buyer, the electrical energy taken from the system must be matched by an amount equal to the buyer's purchases, plus losses incurred in delivering such amounts to the buyer's system by the sellers. This is the basis for the dollar payments.

In looking at the dollar flow for wholesale purchases and sales, energy flow data is essentially irrelevant. Buyers pay for kWhs received from the system at a particular place; sellers are paid for

Table 1

Environmental Claims in the New Hampshire and Massachusetts Pilot Programs

Directly related to power supply:

- 100 percent hydropower (Northfield Mountain Energy)
- Working Assets Green Power does not rely on nuclear power, coal or Hydro-Quebec (Working Assets)
- "Our power sources are diversified both in fuels and geographic location. They include long-term contracts with Canadian provinces, several New England nuclear plants, and hydroelectricity from New York, Vermont and Quebec. We also get power from our own small hydroelectric generating stations, wood burning plants in Vermont as well from a variety of independent power producers in Vermont and New Hampshire." (Central VT)
- "There's no perfect way to produce electricity. There's always an impact on the earth's resources. That's why Green Mountain Energy Partners relies heavily on renewable energy sources, like hydroelectric power, that offer the most environmentally sound forms of electric generation." and "More than 90 percent of the electricity in Green Mountain Energy Partners' supply comes from hydropower sources. These sources produce zero air emissions." (GMEP)
- "...we have an unusual approach to energy-making: Water is pumped up the mountain at night and flows down during the day to drive our generators located deep inside the mountain. It's quite efficient. So much so that we pass the savings on to you." (Northfield Mountain Energy)

Indirectly related to power supply:

- permanent retirement of SO2 emissions credits (AllEnergy)
- community-based solar systems (AllEnergy)
- energy/environmental survey (Enova Energy, Northfield Mountain Energy and others)
- quarterly usage reports and rewards (Enova Energy)
- energy conservation products and services (Northfield Mountain Energy, Freedom Energy/Xenergy, Green Mountain Energy Partners, and others)

Unrelated to power supply:

- donations to environmental projects and organizations (Enova Energy, Northfield Mountain Energy, Working Assets and others)
- raffled electric vehicles (Enova Energy)

General statements:

- "solid environmental record" (Central Maine Power)
- "only energy supplier in the pilot to receive the President's Environment and Conservation Challenge Award for our long-standing commitment to protecting the environment" (Granite State Energy)
- "A company which, since its very first hydroelectric facility began operating in 1909, has treated our environment with the respect and care it deserves — planting more than a million trees; preserving our properties and their surrounding recreational lands, trails, and water supplies; helping wildlife through habitat preservation; and much more. In fact, since 1987 we have invested *over $550 million* in conservation efforts — more than any other utility in New England." (Granite State Energy)
- "A history of environmental leadership, including the installation of 'clean coal' technology at the Merrimack station, which received EPA and Governor's Energy Office awards" (PSNH Energy)
- "You'll save money, use cleaner power and..." (Working Assets)
- "Choose Wisely. It's A Small Planet" (Green Mountain Energy Partners)
- "Now is the time to start saving money and saving the planet." (Green Mountain Energy Partners)
- "It's the beginning of our long-term commitment to you and the earth." (Green Mountain Energy Partners)

kWhs delivered to the system. Except for questions of system reliability, and sometimes transmission pricing, the dollar flow is more important than energy flow. Dollar flows dictate financial risks and rewards of power plant investment, expansion, operation and retirement decisions, and these are the decisions that result in more or less environmental harm.

3.2. Settlements Procedures

The tracking system for emissions and resource mix works by following the dollars. We assume that the electricity a vendor sells and therefore the consumer "uses" is the electricity for which she pays.

For any period, there is a known amount of electricity generated and a known amount of electricity consumed. After accounting for losses and storage, these must be equal. Ultimately, the retail buyers compensate the generators, in some cases through one or more intermediaries. By following the contracts and the flow of money from retail consumers to generators, one can develop a reasonable idea of accountability.

Because of the large number of power plants, the volume and diversity of transactions and the huge flow in dollars, tracking dollars for settlement purposes is and has always been a large task. The metering and data requirements are substantial. Nevertheless, it is a task being done everywhere in the country, and one that will continue, perhaps with even greater urgency, after restructuring. Dollars are tracked in the wholesale market using the following information:

- Metered output of generators. All generators delivering power to the utility grid, regardless of location or ownership, are metered in considerable detail (hourly kWh recordings at a minimum).
- Metered load of buyers. In today's environment wholesale buyers are mostly monopoly utilities. Utility load is generally metered at the substation where power is delivered to the distribution system. In the future there will be many different types of buyers. While metering approaches will vary, all buyers will be metered in some fashion.
- Metered interconnections. All interconnections between utility systems are metered. The net flow into a service territory plus "local" generation (generation located within the service area no matter who owns it) provides a measure of the load plus losses within the service territory.
- Supply rights. Ownership rights and contractual agreements determine who has the rights to specific power sources. These will determine what sources, wherever they may be, are used to meet the load requirements in a service area.

Nationwide billions of dollars change hands based on these few pieces of data.

The following example illustrates the tracing of dollars. Figure 1 shows three utilities that

Table 2
Illustrative Environmental Labeling

Fuel Facts

Your electricity is generated from

Nuclear	**XX%**
Oil	
XX%	
Natural gas	**XX%**
Renewables	**XX%**

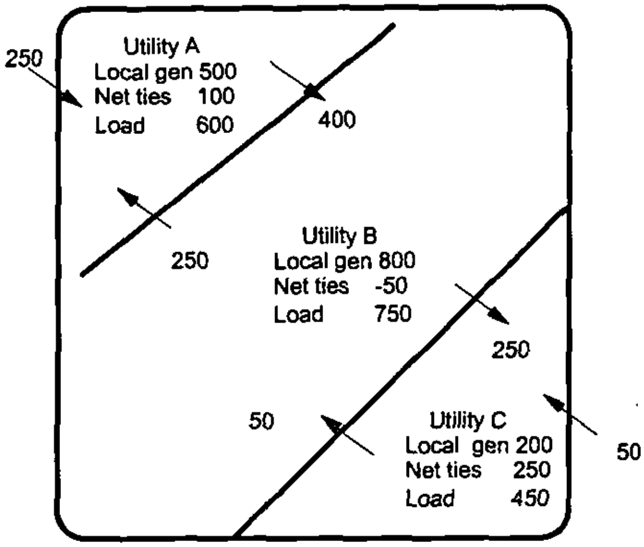
Air Emission Facts

Each of your KWh produces

	% above or below regional average
Sulfur Dioxides YYmg	**XX%**
Oxides of Nitrogen YYmg	**XX%**
Mercury YYmg	**XX%**
Fine Particulates YYmg	**XX%**
Carbon Dioxide YYmg	**XX%**

operate in a state or region with internal and external ties. For a particular hour, Utility A has a total load of 600 MW metered at all of its substations. This represents the aggregate load of all retail consumers within A's territory. Ignoring losses in the distribution system, summing the metered load of each individual retail consumer would equal the same 600 MW (assuming every consumer had real-time meters).

Figure 1



On a physical basis, A's 600 MW load is being met by 500 MW of local generation (generation physically in A's service territory, regardless of who has the rights to the output) plus 100 MW of net interchange with its interstate and intrastate interconnections.

The second half of tracing dollars and the associated supply characteristics requires knowing A's supply rights (owned generation and contracts) and balancing the dollar flow associated with A's load and supply.

In this example A, B and C are meeting their customers' needs through a mix of their own power plants and contracts from suppliers inside and outside the region. As the electric utility industry changes, A, B and C may be utilities, marketers, brokers, aggregators or deregulated generators of one type or another. Whatever their make-up, each will have an hourly demand measured or estimated at the point of retail sale. Each seller will meet its hourly demand through some combination of its own power plants and contracts for supplies from others, possibly including purchases from a spot market.

Tables 1 and 2 provide the needed information to track through our example. Table 1 provides an overview of the supply rights for A, B, and C. The first column begins with the major power flows showm in figure 1. The second column shows the supply rights. Thus we show that of the 500 of local generation in A's territory 400 MW are owned by A and 100 are owned by B.

Tables 3 and 4 provide the needed information to track through our example. Table 3 provides an overview of the supply rights for A, B and C. The first column begins with the major power flows shown in Figure 1. The second column shows the supply rights. Thus, we show that of the 500 MW of local generation in A's territory, 400 MW are owned by A and 100 MW are owned by B.

Imports and exports from metered interconnections are more complicated. A has 500 MW of incoming power flow and 400 MW of outgoing flow giving a net import of 100 MW.[6] The second column of Table 3 shows the supply rights associated with the imports and exports. The third column of Table 3 shows how each part of A's supply rights could be reflected in a disclosure statement.

[6]A has a 250 MW inflow from X, outside the region, and a 150 MW net outflow to B producing to an overall inflow of 100 MW.

Table 4 goes to the next level of detail and for each supply (owned or contract) shows the type of contract, the fuel type and emission characteristics for two pollutants. With respect to fuel mix and emissions, our example shows the source of the data depends on the type of contract. For unit contracts, the supply characteristics are those of the plants or plants involved. For system contracts, the average supply characteristics of the supplying entity can be a reasonable power from a spot electricity market.[7]

[7] In some cases, instead of being measured, hourly demand will be imputed based upon statistical load profile information or some agreed upon protocol.

Table 3

Source	Ownership/Contract	Disclosure Basis
Imports from X (outside region) Net flow X to A = 250 MW	50 MW unit contract to A 100 MW unit contract to B 100 MW unit contract to C	Part of A's average system X's average system on B's Disclosure Part of C's average system
Area A Local Generation Local generation = 500 MW	400 MW owned by A 100 MW owned by B	Part of A's average system Part of B's average system
Interchange A to B Line 1 = -250 MW Line 2 = 400 MW Net flow = 150 MW	-50 MW A generation in B area -100 MW economy purchase B to A 100 MW B's generation in A's area 100 MW pass through of X to B 100 MW pass through X to C	Part of A's average system B's average in A's Disclosure Part of B's average system See B's disclosure See C's disclosure
Area B Local Generation = 800 MW	50 MW owned by A 750 MW owned by B	Part of A's average system 650 MW Part of B's average system
Interchange B to C Line 1 = -50 MW Line 2 = 250 MW Net flow = 200 MW	100 MW unit contract from X to C 100 MW unit contract from B to C	Part of C's average system Part of C's average system
Area C Local Generation = 200 MW	200 MW owned by C	Part of C's average system
Import from Y (outside region) Net flow Y to C = 50 MW	50 MW contracted to C	Part of C's average system

Summary of Table 3:

	Firm A	Firm B	Firm C
Owned Generation - Local	400 MW	650 MW net*	200 MW
Owned Generation - External	50	100	
Purchase from X	50	100	100
Purchase from B	100		100
Purchase from Y			50
Sale to A		-100	
	-------	-----	----
Load	600 MW	750 MW	450 MW

*excludes joint ownership and unit contract

Combining loads shown in Figure 1 and supplies shown in Tables 3 and 4, we arrive at the supply characteristics for this hour for A, B and C shown in Table 5. [8]

This example focused on a single hour. In practice, the settlement process is done over a longer period, usually monthly.

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[8]In this example the mix of one seller depends on the mix of one or more other sellers, so computing the values for the label requires the solution of several simultaneous equations. As the number of participants and transactions between participants grows, the mathematical complexity increases. There are several options to simplify the calculations. For example, one could adopt a simplifying convention and assume sales to be from producer's own generation, unless the producer sells more at wholesale than it produces. If wholesale sales exceed a supplier's own generation, then the extra is assumed to come proportionately from the companies the producer purchases from. This approach allows the complex web of electricity transactions to be dealt with in a straightforward manner, avoiding the difficulties and ambiguities of tracing power transactions back through several companies.

Appendix B is a set of equations describing this system for attributing generation to retail sales in order to attribute emissions and fuel mix. The "balancing equations" describe the relationships between generation, wholesale transactions, internal sales and retail sales. All of the data required for the "balancing equations" is available from EIA, including electricity production by generating unit and owner ($P_{p,g}$), the amounts of energy and participants in wholesale transactions ($W_{p,r}$) and retail sales by company (S_r).

The "environmental equations" relate the emissions factors and fuel mix of the generating units to retail sales. These equations are simply weighted averages of the characteristics of the generators, as assigned to internal sales and wholesale transactions. The data for emissions and fuel mix are available from EPA (state and federal) and EIA, respectively.

Table 4

	A	B	C
Plant 1	owned	owned	owned
Size/output level	500 MW plant located in area A. 400 MW owned by A and 100 MW owned by B	800 MW plant located in area B. 750 owned by B, 50 owned by A, and 100 MW to C by unit contract	200 MW plant located in area C
Fuel	coal	nuclear	gas
Emissions NOx	4500 lbs/GWH	0	1
CO_2	2100 lbs/MWH	0	1
Plant 2	unit contract	system contract	unit contract
Size/output	*50 MW IPP located outside region X*	*100 MW from X located outside region*	*50 MW from Y outside region*
Fuel	biomass	X's average 50% coal 50% gas	coal
Emissions NOx	2500 lbs/GWH	3000 lbs/GWH	4500 lbs/GWH
CO_2	0	1500 lbs/MWH	2100 lbs/MWH
Plant 3	system contract	Owned	unit contract
Size/output	100 MW system purchase from B	100 MW ownership in part of A's 500 MW coal plant	100 MW unit contract from X outside region
Fuel	B's average	coal	hydro
Emissions NOx	1500 lbs/GWH	4000 lbs/GWH	0
CO_2	1000 lbs/MWH	2000 lbs/MWH	0
Plant 4	owned		unit contract
Size/output	50 MW joint ownership in B's nuclear plant		100 MW from B's nuclear plant
Fuel	nuclear		nuclear
Emissions NOx	0		0
CO_2	0		0
Total supply	600 MW	850 MW	450 MW
Local demand	600 MW	750 MW	450 MW
Off system demand	0 MW	100 MW	0 MW

Table 5

	A	B	C
Coal	70%	18%	11%
Nuclear	21%	76%	22%
Gas	1%	6%	44%
Renewables	8%	0%	22%
NOx (% of regional avg)	120%	60%	25%
CO_2 (% of regional avg)	125%	15%	10%

NEPOOL Example

The basic structure of the tracking system is the same in markets based on power pools, markets based on bilateral contracts, or any blend of the two. In markets limited to bilateral contracts, tracking is conceptually straightforward, since every transaction has an identified buyer and seller. But tracking for a power pool is not difficult. The New England Power Pool (NEPOOL) provides a good example because it consists of a complex web of buyers, sellers, generation, and contract types. It is also a good example because it functions like a competitive retail market in which financial contracts, including contracts for differences, operate independently from actual power plant operations or power flows.

Currently, NEPOOL centrally dispatches all power plants in a six-state region to minimize the total operating cost of meeting demand. Least-cost dispatch occurs without regard to plant ownership or contracts. Except for special cases, internal purchases or sales of plant ownership, contracts for plant output or contracts for system power do not affect which plant actually operates. Contract and plant ownership will affect dollar flows and, as discussed earlier, these dollar flows ultimately dictate expansion and retirement decisions.

Despite the complexity and large number of participants and contracts, all of the dollar flows in New England are based on the metering described in connection with Figure 1. The rights and obligations of each participant are written and clearly understood. This allows buyers, sellers and generators to conduct daily operations with confidence that generators will be paid, although at any particular hour, they may not know which buyer will pay the bill. The NEPOOL settlements or billing process clears monthly as is the case with bank accounts and consumer credit card statements. This monthly accounting process is, in essence, the tracking process.

NEPOOL is an especially interesting example because the many hundreds of contracts between participants take many forms (unit, system, interruptible). Yet, because the system is centrally dispatched, all of the contracts are essentially financial. This has not impaired the ability of each participant to report its own fuel mix to EIA and display it prominently in annual corporate reports.[9]

POOLCOs and Bilateral Structures

New competitive structures and new terminology do not affect the underlying need for, or the basic methods of, tracking dollars. For example, in a pure POOLCO model, aggregator A could have a power supply contract with supplier X. Assume the contract does not constrain X's operations in any way so X will be free to meet A's supply requirements as X sees fit. This means X will operate only during hours that pool prices are greater than X's operating costs. X's obligation to meet A's load during other hours will be met with purchases from the pool.

The settlements process would trace dollars based on the same basic informational building blocks as described earlier: A's metered demand, X's metered generation and the contract between A and X. POOLCO will know A's demand and X's level of operation each hour. POOLCO will also know the key terms of the contract between A and X. (This is particularly true if pool rules require sellers to meet reserve requirements by owning or contracting for minimum amounts of capacity.)

The tracking system for disclosure would work much like the tracking system for dollars. A is buying power with X's characteristics to the extent X is running. The remainder of A's needs are met with power from the pool. The pool's characteristics are the averages of all power received that POOLCO has not matched to a seller.

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[9]Annual reports to shareholders often include color graphs showing utility fuel mix and how it has changed historically. Resource diversity and particular types of supply mix are touted as reasons investors should be happy with the company. For example, after graphically displaying its 1980 and 1990 fuel mix, Central Maine Power Company's (CMP) annual report to shareholders says:

> "CMP's new resource additions are a great help in continuing our long-standing policy of diversifying our energy mix, tapping renewable and indigenous resources, promoting cost effective conservation, and reducing our dependence on oil. ... The oil-fired portion of CMP's net generation dropped to 16% in 1990, the lowest level since the early 1950s. CMP's progress, which will continue, offers economic and environmental benefits for the State of Maine at large, as well as for our customers and investors."

Suppose the market structure was bilateral with an ISO or some other settlement agent and no pool. The basic building blocks are the same: metered customer load, metered generation and contracts. Assuming the same actors as our POOLCO example, aggregator A buys from seller X. X will operate or will make separate bilateral contracts with other sellers to match X's demand. The ISO will have hourly information on X's output and on A's load. The ISO will also have basic information on A's contract with X. The information is needed because X's output (including any of X's bilateral support contracts) may be higher or lower than A's demand. To deal with this, X will buy an ancillary, balancing service from the ISO. The ISO needs the contract information to know who to charge for the balancing services.

The example can be made more complex if aggregator A buys from sellers X, Y and Z, and A sells green electricity to some consumers and regular electricity to others. In this case A's purchases are metered as are the deliveries from X, Y and Z. A's total fuel mix is determined by the relative deliveries from X, Y and Z, and the nature of the contracts. The only limitation on A's selling two products is that the weighted average mix of A's green and regular sales must match A's total mix. (See section 4.1 for discussion of sellers offering more than one product.)

Market structures, including any of the examples above, might also adopt simplifying conventions. For example, as described above, the POOL, or spot market in a region would compute and disclose the average POOL characteristics. All sellers could be given the option of using the POOL average in their own disclosures. As was the case above, the POOL average would reflect the average characteristics of all resources not specifically committed to a buyer.

In a fully competitive retail market, the information to be traced will increase significantly as the number of sellers, buyers, and transactions increases. Nevertheless, the basic building blocks of metered load, metered generation and contract administration remain the same. The details of the future settlement processes will vary depending on the market structure adopted. Some market structures will have pools, and some will not. The one constant is that all market systems and related settlements will be based on metered loads, metered output and contracts.

Suppliers A, B and C will be joined by suppliers D through Z. Those joining may be generators, marketers, brokers and aggregators. Each supplier will need to know its load just as A, B and C did. Metering may be different for different sellers, but each seller will be subject to a clearly written agreement outlining how its load will be tracked. A combination of real-time meters and simpler metering with agreed upon load profiles will be required for each supplier.[10]

Competitive markets might also include a variety of financial contracts (as distinguished from power sales contracts) that operate outside the power market and have no direct bearing on the settlements process or disclosure. For example, beyond A's power sales contract with X, A could

[10]The use of load profiles raises issues with respect to which entity takes the risk for errors in these profiles. These issues are beyond the scope of this paper.

sign an insurance policy (or contract for differences) with financial institution Y that reduces X's price volatility. Neither X nor any ISO or POOLCO would need to be aware of this side contract. Supplier X might also have a financial contract, a futures contract for example, to protect against X's risk of meeting A's load at agreed upon prices. Again, neither A nor any POOLCO or ISO would need to know about the futures contract, and if these contracts were purely financial, they would not be reflected in the disclosed fuel mix.

3.4. Data Availability Issues

The data needs for a disclosure system raise two issues. First, will disclosure require the collection of data that is not presently collected? Here the answer is a simple no. For practical purposes all of the data needed to implement resource mix and environmental labeling is already collected.[11]

Second, is the data publicly available? Here the answer is more complex. In all but a few instances the data is publicly reported somewhere. A detailed description of sources of available data is presented in Appendix C. The problems are:

1) The information is not all available on a timely basis, and it is scattered among different federal and state agencies. Data is measured and reported to the EPA, FERC, EIA or the relevant state environmental agency.
2) Some entities including some IPPs, cogenerators and power marketers either do not report all of the needed data or the data is aggregated in a way that is not useful for disclosure purposes.
3) There is a growing trend for all types of market participants to request that reported data be kept confidential.

These issues are discussed below, but our review of the issues and data suggests that an effective disclosure system can rely on current definitions and the raw data already collected. However, while no new measurements are anticipated, speedier availability of useable data is critical. To simplify the collection and reconciliation of existing data bases, the best option is to coordinate with market institutions (power exchanges and ISOs) that are starting to specify the computer software to be used in the tracking process. Software should be designed to handle resource mix and environmental information, along with all other data needed for the safe and efficient operation of the new system.

3.5. Timing

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[11] In some cases, data used for disclosure purposes will be precisely measured or metered data, and in other cases, it may include estimates such as emission factors applied to fuel input and average heat rates. In either case, the necessary degree of accuracy, probably plus or minus 10 percent can be achieved.

The time required for data to be publicly available can be considerable. The FERC Form No. 1 data, for instance, is filed in the spring for the prior calendar year. The bulk power database, a very useful compilation of information on power transactions from various forms, is currently available roughly a year after the end of the data year. In January 1997, the 1995 EIA-767 data (generation and estimated air emissions by plant) was not yet available. The quality checks done by the EPA for continuous emissions monitoring data can take six to nine months. An August 1996 EIA report discusses the data compiled from EIA Forms 860 and 861 (on generators and utilities, respectively) and states that "Data for 1993 are available at no charge on the FedWorld electronic bulletin board" (page 27, EIA, August 1996). A lag time of more than two years is probably too long for reasonable use in an environmental disclosure system for electricity customers.

State environmental agencies issue air emission licenses for essentially all stationary sources. These licenses generally require quarterly filings to be made within weeks of the close of each quarter. Emission, fuel use and generation (or a close proxy) information is publicly available from these filings, but there is no national or regional collection system to simplify collation of the information.

3.6. Coverage and Aggregation

The aggregation of transactions is currently only a problem in a very limited number of cases. The bulk power database includes detailed transaction reporting in an unambiguous way. The reporting requirements for power marketers include prices and quantities of electricity bought and sold. However, the quarterly reports of power marketers appear to lump some transactions together, even when they occur in different regions. For example, the report for a transaction between Coastal Electric Services Company and Electric Clearinghouse in the 4th quarter of 1995 lists a single quantity of electricity transacted at three delivery points: Mid Columbia, Palo Verde and PJM (January 30, 1996 letter from Michael A. Woytowich of Coastal Electric Services to Lois D. Cashell, Secretary, FERC). A disclosure system will need information on a disaggregated basis, at least differentiating by region of the country.

Non-utility generators are also significant participants in the nation's electricity supply. Disaggregated data (on generation, fuel use and emissions) for these sources is publicly available only from state environmental agencies.

3.7. Data Confidentiality Issues

Market participants, emphasizing the changing nature of the industry, are increasingly requesting that various data not be provided or, alternatively, be provided under a protective agreement. A recent and very alarming study surveyed state utility commissions and found that requests for trade secret protection for a wide variety of types of data are being routinely granted (Vine, 1996).

Three facts provide some comfort that widespread and broad-based granting of confidential treatment will not persist. First, most if not all of the requests and commission approvals have occurred before commissions began to focus on the need for consumer information to allow competitive markets to operate efficiently. Second, most requests were unopposed, and it appears they were approved more for administrative ease than as a result of a serious examination of trade secret law.

Finally, the essential data for a disclosure system includes historical generation by unit, the emissions and fuel use associated with generating resources and the buyer, seller and quantity of energy for each transaction. The preliminary conclusion of an upcoming report entitled "Full Consumer Disclosure: Confidentiality vs. Public Right to Know" is that the type of information needed for environmental and other consumer disclosure would not be protected by trade secret laws.

Some agencies, most importantly the FERC, has been more reluctant to approve requests for confidential treatment. The FERC considered and rejected utility arguments that the current information filing requirements (including the generation and transaction data necessary for a disclosure system) are unfair and should be cut back for utilities. The FERC decided that it

> "will not adopt the suggestion made by a number of commenters that we now eliminate the public disclosure of allegedly competitively sensitive, proprietary, or otherwise confidential data submitted to the Commission on Form No. 1, as well as on other Commission forms. The information that we collect for public utilities is necessary to carry out our jurisdictional responsibilities of cost-based rates subject to our jurisdiction and the operation of power markets...
>
> Accordingly, at this time, we will not change our information reporting requirements. As the industry becomes more competitive, we will monitor our reporting requirements to make sure that they are needed, fair to all segments of the industry, and consistent with the workings of a competitive environment." (pages 631 and 633, FERC, 1996).

The FERC has also recently reaffirmed the public reporting of discount rate information.[12] The Natural Gas Act requires a pipeline company to report certain information to FERC, including a shipper's name and the terms of the shipping contract.[13] Two pipeline companies objected to this level of disclosure, arguing that it unduly compromised trade secrets. They presented FERC with two options: cease the public disclosure of information that had been included in the discount

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[12]FERC Order No. 581-A, issued February 29, 1996.

[13]15 U.S.C. 717c(c).

rate reports filed by regulated gas pipeline companies and substitute customer codes for customer names in order to protect the confidentiality of customer-specific information.

FERC rejected both requests. The discount rate information was found to be necessary to the agency's efforts to prevent discriminatory pricing. Supplying customer names serves a similar purpose of enabling competing shippers to determine whether they are entitled to similar treatment. Thus the FERC concluded that the interests of the emerging competitive markets outweighed the value of keeping the terms of transactions or the identity customers confidential.

3.8. The ISO Role in Disclosure

In many regions of the country, new entities are being created (or existing entities are being modified) to support evolving electric power markets. The types of entities include regional transmission groups, power exchanges and independent system operators (ISO). The details and the roles of the various entities are currently being negotiated and will surely differ by region. In all cases, some entity or combination of entities, will be responsible for the settlement process to make sure all generation is accounted for and billed accordingly. For ease of presentation, we will refer to the entity with this responsibility as the ISO.

Masiello and Willis (1996) summarize the software development requirements for implementation of ISO functions, concluding that "the ISO's task will be an order of magnitude greater than that faced by existing utility control center operators" and will need new software integrating the capability to "track several thousand transactions daily" with "advanced power systems analysis technologies" to insure economical and secure operation of the system.

The ISO software for tracking power transactions could be required to be able to keep track of the original generating source and identify the environmental attributes of electricity at the point of retail sale. This should be built into the institutional mission of the ISO and built into ISO's computational capabilities. Over the next few years, ISOs will be obtaining hardware and software to carry out their system operation mandate. The technical specifications for the software should allow for environmental tracking — even as the details of how the tracking system will work are developed. Retrofitting the environmental tracking system into the software could be much more expensive after a system without the capability has been developed, installed, tested and paid for.

4. Other Disclosure Issues

4.1. Disclosure for Products or Companies?

A fundamental question is whether reporting should be done for particular products or for suppliers. Product disclosure allows a large company with a number of polluting power plants to develop and offer a green product. For example, under a product approach a supplier with a small wind project and 99 percent of its generation from coal could offer two products. One, amounting to one percent of its output, would be the full output of the wind project with a disclosure statement showing 100 percent renewable sources and zero emissions. The other, would be all coal, with emissions disclosure based the coal plant's performance. With supplier (or company) disclosure, on the other hand, all of the firm's sales would carry a single disclosure label based on the combined operation of the wind and coal plants. Under this approach, all subsidiaries or divisions of the same corporate parent would carry the same disclosure label. In pilots in New Hampshire and Massachusetts, four suppliers provided this type of company disclosure, which is also termed generation profile.

Our review of tracking systems shows that it is possible to report on either a supplier or a product basis, although the likelihood of there being far fewer suppliers than products makes the data requirements simpler for the supplier approach.[14] The examples used in this report nevertheless assume the more complex product approach is used.[15]

The main advantage of product disclosure is that it provides a meaningful opportunity for a large, existing company to develop and offer a green project. For example, a large existing company with little or no renewables now would have little incentive to invest in a new renewable technologies under a supplier approach because the renewable source would be too small to have any significant impact on the overall company disclosure statement.

The main policy disadvantage to product disclosure is that it could result in simply allocating clean resources to those customers who preferred it without resulting in any real change in the electricity supply system. For example, if the existing amount of renewable electricity is sufficient to "satisfy the demand" of customers who want renewable electricity, then disclosure

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[14] If a product approach to disclosure is taken, power contracts must clearly state the source of power, a practice that does not reflect current contracting conventions. Some contracts specify a source, others specify that power is from a system rather than from a particular source, and many are vague. Determining the fuel mix and environmental implications of the many types of contracts may be difficult and subject to some level of internally inconsistent treatment. A reason these problems exist now is that contracts are already included in utility fuel mix and emission reports.

There are also two reasons current practices might change in ways that make the product approach easier. First, current contracting practices take place in an industry in which fuel mix and emission characteristics are less important than they will be when disclosure and full retail competition are in place. Second, in the future to simplify retail disclosure, wholesale sales might be required to specify the associated fuel mix and environmental characteristics at the time of a sale.

[15] It may be possible to construct a disclosure system that draws upon both the product and supplier approaches, getting the benefits of each. Disclosure of the fuel mix and key environmental characteristics by all suppliers can be required on a company-wide basis, including affiliates. "Renewable" for purposes of this supplier disclosure requirement might be defined relatively loosely. This can be combined with an optional part of the label for renewables and other green options.

will not encourage the addition of new renewables.[16]

4.2. Mandatory vs. Optional Disclosure

Should disclosure be required of all sellers or only those that choose to make environmental claims or otherwise voluntarily disclose? There are many policy arguments on both sides of the question, most of which were argued at length during debates over food, car mileage, appliance labels and disclosure statements for loans and securities. Mandatory disclosure combines consumer desire to be able to compare all supply options with the public policy interest in an informed public.

Some who object to mandatory disclosure argue that it is impossible to track the required information and that disclosure should be limited to those who choose to make environmental claims. Thus, Working Assets, who buys power from NEES and sells power that includes "no nuclear, coal, or Hydro Quebec" or Northfield Energy, a subsidiary of NU, that sells "100 percent hydro" would have to disclose fuel mix and environmental characteristics, but others would not. We have two responses to this approach. First, the FTC and state consumer protection laws require that environmental claims be verifiable and substantiated no matter whether disclosure is mandatory or optional.[17] A tracking system will probably be needed if environmental claims of the type we have seen thus far are to be made by any sellers. Second, to disclose fuel mix and environmental characteristics on a voluntary basis requires the adoption of the same credible, verifiable tracking system that would be needed to support disclosure for all sellers.

Assuming a product approach is used and companies are allowed to sell their green supplies to some customers and their less environmentally-preferred supplies to others, two important considerations arise. Unlike other green products, the nature of electricity means if a supplier sells the green part of its mix to some customers, the remainder of its mix automatically becomes browner. Thus, supplier X may have a system that consists of green and not-so-green supplies. If X heavily markets its green supplies, and shows fuel mix accordingly, and then sells the remainder of its supply without any disclosure whatever, consumers may either believe that all of X's products are green or at least be unaware that X's green resources are no longer part of X's mix . To protect consumers and to reveal to them the status of X's sales of green power, disclosure of all products may be needed.

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[16]A second possible disadvantage is that a product approach may undermine label credibility if suppliers that are predominantly fossil based market a green product. Consumers might believe that power comes from all of the supplier's plants, not simply a few nominally earmarked for particular customers. This possibility is being tested in consumer research

[17]See Federal Trade Commission. *Guides for the Use of Environmental Marketing Claims.* (1996) 16 CFR 260

An important and related issue is the need to assure consumers that the same power is not being sold more than once. For example, if supplier A has 100 kW of "green" power, it should not be able to sell its green power to five different 100 kW customers. Likewise as wholesale sales of "system power" to other suppliers, B should not include any of the same green power already sold at retail. To make sure this is the case, the tracking system would need to account for all sales in a way that can reconcile the sum of the parts, or products, with the whole.

4.3 Disclosure of Wholesale Transitions

Since retail disclosure requires knowing the environmental and fuel profiles of all of the retail supplier's sources, a retail seller needs to know the mix of their wholesale suppliers. The best solution is simply to require all suppliers, wholesale and retail, to disclose their mix.

4.4. Communicating Information to Customers

What should the labels look like and where should they appear? The final answer to both questions must await completion of consumer research, but some lessons can be gleaned from the rich history of food labeling. For example, the format for disclosure should be standardized and designed to allow customers to make easy comparisons between competing suppliers. The information should be conveyed in terms that consumers understand (percentages rather than micrograms), and the information should be provided for only the most important characteristics

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Disclosure statements could be made available to customers at key decision points.

Where and how often should consumers receive the information? Customers need the information when they are faced with a buying decision. At a minimum, this means labels should appear in marketing materials and any other solicitations. Because consumers are likely to receive solicitations to switch suppliers and because fuel mix and emission information changes, customers should also receive periodic, perhaps quarterly, reminders and updates.

4.5. Treatment of Energy Efficiency and Offsets

The retail pilot programs show that environmental claims and marketing approaches often include energy efficiency and emissions offsets though other actions, not directly related to generating plants. For example, a firm might offer to plant enough trees to offset carbon dioxide emissions of their power plants. Should the disclosure labels simply reflect the emissions from generation or should the effects of energy efficiency and offsets be netted out?

For this report we focus on a disclosure and labeling system that ties retail electricity sales to generation, reporting physical attributes of that generation mix. It may be possible to include these offset options in labels, but the need to act quickly caused us to focus first on electricity sales. Clearly, firms should be at liberty to market and report energy efficiency, retirement of SO_2 emission credits, procurement of CO_2 offsets and other "environmental currency."

4.6. Timing Issues

How often should disclosure figures be recalculated? Fuel mix and emissions levels change constantly. As a practical matter, annual data, updated quarterly is probably as frequent as needed.

How often should customers receive disclosure information? Disclosure at the time of signing on with a supplier is a necessary first step. After that, suppliers could periodically notify customers of the availability of updates.

Should the information disclosed be historic or prospective? The simpler approach might be to base disclosure on actual performance in a recent historical period. The example used in this report assumes disclosure is based on periodically updated historical data.[18]

4.7. Enforcement

We do not expect enforcement of disclosure requirements to involve a large regulatory commitment. In the first instance, electricity suppliers should be responsible for determining and reporting their disclosure information, much as food suppliers are responsible for the "Nutritional Facts" labels affixed to most food items. There may be a role for a government or independent entity, such as the ISO, to monitor and spot check the information. In most, if not all cases, this could be done using information which is already being reported to various government agencies such as FERC, EPA and EIA.

5. Conclusion

Can we trace electrons or kWh from source to delivery? No.

Can we trace dollars? Yes. In fact, if we cannot trace dollars, we cannot have a competitive electricity market.

Can established dollar tracing methods be used to give consumers meaningful information about and control over the environmental consequences of their purchase decisions? Yes, but with the understanding that the information may not be 100 percent precise when viewed in the very short run (hours). When customers chose a particular supplier, they are, in essence, deciding which firm they will pay for their electricity. In making that decision, they are deciding how much and

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[18]While this might be adequate in most cases, there will be circumstances where a supplier's resource mix changes dramatically, for example due to the construction of new resources and/or the retirement of existing plants. Simple hybrid approaches can be designed to address this. A firm could base its disclosure on a prior year's actual data, but could, as an option, use its own projections. However, if the actual results were much worse than its projections, it might be required to notify consumers or be subject to a penalty of some kind.

what type of resources the firm will need to own or purchase to provide that service. The link between the purchase decision and environmental consequences is clear.

Is it practical to give consumers information? Yes. Giving consumers fuel mix and emission information is clearly practical if the information is aggregated and averaged over months or a year. Depending on the precise form of future pools, ISOs and settlement processes information, it may be practical to provide the information on a more timely basis.

Finally, what are the most important next steps? There are at least three:

1) State commissions, particularly those considering retail competition, should articulate the need for full consumer disclosure to facilitate the efficient operation of a competitive market. Commissions should initiate state or regional workgroups to identify local implementation options and issues. Input should be gathered from a broad cross section of stakeholders.

2) Federal and state commissions should carefully assess the extent to which the public interest in full disclosure outweighs requests for trade secret status

3) Federal and state commissions should recognize that the formative stages of new market institutions, such as ISOs, are the best times to examine how operations can efficiently improve consumer access to key information.

Appendix A

NARUC Resolution

RESOLUTION IN SUPPORT OF CUSTOMER "RIGHT-TO-KNOW" AND PRODUCT LABELING STANDARDS FOR RETAIL MARKETING OF ELECTRICITY

***WHEREAS**, at least 30 million consumers in six states will begin choosing among competitive electricity providers in early 1998 and retail access to competing electricity suppliers is under consideration in many other states; and*

***WHEREAS**, electricity purchases make up a significant portion of the budget of many households;*

***WHEREAS**, the production of electricity imposes very substantial environmental impacts; and*

***WHEREAS**, pilot retail access programs have shown that customer confusion and misleading claims are highly likely; and*

***WHEREAS**, clear and uniform disclosure will promote efficiency through informed product comparisons; and informed customer choice cannot occur in a retail electricity market without full disclosure of all relevant and important facts; and*

***WHEREAS**, the desirability and feasibility of such disclosure is clearly established in nutrition labeling, uniform food pricing, truth-in-lending and many other federal consumer protection programs; and*

***WHEREAS**, the National Association of Regulatory Utility Commissioners (NARUC) at its November, 1994 meeting adopted a resolution on competition and stranded benefits calling for new proposals to preserve environmental and diversity benefits in a more competitive marketplace; and*

***WHEREAS**, The NARUC at its July, 1996 meeting adopted principles to guide the restructuring of the electric utility industry which included market-based mechanisms to promote effective consumer choice and to preserve renewable resources, resource diversity, and environmental protection; now therefore be it*

RESOLVED, that The National Association of Regulatory Utility Commissioners (NARUC), convened at its 108th Annual Convention in San Francisco, California believes that the electric industry should facilitate informed customer choice that will promote efficient markets, resource diversity, and environmental quality; and be it further

RESOLVED that the NARUC supports initiatives leading to minimum, enforceable, uniform standards for the form and content of disclosure and labeling that would allow retail and wholesale consumers easily to compare price, price variability, resource mix, and environmental characteristics of their electricity purchases; and be it further

RESOLVED that the NARUC urges states adopting retail direct access programs to include enforceable standards of disclosure and labeling that would allow retail consumers easily to compare the price, price variability, resource mix, and environmental characteristics of their electricity purchases.

Appendix B

Equations for Attributing Emissions and Fuel Mix to Retail Sales

Balancing Equations:

Producer total generation

$$G_p = \Sigma_g P_{p,g}$$

Producer sales; internal and wholesale

$$I_{p=r} = G_p - \Sigma_{r(\neq p)} W_{p,r}$$

Retailer sales; from internal and wholesale sources

$$S_r = (1-L_{r,r})\, I_{p=r} + \Sigma_{p(\neq r)} (1-L_{p,r})\, W_{p,r}$$

Environmental Equations:

Producer emission factors

$$PE_{p,e} = (\Sigma_g E_{p,e,g} P_{p,g}) / G_p$$

Retailer emission factors

$$RE_{r,e} = (PE_{r,e} I_{p=r} + \Sigma_{p(\neq r)} PE_{p,e} W_{p,r}) / S_r$$

Producer fuel mix

$$PF_{p,f} = (\Sigma_g F_{p,f,g} P_{p,g}) / G_p$$

Retailer fuel Mix

$$RF_{r,f} = (PF_{r,f} I_{p=r} + \Sigma_{p(\neq r)} PF_{p,f} W_{p,r}) / S_r$$

Variables:

$E_{p,e,g}$	Emission factor of type e for generating facility g of producer p
$F_{p,f,g}$	Fuel fraction of type f for generating facility g of producer p
G_p	Total generation for producer p
$I_{p=r}$	Internal company sales
$L_{p,r}$	Loss factor associated with transfers from p to r
$P_{p,g}$	Production from generating facility g of producer p
$PE_{p,e}$	Producer average emission factor
$RE_{r,e}$	Retailer average emission factor
$PF_{p,f}$	Producer average fuel mix factor
$RF_{r,f}$	Retailer average fuel mix factor
S_r	Retailer r sales
$W_{p,r}$	Wholesale sales from producer p to retailer r

Subscripts:

e	Environmental impact category (e.g. SOx, NOx, CO2. …)
f	Fuel type (e.g. Coal, Oil, Gas, Hydro, Nuclear, …)
g	Generating facility
p	Producer
r	Retailer (p=r means same company)

Appendix C
Available Data

Environmental Data

Data on air emissions from power plants is measured by utilities using continuous emissions monitoring systems (CEMS). This data is collected by the EPA and entered into the EPA's emission tracking system (ETS). The coverage of power plants is good . A "complete" database should be available for 1996, omitting only units less than 25 MW and some cogenerators and independent power producers. The EPA conducts quality control checks, summarizes the information and makes it available on the Internet. The EPA has developed specific technical rules for continuous emissions monitoring including the treatment of missing data, record keeping, quality assurance and reporting (40 CFR Parts 9, 72, and 75, *Federal Register,* Volume 60, No. 95, May 17, 1995). The data include emissions of SO_2, NO_x and CO_2, as well as the heat input of the fuel used. Sources of information on emissions data include EPA reports (EPA, 1995, and personal communication with Richard Morgan, Manager, Utility Regulatory Program, Acid Rain Division, US EPA).

There is also a voluntary program for reporting greenhouse gas emissions. While 12 of the 15 highest emitting utilities reported their CO_2 emissions for 1995, the overall coverage of this program is poor, with reported utility CO_2 emissions at only 43 percent of estimated national total electric utility CO_2 emissions (EIA, July 1996).

A great deal of environmental information is available at the state level. Any facility, utility or non-utility, requiring an air emission licence reports all major emissions and fuel input. The data generally reported quarterly, within a few weeks of the close of a quarter.

Generation and Fuel Use Data

The EIA collects and publishes data on electric power plants in the US, specifying the owner, capacity, fuel type and other parameters. Form EIA-860, collected on an annual basis from 900 electric utilities, is summarized and made available in print (EIA, October 1995) or electronic form (http://www.eia.doe.gov). Information specifically on renewable generation is published by the EIA in its Renewable Energy Annual (EIA, December 1995) and in the Renewable Electric Project Information System (REPIS) developed by the National Renewable Energy Laboratory (described in Appendix DISCO of EIA, December 1995). A key limitation of these sources appears to be that they focus upon capacity and do not provide figures for energy generation.

The EIA also collects a great deal of information on fuel use for power generation, most notably the Uranium Industry Annual Survey (Form EIA-858), the Monthly Report of Cost and Quality of Fuels for Electric Plants (Form FERC-423), EIA Form -860 The Annual Electric Generator Report, EIA-759 The Monthly Power Plant Report, and the Annual Report of Major Electric Utilities, Licensees, and Others (Form FERC-1). A private company summarizes key data from the FERC-1 and offers the information for sale on disk (see, for example, UDI, 1996).

A useful summary of data for steam generators in the U.S. is the EIA-767. This is collected annually from 893 respondents and includes information on generators, including owner, generation by unit, fuel use by type and boiler, boiler efficiency, in-service year, emissions control equipment and air emissions. This data is available on disk from the EIA.

Data on generation from plants that are not owned by electric utilities is collected from 1400 non-utility power producers on Form EIA-867. This data includes capacity, fuel use and generation. It is made available only in highly aggregated form (e.g., on a state-level) and so is not very useful for an environmental disclosure system.

Data is also available at the state level. Any generator requiring an air emission license reports fuel input data from which generation can be estimated. In addition, if IPPs or QFs sell to regulated utilities, monthly generation and payments may be available in reports to PUCs.

Electricity Transaction Data

Data on wholesale electricity transactions is collected on seven different forms:

- FERC Form 1 — Annual Report of Major Electric Utilities, Licensees and Others
- FERC Form 1-FERC — Annual Report of Nonmajor Public Utilities and Licensees
- Form EIA-412 — Annual Report of Public Electric Utilities
- Form EIA-861 — Annual Electric Utility Report
- Form FE-781R — Annual Report of International Electrical Export/Import Data

- REA Form 7 — Financial and Statistical Reports (Electric Distribution Borrowers)
- REA Form 12 — Financial and Statistical Reports (Electric Power Supply Borrowers and Electric Distribution Borrowers with Generating Facilities)

The EIA summarizes this information and publishes it in printed form (Electric Trade in the United States 1992, EIA September 1994). Even better, the electronic version of this data is available on-line and with standard EIA codes for companies that make it possible to link the transaction database with other EIA data (e.g., Form EIA-860).

The wholesale electric trade data, also sometimes referred to as the bulk power trade data, is comprehensive, even redundant in its coverage. For most transactions, it has information reported by both the buyer and the seller, providing an opportunity to check for consistency. Transactions are identified as exchanges, purchased power, sales for resale or wheeling. The main limitation on the usefulness of the trade data is that it takes a year or more for the EIA to pull the database together.

Another potentially useful source of information on power transactions is the FERC Form No. 714, the "Annual Electric Control and Planning Area Report." This includes identification of generating plants in the control area, monthly aggregate outages, monthly loads and transactions, hourly loads and marginal costs. The hourly information is provided in electronic form. The high level of aggregation (control areas such as PJM, NYPP and NEPOOL are made up of many companies) makes this data unsuitable as a basic source of information for disclosure. The control area data may, however, be useful as a supplementary source, perhaps for assigning attributes to imported power from a neighboring control area that is not functioning under the same disclosure protocols.

Finally, power marketers, whose numbers are increasing rapidly, file their transaction information in quarterly power marketer reports to FERC. It seems likely that over time, the information filing requirements for power marketers and for utilities will converge. A standardized requirement for monthly or quarterly reporting would probably work better for environmental disclosure than annual reporting.

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Environmentalists' Statement No. 3-SR

8/27/97
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w/ H

Before the

Pennsylvania Public Utility Commission

Pennsylvania Power & Light Company Restructuring Plan

Docket No. R-00973954

DOCUMENT FOLDER

Surrebuttal Testimony of

Peter A. Bradford

P.O. Box 497
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Dated: August 15, 1997

Q. What is your overall reaction to the testimony of Dr. Alfred Kahn.

A. I am very glad to have Dr. Kahn participate in this proceeding for several reasons:

First, PP&L's decision to enlist him at this stage seems to acknowledge the unpersuasiveness of the earlier and more extreme Pennsylvania utility positions, including Dr. Kalt's original testimony asserting the existence of a regulatory compact compelling full recovery of all investment not found to have been imprudent[1].

Second, as his testimony states, we do not differ in our fundamental conclusion regarding the power of the Pennsylvania Commission to condition recovery of strandable investment on the achievement of other necessary goals.

Third, Dr. Kahn's testimony offers an opportunity to clarify genuine differences of view in ways that may prove useful to the Pennsylvania Commission.

Q. You do have points of concern then with Dr. Kahn's testimony?

A. Yes. For example, Dr. Kahn says that he agrees with me (Kahn testimony, p.3) regarding the absence of a binding regulatory compact that compels recovery of all prudent expenditure. He then says that my method of presenting this conclusion invites excessive disallowances and opportunistic behavior. However, several of Dr. Kahn's major presentations on this topic have been more vulnerable than mine to misuse in the direction of mandating full recovery not "expressly conditioned on full utility cooperation in achieving the best result for customers and the environment in the years ahead".

My testimony (pp. 4-6) contains a explicit safeguard against such misuse.

Dr. Kahn's principal past papers on strandable investment have contained no such explicit admonitions against interpretations in favor of an absolute right to full recovery. Indeed, the Edison Electric Institute put the 1994 paper authored by Drs. Kahn, Baumol and Joskow (whose cautionary note is buried midsentence on page 24) into the FERC Open Access NOPR in support of full and mandatory recovery[2] .

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[1]See also the testimony offered by Messrs. Sidak and Brennan on behalf of PECO Energy.

[2]William J. Baumol, Paul L. Joskow, and Alfred E. Kahn, "The Challenge for Federal and State Regulators: Transition from Regulation to Efficient Competition in Electric Power," stating at p.24, "A failure now of policy makers to ensure the companies <u>at least some reasonable level</u> of recovery of their regulatorily approved costs in any transition to competition would leave investors, in effect, with part - a very large part - of the value of their property expropriated by the change in the rules of the game." (emphasis added) When Dr. Kahn wrote a

That paper contained no caution along the lines of "Does the presence of a societal compact compel regulators to require full recovery....? No. The presence of such a compact compels no such result". If it had, the risk of expensive misunderstanding would have been diminished.

Q. Since you and Dr. Kahn apparently agree that the Commission has wide latitude to condition recovery of strandable investment on the achievement of its view of the public interest within the statutory framework, are the remaining areas of disagreement of any consequence?

A. They do allow me to return Dr. Kahn's favor by protecting him from those who, conceivably emboldened also by his recent branding of many state regulators as "kleptocrats[3]", would misuse his testimony to argue for mandatory recovery of all investment not specifically found to have been imprudent. To that end, several further points are necessary.

First, Messrs. Kahn, Kalt and Moul seem to assert that strandable investment in Pennsylvania is occurring entirely because Pennsylvania is deciding to open its retail markets to competition. Therefore, they assert, government is "changing the rules".

In fact, strandable investment has several interdependent causes. It is not brought on only or even primarily by Pennsylvania's decision to permit retail competition[4]. It is at least as much a product of advances in less costly generating technology, compounded in some circumstances by surplus capacity at current prices. It is for this reason and not to encourage "regulatory opportunism"[5] (surely supine allowance of 100% recovery without full protection of other

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separate piece for the October 1994 Electricity Journal, one reader's misunderstanding of his position led to an extended clarification in the December 1994 issue, "I have systematically refrained from making recommendations about the extent of the entitlement of utility companies to recover their sunk costs...It has been my consistent explicit policy to leave such determinations to regulators on the basis of considerations of equity, the likely effect of disallowances on the future cost of capital and assessments in the particular circumstances of the extent to which investors might properly be held to have had foreknowledge of the possibility of the change in the rules to their disadvantage or to have been compensated for such risks." at p.80.

[3]Speech at Electricity Journal conference, Florida, June, 1997.

[4]For reasons discussed in my original testimony, even strandable investment brought on by government decisions has generally not given rise to successful claims for a right of compensation.

[5]Dr. Kahn implication of regulatory "opportunism" on my part (especially pp.16-17, lines 19-3) is not easy to reconcile with his endorsement of the principles upheld by the New York PSC in the 1989 Shoreham settlement in the face of the public sentiment which he describes (pp.11-12). Nor is it consistent with my support of his efforts to get NARUC to endorse marginal cost pricing

legitimate interests is also "regulatory opportunism", perhaps even "kleptocratic") that I pointed out that restructuring at a time when marginal costs were equal to embedded costs would not have given rise to claims of confiscation or opportunism.

Even without the recent Pennsylvania law, wholesale competition coupled with low cost generation, surplus capacity and Pennsylvania's historic position regarding generation not found to be used and useful could produce substantial disallowances of high cost generating plant from rates. Indeed, even with the new law, the statutory provision (Section 2803) defining recoverable investment as that "which traditionally would be recoverable under a regulated environment....." is not as clear in endorsing full recovery of prudent investment as Dr. Kahn asserts , given the Pennsylvania "used and useful" decisions evoked by the word "traditionally".

Of course, investment stranded by competition and by surplus capacity has never been entitled to constitutional protection, so the claims of Pennsylvania utilities must depend ultimately on Pennsylvania's satisfaction with the eventual overall restructuring bargain.

Q. Is this position consistent with the Shoreham result alluded to by Dr. Kahn?

A. Yes. Dr. Kahn's discussion of Shoreham (Kahn testimony, pp.11-13) is instructive in two respects.

First, it illustrates the differences in traditional regulatory practices between New York and Pennsylvania. Pennsylvania commission and court decisions have emphasized the used and useful standard far more stringently than have comparable decisions in New York. I doubt that the 1989 Shoreham settlement would have been sustained in Pennsylvania.

Second, the Shoreham settlement embodies exactly the principle that Dr. Kahn and I agree on. It conditioned the opportunity for full recovery of almost all of the prudent investment in Shoreham on Lilco's agreeing to convey the plant to the Long Island Power Authority, a result that the state did not necessarily have the power to order directly. If Lilco had adopted the view that it had an absolute right to recover its prudent investment and had continued its insistence on running Shoreham as well, the settlement would not have been reached. It was no accident that the ALJ's more sweeping endorsement of a right to recover prudent investment in all circumstances was not approved by the Commission[6].

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in 1975-76.

[6]Similar principles produced similar results during my term on the Maine Commission in 1986-87, when the Maine utilities sold their shares of Seabrook in return for assurances of an opportunity to recover the prudent investment in that plant. In that case also, the utility recovery of nearly all of the prudent cost depended on their cooperation in larger ends that the Commission did not have a clear power to achieve through direct order.

Q. Do you agree with Dr. Kahn's imputation of "significance" (Kahn testimony, footnote 5) to your not having cited commission decisions adopting Professor Bonbright's suggested remedies?

A. Dr. Kahn, with equal significance, makes no claim that Commissions have not done so. Certainly a number of Commissions have adjusted depreciation schedules and returns on equity to reflect shortened service lives or changes in risk. Apparently neither of us has reviewed the Pennsylvania practice in this regard.

Q. Do you advocate retroactive ratemaking (Kahn testimony, p. 19, line 4) when you point out that utilities have historically earned returns comparable to unregulated industrial companies?

A. No. My point was that utility investors have historically been compensated at rates comparable to those available in firms that faced the full range of market risks, including very large possible losses when the imbedded costs of the utility exceeded the costs of their competitors.

Q. What response do you have to the rebuttal testimony of Dr. Kalt?

A. Dr. Kalt's testimony improves the points made in his original testimony but does not introduce new considerations. His general discussion of "the rules of the game" (at pp.49-58) is not specific to Pennsylvania, where - as my original testimony makes clear - investors have never had reason to believe that all investment not disallowed as imprudent would be recovered.

As my original testimony establishes (pp. 18-20), investors had a degree of notice, growing throughout the 1980s, that electric competition was a possibility. They had absolute notice that six and seven figure losses in electric utility investments without imprudence findings were possible, especially in utilities with large nuclear construction programs. They knew that Pennsylvania, in particular, had a strong policy requiring that investment be used and useful even after entering rate base. They had the published view of the chief spokesman for Pennsylvania utilities:

> "Show me the investor who will put his money into electric utility securities under existing (Pennsylvania) conditions and I'll show you the embodiment of the principle that a fool and his money are soon parted[7]".

In short, the Queensberry ideals laid out by the PP&L witnesses and the "the rules of the game" that have shaped the legitimate expectations of Pennsylvania investors seem quite different.

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[7]Vincent Butler, "A Social Compact to be Restored", Public Utilities Fortnightly, 26 December, 1985, p 17-21, at 20.

Q. But could investors have foreseen that the Pennsylvania Legislature would pass a law in late 1996 mandating retail competition?

A. In his novel Gravity's Rainbow, Thomas Pynchon wrote something along the lines of "If they can keep you asking the wrong questions, then they don't have to worry much about the answers."

The foreseeability of retail competition in the electric power industry has grown steadily throughout the 1980s, and - as my original testimony notes - it was seriously discussed by Pennsylvania state government 15 years ago. However, investors are not entitled to specific notice of the nature and timing of each and every risk. Indeed, uncertainty is by definition a component of risk. Furthermore, as noted above, strandable investment is not exclusively the product of government policy and could occur in Pennsylvania even if the 1996 law had not been enacted.

Q. Mr. Moul suggests that investors have not been compensated for the risks of stranded investment and seeks to discredit "the William Foley study". Does his testimony require modification of yours?

A. No. Mr. Moul dismisses the Foley study (presumably the study by Michael Foley and Ann Thompson referred to in my testimony) for several reasons that are unconvincing. His points regarding the foreseeability of retail competition and investor risk in Pennsylvania are rebutted above. In addition:

1) *His specific concerns about the 1972 - 1992 period as being atypical do not take into account* the fact that the Foley study was performed at least twice during the 1980s and reached similar conclusions. While I do not have the earlier versions, I believe that they covered earlier time periods, negating Mr. Moul's concerns about events in 1972 (Moul testimony, p. 32). These concerns are baseless in any case because the multiple holding period technique used by Foley and Thompson would smooth out abnormalities arising from events in a particular year. Finally, several of the 1972 factors cited as abnormal by Mr. Moul work against utility investors, thereby reducing their gains relative to industrial investors and reinforcing the Foley/Thompson conclusions.

2) The update of the Foley Thompson results performed by Mr. Moul still shows utility returns, and PP&L in particular, to be in the same range as the S&P industrials, despite virtually unprecedented S&P performance in recent years. Such growth, of course, tends to depress the relative performance of utility stocks which are generally less volatile. Mr. Moul's testimony does not make clear whether he duplicated the multiple holding period technique used by Foley and Thompson to diminish the impact of such unique events. If he did not, then the impact of the recent events is magnified further.

Q. Does this conclude your surrebuttal testimony?

A. I would like to conclude by reiterating that my testimony does not compel or endorse full disallowance of prudently incurred investment. It seeks to assist in providing a framework within which legitimate expectations can be balanced to achieve a comprehensive restructuring. It also rebuts claims that entitlements to recover all investment not disallowed as imprudent must be honored before negotiation or decision regarding other aspects of restructuring can proceed.

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August 15, 1997

Mr. James J. McNulty, Acting Prothonotary
Pennsylvania Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17105-3265

RE: PP&L Restructuring Proceeding, Docket No. R-00973954 - Surrebuttal Testimony

Dear Mr. McNulty:

Enclosed is a Certificate of Service pursuant to 52 Pa. Code §5.412(f) for filing the surrebuttal testimony and exhibit of David Schoengold, Bruce Biewald, and Peter Bradford on behalf of the Environmentalists in the above referenced docket.

Also enclosed is our office copy which we would appreciate having time-stamped for our files.

If you have any questions, please do not hesitate to contact us.

Sincerely,

Mary Lou Morin

Mary Lou Morin
Secretary to Alan Barak
Attorney for the Environmentalists

/mlm
Enclosure

cc: Service List