Environmentalists' Statement No. 3

Before the

Pennsylvania Public Utility Commission

Application of PECO Energy Company
for Approval of its Restructuring Plan
Under Section 2806 of the Public Utility Code

Testimony and Exhibits of

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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 been involved with 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, PECO'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, and (3) nuclear plant decommissioning costs. These specific issues represent a portion of *The Environmentalists' Vision for the New Electricity Marketplace*, an Exhibit to the Environmentalists' Statement No. 1, the testimony of Joseph Oates Minott. 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, and
- nuclear plant decommissioning costs will be managed carefully and shared equitably.

My testimony should also be considered in conjunction with that of David Schoengold and Roger Colton 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.

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.

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

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

issues.

A. 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 PECO's nuclear decommissioning obligations is about $22 million per year (Cohn direct testimony in the securitization case).
- PECO's filing in this case includes $71 million per year for nuclear decommissioning. One portion of this ($37 million) is the "ongoing" annual contribution, albeit at an increased level, and the other portion ($34 million) is in the CTC for the years 1999 to 2005 to make up for the current "estimated fund deficiency" (sources: Hill Exhibits TPH-3, TPH-4, and TPH-5, page 26 in each; and Cohn Exhibit ABC-1, Schedule 10, page 4).
- PECO has suggested that nuclear decommissioning costs "remain with the 'wires' business" and that a substantial increase in decommissioning expense could be passed on to customers as "one of the exceptions to the rate cap" of the Electric Competition Act (Cohn direct testimony, page 16).
- PECO has provided little justification in its filing for the increase in its annual decommissioning cost.
- PECO 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.
- PECO's estimate of its estimated nuclear decommissioning fund deficiency (Cohn Exhibit ABC-1, Schedule 4, page 1) is only one of several ways that the calculation could be done.

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

- PECO's nuclear decommissioning cost obligation is currently estimated by the Company to be $1.5 billion in today's dollars. This amount is large, very uncertain,

and to some extent within the control of the plant owner.

- PECO'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.

I recommend the following with regard to nuclear decommissioning costs:

- PECO should not be allowed to increase its annual decommissioning cost for purposes of its stranded cost calculation in this case above the currently approved amount of $22 million.
- For any additional costs for decommissioning that PECO is allowed to recover through the CTC or to include in its stranded cost calculations, PECO 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 PECO 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.
- PECO 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.

My findings and recommendations with regard to spent nuclear fuel storage are:

- The spent nuclear fuel from operation of a nuclear power plant is much more radioactive than the plant components themselves.
- PECO has been collecting and paying to the Department of Energy the one mill per kWh fee for nuclear spent fuel disposal.
- PECO's filing includes the ongoing one mill per kWh fee in its projections of nuclear fuel costs (Exhibit TPH-2) and hence these costs for spent nuclear fuel disposal "have been reflected in the calculation of the market value of PECO's nuclear units" (Hill direct testimony, page 10).
- PECO has also included costs of onsite dry case storage of spent nuclear fuel in its decommissioning cost estimates in this case (Exhibit TLG-1, Section 4, page 19; Exhibit TLG-2, Section 4, pages 15 and 16; and Exhibit TLG-3, Section 4, page 14).
- The U.S. Department of Energy has been slow to accept responsibility for spent nuclear fuel from commercial nuclear power plants.
- PECO 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.
- PECO 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 issues are discussed in Section 5 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.

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:

- 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. 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 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.

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 for companies is preferable to one for 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 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. 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 disclosure 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 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 is 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 is 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.

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. The

Testimony of Roger Colton, Environmentalists' Statement No. 4, touches upon this issue.

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 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. (Quoted from the attachment to Environmentalists' Statement No. 1)

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 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 of 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. 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. 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. 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 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.

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." (Exhibit to Environmentalists' Statement No. 1)

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

- The currently approved annual cost amount for PECO's nuclear decommissioning obligations is about $22 million per year (Cohn direct testimony in the securitization case).
- PECO's filing in this case includes $71 million per year for nuclear decommissioning. One portion of this ($37 million) is the "ongoing" annual contribution, albeit at an increased level, and the other portion ($34 million) is in the CTC for the years 1999 to 2005 to make up for the current "estimated fund deficiency" (sources: Hill Exhibits TPH-3, TPH-4, and TPH-5, page 26 in each; and Cohn Exhibit ABC-1, Schedule 10, page 4).
- PECO has suggested that nuclear decommissioning costs "remain with the 'wires' business" and that a substantial increase in decommissioning expense could be passed on to customers as "one of the exceptions to the rate cap" of the Electric Competition Act (Cohn direct testimony, page 16).
- PECO has provided little justification in its filing for the increase in its annual decommissioning cost.
- PECO 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.
- PECO's estimate of its estimated nuclear decommissioning fund deficiency (Cohn Exhibit ABC-1, Schedule 4, page 1) is only one of several ways that the calculation could be done.

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

- PECO's nuclear decommissioning cost obligation is currently estimated by the Company to be $1.5 billion in today's dollars. This amount is large, very uncertain, and to some extent within the control of the plant owner.
- PECO'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:

- PECO should not be allowed to increase its annual decommissioning cost for purposes of its stranded cost calculation in this case above the currently approved amount of $22 million.
- For any additional costs for decommissioning that PECO is allowed to recover through the CTC or to include in its stranded cost calculations, PECO 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 PECO 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.
- PECO 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.

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.
- PECO has been collecting and paying to the Department of Energy the one mill per kWh fee for nuclear spent fuel disposal.
- PECO's filing includes the ongoing one mill per kWh fee in its projections of nuclear fuel costs (Exhibit TPH-2) and hence these costs for spent nuclear fuel disposal "have been reflected in the calculation of the market value of PECO's nuclear units" (Hill direct testimony, page 10).
- PECO has also included costs of onsite dry case storage of spent nuclear fuel in its decommissioning cost estimates in this case (Exhibit TLG-1, Section 4, page 19; Exhibit TLG-2, Section 4, pages 15 and 16; and Exhibit TLG-3, Section 4, page 14).
- 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:

- PECO 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.
- PECO 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 PECO's stranded cost calculation

Q. How does PECO treat nuclear decommissioning costs in its estimate of stranded costs?

A. There are two places where nuclear decommissioning costs are reflected in PECO's

stranded cost calculation -- the fund deficiency and the ongoing decommissioning expense accruals. Mr. Cohn estimates the fund deficiency will be $236.9 million at the end of 1998 (Exhibit ABC-1, schedule 4). This amount is included in the $6.8 billion total stranded cost estimate (Exhibit TPH-7), and appears in the CTC in an amount of $33.8 million per year (Cohn Exhibit ABC-1, Schedule 10, page 4).

In addition, PECO includes an annual amount of $36.7 million for nuclear decommissioning in its market revenue calculations. The unit-specific contributions are as follows (from page 26 of Exhibits TPH-3, THP-4, and THP-5):

	Annual Decommissioning Expense (1000$)
Limerick 1	$8,780
Limerick 2	$10,753
Peach Bottom 2	$4,380
Peach Bottom 3	$5,611
Salem 1	$3,497
Salem 2	$3,687
Total	$36,708

This amount is the same in every year through 2013, at which point it is expected to decline with each unit's retirement through the year 2029, at which point the last of PECO's nuclear units, Limerick 2, is projected to retire. These same annual decommissioning costs are used in all three of PECO's calculations of stranded costs -- in Mr. Bustard's market revenue estimates, in Dr. Venkateshwara's market revenue estimates, and in Dr. Hieronymus' market revenue estimates. Mr. Cohn points out that

> decommissioning expense that accrues on and after January 1, 1999, will be an element of the ongoing operating and maintenance expenses of the Company's nuclear generating units. That cost, like other components of operating and maintenance expense, is a deduction from the market price of generation. As such, these prospective decommissioning expense accruals must be reflected in the calculation of the market value of the Company's nuclear generating assets. (Cohn direct testimony, page 13)

Q. How does the annual amount for decommissioning included in PECO's stranded cost calculation compare with what it currently collects in rates for decommissioning?

The amount of decommissioning costs assumed in PECO's stranded cost calculation is

$36.7 million per year, not counting the amount of decommissioning costs requested by PECO in the CTC. This is 60 percent higher than the $22 million per year that PECO currently is authorized to collect in its rates for decommissioning (Cohn direct testimony in the Securitization case, page 10). With the CTC amount of decommissioning costs added, the annual amount of decommissioning costs that customers would pay according to PECO's filing is $67.6 million. This is an increase of roughly 200 percent.

PECO should not be allowed to raise the decommissioning cost numbers without a proper review. The stranded cost calculation for PECO should not include this higher number unless and until the Commission has examined the changes in underlying assumptions, and made an informed decision about whether the changes are appropriate and how the additional costs should be allocated between customers and shareholders.

Nuclear decommissioning costs and stranded cost mitigation

Q. What is the estimated magnitude of PECO's nuclear decommissioning costs?

A. PECO has estimated its nuclear decommissioning cost to be $1.5 billion as of year-end 1998 (Cohn direct testimony, page 11, line 3).

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

A. No. PECO'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 PECO's nuclear units.

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 PECO 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 PECO'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 PECO 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 PECO's units shut down early there will be a net deficit in the funding available to decommission the units.

Q. How do PECO's nuclear units compare in terms of operating economics?

A. In my *Electricity Journal* paper, I identified Salem as one of the ten at-risk plants. Similarly, an assessment by Donaldson, Lufkin & Jenrette based upon Systematic Assessment of Licensee Performance (SALP) reviews, production costs, and capacity factors put Limerick in the top quartile, Peach Bottom slightly below the middle, and Salem at the bottom with the lowest possible overall score (*From Top to Bottom - III: A Study Benchmarking Performance of U.S. Nuclear Power Plants*, July, 1996). The INGAA report put Limerick in the group of "sites that are cost competitive with regional price" and Peach Bottom and Salem in the group of "sites that are vulnerable to shutdown.

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.

Bankruptcy of a utility is a serious possibility. Mr. J. Barry Mitchell discusses securitization and the "steps ... taken to isolate the asset and its revenue stream from the credit risks of the original owner of the asset, such as the risk that the owner will go bankrupt." (Mitchell direct testimony in PECO's securitization case, page 4) This same notion applies in the case of nuclear decommissioning funding. That is, it is important to isolate the decommissioning funds from the Company itself, to ensure that the funds will be available for decommissioning.

Q. Does PECO 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 PECO 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. I understand that PECO has accelerated the depreciation of some of its generating assets (Exhibit TPH-8) and that this is one of the mitigation strategies identified in Section 2808 (c)(4) of the Restructuring Act. Accelerating decommissioning funding, in order to reduce the fund deficiency, would be a similar activity.

Indeed, there is a logic to using the same asset life for both depreciation of plant construction costs and funding of decommissioning costs. At this point, based upon the limited information available to me, it appears that the Limerick plant's life for depreciation accrual is 10 years shorter than its assumed life for decommissioning funding. If there is to be a difference in the assumed life, decommissioning should use a shorter life assumption, as the recovery of decommissioning costs has a public health and safety dimension.

Also, 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 PECO program to minimize the billion-plus dollars in 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 PECO 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 securitization of stranded costs. PECO'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 PECO that it take clear and significant efforts to mitigate its future nuclear stranded investment. PECO'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 PECO'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 PECO's customers will be asked in the future to pay for additional, as-yet-unfunded nuclear decommissioning costs.

Q. Is it efficient for PECO 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 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.

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.

We should not rely on this 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 PECO Energy. For instance, PECO may in the future spin-off of its nuclear assets into generating companies that lack the solid funding of the T&D monopoly. As the formerly PECO nuclear plants 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 shutdown 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. 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. PECO proposes that the Commission "establish a separate charge for nuclear decommissioning expense as part of the Company's transmission and distribution business" (Cohn direct testimony, page 16). Do you agree with this proposal?

a. I agree with PECO'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.

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 utilities' 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, based upon informal discussions, 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. 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 PECO's filing, these costs of spent nuclear fuel disposal are included in the nuclear fuel cost projections (Exhibit TPH-2) and hence "have been reflected in the calculation of the market value of PECO's nuclear units" (Hill direct testimony, page 10). If these costs are understated then the plants 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.

Q. Does this conclude your testimony?
a. Yes.