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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY FOR APPROVAL OF ITS RESTRUCTURING PLAN UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE	:	Docket No. R-00973953

DIRECT TESTIMONY

OF

DOUGLAS C. SMITH

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PROTHONOTARY'S OFFICE

On Behalf of:

OFFICE OF CONSUMER ADVOCATE

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TESTIMONY OF DOUGLAS C. SMITH

PECO Market Price Testimony

Introduction

Q: PLEASE STATE YOUR NAME, CURRENT OCCUPATION, AND BUSINESS ADDRESS.

A: My name is Douglas C. Smith. I am a Senior Utility Analyst at La Capra Associates, 333 Washington Street, Boston, MA 02108.

Q: PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A: I received a Bachelor of Science degree in Mechanical Engineering from Brown University, Providence, Rhode Island, in May, 1986. I joined the Vermont Department of Public Service ("the Department") as Power Cost Analyst in 1986, and was promoted to the position of Electrical Planning Engineer in 1988. My responsibilities at the Department included the examination of electric utility power costs for ratemaking purposes, the analysis of short and long term power purchases, and other electric utility planning analyses.

Since joining La Capra Associates in 1991, I have worked for a range of clients in the energy industry, including regulated utilities, state regulatory agencies, non-utility power producers, and customers. I have performed dispatch simulations of numerous electric utility systems -- including the New England Power Pool, the Puerto Rico Electric Power Authority, the state of Maharashtra (India), and numerous individual U.S. utilities -- to examine the cost and reliability implications of alternative resource choices and planning assumptions. I have conducted solicitations for electric energy and capacity transactions, and have managed the power supply of the Vermont Electric Cooperative, Inc. since 1991. I have provided expert testimony regarding electric utility planning issues, avoided costs, and power costs in the context of rate cases. A copy of my resume is attached as Exhibit DCS-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to review the evidence that PECO Energy Company ("PECO") has presented regarding the future market price of electricity in the PJM market. Specifically, my testimony will address the testimony and market price analyses presented by PECO witnesses Bustard, Hieronymus, and Venkateshwara. My testimony will:

- Critique the methodologies and input assumptions that the PECO witnesses have used in their market electricity price analyses;
- Present an alternative analysis of market electricity prices for the PJM area, based on a detailed simulation of the PJM system using more appropriate assumptions.
- Discuss the determination of stranded costs for PECO, in the context of an integrated PJM power market.

Q. PLEASE SUMMARIZE YOUR MAJOR FINDINGS.

A. My primary findings are as follows:

- The PECO market price analysis conducted by Dr. Hieronymus of Putnam, Hayes and Bartlett ("PHB") -- which is used by Mr. Hill to develop the Company's stranded generation costs -- relies on a flawed methodology which inappropriately defines and calculates the clearing price of electric energy. This methodological flaw causes PECO's generation market revenue forecast to be systematically understated. To the extent that PECO's actual market prices and generation revenues turn out to exceed the Company's forecasts for this reason, PECO will obtain a windfall at ratepayers' expense.
- Some PECO generating units will obtain additional revenue from at least one market product (operating reserves); these revenues are not reflected in PECO's market price analyses;

- Some of PECO's assumptions regarding the costs of new electric generation sources are optimistic, and tend to understate future generation market prices.
- I have conducted an alternative generation market analysis, based on publicly available generation and load data, which provides a more appropriate basis upon which to estimate PECO's stranded generation costs. I project a net contribution toward fixed costs significantly higher than that projected by PECO witness Hieronymus.
- Actual market electricity prices will, of course, differ from today's projections. The Commission should keep in mind the potential variation of market price outcomes when evaluating the magnitude of PECO's stranded costs, and the amount of stranded cost which PECO should be allowed to recover through a competitive transition charge. The Company's market price analyses have not defined the range of potential net generation revenue, or tested the likely symmetry of risk between ratepayers and the Company regarding the potential alternative outcomes.

<u>Critique of PECO's Market Energy Price Methodology</u>

Q. PLEASE EXPLAIN HOW PECO REPRESENTS THE GENERATION MARKET.

A. Each PECO market price witness represents the generation market in terms of two primary components: capacity and energy. The energy market is described as an hourly interaction between supply (all the available generating units in PJM) and demand; each witness simulates this interaction using a dispatch simulation model. The capacity market is described in terms of fixed payments in exchange for the right to call on the seller's electric energy, and the clearing price for peaking capacity is assumed to equal the annualized price of a new combustion turbine.

Q. PLEASE SUMMARIZE YOUR FIRST CONCERN WITH THE METHODOLOGY THE COMPANY USED TO DEVELOP ITS ESTIMATES OF THE ENERGY CLEARING PRICE IN PJM.

A. The market energy price is a very important component of the stranded cost analysis, because in the restructured PJM energy market, all generating units selected to operate in PJM at any given time will receive the single PJM market energy price. An important concern is that two of PECO's three analyses (specifically, those developed by PHB and EDS) base the market energy price on the **incremental cost** of changing the output of the marginal generating unit(s) during a given hour or period, rather than the average cost. In contrast, the market price analysis sponsored by ICF represents each generating unit using a single heatrate, intended to reflect the average efficiency of the unit during its operation (including operation at less efficient part load conditions).

The marginal generating units in PJM are typically coal or oil units which feature a declining heat rate curve. That is, the thermal efficiency at low output levels is low, and at most output levels the incremental rate of fuel required per incremental kWh output is less (in some cases, much less) than the average rate of fuel per kWh at that output level. If the PJM market energy price were based on the incremental heatrate of generating units bidding in the market, it would be systematically lower than the actual fuel costs incurred by the marginal unit (and potentially many other units with similar variable costs). In other words, energy bids priced on this basis would often be inadequate to recover the generator's variable costs.

Q. IS THIS A REASONABLE EXPECTATION IN A COMPETITIVE GENERATION MARKET?

A. No. Dr. Hieronymus recognized this possibility of "negative cost recovery," and noted that such an outcome would not be in the interest of generating unit owners. Dr. Hieronymus expects that the problem will be resolved either through pool rules or through generating unit owners increasing their bid prices.

For the purpose of his PECO analysis, Dr. Hieronymus addressed the negative cost recovery problem by reviewing his dispatch simulation to identify each loading cycle during which one or more generating units fail to recover their variable costs. He then computed the additional revenue (above the market energy price) that each such unit would require to recover its variable costs (but no more), and assumed that each unit would receive such additional revenue through an "uplift payment." The uplift payments were not, however, added to the energy market price.

Q. IS IT APPROPRIATE TO ASSUME THAT PECO'S FUTURE GENERATION MARKET REVENUES WILL BE BASED ON THE METHOD IN DR. HIERONYMUS' ANALYSIS -- WITH MARKET ENERGY PRICE BIDS BASED ON INCREMENTAL GENERATOR HEATRATES, AND UPLIFT PAYMENTS ASSIGNED TO THOSE GENERATORS THAT FAIL TO RECOVER THEIR VARIABLE OPERATING COSTS FOR A CYCLE?

A. No, it is not. Assigning uplift payments only to select suppliers, and excluding them from the market energy price, would cause the energy market price to systematically understate the actual value of energy to PJM -- that is, the decremental energy costs which PJM incurs through the commitment and dispatch of suppliers' generating units. An understated market energy price would send an incorrect (low) price signal, and would fail to encourage the least-cost amount and type of generating capacity and external purchases.

Q. YOU HAVE JUST PRESENTED A THEORETICAL DISCUSSION CONCLUDING THAT DR. HIERONYMUS' ESTIMATE OF THE MARKET ENERGY PRICE IS UNDERSTATED. HOW SIGNIFICANT IS THE OVERSTATEMENT?

A. The significant magnitude of this issue can be illustrated by examining the results for two types of PECO generating units. First, Dr. Hieronymus projects that in 1999, Eddystone Units 3 and 4 (which total 780 MW, and are projected to be marginal generating units in PJM) will be dispatched to produce about 1,586 Gwh, incurring a cost of about \$44.2 million (\$27.8/MWh) for fuel, and an additional \$0.5/MWh for variable O&M costs. For that output, Dr. Hieronymus projects that Eddystone 3 and 4 will receive energy market revenue of about $35 million, for an average of $22.1/MWh. Dr. Hieronymus projects that while the system operator will find it cost-effective to operate Eddystone 3 and 4 during a significant fraction of hours, the market energy price during those same hours will be far less than even the units' fuel costs. His analysis assumes that an additional $10 million (more that $6/MWh of annual output) will be paid to Eddystone 3 and 4 through uplift payments that other generators operating in the same hours (i.e. PECO's baseload coal and nuclear units) do not receive.

Similarly, Dr. Hieronymus projects that in 1999, PECO's 835 MW of existing combustion turbine units will be dispatched to produce about 15 Gwh, at an average fuel cost of about $250/MWh (representing significant operation at inefficient part load output levels). For that output, Dr. Hieronymus projects that the combustion turbines will receive energy market revenues of about $1 million, for an average of about $66/MWh. During those same hours, Dr. Hieronymus projects that the combustion turbine units will also be paid an additional $3 million (almost $200/MWh), through uplift payments which other generators operating in the same hours do not receive.

Clearly, if the market energy price were estimated to include the actual operating costs of the most costly units selected to operate in each hour, the resulting market energy price and generation revenues could greatly exceed those projected in Dr. Hieronymus' analysis during some hours.

Q. IN THE FRAMEWORK THAT PECO HAS USED TO PROJECT FUTURE MARKET ENERGY PRICES, IS IT INAPPROPRIATE TO INCLUDE ANY SORT OF "UPLIFT CHARGES"?

A. Not necessarily. I understand that in Dr. Hieronymus' analysis, the need for uplift payments arises from two situations. The first situation is when generating units are assumed to bid energy into the market at only their incremental variable cost of production, and are dispatched in economic order. Since (as discussed above) incremental variable costs of many generating units are lower than their average variable costs, the highest-cost generating units dispatched in each hour may fail to recover their variable costs of operation through the market energy price. In Dr. Hieronymus' analysis, this appears to occur regularly. Dr. Hieronymus identified this problem of "negative cost recovery" and he expects that the problem will be resolved either through pool rules **or through generating unit owners increasing their bid prices** compared to the incremental prices reflected in his analysis. Importantly, Dr. Hieronymus' analysis does not address this latter possibility. If we assume (as Dr. Hieronymus has) that the solution will be a set of pool rules that assign uplift charges only to generating units that fail to cover their variable costs, then the resulting energy price signal will systematically understate the market's decremental cost of energy production. Rather than assuming an awkward uplift payment process that yields an economically inefficient price signal, it is appropriate to assume that affected generating units will increase their energy bids to levels that are sufficient to cover their variable costs. PECO witness Venkateshwara has utilized this approach in his analysis, and I will utilize it in my own market price analysis (discussed below).

The second situation in which uplift charges may be required is during periods (likely offpeak) when one or more generating units are dispatched out of economic order, in order to ensure that their output will be available in later peak hours. In this instance, the system operator is incurring "additional" costs during some hours in order to obtain greater savings in other hours, minimizing the market's total cost of energy. In this instance, it would be appropriate and economically efficient to cover the generator's shortfall in variable costs through an uplift payment, and to exclude the uplift payment from the market energy price.

Without a burdensome review of Dr. Hieronymus' uplift charge calculation, we cannot know precisely what fractions of his projected uplift charges are attributable to the two situations that I have just described. However, the Eddystone and combustion turbine examples described in the previous response suggest that a large fraction of the projected uplift charges are attributable to the first situation (economic dispatch), and that Dr. Hieronymus' market energy price projection is significantly understated.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH THE IMPLEMENTATION OF UPLIFT CHARGES IN DR. HIERONYMUS' MARKET PRICE ANALYSIS?

A. Yes. Putting aside my concerns with a potential system of cost-based energy bids and uplift payments, it appears that if the PJM market were to actually utilize such an approach over the long term, the magnitude of the payments would be greater than those Dr. Hieronymus has assumed. Specifically, Dr. Hieronymus calculates uplift charges whenever they are necessary to produce a zero net cycle cost -- that is, for a generator's market energy revenues during a particular start/stop cycle to equal its variable costs during the cycle. Dr. Hieronymus allows hours of positive and negative energy revenue to offset one another, so that during cycles which contain some negative hours but are positive on the whole, no adjustment is made. I believe that this calculation is flawed from at least two perspectives, and if an uplift payment is assumed for some generating units, that the payments should be calculated on an hourly basis to reflect each unit's projected no-load and operating costs.

Q. PLEASE EXPLAIN.

A. Sections 1.6.1 and 1.6.2 of the revised Operating Agreement of the PJM Interconnection outline a system in which: a) each market seller will submit binding offers for energy and related services, along with startup and no-load fees for resources with minimum notification or startup requirement greater than 24 hours; b) The Office of the Interconnection will select pool-scheduled resources "on the basis of the prices offered for energy and related services, startup, no-load and cancellation fees, and the specified operating characteristics offered..." and c) sellers selected as pool-scheduled resources will receive payments for each of the items in its binding offer. In short, if it is cost-effective (from the perspective of the pool) to operate a seller's generating unit, then the pool will accept the seller's binding offer and pay each price component of that offer. In contrast, Dr. Hieronymus' analysis appears to assume that the pool will pay only those components of the offer required to ensure that the seller's revenues for each start/stop cycle exceed its variable operating costs. Setting aside the precise wording and implementation of PJM scheduling procedures, it seems unrealistic to assume that in a competitive market, a seller will be content to absorb losses (through no payment or partial payment of startup and no-load costs) in some hours, even when that seller is the pool's most cost-effective energy resource.

Two other U.S. electricity markets (California and NEPOOL) envision market-based bids for energy and related products. The PJM Interconnection presently requires that offers for energy or other services on the PJM Interchange Energy Market be cost-based. This requirement, however, pertains "unless and until the FERC shall authorize the use of market-based prices in the PJM Interchange Energy Market..."

In conclusion, even if one were to assume that a system of incrementally-based energy market prices is implemented for a sustained period, it seems likely that the associated uplift charges would be implemented to compensate sellers for their variable costs on an hourly basis, not only across a full operating cycle. The result will be higher revenues for some PECO generating units (namely Eddystone 3 and 4, and the Company's combustion turbine units) than those simulated in Dr. Hieronymus' analysis.

Q. PLEASE EXPLAIN HOW THE COMPANY'S MARKET PRICE ANALYSIS ADDRESSES START-UP COSTS.

A. Start-up costs represent fuel consumed during startup, and labor and other operating costs associated with startup. The generation market price projections developed by PHB and EDS exclude start-up costs from the derivation of the energy market price. Start-up costs make up only a minor portion of operating costs for most generating units, but they are legitimate, unavoidable operating costs that thermal generating units will incur. The ICF analysis, which I understand approximates each thermal generating unit's energy bid based on its as-operated heatrate, implicitly captures the fuel burned during startups. I will use the same approach in my PJM market price analysis.

Q. TAKING INTO ACCOUNT YOUR DISCUSSION OF INCREMENTAL HEATRATES, STARTUP AND NO-LOAD COSTS, AND UPLIFT CHARGES, HOW SHOULD BIDDERS IN THE PJM ENERGY MARKET BE REPRESENTED?

A. For the purpose of forecasting PJM energy market prices, it is appropriate to represent the energy bid of each thermal generating unit based on the unit's "as-operated" average heatrate, which reflects the unit's actual operating role in the electric system.

For units that are operated strictly at full load, the "as operated" heatrate will tend to approximate the unit's full load average heatrate. For units that are operated regularly at less efficient partial output levels, the as-operated heatrate will tend to exceed the full load average heatrate. The as-operated heatrate reflects the realistic efficiencies incurred by thermal generating units during operation (including low load and cycling conditions), and captures the fuel consumed during startups.

Q. DO PECO'S ANALYSES IN THIS CASE REFLECT ALL LIKELY SOURCES OF REVENUE FOR THE COMPANY'S GENERATING UNITS?

A. No, PECO's generation market price and revenue projections do not include generator revenues which some of its generating units will receive for ancillary services, such as operating reserves. In addition to procuring energy to meet PJM's hourly loads, and installed capacity sufficient to provide reserve against unexpected generating unit outages, the system operator will also need at all times to purchase adequate operating reserves to maintain system reliability in the event of fluctuations in generation or loads. Some PECO generating units (in particular, pumped storage hydro and oil steam units) may be economical sources to provide operating reserves. To the extent that they are selected to do so, these units will receive some amount of revenue that is not reflected in either

PECO's revenue estimates or my own. The magnitude of the operating reserve market will be secondary to those for energy and capacity, but revenues could be significant for particular generating units.

Q. HOW HAS THE COMPANY REPRESENTED THE COSTS OF EMISSION COMPLIANCE IN ITS MARKET PRICE ANALYSIS?

A. The Company has approximated the effect of emission constraints related to SO_2 and NOx emissions by including emission allowance "adders" in the dispatch price of emitting units. While I have not exhaustively analyzed all of PECO's assumptions on the subject, the Company's approach appears reasonable.

It is not clear whether the Company's dispatch assumptions reflect an effective plan with respect to control of sulfur dioxide emissions. In particular, the Company's market price analysis appears to assume that its coal-fired generating units will continue to burn coal with the same sulfur content as has been burned in the past. To the extent that additional compliance measures (such as fuel switching of one or more existing coal units to more expensive lower sulfur coal) are required to control So_2 emissions, PECO's projection of market prices would be understated.

It is also possible that additional compliance measures will be needed, to control emissions of NOx or small particulates. I have not attempted to quantify the potential effect of stricter requirements for these emissions.

<u>Critique of PECO Input Assumptions</u>

Q. HOW DO FUEL PRICE ASSUMPTIONS AFFECT PECO'S ESTIMATES OF GENERATION MARKET PRICES AND STRANDED GENERATION COSTS?

A. PECO owns numerous generating units, which burn a range of fuels. As a result, the Company's future operating costs will depend in part on the delivered cost of those fuels, which include coal; natural gas; residual oil; distillate oil; and uranium. Specifically, PECO generates the majority of its electricity with nuclear and coal-fired units; oil and natural gas play a limited role.

The market prices that PECO will receive for the output of its generating units will also depend significantly on fuel prices. However, those prices will depend primarily on the fuel prices faced by the "marginal" generating units in the PJM electricity market -- those units that tend to operate during high demand periods, but not on an around-the-clock basis. In PJM, the margin is defined primarily by coal, oil, and gas-fired sources. Nuclear and hydroelectric sources will rarely (if ever) define the market price.

Because PJM's fuel mix (and those of most Pennsylvania utilities) differs significantly from the fuel mix that will define PJM market energy prices, changes in fossil fuel prices will affect PECO's generation market revenues more strongly than its generation costs. To the extent that actual fossil fuel prices turn out significantly higher than forecast today, the Company could reap much greater market revenues than expected from its generating sources, substantially lowering the Company's actual stranded generation costs. For example, in Docket R-00973877, OCA witness Richard La Capra illustrated that a hypothetical 10 percent increase in fuel costs would reduce PECO's stranded generation costs by about $586 million.

Q. HAVE YOU REVIEWED THE FOSSIL FUEL PRICE ASSUMPTIONS UPON WHICH PECO'S MARKET PRICE ANALYSES ARE BASED?

A. Yes, I have reviewed the Company's approach, although not the fuel price assumptions for each and every generating unit in the PJM market. PECO's generation market price analyses begin with recent historical fuel prices in a general sense, but do not utilize the same specific fuel prices. I understand that each PECO witness developed base year fuel prices for each PJM generating unit or station based on a review of his own historical price information, and in the format (i.e. annual, monthly, etc.) suitable to his production cost model.

With respect to escalating base year fuel prices, the market analyses sponsored by PECO witnesses Bustard and Hieronymus utilized fuel price escalation rates for Middle Atlantic Electric Utilities from the DRI McGraw-Hill World Energy Service's U.S. Outlook, Fall/Winter 1996/1997 ("DRI forecast"). PECO witness Venkateshwara sponsors an analysis based on a fuel price forecast developed by his firm, ICF.

Q. PLEASE SUMMARIZE YOUR FINDINGS WITH RESPECT TO FUEL PRICE ASSUMPTIONS.

A. A review of PECO's fuel price assumptions yields several apparent inconsistencies. First, since all three PECO market forecasts rely on historical fuel prices and the same escalation forecast, one would expect their specific fuel price figures to be similar. In fact, the analyses feature significantly different prices for some PECO generating units. In addition, the PECO witnesses' base year fuel price assumptions all appear to be lower than the actual prices reported in the Company's 1996 FERC Form 1.

PECO'S filing in this case does not present the Company's specific fuel price assumptions for 1996. Instead, the market price witnesses' exhibits present some sample prices for 1999 and other years, and Thomas Hill's Exhibits TPH-3 through TPH-5 present the assumed energy rate (in dollars per MWh) for each PECO generating unit. Exhibit DCS-2 presents the fuel price assumptions used by the PECO witnesses for several PECO fossil units in 1999, the first year of their market analyses. Exhibit DCS-2 includes the Company's actual 1996 fuel prices (as reported in the Company's FERC Form 1), inflated to 1999 using the DRI fuel price escalators. Notably, the Company's 1996 fuel price assumptions for each fossil unit (except seldom-used combustion turbines) are lower than the 1996 actual. This result suggests that the Company's projections of generation revenues and net market revenues are understated, and that its estimate of stranded generation costs is therefore overstated.

Second, the presentation of DRI fuel prices in Exhibit JFB-5 does not accurately represent the Company's fuel price assumptions. While the exhibit presents annual fuel prices (in \$/MBTU) for three fuel types, I understand from Mr. Bustard that these specific values were not used in PECO's analysis. Rather, the Company based its analysis on recent historical fuel prices for each generating unit, and applied only the escalation rates from Exhibit JFB-5. Further, the column on Exhibit JFB-5 labeled "oil" represents the projected average price paid for several oil products -- that is, a weighted average in which the mix of oil products changes over time. The underlying DRI projections for the price of residual and distillate oil are each lower than those in Exhibit JFB-5. Exhibit DCS-3 summarizes these underlying oil price escalation assumptions which were actually used in PECO's analysis.

Third, a review of PECO Exhibit TPH-4 (sponsored by Thomas Hill, and illustrating the results of Dr. Venkateshwara's analysis) shows an increase of more than 20 percent in the delivered price of coal at Keystone station between 1999 and 2000. Dr. Venkateshwara's Exhibit BSV-2 does not show this increase. I discovered this apparent discrepancy only recently, and was not able to determine its basis. It is possible that this change represents an intended change in the type or price of fuel (such as an assumed switch to lower sulfur coal). To the extent that the fuel price increase is in error, Dr. Venkateshwara's market price estimate would be overstated.

Q. HOW DO MULTI-FUEL GENERATING UNITS AFFECT PJM MARKET ELECTRICITY PRICES?

A. In addition to the prices of various fuels, future market energy prices will also depend in part on the mix of fuels burned by generating units in PJM. For this reason, the representation of dual-fuel units is relevant to PECO's market price analysis. For example, if a particular generating unit were able to burn a less costly fuel (such as natural gas) during summer but needed to burn a more costly fuel (such as residual or distillate oil) during winter, that unit would need to charge a higher price for its output during hours when only oil is available. Several generating units in PJM, amounting to more than 2,000 MW, burned substantial fractions of more than one fuel during 1996. I have not been able to verify whether in their market price analyses, the PECO witnesses represented dual fuel units in PJM based only on their less expensive fuel, rather than on the mix of fuel actually being burned. This method would tend to understate the bid prices of such generating units, and therefore to understate the market energy price in PJM. Because multi-fuel units are at times PJM's marginal resources, the degree of understatement could be significant.

Q. PLEASE SUMMARIZE HOW VARIABLE O&M COSTS FOR EXISTING GENERATING UNITS ARE REPRESENTED IN THE COMPANY'S MARKET PRICE ANALYSES.

A. Each of PECO's market price witnesses has represented the energy bids of existing PJM generating units as the sum of projected fuel costs and variable O&M costs. I believe that this is an appropriate approach to use in the analysis of PJM generation market prices.

I have a concern, however, regarding PECO's specific implementation. For coal-fired generating units in which PECO has ownership, all three PECO witnesses used the same variable O&M assumptions: \$3.38/MWh for Cromby, \$4.07/MWh for Eddystone 1, and \$3.24/MWh for Eddystone 2. My concern is that for PJM coal units not owned by PECO, Dr. Hieronymus and Mr. Bustard each assumed a significantly lower variable O&M cost of about \$2.00/MWh, in 1997 dollars. These assumptions would suggest that variable O&M costs at PECO's coal units are roughly twice those incurred by all other PJM coal units. I am not aware of why this would be the case. To the extent that O&M costs at other PJM coal units are comparable to PECO's assumptions for its own units, then each of the Company's estimates of market energy prices is understated by some amount.

To the extent that the variable O&M rate at PECO's coal units is actually comparable to that of other PJM utilities, then either the Company's projection of its future generation costs is overstated or its projection of future market prices is understated. In either instance, PECO's estimate of stranded generation costs would be overstated by at least several million dollars per year.

<u>New Generating Capacity</u>

Q. WHAT GENERATING CAPACITY OPTIONS DOES PECO ASSUME WILL BE AVAILABLE IN PJM TO MEET DEMAND GROWTH AND ATTRITION OF EXISTING GENERATING UNITS?

A. Each of PECO's market price witnesses assumes two primary options for new electric generating capacity in PJM. For peaking duty, large scale, simple cycle combustion turbine ("CT") units were assumed to be available for construction when needed. For baseload and cycling duty, PECO assumed that large scale combined cycle combustion turbine ("CC") plants burning natural gas would be available. Based on current planning assumptions, these two options represent the most cost-effective generation options for their respective operating roles.

Q. WHAT GENERAL ASSUMPTIONS DOES PECO MAKE FOR THESE OPTIONS?

A. There have been substantial improvements in the CT and CC technologies in recent years, resulting in substantial thermal efficiency improvements. The PECO witnesses assume heat rates for new capacity options consistent with advanced equipment that is just reaching commercial production, and is expected to be available during the next several years.

In addition, the capital cost of CT and CC plant equipment has declined significantly in recent years, due in part to these same technological improvements (i.e. increasing the output of particular units). This price decline appears to also reflect increased competition among suppliers of combustion turbines and ancillary equipment. PECO has estimated the cost of future CT and CC plants based on current market conditions, which reflect a historical low point; it is not clear whether this market-based price decline will be sustainable.

Q. PLEASE COMMENT ON THE SPECIFIC CAPITAL COSTS THAT PECO HAS ASSUMED FOR THE CC AND CT OPTIONS.

A. Each PECO market price witness developed his own capital cost assumptions for the CC and CT options. For the year 2002, the assumed capital cost per kW for the CC option ranged from \$525/kW to \$625/kW; the assumed capital cost per kW in 2002 for the CT option ranged from \$322/kW to \$379/kW.

Dr. Hieronymus derived his CC and CT capital costs by assembling the estimated cost of specific plant components and associated interconnection costs, and is therefore a useful point of reference from which to review the Company's capital cost assumptions. The PHB analysis begins with the estimated turnkey cost of turbine/generator equipment based on a recent industry survey; these estimates appear to be reasonable. Dr. Hieronymus' derivation of combined cycle capital costs includes specific cost assumptions for most major plant items (such as electrical and gas interconnection costs). This approach appears reasonable as far as it goes, but for both the CC and CT units it lacks the following significant items:

- Interest during construction. While expected development and construction periods have shortened somewhat in recent years, a CC or CT project cannot be developed overnight. Installation of a new CC unit will likely require at least one year, plus additional time beforehand for project development, permitting, and financing. Assuming a construction period interest rate of 10 percent per year, even a conservative average financing period of six months would add five percent to the effective capital cost of a new unit.
- Project development costs, which would include expenses to support the legal, financing, and permitting efforts needed to develop a successful project. The Gas Turbine World 1996 Handbook, which is Dr. Hieronymus' source document for

the cost of turbine/generator equipment, states: "...not included are the indirect, or so-called 'soft costs' that can significantly increase the overall project budget costs. These soft costs would include interest during construction, financing and legal fees, licensing and permitting, insurance and bonding, workman's compensation, sales tax, extensive inland freight, owner's cost and overhead, and finally, project contingency funds." For projects of significant size, such as those assumed by the PECO witnesses, the development costs alone would conservatively amount to at least several million dollars.

In addition to the items above, actual new generating units may require the following additional features and costs:

- Selective catalytic reduction ("SCR") equipment for control of NOx emissions on combined cycle units. The turnkey equipment costs utilized by Dr. Hieronymus is intended to include dry low-NOx burners, but specifically excludes equipment for catalytic reduction of NOx or CO_2 emissions. To the extent that SCR is required for new generating units built in some areas of PJM, additional capital and operating costs will be required for CC units.
- Non-standardized plant features. As noted in The Gas Turbine World Handbook, there are tradeoffs in plant design between a plant's cost on the one hand, and its expected thermal efficiency and reliability on the other hand. For example, combined cycle units with the most complex and efficient steam cycles will tend to cost more, as will units with reliability features such as a bypass stack or multiple shaft design. The Handbook goes on to state: "These turnkey plant price levels, as noted, are for 'plain vanilla' plant equipment and services. Extended site work such as cogeneration process steam or utility plant tie-ins are not covered, nor are extensive buildings, nor a large inventory of operational spares such as combustor baskets, blades and vanes, etc." I believe that PECO's witnesses have assumed quite competitive reliability (annual availabilities on the order of 90 percent) and thermal efficiencies (heatrates significantly better than units constructed even

several years ago) for new CC units, making it unlikely that they will also feature the cheapest designs.

Finally, Dr. Hieronymus assumed significant scale economies (i.e. lower costs per kW) for significant factors such as electrical and gas interconnection, and infrastructure costs, by assuming that CT and CC plants will be developed in configurations with 1,000 MW of new capacity at a single site. This assumption appears achievable at some stations, but may be optimistic as a general planning assumption. On the other hand, Dr. Hieronymus assumed that such infrastructure costs would be required at all new facilities. In actual practice, some new units will probably be able to reduce capital costs by locating at existing generation sites, and utilizing one or more types of existing infrastructure.

Q. WHAT CAPITAL COSTS DO YOU BELIEVE ARE REPRESENTATIVE FOR THE CC AND CT OPTIONS IN THE PJM MARKET?

A. In view of the factors discussed in the previous response, I conclude that the PECO witnesses' assumed capital costs are plausible, but somewhat optimistic. With the objective of obtaining a reasonable base case estimate, I therefore adopted initial capital costs of $550/kW ($1996) for the CC option, and $290/kW ($1996) for the CT option. These capital costs are approximately equal to Dr. Hieronymus' capital cost assumptions, adjusted for conservative estimates of two additional cost factors: interest during construction, and project development/siting costs.

As discussed above, the cost of a new CC unit could also be increased by the choice of a relatively complex unit design, or the need to install SCR or other emission controls more costly than the basic plant design. The estimated CC and CT capital costs presented in the previous paragraph do not include any such costs, nor any general plant allocation or decommissioning costs.

Q. ONCE THE CAPITAL COST OF A FUTURE CAPACITY OPTION IS ESTIMATED, HOW DOES THE COMPANY'S MARKET PRICE ANALYSIS REFLECT THE RECOVERY OF AND RETURN ON THAT INVESTMENT OVER TIME?

A. In electric utility planning, it is common practice to represent the expected recovery of and return on power plant investments through a series of annual "carrying charges." Each of PECO's market price witnesses has utilized "real-levelized" carrying charge rates in this case, translating the capital cost of projected generation investments into a series of annual carrying charges that increase annually at the rate of general inflation. Over the life of the investment, the carrying charges are designed to cover appropriate levels of depreciation, interest, return on investment, and income taxes. Carrying charges may also be calculated to include other expenses related directly to the size of the capital investment, such as property taxes or insurance. The PECO witnesses used real-levelized carrying charges of between 12 and 13 percent. This means that for a $100 plant investment, a real-levelized carrying charge rate of 12 percent would produce an annual carrying charge of $12 in year 1, $12 plus one year of inflation in year 2, and so forth.

Q. HAVE YOU REVIEWED THE SPECIFIC REAL-LEVELIZED CARRYING CHARGES USED BY PECO TO REPRESENT NEWLY CONSTRUCTED GENERATING UNITS IN THIS CASE?

A. Yes, the Company's derivations of carrying charge rates appear to omit several significant components. First, the carrying charge rates utilized by Dr. Hieronymus and Mr. Bustard reflect an effective tax rate of 35.0 percent, apparently based on the marginal federal corporate income tax rate. To the extent that developers of electric generation projects face state income taxes, their effective cost of capital will be greater. For example, I understand that Pennsylvania's state income tax rate is 9.99 percent, which would yield a combined effective income tax rate of 41.49 percent.

Second, Dr. Hieronymus' 12.0 percent real levelized carrying charge rate does not include the expenses of project insurance or property tax. It also appears clear that Dr.

Hieronymus' analysis does not cover property taxes or insurance in the assumed fixed O&M charges, since he bases those fixed O&M charges on a review of FERC Form 1 expenses which clearly do not include these costs. I have not independently analyzed the specific property tax and insurance rates that would be faced by new electric generators in the PJM geographic area. The EDS carrying charge analysis submitted in Response PAIEUG-VI-4 includes a constant property tax rate equal to 2.5 percent of the gross plant investment, and an insurance expense rate equal to 1.0 percent of the gross plant investment. Dr. Hieronymus' carrying charge assumption for new CC and CT capacity therefore appears to be understated by these amounts.

Third, the carrying charge developed by EDS and sponsored by Mr. Bustard reflects a traditional regulated utility cost recovery approach, spreading that recovery over a 30 year period. I believe that a 30 year economic life is unrealistically long to assume for new generating units being constructed in a competitive generation market environment. In contrast to previous utility-constructed generating units, and to non-utility units constructed to provide power under long term firm contracts, generation revenues for a new unit selling to the spot market (or through short term bilateral contracts) will not be guaranteed, and they will vary with actual market conditions over which the individual owner probably has little control. It is therefore reasonable to expect that developers will try to recover their capital investment over a significantly shorter horizon, and that project financing will not be available for a term as long as 30 years. A 20 year investment horizon and 15 year debt term would be more realistic assumptions to use for future generating units. By recovering the capital investment over a shorter period, this change will tend to increase the carrying charges associated with new generating capacity.

In conclusion, the real-levelized carrying charges presented by PECO are understated in several respects, including the lack of a state income tax rate; the lack of property tax and insurance expenses; and an unrealistically long period for debt recovery and project return. For my market price analysis, I used a real-levelized carrying charge rate of 12.75 percent, which is similar to those used in PECO's EDS and ICF analyses and somewhat higher than that used in PECO's PHB analysis. Based on the discussion above, I believe that the 12.75 carrying charge rate I have used is within the range of plausible outcomes, but probably optimistic as an expected value. Using this carrying charge rate, and the CC and CT capital cost assumptions outlined above, the real-levelized carrying charge associated with a new CC unit is about $70/kW-year ($1996), and for a new CT unit is about $37/kW-year ($1996).

Q. HAVE YOU REVIEWED PECO'S ASSUMPTIONS REGARDING FIXED O&M COSTS FOR FUTURE PJM GENERATING UNITS?

A. Yes, I have. For new CC units, PECO's witnesses assume an annual fixed O&M charge ranging from $7/kW-year to $18/kW-year (both in $1996). Dr. Hieronymus, whose market price results were used to develop the Company's stranded generation cost figures, assumed fixed O&M for a CC plant of about $9/kW-year. By fixed O&M, I refer to all non-fuel expenses associated with operating and maintaining a generating facility. Fixed O&M costs would include plant staffing, consulting services, and other operating costs not directly associated with the plant's output.

PECO witnesses Bustard and Hieronymus assume annual fixed O&M costs of roughly $9/kW-year and $7/kW-year, respectively (each increasing at inflation) for a newly constructed combined cycle unit; these values appear optimistic. I am concerned that these costs may not be sufficient to cover significant fixed costs such as property taxes and insurance (to the extent that the carrying charge rate used in a particular analysis does not include these costs), or the periodic capital additions that will be required to maintain the combined cycle facility's availability and performance at assumed levels. For example, while Dr. Hieronymus cites actual O&M costs of less than $10/kW-year for two newer combined cycle plants (Hay Road and Bergen), the reported costs are only for the first year or two of operation, and are therefore probably not representative of the long term level of required maintenance and overhaul costs. Further, the operating costs reported in the FERC Form 1 for individual generating units are defined to include neither property taxes nor capital additions.

For newly constructed CC and CT units, a regimen of equipment maintenance and refurbishment will be needed to maintain the equipment's thermal efficiency and output at original levels. Whether classified as fixed O&M costs or capital additions, the costs of this effort are likely to make up a significant portion of a CC unit's non-fuel operating costs. There is not an extensive record of industry experience with the advanced equipment that PECO assumes will provide PJM's CC capacity option, and it appears quite optimistic to assume going-forward fixed O&M costs as low as projected by Mr. Bustard and Dr. Hieronymus without assuming significant additional capital expenditures. It appears that for new CC units, Dr. Venkateshwara's fixed O&M value of about $17/kW-year provides a reasonable (although possibly optimistic) representation of fixed O&M and capital additions for the CC option.

Q. HOW DOES PECO'S ANALYSIS OF STRANDED GENERATION COSTS REPRESENT ADMINISTRATIVE AND GENERAL COSTS?

A. Administrative and general ("A&G") costs for an electric utility include required salaries and costs not assigned to specific generation, distribution, or production functions. As reported on the FERC Form 1, major categories of A&G costs include employee pensions and benefits, office supplies and expenses, regulatory commission expenses, and administrative and general salaries.

PECO's projection of stranded generation costs assigns significant amounts of the Company's total A&G costs to individual generating units. Specifically, in 1999 PECO includes about $10.7 million of allocated A&G costs in the estimated going-forward costs of its fossil-fired generating units (excluding Conemaugh and Keystone, because their O&M costs are accounted for differently). This amounts to an average A&G cost of about $4 per kW-year of installed capacity, or about 13 percent of the units' projected

O&M costs in the same year. In contrast, none of PECO's market price analyses appear to include any corresponding A&G costs for future generating units assumed to be constructed in the PJM market.

In the context of stranded cost analysis, it is appropriate to reflect A&G costs in a consistent manner, assigning reasonable A&G costs to both PECO generating units and new market entrants. For the purpose of this analysis, I have assumed that A&G costs associated with plant operations will add 10 percent to the projected fixed O&M costs for a CC unit; this adds about $2/kW-year to the unit's annual non-fuel costs.

Q. WHEN WILL PJM NEED ADDITIONAL GENERATING CAPACITY, AND WHAT WILL BE THE EFFECT ON MARKET CAPACITY PRICES?

A. PECO witness Bustard assumes (as illustrated in his Exhibit JFB-7) that the PJM Interconnection will maintain a modest surplus of installed generating capacity in 1999, reaching equilibrium in 2000 and requiring additional capacity thereafter. He assumes that the market capacity price will approximate the carrying cost of new peaking capacity by 2001. While I agree that a surplus of installed capacity would tend to suppress market capacity prices, several factors make it doubtful that prices will reflect a surplus condition for any significant period.

First, even if supply and demand conditions evolve more favorably than assumed in Mr. Bustard's analysis, upward pressure on capacity prices will exist before PJM's installed capacity surplus reaches zero. As the surplus declines, uncertainties in loads and resources will make producers increasingly reluctant to sell their excess installed capacity for a long period.

Second, neighboring interconnected regions may be able to sell into PJM, but may also seek to purchase capacity. In particular, the New England Power Pool expects to have a substantial need for installed capacity and associated energy during the next 6 to 18 months, due primarily to the retirement of the Connecticut Yankee unit (560 MW), and to the continued unavailability of four units on the Nuclear Regulatory Commission's Watch List: Maine Yankee (870 MW) and Millstone Units 1, 2 and 3 (over 2,600 MW). Maine Yankee's owners recently stated their intention to reduce ongoing expenditures, consistent with a "protect and preserve" posture, and to consider closing the unit for economic reasons if a buyer cannot be found in the near future. To the extent that these or other major generating units in the Northeast and Mid-Atlantic remain unavailable, upward pressure will be exerted on energy and capacity prices.

Finally, the capacity market will be affected not only by the amount of installed capacity, but also by the economic competitiveness of that capacity. Because revenues will not be guaranteed in a competitive generation market, the owner of a generating unit with relatively high going-forward costs may choose to close the unit for economic reasons, even if the unit is still physically operable. PECO's generation market analysis identified some units that may be candidates for such economic retirement.

Independent Market Price Analysis

Q. WHY DID YOU DECIDE TO CONDUCT AN INDEPENDENT ANALYSIS OF THE PJM GENERATION MARKET, RATHER THAN RELYING ON THE ANALYSES PECO HAS PRESENTED IN THIS CASE?

A. First and perhaps most important, conducting an independent analysis provides the Commission with a practical mechanism to assess the stranded costs and restructuring plan on a common basis.

In addition, it has been difficult to verify some of the assumptions and methods of PECO's analyses, due in large part to the sheer volume of information and the fact that the Company presented three truly distinct analyses. While useful information can be obtained by requesting the Company to perform alternative analyses (as OCA did in Request XII-

10), the time and effort required for the Company to properly characterize and perform such analyses has proven to be substantial.

Finally, my analysis is intended to assist the Commission by providing a balanced, non-utility perspective on generation market issues. My general approach in developing assumptions and methods used in the analysis was not, however, to develop a high bound or "counter" to the Company's analysis. As shown in my discussion of the costs and carrying charges associated with new generating units, I have sought a reasonable expected value outcome on each issue. I believe that I have chosen assumptions that have equal likelihood of being above or below the actual outcome.

Q. PLEASE SUMMARIZE THE METHODOLOGY UPON WHICH YOUR MARKET PRICE ANALYSIS IS BASED.

A. My analysis assumes the same basic market structure as each of PECO's analyses: the vast majority of market revenues are associated with two market components: an hourly market for electric energy, which will reflect the interaction of hourly supply and demand, and a market for installed generating capacity, reflecting the relative scarcity of capacity in the PJM region.

To approximate the PJM energy market, we conducted a dispatch analysis of the PJM system using the ENPRO dispatch simulation model. ENPRO is a detailed, chronologic model well suited to represent a large electric system like PJM, and the model is used by utilities and others for a range of operational and planning analyses. ENPRO represents unplanned (or "forced") outages of generating capacity randomly, on a daily basis. ENPRO was used to represent the PJM Interconnection as a whole, and does not distinguish potential market price differences due to transmission constraints within PJM. Imports from ECAR are represented explicitly as available sources to be dispatched when economic.

The most important methodological difference between my analysis and Dr. Hieronymus' PECO analysis is in the derivation of the energy clearing price. I have represented the energy market in terms of bids for delivered energy from each PJM generating unit, in which the energy market price is defined by the highest selected bidder, and each bidder is assumed to bid based on its **total variable cost.** My approach is consistent with that utilized by PECO witness Venkateshwara, and (as discussed in detail earlier in my testimony) contrasts with the approach utilized by PECO witness Hieronymus, who assumes that the market energy price at any time will reflect the **incremental variable cost** of the marginal generating unit(s).

Like the PECO analyses, my analysis reflects the assumption that over time, the market price for capacity will approximate the carrying costs of the CT option, the least costly type of additional generating capacity.

Q. PLEASE SUMMARIZE THE PRIMARY INPUT ASSUMPTIONS UTILIZED IN YOUR PJM MARKET ANALYSIS.

A. Each of the fundamental input assumptions (or groups of assumptions) in my analysis is based either on an assumption from the Company's market price analyses or on publicly available data. The primary data sources are as follows:

- PJM generating units and their maximum capacities were identified from EIA Form 860;
- Actual annual fuel prices for PJM generating units were obtained on a station basis for calendar year 1996, from the FERC Form 1. From 1997 forward, fuel prices were escalated according to major fuel type (i.e. coal, or residual oil), based on escalation rates from the Fall 1996/Winter 1997 DRI price forecast used by PECO witnesses Bustard and Hieronymus; the annual escalation values are presented in Exhibit DCS-3;
- Variable O&M costs: based on PECO's assumptions, both for its own generating

units and for other PJM units;

- Heatrates: the energy bid of each thermal generating unit is represented based on its average as-operated heatrate for 1996, as obtained from EIA Form 860. This is the bid which will, over a generating unit's dispatch cycle, approximate the unit's total actual fuel costs;
- Generating unit availabilities: developed for major classes of generating units, based on NERC records of 1990-1994 actual generating unit availabilities, with the following exceptions: (1) Output of PJM hydro units was based on the estimated long term average output; (2) Nuclear generating units in PJM are assumed to produce at a 75 percent annual capacity factor in each year of the analysis; and (3) non-utility generating capacity was projected in accordance with the North American Electric Reliability Council's 1996 Electric Supply and Demand Database.
- Projected peak load and energy requirements for PJM were based on MAAC Form EIA-411, as summarized in Mr. Bustard's Exhibit JFB-6.

Q. YOU NOTED THAT YOU USED PUBLICLY AVAILABLE INFORMATION WHERE POSSIBLE FOR YOUR ANALYSIS. IS THE DRI FORECAST THAT YOU UTILIZED PUBLICLY AVAILABLE?

A. No. I understand that PECO subscribes to DRI forecasting services; I obtained the escalation rates associated with PECO's analysis in discovery. I used them for my analysis because the Company used them, DRI is a well-known forecasting firm that has been used in numerous electric industry analyses, and the future described by the DRI escalation rates is reasonable. Specifically, coal prices are assumed to decline steadily in real terms over 20 years. Oil and gas prices are assumed to initially decline by about 10 percent in real terms, and then to increase more rapidly. Over 20 years, oil and gas prices are assumed to increase by between 15 and 20 percent in real terms. Uranium prices are assumed to remain constant in real terms over the planning horizon.

In addition, I attempted to have the Company rerun each of its market price analyses using a set of publicly available fuel price escalation rates published by the U.S. Energy Information Agency. Despite the Company's efforts, I did not receive the Company's results in time to examine them in detail. An initial review of the Company's results indicates that EDS and ICF obtained similar market revenue results, as might be expected with the same fuel price outlook. Interestingly, the market revenues that PHB obtained using that outlook are significantly lower.

Market Price Results

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR MARKET PRICE ANALYSIS.

A. Exhibits DCS-4 and DCS-5 summarize the results. Exhibit DCS-4 presents the projected annual average market energy price, annual market capacity price, and total market price (including energy and capacity) from 1999 to 2015. These values represent the unweighted average of market prices for all hours of the year, and would represent the realized wholesale market revenue of a generating source producing at maximum capacity during all hours of the year.

Exhibit DCS-5 presents the average annual energy, capacity, and total market revenues projected to be achieved by PECO's generating units in each year of the analysis. Because some of PECO's generating units are load-following, and tend to produce during higher-cost peak hours, the achieved market prices in Exhibit DCS-5 are somewhat higher than the unweighted averages in Exhibit DCS-4.

In summary, the results of my analysis show significantly higher market energy prices than those projected by PECO witness Hieronymus, particularly in the near term. This appears to be due primarily to the methodological differences in how the market energy price is calculated. My market price results are somewhat higher than those of PECO's two other market witnesses, Mr. Bustard and Dr. Venkateshwara.

Q. PLEASE DESCRIBE THE CONSTRAINTS ON YOUR MARKET ANALYSIS.

A. My energy market analysis is conservative (i.e. tends to understate market prices) in two ways. First, the analysis does not reflect the inflationary effect of emission allowance prices on the energy market. PECO chose to represent the effect of emission constraints by including emission "adders" (in dollars per Mwh) to the dispatch price of each emitting generating unit. While I have not examined in detail the derivation of specific adders, PECO's approach appears reasonable.

I did not, however, have sufficient information to similarly represent the effects of SO_2 and NOx constraints on the dispatch prices of all PJM generating units in my analysis. I therefore simulated the operation of the PJM energy market based solely on the direct fuel costs and estimated variable O&M costs of PJM generating units. Had I been able to include the effects of SO_2 and NOx emission adders in the energy market analysis, the resulting energy market prices would have been higher in many hours of the year. Because a substantial fraction of PECO's generation (i.e. nuclear and hydro) incurs no allowance costs, the inclusion of allowances in the analysis would increase PECO's net generation revenues. The magnitude of the NOx adders is limited in the context of overall market prices, with adders for individual generating units ranging from roughly \$0.20/MWh to \$1.69/MWh from 1999 to 2002, and roughly \$0.76/MWh to \$3.10/MWh from 2003 onward. The effect of including NOx adders in the market price analysis would be to increase costs and revenues for generating units that require the adders, and to increase revenues for units that do not require the adders. Based on these adders for PECO generating units, I estimate that the net effect of including NOx adders in the PJM market price analysis would be to increase market generation prices by less than \$1/MWh on average. Even an increase of \$0.5/MWh, however, would raise PECO's net revenues by \$10 million or more per year.

Second, the commitment and dispatch of generating units in the analysis does not reflect spinning reserve requirements, which would tend to require commitment of additional, more costly generating units.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. The generation market price analysis upon which the Company's estimate of stranded generation costs relies is methodologically flawed, and systematically understates the likely energy prices in the PJM market. My alternative analysis, which is based on publicly available generation and load data (including average generating unit heatrates), provides a practical way for the Commission to implement consistent market price assumptions in its determination of stranded generation costs. My analysis yields generation market prices that are significantly higher than the PECO analysis developed by PHB, and somewhat higher than the prices developed by EDS and ICF.

It is also important to note that my analysis does not represent a high bound on market prices. A host of factors -- including environmental compliance costs, higher fossil fuel costs, poor performance of existing generating units, and higher carrying charge rates for new generation -- could significantly increase generation market prices (and therefore PECO's net generation revenue).

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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Douglas C. Smith

LA CAPRA ASSOCIATES
Senior Analyst

Mr. Smith is a Senior Associate with La Capra Associates with over ten (10) years of experience in utility economics and planning. As Electrical Planning Engineer and Power Cost Analyst for the Vermont Department of Public Service, Mr. Smith specialized in electric utility power costs, resource planning, and modeling issues. Since joining La Capra Associates in 1991, Mr. Smith has assisted a range of clients in the areas of resource planning, operational issues, and market transactions.

Mr. Smith's professional accomplishments include:

Market Price/Transaction Analysis

On behalf of the New Hampshire Public Utilities Commission, played a central role in the projection of New England power prices in a restructured electricity market, for use in the determination of stranded cost charges for New Hampshire utilities.

On behalf of the World Bank, assisted in the review of pricing and policy issues related to the acquisition of non-utility power in India. On behalf of utilities and regulatory agencies, performed comprehensive evaluations of proposed wholesale electric power transactions, including domestic and international transactions of up to 20 years in duration.

Competitive Power Solicitation and Management

Manages and conducts all power transactions of the Vermont Electric Cooperative, Inc. Responsibilities include initial analyses of need, negotiation with potential trading partners, and development of contract terms. Responsible for familiarity with the New England Power Pool's requirements regarding energy, capacity, and ancillary services (a significant factor for the Cooperative), and ensuring that they are met in the least costly manner possible.

Conducted formal solicitations for long term and short term electricity transactions. Played a primary role in the solicitation, evaluation, and negotiation of long term power supply agreements for the Nantucket Electric Company and the Vermont Electric Generation & Transmission Cooperative, Inc.

Electric Utility System Operation

Performed detailed, probabilistic dispatch simulations of electric utility systems -- including the New England Power Pool, the state of Maharashtra (India), and individual U.S. utilities -- to identify the cost implications of alternative resource choices and planning assumptions.

Developed a generating unit dispatch plan to minimize fuel and operating costs for the Nantucket Electric Company, taking into account factors such as part load thermal efficiencies and system operating reserve.

Presented expert testimony before state regulatory commissions in dockets relating to electric utility planning, rate cases, and long term avoided costs.

Cooperative Utility Analysis

Responsible for developing the Vermont Electric Cooperative's power supply budgets since 1992. In retail rate proceedings, sponsored the Cooperative's power supply and transmission costs. Assisted Cooperative staff in the development of demand-side management and interruptible load programs. Assisted La Capra Associates staff in developing financial analyses supporting the Cooperative's negotiations with the Rural Utility Service, and presentation of its business plan before the U.S. bankruptcy court.

Electric Utility Resource Planning

Managed the development of Integrated Resource Plans for several electric utilities.

Used simulations to determine the amount of additional generating capacity that the Puerto Rico Electric Power Authority will require in order to maintain its system reliability objectives. Identified the factors that would most strongly affect the capacity need, and identified how variations in those factors would advance or defer the need for capacity. Supported the results in direct testimony before the Planning Board of Puerto Rico.

Developed "avoided cost" rates to represent the value of electric power from Qualifying Facilities, and from demand modifications associated with utility Demand-Side Management ("DSM") programs.

Electric Transmission Issues

Critically examined a long term transmission contract between two New England electric utilities. Identified inappropriate booking of transmission plant, and an overstatement of electrical losses on the seller's system. Developed written testimony before the Federal Energy Regulatory Commission. Participated in negotiation of a successful settlement, which includes a substantial refund of back charges and significant reduction in future charges.

Other Energy Analyses

Analyzed the technical and economic feasibility of self-generating steam and chilled water to serve the medical campus of Boston City Hospital and Boston University.

PROFESSIONAL EXPERIENCE:

- Electrical Planning Engineer, VERMONT DEPARTMENT OF PUBLIC SERVICE. October, 1988 to December, 1990.
- Power Cost Analyst, VERMONT DEPARTMENT OF PUBLIC SERVICE. June, 1986 to October, 1988.

EDUCATIONAL BACKGROUND:

- Sc.B. in Mechanical Engineering with Energy Conversion emphasis, **BROWN UNIVERSITY**, Providence, Rhode Island.
- EPRI Seminars on Utility Planning and Production Costing Techniques.
- Users' group and other training seminars associated with the UPLAN and ENPRO production costing models.

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Comparison of 1999 Fuel Prices ($/MBTU)

PECO Energy Company

Source	Escalation Forecast	Conemaugh 1&2 coal	Keystone 1&2 coal	Cromby 1 coal	Eddystone 1&2 coal
FERC 1 plus DRI	DRI 10/96	$1.22	$1.55	$1.73	$1.65
Venkateshwara	ICF	$1.03	$1.03	$1.51	$1.51
Heironymus	DRI 10/96	$1.09	N/A	$1.45	N/A
Bustard	DRI 10/96	$1.23	N/A	N/A	$1.50

DRI FUEL PRICE ESCALATION RATES

YEAR	GAS	COAL	F02	FO6
1997	-6.0%	0.0%	-4.9%	-8.2%
1998	1.3%	0.7%	1.4%	0.0%
1999	1.3%	2.8%	-0.4%	-2.3%
2000	6.6%	2.8%	5.7%	6.3%
2001	3.9%	1.3%	5.2%	5.4%
2002	5.2%	2.0%	5.1%	5.2%
2003	5.7%	2.0%	5.3%	5.7%
2004	5.7%	1.9%	5.3%	5.8%
2005	4.4%	1.3%	5.5%	5.9%
2006	3.6%	1.9%	5.5%	5.9%
2007	5.6%	2.4%	5.5%	5.8%
2008	6.4%	2.4%	5.4%	5.7%
2009	6.0%	2.3%	5.0%	5.2%
2010	5.7%	2.8%	4.9%	5.1%
2011	4.9%	0.6%	5.0%	5.1%
2012	4.2%	2.7%	4.9%	5.0%
2013	4.1%	2.7%	4.8%	5.0%
2014	4.7%	2.6%	4.8%	4.9%
2015	4.3%	2.5%	4.6%	4.5%

EXHIBIT DCS-4

PJM MARKET PRICE ESTIMATE

YEAR	ENERGY $/MWh	CAPACITY $/KW-YR	TOTAL $/MWh
	ALL HOURS		ALL-HOURS
1999	23.24	19.73	25.50
2000	24.96	30.43	28.44
2001	26.54	41.67	31.30
2002	28.11	43.12	33.03
2003	30.03	44.20	35.07
2004	30.75	45.66	35.96
2005	33.42	47.12	38.80
2006	35.04	48.91	40.62
2007	36.97	50.38	42.73
2008	38.43	52.19	44.38
2009	39.63	54.02	45.79
2010	41.99	56.18	48.40
2011	43.37	57.98	49.99
2012	44.68	60.12	51.55
2013	47.46	62.29	54.57
2014	48.43	64.47	55.79
2015	50.46	66.66	58.07

EXHIBIT DCS-5

YEAR	PECO WEIGHTED GENERATION PRICE, $/MWH
1999	28.37
2000	32.69
2001	36.86
2002	38.73
2003	40.98
2004	42.07
2005	45.17
2006	47.13
2007	49.17
2008	50.74
2009	52.10
2010	55.18
2011	56.89
2012	58.68
2013	62.01
2014	64.43
2015	68.51