R-00973953
PECO Stmts 4, 5, 6, 7
Exhibits JFB 1-9
BSV 1 + 2
WHH 1 thru 5
JD 1 thru 5

BEFORE THE Phila 10/14, 15, 16/97
R. Holbert

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

Exhibit 1
VOLUME III

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PECO STATEMENT NO. 4

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

DIRECT TESTIMONY

OF

JOHN F. BUSTARD

Regarding Market Price Analysis For PECO Generation Assets

TABLE OF CONTENTS

DIRECT TESTIMONY OF JOHN F. BUSTARD

I. QUALIFICATIONS

Q. **Please state your name and business address for the record.**

A. John F. Bustard, 2301 Market Street, Philadelphia, Pennsylvania, 19103.

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

A. I am a Senior Engineer in the Bulk Power Enterprises group of PECO Energy Company ("PECO" or the Company).

Q. **What is your educational background?**

A. I graduated in 1968 from Lehigh University with a Bachelor of Science in Electrical Engineering and in 1973 from the University of Illinois with a Master of Science in Electrical Engineering specializing in Power Systems.

Q. **Are you professionally certified?**

A. I am a registered professional engineer in the Commonwealth of Pennsylvania, PE-023180-E.

Q. **Please summarize your experience with PECO.**

A. I joined PECO in 1973 as an Engineer in the System Planning Division. For 15 months in 1976-1977, I was a Project Manager with the Electric Power Research Institute, on loan from PECO. In 1986 I was promoted to Senior Engineer and in 1989 to Supervising Engineer in System Planning. In 1993 I was named a

Manager in Supply and Demand Planning. In 1994, my team was moved to the Business Planning and Financial Analysis section in the Consumer Energy Services group. In 1995, I transferred to Transmission Management within the Bulk Power Enterprises group as a Senior Engineer.

Q. **What are your responsibilities in your current position?**

A. I am responsible for PECO's analysis of generation operation and costs while explicitly recognizing transmission constraints

Q. **What previous experience at PECO qualifies you to make estimates of market revenue?**

A. Throughout my career at PECO, I have determined costs and benefits associated with PECO's generation and transmission and the cost of serving load. I was responsible for preparation of PECO Energy's first Integrated Resource Plan, first Coal Upgrade Report, providing avoided costs to potential non-utility generators, and planning for Demand Side Management programs. I developed costs and benefits and testified before the Commission on the prudence of PECO's Phase I compliance with the 1990 Clean Air Act Amendments.

Q. **Did you submit testimony in PECO's Application for Issuance of a Qualified Rate Order filing?**

A. Yes. I submitted PECO Statement No.7, PECO Statement No 7-R and accompanying Exhibits Nos. JFB-1 to JFB-9.

Q. Have you participated in other related activities?

A. Yes. I was an Adjunct Assistant Professor at Drexel University from 1973 to 1987 teaching undergraduate and graduate courses on Power Systems, Power System Economics, Power System Dynamics and Computer Applications to Power Systems.

II. INTRODUCTION AND SUMMARY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the results of several analyses, performed at PECO's request, to project the market price and corresponding market revenues which each of PECO's generating units could reasonably be expected to command in a competitive generation market commencing January 1, 1999. A list of PECO's generating units is presented by Alan B. Cohn (Statement No. 3) in Exhibit ABC-2. In the process of doing so, I will discuss the framework for these analyses and will identify the major factors that will determine the market value of those facilities.

Q. Why did PECO initiate these market price analyses?

A. As explained by Thomas P. Hill, Jr. (Statement No. 1) in his testimony, to calculate PECO's stranded costs it is necessary to assign a market value to its existing generation units. Their market value, in turn, will be a function of how frequently they operate, what price can be obtained for their output and their capacity to operate when needed.

Q. **Please describe, in general terms, the market price studies that were performed at PECO's behest.**

A. Three separate studies were conducted. The first was performed by the EDS Utilities Division, utilizing its Power Market Decision Analysis Model (PMDAM). The second study was conducted by William H. Hieronymus of Putnam, Hayes & Bartlett (PHB). Dr. Hieronymus presents the results of his analysis in his direct testimony (Statement No. 6). The third market price study was performed by ICF Resources Inc. (ICF), and is described by Bangalore S. Venkateshwara in his direct testimony (Statement No. 5).

Q. **Why did PECO procure multiple market price estimates?**

A. PECO is submitting the results of several expert analyses in an effort to develop a range of reasonable expectations for the Commission's consideration.

Q. **Please summarize your conclusions regarding PECO's market price analyses.**

A. The results of the studies conducted by EDS, PHB and ICF are set forth in Exhibits JFB-1 through JFB-3 and are described in the following sections of my testimony.

III. MARKET PRICE, MARKET REVENUE AND MARKET REVENUE NET OF FUEL

Q. **What is the market price of PECO's generation?**

A. The market price PECO can expect to receive for its generation will be a weighted market price. The annual prices for each of the three market clearing price analyses are set forth in Exhibit JFB-1.

Q. **What does PECO's weighted market price represent?**

A. The weighted price takes into account the variation in expected market prices among different generating units. A particular unit's market price multiplied by its megawatt (MW) output during each hour summed over all hours of a year equals its market revenue for its energy. Market revenue for a unit's capacity equals its net rating multiplied by the market price of capacity. The sum of the market revenues for all generating facilities divided by the sum of the megawatt hours (MWh) output of all such units equals the weighted average price.

Q. **What is PECO's estimate of the market revenue to be produced by its generating facilities?**

A. PECO's total market revenue for each of the three analyses is set forth in Exhibit JFB-2.

Q. **What do you estimate to be the market revenue net of fuel of PECO's generating facilities?**

A. The value of PECO's generating facilities, as defined in terms of market revenue less fuel cost, for each of the three analyses, is set forth in Exhibit JFB-3.

IV. BASIS FOR DETERMINING MARKET PRICE

Q. **In developing the market price estimates, what assumptions were made regarding the market in which PECO's generating facilities would compete?**

A. All of PECO's generating units are located in the Mid Atlantic Area Council (MAAC), which geographically is the same as the Pennsylvania-New Jersey-Maryland (PJM) Interconnection. However, FERC initiatives, including Orders 888-A and 889-A, have opened up the transmission system to all wholesale buyers and sellers. As a result, the PJM Interconnection which has operated as a power pool since 1928 is now only a part of a much larger power market. Consequently, all three studies reflect the fact that PECO's generation will be competing for sales not only within the PJM Interconnection, but also over a much larger area, including the New York and New England Power Pools and the Midwest and Southeastern states.

Q. **How will PECO and other participants sell their generation into a competitive energy market?**

A. For electricity, like other competitive markets, bidders will sell at the highest price they can expect to receive for their product, subject to not selling below their cost.

Therefore, an equilibrium of supply and demand exists at the marginal cost of producing the product.

Q. **At what price will the energy market clear?**

A. For the electric energy market, the equilibrium of supply and demand must be maintained on an instantaneous basis. Market participants will have quick feedback on the market price at any time. With such feedback, the market can be expected to clear at the highest marginal cost generating unit operating in any hour. This will occur whether the market evolves into a bilateral market or a spot market. Dr. Hieronymus further discusses bilateral and spot markets in his testimony. Therefore, because the market will clear at the hourly marginal cost, and because price in the spot market represents price in a bilateral market, an assessment of future market prices can be made using the same production cost estimating tools which utilities have been using for years.

Q. **You previously indicated that the studies conducted by EDS, PHB and ICF each calculated market prices on an individual generating unit basis. Why was this necessary?**

A. The varying demand for electricity means that during all but a few hours part of the generation supply will not operate. Economic dispatching of supply has historically been done to minimize costs. I expect the objective under competition of maximizing net market value to cause units to be dispatched in a similar way as they would have under economic dispatch. Therefore, the market price for high cost units is not the yearly average of all hourly prices, but is based on the market price during the subset of hours that they operate.

Q. **Is this the method you used to determine the weighted market price?**

A. Yes. *If I perform a similar analysis to get the market price that applies to each* generator, sum to get total market revenue for all generators and divide by the total output, I get the weighted market price.

Q. **Is this weighted market price as such used as an input to the stranded investment determination in Mr. Hill's testimony?**

A. No. The market prices and associated market revenue for individual generators drive the analysis. The weighted market price is presented as a way of summarizing the prices of the individual generators.

Q. **How does this weighted market price compare to an all hours market price?**

A. The annual average of the market prices for all hours for each of the three market price analyses is set forth in Exhibit JFB-4. Weighted market prices as set forth in Exhibit JFB-1 are higher than all hours prices.

Q. **What other factors, if any, affect the market price of a generating unit?**

A. When the transmission system is constrained, market price is also a function of the location of a particular generating unit within the electric system. When the transmission system cannot reliably transmit electric energy with only the lowest bidding generators operating, the system operator will accept bids that are above the unconstrained market clearing price. The system operator will do this in a way that minimizes the amount of constraint control but, at times, the most efficient way of operating the system will require constraint control payments. The calculation of market price must account for bids accepted because of transmission system effects. All three market price analyses (EDS, PHB and ICF) take transmission into consideration and a PECO analysis using PROMOD IV further quantifies this transmission system effect.

Q. **Besides energy, what else is included in the market price?**

A. The need of an electric system to instantaneously match supply and demand even under quickly changing conditions such as load increases or unit outages requires that adequate backup supply be available at all times. The Competition Act recognizes this fact by requiring generation suppliers to maintain adequate reserve margins to keep supply available in the event of unit outages. Therefore, the market price of an individual generating unit must include the market price of its capacity or ability to supply power even when not actually supplying energy.

Q. **How was this market price of capacity calculated?**

A. Each expert determined the market price of capacity in $/kW-year and then determined capacity revenue based on the rating of each generator.

Q. What use do you make of the market revenue from capacity?

A. I add the market revenue from capacity to the market revenue of energy to determine the total revenue shown in Exhibit JFB-2. The weighted market price of Exhibit JFB-1 includes the market revenue from capacity.

V. KEY FACTORS THAT WILL DRIVE FUTURE MARKET PRICES

Q. What are the key factors that will drive the future market price of electricity?

A. There are many factors that will affect the future price of electricity. The three that stand out, and which I will discuss, are (1) fossil fuel prices, (2) consumption levels and (3) customer reliability requirements.

Q. What fossil fuel price projections were utilized by the various consultants in their market price analyses?

A. EDS and PHB used the latest (October 1996) DRI/McGraw-Hill forecast of coal, oil and gas prices for the Middle Atlantic region independently developed by DRI. Those estimates are set forth in tabular and graphic form in Exhibit JFB-5. Dr. Venkateshwara utilized a fossil fuel price forecast independently developed by ICF.

Q. How did the consultants estimate future electric consumption levels?

A. All three relied on the annual load growth forecast submitted by MAAC to the North American Electric Reliability Council (NERC) and the Energy Information Agency (EIA) on April 1, 1996, the results of which are presented in Exhibit JFB-

6. As shown, that forecast extends only through 2005. Consequently, for purposes of estimating market prices after that date, load was projected to continue to grow at a constant rate equal to that projected, on average, for the 2003-2005 period. For other regions of North America, the consultants relied on data submitted to EIA by those other regions.

Q. **Regarding the third factor, what projections were made with respect to future reliability requirements?**

A. For purposes of their analyses, the consultants projected that MAAC/PJM would adhere to an 18% reserve margin standard. Mr. Cucchi discusses the 18% reserve margin standard in his testimony. It is predicted that MAAC will reach an 18% reserve margin in 2001 as set forth in Exhibit JFB-7.

Q. **Apart from the three fundamental factors which you just discussed, what other factors were examined to develop future market price projections for PECO's various generating units?**

A. Each of the three analyses incorporated somewhat different views on other factors that affect market price. Examples of these other factors are the type of new generation added over time, retirement of older generation, variable O&M costs of generation, changes in availability and efficiency of generation, fuel switching and strategies for meeting emission standards. Transmission factors which affect the market price of generation are transmission wheeling costs, transmission constraints and transmission expansion to alleviate constraints and ancillary services.

VI. EDS MARKET PRICE PROJECTIONS

Q. **Please describe the market price projections developed by EDS.**

A. The results of the EDS analysis are included in the data set forth in Exhibits JFB-1, JFB-2 and JFB-3. Exhibit JFB-1 projects the weighted market price available to PECO generation. Similar projections of market revenues and net market revenues (net of fuel costs) may be found in Exhibits JFB-2 and JFB-3, respectively.

Q. **Why did you rely on EDS for projections of market price rather than your own work?**

A. Experts within PECO do not have a long-range database available to model market price beyond the next few years.

Q. **What makes EDS qualified to make projections of market price?**

A. EDS has the expertise and data to determine market price. They provide estimates of market price using their PMDAM model to over 15 clients across the USA Those clients include entities on all sides of the electricity market including power marketers and independent power producers.

Q. **What was the basis of the EDS projection of market price?**

A. Factors affecting the price projections are set forth in Exhibit JFB-8.

Q. **How did EDS develop its projections?**

A. As I mentioned previously, *EDS utilizes* its own PMDAM model, the principal features of which are described in Exhibit JFB-9. EDS' data base is quite comprehensive and incorporates generation, transmission and load data from all of MAAC/PJM, the East Central Area Reliability Coordination Agreement (ECAR), which lies to the west of MAAC, and the Southeastern Electric Reliability Council (SERC), which lies to the south.

Q. **How does EDS treat differences in market price by location?**

A. EDS models companies with separate transmission tariffs each as a node. Transfer of energy between nodes is charged the firm or non-firm transmission rate and transmission loss factor. PJM is represented as having one transmission tariff and is one node. Differences in prices are represented between different nodes but all prices within PJM are the same.

Q. **How does EDS estimate the price of capacity?**

A. EDS estimates that capacity will be freely traded in a deregulated capacity market. EDS further recognizes that each hour's need for capacity can be supplied from anywhere in the interconnection subject to available transmission transfer capability and to the cost of firm transmission service. The price of capacity is capped at the cost of a new unit.

Q. **Did you use the *EDS* estimates of the price of capacity in all years?**

A. No. From 1999 through 2001, ICF provided a better estimate of the capacity price on the PJM and was used instead of EDS estimates. EDS does not model the North East Power Coordinating Council (NPCC) and EDS' estimates did not incorporate possible purchases of capacity into PJM from that pool.

Q. **What years did EDS project?**

A. EDS projected market price annually from 1999 through 2015.

Q. **What do you project the market price to be beyond 2015?**

A. Beyond 2015, I project both market price and fuel costs to increase at the same 3.5% per year rate as the DRI/McGraw Hill projected change in the GDP deflator. This is reasonable given the uncertainty of projecting market trends 18 years in the future.

Q. **How do the EDS findings compare to the market price projections developed by PHB and ICF?**

A. The results of all three market price analyses are summarized in Exhibit JFB-1. As can be seen, the EDS market price projections are slightly higher than the values developed by PHB and ICF for most of the analysis. Similar comparisons of market revenues and net market revenues appear in Exhibits JFB-2 and JFB-3.

VII. PECO ASSESSMENT OF THE EFFECT OF LOCATION ON THE ENERGY MARKET PRICE OF PECO GENERATION

Q. Has PECO done any additional analysis of market price?

A. Yes. PECO used the PROMOD IV model which it licenses from EDS Utilities Division to assess the effect of the location of PECO generators on the energy market price available to PECO generators. PECO ran its PROMOD IV model for 1999 to examine the effect of location on the energy market price of PECO generation.

Q. How do the energy projections from PROMOD IV compare to the other three projections?

A. PROMOD IV projections for market price, market revenue of energy and market revenue of energy net of fuel for 1999 are in the same range as the other three projections.

Q. What is PROMOD IV?

A. PROMOD IV is a software package designed to calculate system production cost and plant operation by combining generating unit commitment modeling with an fully integrated transmission constrained dispatch.

Q. What is the basis for determining the market price of energy using PROMOD IV?

A. Similar to the other analyses, PROMOD IV determined the price available to generators based on its determination of the price at which the energy market will clear.

Q. What key factors were used in the PROMOD IV analysis?

A. PECO used DRI fuel price projections and EIA-411 load projections as used in the EDS analysis.

Q. What part of the Eastern Interconnection was modeled in the PROMOD IV analysis?

A. The PROMOD IV analysis modeled in detail the operation of all generators and load within PJM on an hourly basis. Generators outside PJM were modeled as equivalent supply curves. Sales outside PJM were modeled as fixed sales. Transmission was explicitly modeled for all parts of PJM and relevant parts of NEPOOL, ECAR and SERC.

Q. Why was PROMOD IV not used to project beyond 1999?

A. In 1999 the data base uses information about the characteristics of existing generation or known generator additions. PECO does not have a database that projects future new generation additions based on the relative economics of technologies and fuels.

Q. How does PROMOD IV project the value of generation based on its location?

A. PROMOD IV projects the value of generation in two ways. In the first method, prices are based on either the clearing price in the PJM pool absent transmission constraints or on operating costs when generation is operated to relieve constraints. This is the market clearing price method (MCP). In the second method, PROMOD IV calculates hourly locational spot prices for each PECO generator. Locational spot prices reflect the marginal price of serving one additional increment of load at that location. This is the locational spot price method (LMP). In either case, the price available to each generator multiplied by the generator's output gives an hourly market value which can be summed to get an annual market value.

Q. How do the projections from the two methods compare?

A. Exhibit JFB-10 provides PROMOD IV projections for PECO generation for energy only using the market clearing price method and the locational spot price method. The difference in market value net of fuel is extremely small. The locational spot price has $1.6 million lower value than the market clearing price method.

Q. How do the projections compare to projections without transmission constraints?

A. Exhibit JFB-10 provides the unconstrained energy only market price for PECO generation. This difference in market value net of fuel is less than $1.5 million.

Q. What is your conclusion based on your analysis?

A. The effect of transmission constraints on the energy revenue produced by PECO generation is minimal.

Q. Does the value of capacity vary by location within PJM?

A. Although capacity could be more valuable in a location with severely limited transmission capability, PJM has historically never valued capacity differently by location within PJM. My analysis projects that the location of generation within PJM will not affect the value of capacity in the future.

VIII. CONCLUSION

Q. Does this conclude your testimony?

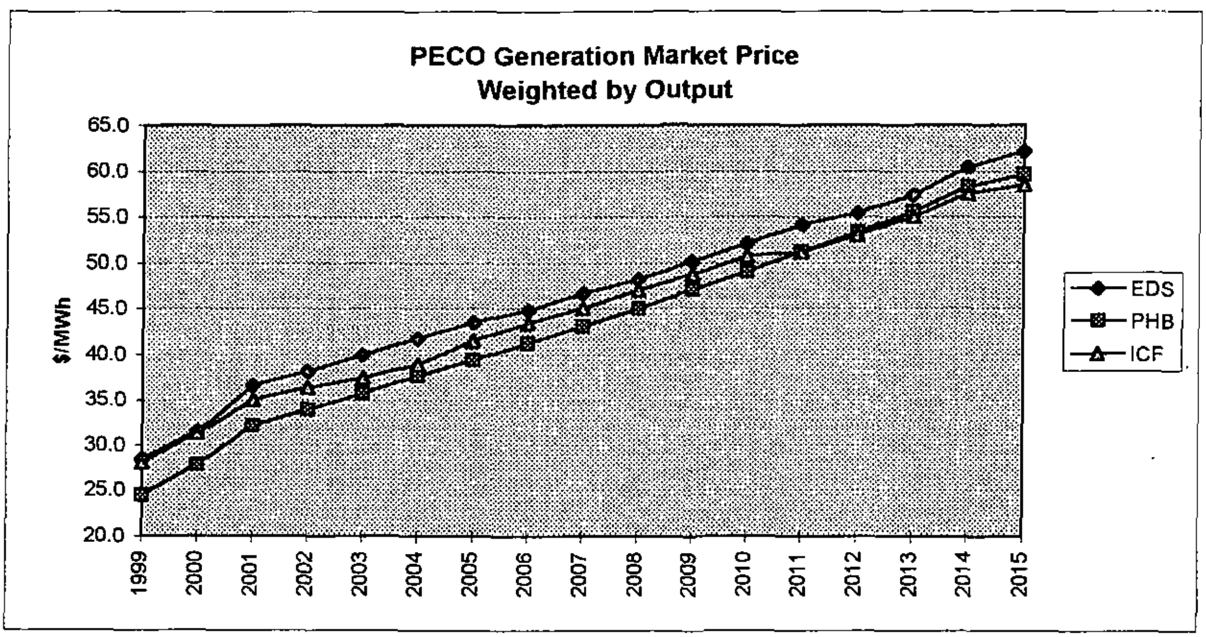
A. Yes.

PECO Generation Market Price

Weighted by Output (1)

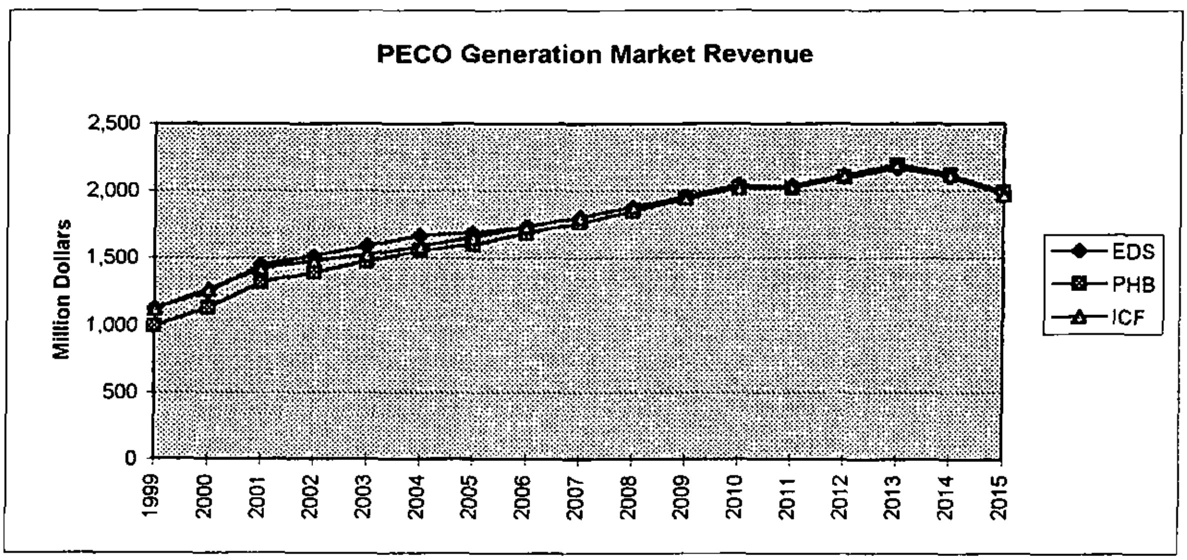
	$/MWh		
	EDS	PHB	ICF
1999	28.4	24.5	28.1
2000	31.5	27.8	31.3
2001	36.6	32.2	35.0
2002	38.2	33.9	36.4
2003	39.9	35.7	37.5
2004	41.7	37.6	38.9
2005	43.4	39.3	41.4
2006	44.8	41.1	43.3
2007	46.6	43.0	45.0
2008	48.2	44.9	47.0
2009	50.1	47.0	48.7
2010	52.1	49.0	50.6
2011	54.1	51.1	51.1
2012	55.4	53.3	53.0
2013	57.3	55.6	55.0
2014	60.4	58.3	57.5
2015	62.2	59.7	58.4

(1) - Weighted market price is the sum of market revenues for each PECO generating unit divided by the total output from all PECO generating units



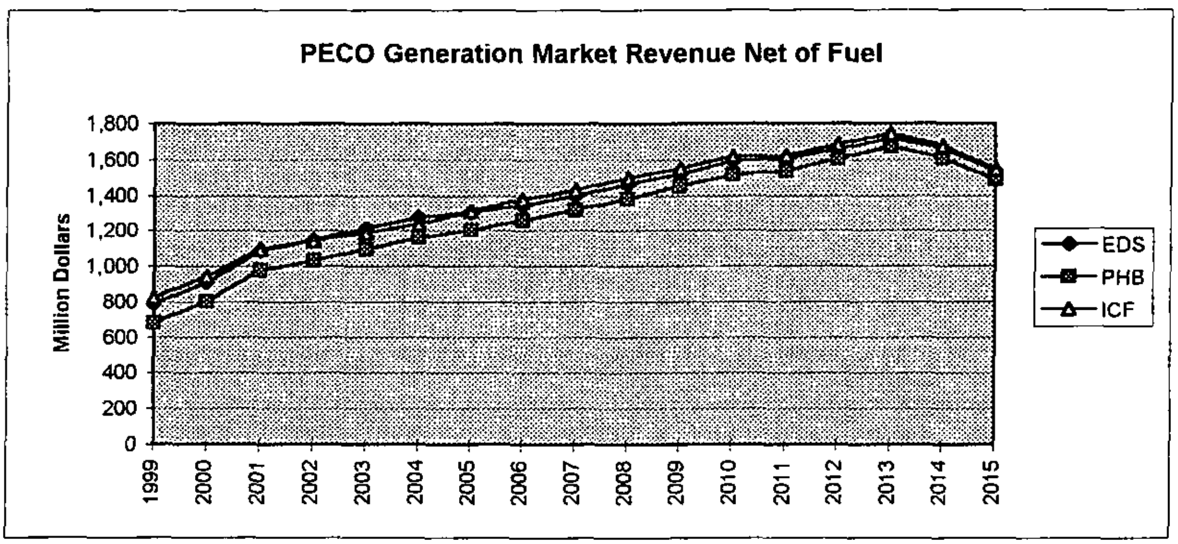
PECO Generation Market Revenue

	Million Dollars		
	EDS	PHB	ICF
1999	1,124	998	1,121
2000	1,249	1,133	1,266
2001	1,443	1,316	1,420
2002	1,513	1,391	1,478
2003	1,591	1,470	1,525
2004	1,665	1,557	1,585
2005	1,683	1,598	1,651
2006	1,729	1,676	1,729
2007	1,801	1,758	1,797
2008	1,878	1,845	1,878
2009	1,953	1,938	1,942
2010	2,042	2,019	2,020
2011	2,028	2,017	2,038
2012	2,096	2,102	2,115
2013	2,169	2,191	2,195
2014	2,106	2,120	2,121
2015	1,972	1,988	1,971



PECO Generation Market Revenue Net of Fuel

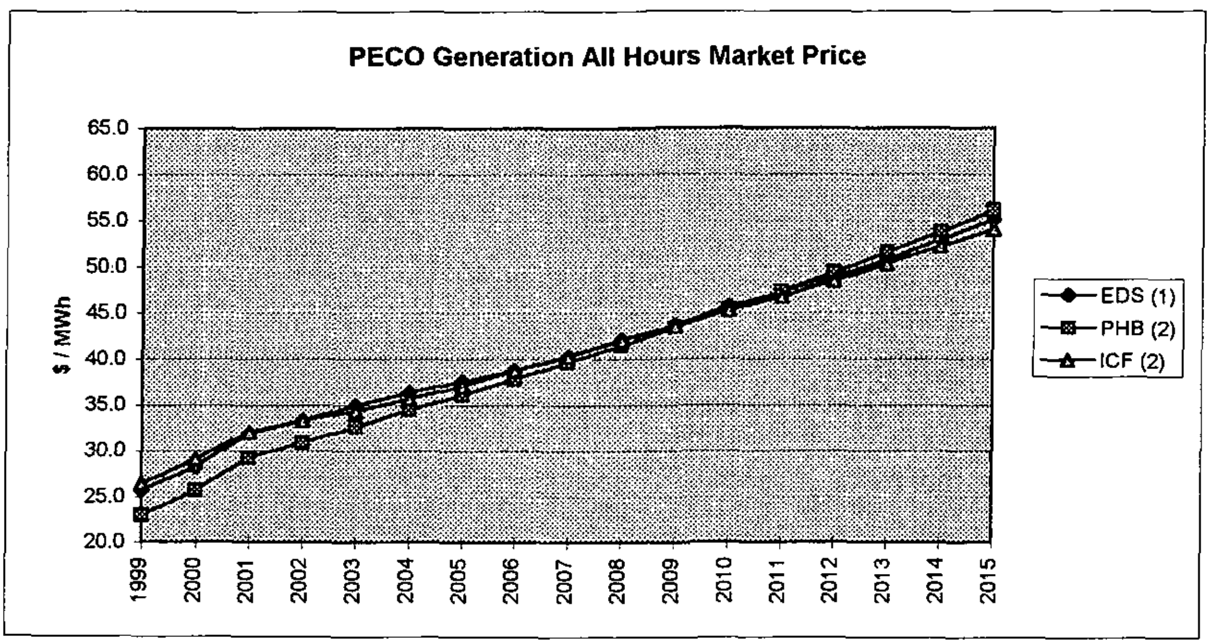
	Million Dollars		
	EDS	PHB	ICF
1999	791	680	823
2000	907	805	943
2001	1,090	976	1,094
2002	1,146	1,033	1,145
2003	1,211	1,094	1,186
2004	1,276	1,158	1,237
2005	1,303	1,201	1,312
2006	1,341	1,258	1,378
2007	1,398	1,318	1,432
2008	1,461	1,382	1,498
2009	1,518	1,450	1,552
2010	1,593	1,513	1,616
2011	1,603	1,535	1,621
2012	1,660	1,602	1,684
2013	1,719	1,673	1,745
2014	1,661	1,608	1,677
2015	1,534	1,486	1,544



PECO Generation All Hours Market Price

	$/MWh		
	EDS (1)	PHB (2)	ICF (2)
1999	25.7	23.0	26.4
2000	28.2	25.7	29.2
2001	31.9	29.2	32.1
2002	33.3	30.9	33.3
2003	34.9	32.6	34.3
2004	36.4	34.5	35.7
2005	37.6	36.1	37.1
2006	38.8	37.8	38.8
2007	40.3	39.6	40.3
2008	42.1	41.5	42.1
2009	43.7	43.5	43.5
2010	45.7	45.4	45.3
2011	47.3	47.3	46.8
2012	49.0	49.4	48.5
2013	50.7	51.5	50.3
2014	52.9	53.8	52.2
2015	55.1	56.1	54.0

(1) PECO generation all hours market price
(2) Limerick market price. Limerick is a close approximation to PECO generation all hours market price because Limerick operates all hours that it is available and is located in eastern PJM.

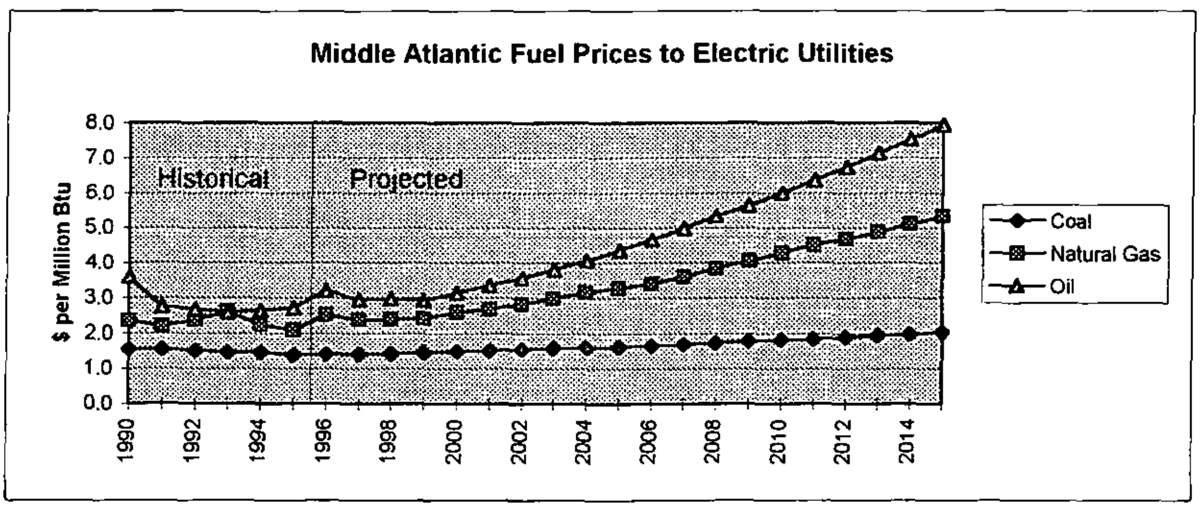


Historical and Expected Fuel Prices

Source: DRI McGraw-Hill World Energy Service U.S.Outlook, Fall/Winter 1996/97 Released Oct 1996

Price of Fuel Delivered to Middle Atlantic Electric Utilities

	(Dollars per Million Btu)		
	Coal	Natural Gas	Oil
1990	1.55	2.35	3.60
1991	1.55	2.18	2.74
1992	1.50	2.37	2.68
1993	1.46	2.60	.2.58
1994	1.45	2.22	2.63
1995	1.39	2.08	2.71
1996	1.40	2.51	3.21
1997	1.40	2.36	2.94
1998	1.41	2.39	2.97
1999	1.45	2.42	2.92
2000	1.49	2.58	3.14
2001	1.51	2.68	3.35
2002	1.54	2.82	3.57
2003	1.57	2.98	3.81
2004	1.60	3.15	4.08
2005	1.62	3.29	4.36
2006	1.65	3.41	4.66
2007	1.69	3.60	4.98
2008	1.73	3.83	5.32
2009	1.77	4.06	5.64
2010	1.82	4.29	5.99
2011	1.83	4.50	6.35
2012	1.88	4.69	6.73
2013	1.93	4.88	7.12
2014	1.98	5.11	7.54
2015	2.03	5.33	7.95



MAAC (PJM) Estimated Net Energy and Peak Demand for 1996 - 2005 and Actual Data for 1990-1995

01 Summer Peak Hour Demand - MW (1)

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
47,238	47,923	48,623	49,280	50,044	50,707	51,430	52,082	52,448	53,082

02 Winter Peak Hour Demand - MW (1)

1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06
41,891	42,678	43,301	43,982	44,748	45,309	46,008	46,652	46,672	47,413

03 Net Energy - GWh

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
242,963	246,608	250,390	254,039	257,992	262,238	265,877	269,705	271,905	276,054

01 Summer Peak Hour Demand - MW (1),(2)

1990	1991	1992	1993	1994	1995
42,613	45,937	43,658	46,494	46,019	48,577

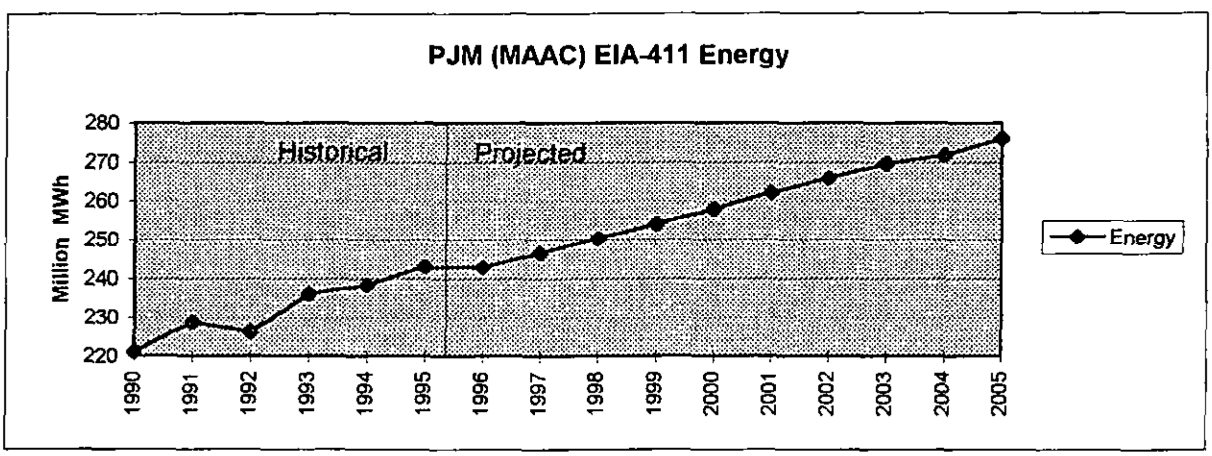
02 Winter Peak Hour Demand - MW (1),(2)

1990	1991	1992	1993	1994	1995
36,551	37,983	37,915	41,406	40,653	40,790

03 Net Energy - GWh

1990	1991	1992	1993	1994	1995
221,099	228,588	226,154	235,980	238,379	243,043

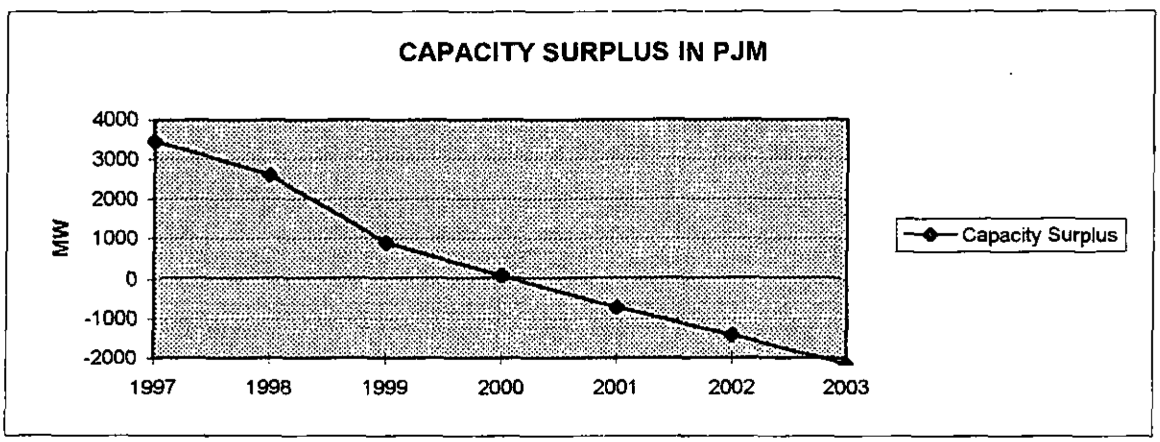
(1) Monthly coincident
(2) Metered peak demand.



PJM LOAD AND CAPACITY FORECAST

MW							
	1997	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**
Gross Capacity (1)	57,208	57,056	57,439	57,912	58,454	58,872	59,500
Uncommitted Capacity or	0	40	1,507	2,057	2,757	3,093	3,779
Removed from Service (2)							
Committed Capacity (3)	57,208	57,016	55,932	55,855	55,697	55,779	55,721
Load with Interruptible Load	45,554	46,093	46,643	47,257	47,804	48,463	49,050
Implemented (4)							
Required Capacity (5)	53,754	54,390	55,039	55,763	56,409	57,186	57,879
Capacity Surplus (6)	3,454	2,626	893	92	-712	-1,407	-2,158

(1) *Expected Load and Capacity Forecast (Summer) - PJM Capacity*
(2) Capacity Additions 1995-2010 Summer Capacity (includes all RFPs, bids, and unspecified purchases) and Removal of Cromby 2, Delaware 7&8 and Schuylkill 1
(3) = (1) - (2)
(4) Expected Load and Capacity Forecast (Summer) - PJM Load
(5) = 1.18 * (4) (assumes 18% reserves required to meet "1 in 10" MAAC criterion)
(6) = (3) - (5)



Key Factors Used in EDS Projections

Net Energy For Load

	PJM Energy GWh
1999	251,069
2000	254,922
2005	274,848
2010	295,872

Planning Reserve Margin

	MAAC	Other Regions
1999	18%	15%
2000	18%	15%
2005	18%	15%
2010	18%	15%

Fuel Prices for Typical Generating Units with No Season Variation

	Cone-maugh Coal	Eddystone Coal	Delaware Residual Oil	Cromby Gas	Croydon Distillate Oil
	$ per million Btu				
1999	1.23	1.50	2.42	2.42	4.19
2000	1.27	1.54	2.58	2.58	4.50
2005	1.34	1.68	3.29	3.29	6.25
2010	1.51	1.89	4.29	4.29	8.59

Generating Unit Non-Fuel Variable O&M Costs

	Coal	Oil	Gas
	$ per MWh		
1999	2.14	1.07	1.07
2000	2.20	1.10	1.10
2005	2.55	1.27	1.27
2010	3.04	1.52	1.52

Transmission Cost for All Control Areas

	Firm $/kW-month	Non-Firm $/MWh	Losses %
1999	1.60	3.21	3%
2000	1.65	3.29	3%
2005	1.91	3.82	3%
2010	2.28	4.56	3%

Transmission Limits Into PJM

	APS	CEI	VEPCO
	MW		
All Years	2294	306	2700

PMDAM™ MODELING SYSTEM OVERVIEW

Prepared for PECO Energy Company

The information contained within has been prepared for PECO Energy Company in relation to their Market Price Forecast Study performed in March 1997. The information is specific to the methodologies used for this particular study and may not comprehensively describe all capabilities of the PMDAM model.

PMDAM MODELING SYSTEM OVERVIEW

Introduction

The Power Market Decision Analysis Model (PMDAM) is a FORTRAN-based computer software model developed by Dr. Edward Cazalet in conjunction with the Bonneville Power Administration (BPA) to design and support competitve and regulated market analysis of power marketing resource acquisition transmission facilities, and power rate decisions. EDS/EMA acquired PMDAM to support strategic planning, competitive market modeling, multi-regional production costing and transmission economics modeling. The PMDAM model combines high-integrity planning software, up-to-date maintenance of data and power marketing information, the EDS commitment to on-going support, and fast response to client needs.

Figure 1 illustrates the basic structure of the PMDAM modeling system. All inputs into the center box determine equations which simulate physical utility operations as well as rules for decision making which determine when and how power contract and generating resource acquisition occurs. The bottom box shows the iterative solution algorithm that solves the system of equations. Based on the solution to these equations, PMDAM provides information on the operation and acquisition of the system elements and decision criteria outcomes. The double arrow lines in Figure 1 indicate this feedback.

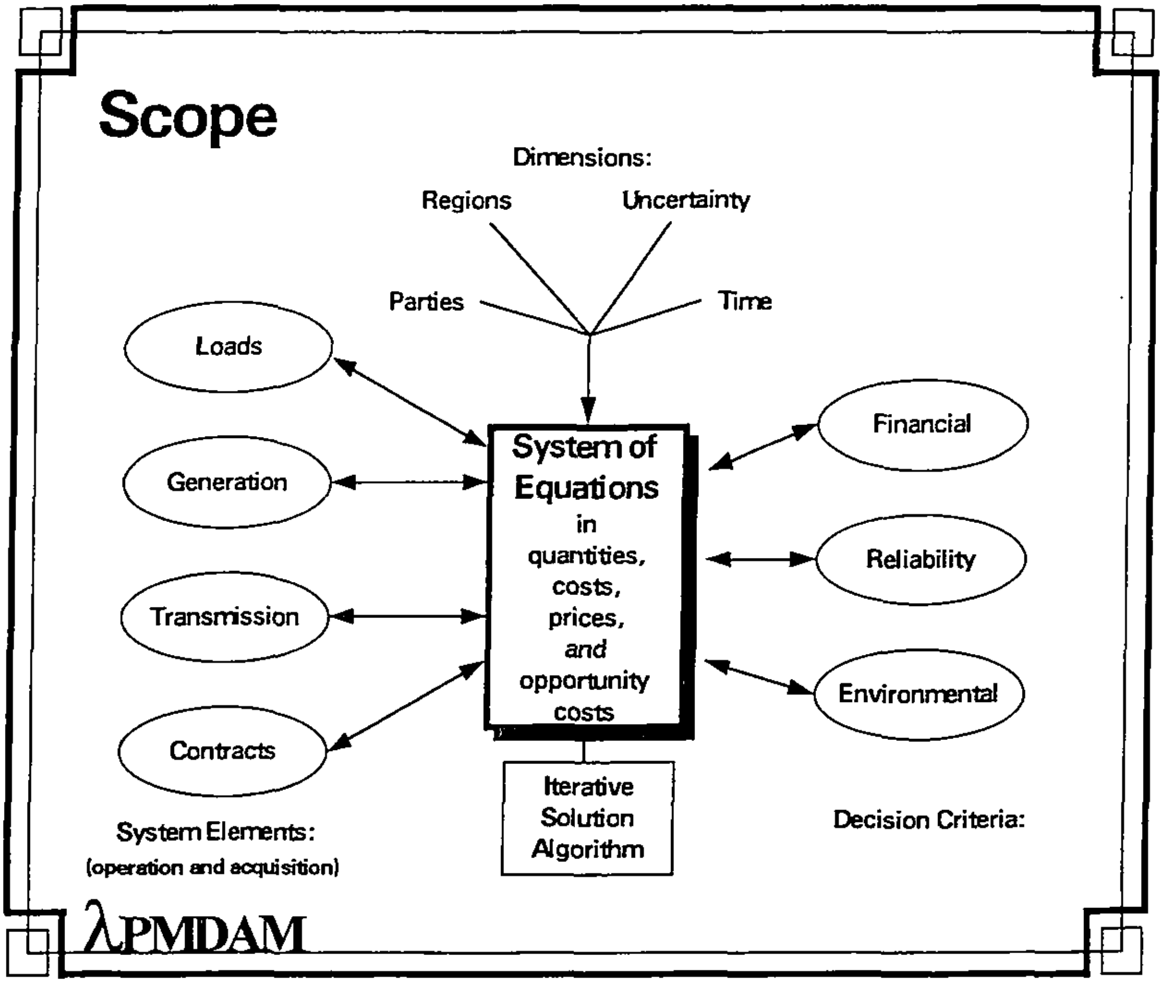


Figure 1 Structure of the PMDAM Modeling System

Capabilities

PMDAM models the operation and acquisition of generating and contract resources simultaneously through an iterative algorithm briefly described in the "Methodology" section below. In addition, PMDAM models ownership of all major inter-regional transmission lines including estimates of inter-regional losses. Scheduled transmission flows are based on the economic operation of generating resources and power contracts subject to contractual and transmission scheduling limits. For more information regarding the transmission modeling capabilities in PMDAM, see the section below titled "Transmission Modeling In PMDAM".

The PMDAM model represents all existing long-term power contracts between parties, as well as a large number of generic new contracts among all parties. This enables the model to decide on the amount of each type of contract to write among the parties. For more information regarding the contract modeling capabilities in PMDAM, see the section below titled "Contract Modeling In PMDAM".

Methodology

The following simple example illustrates the iterative algorithm applied by PMDAM to solve the large system of physical and behavioral equations and constraints. Every constraint/equation within the PMDAM system is associated with an opportunity cost (also referred to as marginal cost). A primary physical equation requires that, for a given hour and party operating in a particular region, total generation plus power purchases equal native load plus any sales.

The iterative algorithm starts with an initial system marginal cost estimate in mills/kWh at which the described equation is in balance. The model then dispatches all generating units and seeks all purchases (from other parties) which cost less than the estimated marginal cost and serve only those sales loads worth more than the estimate. PMDAM then computes the actual surplus or deficient energy resulting from this estimate. Next, the model makes an adjustment to the estimate of the marginal cost by applying a step-size multiplier against the calculated energy surplus / deficiency. This process repeats until the surplus / deficiency converges toward zero. Figure 2 illustrates this simplified iterative algorithm.

The way the algorithm is constructed, the solution includes no additional energy from generation or purchases that would cost less than the converged marginal cost and no additional sales opportunity worth more than the same marginal cost. Therefore the solution is a least-cost one.

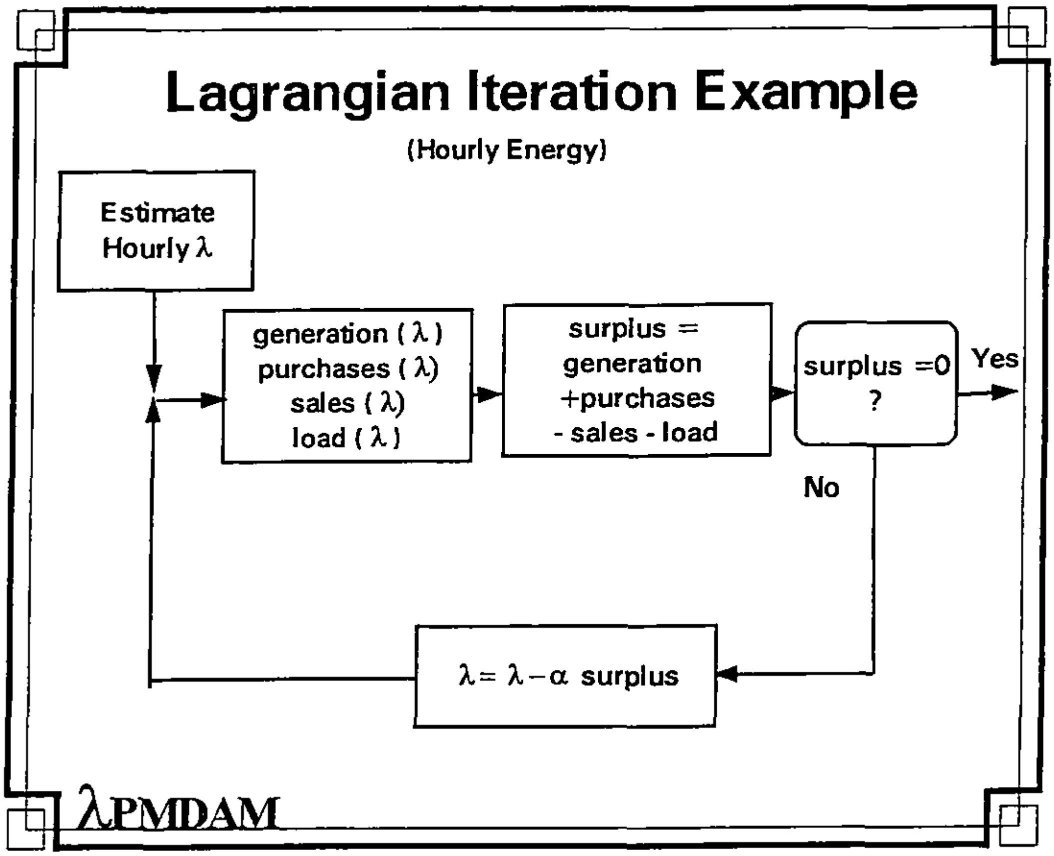


Figure 2 Lagrangian Iteration

Using this iterative methodology, the model calculates other opportunity or marginal costs associated with other equations and constraints such as non-firm energy, firm energy, and transmission and generation capacity costs. These opportunity costs show not only how much a party is willing to pay for each fundamental commodity in the market, but also the minimum price a party will accept for the sale of such commodities.

The power of this iterative algorithm is that the model automatically addresses the interconnection of a party's optimization problem (finding the least cost-of-service solution) to other parties' optimization problems. Simultaneous equation-solving capability allows PMDAM to correctly address the interdependence of some model variables. For example, the opportunity price of hydro energy is dependent on the operating cost of thermal energy generation. It is necessary to make decisions to generate hydro energy or increase storage capacity subject to maximum and minimum storage levels in conjunction with the commitment and dispatch of thermal units.

Decisions to invest in inter-regional transmission upgrades, acquire generating resources, and enter into power contract negotiations are highly interrelated and are best modeled in unison to capture the dynamics of the bulk power market. In multi-regional production costing and transmission modeling everything seems to be interconnected. The principal purpose of PMDAM is to cut through this complexity and develop insight into the key factors as well as key areas determining significant opportunities for increased efficiency and cost savings.

Contract Modeling in PMDAM

Firm Energy and Capacity Contracts:

Energy puts and calls can be modeled to meet the buyer's firm energy requirements without guaranteeing capacity. The decision maker on operation of the contracts can be either the buying party (call) or the selling party (put). PMDAM automatically operates the contract from the viewpoint of the decision maker who is seeking to minimize production costs. The energy delivered on such contracts can be limited by an annual load factor or represent take-or-pay type contracts where the buyer must take all energy specified by the contract.

New Generic Contracts:

The contract writing capability within the PMDAM modeling system will give you valuable insight into the bulk power market and as well as understanding of important buyer and seller market signals. Depending on inherent economic benefits for the potential buyer and seller of capacity, PMDAM writes non-firm and firm energy contracts between parties. Outputs from the PMDAM modeling system include quantities, prices, and duration of power contracts for the delivery of firm or non-firm energy and capacity.

Economy interchange transactions require almost no input, as PMDAM will automatically schedule hourly spot market transactions between the parties based on differentials in system marginal energy costs. In addition, economy energy flows are subject to physical constraints and limitations on transmission capabilities. The model will examine all contract combinations between parties defined in the database based on a pre specified maximum number of transmission owners over which the economy energy transaction is to occur. The user may control the amount of economy energy flows by specifying a minimum margin for such transactions expressed in mills/kWh. In addition, input variable margins for economy energy will determine how much additional economy energy to schedule per mill of benefit to the selling party. In this fashion, imperfect market conditions and behavioral decision making may be modeled.

PMDAM defines energy firmness as the ability of a utility to meet its firm load requirements under adverse hydro conditions and use of its committed resources year round. The model seeks out utilities which place different values on firmness of energy. For example, a one utility may place a high value on energy firmness due to the low flexibility in its hydro energy generation, whereas another may not value energy firmness as the utility has enough thermal resources installed to meet its annual energy requirements under adverse hydro conditions. The PMDAM modeling system automatically writes firm energy contracts between such parties where there is an economic benefit to both parties. Depending on the underlying loadshapes of the two parties and which party is decision maker in scheduling of the contract, PMDAM calculates the appropriate load factors, contract size, and prices for such transactions.

Demand contracts writing takes place between parties which have different needs for capacity. Based on respective reserve margin or loss of load probability criteria, installed capacity, and peak load hours, two parties may be on opposite ends of the spectrum with respect to how they view the value of capacity. One may have a surplus, the other a shortage. PMDAM recognizes such differences on a monthly basis and suggests monthly amounts of contract capacity between parties. The decision for two parties in the model to enter into a long-term or short-term capacity contract is dependent on the value of capacity over time. One party may be limited to building more costly generating resources and may want to enter into a long-term capacity contract to defer installation of expensive generation. Another utility may be part of a subregion in which its neighboring utilities have an abundance of capacity and opt for a shorter-term capacity contract with substantial savings over long-term contract rates.

Acquisition of Resources

The decision for a utility to acquire new generating resources is directly linked to the decision to acquire demand and capacity contracts. PMDAM currently has extensive capacity expansion capability both for firm contracts and generating facilities. PMDAM, by design, determines the least-cost amount and mix of generating capacity additions and firm power contracts among companies. The capacity expansion plans generated by PMDAM reflect transmission constraints, access, ownership, and losses. The plans are integrated with the modeling of system operation and account for the individual reliability, discount rate, environmental, load, and cost factors each utility faces.

In a competitive marketplace, the value of capacity is not dependent on the embedded cost of the resource but on supply and demand. Depending on the availability of capacity in the subregions modeled, a party short on capacity may be well advised to seek a long-term power contract in favor of building a new resource. PMDAM performs this type of cost-benefit analysis. Figure 3 shows the components of the net benefits associated with contract and resource acquisition decision.

making. Based on the comparison of the sum of these net benefits on a present- value basis, PMDAM will form the buy-versus-build decision.

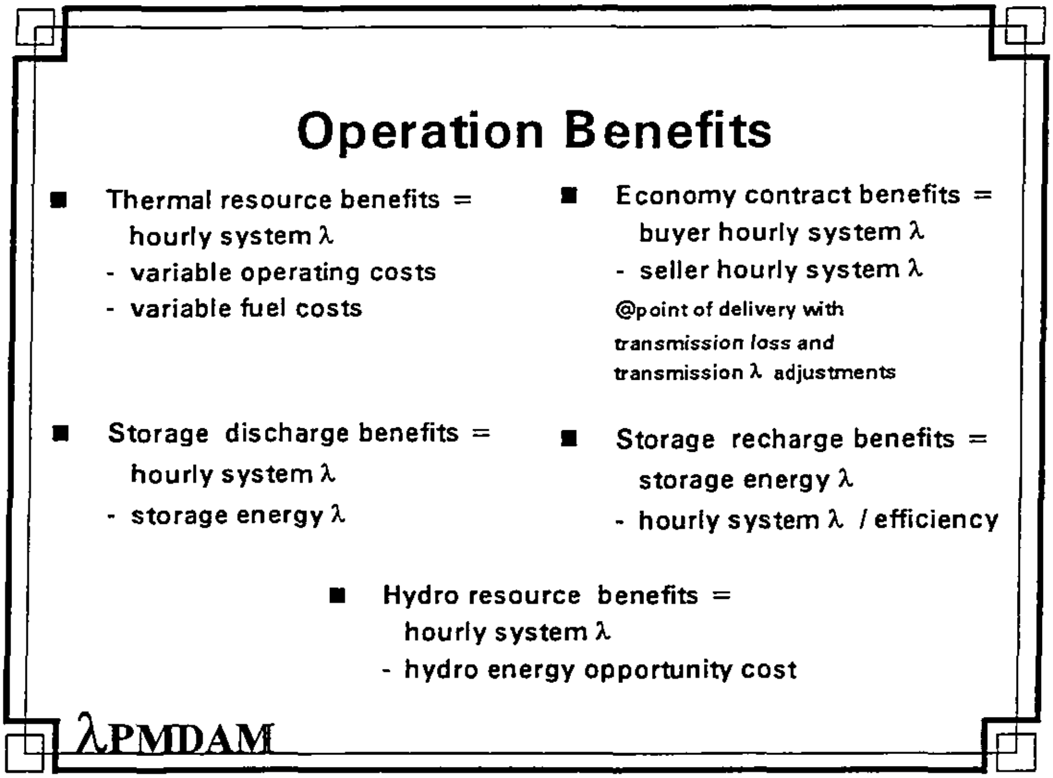


Figure 3 Operation Benefits

Mothball Analysis

In an increasingly competitive environment, utilities will closely examine the decision to mothball existing power plants if the fixed O&M savings resulting from mothballing outweigh any operational and reliability value of the units. PMDAM will allow the user to enter mothball costs by unit and will make to decision to mothball if the savings outweigh the net benefits. As load growth occurs over time and the value of capacity increases, PMDAM will take the unit out of mothball status and return it to operation if the underlying economics warrant such action.

Transmission Modeling in PMDAM

The PMDAM transmission model is data driven. It is possible to represent any number of lines, busses areas, and points of delivery in the model. In the PMDAM model each line in the network can be the property of one or more model parties or companies. The ownership of a line can change at intermediate points of delivery on the line. Limits are provided on each line by ownership and on the simultaneous transfer among groups of lines. Limits can depend on other variables so it is possible to model nomograms and area requirements.

Hourly Transmission Operation

The PMDAM model solves a system of equations for each hour representing both the physics and the economics of the transmission system. This system of equations is fully integrated with the systems of equations used by the model for production costing, acquisition, and all other model computations. PMDAM uses no sequential approximations on the solution of these equations, in contrast to other models that use a less accurate step-by-step procedural approach. The model carries out these computations in chronological order hour by hour.

The PMDAM model can represent hourly transmission system operation using a pipeline/transportation model. In the pipeline/transportation model, scheduled and actual flows are identical and losses are proportional to the square of the flow or load on a line. In this transportation mode, PMDAM will dispatch generating projects to provide the least-cost mix of generation, purchases, and sales for each company, assuming only mutually beneficial interchange among companies. Interchange sales on the transmission network are limited by ownership shares of lines along access paths determined by the model users. It is also possible to simulate open access. All of the interchange transactions recognize losses as a function of line loading and these losses affect the economics of the transactions. The model computes prices on transmission lines as a part of the algorithm. These prices may be cost of service or market based.

Transmission Firm Planning

PMDAM also uses the firm capability of each line, or group of lines, to limit and allocate the use of the transmission system for firm contracts. All existing firm contracts among parties are input to PMDAM. PMDAM adds new firm power contracts as part of the generation and power contact acquisition process in the model. The total requirement for firm transmission capacity specified in these contracts is compared to the available firm transmission capacity. Determination of access to firm transmission capacity is through model input data.

The PMDAM algorithm simultaneously solves for the least-cost additions of generation projects and power contracts in each month and year of the model horizon, the firm capacity opportunity cost in $/kW-mo for each party and area, and the firm transmission capacity opportunity cost for each line. This transmission opportunity cost is related to the differences in capacity opportunity costs among the model areas.

The firm transmission opportunity cost in each direction plus the hourly transmission opportunity costs provide valuable information to transmission planners on the need and value of new lines or upgrades to eliminate bottlenecks.

PMDAM can also summarize the firm and hourly transmission opportunity costs as a present value over the assumed life of a transmission line. This present value can be compared to the present value of capital and operating costs of a project to add transmission capability. In contrast to other models, with PMDAM it does not take multiple runs to determine the opportunity cost of transmission capacity. A single run will provide operating and firm transmission opportunity costs for all lines in the model.

A potential and very feasible enhancement of PMDAM would be to provide information on the costs of new lines and upgrades and let PMDAM simulate the acquisition of these lines in the same way it simulates the acquisition of generating resources and power contracts.

Comparison of PROMOD IV to Other Projections

1999

		EDS	ICF	PHB	PROMOD
Weighted Market Price Energy Only	$/MWh	23.2	22.9	21.1	22.6
Market Revenue from Energy Only	$ 000	919,671	915,800	859,282	902,916
Market Revenue from Energy Net of Fuel	$ 000	586,054	617,500	541,592	604,345

PROMOD Based on Market Clearing Price Method

Effect of Transmission Constraint Control on Market Price of Energy
PROMOD IV ANALYSIS

1999 Energy Only

				Market Price			Market Revenue			Market Revenue Net of Fuel		
	MCP	LMP	Uncon.	MCP	LMP	Uncon.	MCP	LMP	Uncon.	MCP	LMP	Uncon.
		GWh			$/MWh			(1000 $)			(1000 $)	
Cromby 1		910.7			22.78			20,746			6,369	
Cromby 2		399.6			27.35			10,929			513	
Delaware 7		38.2			32.58			1,244			-129	
Delaware 8		129.6			30.12			3,904			-39	
Eddystone 1		1,254.0			22.67			28,427			8,981	
Eddystone 2		1,319.7			22.24			29,356			8,965	
Eddystone 3		70.5			33.21			2,341			-604	
Eddystone 4		54.5			32.90			1,793			-580	
Schuylkill 1		28.8			34.89			1,005			-128	
Limerick 1		8,970.7			21.81			195,644			157,213	
Limerick 2		8,485.0			22.42			190,274			154,472	
Peach Bottom 2		3,163.1			22.35			70,705			52,858	
Peach Bottom 3		2,908.4			21.70			63,119			46,362	
Salem 1		1,971.3			22.38			44,120			32,561	
Salem 2		2,015.4			22.16			44,669			32,642	
Keystone 1		1,214.7			22.38			27,180			14,916	
Keystone 2		1,338.4			22.10			29,584			16,109	
Conemaugh 1		1,448.4			22.07			31,973			14,713	
Conemaugh 2		1,199.5			22.21			26,640			12,204	
PECo CTs		3.3			40.86			135			-39	
PECo Diesels		0.2			49.89			10			2	
Conowingo		1,771.0			24.24			42,929			42,929	
Muddy Run - PS		1,764.5			18.21			-32,131			-32,131	
Muddy Run - Gen		1,246.2			27.76			34,599			34,599	
Total		39,941.2			22.57			901,325			634,888	

PECO STATEMENT NO. 5

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

DIRECT TESTIMONY

OF

BANGALORE S. VENKATESHWARA

Regarding Market Price for PECO Energy Generation

TABLE OF CONTENTS

DIRECT TESTIMONY OF B. VENKATESHWARA

I. QUALIFICATIONS

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

A. My name is Bangalore S. Venkateshwara. I am a Vice President at ICF Resources Incorporated. My address is 9300 Lee Highway, Fairfax, Virginia, 22031. ICF Resources has been at the forefront of consulting on energy issues for over 20 years. The firm provides consulting services related to all sectors of the U.S. energy economy, including oil, natural gas, coal, electric utilities, and independent power.

Q. **Please describe your educational and professional background as well as your responsibilities at ICF Resources.**

A. Appendix A to this testimony contains a copy of my resume which provides the requested information.

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

I direct analytic projects in the energy area for a wide range of clients, both in the public and private sectors and have offered expert testimony in several jurisdictions. I have also been responsible for directing a large number of studies dealing with projections of electric prices in several U.S. bulk power markets including, for instance, PJM, the New York Power Pool, (NYPP), the New England Power Pool (NEPOOL), Virginia and the Carolinas (VACAR), Peninsular Florida, and the Midwest. These studies have been based on integrated, market-wide modeling designed to reflect the workings of a deregulated bulk power market. In particular, many of these studies have focused on PJM.

II. INTRODUCTION AND SUMMARY

Q. **On whose behalf are you testifying?**

A. I am testifying on behalf of PECO Energy Company ("PECO"), 2301 Market Street, Philadelphia, PA 19103.

Q. **What is the purpose of your testimony?**

A. As part of its application seeking approval of its Restructuring Plan, PECO Energy has prepared estimates of its stranded costs and is seeking recovery of those costs. One element of such an estimate of stranded costs is the market price for electric capacity and energy that is expected to prevail in the future PJM bulk power market. A related calculation is the electric capacity and electric energy revenues that each specific PECO unit would expect to realize if it sold its output into the PJM bulk power market. The revenues that a specific unit would realize will depend upon its operating characteristics (e.g., a higher variable cost unit would operate for fewer hours than a lower variable cost unit, affecting the respective electric energy revenues of each). As further discussed by Thomas P. Hill, Jr., (Statement No. 1) the electric capacity and electric energy revenues on a unit-by-unit basis are used, in part, to derive a present value income estimate for generation units.

In the above context, the purpose of this testimony is to provide the following:

1. Estimates of the electric capacity and electric energy revenues that each PECO unit is expected to derive by selling its electric capacity and energy into the future PJM bulk power market.

2. Estimates of the underlying fuel and related costs that each PECO unit is expected to see, assuming that it faces the same market for fuels and SO_2 allowances as other, competing bulk power generators.

Q. **Please summarize the results of your work.**

A. The results of my work are summarized in Exhibit BSV-1.

Q. **Did you submit testimony in PECO's Application for Issuance of a Qualified Rate Order filing?**

A. Yes. I submitted direct and rebuttal testimony.

III. APPROACH

Q. **You have mentioned that your estimates pertain to the "future PJM bulk power market." Please explain what you mean by this phrase.**

A. At the present time, PJM functions as if it were one system to achieve the highest practicable degree of economy and reliability. The current PJM system is governed by the PJM Interconnection Agreement, which is an agreement entered into by the various regulated, franchised utilities in PJM.

PJM, like other markets, is in the process of reforming its institutional arrangements so as to facilitate an open and competitive bulk power market, consistent with the Federal Energy Regulatory Commission's (FERC) Order 888-A. Issues relating to the new institutional arrangements that will govern PJM have not yet been settled, although several proposals have been made. In a February 28, 1997 Order, FERC allowed the PJM filings to become effective March 1, 1997, subject to refund and subject to the issuance of further orders (see FERC Order in Docket Nos. OA97-261-000 and ER97-1082-000). Thus, while many details remain to be resolved, the outlines of the "future PJM bulk power market" are becoming clear. They are:

1. The responsibility for operation and real-time coordination of the bulk power system across the single control area, PJM, will be in the hands of an Independent System Operator (ISO). The ISO will (i) administer one PJM-wide transmission tariff aimed at facilitating an open and competitive bulk power market, and (ii) set "rules of the road", as necessary, to maintain reliability.

2. Owners of generation ("generators" or "generation companies") within PJM will be able to sell their output to "Load-Serving Entities" (LSEs) -- or those who serve electric customers at retail -- by delivering such output anywhere on the PJM bulk power transmission system. This sale of output will be facilitated by the fact that LSEs will be eligible for Network Transmission Service or service that will enable them to take receipt of electric output anywhere on the bulk power transmission system.

3. Generation companies outside PJM will be able to deliver their output on the PJM bulk power transmission system pursuant to the applicable transmission tariff administered by the ISO. Similarly, generation companies within PJM will be able to sell their output to buyers outside PJM and will have the ability to deliver their output to interconnection points between PJM and neighboring regions pursuant to applicable ISO-administered transmission tariffs. Service into PJM, outside PJM, or through PJM will be subject to the availability of adequate transmission capacity.

4. In this context, there will be an active hourly market for electric energy in which the price of electric energy will be determined by the interaction of hourly supply and demand. The hourly market price for electric energy (i.e., spot energy) will be visible to buyers in after-the-fact hourly prices declared by an exchange and in indices that track market information on the transactions entered into by willing buyers and willing sellers.

5. Buyers and sellers will also enter into agreements for (a) "pure capacity" (as discussed below), as well as (b) capacity and associated energy, on both a short and long-term basis.

6. It is conceivable, although not certain, that in the future there may exist an hourly market that reflects the price of both capacity and energy.

My analysis is based upon the premise that a number of generators (i.e., sellers inside and outside PJM) and LSEs (i.e., buyers inside and outside PJM) will participate in what will be a competitive bulk power market and that the price of electric capacity and energy will be determined by the resulting dynamics of supply and demand.

Q. **Assuming that the future bulk power market will possess the above characteristics, please provide the conceptual underpinnings for your market price of capacity and energy.**

A. The market price of electric capacity and energy (or the market price of electric output) in the bulk power market of the future can be thought of as having two components:

1. The price of electric capacity refers to a payment (typically stated in \$/kW/month or \$/kW/year) that a buyer makes to a seller in exchange for which payment the buyer obtains the right to call on the seller's electric energy at a known price for electric energy. The buyer makes the payment in \$/kW/month or \$/kW/year regardless of whether or not it calls upon electric energy. The price for electric energy is paid only if the buyer calls upon such energy. I use the term "pure capacity" to refer to a situation in which the price of electric energy attaching to the capacity is set at a relatively high level, so that the buyer does not call upon the energy often. A classic example would be one in which the price of electric energy is set equal to say, the variable cost of producing electric energy using an aging combustion turbine. A buyer that has paid for and purchased such a right has effectively protected itself against a curtailment or a sharp run-up in the

price of electric energy during hours when the balance between supply and demand is tight.

2. The price of electric energy can be viewed as the price during an upcoming hour at which a single buyer can buy a reasonable increment and a single seller can sell a reasonable increment of electric energy in MWh/hr, provided that either buyer or seller can terminate the transaction with one-half hour's notice. Under this definition, during all hours, except those hours when load might exceed available resources in the marketplace, the marginal generation will determine the price of electric energy. During hours when loads exceed available resources, the price effectively will be set by the "willingness to pay to avoid being curtailed" on the part of buyers.

Q. **What methodology do you employ to project the market price of pure electric capacity?**

A. With respect to the price of "pure capacity", it will be equal to the properly annualized market-based price of a new combustion turbine, as of the date when the market will need to add capacity to maintain adequate reliability. This is because a combustion turbine represents the most attractive source for providing "pure capacity" and hence the market price for "pure capacity" generally will be determined by a combustion turbine. Prior to the date when additional capacity is needed to maintain adequate reliability, the market is in "excess capacity". During such period of excess capacity, the price of capacity will be greater than zero, but less than the properly annualized market-based price of a new combustion turbine. The approach I employ is to infer the price of pure capacity during periods of excess capacity by examining (i) the degree of excess capacity, measured by the extent to which the prevailing reserve margin exceeds the level required to *maintain adequate reliability; and (ii) actual transactions for "pure capacity"* entered into by willing buyers and willing sellers, during periods of excess capacity.

Q. You state above that the market price for "pure capacity" generally will be determined by a combustion turbine. Are there circumstances when that is not true?

A. There can arise circumstances where the market price for "pure capacity" can become lower than the appropriately annualized cost of a combustion turbine. In particular, depending on the market price for electric energy, and the overall economics of new combined cycle unit investments, there are conditions under which a new combined cycle unit can be an economically attractive investment even with pure capacity payments lower than that associated with a new combustion turbine. I project, however, that within PJM, under my assumptions, the economics of new combined cycle units are not clearly attractive enough to make such a downward pressure on pure capacity prices very likely.

Q. **What methodology do you employ to project the market price of electric energy?**

A. To project the market price of electric energy, I employ a multi-area production cost modeling framework that mimics the behavior of the future bulk power market. In particular, the production cost model, the Integrated Planning Model (IPM), reflects the following:

1. A representation of PJM that (a) delineates East, West and South PJM with realistic transmission constraints across these regions; and (b) reflects appropriately constrained transmission links between PJM and other bulk power markets, notably the New York Power Pool (NYPP) and the East Central Area Reliability Council (ECAR). In my model-based projections, all the loads and generating resources in NYPP and the New England Power Pool (NEPOOL) are represented, while the imports from ECAR into PJM are modeled as an external transaction.

2. A representation of loads and generating resources across the PJM bulk power market.

   In particular, as part of representing this balance into the future, loads are projected into the future and future generating resources that the market can be rationally expected to bring on line are incorporated. Similarly, the availability and operating characteristics of existing units are represented. As noted, it is this balance between supply and demand that determines the spot electric energy price.

3. Future fuel prices faced by the bulk power market which, absent unit-specific circumstances, will be the same for PECO and all other generators are based on explicit projections.

4. Acid rain compliance decisions are represented and their effect on the spot electric energy price is taken into account. No comparable adjustment is made for NO_x or particulate emissions.

A more detailed explanation of the workings of IPM can be found in Appendix B. The IPM results can be used to derive a spot electric energy price that matches the definition set forth above. In particular, IPM generates a spot electric energy price for each model segment in each season. These results can be interpreted by a sequence of additional calculations to yield hourly spot electric energy prices. For the purpose of estimating unit-by-unit revenues, however, I have relied upon model-based, segment specific, spot energy prices rather than interpreted hourly spot prices.

Q. **Please explain whether the results from IPM capture differences in spot electric energy prices across the model regions and the significance of these results in the context of the estimates presented here.**

A. The results from IPM do capture differences in spot electric prices across the model regions (i.e., East, West, and South). Notably, during transmission-constrained periods, the spot price in a transmission constrained receiving region such as East PJM will be higher than the spot price in an exporting region such as West PJM. For purposes of estimating the revenue realized by each PECO unit, I use the spot price corresponding to the region in which the unit is located.

Because a large number of PECO units are located in East PJM and spot electric energy prices in East PJM are in general higher than West PJM, the resulting realized revenue for PECO units will be higher than what might have been realized with unconstrained spot prices. This, in turn, means that from the perspective of estimating stranded costs, the approach of using area-specific spot prices is conservative (i.e., acts to lower stranded cost estimates).

Q. Are your results for spot electric prices consistent in concept with the way PJM will work in the future?

A. Because the use of regional spot energy prices projected by IPM for PJM is, as noted, conservative in the context of this work, I have used IPM's regional spot energy prices. The regions in IPM are East PJM, West PJM, and South PJM. In addition to being conservative in the context of this proceeding, the use of regional spot energy prices may well turn out to be the direction in which PJM evolves, although these regional spot energy prices may be replaced by locational marginal prices with yet-to-be-determined locations. In particular, in its February 28 Order in Docket Nos. OA97-261-000 and ER97-1082-000, FERC expressed its view that ultimately the proposal of the PJM Supporting Companies [1] to use locational marginal prices will "promote more efficient trading and will be more compatible with the type of competitive market mechanisms we are encouraging."

[1] Supporting Companies is a reference to all current PJM members except PECO Energy. PECO Energy supported an alternative proposal.

IV. RESULTS

Q. **In addition to the basic premises listed above with respect to the future bulk power market, are your results based upon specific projections about the fuel market and economic conditions?**

A. Yes, they are based upon a set of explicit projections.

Q. **Please state the key projections underlying your results.**

A. The key projections relate to (a) overall electric market conditions, including electric load growth, the response of the marketplace to such load growth, and the performance of existing and future generating units (notably their availability); and (b) future market conditions in the gas, oil and coal markets.

Exhibit BSV-2 sets forth the key projections underlying my results. These projections fall within a reasonable range.

Q. **How far in time do your model-based projections extend?**

A. My model-based projections extend through 2015. Given the inherent uncertainty, especially after 2015, in the underlying drivers, I felt it appropriate to terminate the model-based projections as of 2015.

Q. **Are there any points you would like to emphasize with respect to your projections?**

A. Yes, I would. In particular, with respect to the driving projections, there are four items I would like to emphasize.

1. I have used the official projection of the Mid Atlantic Area Council (MAAC) utilities as embodied in their annual filing known as the EIA-411 in order to maintain consistency with the official peak and energy demand projections of the individual PJM utilities.

2. My fuel prices reflect the most recent projections independently developed by ICF Resources.

3. My projection is that, over the long-term, poolwide planning reserve margins in PJM will settle around 18 percent. For the 1998-99 planning year it has fallen to 20 percent. The expectation of a further decline to 18 percent is reasonable, given certain trends that are in place today. Notably, with a deregulated market, there will be a greater incentive to improve unit availabilities and this, in turn, will lower the required reserve margin, all else being the same.

4. PECO has shown Cromby 2, Delaware 7 & 8, and Schuylkill 1 to be uneconomic to continue in operation. My projection reflects the assumption that these units will not be available for service during the forecast period. In addition, I removed the nuclear units Peach Bottom 2 (1,093 MW) and Peach Bottom 3 (1,093 MW) from service in 2014 and 2015, respectively, based on the expiration of their commercial operating licenses. I also removed the Oyster Creek (619 MW) in 2009, Three Mile Island 1 (786 MW) in 2015, and Calvert Cliffs (835 MW) in 2015, based

on the expiration of their commercial operating licenses. A complete list of units removed from service is contained in Exhibit BSV 2.

Q. **Please describe the results of your analyses.**

A. The results of my analyses are set forth in Exhibit BSV-1. Exhibit BSV-1 shows the realized market price of PECO units, taking into account both the market price for capacity and energy. In particular, the realized market price reflects (a) the capacity value as the product of the market price for capacity in $/kW/year and the available capacity of the PECO unit; and (b) the energy value as the product of the electric output supplied by the PECO units during their hours of operation and the market price for electric energy during those hours of operation. For convenience the total value realized in dollars is divided by the electric output in MWh and the resulting number is expressed in $/MWh.

Q. **Do you have any other observations to make with respect to these results?**

A. Yes. It is worth noting that while my projections allow for interactions with other regions, subject to transmission constraints, in determining electric energy prices, they do not reflect the ability of buyers in PJM to buy pure capacity from neighboring markets. My rationale for this somewhat conservative assumption is that the planning reserve margins established for the PJM market in my modeling already reflect the ability of the market, as a whole, to rely on capacity from other regions (subject to available transmission) to prevent a loss of load. However, subject to a specific examination of the transmission situation, it is conceivable that a buyer could arrange to purchase pure capacity from a neighboring region to meet its PJM capacity obligation. Assuming that some level of available capacity from outside PJM could participate in the PJM capacity market will mean downward pressure on PJM capacity prices.

Q. **Does that conclude your direct testimony?**

A. Yes, it does.

Summary of Results

Year	**Realized Market Price for All PECO Units**[1] Nominal$/MWh [2]	**Associated Fuel Cost for All PECO Units** Nominal $/MWh [2]
1999	28.1	7.5
2000	31.3	8.0
2001	35.0	8.0
2002	36.4	8.2
2003	37.5	8.3
2004	38.9	8.5
2005	40.4	8.7
2006	42.2	9.1
2007	43.8	9.4
2008	45.8	9.8
2009	47.4	10.0
2010	49.3	10.4
2011	50.9	10.7
2012	52.9	11.1
2013	54.8	11.6
2014	57.3	12.4
2015	60.0	13.1

[1] These projections represent the market price realized by all PECO units for sales into the PJM bulk power market:

$$\frac{\text{Total Revenues for Capacity and Energy Realized by all PECO Units}}{\text{Total MWh Generated by all PECO Units}}$$

[2] Stated in nominal dollars applying GDP deflator projections supplied by PECO

OVERVIEW OF KEY DRIVING PROJECTIONS

PJM Load Growth

PJM Load Growth

	Year	Net Internal Demand (MW)	Net Energy for Load (GWh)
Actual	1994	46,019	238,379
	1995	48,577	243,043
Projected	1999	46,965	254,039
	2000	47,667	257,993
	2002	48,889	265,877
	2004	49,745	271,905
	2006	50,840	279,817
	2008	51,946	287,496
	2010	53,074	295,387
	2012	54,225	303,494
	2014	55,404	311,824
	2015	56,001	316,074

Response to Load Growth

Poolwide Planning Reserve Margin - 18%

New Unit Assumptions
(1996$)

Type	Capital Cost ($/kW)	Fixed O&M. ($/kW/year)	HHV Heat Rate Btu/kWh	EAF (%)
Combustion Turbine	300	1.9	11000	92
Combined Cycle	450	17.1	6700	90

Fuel Price Projections

Gas Price Projections
(All values in Nominal Dollars per Million Btu)

Year	Commodity Gas Price Projection	PJM Delivered Gas Price Summer	Winter	Other
1999	1.99	2.18	2.86	2.46
2000	2.09	2.29	2.99	2.57
2001	2.17	2.38	3.10	2.67
2002	2.29	2.50	3.24	2.80
2003	2.38	2.60	3.36	2.91
2004	2.49	2.72	3.51	3.04
2005	2.61	2.84	3.66	3.18
2006	2.74	2.98	3.83	3.33
2007	2.85	3.09	3.96	3.45
2008	2.98	3.23	4.14	3.60
2009	3.11	3.38	4.31	3.76
2010	3.27	3.54	4.51	3.94
2011	3.41	3.69	4.69	4.10
2012	3.57	3.86	4.90	4.29
2013	3.73	4.04	5.11	4.48
2014	3.90	4.22	5.33	4.67
2015	4.07	4.40	5.55	4.87

Delivered Coal Prices for Certain PECO Units
(All values in Nominal Dollars per Million Btu)

Year	Cromby 1	Eddystone 1&2	Conemaugh 1&2	Keystone 1&2
1999	1.51	1.51	1.03	1.03
2000	1.52	1.52	1.03	1.03
2002	1.54	1.54	1.04	1.04
2004	1.55	1.55	1.05	1.05
2006	1.60	1.60	1.08	1.08
2008	1.66	1.66	1.13	1.13
2010	1.74	1.74	1.19	1.19
2012	1.82	1.82	1.25	1.25
2014	1.91	1.91	1.31	1.31
2015	1.96	1.96	1.34	1.34

Fuel Price Projections (continued)

Delivered Oil Price Projections for PJM
(All values in Nominal Cents per Million Btu)

Year	1.0% Sulfur	2.0% Sulfur	Distillate
1999	3.29	2.95	4.33
2000	3.37	3.03	4.44
2001	3.50	3.15	4.60
2002	3.66	3.29	4.80
2003	3.79	3.42	4.96
2004	3.96	3.57	5.17
2005	4.12	3.72	5.38
2006	4.32	3.91	5.63
2007	4.50	4.07	5.84
2008	4.71	4.26	6.10
2009	4.92	4.46	6.36
2010	5.16	4.69	6.67
2011	5.38	4.89	6.94
2012	5.64	5.13	7.26
2013	5.90	5.38	7.58
2014	6.17	5.62	7.91
2015	6.44	5.88	8.25

SO2 Allowance Prices
(Nominal Dollars)

Year	($/ton)
2000	198
2002	210
2004	313
2006	335
2008	474
2010	511
2012	547
2014	743
2015	768

Retirements

Projected Retirements of Significant Units in PJM, NEPOOL and NYPP
(1999 through 2015)

Region	Unit Name	Capacity (MW)	Year Removed from Service
NEPOOL	Connecticut Yankee	560	before 1999
PJM	Cromby 2	201	before 1999
PJM	Delaware 7, 8	350	before 1999
PJM	Schuylkill	166	before 1999
NYPP	Huntley 63-66	340	1999
NYPP	Beebee 12	80	2000
NYPP	Nine-Mile 1	617	2010
NYPP	Ginna 1	470	2011
NYPP	Indian Point 2	931	2014
NEPOOL	W.F. Wyman 1-3	230	2000
NEPOOL	Millstone	652	2010
NEPOOL	Pilgrim 1	665	2012
NEPOOL	Maine Yankee	870	2013
NEPOOL	Vermont Yankee	496	2013
NEPOOL	Millstone	863	2015
PJM	Deepwater 4	54	1999
PJM	Indian River 1	89	1999
PJM	Oyster Creek	619	2009
PJM	Peach Bottom 2	1093	2014
PJM	Peach Bottom 3	1093	2015
PJM	Three-Mile Island 1	786	2015
PJM	Calvert Cliffs 1	835	2015

Power Purchase Assumptions

Available Firm Energy

PEPCO imports 450 MW from Ohio Edison throughout the forecast horizon. This energy is available all the time. The energy is priced at $17.0/MWh.

The NYPP contract with Hydro Quebec was modeled as a 800 MW maximum with an energy limit of 3,000 GWh on an annual basis. The energy is available only in the Summer and Shoulder seasons.

The Hydro Quebec firm transaction with NEPOOL was modeled as a 2000 MW maximum with an energy limit of 10,000 GWh. The pool receives only 1,800 MW of reserve margin credit for this interaction.

Available Economy Energy

Economy energy available from Ontario Hydro and Hydro Quebec to NYPP was modeled as a 1,000 MW maximum with an energy limit of 5,000 GWh, priced at $24.00/MWh.

Economy energy available from NYPP to Ontario Hydro was modeled as a 250 MW maximum available only during the winter season.

Economy energy available to PJM from ECAR was modeled as two transactions. The first transaction was available during load segments 7 through 10, which typically reflect off-peak hours. This transaction was modeled as a 3,400 MW maximum in 1999 through 2005, a 2,400 MW maximum in 2006, a 1,400 MW maximum in 2007, and a 400 MW maximum in 2008 with a 14.7% maximum annual capacity factor in all years. The energy was available at a price of $17.00/MWh in 1999-2005 and $19.00/MWh thereafter. The second transaction was available during load segments 1-6, which typically refer to peak hours. This transaction was modeled as a 1,300 MW maximum in 1999 through 2005, and as a 300 MW maximum in 2006 with a 14.7% maximum annual capacity factor in all years. The energy was available at a price of $21.00/MWh 1999-2005 and $24.00/MWh thereafter.

Resume

B. VENKATESHWARA

EDUCATION

1983	Ph.D, Energy Management and Policy, University of Pennsylvania
1980	M.B.A. Finance/Quantitative Methods, Wharton School, University of Pennsylvania
1977	M.S. Mechanical Engineering, Clemson University
1976	B. Tech, Mechanical Engineering, Indian Institute of Technology

EXPERIENCE

Dr. Venkateshwara is a Vice President at ICF Resources Incorporated and directs work dealing with electric markets. He has directed analytic projects in the energy area for a wide range of clients both in the private and public sectors. Dr. Venkateshwara has offered expert testimony in a number of matters in several jurisdictions.

In a recent Massachusetts proceeding on electric industry restructuring, he offered testimony and prepared a report on the use of auction processes to estimate generation-related stranded costs. In a Pennsylvania proceeding dealing with the complaints of three cogenerators, Dr. Venkateshwara offered expert testimony on avoided cost and capacity need issues. He also provided a sworn affidavit on the matter of estimated payments in excess of avoided cost in a Federal Energy Regulatory Commission (FERC) proceeding. Other matters on which Dr. Venkateshwara has led analytic efforts include: assessment of market power in the relevant product and geographic markets for electric power; analyses of electricity and coal transportation markets from an anti-trust perspective; and an evaluation of natural gas purchase contracts in a FERC proceeding dealing with the affiliated entities test under the Natural Gas Policy Act (NGPA).

Dr. Venkateshwara has served as a principal in multi-disciplinary teams and dealt with the evaluation and negotiation of several dimensions of project-specific transactions: economic analyses; project financing factors; and regulatory considerations. Also, Dr. Venkateshwara has directed the analyses of several studies dealing with the economic aspects (e.g., dispatch, transmission, power sales revenue projections, and avoided cost projections) of specific QF/IPP transactions. In addition, Dr. Venkateshwara has also managed dozens of analytic studies covering such areas as the impact of deregulation on various players in the electric industry, the impact of low oil and gas prices on U.S. electric generation, integrated (supply and demand) modeling of utility systems and power pools, natural gas industry contract problems and possible solutions, and interfuel competition in industrial end-use markets.

Analyses to Support Specific Transactions and Regulatory Proceedings

- Support for Regulatory/Legal Proceedings: Dr. Venkateshwara has served as the principal analyst in several regulatory/legal proceedings in which ICF has provided research and analytic assistance. In particular, his experience includes:

  - Expert testimony in a recent Massachusetts proceeding dealing with electric industry restructuring on the matter of using an auction process to estimate stranded costs. In particular, the characteristics of alternative auction approaches, including the ascending bid auction used to auction radio spectrum licenses, were assessed.

  - Prepared a report to support a Federal Energy Regulatory Commission (FERC) filing seeking blanket authorization to engage in wholesale electric sales. The report assessed the market power (or lack thereof) of an electric utility in the relevant geographic and product markets for generation..

  - Sworn affidavit on behalf of a New York utility estimating payments to a Qualifying Facility (QF) in excess of avoided cost..

  - Expert testimony in a proceeding before the Pennsylvania Public Utility Commission on the issues of capacity need and avoided cost. Issues addressed by Dr. Venkateshwara include: utility load projections; avoided cost standards pursuant to the Pennsylvania PURPA regulations; and ratepayer impacts.

- Analytic direction for an ICF study, performed for the Federal Energy Regulatory Commission (FERC), dealing with the environmental impacts of the FERC's Notice of Proposed Rulemaking (NOPR) on independent power producers and bidding programs, including consideration of "wheeling-in/wheeling-out" proposals.

- Preparation of research and analytic materials addressing anti-trust issues in coal transportation markets

- Assistance to lead counsel in a Federal Energy Regulatory Commission (FERC) proceeding concerning pipeline gas purchases from an affiliate.

- Assistance in the Negotiation of Specific Transactions: The implementation of energy projects generally requires a balancing of the multiple and sometimes conflicting aims of different parties within the constraints imposed by market, technical, and regulatory factors. At the request of clients, Dr. Venkateshwara has served as a principal on teams responsible for negotiating project-specific agreements. For example, he served as a principal on a team that negotiated on behalf of a state agency in the Northeast in connection with the cost and payment terms for a 115 kV underwater transmission line. These negotiations covered all aspects of the transaction: negotiating strategy, economics, regulatory factors, and technical constraints. For other clients, Dr. Venkateshwara has been a direct contributor to power sales contract negotiations. The negotiations have included interconnection and transmission considerations.

- Analytic Support for Specific Transactions: Dr. Venkateshwara has provided financial institutions and energy project developers with an independent evaluation of complex contractual provisions and market conditions. Examples include: an independent assessment of the expected hours of operation of several large (total value in excess of $1 billion) dispatchable cogeneration projects in PJM; forecasts of electric revenues that could be expected under market-based pricing provisions in power sales contracts (e.g., revenues tied to the PJM billing rate; revenues based on tariff-based contracts in New Jersey); and the risk-return tradeoff inherent in "front-loading" of power sales contracts. In certain cases, Dr. Venkateshwara has focused on transmission possibilities in inter-regional power markets (e.g., Southern Company to Florida).

Energy Market Analyses

- Integrated Modeling of Electric Utility Systems/Power Pools: Dr. Venkateshwara has managed and provided analytic leadership for various ICF consulting assignments dealing with integrated (i.e., the load and the supply side) modeling of individual utility systems or power pools. The systems examined include Penn-Jersey-Maryland (PJM), New York Power Pool (NYPP), and New England Power Pool (NEPOOL). These analyses focused on dispatch and avoided cost calculations.

- Industry Analyses: Dr. Venkateshwara has considerable experience in directing industry-wide studies that provide clients with an understanding of the fundamental factors affecting an industry and the opportunities and challenges that result. For example, Dr. Venkateshwara was the lead analyst on a major Gas Research Institute study of the potential for industrial cogeneration. In the natural gas area, he assessed for a major financial institution the magnitude of the take-or-pay problem in the U.S. gas industry and the prospects for resolution. Other industry studies directed by Dr. Venkateshwara include: impact of wellhead gas deregulation on the domestic pipeline industry, and the implication of lower oil and gas prices for the electric generation market and the coal industry.

- Market Studies: Shifts in fundamental economic factors or in the regulatory/legal environment can translate into opportunities or threats in specific markets. Dr. Venkateshwara has assisted numerous clients understand both qualitatively and quantitatively the scope and nature of such opportunities and threats. Market studies in which Dr. Venkateshwara was a principal include: studies of the impact of avoided cost prescriptions or contractual pricing provisions on the power sales revenue and associated risk for non-utility power producers; the possible use of electric market indicators such as PJM billing rate differentials to estimate the opportunity cost of transmission; studies of the impact of inter-regional competition and interstate pipeline tariffs on wellhead gas pricing in a single producing region; analyses of the possible options open to a utility to create competition for coal transportation services in a specific origin-destination markets;

and competitive analyses of alternative industrial technologies and the implications for natural gas and electricity use.

- Financial Studies: Dr. Venkateshwara has supervised the evaluation of alternative financing options for energy projects, including consideration of tax and regulatory factors. In the cogeneration/independent power area, these evaluations have dealt with such options as limited partnership arrangements, leveraged leasing, and sale-leaseback options. In a recent project, Dr. Venkateshwara assisted a financial institution examine alternative ways of dealing with a bankrupt resource recovery facility to which substantial amounts of capital had been loaned. The work included a review of alternative power sales opportunities including the prospects for wheeling power.

PROFESSIONAL AFFILIATIONS

The Cogeneration Institute
Association of Energy Engineers
International Association of Energy Economists

SELECTED PUBLICATIONS AND PRESENTATIONS

"Power Pricing Strategies for the Generation Company," Invited Speech to the Infocast Conference on *Becoming a Profitable Genco in a Competitive Market,* November 14, 1996.

"Creating Value in the Delivery of Energy and Capacity and Some Predictions of Future Price Trends," Invited Speech to the Infocast Conference on *Strategic Issues for Power Marketers,* May 2, 1996.

"Considering in Emerging Renewable/Industrial Project Financing Opportunities," Invited Speech to McGraw Hill Conference on the *Market for Project Financing,* New York, May 6, 1992.

"Special Considerations for Financing Transmission Facilities: How One Transmission Line Was Financed," Invited Speech to Infocast Conference on *Power Transmission: Access, Pricing, & Regulation,* Washington, D. C., April 22-23, 1991.

"The Essence of Feasibility Studies," Invited Speech to Infocast Conference on *Project Finance,* Los Angeles, April 30, 1990.

"Sorting Out the Good Deals from the Marginal Ones in Independent Power Projects", Presented to the 12th World Energy Engineering Congress, October 26, 1989.

"Marketing Gas to Future Electricity Producers: More than Writing Purchase Orders" (co-authored with Daniel Klein), published in *Natural Gas*, July 1988.

"Risks to Partnerships in Cogeneration Ventures." Presented to the Second International Modeling and Computer Simulation Symposium on Energy Modeling and Simulation, August 1984.

"Investment Decisions Under Certainty: A Behavioral Hypothesis." Presented to the Joint National Meeting of the Institute of Management Sciences and the Operations Research Society of America, April 1983.

SELECTED ICF REPORTS

"Assessment of IPL's Position in the Relevant Geographic and Product Markets for Electric Generation", Prepared for American Energy Service Corporation (an affiliate of Indianapolis Power & Light), September 1996.

"Design of Auction Process to Mitigate and Estimate Stranded Costs of COM/Elec's Generation Entitlements," Prepared for COM/Electric and submitted to the Massachusetts Department of Public Utilities in D.P.U 96-100, June 1996.

"Incremental Cost Pricing of Transmission Services", Prepared under contract with U.S. Department of Energy, December 1994.

Several confidential reports dealing with dispatch and power sales prices applicable to specific QF projects. 1989-1996.

"Review and Analysis of PJM Billing Rate Forecasts", Confidential Report for a Private Client, May 1989.

"Low Oil Prices and U.S. Coal Demand," Prepared for the U.S. Department of Energy, May 1987.

"The Take-or-Pay Problem in the Interstate Gas Transmission Industry", Confidential Report for a Private Client, August 1986.

EMPLOYMENT HISTORY

ICF Resources Incorporated	Vice President	1986-Present
Energy and Environmental Analysis, Inc.	Senior Consultant	1983-1986
Synergic Resources Corporation	Analyst	1982-1983

APPENDIX B

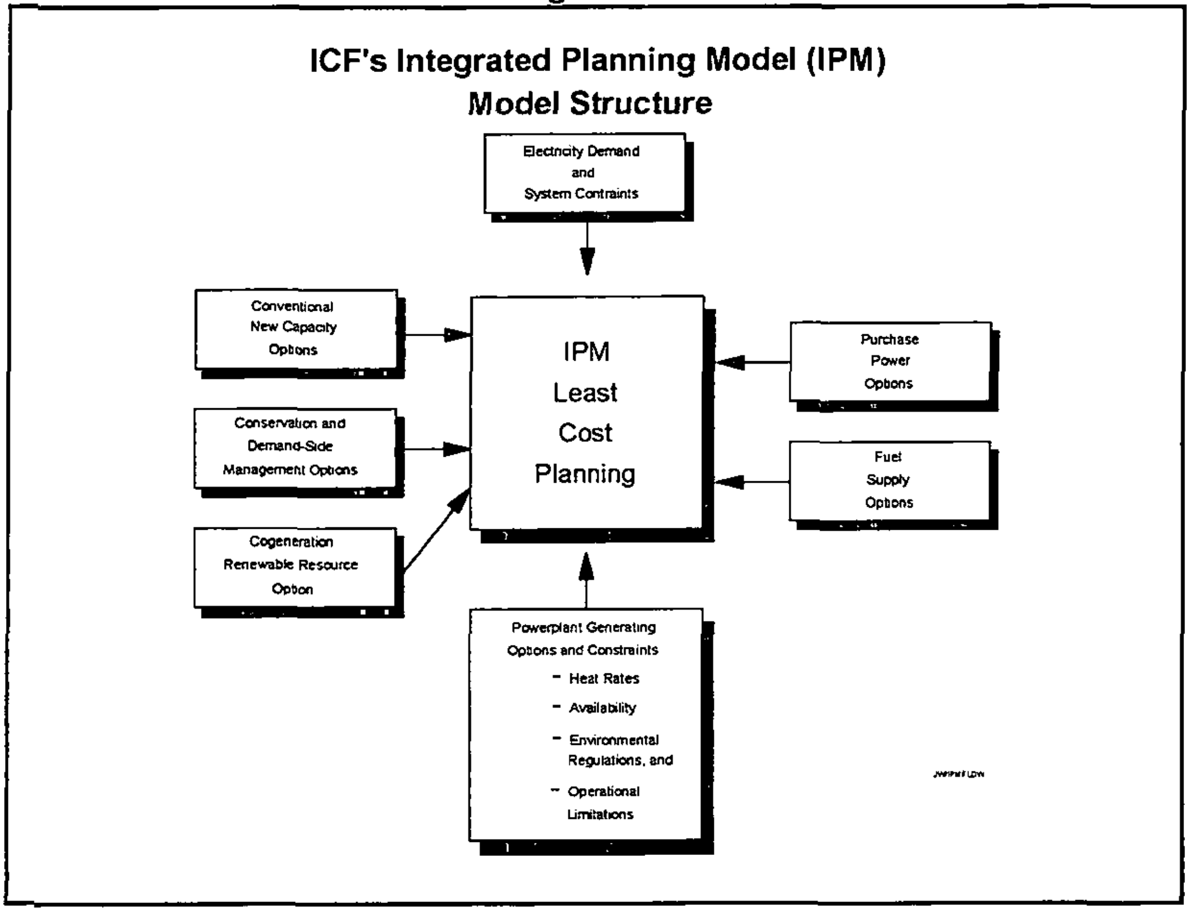
ICF Resources' Integrated Planning Model

ICF RESOURCES' INTEGRATED PLANNING MODEL ("IPM©")

ICF Resources' IPM© is the principal analytic tool used in this study. IPM© is a linear programming model which finds an optimal dispatch pattern and choice of resource options to meet electricity demand at the minimum cost. The model can be used to study several behavioral factors, such as how a utility responds to load growth or changing fuel prices. IPM© can also be used to model the detailed dispatch by which a single utility meets its load. IPM© has been used by several ICF Resources clients to address a wide range of questions related to dispatch in many utility systems.

IPM© develops a least cost strategy for a utility to meet its load over a planning horizon within a specified set of financial, environmental, and operations and transmission constraints (see Figure B-1). Utility operations are modeled using a linear programming algorithm. The model is dynamic in that it can generate a simultaneous optimal solution for the entire planning horizon rather than for each year individually. Thus, it combines system capacity expansion planning and unit dispatching decisions to provide the lowest net present value generation costs over the full planning horizon.

Figure B-1



It considers future fuel prices and generation requirements when making decisions for the present, and it simultaneously determines optimal resource utilization given fuel prices, operating characteristics, and constraints.

The model can determine the optimum capacity expansion plan given a set of utility options, demand growth, and reliability criteria. Also, given a capacity expansion schedule, it can determine the optimum utilization of different units given their operating characteristics, fuel prices, and known transmission and operational constraints.

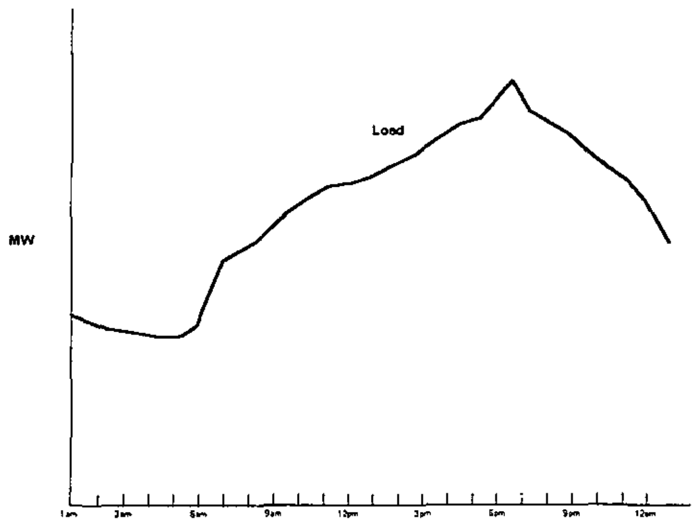
In the real-world, utility loads vary literally every instant. In our analytic approach, this complexity is represented by means of a Load Duration Curve made up of ten analytic segments. Furthermore, separate Load Duration Curves are developed for each of three seasons. This approach has many advantages:

- The analytic simplification allows a better representation of inter-regional transmission constraints and the dispatching of hydro units and pumped storage units relative to hourly simulation models. At the same time, our research over the years has shown that, for historical years, our model-based projections match actual conditions with adequate reliability.

- The costs related to data development and computer processing are modest enough to allow users to conduct multiple scenario analyses cost-effectively.

ICF Resources' development of the Load Duration Curves is grounded in empirical analysis. Typically, the load on a utility fluctuates from a minimum level in the middle of the night to a maximum level during the afternoon and early evening. Figure B-2 shows a typical daily load shape. When these hourly loads are sorted from highest to lowest, the resulting curve is a "Load Duration Curve" (see Figure B-3). The Load Duration Curve can then be approximated using a step function. IPM© divides a year into a number of "seasons" and uses seasonal Load Duration Curves.

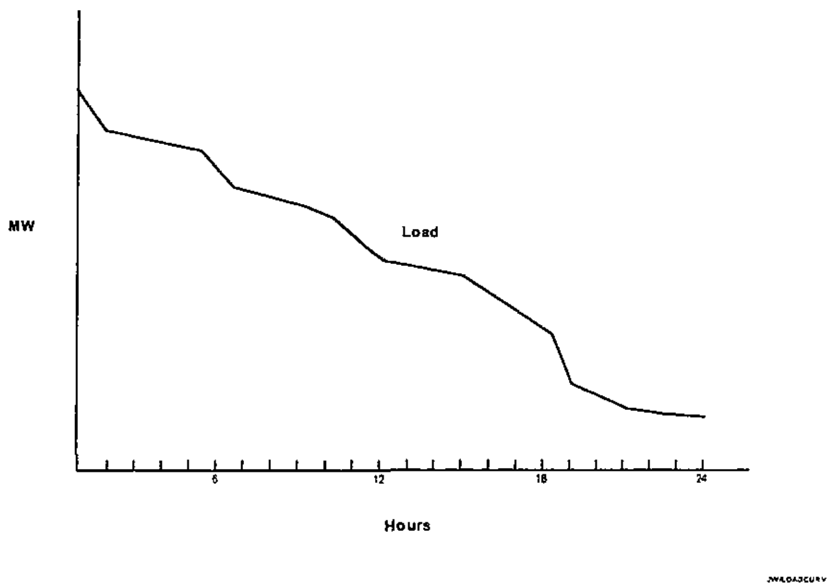
Figure B-2
Typical Daily Load Shape



Load Duration Curves provide a means of integrating hourly unit dispatch decisions over a season. Integrating these decisions across a given season is important when modeling energy limited technologies, such as hydro and pumped storage, as well as purchases with a maximum energy limit, such as off-system purchases. Each of these curves is approximated using 10 steps or load "segments." Figure B-5 shows a typical segmented Load Duration Curve.

Based on the Load Duration Curves, IPM© determines the dispatch of generating units for each segment in each season. That is, it determines which units are operated during each segment (and at what level) to meet the load at minimum cost, subject to various technical constraints (e.g., forced outages, maintenance outages, minimum turndown, etc.). Using these segment-by-segment dispatch patterns along with hourly load data, the model also calculates hourly marginal energy costs.

Figure B-3
Typical Daily Load Duration Curve

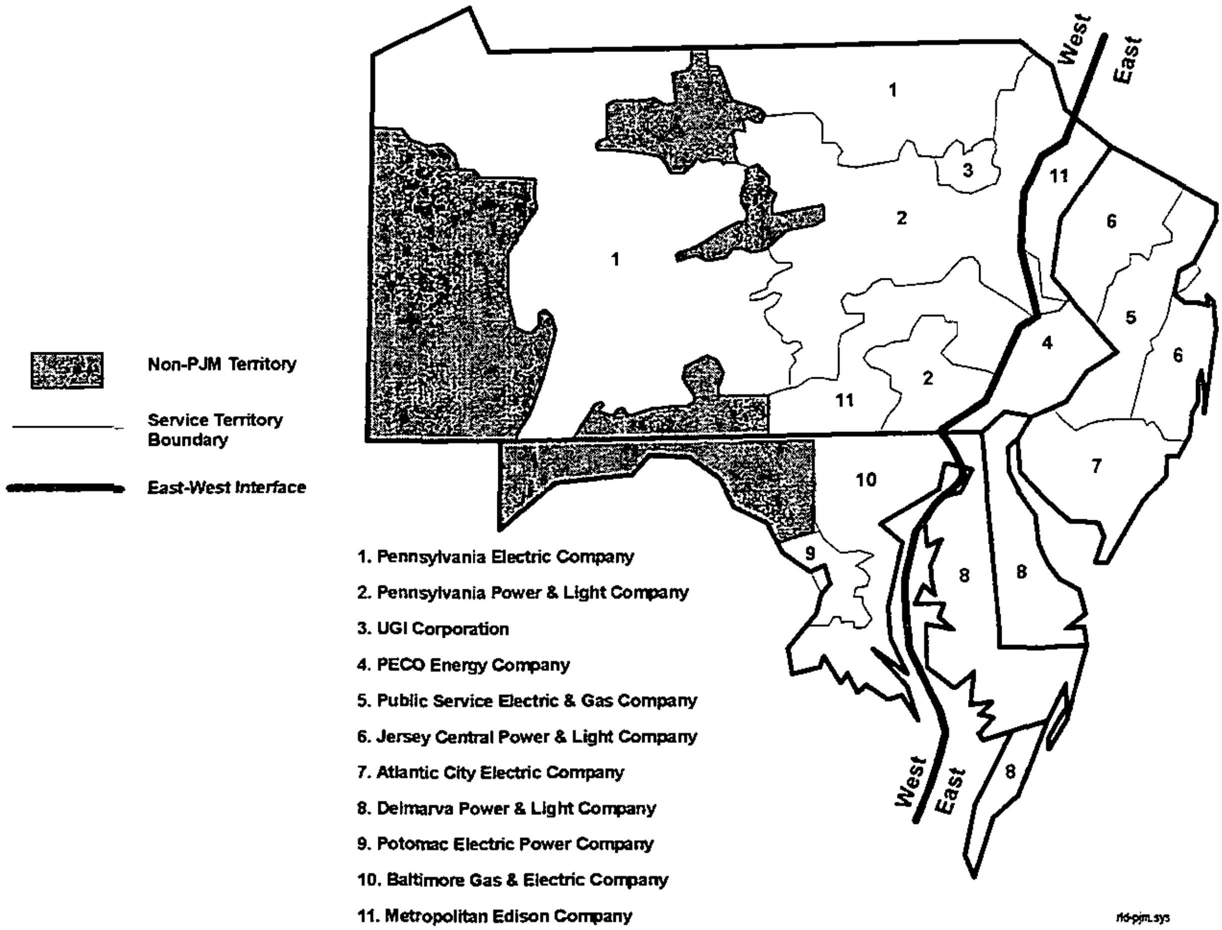


In addition to operating constraints on PJM, such as the must-run constraints discussed below, IPM© takes into account planned outages (i.e., for maintenance), forced outages (i.e., unanticipated shut downs), and unit-by-unit emission constraints. Planned outages can be either specified to correspond with the actual plan of the utility or optimized by the model using the criteria for reserve levelization. Unit-by-unit information on planned outages by season can be provided to IPM© based upon actual operating experience.

Forced outage rates on a unit-by-unit basis are also provided as an input. Because forced outages are not within the control of the utility system, they generally do not vary by season. As in the case of planned outages, forced outage information is based on actual operating experience for existing units. For future units (and QFs), it is based largely on engineering and vendor studies.

The geographic extent of the PJM bulk power market and the major franchised electric utilities within that market is shown in Figure B-4.

FIGURE B-4
THE PJM SYSTEM



For several years, the availability of low variable cost coal capacity over and above local load levels in Western parts of PJM (notably the service territory of Pennsylvania Power & Light) has provided opportunities for the sale of such power to displace high variable cost oil or gas generation in the Eastern parts of PJM (e.g., the service territories of JCP&L and Public Service Electric & Gas in New Jersey). A similar situation exists with respect to the sale of low variable cost, coal-fired power from Allegheny Power System and American Electric Power in the ECAR (East Central Area Reliability) region to utilities in the Eastern part of PJM. The economic incentive to displace high variable cost power with low variable cost power has resulted in a pattern of substantial flow of power from West to East within PJM. Transmission constraints, however, restrict the level of power that can be transmitted between these regions. Therefore, it is useful for analytic purposes to divide PJM into different regions and represent quantitatively the transmission constraints that exist between regions.

Based on analysis of physical transmission constraints, ICF Resources divides PJM into the following three regions. (Figure B-4)

- East PJM which includes the service territories of Atlantic Electric, Public Service Electric & Gas, Jersey Central Power & Light, PECO Energy Company, and Delmarva Power & Light.

- West PJM which includes the service territories of Pennsylvania Electric, Metropolitan Edison, and Pennsylvania Power & Light.

- South PJM which includes the service territories of Baltimore Gas & Electric and Potomac Electric Power Company.

The division of PJM into regions has important implications for representing capacity and transmission constraints in IPM. In particular:

Generating Capacity: For analytic purposes the generating capacity included within a PJM region such as, for example, East PJM is the capacity that is actually located in the geographic area covered by that region. Certain utilities in the East may, of course, hold shares of capacity that is located in the West (e.g., PECO Energy, an East PJM utility owns a substantial share of the Peach Bottom nuclear units 2 and 3, which are a part of West PJM capacity). For purposes of dispatch such capacity is counted as capacity in the West, i.e., the area where it is located. Also, although Jersey Central Power & Light, Pennsylvania Electric, and Metropolitan Edison are all subsidiaries of General Public Utilities ("GPU"), the generating capacity owned by the individual companies is placed in the region in which such capacity is located.

Transmission Constraints: The transmission constraints state, in mathematical terms, the maximum level of power that can be transferred between regions. For example, one transmission constraint provides a mathematical equation for the maximum level of power that can be moved from the West to the East, given a certain level of flow from West to South. The constraints also place absolute bounds on the level of power that can be transmitted from one region to another. By ensuring that the dispatching of plants to meet loads at least cost simultaneously satisfies *these transmission constraints, the model-based dispatch mimics the real-*world. Based on currently available information, the PJM utilities are not likely to complete any major transmission projects that would mean a substantial change in our assumptions on transmission limits.[2]

Links to Other Regions: The IPM modeling framework for PJM includes all the load and generating resources within the New York Power Pool (NYPP) and the New England Power Pool (NEPOOL). This is achieved by modeling NEPOOL as a region and the NYPP as two regions (Long Island and the rest of NYPP). PJM's interactions with ECAR are represented as a transaction.

SEGMENTING THE LOAD DURATION CURVE

The segmentation of the Load Duration Curve is an important step in IPM-based analyses. The first step in the segmentation process is to analyze the hourly load data, by month, to determine the number of representative seasons per year that are necessary to characterize the seasonal load patterns. Based upon an analysis of hourly load data for PJM, ICF Resources determined that it would be appropriate to divide the year into three seasons: summer, shoulder and winter. Table B-1 shows the combination of months represented in each season.

TABLE B-1
SEASONAL BREAKDOWN IN IPM

Season	Months Included	Hours/Season	Proportions of Year
Summer	June, July, August, September	2,928	33.4%
Shoulder	March, April, May, October, November	3,672	41.9%
Winter	December, January, February	2,160	24.7%
Total		8,760	100.0%

[2] The proposed Jersey Central Power & Light (JCPL) and Metropolitan Edison (Met-Ed) energy and capacity purchase from the Duquesne Light Company (Duquesne) included the construction of a 500 kV transmission line between Duquesne and Met-Ed with an expected transfer capability of 1500 MW. This project has, however, been terminated.

The second step is to divide each season into segments in such a manner that the hours in each segment are very similar in terms of the level of peak load. The actual load for all hours represented in one segment will generally not be identical; however, by carefully splitting the load duration curve into ten segments of varying width, it is possible to achieve an adequate representation of the seasonal load duration curve. The development of the Load Duration Curve for the PJM pool as well as for IPM's East, West, and South PJM is based upon available industry information on load data and load shapes.

An example of the segmentation of the PJM poolwide load duration curve is shown in Figure B-5. Several points about Figure B-5 are worth noting:

- There are relatively few hours during which demand is at or about the annual peak load (49.0 GW in 1995).

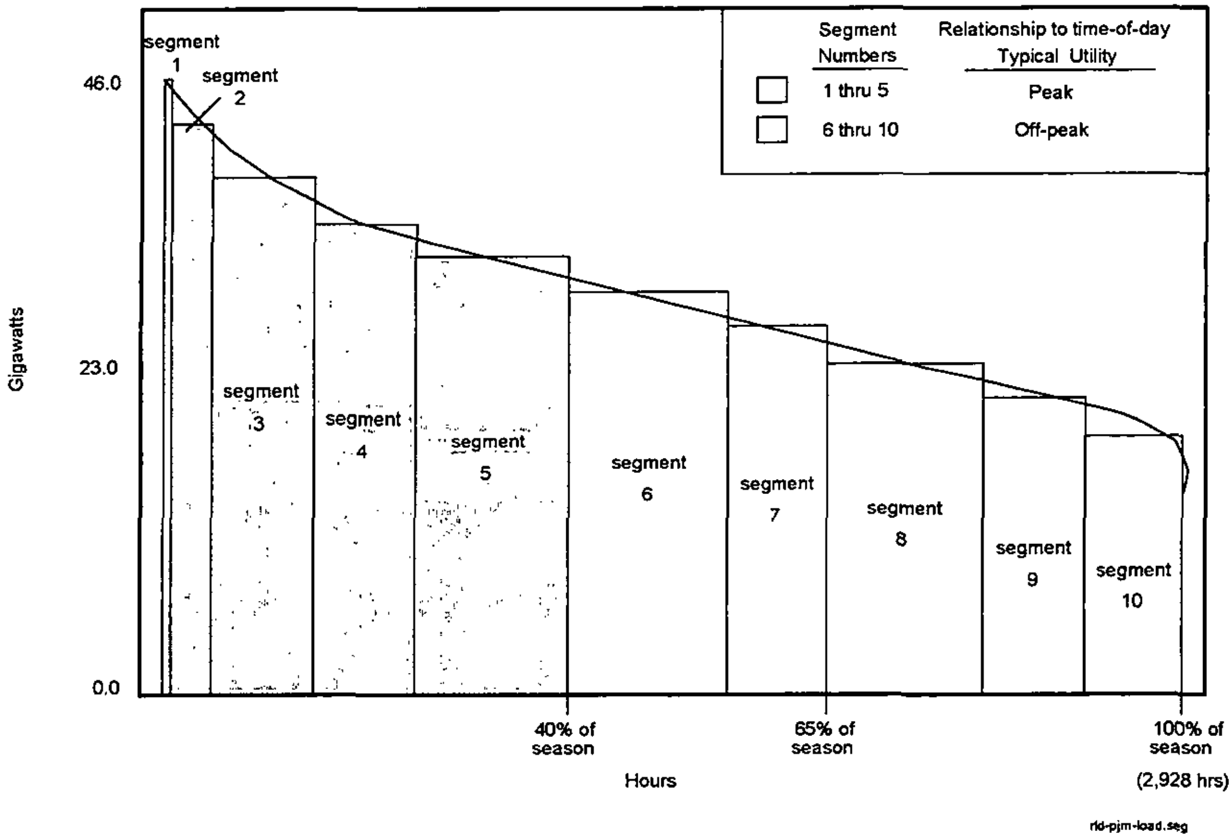
- *For 40% of the season, loads were at a level higher than about 33 GW;* conversely, for 60% of the hours loads were lower than 33 GW.

- Loads rarely fall below about 15 GW, or 25 percent of the summer peak load.

The shape of the demand curve is important because it is the intersection of demand and available resources (the poolwide supply curve), on an hourly basis, that determines marginal energy costs and, hence, the dispatch of individual resources on the PJM system.

The third step in the segmentation process is to establish the relationship between the segments and the time-of-day periods.

Figure B-5
Illustration of Segmentation of the PJM Poolwide Load Duration Curve (Summer Season)



ICF Resources analyzed the hourly observations contained in the seasonal load duration curves such as the one shown in Figure B-5 in order to establish the relationship of segments to time-of-day. This analysis showed that:

- For most PJM utilities, the hourly observations represented in segments 1 through 5 met the peak-hour definitions with a very small number of exceptions. Segments 1 through 5 represent about 40 percent of the hours of the season which is the proportion of annual peak-hours for most PJM utilities.

- Segments 6 through 10 generally represent the off-peak hours, which account for about 60 percent of the hours of the season.

Unit-Specific Data

Unit-by-unit information for existing generating capacity is a part of ICF Resources' PJM Generating Unit Data Base, which is one of the major input files provided to the IPM. This comprehensive data base, built and maintained by ICF Resources, contains unit-by-unit information not only on planned outage and forced outage rates, but also on such items as summer capacity, heat rates, variable operation and maintenance costs, and emission limits. For modeling purposes, units in the same model region that possess similar economic and operating characteristics (e.g., similar fuel prices and sources, similar heat rates, similar outage rates, etc.) are combined to yield larger "aggregate units". For example, nuclear plants in East PJM are treated as one large aggregate unit. Aggregation need not sacrifice features specific to individual units. For example, the shutdown of a specific unit can be readily modeled by appropriately reducing the capacity of the corresponding aggregate unit.

ICF's modeling of the PJM system considers certain units as "must-run" units. These include units located close to large load centers that have to be operated whenever available primarily for safety and system stability reasons. The central dispatching entity takes such constraints into account in making the dispatch decision. Also, a large number of QFs have contracts under which the utility is obligated to purchase all power tendered. Regardless of the contract price for power, these QFs are properly considered must-run units.

For technical reasons, some units (e.g., coal-fired steam turbine-based units) cannot be frequently cut back below a certain percent of full load. Therefore, a dispatching entity might need to chose between (a) running such a unit at least at its "minimum turndown" level to allow the option of running harder during times of higher demand (even if such a choice is not in a strict sense the "least cost" option) and, (b) shutting down the unit completely. This constraint often results in certain units running at least at their minimum turndown levels during weekdays (when most utilities experience their peak loads) and being shut down completely during the weekends (which represent the off-peak period for most utilities). In utility parlance, these are "cycling" units.

Emission and Acid Rain Legislation

Allowable emission rates on a unit-by-unit basis can be provided as an input to the IPM. Currently, these emission rates are determined by the regulatory status of the plant (e.g., plants covered by the New Source Performance Standards ("NSPS") of 1977; plants not covered by any NSPS but subject to State Implementation Plans ("SIPs"); etc.).

The IPM provides a flexible framework to model different acid rain provisions. In particular, each model unit can be provided with a number of compliance options such as scrubbing, coal switching, or allowance purchases at a "market price," and the choice between options can be based upon achieving least cost compliance within the requirements of the law.

ANALYTICAL OUTPUT

Generation has value in both PJM's capacity market and the electric energy market. ICF Resources' competitive price of wholesale electric generation projections are therefore based on separate projections of the competitive price of electric capacity and the competitive price of electric energy, with the total being the sum of the two.

The competitive energy price projections were prepared using ICF Resources' representation of the PJM system using its Integrated Planning Model (IPM©). As discussed above, IPM© utilizes a linear programming algorithm to find an optimal dispatch pattern and choice of resource options to meet electric energy demand at the minimum cost. By overlaying hourly load data onto this dispatch pattern, the model calculated a marginal energy cost, i.e., competitive energy price, for each hour.

The projection of the competitive price of capacity is based upon (i) the forecasted capacity and load balance in PJM and (ii) market information available from recent capacity sales and purchases entered into by PJM utilities. As discussed above, interactions between buyers and sellers in the existing PJM market can be seen as a functioning market. In equilibrium, when capacity and demand are in balance, i.e. when amount of capacity available on the pool is equal to the expected peak plus required capacity reserves, the spot capacity price is set by the cost of installing a combustion turbine. This is because a combustion turbine is the source of new capacity with the lowest capital cost. During periods of excess capacity, the price of capacity is lower, but not zero. This is due to the positive benefit additional capacity creates by lowering the probability of a supply shortage.

PECO STATEMENT NO. 6

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DIRECT TESTIMONY

OF

WILLIAM H. HIERONYMUS

Regarding Market Prices for PECO Energy Generation

DIRECT TESTIMONY OF WILLIAM H. HIERONYMUS

I. QUALIFICATIONS

Q. Please state your name and business address.

A. My name is William H. Hieronymus. My business address is Putnam, Hayes & Bartlett, Inc., One Memorial Drive, Cambridge, Massachusetts 02142.

Q. By whom are you employed?

A. I am a Managing Director of Putnam, Hayes & Bartlett. Inc. (PHB), an economic and management consulting firm with offices in Cambridge, Washington D.C., Palo Alto and Los Angeles.

Q. What is your educational background and work experience?

A. I received my bachelor's degree from the University of Iowa in 1965, my master's degree in economics in 1967 and a doctoral degree in economics in 1969 from the University of Michigan, where I was a Woodrow Wilson Fellow and National Science Foundation Fellow. After serving in the U.S. Army, I began my consulting career.

In 1973 I joined Charles River Associates Inc. as a specialist in antitrust economics. By the mid-1970s my focus was principally on the economics of energy and network industries. In 1978 I joined PHB where my consulting practice has focused almost exclusively on network industries, particularly electric utilities.

During the past 23 years, I have completed numerous assignments for electric utilities; state and federal government agencies and regulatory bodies; energy and equipment companies; research organizations and trade associations; independent power producers and investors; international aid and lending agencies; and foreign governments. While I have worked on most economics-related aspects of the utility sector, a major theme has been public policies and their relation to the operation of utility companies.

Since about 1988, the main focus of my consulting has been on electric utility industry restructuring, regulatory innovation and privatization. In that year I began work on the restructuring and privatization of the electric utility industry of the United Kingdom, an assignment on which I worked nearly full time through the completion of the restructuring in 1990. I also led a major study of the reorganization of the New Zealand electricity sector, focusing mainly on competition issues in the generating sector. Following privatization of the UK industry, I continued to work in the United Kingdom for electricity clients based there and I also was involved in restructuring studies concerning the former Soviet Union, eastern Europe, the European Union and specific European countries.

Late in 1993, I returned to the United States, where I have worked on the restructuring, regulatory reform and increasingly competitive future of the US electricity industry.

I have testified before state and federal regulatory bodies, legislative bodies and federal courts on numerous occasions, principally on electric utility matters but also on antitrust and civil litigation. I have testified before the Pennsylvania PUC as an expert on various aspects of utility economics on behalf of PECO Energy (PECO), Pennsylvania Power and Light, Penn Power and Peoples Natural Gas on numerous occasions. Most recently, I testified on the subject of market rates for energy and capacity in PECO Energy's securitization proceeding, Docket No. R-00973877.

My resume is attached as Appendix WHH-1.

II. INTRODUCTION AND SUMMARY

Q. **What is the purpose of your testimony?**

A. I have been asked by PECO to provide unit-by-unit estimates of market revenues that contribute to covering fixed costs, overhead and profits for each of its generating units or unit entitlements. More specifically, I have provided, for each unit and for the period 1999 to 2015, estimates of annual average prices of energy and capacity sold, the amount of energy and capacity sold and the fuel and variable operations and maintenance expense (O&M) required to produce the forecasted amount of energy. Estimates for the totality of PECO's generation are provided in Schedule WHH-2, with a unit-by-unit summary in a later exhibit. Schedule WHH-2 shows that revenues per MWh generated rise quickly from less than $25 per MWh in 1999 to nearly $35 per MWh in 2001 due principally to tightening of the capacity market. They then rise much more gradually to nearly $60 per MWh in 2015.

Q. How is your testimony organized?

A. After this introduction, my testimony is organized into three sections. First, I discuss the revenue estimates. Second, I discuss the costs estimates. Third, I discuss the GE MAPS model, upon which I relied for most of the revenues and cost estimates, as well as the sources of inputs used to run the model.

III. REVENUE PROJECTIONS

Q. What estimates of revenues did you provide?

A. I provided estimates of energy and capacity revenues for each generating unit for the years 1999 through 2015.

Q. How did you estimate energy revenues?

A. I used the General Electric Multi-Area Production Simulation Program (GE MAPS) model to estimate energy revenues for each generating unit. As described more fully below, the GE MAPS model is a transmission and generation dispatch model that simulates the central dispatch of a region, in this case PJM, (and flows into and out of it from adjacent regions) taking into account any transmission limitations that may arise from economic dispatch. While these formally are "spot" prices, they are an equally valid forecast of prices for energy sold under bilateral contracts. The outputs of the GE MAPS model include the locational spot price for each generation unit per hour and the generation (in kilowatt-hours) of each generating unit per hour. Energy revenues in a year are calculated as the locational spot price for the generator in an hour times the generation in that hour, summed across all the hours in the year. As discussed briefly below, revenues earned by units that run in any commitment cycle were, at a minimum, sufficient to recover full incremental costs over the cycle.

Q. For what years did you run GE MAPS?

A. I ran GE MAPS for 1999, 2004, and 2009. I did not run GE MAPS for other years because each run takes a long time, because the outputs are voluminous, and because I felt that I could represent the entire period well with these three years.

Q. How did you develop revenue and cost estimates for the years between 1999 and 2004, 2004 and 2009, and 2009 and 2015?

A. Between 1999 and 2004, I interpolated; specifically, I projected that the revenues and costs changed in constant annual percentages from the 1999 estimate to the 2004 estimate. I did the same for the period between 2004 and 2009. From 2009 to 2015, I assumed that energy revenues would increase at the same rate as the price of natural gas, since natural gas becomes increasingly on the margin in this period. Since gas escalates at a higher rate than other fuels, the assumption that the price in all hours escalates at the gas price will tend to somewhat over-state the rate of post-2009 revenue escalation. I projected that capacity revenues would increase with the rate of inflation (the GDP implicit deflator). I projected that fuel costs would increase at the DRI forecasted escalation rate for each fuel - coal costs at the rate for coal, gas costs at the rate for gas, and oil costs at the rate for oil. I projected that variable operations and maintenance costs would increase at the rate of inflation.

Q. Have you provided forecasts of costs and revenues beyond 2015?

A. No. However, I understand that PECO needs to make projections also for the years 2016 through 2029 to value units projected to remain in service into this period. Given the very considerable uncertainties about fuels markets, environmental requirements and technological change so far into the future, my best advise to PECO is to project that costs and revenues will increase at the rate of inflation.

Q. What was assumed about capacity additions and closures over this period?

A. I projected that all existing capacity, except for that currently projected by the owners to be closed prior to 2009, would remain open. Based on that assumption, I then determined how much new capacity would be needed to meet a reserve requirement of 18 percent for the PJM, New York (NYPP) and New England (NEPOOL) power pools, and capacity was added to meet this requirement. I believe this to be a reasonable estimate of reserve requirements for these pools in these periods; if anything, it is likely to overstate the requirement for capacity (and hence the rapidity with which capacity value rises to the cost of entry) since market restructuring is likely to lead to more customers receiving real time prices and a consequent reduction in the peak loads currently being forecasted. New capacity was needed in PJM and NEPOOL by the 2004 energy market simulation and in NYPP by the 2009 energy market simulation.

Two types of new generating units were considered: Gas-fired simple cycle turbines and gas-fired combined cycle units. In NYPP and NEPOOL forecasted market prices for energy and capacity are high enough to support the addition of combined cycle units. In PJM forecasted market prices are not high enough in either 2004 or 2009 to support the addition of combined cycle units.

The relative economics of the two candidate replacement capacity types in PJM were also tested in each model year using 10 MW dummy units that have the same cost and operating parameters as market-size units. These units did not earn sufficient energy margins to cover their additional capital cost, confirming that simple cycle turbines are optimal in PJM in 2004 and 2009.

Based on these economics, the appropriate type of plant was added to maintain the required reserve. Generally, capacity was added in areas with the highest prices for each of the three pools, since this is where merchant plants would earn the highest revenues.

Q. How did you assume that energy would be bid into the PJM interchange and outside pools that you modeled?

A. I assumed that each block of power from each unit would be bid at marginal cost -- fuel plus variable O&M. This is the conventional assumption in modeling dispatch and is consistent with competitive generator behavior. A competitive generator who receives, as we assume, market prices rather than its bid price will bid at marginal cost. If it bids higher, it risks not being dispatched when it would be profitable to run. If it bids lower, it risks being run at a loss.

Q. You indicated that revenues for each unit were derived on the basis of hour-by-hour spot prices at the generator's location. How were these spot prices derived?

A. The GE MAPS model, simulating the behavior of an independent system operator, commits and dispatches the available units to minimize total system costs. If there are no transmission constraints, the market price across the system will be the same and would be the cost of the highest unit required to meet load, often called the "system Lambda".

If there are transmission constraints, then the price will not be uniform. Some low cost power will not be able to flow to areas in which the remaining available generation has higher variable costs. As a result, the price in the high cost area will be set by local generation and will be higher than if there are no constraints. Conversely, prices in the areas with a surplus of lower cost generation that cannot be transmitted to the high cost area will be lower than if transmission were unconstrained.

Q. Did you find transmission constraints in PJM?

A. Yes. The GE MAPS model reveals that, as the system would be operated in 1999-2009 conditions, there are three interfaces within PJM that may be constrained. The first is an interface just east of the Keystone and Conemaugh stations. The second is the central/southern interface, which runs approximately along the southern border of Pennsylvania from the east and then north slightly west of Harrisburg. The third is the eastern interface which runs just west of PECO's service territory. These constrainable interfaces do not bind frequently. Using the 1999 simulation as an example, the western interface, which potentially limits the flow of power from ECAR (the reliability council west of PJM) and western Pennsylvania into the rest of PJM, is not forecast to bind. The central interface is forecast to bind about 2 % of the time. This limits the flow of power from southern and western PJM and from ECAR into the rest of PJM. The eastern interface is forecast to bind less than 1% of the time. This limits the flow of power to PECO and the rest of eastern PJM. Because capacity is added in high price regions (and because the economic surplus energy available from ECAR reduces over time), these interfaces do not bind in later years.

Q. *What is the effect of these constraints on the locational spot prices that would be paid to PECO's generating units?*

A. The effect is to increase the prices paid to PECO's generating units in eastern PJM and to decrease the prices paid to Keystone and Conemaugh. If these interfaces were not constrained, the prices paid to PECO's generating units in eastern PJM would be lower and the prices paid to Keystone and Conemaugh would be higher. On balance, this increases the revenues earned by PECO units relative to an unconstrained case.

Q. Does the assumption that all generation receives the spot energy price at its location depend on the pool rules adopted for the PJM Interchange?

A. Not importantly. While we modeled prices earned by PECO generating units based on locational spot prices partly for convenience, since this is the architecture of the GE MAPS model, I also believe that locational spot prices will vary by location to reflect the impact of constraints. Quite simply, in a constrained area buyers of contract or spot energy will not have energy from outside the constraint available as an alternative to serve incremental load. Prices will reflect supply and demand conditions inside the constraint, hence the marginal price in the constrained area. Similarly, when constraints keep low cost energy from flowing out of an area, suppliers will have to compete to meet the local load and prices will be lower.

Q. Do any of PECO's units fail to recover their out of pocket generating costs if bids are based on marginal costs?

A. Had we not adjusted revenues to assure that out of pocket costs were recovered (for example, in "uplift"), some of PECO's mid-merit steam units would not have recovered all costs on some days. The possibility of negative cost recovery occurs if a unit with start up and no load costs is run for few hours and the difference between its cost and market prices in those hours is low. This clearly is not in the interest of the unit's owner, and the problem will be resolved either through pool rules or through the owner increasing its bid costs until the unit either is not committed or revenues earned are high enough to recover out of pocket costs when it is.

My understanding of the recent FERC order concerning changes to the PJM agreement[1] is that PJM has been directed to develop the relevant part of the PJM agreement according to the plan of the Supporting Companies Group. This proposal is that start up and no-load/minimum load costs not recovered in energy market prices will be compensated through an uplift payment. Energy market prices paid to other generators will not be affected by the amount of uplift. To reflect this, I had the cycles with negative cost recovery identified and computed the increased revenues for the specific generating units

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[1] Pennsylvania-New Jersey-Maryland Interconnection, Docket Nos. OA97-262-000 and ER97-1082-000, mimeo at (February 28, 1997).

needed to fully cover variable costs over the run cycle. These adjustments add only about 0.3 to 0.4 mills per kWh to the price received by PECO for its generation.

Q. How did you estimate capacity revenues?

A. The market value of capacity will be determined by conditions of supply and demand. Currently, capacity is in excess supply in PJM. Recent transactions indicate that the market price of capacity in PJM currently is approximately $15 per kilowatt-year. Changes in supply and demand between now and 1999 are unlikely to change that price materially. Hence, I have used that price, adjusted for inflation, as the capacity price in 1999.

Based on the OE-411 form filed by MAAC in 1996, an 18 percent reserve requirement would require new capacity in PJM by about 2001. Hence, the 2001 revenues earned by new generation will have to rise to a level sufficient to make capacity economic, since no market participant would build it otherwise. The price of capacity in 2001 may have to *rise to the level of the annualized cost of a simple cycle combustion turbine peaking unit,* which is about $35 per kilowatt year in 1996 dollars. Between 1999 and 2001 (i.e. for 2000) I interpolated between the current market price of capacity and the 2001 price.

This capacity price is applied to all of PECO's capacity. In electricity systems in which market mechanisms included a separately priced value of capacity (which include both the current and proposed PJM interchange) all capacity that meets availability requirements receives, implicitly or explicitly, the market value of capacity.

Q. You have based your calculation of revenues earned by PECO's generating units on the spot price of energy plus the estimated market value of capacity. In your opinion, is PECO likely to receive higher revenues if it sells energy and capacity under bilateral contracts?

A. No. The only reason why the value of a contract might differ from the expected value of spot revenues is that a contract provides greater price certainty. This hedging function of contracts is valuable to both buyers and sellers. There is no reason in fact or theory to assume that contracts will systematically result in higher revenues. For example, in the UK I assisted load-serving buyers in evaluating contract offers. The analysis performed by buyers always was based on the expected value of the spot market and accorded no premium to price certainty. Moreover, over the last several years, new contract prices and spot prices in the UK market have been at very similar levels.

IV. GENERATION COST PROJECTIONS

Q. What cost forecasts did you provide to PECO?

A. I provided estimates of fuel costs and variable costs for each generating unit.

Q. How did you estimate fuel costs?

A. I used the GE MAPS model to estimate fuel costs for each generating unit. The fuel costs for a unit are calculated from its generation, its heat rate (which varies with the level of generation), and the fuel price for that unit. The sources of these inputs are described later in my testimony.

Q. How did you estimate variable operations and maintenance costs for each unit?

A. I used the GE MAPS model to estimate the variable operations and maintenance costs for each generating unit. These are calculated by multiplying input values for variable operations and maintenance cost per kilowatt-hour by the kilowatt-hours of generation by the unit.

V. THE GE MAPS MODEL AND COST INPUTS

Q. What is the GE MAPS model?

A. The GE MAPS model was developed and is licensed by the General Electric Company. A description of this model is provided in Exhibit WHH-5. Like other production costing models, GE MAPS will commit and dispatch generating units based on bid or cost data for each generating unit. Its more unique capability is in taking into account transmission constraints when it does unit commitment and dispatch. It is this capability that caused me to prefer it for modeling prices in PJM. Transmission constraints can and will have significant effects on the unit commitment and dispatch decisions of the Independent System Operator. As a result of its ability to incorporate properly the effects of transmission constraints, the GE MAPS model can forecast locational spot prices for each generating unit. This capability is critical to the ability to forecast generating revenues that are based on locational spot prices.

Q. What are the outputs of GE MAPS?

A. There are many outputs of GE MAPS. These include for each generating unit locational spot prices, generation, fuel costs, and variable operations and maintenance costs by hour. From these outputs, net negative cycle costs also can be calculated and then summed to estimate uplift revenues. The GE MAPS outputs also quantify transmission flows over the transmission network and the shadow price associated with any transmission constraint, by hour. The outputs of the GE MAPS model (set up for this analysis) also include transmission flows between three power pools - PJM, NYPP, and NEPOOL - and also imports from ECAR, Hydro Quebec, and Ontario Hydro.

Q. What are the inputs to GE MAPS?

A. There are many inputs to GE MAPS, which can be separated into five categories. The first category includes generating unit characteristics, including such parameters as capacity, heat rates by unit block, ownership, variable operations and maintenance costs, planned maintenance, and forced outage rates. A second category includes fuel prices, SOx offset costs, and NOx offset costs, all specified as a base year price and escalators from the base year prices. A third category includes loads, load shapes, and load growth for the various load buses. A fourth category includes transmission data, including transmission constraints and shift factors which capture the effect of a generating unit on various elements of the AC transmission network. A fifth category includes other key inputs such as potential imports from ECAR, Ontario Hydro, and Hydro Quebec, wheeling rates between pools, and transmission rates within pools.

Q. **What are the sources for these inputs?**

GE already possessed, and provided to us, a data base that it had derived from various internal and public sources. This database is a commercial product of GE's. Under my direction, PHB staff reviewed this data base and, where necessary, made adjustments to it. I will discuss these refinements later in my testimony.

Q. **Did the GE data base provide information of future units required to meet reserve requirements in PJM, NYPP and NEPOOL?**

A. No. The GE data base was not set up for simulation of a period as long as required for this study. As noted earlier, our assessment of the economics of the northeastern US electricity market caused us to conclude that the capacity that most cost-effectively would be added is either combined cycle gas capacity or combustion turbines. The most cost-effective mix of these unit types were added to meet reliability requirements. The operating characteristics, amount and timing of the units we added are shown on Exhibit WHH-3, page 2.

Q. **Did PHB change the variable operations and maintenance cost estimates provided by GE?**

A. Not in most cases. We reviewed these estimates, but we did not change them. Exhibit WHH-3, page 3, provides the variable operations and maintenance costs estimates from GE. PECO data were used for PECO units. These were used in order to insure consistency between the model's cost outputs and dispatch decisions with the calculations that other PECO witnesses sponsor concerning total plant O&M as used in the stranded cost calculations. In most cases the PECO data were similar to the GE data, the exception being units with unusual characteristics such as the scrubbers on the Cromby and Eddystone coal units.

Q. **Did PHB adjust the heat rates provided by GE?**

A. Yes. The GE heat rates are design heat rates, based on the technical specifications of each generating unit. In many cases, design heat rates are lower than the heat rates actually achieved by utilities. It is reasonable to assume that competition will cause utilities to reduce heat rates somewhat from current levels. That is what I understand that the generators in the UK have been able to achieve. However, it may be too optimistic to assume that design heat rates can be achieved on a basis that is both economic and preserves unit reliability. To make allowance for this, we increased the GE-provided fossil plant heat rates by 5 percent. The effect of this change is to increase incremental generating costs for fossil plants by about 5 percent. Since fossil plants almost always set spot market energy prices (directly or indirectly through operation of pumped storage units), the effect is to increase PECO's forecasted energy revenues by a similar 5 percent relative to what would have been forecasted without the change. It also increases its fossil energy costs by nearly comparable amounts. However, this does not fully offset the revenue increase since much of PECO's energy comes from nuclear units. Hence, the result of this change is to increase PECO's operating profits in energy markets and reduce the consequent estimate of its strandable costs.

Also, PECO informs me that the full load heat rate at Eddystone 1 and 2 is 10,500 btu per kWh, materially higher than the GE estimate of less than 9000. Eddystone was designed as an extremely efficient plant. However, it did not operate reliably at design efficiency, and reliable operation resulted in reduced efficiency. Further, scrubbers were subsequently added to these units, and the scrubbers reduced the efficiency further. On this basis, I have increased the input heat rates of Eddystone 1 and 2 to better reflect actual as-operated unit efficiencies. Heat rates for similar fossil-steam units owned by other utilities were increased by 10 percent. This, of course, reduces the value of the facilities and may marginally increase prices.

Q. What changes did PHB make to the second category of data - fuel prices and environmental offset costs?

A. We reviewed these data against other data sources. Where necessary, we modified the data received from GE, correcting errors and incorporating other information, such as information on spot market fuel prices. This somewhat revised GE data base provided base year fuel costs. Fuels cost escalation over the study period was on the basis of a 1996 forecast by DRI, provided to us by PECO. Exhibit WHH-3, pages 4 and 5 show the DRI forecast and representative prices for PECO units. The cost of environmental offsets was estimated by PHB on the basis of in-house studies. These also are shown on Page 5 of Exhibit WHH-3.

Q. Did PHB make changes to the third category of data - loads, load shapes, and load growth?

A. No. We relied entirely on the GE data. The GE data in turn are based principally on the 1994 FERC Form 714 filings for PJM and NYPP companies, and on data provided by Northeast Utilities for NEPOOL companies.

Q. Were changes made to the transmission data contained in the commercial version of the GE MAPS model?

A. No.

Q. What was the source of the fifth category of data - potential imports and wheeling rates?

A. The GE MAPS model and data that I used include explicit modeling of PJM and as well as the New York and New England power pools. Both NEPOOL and NYPP plan to have non-pancaked transmission rates. Because there is no pancaking, and transmission capability is modeled explicitly by GE MAPS, no assumptions had to be made concerning the cost of, and constraints affecting, intra-pool transactions within them. Inter-pool transmission is assumed *to be priced at 2 mills per kWh. Inter-pool imports and exports were forecasted by the model* taking into account the variable costs in each pool, these wheeling charges, and transmission limitations. GE had not incorporated data on imports available from ECAR or from Ontario Hydro and Hydro Quebec. These data inputs were created by PHB as a part of on-going projects for various clients in the northeastern US and reflect PHB fact-finding and analysis. In the case of ECAR, available surplus energy was modeled assuming pan-caking within ECAR and a 1 mill rate for economy energy. The forecasted quantities and prices for ECAR and Canadian energy are shown on pages 6 and 7 of Exhibit WHH-3.

Q. Is the GE-MAPS model difficult to use?

A. Yes. While a single-year run of the model can be executed over night, creating a new case to run the model can take several person days for creating and de-bugging a new input set and post-processing outputs into a usable form. Of course, the difficulty depends on the complexity of the changes. For example, adding a further year of analysis requires creating new load files, changed fuels prices, determining what new generation capacity is required, and so forth. While conceptually simple, these tasks require substantial changes to the input files with consequent opportunities for error and need for auditing. The scope of effort is in the range of 2 person-weeks. It is for this reason that I did not run additional years in this analysis.

VI. CONCLUSION

Q. Have you produced an exhibit that shows the unit by unit revenue and cost data *that you provided to PECO?*

A. Yes. These data are shown on Exhibit WHH-4.

Q. Does this conclude your testimony?

A. Yes.

WILLIAM H. HIERONYMUS **Managing Director**

William Hieronymus has consulted extensively to managments of electricity and gas companies, their counsel, regulators and policy makers. His principal areas of concentration are the structure and regulation of network utilities and associated management, policy and regulatory issues. He has spent the last several years working on restructuring and privatization of utility systems internationally and on changing regulatory systems and management strategies in mature electricity systems. In his twenty-plus years of consulting to this sector he also has performed a number of more specific functional tasks including the selection of investments, determining procedures for contracting with independent power producers, assistance in contract negotiation, tariff formation, demand forecasting and fuels market forecasting. Dr. Hieronymus has testified frequently on behalf of utility clients before regulatory bodies, federal courts and legislative bodies in the United States and United Kingdom. Since joining Putnam, Hayes & Bartlett, Inc. (PHB) he has contributed to numerous projects, including the following:

ELECTRICITY SECTOR STRUCTURE, REGULATION AND RELATED MANAGEMENT AND PLANNING ISSUES

U.S. Assignments

- Dr. Hieronymus served as an advisor to a western electric utility on restructuring and related regulatory issues and has worked with senior management in developing strategies for shaping and adapting to the emerging competitive market in electricity. As a part of this general assignment he helped develop, and testified respecting, a settlement with the state regulatory commission staff that provides, among other things for accelerated recovery of strandable assets. He also prepared numerous briefings for the senior management group on various topics related to restructuring.

- For several utilities seeking merger approval he has prepared and testified to market power analyses at FERC and before state commissions. These analyses cover the destination market-oriented traditional FERC tests, Justice Department-oriented market structure tests, behavioral tests of the ability to raise prices and examination of vertical market power arising from ownership of transmission and generation. The mergers on which he has testified include both electricity mergers and combination mergers involving electricity and gas companies.

- For utilities and power pools preparing structural reforms, he has assisted in examining various facets of proposed reforms. This analysis has included both features of the proposals affecting market efficiency and those that have potential consequences for market power. Where relevant, the analysis also has examined the effects of alternative reforms on the clients financial performance and achievement of other objectives.

- For the New England Power Pool he examined the issue of market power in connection with its movement to market-based pricing for energy, capacity and ancillary services. The main results of his analysis are incorporated in NEPOOL's market power filing before FERC.

- As part of a large PHB team he assisted a midwest utility in developing an innovative proposal for electricity industry restructuring. This work formed the basis for that utility's proposals in its state's restructuring proceeding.

- Dr. Hieronymus has contributed substaintially to PHB's activities in the restructuring of the California electricity industry. In this context he also is a witness in California and FERC proceedings on the subject of market power and mitigation.

- He has contributed to the development of benchmarking analyses for U.S. utilities. These have been used in work with PHB's clients to develop regulatory proposals, set cost reduction targets, restructure internal operations and assess merger savings.

- Dr. Hieronymus was a co-developer of a market simulation package that PHB has tailored to region-specific applications. He and other PHB personnel have provided numerous multi-day training sessions using the package to help our utility clients in educating management personnel in the consequences of wholesale and retail deregulation and in developing the skills necessary to succeed in this environment.
- Dr. Hieronymus has made numerous presentations to U.S. utility managements on the U.K. electricity system and has arranged meetings with senior executives and regulatorsin the U.K. for the senior managements of U.S. utilities.
- For a task force of utilities, regulators, legislators and other interested parties created by the Governor's office of a northeastern state he prepared background and briefing papers as part of a PHB assignment to assist in developing a consensus proposal for electricity industry restructuring.
- Dr. Hieronymus has testified before state commissions on market pricing and stranded costs associated with the movement to retail competition. He also assisted a northeastern utility in drafting its submission to a state PUC proceeding on the measurement and recovery of stranded costs and has assisted various other utilities in their internal studies of stranded costs.
- For an East Coast electricity holding company, he prepared and testified to an analysis of the logic and implementation issues concerning utility-sponsored conservation and demand management programs.
- In connection with nuclear generating plants nearing completion, he has testified in Pennsylvania, Louisiana, Arizona, Illinois, Missouri, New York, Texas, Arkansas, New Mexico and before the Federal Energy Regulatory Commission in plant-in-service rate cases on the issues of equitable and economically efficient treatment of plant cost for tariff setting purposes, regulatory treatment of new plants in other jurisdictions, the prudence of past system planning decisions and assumptions, performance incentives and the life-cycle costs and benefits of the units. In these and other utility regulatory proceedings, Dr. Hieronymus and his colleagues have provided extensive support to counsel, including preparation of interrogatories, cross-examination support and assistance in writing briefs.
- On behalf of utilities in the states of Michigan, Massachusetts, New York, Maine, Indiana, Pennsylvania, New Hampshire and Illinois, he has submitted testimony in regulatory proceedings on the economics of completing nuclear generating plants that are currently under construction. His testimony has covered the likely cost of plant completion, forecasts of operating performance and extensive analyses of ratepayer and shareholder impacts of completion, deferral and cancellation.
- For utilities engaged in nuclear plant construction, Dr. Hieronymus has performed a number of highly confidential assignments to support strategic decisions concerning continuing the construction projects. Areas of inquiry included plant cost, financial feasibility, power marketing opportunities, the impact of potential regulatory treatments of plant cost on shareholders and customers and evaluation of offers to purchase partially completed facilities.
- For an eastern Pennsylvania utility that suffered a nuclear plant shutdown due to NRC sanctions relating to plant management, he filed testimony regarding the extent to which replacement power cost exceeded the costs that would have occurred but for the shutdown.

- For a major midwestern utility, he headed a team that assisted senior management in devising its strategic plans including examination of such issues as plant refurbishment/life extension strategies, impacts of increased competition and diversification opportunities.
- On behalf of two West Coast utilities, he testified in a needs certification hearing for a major coal-fired generation complex..
- For a large western combination utility, Dr. Hieronymus participated in a major 18-month effort to provide it with an integrated planning and rate case management system. His specific responsibilities included assisting the client in design and integration of electric and gas energy demand forecasts, peak load and load shape forecasts and forecasts of the impacts of conservation and load management programs.
- For two midwestern utilities, he prepared an analysis of intervenor-proposed modifications to the utilities' resource plans. He then testified on their behalf before a legislative committee..
- For a major combination electric and gas utility, he directed the adaptation of a PHB-developed financial simulation model for use in resource planning and evaluation of conservation programs.

U.K. Assignments

- Following promulgation of the White Paper setting out the general framework for privatization of the electricity industry in the United Kingdom, Dr. Hieronymus participated extensively in the task forces charged with developing the new market system and regulatory regime. His work on behalf of the Electricity Council and the twelve regional electricity councils focused on the proposed regulatory regime, including the price cap and regulatory formulas, and distribution and transmission use of system tariffs. He was an active participant in industry-government task forces charged with creating the legislation, regulatory framework, initial contracts and rules of the pooling and settlements system. He also assisted the regional companies in the valuation of initial contract offers from the generators, including supporting their successful refusal to contract for the proposed nuclear power plants that subsequently were canceled as being non-commercial.
- During the preparation for privatization, he assisted several of the U.K. individual electricity companies in understanding the evolving system, in development of use of system tariffs, and in developing strategic plans and management and technical capabilities in power purchasing and contracting. He continued to advise a number of clients, including regional companies, power developers, large industrial customers and financial institutions on the U.K. power system for a number of years after privatization.
- Dr. Hieronymus assisted four of the regional electricity companies in negotiating equity ownership positions and developing the power purchase contracts for an 1,825 megawatt combined cycle gas station. He also assisted clients in evaluating other potential generating investments including cogeneration and non-conventional resources.
- He also has consulted on the separate reorganization and privatization of the Scottish electricity sector. PHB's role in that privatization included advising the larger

of the two Scottish companies and, through it, the Secretary of State on all phases of the restructuring and privatization, including the drafting of regulations, asset valuation and company strategy.

- He has assisted one of the Regional Electricity Companies in England and Wales in the 1993 through 1995 regulatory proceedings that reset the price caps for its retailing and distribution businesses. Included in this assignment have been policy issues such as incentives for economic purchasing of power, the scope of the price control, and the use of comparisons among companies as a basis for price regulation. His model for determining network refurbishment needs was used by the regulator in determining revenue allowances for capital investments.
- He assisted this same utility in its defense against a hostile takeover, including preparation of its submission to the Cabinet Minister who had the responsibility for determining whether the merger should be referred to the competition authority.

Assignments Outside the U.S. and U.K.

- Dr. Hieronymus has assisted a large state-owned European electricity company in evaluating the impacts of the 1997 EU directive on electricity that *inter alia* requires retail access and competitive markets for generation. The assignment includes advice on the organizational solution to elements of the directive requiring a separate transmission system operator and the business need to create a competitive marketing function.
- For the European Bank for Reconstruction and Development he performed analyses of least cost power options, evaluation of the return on a major plant investment that the Bank was considering and forecasts of electricity prices in support of assessment of a major investment in an electricity intensive industrial plant.
- For the OECD he performed a study of energy subsidies worldwide and the impact of subsidy elimination on the environment, particularly on greenhouse gases.
- For the Magyar Villamos Muvek Troszt, the electricity company of Hungary, he developed a contract framework to link the operations of the different entities of an electricity sector in the process of moving from a centralized command and control system to a decentralized, corporatized system.
- For Iberdrola, the largest investor-owned Spanish electricity company, he assisted in development of their proposal for a fundamental reorganization of the electricity sector, its means of compensating generation and distribution companies, its regulation and the phasing out of subsidies. He also has assisted the company in evaluating generation expansion options and in valuing offers for imported power.
- Dr. Hieronymus contributed extensively to a project for the Ukrainian Electricity Ministry, the goal of which is to reorganize the Ukrainian electricity sector and prepare it for transfer to the private sector and the attraction of foreign capital. The proposed reorganization will be based on regional electricity companies, linked by a unified central market, with market-based prices for electricity.
- At the request of the Ministry of Power of the USSR, Dr. Hieronymus participated in the creation of a seminar on electricity restructuring and privatization. The seminar was given for 200 invited Ministerial staff and senior managers for the USSR power system. His specific role was to introduce the requirements and methods of privatization. Subsequent to the breakup of the Soviet Union, he continued to advise

the Russian energy and power ministry and government-owned generation and transmission company on restructuring and market development issues.

- On behalf of a large continental electricity company he analyzed the proposed directives from the European Commission on gas and electricity transit (open access regimes) and on the internal market for electricity. The purpose of this assignment was to forecast likely developments in the structure and regulation of the electricity sector in the common market and assist the client in understanding their implications.
- For the electric utility company of the Republic of Ireland, he assessed the likely economic benefit of building an interconnector between Eire and Wales for the sharing of reserves and the interchange of power.
- For a task force representing the Treasury, electric generating and electricity distribution industries in New Zealand, he undertook an analysis of industry structure and regulatory alternatives for achieving economically efficient generation of electricity. The analysis explored how the industry likely would operate under alternative regimes and their implications for asset valuation, electricity pricing, competition and regulatory requirements.

TARIFF DESIGN METHODOLOGIES AND POLICY ISSUES

- Dr. Hieronymus participated in a series of studies for the National Grid Company of the United Kingdom and for ScottishPower on appropriate pricing methodologies for transmission, including incentives for efficient investment and location decisions.
- For a U.S. utility client, he directed an analysis of time-differentiated costs based on accounting concepts. The study required selection of rating periods and allocation of costs to time periods and within time periods to rate classes.
- For EPRI, he directed a study that examined the effects of time-of-day rates on the level and pattern of residential electricity consumption.
- For the EPRI-NARUC Rate Design Study, Dr. Hieronymus developed a methodology for designing optimum cost-tracking block rate structures.
- On behalf of a group of cogenerators, he filed testimony before the Energy Select Committee of the UK Parliment on the effects of prices on cogeneration development.
- For the Edison Electric Institute (EEI), he prepared a statement of the industry's position on proposed federal guidelines on fuel adjustment clauses. He also assisted EEI in responding to the U.S. Department of Energy (DOE) guideline on cost-of-service standards.
- For private utility clients, he assisted in the preparation of comments on draft Federal Energy Regulatory Commission (FERC) regulations and in preparing their compliance plans for PURPA Section l33.
- For the EEI Utility Regulatory Analysis Program, he co-authored an analysis of the DOE position on the purposes of the Public Utilities Regulatory Policies Act of 1978. The report focused on the relationship between those purposes and cost-of-service

and ratemaking positions under consideration in the generic hearings required by PURPA.

- For a state utilities commission, Dr. Hieronymus assessed its utilities' existing automatic adjustment clauses to determine their compliance with PURPA and recommended modifications.

- For the DOE, he developed an analysis of automatic adjustment clauses currently employed by electric utilities. The focus of this analysis was on efficiency incentive effects.

- For the commissioners of a public utility commission, he assisted in preparation of briefing papers, lines of questioning and proposed findings of fact in a generic rate design proceeding.

SALES FORECASTING METHODOLOGIES FOR GAS AND ELECTRIC UTILITIES

- For the White House Sub-Cabinet Task Force on the future of the electric utility industry, Dr. Hieronymus co-directed a major analysis of "least-cost planning studies" and "low-growth energy futures." That analysis was the sole demand-side study commissioned by the task force and formed an important basis for the task force's conclusions concerning the need for new facilities and the relative roles of new construction and customer side-of-the-meter programs in utility planning.

- For a large eastern utility, he developed a load forecasting model designed to interface with the utility's revenue forecasting system- planning functions. The model forecasts detailed monthly sales and seasonal peaks for a 10-year period.

- For the DOE, he directed the development of an independent needs assessment model for use by state public utility commissions. This major study developed the capabilities required for independent forecasting by state commissions and constructed a forecasting model for their interim use.

- For several state regulatory commissions, Dr. Hieronymus has consulted in the development of service area level forecasting models of electric utility companies.

- For EPRI, he authored a study of electricity demand and load forecasting models. The study surveyed state-of-the-art models of electricity demand and subjected the most promising models to empirical testing to determine their potential for use in long-term forecasting.

- For a midwestern electric utility, he has provided consulting assistance in improving its load forecast and has testified in defense of the revised forecasting models.

- For an East Coast gas utility, he testified with respect to sales forecasts and provided consulting assistance in improving the models used to forecast residential and commercial sales.

OTHER STUDIES PERTAINING TO REGULATED AND ENERGY COMPANIES

- In a number of antitrust and regulatory matters, Dr. Hieronymus has performed analyses and litigation support tasks. These include both Sherman Act Section One and Two cases, contract negotiations, generic rate hearings, ITC hearings and a major asset valuation suit. In a major antitrust case, he testified with respect to the demand for business telecommunications services and the impact of various practices on demand and on the market share of a new entrant. For a major electrical equipment vendor he has testified on damages with respect to alleged defects and associated fraud and warranty claims. In connection with mergers for which he is the market power expert, he is assisting clients in responding to the Antitrust Division of the U.S. Department of Justice's Hart-Scott-Rodino requests.

- For a private client, he headed a project that examined the feasibility and value of a major synthetic natural gas project. The study analyzed both the future supply costs of alternative natural gas sources and the effects of potential changes in FPC rate regulations on project viability. The analysis was used in preparing contract negotiation strategies.
- For a industrial client considering development and marketing of a total energy system for cogeneration of electricity and low-grade heat, he developed an estimate of the potential market for the system by geographic area.
- For the U.S. Environmental Protection Agency (EPA), Dr. Hieronymus was the principal investigator in a series of studies for forecasting future supply availability and production costs for various grades of steam and metallurgical coal to be consumed in process heat and utility uses.

Dr. Hieronymus has addressed a number of conferences on such issues as market power, industry restructuring, utility pricing in competitive markets, international developments in utility structure and regulation, risk analysis for regulated investments, price squeezes, rate design, forecasting customer response to innovative rates, intervenor strategies in utility regulatory proceedings, utility deregulation and utility-related opportunities for investment bankers.

Before joining PHB, Dr. Hieronymus was program manager for Energy Market Analysis at Charles River Associates. Previously, he served as a project director at Systems Technology Corporation and as an economist while serving in the U.S. Army. He is a present or past member of the American Economics Association and the International Association of Energy Economists, and a past member of the Task Force on Coal Supply of the New England Energy Policy Commission. He is the author of a number of reports in the field of energy economics and has been an invited speaker at numerous conferences.

Dr. Hieronymus received a B.A. from the University of Iowa and M.A. and Ph.D. degrees in economics from the University of Michigan.

SUMMARY OF FINDINGS

	Average Market Price $/MWh	Average Fuel Cost $/MWh
1999	24.5	7.8
2000	27.7	8.0
2001	32.1	8.3
2002	33.8	8.7
2003	35.7	9.1
2004	37.6	9.6
2005	39.3	10.0
2006	41.1	10.5
2007	42.9	11.0
2008	44.9	11.5
2009	47.0	12.1
2010	48.8	12.5
2011	50.6	12.9
2012	52.6	13.3
2013	54.6	13.7
2014	56.7	14.2
2015	58.9	14.6

PJM Energy Demand

Year	Energy Demand (GWh)
1999	256,675
2004	276,437
2009	289,059

New Capacity

New gas-fired combined cycle (CC) units were added in NEPOOL and NYPP to maintain an 18% reserve margin. In PJM, new simple-cycle combustion turbine (CT) units were added to maintain an 18% reserve margin. The characteristics of these units are shown below:

New Simple-Cycle Combustion Turbine Characteristics

Parameter	
Unit size	250 MW
Full load heat rate	10,000 Btu/kWh
Variable O&M (1996$)	$2.7/MWh

New Combined-Cycle Characteristics

Parameter	
Unit size	375 MW
Full load heat rate	6,600 Btu/kWh
Variable O&M (1996$)	$1.4/MWh

The types and numbers of the new units added are as follows:

Capacity Additions (number of units)

Pool	Unit Type	1999	2004	2009
PJM	250 MW CT	0	15	12
NEPOOL	375 MW CC	0	1	5
NYPP	375 MW CC	0	0	4

Unit Variable Operating and Maintenance Costs

The following general rules were applied by GE in specifying variable operating and maintenance costs. There are some minor differences from this pattern in the database.

Unit Type	Variable O&M (1996$)
Nuclear units	0.60
Coal units	2.00
Gas-fired units	1.25
Residual oil units	1.92
Distillate oil units	1.50

The following data were used for PECO units:

Unit Type	Variable O&M (1997$)
Cromby 1	3.38
Cromby 2	0.51
Eddystone 1	4.07
Eddystone 2	3.24
Eddystone 3&4	0.48
CTs	2.22

Sample Delivered Fuel Prices ($/mmBtu)

Fuel Prices

An assessment of fuels that are likely to be used by generating units was made (including the sulfur content of the fuel). Current market price estimates for fuels delivered to these units or to nearby units was used as a starting point for fuel prices. All coal, gas and oil prices were revised.

Current fuel prices were escalated to future year (nominal) prices using DRI price escalators.[1]

CROMBY COAL PRICES

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1999	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45
2004	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60
2009	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80

CONEMAUGH COAL PRICES

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1999	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09
2004	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
2009	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35

CROMBY NATURAL GAS PRICES

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1999	2.77	2.66	2.55	2.45	2.34	2.34	2.34	2.45	2.45	2.55	2.66	2.77
2004	3.64	3.50	3.36	3.22	3.08	3.08	3.08	3.22	3.22	3.36	3.50	3.64
2009	4.69	4.51	4.33	4.15	3.97	3.97	3.97	4.15	4.15	4.33	4.51	4.69

EDDYSTONE RESIDUAL FUEL OIL PRICES

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1999	3.00	2.89	2.73	2.58	2.45	2.45	2.45	2.58	2.73	2.86	2.97	3.00
2004	4.07	3.93	3.71	3.51	3.32	3.32	3.32	3.51	3.71	3.89	4.03	4.07
2009	5.47	5.28	4.99	4.72	4.46	4.46	4.46	4.72	4.99	5.22	5.41	5.47

SCHUYKILL DISTILLATE FUEL OIL PRICES

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[1] Data Resources Inc.

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1999	4.93	4.71	4.49	4.22	4.05	4.05	4.05	4.22	4.49	4.71	4.93	4.93
2004	6.57	6.28	5.99	5.62	5.40	5.40	5.40	5.62	5.99	6.28	6.57	6.57
2009	8.69	8.30	7.92	7.43	7.14	7.14	7.14	7.43	7.92	8.30	8.69	8.69

Cost of SO_2 and NO_x Allowances

SO_2 and NO_x allowance prices were estimated and added to oil, gas and coal prices based on the following assumptions:

Allowance Prices ($/Ton)

Year	$/Ton SO_2	$/Ton NO_x
1999	150	1,000
2004	250	1,500
2009	400	1,500

NO_x allowances were added during the "summer ozone season," May - September only.

The following generic NO_x cost adders were assumed, based on average assumed emission rates by plant type in the future:

NO_x Cost Adders ($/mmBtu)

Fuel Type	1999	2004	2009
Coal	0.15	0.15	0.15
Gas	0.05	0.075	0.075
Oil	0.1	0.15	0.15

In 2004 and 2009, coal prices were also increased by the equivalent of $1/MWh in the summer ozone season to account for the additional variable cost of pollution control equipment.

NO_x allowance costs are added to all units. SO_2 allowance costs only apply to some coal units in PJM, NEPOOL and NYPP prior to 2000. Beginning in 2000, all coal and oil-steam units greater than 25 MW would require SO_2 allowances.

Imports and Wheeling Rates

Wheeling Rates

- Each pool (PJM, NYPP, and NEPOOL) was assumed to have no internal wheeling rate
- Wheeling costs between pools were assumed to be $2/MWh

Firm Import Potential

- PEPCO imports 450 MW from Ohio Edison. This is priced at $10/MWh and is available all the time.
- The Hydro Quebec Phase II contract is modeled as 1500 MW maximum with an energy limit of 280,000 MWh per month for January - March and November - December, and 800,000 MWh per month for April - October.

Economy Import Potential

Ontario Hydro to NYPP

Ontario Hydro supply is available 7 am to 10 pm weekdays at 240 MW. It is priced at $23.07/MWh in 1999, $26.75/MWh in 2004 and $31.01/MWh in 2009.

Hydro Quebec Economy to NYPP and NEPOOL

Hydro Quebec supply over and above firm commitments was estimated as 3000 MW in 1999, 1300 MW in 2004 and 0 MW in 2009. This supply is available in NEPOOL and NYPP (with a joint limit). In addition, the supply from Hydro Quebec to NEPOOL from the Phase II contract and economy (the sum thereof) is limited to 2000 MW.

Energy is priced at $16.39/MWh, $19.00/MWh and 22.02/MWh in 1999, 2004 and 2009, resp. It is available 7 am to 10 pm weekdays

ECAR to PJM

ECAR supply curves was estimated for each month for on- and off-peak periods. Average prices per block were calculated. The monthly on- and off-peak prices and MW blocks are shown below.

1999 Off-Peak

Block Size (MW)	*Jan*	*Feb*	*Mar*	*Apr*	*May*	*June*	*July*	*Aug*	*Sept*	*Oct*	*Nov*	*Dec*
800	17.50	17.96	17.17	16.73	16.58	16.73	17.29	17.97	16.58	16.58	17.41	17.88
800	17.85	18.29	17.40	16.97	16.83	17.34	17.88	18.57	16.97	16.95	17.46	18.29
550	18.15	18.57	17.41	17.17	16.95	17.41	18.29	18.57	17.17	17.04	17.74	18.57

1999 On-Peak

	Jan	*Feb*	*Mar*	*Apr*	*May*	*June*	*July*	*Aug*	*Sept*	*Oct*	*Nov*	*Dec*
800	20.12	20.43	18.57	18.29	18.08	20.52	23.71	33.86	18.57	18.29	18.60	20.12
800	20.52	20.66	18.63	18.57	18.57	20.83	25.24	33.86	18.60	18.57	19.11	20.52
550	20.83	20.87	19.11	18.82	18.59	21.11	28.46	34.86	19.39	18.85	19.78	20.81

2004 Off-Peak

	Jan	*Feb*	*Mar*	*Apr*	*May*	*June*	*July*	*Aug*	*Sept*	*Oct*	*Nov*	*Dec*
800	20.78	21.44	20.55	19.49	19.01	20.44	20.74	22.53	19.49	19.40	20.73	21.14
800	21.02	21.54	20.73	19.94	19.37	20.54	21.02	22.86	19.97	19.63	20.74	21.52
550	21.47	22.20	20.78	20.51	19.49	20.74	21.77	23.50	20.52	19.97	20.94	22.08

2004 On-Peak

	Jan	*Feb*	*Mar*	*Apr*	*May*	*June*	*July*	*Aug*	*Sept*	*Oct*	*Nov*	*Dec*
800	25.93	26.45	23.51	22.53	22.53	30.51	37.48	37.48	23.63	22.53	23.62	25.93
800	27.25	29.11	23.76	22.86	22.84	30.89	37.48	37.48	23.89	23.50	24.18	27.25
550	30.51	30.89	23.89	23.50	23.15	34.81	37.48	37.48	24.03	23.63	24.70	30.51

2009 Off-Peak

	Jan	*Feb*	*Mar*	*Apr*	*May*	*June*	*July*	*Aug*	*Sept*	*Oct*	*Nov*	*Dec*
800	27.54	27.95	25.22	23.49	22.71	25.46	27.87	28.46	23.49	23.37	26.50	27.84
800	27.87	28.29	25.67	23.93	22.98	26.51	28.26	29.64	24.08	23.51	27.28	28.21
550	27.99	28.39	26.04	24.20	23.43	27.28	28.39	31.67	24.29	24.08	27.62	28.32

2009 On-Peak

	Jan	*Feb*	*Mar*	*Apr*	*May*	*June*	*July*	*Aug*	*Sept*	*Oct*	*Nov*	*Dec*
800	44.12	44.12	29.87	28.46	28.46	44.12	44.12	44.12	32.05	28.70	33.45	44.12
800	44.12	44.12	31.67	28.88	28.70	44.12	44.12	44.12	33.13	29.56	37.35	44.12
550	44.12	44.12	32.71	29.56	29.46	44.12	44.12	44.12	33.45	30.46	44.12	44.12

		Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
Capacity (MWs)			352	512	144			279	302	760	355	1,155	1,115
Capacity Factor		1999	85%	38%	73%			72%	72%	24%	85%	75%	75%
	%	2000											
		2001											
		2002											
		2003											
		2004	86%	38%	70%			68%	70%	25%	86%	75%	75%
		2005											
		2006											
		2007											
		2008											
		2009	85%	38%	73%			73%	72%	27%	85%	75%	75%
		2010											
		2011											
		2012											
		2013											
		2014											
		2015											
Energy Output		1999	2,632,305	1,693,000	915,431			1,759,319	1,917,563	1,585,901	2,657,446	7,595,118	7,332,084
	MWh	2000	2,633,889	1,693,000	907,731			1,739,985	1,905,784	1,602,953	2,659,046	7,600,129	7,336,921
		2001	2,635,475	1,693,000	900,096			1,720,864	1,894,078	1,620,189	2,660,646	7,605,143	7,341,761
		2002	2,637,061	1,692,999	892,525			1,701,953	1,882,444	1,637,610	2,662,248	7,610,160	7,346,605
		2003	2,638,648	1,692,999	885,017			1,683,249	1,870,882	1,655,218	2,663,850	7,615,181	7,351,452
		2004	2,640,237	1,692,999	877,573			1,664,751	1,859,390	1,673,015	2,665,453	7,620,205	7,356,302
		2005	2,638,507	1,692,907	887,030			1,688,739	1,868,765	1,694,037	2,663,636	7,614,718	7,350,557
		2006	2,636,779	1,692,815	896,589			1,713,071	1,878,187	1,715,323	2,661,820	7,609,234	7,344,817
		2007	2,635,052	1,692,723	906,251			1,737,755	1,887,656	1,736,877	2,660,006	7,603,755	7,339,081
		2008	2,633,326	1,692,630	916,017			1,762,794	1,897,173	1,758,701	2,658,192	7,598,280	7,333,350
		2009	2,631,601	1,692,538	925,889			1,788,194	1,906,738	1,780,799	2,656,380	7,592,808	7,327,624
		2010	2,631,601	1,692,538	925,889			1,788,194	1,906,738	1,780,799	2,656,380	7,592,808	7,327,624
		2011	2,631,601	1,692,538	925,889			1,788,194	1,906,738	1,780,799	2,656,380	7,592,808	7,327,624
		2012	2,631,601	1,692,538	925,889			1,788,194	1,906,738	1,780,799	2,656,380	7,592,808	7,327,624
		2013	2,631,601	1,692,538	925,889			1,788,194	1,906,738	1,780,799	2,656,380	7,592,808	7,327,624
		2014	2,631,601	1,692,538	925,889			1,788,194	1,906,738	1,780,799	2,656,380	7,592,808	7,327,624
		2015	2,631,601	1,692,538	925,889			1,788,194	1,906,738	1,780,799	2,656,380	7,592,808	7,327,624

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Muddy Run	PeachBotto	PeachBotto	Salem 1	Salem 2	Schuylkill	CT's				
Muddy R	Peach B 2	Peach B 3	Salem 1	Salem 2	Schuylk 1	CT's	Total	Average	Year	
880	464	464	471	471		829	8,553			Capacity (MWs)
										Capacity
4%	75%	75%	75%	75%		0%		54%	1999	Factor
									2000 %	
									2001	
									2002	
									2003	
13%	75%	75%	75%	75%		0%		55%	2004	
									2005	
									2006	
									2007	
									2008	
20%	75%	75%	75%	75%		0%		56%	2009	
									2010	
									2011	
									2012	
									2013	
									2014	
									2015	
								Capacity		Energy
326,706	3,051,139	3,051,139	3,097,529	3,097,529		15,147	40,727,353	54%	1999	Output
406,847	3,053,151	3,053,151	3,099,572	3,099,572		13,789	40,856,220	55%	2000 MWh	
506,647	3,055,166	3,055,166	3,101,617	3,101,617		12,553	40,985,494	55%	2001	
630,929	3,057,181	3,057,181	3,103,663	3,103,663		11,427	41,115,177	55%	2002	
785,696	3,059,198	3,059,198	3,105,711	3,105,711		10,403	41,245,271	55%	2003	
978,429	3,061,216	3,061,216	3,107,760	3,107,760		9,470	41,375,777	55%	2004	
1,073,108	3,059,012	3,059,012	3,105,333	3,105,522		8,548	41,530,192	55%	2005	
1,176,948	3,056,809	3,056,809	3,102,908	3,103,286		7,715	41,685,184	56%	2006	
1,290,837	3,054,608	3,054,608	3,100,485	3,101,051		6,964	41,840,755	56%	2007	
1,415,747	3,052,409	3,052,409	3,098,064	3,098,818		6,285	41,996,906	56%	2008	
1,552,743	3,050,211	3,050,211	3,095,644	3,096,586		5,673	42,153,639	56%	2009	
1,552,743	3,050,211	3,050,211	3,095,644	3,096,586		5,673	42,310,958	56%	2010	
1,552,743	3,050,211	3,050,211	3,095,644	3,096,586		5,673	42,468,864	57%	2011	
1,552,743	3,050,211	3,050,211	3,095,644	3,096,586		5,673	42,627,359	57%	2012	
1,552,743	3,050,211	3,050,211	3,095,644	3,096,586		5,673	42,786,445	57%	2013	
1,552,743	3,050,211	3,050,211	3,095,644	3,096,586		5,673	42,946,126	57%	2014	
1,552,743	3,050,211	3,050,211	3,095,644	3,096,586		5,673	43,106,402	58%	2015	

	Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
Average Market Price of Energy $/MWh	1999	20.7	21.7	21.2			21.4	21.0	22.1	20.5	20.4	20.6
	2000											
	2001											
	2002											
	2003											
	2004	28.0	29.9	29.5			29.6	28.9	29.8	28.1	28.1	27.9
	2005											
	2006											
	2007											
	2008											
	2009	36.2	38.5	37.8			37.6	37.2	38.7	36.1	36.3	36.0
	2010											
	2011											
	2012											
	2013											
	2014											
	2015											
Energy Revenues millions$	1999	$54	$37	$19			$38	$40	$35	$55	$155	$151
	2000	$58	$39	$21			$40	$43	$38	$58	$165	$160
	2001	$62	$42	$22			$42	$45	$40	$62	$176	$171
	2002	$65	$44	$23			$44	$48	$43	$66	$188	$182
	2003	$70	$47	$24			$47	$51	$46	$70	$200	$193
	2004	$74	$51	$26			$49	$54	$50	$75	$214	$205
	2005	$78	$53	$28			$52	$57	$53	$79	$225	$216
	2006	$82	$56	$29			$56	$60	$57	$83	$237	$227
	2007	$86	$59	$31			$59	$63	$60	$87	$249	$238
	2008	$91	$62	$33			$63	$67	$65	$91	$262	$251
	2009	$95	$65	$35			$67	$71	$69	$96	$275	$264
	2010	$100	$68	$37			$70	$74	$72	$100	$288	$276
	2011	$104	$71	$38			$74	$78	$75	$105	$302	$289
	2012	$109	$75	$40			$77	$81	$79	$110	$316	$303
	2013	$115	$78	$42			$81	$85	$83	$115	$331	$317
	2014	$120	$82	$44			$85	$89	$87	$121	$346	$332
	2015	$126	$86	$46			$89	$93	$91	$126	$363	$347

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Muddy Run Muddy R	PeachBotto Peach B 2	PeachBotto Peach B 3	Salem 1 Salem 1	Salem 2 Salem 2	Schuylkill Schuylk 1	CT's CT's	Total	Average	Year	
								($/MWh)		Average
25.3	20.5	20.7	20.5	20.7		26.6		20.8	1999	Market
									2000	Price of
									2001	Energy
									2002	$/MWh
									2003	
33.5	27.8	28.1	27.9	28.0		36.0		28.4	2004	
									2005	
									2006	
									2007	
									2008	
42.0	36.0	36.4	35.9	36.4		46.0		36.7	2009	
									2010	
									2011	
									2012	
									2013	
									2014	
									2015	
								($/MWh)		Energy
$8	$63	$63	$63	$64		$0	$846	20.8	1999	Revenues
$11	$67	$67	$68	$68		$0	$902	22.1	2000	millions$
$14	$71	$71	$72	$72		$0	$963	23.5	2001	
$19	$75	$76	$76	$77		$0	$1,028	25.0	2002	
$25	$80	$81	$81	$82		$0	$1,098	26.6	2003	
$33	$85	$86	$87	$87		$0	$1,175	28.4	2004	
$38	$89	$90	$91	$92		$0	$1,241	29.9	2005	
$43	$94	$95	$96	$97		$0	$1,311	31.4	2006	
$50	$99	$100	$101	$102		$0	$1,385	33.1	2007	
$57	$104	$106	$106	$107		$0	$1,464	34.9	2008	
$65	$110	$111	$111	$113		$0	$1,548	36.7	2009	
$68	$115	$116	$117	$118		$0	$1,621	38.3	2010	
$72	$120	$122	$122	$124		$0	$1,697	40.0	2011	
$75	$126	$127	$128	$129		$0	$1,776	41.7	2012	
$78	$132	$133	$134	$135		$0	$1,860	43.5	2013	
$82	$138	$140	$140	$142		$0	$1,947	45.3	2014	
$86	$145	$146	$147	$148		$0	$2,039	47.3	2015	

		Conemaugh	*Conowingo*	*Cromby1*	*Cromby 2*	*Delaware*	*Eddystone*	*Eddystone*	*Eddystone*	*Keystone1&2*	*Limerick 1*	*Limerick 2*
	Year	Cone 1&2	Cono	Cromby1	Cromby 2	Dela 7&8	Eddy 1	Eddy 2	Eddy 3&4	Key 1&2	Limerick 1	Limerick 2
Uplift												
Revenues	1999	$0	$0	$0			$0	$0	$10	$0	$0	$0
millions$	2000	$0	$0	$0			$0	$0	$10	$0	$0	$0
	2001	$0	$0	$0			$0	$0	$11	$0	$0	$0
	2002	$0	$0	$0			$0	$0	$11	$0	$0	$0
	2003	$0	$0	$0			$0	$0	$12	$0	$0	$0
	2004	$0	$0	$0			$0	$0	$12	$0	$0	$0
	2005	$0	$0	$0			$0	$0	$13	$0	$0	$0
	2006	$0	$0	$0			$0	$0	$14	$0	$0	$0
	2007	$0	$0	$0			$0	$0	$14	$0	$0	$0
	2008	$0	$0	$0			$0	$0	$15	$0	$0	$0
	2009	$0	$0	$0			$0	$0	$16	$0	$0	$0
	2010	$0	$0	$0			$0	$0	$16	$0	$0	$0
	2011	$0	$0	$0			$0	$0	$16	$0	$0	$0
	2012	$0	$0	$0			$0	$0	$17	$0	$0	$0
	2013	$0	$0	$0			$0	$0	$17	$0	$0	$0
	2014	$0	$0	$0			$0	$0	$18	$0	$0	$0
	2015	$0	$0	$0			$0	$0	$18	$0	$0	$0
Energy												
Plus	1999	$54	$37	$19			$38	$40	$45	$55	$155	$151
Uplift	2000	$58	$39	$21			$40	$43	$48	$58	$165	$161
Revenues	2001	$62	$42	$22			$42	$45	$51	$62	$176	$171
millions$	2002	$65	$44	$23			$44	$48	$55	$66	$188	$182
	2003	$70	$47	$24			$47	$51	$58	$70	$200	$193
	2004	$74	$51	$26			$49	$54	$62	$75	$214	$205
	2005	$78	$53	$28			$52	$57	$66	$79	$225	$216
	2006	$82	$56	$29			$56	$60	$70	$83	$237	$227
	2007	$86	$59	$31			$59	$63	$75	$87	$249	$239
	2008	$91	$62	$33			$63	$67	$79	$91	$262	$251
	2009	$95	$65	$35			$67	$71	$84	$96	$275	$264
	2010	$100	$68	$37			$70	$74	$88	$100	$288	$276
	2011	$104	$71	$38			$74	$78	$92	$105	$302	$289
	2012	$109	$75	$40			$77	$81	$96	$110	$316	$303
	2013	$115	$78	$42			$81	$85	$100	$115	$331	$317
	2014	$120	$82	$44			$85	$89	$104	$121	$347	$332
	2015	$126	$86	$46			$89	$93	$109	$126	$363	$347

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Muddy Run Muddy R	PeachBotto Peach B 2	PeachBotto Peach B 3	Salem 1 Salem 1	Salem 2 Salem 2	Schuylkill Schuylk 1	CT's CT's	Total	Average	Year	
								($/MWh)		Uplift
$0	$0	$0	$0	$0		$3	$13	0.3	1999	Revenues
$0	$0	$0	$0	$0		$3	$14	0.3	2000	millions$
$0	$0	$0	$0	$0		$3	$14	0.3	2001	
$0	$0	$0	$0	$0		$3	$15	0.4	2002	
$0	$0	$0	$0	$0		$3	$15	0.4	2003	
$0	$0	$0	$0	$0		$3	$15	0.4	2004	
$0	$0	$0	$0	$0		$3	$16	0.4	2005	
$0	$0	$0	$0	$0		$3	$16	0.4	2006	
$0	$0	$0	$0	$0		$2	$17	0.4	2007	
$0	$0	$0	$0	$0		$2	$17	0.4	2008	
$0	$0	$0	$0	$0		$2	$18	0.4	2009	
$0	$0	$0	$0	$0		$2	$18	0.4	2010	
$0	$0	$0	$0	$0		$2	$19	0.4	2011	
$0	$0	$0	$0	$0		$2	$19	0.5	2012	
$0	$0	$0	$0	$0		$2	$20	0.5	2013	
$0	$0	$0	$0	$0		$3	$20	0.5	2014	
$0	$0	$0	$0	$0		$3	$21	0.5	2015	
								($/MWh)		Energy
$8	$63	$63	$63	$64		$4	$859	21.1	1999	Plus
$11	$67	$67	$68	$68		$4	$916	22.4	2000	Uplift
$14	$71	$71	$72	$72		$4	$977	23.8	2001	Revenues
$19	$75	$76	$76	$77		$3	$1,042	25.4	2002	millions$
$25	$80	$81	$81	$82		$3	$1,113	27.0	2003	
$33	$85	$86	$87	$87		$3	$1,190	28.8	2004	
$38	$89	$90	$91	$92		$3	$1,257	30.3	2005	
$43	$94	$95	$96	$97		$3	$1,327	31.8	2006	
$50	$99	$100	$101	$102		$3	$1,402	33.5	2007	
$57	$104	$106	$106	$107		$3	$1,481	35.3	2008	
$65	$110	$111	$111	$113		$3	$1,566	37.1	2009	
$68	$115	$116	$117	$118		$3	$1,639	38.7	2010	
$72	$120	$122	$122	$124		$3	$1,715	40.4	2011	
$75	$126	$127	$128	$129		$3	$1,796	42.1	2012	
$78	$132	$133	$134	$135		$3	$1,880	43.9	2013	
$82	$138	$140	$140	$142		$3	$1,968	45.8	2014	
$86	$145	$146	$147	$148		$3	$2,060	47.8	2015	

[redacted]

	Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
Capacity Price	1999	16.2	16.2	16.2			16.2	16.2	16.2	16.2	16.2	16.2
$/KW	2000	25.3	25.3	25.3			25.3	25.3	25.3	25.3	25.3	25.3
	2001	39.7	39.7	39.7			39.7	39.7	39.7	39.7	39.7	39.7
	2002	40.7	40.7	40.7			40.7	40.7	40.7	40.7	40.7	40.7
	2003	41.7	41.7	41.7			41.7	41.7	41.7	41.7	41.7	41.7
	2004	42.8	42.8	42.8			42.8	42.8	42.8	42.8	42.8	42.8
	2005	43.9	43.9	43.9			43.9	43.9	43.9	43.9	43.9	43.9
	2006	45.0	45.0	45.0			45.0	45.0	45.0	45.0	45.0	45.0
	2007	46.1	46.1	46.1			46.1	46.1	46.1	46.1	46.1	46.1
	2008	47.2	47.2	47.2			47.2	47.2	47.2	47.2	47.2	47.2
	2009	48.4	48.4	48.4			48.4	48.4	48.4	48.4	48.4	48.4
	2010	49.6	49.6	49.6			49.6	49.6	49.6	49.6	49.6	49.6
	2011	50.9	50.9	50.9			50.9	50.9	50.9	50.9	50.9	50.9
	2012	52.1	52.1	52.1			52.1	52.1	52.1	52.1	52.1	52.1
	2013	53.4	53.4	53.4			53.4	53.4	53.4	53.4	53.4	53.4
	2014	54.8	54.8	54.8			54.8	54.8	54.8	54.8	54.8	54.8
	2015	56.1	56.1	56.1			56.1	56.1	56.1	56.1	56.1	56.1
Capacity Revenues	1999	$6	$8	$2			$5	$5	$12	$6	$19	$18
millions$	2000	$9	$13	$4			$7	$8	$19	$9	$29	$28
	2001	$14	$20	$6			$11	$12	$30	$14	$46	$44
	2002	$14	$21	$6			$11	$12	$31	$14	$47	$45
	2003	$15	$21	$6			$12	$13	$32	$15	$48	$47
	2004	$15	$22	$6			$12	$13	$33	$15	$49	$48
	2005	$15	$22	$6			$12	$13	$33	$16	$51	$49
	2006	$16	$23	$6			$13	$14	$34	$16	$52	$50
	2007	$16	$24	$7			$13	$14	$35	$16	$53	$51
	2008	$17	$24	$7			$13	$14	$36	$17	$55	$53
	2009	$17	$25	$7			$14	$15	$37	$17	$56	$54
	2010	$17	$25	$7			$14	$15	$38	$18	$57	$55
	2011	$18	$26	$7			$14	$15	$39	$18	$59	$57
	2012	$18	$27	$8			$15	$16	$40	$19	$60	$58
	2013	$19	$27	$8			$15	$16	$41	$19	$62	$60
	2014	$19	$28	$8			$15	$17	$42	$19	$63	$61
	2015	$20	$29	$8			$16	$17	$43	$20	$65	$63

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Muddy Run Muddy R	PeachBotto Peach B 2	PeachBotto Peach B 3	Salem 1 Salem 1	Salem 2 Salem 2	Schuylkill Schuylk 1	CT's CT's	Total	Average	Year	
								($/KW)		Capacity
16.2	16.2	16.2	16.2	16.2		16.2		16.2	1999	Price
25.3	25.3	25.3	25.3	25.3		25.3		25.3	2000	$/KW
39.7	39.7	39.7	39.7	39.7		39.7		39.7	2001	
40.7	40.7	40.7	40.7	40.7		40.7		40.7	2002	
41.7	41.7	41.7	41.7	41.7		41.7		41.7	2003	
42.8	42.8	42.8	42.8	42.8		42.8		42.8	2004	
43.9	43.9	43.9	43.9	43.9		43.9		43.9	2005	
45.0	45.0	45.0	45.0	45.0		45.0		45.0	2006	
46.1	46.1	46.1	46.1	46.1		46.1		46.1	2007	
47.2	47.2	47.2	47.2	47.2		47.2		47.2	2008	
48.4	48.4	48.4	48.4	48.4		48.4		48.4	2009	
49.6	49.6	49.6	49.6	49.6		49.6		49.6	2010	
50.9	50.9	50.9	50.9	50.9		50.9		50.9	2011	
52.1	52.1	52.1	52.1	52.1		52.1		52.1	2012	
53.4	53.4	53.4	53.4	53.4		53.4		53.4	2013	
54.8	54.8	54.8	54.8	54.8		54.8		54.8	2014	
56.1	56.1	56.1	56.1	56.1		56.1		56.1	2015	
								($/MWh)		Capacity
$14	$7	$7	$8	$8		$13	$138	3.4	1999	Revenues
$22	$12	$12	$12	$12		$21	$217	5.3	2000	millions$
$35	$18	$18	$19	$19		$33	$340	8.3	2001	
$36	$19	$19	$19	$19		$34	$348	8.5	2002	
$37	$19	$19	$20	$20		$35	$357	8.7	2003	
$38	$20	$20	$20	$20		$35	$366	8.8	2004	
$39	$20	$20	$21	$21		$36	$375	9.0	2005	
$40	$21	$21	$21	$21		$37	$385	9.2	2006	
$41	$21	$21	$22	$22		$38	$394	9.4	2007	
$42	$22	$22	$22	$22		$39	$404	9.6	2008	
$43	$22	$22	$23	$23		$40	$414	9.8	2009	
$44	$23	$23	$23	$23		$41	$424	10.0	2010	
$45	$24	$24	$24	$24		$42	$435	10.2	2011	
$46	$24	$24	$25	$25		$43	$446	10.5	2012	
$47	$25	$25	$25	$25		$44	$457	10.7	2013	
$48	$25	$25	$26	$26		$45	$468	10.9	2014	
$49	$26	$26	$26	$26		$47	$480	11.1	2015	

	Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
Energy												
Plus	1999	$60	$45	$22			$42	$45	$57	$60	$174	$169
Uplift	2000	$67	$52	$24			$47	$50	$67	$67	$195	$189
Plus	2001	$76	$62	$28			$53	$57	$81	$76	$222	$215
Capacity	2002	$80	$65	$29			$56	$60	$86	$80	$235	$227
Revenues	2003	$84	$69	$30			$58	$63	$90	$85	$249	$240
millions$	2004	$89	$73	$32			$61	$67	$95	$90	$263	$253
	2005	$93	$76	$34			$65	$70	$99	$94	$276	$265
	2006	$98	$79	$36			$68	$74	$104	$99	$289	$277
	2007	$102	$82	$38			$72	$77	$110	$103	$302	$290
	2008	$107	$86	$40			$76	$81	$115	$108	$316	$303
	2009	$112	$90	$42			$81	$85	$121	$113	$331	$318
	2010	$117	$94	$44			$84	$89	$126	$118	$346	$331
	2011	$122	$98	$46			$88	$93	$130	$123	$361	$346
	2012	$128	$102	$48			$92	$97	$135	$129	$376	$361
	2013	$133	$106	$50			$96	$101	$141	$134	$393	$376
	2014	$139	$110	$52			$100	$106	$146	$140	$410	$393
	2015	$145	$115	$54			$104	$110	$151	$146	$428	$410

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Energy Plus Uplift Plus Capacity Revenues millions$

Muddy Run Muddy R	PeachBotto Peach B 2	PeachBotto Peach B 3	Salem 1 Salem 1	Salem 2 Salem 2	Schuylkill Schuylk 1	CT's CT's	Total	Average ($/MWh)	Year
$22	$70	$71	$71	$72		$17	$998	24.5	1999
$33	$78	$79	$79	$80		$25	$1,133	27.7	2000
$49	$89	$90	$91	$91		$37	$1,316	32.1	2001
$55	$94	$95	$96	$96		$37	$1,391	33.8	2002
$62	$99	$100	$101	$102		$38	$1,470	35.7	2003
$70	$105	$106	$107	$107		$39	$1,557	37.6	2004
$76	$110	$111	$112	$112		$39	$1,632	39.3	2005
$83	$115	$116	$117	$118		$40	$1,712	41.1	2006
$90	$121	$122	$122	$123		$41	$1,796	42.9	2007
$98	$126	$127	$128	$129		$42	$1,885	44.9	2008
$108	$132	$134	$134	$135		$43	$1,980	47.0	2009
$112	$138	$139	$140	$141		$44	$2,063	48.8	2010
$116	$144	$145	$146	$147		$45	$2,150	50.6	2011
$121	$150	$152	$152	$154		$46	$2,241	52.6	2012
$125	$157	$158	$159	$161		$47	$2,337	54.6	2013
$130	$164	$165	$166	$168		$48	$2,436	56.7	2014
$135	$171	$172	$173	$175		$49	$2,540	58.9	2015

		Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
Average													
Fuel		1999	11.1	0.0	14.8			14.2	14.3	27.8	10.6	4.5	4.5
Cost		2000											
	$/MWh	2001											
		2002											
		2003											
		2004	12.7	0.0	19.7			19.1	19.4	36.6	15.8	4.6	4.6
		2005											
		2006											
		2007											
		2008											
		2009	14.3	0.0	23.3			22.5	23.1	46.8	19.5	5.4	5.4
		2010											
		2011											
		2012											
		2013											
		2014											
		2015											
Fuel													
Cost		1999	$29	$0	$14			$25	$28	$44	$28	$34	$33
	million$	2000	$30	$0	$14			$26	$29	$47	$31	$34	$32
		2001	$31	$0	$15			$28	$31	$50	$33	$34	$32
		2002	$32	$0	$16			$29	$32	$54	$36	$34	$33
		2003	$33	$0	$16			$30	$34	$57	$39	$35	$33
		2004	$33	$0	$17			$32	$36	$61	$42	$35	$34
		2005	$34	$0	$18			$33	$37	$65	$44	$36	$34
		2006	$35	$0	$19			$35	$39	$69	$46	$37	$36
		2007	$36	$0	$20			$37	$41	$74	$48	$39	$37
		2008	$37	$0	$21			$38	$42	$78	$50	$40	$39
		2009	$38	$0	$22			$40	$44	$83	$52	$41	$40
		2010	$39	$0	$22			$41	$45	$87	$53	$43	$41
		2011	$40	$0	$23			$42	$46	$91	$55	$44	$43
		2012	$41	$0	$23			$44	$48	$96	$56	$46	$44
		2013	$42	$0	$24			$45	$49	$100	$57	$48	$46
		2014	$43	$0	$25			$46	$50	$105	$59	$49	$48
		2015	$44	$0	$25			$47	$52	$110	$61	$51	$49

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Average Fuel Cost $/MWh

Muddy Run Muddy R	PeachBotto Peach B 2	PeachBotto Peach B 3	Salem 1 Salem 1	Salem 2 Salem 2	Schuylkill Schuylk 1	CT's CT's	Total	Average ($/MWh)	Year
24.4	5.8	5.8	5.8	5.8		254.3		7.8	1999
									2000
									2001
									2002
									2003
33.0	5.8	5.8	5.8	5.8		340.3		9.6	2004
									2005
									2006
									2007
									2008
41.0	6.8	6.8	6.8	6.8		437.7		12.1	2009
									2010
									2011
									2012
									2013
									2014
									2015

Fuel Cost million$

Muddy Run	Peach B 2	Peach B 3	Salem 1	Salem 2	Schuylk 1	CT's	Total	Average ($/MWh)	Year
$8	$18	$18	$18	$18		$4	$318	7.8	1999
$11	$18	$18	$18	$18		$4	$328	8.0	2000
$14	$17	$17	$18	$18		$4	$341	8.3	2001
$18	$17	$17	$18	$18		$3	$358	8.7	2002
$24	$18	$18	$18	$18		$3	$376	9.1	2003
$32	$18	$18	$18	$18		$3	$398	9.6	2004
$37	$18	$18	$18	$18		$3	$416	10.0	2005
$42	$19	$19	$19	$19		$3	$437	10.5	2006
$49	$20	$20	$20	$20		$3	$460	11.0	2007
$56	$20	$20	$21	$21		$3	$484	11.5	2008
$64	$21	$21	$21	$21		$2	$510	12.1	2009
$67	$22	$22	$22	$22		$3	$529	12.5	2010
$70	$22	$22	$23	$23		$3	$547	12.9	2011
$73	$23	$23	$24	$24		$3	$567	13.3	2012
$77	$24	$24	$24	$24		$3	$587	13.7	2013
$80	$25	$25	$25	$25		$3	$608	14.2	2014
$84	$26	$26	$26	$26		$3	$630	14.6	2015

	Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
Revenues												
Minus	1999	$31	$45	$8			$17	$18	$13	$32	$140	$136
Fuel	2000	$37	$52	$10			$21	$21	$20	$37	$161	$156
Costs	2001	$45	$62	$13			$25	$27	$31	$43	$189	$182
million$	2002	$48	$65	$13			$27	$28	$32	$45	$201	$194
	2003	$52	$69	$14			$28	$29	$33	$46	$214	$206
	2004	$56	$73	$15			$30	$31	$33	$48	$228	$219
	2005	$59	$76	$16			$31	$33	$34	$50	$240	$230
	2006	$63	$79	$17			$33	$35	$35	$53	$251	$241
	2007	$66	$82	$18			$36	$37	$36	$56	$264	$253
	2008	$71	$86	$19			$38	$39	$37	$58	$276	$265
	2009	$75	$90	$20			$41	$42	$38	$61	$290	$278
	2010	$79	$94	$22			$43	$44	$39	$65	$303	$290
	2011	$83	$97	$23			$46	$47	$39	$69	$316	$303
	2012	$87	$102	$24			$48	$49	$40	$73	$330	$316
	2013	$92	$106	$26			$51	$52	$40	$77	$345	$330
	2014	$96	$110	$27			$54	$55	$41	$81	$360	$345
	2015	$101	$115	$29			$57	$59	$42	$86	$377	$361

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Revenues
Minus
Fuel
Costs
million$

Muddy Run Muddy R	PeachBotto Peach B 2	PeachBotto Peach B 3	*Salem 1* Salem 1	*Salem 2* Salem 2	Schuylkill Schuylk 1	CT's CT's	Total	Average ($/MWh)	Year
$15	$52	$53	$53	$54		$13	$680	16.7	1999
$23	$61	$61	$62	$62		$21	$805	19.7	2000
$35	$72	$72	$73	$74		$33	$976	23.8	2001
$36	$77	$77	$78	$78		$34	$1,033	25.1	2002
$37	$82	$83	$83	$84		$35	$1,094	26.5	2003
$38	$87	$88	$89	$89		$36	$1,158	28.0	2004
$39	$92	$93	$93	$94		$36	$1,216	29.3	2005
$40	$96	$97	$98	$99		$37	$1,275	30.6	2006
$42	$101	$102	$103	$104		$38	$1,336	31.9	2007
$43	$106	$107	$108	$109		$39	$1,401	33.4	2008
$44	$112	$113	$113	$114		$40	$1,470	34.9	2009
$45	$116	$118	$118	$119		$41	$1,534	36.3	2010
$46	$122	$123	$123	$125		$42	$1,603	37.8	2011
$48	$127	$128	$129	$130		$43	$1,675	39.3	2012
$49	$133	$134	$134	$136		$44	$1,750	40.9	2013
$50	$139	$140	$141	$142		$45	$1,828	42.6	2014
$51	$145	$147	$147	$149		$46	$1,910	44.3	2015

	Year	Conemaugh	Conowingo	Cromby1	Cromby 2	Delaware	Eddystone	Eddystone	Eddystone	Keystone1&2	Limerick 1	Limerick 2
		Cone 1&2	Cono	Cromby1	Cromby 2	Dela 7&8	Eddy 1	Eddy 2	Eddy 3&4	Key 1&2	Limerick 1	Limerick 2
Variable O&M Cost $/MWh	1999	2.2	0.0	3.6			4.3	3.4	0.5	2.2	0.6	0.6
	2000											
	2001											
	2002											
	2003											
	2004	2.4	0.0	4.0			4.8	3.9	0.6	2.4	0.7	0.7
	2005											
	2006											
	2007											
	2008											
	2009	2.8	0.0	4.5			5.5	4.4	0.6	2.8	0.8	0.8
	2010											
	2011											
	2012											
	2013											
	2014											
	2015											
Variable O&M Cost million$	1999	$6	$0	$3			$8	$7	$1	$6	$5	$5
	2000	$6	$0	$3			$8	$7	$1	$6	$5	$5
	2001	$6	$0	$3			$8	$7	$1	$6	$5	$5
	2002	$6	$0	$3			$8	$7	$1	$6	$5	$5
	2003	$6	$0	$3			$8	$7	$1	$6	$5	$5
	2004	$6	$0	$4			$8	$7	$1	$6	$6	$5
	2005	$7	$0	$4			$8	$7	$1	$7	$6	$6
	2006	$7	$0	$4			$9	$8	$1	$7	$6	$6
	2007	$7	$0	$4			$9	$8	$1	$7	$6	$6
	2008	$7	$0	$4			$9	$8	$1	$7	$6	$6
	2009	$7	$0	$4			$10	$8	$1	$7	$6	$6
	2010	$7	$0	$4			$10	$9	$1	$8	$6	$6
	2011	$8	$0	$4			$10	$9	$1	$8	$7	$6
	2012	$8	$0	$5			$11	$9	$1	$8	$7	$7
	2013	$8	$0	$5			$11	$9	$1	$8	$7	$7
	2014	$8	$0	$5			$11	$9	$1	$8	$7	$7
	2015	$8	$0	$5			$11	$10	$1	$8	$7	$7

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Muddy Run Muddy R	PeachBotto Peach B 2	PeachBotto Peach B 3	Salem 1 Salem 1	Salem 2 Salem 2	Schuylkill Schuylk 1	CT's CT's	Total	Average ($/MWh)	Year	Variable O&M Cost $/MWh
0.0	0.6	0.6	0.6	0.6		2.3		1.2	1999	
									2000	
									2001	
									2002	
									2003	
0.0	0.7	0.7	0.7	0.7		2.6		1.3	2004	
									2005	
									2006	
									2007	
									2008	
0.0	0.8	0.8	0.8	0.8		3.0		1.4	2009	
									2010	
									2011	
									2012	
									2013	
									2014	
									2015	

Muddy R	Peach B 2	Peach B 3	Salem 1	Salem 2	Schuylk 1	CT's	Total	($/MWh)	Year	Variable O&M Cost million$
$0	$2	$2	$2	$2		$0	$47	1.2	1999	
$0	$2	$2	$2	$2		$0	$48	1.2	2000	
$0	$2	$2	$2	$2		$0	$49	1.2	2001	
$0	$2	$2	$2	$2		$0	$50	1.2	2002	
$0	$2	$2	$2	$2		$0	$51	1.2	2003	
$0	$2	$2	$2	$2		$0	$53	1.3	2004	
$0	$2	$2	$2	$2		$0	$54	1.3	2005	
$0	$2	$2	$2	$2		$0	$56	1.3	2006	
$0	$2	$2	$2	$2		$0	$57	1.4	2007	
$0	$2	$2	$2	$3		$0	$59	1.4	2008	
$0	$3	$3	$3	$3		$0	$61	1.4	2009	
$0	$3	$3	$3	$3		$0	$62	1.5	2010	
$0	$3	$3	$3	$3		$0	$64	1.5	2011	
$0	$3	$3	$3	$3		$0	$65	1.5	2012	
$0	$3	$3	$3	$3		$0	$67	1.6	2013	
$0	$3	$3	$3	$3		$0	$69	1.6	2014	
$0	$3	$3	$3	$3		$0	$70	1.6	2015	

	Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
Total Incremental Costs million$	1999	$35	$0	$17			$33	$34	$45	$34	$39	$37
	2000	$36	$0	$17			$34	$36	$48	$36	$39	$37
	2001	$37	$0	$18			$35	$37	$51	$39	$39	$37
	2002	$38	$0	$19			$37	$39	$55	$42	$39	$38
	2003	$39	$0	$20			$38	$41	$58	$45	$40	$39
	2004	$40	$0	$21			$40	$43	$62	$49	$41	$39
	2005	$41	$0	$22			$42	$45	$66	$51	$41	$40
	2006	$42	$0	$23			$44	$47	$70	$53	$43	$41
	2007	$43	$0	$24			$46	$48	$75	$55	$45	$43
	2008	$44	$0	$25			$48	$50	$79	$57	$46	$45
	2009	$45	$0	$26			$50	$52	$84	$59	$48	$46
	2010	$46	$0	$26			$51	$54	$88	$61	$49	$48
	2011	$47	$0	$27			$53	$55	$93	$62	$51	$49
	2012	$48	$0	$28			$54	$57	$97	$64	$53	$51
	2013	$50	$0	$29			$56	$58	$101	$66	$54	$53
	2014	$51	$0	$29			$57	$60	$106	$67	$56	$54
	2015	$52	$0	$30			$59	$61	$111	$69	$58	$56
Margin million$	1999	$25	$45	$5			$10	$11	$12	$26	$135	$132
	2000	$31	$52	$7			$13	$15	$19	$31	$156	$151
	2001	$39	$62	$9			$18	$20	$30	$37	$183	$178
	2002	$42	$65	$10			$19	$21	$31	$38	$196	$189
	2003	$45	$69	$11			$20	$22	$32	$40	$209	$201
	2004	$49	$73	$11			$21	$24	$33	$41	$223	$214
	2005	$52	$76	$12			$23	$25	$33	$44	$234	$225
	2006	$56	$79	$13			$25	$27	$34	$46	$246	$236
	2007	$60	$82	$14			$27	$29	$35	$49	$258	$247
	2008	$63	$86	$15			$29	$31	$36	$51	$270	$259
	2009	$68	$90	$16			$31	$33	$37	$54	$284	$272
	2010	$71	$94	$17			$33	$36	$37	$57	$296	$284
	2011	$75	$97	$19			$35	$38	$38	$61	$310	$296
	2012	$79	$102	$20			$38	$41	$39	$65	$324	$310
	2013	$84	$106	$21			$40	$43	$39	$69	$338	$324
	2014	$88	$110	$23			$43	$46	$40	$73	$353	$338
	2015	$93	$115	$24			$46	$49	$40	$77	$369	$354

Exhibit WHH-4
Hieronymus
Testimony
1/16/97

Muddy Run	PeachBotto	PeachBotto	Salem 1	Salem 2	Schuylkill	CT's				
Muddy R	Peach B 2	Peach B 3	Salem 1	Salem 2	Schuylk 1	CT's	Total	Average	Year	
								($/MWh)		Total
$8	$20	$20	$20	$20		$4	$365	9.0	1999	Incremental
$11	$20	$20	$20	$20		$4	$376	9.2	2000	Costs
$14	$19	$19	$20	$20		$4	$390	9.5	2001	million$
$18	$20	$20	$20	$20		$3	$408	9.9	2002	
$24	$20	$20	$20	$20		$3	$427	10.4	2003	
$32	$20	$20	$20	$20		$3	$451	10.9	2004	
$37	$21	$21	$21	$21		$3	$470	11.3	2005	
$42	$21	$21	$22	$22		$3	$493	11.8	2006	
$49	$22	$22	$22	$22		$3	$517	12.4	2007	
$56	$23	$23	$23	$23		$3	$543	12.9	2008	
$64	$23	$23	$24	$24		$3	$570	13.5	2009	
$67	$24	$24	$25	$25		$3	$591	14.0	2010	
$70	$25	$25	$25	$25		$3	$611	14.4	2011	
$73	$26	$26	$26	$26		$3	$632	14.8	2012	
$77	$27	$27	$27	$27		$3	$654	15.3	2013	
$80	$28	$28	$28	$28		$3	$677	15.8	2014	
$84	$29	$29	$29	$29		$3	$700	16.2	2015	
								($/MWh)		Margin
$15	$50	$51	$51	$52		$13	$633	15.5	1999	million$
$23	$59	$59	$60	$60		$21	$756	18.5	2000	
$35	$70	$70	$71	$71		$33	$926	22.6	2001	
$36	$75	$75	$76	$76		$34	$983	23.9	2002	
$37	$80	$80	$81	$82		$35	$1,043	25.3	2003	
$38	$85	$86	$86	$87		$35	$1,106	26.7	2004	
$39	$89	$90	$91	$92		$36	$1,162	28.0	2005	
$40	$94	$95	$95	$96		$37	$1,219	29.2	2006	
$42	$99	$100	$100	$101		$38	$1,279	30.6	2007	
$43	$104	$105	$105	$106		$39	$1,342	32.0	2008	
$44	$109	$110	$110	$112		$40	$1,409	33.4	2009	
$45	$114	$115	$115	$117		$41	$1,472	34.8	2010	
$46	$119	$120	$120	$122		$42	$1,540	36.3	2011	
$48	$124	$126	$126	$128		$43	$1,609	37.8	2012	
$49	$130	$131	$132	$133		$44	$1,683	39.3	2013	
$50	$136	$137	$138	$139		$45	$1,759	41.0	2014	
$51	$142	$144	$144	$146		$46	$1,840	42.7	2015	

Overview of the Multi-Area Production Simulation (MAPS) Program[1]

MAPS is a highly detailed model that simulates the operations of a power system while explicitly recognizing the constraints on generation commitment and dispatch imposed by the transmission system. MAPS performs a security-constrained commitment and dispatch using a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved AC load flow, to calculate the real power flows for each generation dispatch. This makes it possible to calculate the economic penalties of redispatching generation to satisfy transmission line flow limits and security constraints.

The following sections provide more details on the specific modeling capability of MAPS. Production costing features are outlined first, followed by a discussion of how transmission system characteristics are incorporated into MAPS.

PRODUCTION COSTING

MAPS models the power system chronologically through time, dispatching generation to serve load for all of the hours in the year. In so doing, MAPS is able to capture the load diversity that may exist within the system and to model resources such as energy-storage and demand-side management accurately.

The hourly load data are input to the program in EEI (Edison Electric Institute) format for each load forecast area. These hourly load profiles are then adjusted to meet the peak and energy forecasts input to the model. In order to accurately calculate the electrical flows on the transmission system, MAPS requires information on the hourly loads at each bus in the system. This is specified by assigning one, or a combination of several, of the hourly load profiles to each load bus.

In addition to studying all of the hours in the year, MAPS can be directed to study all of the days in the year on a bi-hourly basis, or a typical week per month on an hourly or bi-hourly basis. With all of these modeling options, MAPS simulates the loads in chronological order and does not transform them into a load duration curve that would lose the chronology.

Marginal cost information

MAPS computes hourly marginal costs at individual buses. The bus marginal cost is the cost of supplying an additional MW of load at the bus and includes the cost of generating the

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1 This overview of MAPS has been prepared by PHB. It is based generally on the similarly titled GE publication.

energy including any costs associated with re-dispatching generation to the extent that the incremental load creates or exacerbates congestion on the transmission system.

MAPS can also develop marginal costs on a company and pool basis. There are two types of marginal cost calculations in MAPS: incremental and delta. Incremental marginal costs are calculated from a single dispatch and are equal to the cost of the last increment of power generated. Delta costs are calculated from two dispatches and equal the average cost of the change in energy dispatched. The hourly marginal costs can be summarized for on-, mid-, and off-peak periods by month, season, and year.

Thermal unit characteristics

Listed below are the thermal unit characteristics modeled in MAPS. Essentially all of the unit characteristics input to MAPS can be changed on a weekly, monthly, or annual basis.

a. Each unit can have up to seven loading segments (power points).

b. Generating units can burn a blend of up to three fuel types in addition to a start-up fuel. The percentage of each fuel burned can vary by unit power point.

c. In the unit commitment process, MAPS recognizes minimum up- and down-times on thermal units. Units can also be identified as must-run with the user specifying how many MWs are fixed and how many may be economically dispatched as needed.

d. MAPS models summer and winter unit capacities. The user defines the summer and winter seasons.

e. MAPS calculates start-up costs as a function of the number of hours that the unit has been off-line, accounting for the reduced costs of a "warm" start as opposed to a "cold" start.

f. MAPS allows the user to specify the portion of each thermal unit that can be counted toward meeting the load plus spinning reserve requirements, and the portion that can be considered as quick-start capacity. A spinning reserve credit can also be taken for unused pondage hydro and energy-storage resources.

g. Full and partial forced outage information is specified to MAPS in terms of separate forced outage rates.

h. MAPS models fixed O&M in $/kW/yr and variable O&M in $/MWh and $/fired hour. The user controls whether the variable O&M is included in determining the order for unit commitment and dispatch.

i. Maintenance can be specified on a daily basis for any number of maintenance periods during the year. The user can also identify units as being unavailable for specific hours during the day.

j. MAPS allows all types of generating units (thermal, pondage hydro, and energy storage) to be owned by more than one company in a multi-utility simulation. The output and cost of these units are allocated to the owning companies based on the user-specified percentages.

Centralized and local area commitment and dispatch on an hour-by-hour basis

MAPS models the system chronologically, dispatching the generation to serve the load and operating reserve requirements for all of the hours in the year. Several options are available when doing the thermal unit commitment. First, if desired, separate unit commitments are used for the system and company own-load dispatches (see the next section). The commitment first is done for the entire system, taking into account the continuous rating of the units' operating characteristics such as minimum up- and down-times, the area loads, and the transfer limitations between the areas. Additional generation is then committed as needed to meet the spinning reserve requirements of each area, if applicable, and the system as a whole. Individual company commitments are then performed subject to the company spinning reserve requirements.

The next option begins with the system commitment to meet load. Additional units are then committed to ensure that each company has sufficient capacity committed to meet its load, if required. Additional generation is then committed to meet the spinning reserve requirements of the companies, areas, and system, as applicable. This commitment is then used for the system and company own-load dispatches.

The final option uses the sum of the company commitments for the system commitment, with additional units committed as needed to meet system spinning reserve requirements. This commitment is then used for both the system and own-load dispatches, if applicable.

Ability to model two modes of dispatch: system and company

Within a single run of the computer program, MAPS performs two separate dispatches of generation. In the system dispatch, all resources are dispatched to serve the load at least cost (or bid-price), subject to the constraints imposed by the transmission system. In the company own-load dispatch, if required, each company's resources (including its firm transactions with other companies) are economically dispatched to serve its own load.

System simulations on an hourly chronological basis

MAPS simulates the system on a chronological basis, modeling the forced outages through a Monte Carlo approach. In the Monte Carlo approach, forced outages of generating units are modeled through the use of random outages. This method is stochastic over the course of the entire year and results in the units being on forced outage for (randomly) selected weeks during the year. The number of weeks of outage for each unit is determined by its forced outage rate. Partial outages on the generating units can also be modeled with this method. The random outage method permits accurate treatment of forced outages over the course of the year while allowing each hour to be deterministically dispatched, thus providing for the most accurate treatment of transmission limits when operating in the detailed electrical mode.

Algorithms to minimize production costs, including modeling fuel constraints

The objective of the commitment and dispatch algorithms in MAPS is to simulate the least-cost (or bid-price) operation of the generating units on the system, subject to the operating characteristics of the individual generating units, the constraints imposed by the transmission system, and other operational considerations such as operating and spinning reserve requirements. The economics used for dispatch can be adjusted through the use of penalty factors which can move a unit within the commitment and dispatch merit order.

In MAPS, *minimum fuel usage and maximum fuel limits are modeled and enforced on a* monthly basis. If the maximum fuel limit is reached, the affected units will be switched to an alternate fuel.

Modeling of emission costs, and variable and fixed O&M costs

MAPS models emission costs, variable O&M costs (in $/MWh and $/fired hour), and fixed O&M costs (in $/kW/year). The user can specify whether the emission costs and variable O&M are to be included in the incremental costs used to determine the bid prices that, in turn, determine the order in which the units are dispatched. In addition, the user can specify whether the start-up costs (along with emission costs and variable O&M) should be included in the full-load costs used to determine the order in which the units are committed.

MAPS models two general types of emissions. The first type is a function of the amount of fuel being used. This type would typically be used to model sulfur and particulate emissions. The second type is a function of the unit operation, but is not directly related to the amount of fuel burned. This type could be used to model NOx emissions which can decrease with increased power output.

In addition to the emission rates which are modeled by fuel type or by unit, the user can input, by thermal unit and emission type, the removal efficiency of emission control equipment, and the removal and allowance costs in dollars per ton of emission. Penalty factors on the removal and allowance costs can also be input to modify the operation of the units based on their environmental characteristics.

Modeling of dispatchable purchase and sales contracts

MAPS can model internal transactions (purchase and sales contracts) between companies within the system, and external transactions with companies outside of the study system.

The internal transactions can be either "firm" or "economy." Firm transactions between companies can be specified in MW on an hourly basis, or as a minimum and maximum rating (MW) and a monthly energy amount (MWh). *Firm transactions* occur regardless of economics. Economy transactions occur between companies in the system dispatch to the extent that it is cheaper for a company to purchase energy to serve its load than to generate from its own units.

The external contracts can also be categorized as "firm" or "economy." The primary difference is that firm external contracts are evaluated as part of the base dispatch each hour, while economy external contracts involve multiple dispatches each hour to evaluate the price paid for the energy.

Firm external contracts are modeled as unit modifiers located outside of the study system, but in all other respects they are treated the same as any other system resource. Company ownerships are assigned to the units, and they are modeled in the commitment and dispatch along with the "local" generation.

Modeling of security constraints such as must-run units, minimum generation by geographical area, maximum simultaneous import limits, etc.

In MAPS, the production simulation is formulated as a linear programming (LP) problem where the objective function is to minimize production costs subject to electrical, business and unit characteristics constraints. Users may also specify operating nomograms, such as those often used by system operators to represent voltage and transient stability limits. MAPS monitors the flows on individual transmission lines and interfaces on an hourly (or bi-hourly, as applicable) basis to ensure that the line or interface limits, or other security constraints such as import limits, are not violated while committing or dispatching units to meet customer needs.

MAPS can also consider other user-specified contingencies such as the tripping of lines or groups of lines, or the tripping of load or generation at specified buses. The final generation dispatch developed by MAPS will be secure in the sense that the system will be operating within all of its recognized transmission operating limits even under the contingency conditions.

Model of reserves (planning, commitment, and spinning) by area or company or for the whole system

During the unit commitment process, MAPS models operating reserve requirements for areas, companies, pools, and the entire system, as applicable. The operating reserve requirement can be calculated based on a combination of the load, a fixed MW adder, or a percentage of the continuous rating of the largest committed unit as specified in the model inputs.

The total operating reserves can be met by a user-specified combination of quick-start reserves (units not actually running but which can be brought on line very quickly) and spinning reserves. The portion of operating reserves that can be met by quick-start reserves can be specified by area, company, pool, or system, if desired. The user identifies which units have quick-start capability.

A spinning reserve credit can be taken for unused generation from energy-storage units. The user can also specify the portion of each committed thermal unit that can be applied toward the spinning reserve requirement.

Variable simulation time steps to reduce execution time (such as typical week per month)

MAPS has considerable flexibility in the simulation time steps that it models. In its most detailed mode, MAPS studies all of the days in the year on an hourly basis. Through a simple change in input, the program can be directed to study all of the days in the year on a bi-hourly basis, or a typical week per month on an hourly or bi-hourly basis. Increasing the time step or equivalently reducing the number of hours or bi-hours specifically simulated can significantly reduce the required run time for MAPS and any subsequent processing of its outputs.

The user can specify the starting and ending years of the study period. Within the study period, the user can indicate which years to study and whether the entire year or only a portion thereof is to be simulated.

TRANSMISSION NETWORK

MAPS contains two distinct models for representing the transmission system. The model of primary interest (*the electrical mode*) performs a security-constrained production simulation that uses a detailed electrical model of the transmission network along with generation shift factors determined from a solved AC load flow, to calculate the real power flows for each generation dispatch. This model captures the economic penalties of redispatching the generation to satisfy transmission line flow limits and other security constraints. In this model, all physical components of the transmission system are modeled, including transmission lines, phase-angle regulators, and HVDC lines, as applicable. Alternatively, MAPS has the capability to characterize the transmission system in terms of a "transportation model." In this model (*the transportation mode*) transfers between interconnected areas are limited to pre-specified levels during the dispatch of the system generation.

Representation of transmission flows and limits on an hourly basis

In both the transportation mode and the electrical mode, MAPS calculates and limits the transmission flows on an hourly (or bi-hourly, as applicable) basis. In the electrical representation, the load and generation are assigned to individual buses and the transmission system is modeled in terms of the individual transmission lines, interfaces (which are groupings of lines), phase-angle regulators (PARs), and HVDC lines. Limits can be specified for the flow on the lines and the operation of the PARs. Additionally, operating nomograms can be modeled in MAPS to reflect:

- transmission line or interface limit as function of area or company load;
- net imports to an area as a function of load;
- simultaneous imports into an area;
- minimum generation by area.

In the transportation mode, the utility system is modeled as discrete operating areas which contain generation and load. The transmission system is represented in terms of transfer limits on the interfaces between the interconnected areas. These limits can be different for the two directions of interface flow, and can be specified on an hourly (or bi-hourly, as applicable) basis. These limits can also vary on an hourly basis (or bi-hourly, as applicable) in response to user-specified conditions as to whether or not specified units are available (for commitment) or have been committed (for dispatch).

The user can control the extent to which MAPS will enforce the limits assigned to an interchange path, transmission line, or other system element. Each monitored element is assigned an overload cost in $/MWh. If violating the limit will result in production cost savings greater than or equal to the overload cost, the limit can be ignored. An element with a large overload cost will be modeled with "hard" limits that are strictly enforced and rarely, if ever, violated, necessitating a redispatch of the generation to correct the violations.

Representation of various power market participants

Through the appropriate assignment of loads and generation, various participants in the power market can be represented in MAPS. Integrated utilities would have generation, transmission and be responsible for serving load. Separate distribution entities would not own any generation, but would purchase all of the energy they need to meet their load obligations. Independent power producers would be modeled as companies with generation but no transmission or load. The commitment, dispatch and cost allocation functions in MAPS itself would represent the independent system operator. The wholesale power broker would be modeled as a company with firm contracts to buy energy from other companies, which would then be resold on a firm or economy basis.

Representation of bilateral contracts in the power market

MAPS models bilateral contracts as firm transactions between the selling and buying companies. These contracts can be specified in terms of hourly MW values, or as minimum and maximum MW ratings and available monthly energy that would be scheduled by the program.

OTHER FEATURES

Data Input/Output -- Flexible data entry and storage and customized output reports

The MAPS data are input through data tables that are stored as a text file which can be very easily accessed and edited through standard text editors. The table structure is essentially free-format with no stringent requirements that data be input in specific positions or columns within a line. The table structure in MAPS is self-documenting and allows the user to freely insert comments in the data to aid in documentation.

All of the MAPS output is stored in binary files to allow for report generation and customization at a later date. Among the results stored in binary files are the individual unit quantities on an hourly, monthly, annual, and study period basis for the system and own-load dispatches and the hourly interface flows. The stored results of the transmission analysis when MAPS is run in the electrical mode include the hourly (or bi-hourly, as applicable) flows and plant outputs, the limiting elements for each hour and the marginal benefit of relaxing each limiting constraint.

These binary data can be accessed through user-developed post-processing programs or through the MAPS Report Analyzer (MRA) that is part of the MAPS software package. The MRA loads the data from the binary files into a database and allows the user to create customized reports and graphs through the use of built-in commands and a simple programming language.

Realistic representation of hydro, pondage, and energy storage scheduling

MAPS offers three distinct possible representations for modeling hydro plants: hourly modifiers, pondage modifiers, or energy-storage devices. This flexibility allows the program to model each hydro plant based on its operating characteristics.

Hourly modifiers allow the user to specify the actual hour-by-hour operation of the plant in MW. These data can be specified for the 168 hours of a typical week of operation, with the option to change these data on a monthly basis. Alternatively, the hourly operation for the entire year (8,760 or 8,784 hours) can be input. This feature can also be used to model firm company transactions that can be specified on an hourly basis.

Hydro plants can also be modeled as pondage modifiers. Each pondage modifier is defined by a monthly minimum and maximum output (MW) and a monthly available energy (MWh). The minimum capacity is base-loaded for all of the hours in the month, representing the run-of-river portion of the plant. The remaining capacity and energy are scheduled in a peak-shaving or valley-filling mode over the month. The user identifies the specific load shape to use for scheduling the plant. Options include the system load, combinations of selected company loads, or combinations of selected area loads.

For energy-storage devices, which include pumped-storage hydro and batteries, MAPS automatically schedules the operation based on economics and the characteristics of the storage device. The characteristics specified include the charging (or pumping) and generator ratings, the maximum storage capacity in MWh, the full-cycle efficiency (which recognizes losses in the pump/generate cycle), and the scheduling period (daily or weekly). The program examines the initial thermal unit commitment to develop a cost curve for the week. This cost curve is then combined with the appropriate chronological load profile to develop an hourly schedule which will minimize costs without violating the storage constraints. This schedule is then "locked in" and the thermal unit commitment process is repeated to develop the final commitment schedule.

For all three hydro representations, the user also specifies the ownership of the plant, energy costs in $/MWh, and the transmission system bus or buses at which the plant is located.

Modeling dispatchable load management strategies and non-dispatchable renewables

MAPS can model some types of dispatchable demand-side management (DSM) and load control as thermal generating units with appropriate characteristics and costs. Load management strategies such as batteries or thermal energy storage can be modeled as energy-storage devices.

MAPS models non-dispatchable DSM and load control and renewables such as photovoltaic or wind energy as hourly modifications to the load. This modification can be specified for the 168 hours of a typical week, with the option to change these data on a monthly basis, or by specifying the data for the entire year (8,760 or 8,784 hours).

The generating units used to represent DSM, load control and renewables can be assigned to the appropriate areas throughout the system to accurately capture the dispersed nature of such resources, as appropriate.

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PECO STATEMENT NO. 7

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

DIRECT TESTIMONY

OF

JOHN DOERING JR.

Regarding Future Generation Operating and Maintenance Expenses, Life extensions, Capital Additions, Availability Factors and Capacity Factors.

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DIRECT TESTIMONY OF JOHN DOERING, JR.

I. QUALIFICATIONS

Q. **Please state your name and business address for the record.**

A. J. Doering, Jr., PECO Energy Company ("PECO"), 2301 Market Street, Philadelphia, PA 19103.

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

A. I am employed by PECO as Vice President-Operations for the Power Generation Group. In this position, I am responsible for all non-nuclear power generation by PECO.

Q. **Please provide your educational background and prior work experience.**

A. I hold a B.S. in Mechanical Engineering from the University of Pennsylvania. Following graduation, I served in the United States Navy as a helicopter pilot and squadron officer. In 1971, I was employed by PECO as a system engineer at its Richmond Generating Station. In this position, I worked on steam and combustion turbines. From 1972 to 1978, I worked as an engineer at Peach Bottom Nuclear Generating Station. My responsibilities included engineering matters related to turbine controls, emergency systems and integrated leak rate testing.

From 1978 to 1993, I held various positions at the Limerick Nuclear Generating Station. My positions included Superintendent of Operations, Project Manager and , ultimately Plant Manager. Through these various positions, I was involved in virtually every aspect of plant operations at Limerick. Additionally, I hold Senior Reactor Operator licenses for both Peach Bottom and Limerick.

From 1993 to 1996, I was Director of Nuclear Strategic Support and Chairman of PECO's Nuclear Review Board. In this position, I reported directly to PECO's Senior Vice President and Chief Nuclear Officer. My responsibilities included formulating strategies for improvement of outage management cost control and information technology for all nuclear plants. In addition, I was responsible for management assessments related to the operations at Limerick, Peach Bottom and Salem stations.

I returned to the Fossil and Hydroelectric Department, now the Power Generation Group, to assume my present position in 1996.

Q. Have you ever provided testimony in an administrative proceeding?

A. Yes. I provided testimony on behalf of PECO before the Nuclear Regulatory Commission ("NRC") related to the licensing of the Limerick Generating Station.

II. INTRODUCTION AND SUMMARY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the basis for PECO's projections of the operating and maintenance costs for PECO's fossil and nuclear generating stations. I will also explain the derivation of PECO's projections of capital expenditures with respect to those generating stations, including the estimated life extension costs. Finally, I will discuss and support the availability factors for our fossil units and the capacity factors for our nuclear units.

This information has been provided to Mr. Thomas P. Hill, Jr. (Statement No. 1) to assist in the determination of the future market value of the generating stations.

III. OPERATING AND MAINTENANCE EXPENSES

Q. Please provide a general description of the procedure that you used to estimate operating and maintenance (O&M) expenses for PECO's generating stations.

A. I projected O&M expenses on a station basis expressed in 1997 dollars. These expenses were escalated for future years by Mr. Hill using a general inflation factor.

Projections of operating and maintenance expense for PECO's wholly-owned fossil and hydroelectric stations including Eddystone, Cromby, Delaware, Schuylkill, Conowingo, Muddy Run and PECO's fleet of combustion turbines are based on the projections for 1997 developed under my direction by the PECO Power Generation Group. For each station, estimates were made separately for fixed and variable operating expenses.

Variable costs include traditional variable expenses as well as costs associated with NOx emission compliance.

Projections of jointly-owned fossil units, Keystone and Conemaugh, are based on PECO's share of the 1997 budgets as approved by the Joint Owners Committee. O&M projections for Limerick and Peach Bottom nuclear stations are based on our internal nuclear group forecasts for 1997 which have been normalized to levelize the cost impact of refueling outages which occur on a 24 month cycle. O&M projections for the Salem station were provided by Public Service Electric and Gas, the operator of the plant, and reflect a similar normalization to levelize for an 18-month refueling outage for each unit. Salem's operating and maintenance expense also includes a portion of administrative and general costs and property taxes incurred by the operator of the station and for which PECO is responsible under the terms of the Joint Owners Agreement.

I note that the O&M projection for each unit at a two unit nuclear station is the same, because there are no significant design differences that would necessitate different operating costs at the same location.

Q. **Based upon your experience with respect to both nuclear and fossil fuel generation, do you believe these projections to be reasonable?**

A. Yes, they are reasonable, but I would suggest that they are also conservative in that they do not reflect costs for extraordinary outages or major equipment failures.

Q. **How do these projections compare to past experience?**

A. Actual O&M expenses for all generating stations for the years 1994-1996 are shown on Exhibit JD-1. With respect to most of the stations individually, and on an overall basis, the 1997 projection is less than the average of the prior three years' experience. Additionally, data for years 1994-1996 are expressed in current year dollars. If they are expressed on a constant dollar basis with the inflation factors supplied by Mr. Hill, it shows a clearer picture as to how conservative our 1997 estimates are for purposes of forecasting. Exhibit JD-2 provides the constant dollar comparison.

Q. **In your opinion, are there any substantial opportunities for PECO Energy to reduce its O&M costs below these projections?**

A. I do not believe so. We have been very aggressive in recent years in our efforts to control O&M costs in the face of ongoing inflationary pressures. I believe that the projections developed for 1997 represent aggressive targets which are well below our actual experience in the last three years. Additionally, we have significantly reduced staffing at all of our stations, both fossil and nuclear, over the past 7 years through early retirement programs. Process improvements and reorganization have enabled us to achieve these levels of improvement. Based upon my engineering judgment and experience in power generation, it would not be reasonable to assume a continuation of this trend. I would note that labor is the largest component of operating cost at stations other than the cost of fuel, and these costs have been significantly reduced over the past 7 years, for the reasons explained above.

Q. **You note that Mr. Hill projects expenses beyond 1997 using an inflation adjustment. Have you reviewed Mr. Hill's expense levels beyond 1997, and do you find them to be reasonable?**

A. Yes, I have reviewed Mr. Hill's projections of expenses for the years beyond 1997, using a general inflation factor, and I believe these projections are reasonable, and conservative for the reasons previously discussed.

Q. The O&M costs also reflect projected costs in future years for NOx mitigation at the fossil fuel stations. Can you explain the basis for these projections?

A. The cost projections reflect the expected allocation of NOx credits to PECO from the Pennsylvania Department of Environmental Protection (PADEP). The year 1990 was utilized by the PADEP as the base emissions year for determination of credits to be distributed to all affected NOx sources in the Commonwealth. The future market value of NOx credits was determined from the best estimates available from a review of published industry price sources.

IV. NEW CAPITAL EXPENDITURES

Q. How was the projected level of capital expenditures for the generating stations determined?

A. Projections of ongoing capital expenditures were developed on a station-specific basis for 1997 and were escalated for future years using a general inflation factor. Projections of 1997 capital expenditures for PECO's fossil stations are based on an ongoing base level of capital expenditures plus an allowance for the normalized cost of a five-year cycle maintenance outage for each unit. This analysis was done by removing outage related capital expenditures from the historic data and then using the adjusted data to estimate a base level of capital expenditures exclusive of outage costs for 1997. I then added one-fifth of the typical capital cost from an outage to the 1997 base cost to derive a normalized level of capital additions. I also excluded one-time non-recurring costs in developing the projections.

Similarly, projections of 1997 capital expenditures for PECO's nuclear units are based on normalized capital requirements as budgeted for 1997 with adjustments to exclude certain one-time projects. Additionally, Limerick capital expenditures include carrying costs on nuclear fuel because the Limerick fuel is owned by PECO while fuel for the other nuclear stations is leased.

Q. **Did PECO develop a station-specific projection of capital expenditures for the Salem nuclear units?**

A. Yes. PECO's nuclear group staff has performed an analysis of the capital projects that are expected to occur following the restart of the Salem units, and we have used those data as a baseline for 1997.

Q. **In the Securitization Filing, PECO used the same capital expenditure estimate for Salem and Peach Bottom. Why has it changed?**

A. As noted above, PECO's Nuclear Group staff did further evaluation of the Salem capital expenditures and determined that the ongoing level of expenditures at a pressurized water reactor (PWR) like Salem will be lower than at a boiling water reactor (BWR) like Peach Bottom. This is principally because, given the design of PWRS, a larger portion of the plant, including the turbine, condenser, and fuel water pumps, is not radioactive and, therefore, work in this area does not require exposure safeguards and resulting losses in productivity as would be the case in a BWR.

Q. **Why are capital expenditures needed for plants that are considered by the company to be, in part, stranded investments?**

A. The term stranded investment is a financial term, not an operating term. Whether or not a portion of the plant investment is stranded is irrelevant in determining the level of expenditures necessary to operate the plant. The continued operation of a plant requires a certain level of expenditures. Certain of these expenditures are capitalized and others are expensed. It is accounting rules established by the Federal Energy Regulatory Commission (FERC) that determine which of these expenditures are operation and maintenance expense and which are capital expenditures. Capital expenditures necessary for the routine operation of the plant are included in the base level of capital expenditures.

Q. **In your experience, are these capital expenditures reasonable in amount?**

A. Yes. I note that, as was the case with O&M expenses, the projected 1997 capital expenditures for most units individually, and on an overall basis, are less than one-half the average of the prior three years' experience. In fact, the capital expenditure projections are less than one-half the average of the prior three years. Exhibit JD-3 provides the data, in current dollars, that establish this fact. As with operating and maintenance expense, if a constant dollar comparison is made, the reduction in capital expenditures is even greater. This comparison is provided in Exhibit JD-4.

Q. **Do you believe that Mr. Hill's projection of future increases in capital investments for these stations is reasonable?**

A. Yes, I do, for the same reasons I expressed with respect to O&M expenses, recognizing that there is no provision included for extraordinary or one time events which may increase capital requirements for the future. Most of the capital requirements included are for "replacement-in-kind", which generally are affected directly by the impact of general price inflation on material and labor costs.

Q. **With respect to certain fossil fuel stations, the Company assumes that additional capital expenditures will be made in the future to extend their lives beyond their current depreciable lives. How were these additional investment amounts determined?**

A. Projections of the cost of a fifteen year life extension project were developed for each fossil station. The components included in the life extension costs depend upon the type and size of the unit. For the coal units such as Eddystone 1 and 2, Keystone, and Conemaugh, life extension costs include replacement of the following components:

1) Boiler waterwall tube section
2) Boiler economizer tube section
3) Boiler superheater tube section
4) Boiler reheater
5) Turbine rotor replacement
6) Continuous emissions monitoring equipment
7) Repair of SO_2 removal equipment.

In the case of combustion turbines, the life extension costs are based upon replacement of the combustion chamber. Finally, for hydroelectric facilities (Muddy Run, Conowingo), life extension costs were based upon the estimated cost of runner and pump replacements.

Q. **Why has the Company used 15 years as the appropriate length of a life extension at its facilities?**

A. The decision to use 15 years is an engineering judgment based upon the following considerations. The initial expected life of the units was 35 years. While the major components being replaced could last for 25 to 30 years, there is no experience with units that actually confirm this. Furthermore, experience with units over 50 years old is limited in this industry. Additionally, other components may have to be replaced as the unit ages. Based upon these facts and the estimated age of the units, some of which are over 40 years old, 15 years was judged to be the most reasonable time horizon for life extension.

V. AVAILABILITY FACTORS

Q. What level of availability has the Company's fossil units experienced over the past several years?

A. There are many factors that impact availability, such as the unit's age, type of unit, specific design criteria, and type of fuel. The Company's fossil fleet, which has many different types of units, has experienced, in aggregate, significantly improved availability factors over the past eight years.

Q. Are the unit availability factors used for the Company's units in the market analysis of Mr. Bustard, Dr. Hieronymus, or Dr. Venkatashwara reasonable?

A. Yes. The availability factors used in these models were consistent with the factors explained above, including the recent operating experience of PECO's fossil units as a whole.

VI. CAPACITY FACTORS

Q. Mr. Doering, what capacity factor does PECO recommend using over the remaining life of its nuclear plants?

A. I recommend using a 75% capacity factor. While this level is higher than the lifetime capacity factors for PECO's units, excluding the effect of the current Salem outage and the Peach Bottom outage in the late 1980s, I believe it is reasonable. I have provided the year-by-year capacity factors for PECO's units as Exhibit JD-5.

Q. Does this estimate recognize the current performance of PECO's units?

A. Yes, however, it also reflects the historic performance of the units and anticipates some unavailability that may result from major capital and generating changes over the remaining lives of these units. Some prior examples of such changes which resulted in significant outage time are the Peach Bottom pipe replacement, the Peach Bottom condensers, the Salem steam generator replacement and the Limerick turbine rotor replacement.

Q. **What has been the average performance of all BWR and PWR units during the past several years?**

A. The national average nuclear capacity factor for the 1990-1995 period was 73%. Again this shows the reasonableness of the 75% capacity factor assumed for the long term in the market value analysis.

Q. **Does this conclude your direct testimony?**

A. Yes.

Exhibit JD-1

PECO Energy Company
Operating & Maintenance Costs
Actual ($1000)

	1994	1995	1996	1997-base
Limerick 1	$ 98,434	$ 76,363	$ 95,778	$ 87,253
Limerick 2	$ 74,749	$ 91,678	$ 71,579	$ 87,253
Peach Bottom 2	$ 53,885	$ 28,482	$ 48,153	$ 35,711
Peach Bottom 3	$ 25,631	$ 47,870	$ 24,217	$ 35,711
Salem 1	$ 60,924	$ 73,035	$ 80,685	$ 63,194
Salem 2	$ 55,692	$ 58,183	$ 93,883	$ 63,194
Muddy Run	$ 4,870	$ 4,719	$ 8,525	$ 7,786
Schuylkill	$ 6,075	$ 2,910	$ 3,474	$ 2,713
CT	$ 7,651	$ 5,117	$ 11,536	$ 9,164
Conemaugh	$ 11,459	$ 9,980	$ 12,139	$ 7,677
Conowingo	$ 9,942	$ 8,018	$ 8,474	$ 10,118
Cromby 1	$ 14,466	$ 8,849	$ 10,002	$ 9,857
Cromby 2	$ 5,540	$ 7,398	$ 4,211	$ 3,842
Delaware	$ 7,742	$ 7,736	$ 6,463	$ 4,789
Eddystone 1	$ 25,813	$ 23,358	$ 18,298	$ 18,743
Eddystone 2	$ 21,560	$ 16,841	$ 15,090	$ 15,741
Eddystone 3&4	$ 19,702	$ 6,915	$ 9,223	$ 9,846
Keystone	$ 10,893	$ 9,809	$ 10,486	$ 6,811
TOTAL O & M	$ 515,028	$ 487,261	$ 532,216	$ 479,403

PECO Energy Company
Operating & Maintenance Costs
1997 Dollars ($1000)

	1994	1995	1996	1994-96 avg	1997-base
Limerick 1	$ 104,930	$ 79,417	$ 97,655	$ 94,001	$ 87,253
Limerick 2	$ 79,682	$ 95,344	$ 72,982	$ 82,669	$ 87,253
Peach Bottom 2	$ 57,441	$ 29,621	$ 49,097	$ 45,386	$ 35,711
Peach Bottom 3	$ 27,322	$ 49,784	$ 24,692	$ 33,933	$ 35,711
Salem 1	$ 64,944	$ 75,956	$ 82,266	$ 74,389	$ 63,194
Salem 2	$ 59,367	$ 60,510	$ 95,723	$ 71,867	$ 63,194
Muddy Run	$ 5,191	$ 4,908	$ 8,692	$ 6,264	$ 7,786
Schuylkill	$ 6,476	$ 3,026	$ 3,542	$ 4,348	$ 2,713
CT	$ 8,156	$ 5,322	$ 11,762	$ 8,413	$ 9,164
Conemaugh	$ 12,215	$ 10,379	$ 12,377	$ 11,657	$ 7,677
Conowingo	$ 10,598	$ 8,339	$ 8,640	$ 9,192	$ 10,118
Cromby 1	$ 15,421	$ 9,203	$ 10,198	$ 11,607	$ 9,857
Cromby 2	$ 5,906	$ 7,694	$ 4,294	$ 5,964	$ 3,842
Delaware	$ 8,253	$ 8,045	$ 6,590	$ 7,629	$ 4,789
Eddystone 1	$ 27,516	$ 24,292	$ 18,657	$ 23,488	$ 18,743
Eddystone 2	$ 22,983	$ 17,515	$ 15,386	$ 18,628	$ 15,741
Eddystone 3&4	$ 21,002	$ 7,192	$ 9,404	$ 12,532	$ 9,846
Keystone	$ 11,612	$ 10,201	$ 10,692	$ 10,835	$ 6,811
TOTAL O & M	$ 549,016	$ 506,748	$ 542,647	$ 532,804	$ 479,403

Exhibit JD-3

PECO Energy Company
Capital Expenditures
Actual ($1000)

	1994	1995	1996	1997-base
Limerick 1	$ 22,183	$ 16,445	$ 19,128	$ 10,384
Limerick 2	$ 23,474	$ 23,350	$ 8,716	$ 10,384
Peach Bottom 2	$ 23,061	$ 9,449	$ 10,201	$ 7,542
Peach Bottom 3	$ 5,891	$ 12,511	$ 6,331	$ 7,542
Salem 1	$ 20,218	$ 30,773	$ 73,724	$ 5,930
Salem 2	$ 20,800	$ 29,433	$ 47,051	$ 5,930
Muddy Run	$ 3,830	$ 3,936	$ 14,569	$ 1,100
Schuylkill	$ 1,509	$ 104	$ -	$ 800
CT	$ 1,931	$ 282	$ 804	$ 900
Conemaugh	$ 27,638	$ 8,752	$ 5,196	$ 1,960
Conowingo	$ 943	$ 6,100	$ 13,723	$ 1,400
Cromby 1	$ 10,217	$ 429	$ 70	$ 1,500
Cromby 2	$ 827	$ 3,334	$ 88	$ 900
Delaware	$ 1,617	$ 136	$ -	$ 1,600
Eddystone 1	$ 5,895	$ 8,415	$ 650	$ 1,800
Eddystone 2	$ 4,393	$ 5,141	$ 420	$ 1,800
Eddystone 3&4	$ 13,223	$ 3,573	$ 855	$ 1,800
Keystone	$ 11,156	$ 7,274	$ 3,760	$ 2,760
TOTAL Cap Ex	$ 198,806	$ 169,437	$ 205,286	$ 66,032

Exhibit JD-4

PECO Energy Company
Capital Expenditures
1997 Dollars ($1000)

	1994	1995	1996	1994-96 avg	1997-base
Limerick 1	$ 23,647	$ 17,103	$ 19,503	$ 20,084	$ 10,384
Limerick 2	$ 25,023	$ 24,284	$ 8,887	$ 19,398	$ 10,384
Peach Bottom 2	$ 24,583	$ 9,827	$ 10,401	$ 14,937	$ 7,542
Peach Bottom 3	$ 6,280	$ 13,011	$ 6,455	$ 8,582	$ 7,542
Salem 1	$ 21,552	$ 32,004	$ 75,169	$ 42,908	$ 5,930
Salem 2	$ 22,173	$ 30,610	$ 47,973	$ 33,585	$ 5,930
Muddy Run	$ 4,083	$ 4,093	$ 14,855	$ 7,677	$ 1,100
Schuylkill	$ 1,609	$ 108	$ -	$ 572	$ 800
CT	$ 2,058	$ 293	$ 820	$ 1,057	$ 900
Conemaugh	$ 29,462	$ 9,102	$ 5,298	$ 14,621	$ 1,960
Conowingo	$ 1,005	$ 6,344	$ 13,992	$ 7,114	$ 1,400
Cromby 1	$ 10,891	$ 446	$ 71	$ 3,803	$ 1,500
Cromby 2	$ 882	$ 3,467	$ 90	$ 1,480	$ 900
Delaware	$ 1,724	$ 141	$ -	$ 622	$ 1,600
Eddystone 1	$ 6,284	$ 8,752	$ 663	$ 5,233	$ 1,800
Eddystone 2	$ 4,683	$ 5,347	$ 428	$ 3,486	$ 1,800
Eddystone 3&4	$ 14,096	$ 3,716	$ 872	$ 6,228	$ 1,800
Keystone	$ 11,892	$ 7,565	$ 3,834	$ 7,764	$ 2,760
TOTAL Cap Ex	$ 211,926	$ 176,213	$ 209,310	$ 199,149	$ 66,032