Conectiv Cross-Exhibit

R-00973963, R-00973965

10/14/97

DOCUMENT FOLDER

DOCKETED OCT 22 1997

PECO ENERGY COMPANY - 1998 COST OF SERVICE STUDY (REBUTTAL)
SECTION IV - ALLOCATION SCHEDULES PAGE 2 OF 6

	TOTAL	HT	EP	PD	GS	RH	R	OP	SLP	SLS	SLE	OTHER	INTERDEP
A9120	11,994	1,754	85	191	1,965	1,149	6,732	47	25	9	17	9	11
A9130	93	14	1	1	15	9	52	0	0	0	0	0	0
B4	12,087	1,768	86	193	1,980	1,158	6,784	47	25	9	17	9	11
....	1.00000	0.14625	0.00708	0.01594	0.16382	0.09582	0.56127	0.00390	0.00206	0.00077	0.00143	0.00075	0.00091
A9080	7,221	1,056	51	115	1,183	692	4,053	28	15	6	10	5	7
A9090	1,917	280	14	31	314	184	1,076	7	4	1	3	1	2
A9100	15,678	2,293	111	250	2,568	1,502	8,800	61	32	12	22	12	14
B5	24,816	3,629	176	396	4,065	2,378	13,928	97	51	19	35	19	23
....	1.00000	0.14625	0.00708	0.01594	0.16382	0.09582	0.56127	0.00390	0.00206	0.00077	0.00143	0.00075	0.00091
	1,529,273	459,888	22,150	42,598	310,662	123,741	540,178	12,281	7,530	3,940	3,367	426	2,513
5010	207,621	83,092	3,868	6,829	42,378	18,093	49,482	2,414	571	109	302	58	446
-5040	0	0	0	0	0	0	0	0	0	0	0	0	0
-5070	1,512	546	22	48	373	91	429	0	0	0	0	0	3
-5120	31,648	12,666	590	1,041	6,460	2,756	7,540	388	87	17	46	9	68
-5180	128,991	51,624	2,403	4,243	26,329	11,241	30,730	1,500	354	67	188	36	277
-5190	7,714	2,785	113	243	1,904	465	2,188	0	0	0	0	0	15
-5260	17,628	6,473	264	566	4,426	1,080	6,065	0	1	0	0	0	36
-5360	1,331	481	20	42	328	80	378	0	0	0	0	0	3
-5400	(643)	(232)	(9)	(20)	(159)	(39)	(182)	0	(0)	(0)	(0)	(0)	(1)
-5470	14,392	5,760	268	473	2,938	1,254	3,429	167	40	8	21	4	31
-5500	0	0	0	0	0	0	0	0	0	0	0	0	0
-5550	0	0	0	0	0	0	0	0	0	0	0	0	0
-5561	69,857	27,958	1,301	2,298	14,259	6,088	16,642	812	192	37	102	19	150
-5570	(31,106)	(12,872)	(599)	(1,014)	(6,187)	(2,642)	(7,221)	(352)	(83)	(16)	(44)	(8)	(87)
-5870	5,113	1,846	75	161	1,262	308	1,450	0	0	0	0	0	10
-5890	0	0	0	0	0	0	0	0	0	0	0	0	0
-5891	6,013	759	147	101	1,063	689	3,019	55	132	78	63	4	4
-9040	65,400	3,479	0	1,683	1,125	11,275	46,582	1,262	0	0	0	3	0
-9210	84,562	23,696	1,167	2,201	18,035	6,180	31,675	621	513	297	221	25	131
-9230	17,162	4,789	237	447	3,660	1,254	6,428	106	104	60	45	5	27
-9240	6,968	2,159	91	208	1,611	482	2,317	17	33	22	15	1	12
-9250	16,906	4,717	233	440	3,606	1,235	6,333	104	102	59	44	5	26
9260	111,028	30,981	1,533	2,890	23,680	8,114	41,568	684	673	389	290	33	172
9280	0	0	0	0	0	0	0	0	0	0	0	0	0
-9281	6,492	1,889	92	202	1,491	562	2,135	51	27	10	19	4	11
-9290	(3,433)	(1,239)	(50)	(108)	(847)	(207)	(974)	0	(0)	(0)	(0)	(0)	(7)
-9310	4	0	0	0	0	0	0	0	0	0	0	0	0
B6	763,813	208,633	10,384	19,623	162,929	55,479	291,148	4,582	4,784	2,803	2,055	228	1,163
....	1.00000	0.27315	0.01360	0.02569	0.21331	0.07263	0.38118	0.00600	0.00626	0.00367	0.00269	0.00030	0.00152
C1	35,652,494	14,268,559	664,139	1,172,653	7,277,077	3,106,939	8,493,499	414,583	97,976	18,650	51,666	9,930	76,624
....	1.00000	0.40021	0.01863	0.03289	0.20411	0.08715	0.23823	0.01163	0.00275	0.00052	0.00145	0.00028	0.00215
C2	33,166,070	13,724,166	638,800	1,081,656	6,596,721	2,816,467	7,699,431	375,823	88,820	16,908	47,017	9,002	71,260
....	1.00000	0.41380	0.01926	0.03261	0.19890	0.08492	0.23215	0.01133	0.00268	0.00051	0.00142	0.00027	0.00215
D1	1,573,214	2,252	3	1,047	145,604	154,794	1,169,654	98,781	1	442	319	216	101
....	1.00000	0.00143	0.00000	0.00067	0.09255	0.09839	0.74348	0.06279	0.00000	0.00028	0.00020	0.00014	0.00006
D2	1,474,218	2,252	3	1,047	145,604	154,794	1,169,654	0	1	442	319	1	101
....	1.00000	0.00153	0.00000	0.00071	0.09877	0.10500	0.79341	0.00000	0.00000	0.00030	0.00022	0.00000	0.00007
D3	98,781	0	0	0	0	0	0	98,781	0	0	0	0	0
....	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000

R-00973953, R-00973953 C0001 - C0007

Conectiv
Cross-Exam
Exhibit 2

Docket No. R-00973953

Phila 10/14/97 E. Nuthurst

Interrogatory Environmentalists II-112

Environmentalists II-112 Question:

Please provide a copy of PECO's current integrated resource planning report.

Environmentalists II-112 Answer:

The information requested is provided as Attachment Environmentalists II-112(a).

EXTRA COPY

Responsible Witness: T. P. Hill, Jr.

1997 Annual Resource Planning Report

May 1, 1997

TABLE OF CONTENTS

Appendix A

§57.141. General

Accompanying Forms:

None

Discussion:

PECO Energy files this Annual Resource Planning Report (ARPR) with the Pennsylvania Public Utility Commission (Commission) in response to 52 Pa. Code §§ 57.141 - 57.153. A brief ARPR summary is provided in response to 52 Pa. Code § 57.154.

Please direct all questions about or requests for PECO Energy's 1996 ARPR to:

Mr. Alfred A. Miller
Director - Rates
PECO Energy Company
2301 Market Street
Philadelphia, PA 19103
Phone: (215) 841-5760

The ARPR is available at a cost of $150 (payable by check to "PECO Energy") or may be viewed at PECO Energy offices during normal business hours. The ARPR Summary is available at no charge from the address shown above and may also be viewed at PECO Energy offices.

Information which has been designated as proprietary and confidential is indicated by those words at the top right of the respective pages. Such information is not available to the general public. Below is a list of those pages designated *proprietary and confidential:*

Page	Description
10	Table § 57.146-A - Fuel and General Inflation Assumptions
11	Table § 57.146-B - Average Energy Cost Projection by Fuel Type
A - 15	IRP-ELEC 3B - Existing Generating Capability (Supplemental Information)
A - 17	IRP-ELEC 4 - Future Generating Capability Installations, Changes and Removals
A - 18	IRP-ELEC 5 - Cogeneration and Independent Power Production Facilities
A - 20	IRP-ELEC 6 - System Cost Data
A - 25	IRP-ELEC 8A - Distribution of Net Generation by Fuel Type
A - 47	IRP-ELEC 11 - Comparison of Costs of Preferred Resource Plan with Alternative Plans

§57.142. Forecast of Energy Resources, Demands and Reserves.

<u>Accompanying Forms:</u>

IRP-ELEC 1A....................Historical and Forecast Energy Demand (Base, Low and High)
IRP-ELEC 1B.......................... Historical and Forecast Peak Load (Base, Low and High)
IRP-ELEC 1C........... Historical and Forecast Number of Customers (Base, Low and High)
IRP-ELEC 2A..........................Estimated Summer Peak Resources, Loads and Reserves
IRP-ELEC 2B............................Estimated Winter Peak Resources, Loads and Reserves

<u>Discussion:</u>

PECO Energy uses a load growth scenario that reflects the Company's most likely assumptions for economic variables and is used for corporate financial budgeting as a basis for resource planning. This scenario is the Base load growth scenario used in this ARPR.

The PECO Energy load growth forecast incorporates both end-use and econometric forecasts. Assumptions are first developed which affect all classes of service and then assumptions which specifically apply to each class are developed. This procedure is followed for the Base load growth forecast. Alternative low and high forecasts are then developed.

Included in Forms IRP-ELEC 1A - 2B are the projected energy and peak demand impacts from the implementation of the Demand Side Management (DSM) programs proposed in PECO Energy's 1995 Demand Side Management Program. Because this DSM plan has not yet been approved by the Commission, the impacts stated in Forms IRP-ELEC 1A - 2B are identical to those from the DSM plan delayed one year.

The impacts from PECO Energy's existing DSM programs are inherently included in the load forecasts. The incremental effects of those programs in the 1995 DSM Plan are those shown in the individual DSM column. Commercial and industrial rate incentive DSM programs are shown in the interruptible load columns.

Assumptions such as general inflation and fuel cost inflation are provided in response to §57.146 and are shown in Tables §57.146-A and -B on pages 7 and 8, respectively.

§57.143. Existing and Planned Generating Capability.

Accompanying Forms:

Discussion:

PECO Energy currently plans to continue in operation all of its currently operating generating capability through the 20-year planning period. Although PECO Energy has no formal life extension program, the economic benefits of continued operation are periodically reviewed to ensure unit retirement is not economically beneficial.

The three future resource changes identified in IRP-ELEC 4 Future Generating Capability Installations, Changes and Removals as "Resource Acquisition" represent increases in the Company's ability to meet its customers' requirements. These acquisitions may include supply-side capacity, demand-side management programs, or a combination of the two. The capability may be built or managed by PECO Energy or by others as these resources will likely be provided under the Commission's proposed competitive procurement regulations.

Major Capital Projects Planned at Base Load or Coal Units

Limerick
Currently the company is planning to replace the rotors of Limerick 1 and 2 in 1998 and 1999 respectively. The estimated cost of the project is $85 million with the present value of net benefits equal to $25 million. The rotors are to be replaced with a newer, more efficient design which will result in a 50 MW of additional capacity per unit without requiring additional fuel.

§57.144. Transmission Line Projection.

<u>Accompanying Forms:</u>

IRP-ELEC 12 ....Transmission Line Projections

<u>Discussion:</u>

PECO Energy only schedules transmission line construction for the next five years. The lines indicated in Form IRP-ELEC 12 are the only new transmission lines greater than 35kV that are scheduled to be constructed within the next five years or have been completed in the past year.

As to EMF reduction measures taken by PECO Energy in construction of the transmission lines in Form IRP-ELEC 12:

The Middletown-Morton line is designed to be constructed underground using pipe-type cable.

Open wire portions of the Newtown Square - Goshen Tap line are predominately designed using a delta configuration.

§57.145. Cogeneration and Small Power Production.

Accompanying Forms:

IRP-ELEC 5 .... Cogeneration and Independent Power Production Facilities

Discussion:

Form IRP-ELEC 5 provides the appropriate information.

§57.146. System Cost Data.

Accompanying Forms:

Discussion:

The detailed calculation necessary for the data provided in Form IRP-ELEC 6 is performed by a computerized production cost model. This model is also used to calculate the generation mix shown in Forms IRP-ELEC 7A and 8A.

Fuel and interchange costs are based on input data modeling the generation of companies in a power pool, expected loads of the members of the pool and expected fuel costs. Fuel costs result from the cost of operating generation based on the commitment and dispatch of generation for minimum cost to the pool. Interchange costs can result from transactions based on specified costs with other utilities or non-utility generation; or transactions with costs based on predetermined formulas. Both unit commitment and dispatch decisions are simulated.

Transactions within a pool are based on a predetermined formula. The accounting formula used by PJM is a 50-50 split savings between buyers' and sellers' costs. For 1997 on, the basic split savings formula has been eliminated. The interchange cost for 1997 on is based upon the cost of the highest cost unit running.

On the following pages Tables §§ 57.146-A and -B show the fuel cost assumptions which were used when calculating the system costs as well as the projected average cost of fuel by fuel type, respectively.

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§57.147. Forecast of Generating Capability and Generation Distribution.

Accompanying Forms:

IRP-ELEC 7A.............................Distribution of Net Generating Capability by Fuel Type
IRP-ELEC 7B..Scheduled Imports and Exports
IRP-ELEC 8A.....................................Distribution of Net Generation by Fuel Type
IRP-ELEC 8B..Scheduled Imports and Exports

Discussion:

The accompanying forms provide the appropriate information.

§57.148. Demand, Resource and Energy Data.

Accompanying Forms:

IRP-ELEC 9 .... Summary of Demands, Resources and Energy for the Past Year

Discussion:

Form IRP-ELEC 9 provides the appropriate information.

§57.149. Energy Conservation and Load Management.

<u>Accompanying Forms:</u>

IRP-ELEC 10A .... Conservation and Load Management Program Description
IRP-ELEC 10B ....Conservation and Load Management Program Summary
IRP-ELEC 10C .... Conservation and Load Management Cost Benefit Analysis Inputs
IRP-ELEC 10D ....Conservation and Load Management Cost Benefit Analysis Results
IRP-ELEC 10E ....Assessment of Conservation and Load Management Potential

<u>Discussion:</u>

On March 14, 1994, PECO Energy filed the 1995 Demand-Side Management Program with the Commission (Docket No. I-900005). The filing contains information concerning the program selection and evaluation process, which was performed using Annual Resource Planning principles and methods, and details of the design of each program chosen for inclusion in the plan. The 1995 DSM Program has not yet been approved by the Commission.

The filed DSM plan calls for PECO Energy to spend an additional $10 million on DSM, approximately doubling the Company's 1994 level of conservation and load management expenditures.

In the plan PECO Energy proposed the following new DSM programs:

Residential Lighting
Residential House Doctor
Residential HVAC Incentives
Residential Energy Efficient New Construction
Commercial Audits/Surveys
Audits for Large Commercial and Industrial Customers

The selection criteria used to develop the proposed mix of programs includes those from both the traditional perspective of demand side management as a resource option, and the perspective that the electric utility industry is becoming more competitive. The several factors considered include economic cost effectiveness, resource constraints, rate impact and specific needs of each customer class.

The programs described in Form IRP-ELEC 10A include only those programs currently being offered to customers by PECO Energy.

Form IRP-ELEC 10B shows the statistical summary of those DSM programs which were being offered and for which PECO Energy incurred expenses in 1995.

Form IRP-ELEC 10C and 10D show the cost benefit analysis inputs and outputs, respectively, of those DSM programs which had actual 1996 expenditures over $100,000 (the threshold stated in 52 Pa. Code §57.149) and quantifiable electric savings. Rate related conservation and load management programs such as Customer Assistance Program for residential and the Large Interruptible Load Rider for large commercial and industrial customers are not included.

Form IRP-ELEC 10E contains the estimated future cumulative energy and peak demand savings from the 1995 DSM plan and existing programs by customer class over the 1996-2015 period. This is PECO Energy's estimate of a reasonable potential for cost effective DSM. The Company's tariff also contains rates that are designed to encourage load-shifting where appropriate. These include Rate OP, Night Service Riders and Rate RT (Residential Time-of-Use) and rider IR-1. PECO Energy routinely investigates alternative rate options to encourage such customer behavior.

§57.150. Evaluation and Integration of Resources.

<u>Accompanying Forms:</u>

IRP-ELEC 11 .... Comparison of Costs of Preferred Resource Plan with Alternative Plans

<u>Discussion:</u>

PECO Energy examines a number of reasonable and viable resource options that can be used to serve forecast loads. Although the economic benefits of each alternative is not explicitly shown in this years ARPR, each alternative included in the preferred plan has been previously shown to be economical. Because of no substantial change in inflation, capital or fuel cost assumptions over the past two years, the same alternatives, with the exception of the Limerick Rotor Replacements, are assumed to be the most economic and are included in the preferred plan this year. Although the continuation of Delaware and Schuylkill stations was the least economic of the service continuation options in last year's ARPR, their existence provides more than simple generation to the system. Their geographic location in the heart of urban Philadelphia provides system reliability which would be extremely difficult to replace.

Several ongoing or recently completed efforts have the potential to affect the Company's future resource planning, including the pending restructuring of the PJM, PECO Energy's Securitization and Restructuring Filings, and the FERC's "Mega NOPR" on open access in the wholesale market. However, because PECO Energy is not able at this time to determine the effect of these efforts on its resource needs, any significant alterations in the resource plan would be premature.

<u>Preferred Plan</u>

The preferred plan incorporates a number of resources that represent an effort to increase the utilization of existing capacity resources before adding any new supply side resources. It also incorporates PECO Energy's 1995 DSM Program as well as the cost and inflation assumptions shown on page 10 in Table § 57.146-A.

The preferred plan revenue requirements shown in Form IRP-ELEC 11 include the following resources:

Cromby 1 and 2, Delaware 7 and 8, Eddystone 1, 2, 3, and 4, and Schuylkill 1 Continued Operation:

The plan continues all of these fossil fuel steam units in service through the 20-year period. All the units will have reached the end of their nominal 35-year lives by the end of the 20-year period. Continued operation of these units is shown to be the economic choice in this plan.

Resource Acquisition in 300 MW Blocks:

After maximizing the use of existing resources, implementing existing demand-side management programs, and including PECO Energy-owned capacity not currently in rate base, PECO Energy expects to obtain additional capability to serve its customers' needs. This acquisition may include supply-side capacity, demand-side management programs, or a combination of the two. The capability may be built or managed by PECO Energy or by others. Because of the long time until the additional resources are required, no resource acquisition process needs to be initiated prior to filing the 1997 Annual Resource Planning Report.

Demand Side Management:

Forms IRP-ELEC 10A - 10E describe the demand-side management in the preferred plan, which includes DSM programs described in PECO Energy's 1995 DSM Plan with a one year delay in implementation, as well existing and recently designed DSM programs.

Salem 2 Uprate:

The unit capacity will be increased as one benefit of required station engineering work. A comparison of this additional capacity with the Limerick and Peach Bottom upgrades previously described, indicates that this project is highly beneficial to PECO Energy customers.

Non-Utility Generation:

A total of 178 MW of non-utility capacity is planned to be purchased by PECO Energy beginning in 1997. This is made up of 150 MW from Gray's Ferry Cogeneration Partners' facility and 28 MW from the Montenay Montgomery Limited Partnership trash plant.

Nuclear Unit Service Continuation:

Operating licenses for Limerick 1 and 2, Peach Bottom 2 and 3, and Salem 1 and 2 continue through the 20-year period.

Hydroelectric Unit Service Continuation:

Operating licenses for the Conowingo and Muddy Run stations extend through the 20-year period.

Conemaugh Station Service Continuation:

This jointly-owned coal-fired station is expected to remain in operation through the 20-year period. Flue gas desulfurization scrubbers were installed to meet local air emission requirements as well as Clean Air Act Amendments of 1990, Title IV requirements.

Keystone Station Service Continuation:

This jointly-owned coal-fired station is expected to remain in operation through the 20-year period. Keystone is a Phase 2 unit under the Clean Air Act Amendments of 1990, Title IV requirements. The need for flue gas desulfurization scrubbers will be periodically reexamined.

Limerick Rotor Replacements:

Limerick 1 and 2 rotors need to be replaced due to certain design flaws. Replacement with a new, more efficient design will provide the company with 50 MW of additional capacity per unit in 1998 and 1999 respectively.

Combustion Turbines Service Continuation:

All PECO Energy combustion turbines are currently assumed to remain in operation for economic and reliability purposes through the 20-year period.

Sensitivity Analysis:

The low load growth scenario described in Form IRP-ELEC 1A (LOW) delays the first resource bidding capability to beyond the 20-year period. The high load growth scenario requires an advance of the first resource acquisition approximately two years. As the Company is not dependent on new resources it has considerable flexibility in adapting to lower or higher than expected load growth.

§57.151. New Generating Facilities and Expansions of Existing Facilities.

<u>Accompanying Forms:</u>

None

<u>*Discussion:*</u>

The Annual Resource Planning Report is developed in accordance with PECO Energy's resource planning objectives (described below) and reliability, viability, and economic planning criteria (discussed below).

Potential resource options are initially evaluated with regard to the resource viability criteria. In the selection of the preferred plan, those resources which meet the viability criteria are further evaluated with regard to their economic and reliability contributions to service to our customers. These evaluations are analyzed using traditional net present value revenue requirement principles.

Because 900 MW of new generation resources required by PECO Energy starting in 2009 are likely to be supplied through some form of competitive bidding, a specific site has not been designated as a plant construction location. For purposes of the ARPR economic evaluation, the 900 MW of additional generation resources is assumed to be a gas fired combined cycle plant.

The PECO Energy 1995 DSM plan, as filed with the Commission, discusses the selection of the DSM programs using the integrated resource planning methods and criteria described herein.

The forecast of generating energy shown in Form IRP-ELEC 8A is produced using a production cost model which was described in response to §57.146. System Costs Data on page 6.

The FERC recently finalized its Mega NOPR regarding competition in the wholesale market. In addition, PJM is going to be restructured (although the structure is not yet known), and the Pa. PUC is evaluating competition in the retail electric market. Any one of these proposals has the potential to impact the ARPR. As the results are not yet known, any potential impacts have not yet been included into this years ARPR.

RESOURCE PLANNING OBJECTIVES

A. Enhance customer satisfaction by maintaining a reliable electric system by meeting PECO Energy's obligation to provide its equitable share of the PJM *installed capacity reserve requirement and satisfying the needs of all classes of* service for a broad mix of marketable demand-side programs.

B. Achieve and maintain the ability to attract new electric customers by including constraints on the relative price of electricity in our development of a cost-effective resource plan.

C. Maintain our commitments to the prosperity of our communities and the protection of the environment.

D. Manage our expense and capital budgets by creating a cost-effective plan for developing demand-side and supply-side resources.

E. Maintain our flexibility to adapt to external influences which are beyond Company control by developing contingency plans.

F. Maintain fuel source diversity within our generating capability mix.

G. Maintain our ability to maintain system reliability by including real-time operation considerations in our plans.

PLANNING CRITERIA

<u>Installed Reserve Capacity Criterion</u>

As a member company of the Pennsylvania-New Jersey-Maryland Interconnection Association (PJM) and the Mid-Atlantic Area Council (MAAC), PECO Energy is obligated to provide its equitable share of the pool's required reserves. The MAAC reliability criterion for installed generating capacity is that sufficient generating capacity shall be installed to ensure that in each year for the MAAC system the probability of occurrence of load exceeding the available generating capacity shall not be greater, on the average, than one day in ten years.

PECO Energy uses installed capacity reserve targets based on its future PJM reserve obligations. 300 MW resource additions are used to typify the results of resource acquisition. In its analysis, PECO Energy used economic approximations for natural gas combined-cycle units for these 300 MW blocks. However, the actual resources obtained might be one or more generating units of various types, one or more demand-side management programs, or a combination of these to provide an overall resource approximating 300 MW and yielding the reliability and economic benefits required to meet customer requirements. These resources may be built or managed by PECO Energy or by others. In the analysis, PECO Energy has constrained its planned reserves to a general range of about 2% above and below the reserve targets. This range is a screening assumption, not a true economic decision criteria. PECO Energy assumes that any such deviations above or below the capacity reserve target will be offset by short-term capacity sales or purchases.

Resource Viability Criteria

In order for any demand-side or supply-side resource option to receive serious consideration, it must first be shown to be viable. Demand-side options must exhibit potential customer acceptance; they must pass the participant test (i.e. yield projected positive net benefits to the participant) and maintain or improve customer satisfaction (i.e. have a positive or at least neutral effect on participant comfort or value). Supply-side options must meet minimal constraints associated with the geography of PECO Energy's service territory. Both demand-side and supply-side resources must exhibit sufficient technological maturity.

System Cost/Benefit Criteria

PECO Energy uses several cost/benefit criteria in its integrated resource planning process:

1. The Total Resource Cost (TRC) Test (also called the all-ratepayers test) is a measure of the net benefit to the aggregate of all ratepayers. In the case of demand-side options, this test measures the combined impact of costs and benefits of the participant customers and costs and benefits of the utility. In the case of supply-side options, maximizing the TRC net benefit is equivalent to minimizing the utility's revenue requirement.

2. The Rate Impact Test measures the effect of a resource option on the utility's average electric rate (assuming full recovery of revenue requirement). For supply-side options, the impact on rates is minimized by minimizing the utility's revenue requirement. However, recognizing that electric rates are the ratio of revenue requirement divided by electric sales, since demand-side options generally affect both revenue requirement and electric sales, the situation is more complex. In order for a demand-side option to minimize the impact on rates its percentage impact on revenue requirement must exceed its percent impact on electric sales.

3. The Utility Test is a measure of the net benefit from the utility's perspective. It measures only those costs and benefits which have a direct impact on the utility's revenue requirement. The Utility Test is optimized when the utility's revenue requirement is minimized.

While the resource viability criteria can be used objectively as a go or no-go criteria, the three system cost/benefit criteria must generally be applied with some degree of subjectivity since they may at times be at odds with each other.

§57.152. Formats.

The following data forms are contained in Appendix A:

IRP-ELEC 1A	Historical and Forecast Energy Demand
IRP-ELEC 1B	Historical and Forecast Peak Load
IRP-ELEC 1C	Historical and Forecast Number of Customers
IRP-ELEC 2A	Estimated Summer Peak Resources, Loads and Reserves
IRP-ELEC 2B	Estimated Winter Peak Resources, Loads and Reserves
IRP-ELEC 3A	Existing Generating Capability
IRP-ELEC 3B	Existing Generating Capability (Supplemental Information)
IRP-ELEC 4	Future Generating Capability Installations, Changes and Removals
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IRP-ELEC 10A	Conservation and Load Management Program Description
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IRP-ELEC 10C	Conservation and Load Management Cost Benefit Analysis Inputs
IRP-ELEC 10D	Conservation and Load Management Cost Benefit Analysis Results
IRP-ELEC 10E	Assessment of Conservation and Load Management Potential
IRP-ELEC 11	Comparison of Costs of Preferred Resource Plan with Alternative Plans
IRP-ELEC 12	Transmission Line Projections

§57.153. Evaluation Methodology.

Accompanying Forms:

None

Discussion:

PECO Energy uses the cost-benefit methodologies described in §57.151 as prescribed by the Bureau of Conservation, Economics and Energy Planning to evaluate the costs and benefits of conservation, load management and DSM programs. For supply side alternatives, the traditional revenue requirement methodology is used.

§57.154. Public Information.

Accompanying Forms:

None

Discussion:

See the response to § 57.141. General on page 1.

APPENDIX A

Data Forms

Company Name: **PECO Energy**

IRP-ELEC 1A. Historical and Forecast Energy Demand (GWh)

Load Growth Scenario: BASE

Index Year (a)	Actual Year (b)	Residential (c)	Commercial (d)	Industrial (e)	Other* (f)	Sales For Resale (g)	Total Consumption (h)	System Losses (i)	Company Use (j)	Gross Energy	PECO DSM Energy Impact	Net Energy For Load (k)
-6	1991	9,947	5,136	15,967	1,028	723	32,801	2,585	36	35,422	0	35,423
-5	1992	9,522	5,222	15,559	960	730	31,993	2,439	36	34,468	0	34,468
-4	1993	10,264	5,623	15,714	770	765	33,136	3,024	36	36,196	0	35,729
-3	1994	10,412	5,954	15,622	789	784	33,561	2,606	36	36,203	0	36,207
-2	1995	10,660	6,222	15,869	859	784	34,394	2,408	36	36,838	0	36,838
-1	1996	10,657	6,410	14,976	902	1,404	32,945	2,306	36	35,251	0	35,251
0	1997	10,653	6,667	15,299	941	0	33,560	2,349	36	35,945	8	35,937
1	1998	10,732	7,044	15,259	1,042	0	34,077	2,385	36	36,498	30	36,468
2	1999	10,812	7,346	15,271	1,093	0	34,522	2,417	36	36,975	47	36,928
3	2000	10,894	7,650	15,248	1,094	0	34,886	2,442	36	37,364	64	37,300
4	2001	10,976	7,955	15,353	1,095	0	35,379	2,477	36	37,892	82	37,810
5	2002	11,059	8,262	15,333	1,096	0	35,750	2,503	36	38,289	91	38,198
6	2003	11,142	8,572	15,314	1,097	0	36,125	2,529	36	38,690	91	38,599
7	2004	11,225	8,882	15,294	1,098	0	36,499	2,555	36	39,090	87	39,003
8	2005	11,310	9,195	15,278	1,099	0	36,882	2,582	36	39,500	80	39,420
9	2006	11,394	9,510	15,262	1,100	0	37,266	2,609	36	39,911	73	39,838
10	2007	11,479	9,827	15,249	1,101	0	37,656	2,636	36	40,328	67	40,261
11	2008	11,564	10,146	15,237	1,102	0	38,049	2,663	36	40,748	64	40,684
12	2009	11,650	10,466	15,225	1,103	0	38,444	2,691	36	41,171	63	41,108
13	2010	11,736	10,789	15,216	1,104	0	38,845	2,719	36	41,600	60	41,540
14	2011	11,823	11,114	15,208	1,105	0	39,250	2,748	36	42,034	58	41,97[illegible]
15	2012	12,110	11,441	15,201	1,106	0	39,858	2,790	36	42,684	51	42,63[illegible]
16	2013	11,997	11,769	15,196	1,107	0	40,069	2,805	36	42,910	40	42,870
17	2014	12,086	12,101	15,192	1,108	0	40,487	2,834	36	43,357	30	43,327
18	2015	12,174	12,434	15,191	1,109	0	40,908	2,864	36	43,808	21	43,787

* *'Other' sales include public street and highway lighting, other sales to public authorities, sales to railroads and railways and interdepartmental sales.*

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Company Name: **PECO Energy**

IRP-ELEC 1A. Historical and Forecast Energy Demand (GWh)

Load Growth Scenario: LOW

Index Year (a)	Actual Year (b)	Residential (c)	Commercial (d)	Industrial (e)	Other* (f)	Sales For Resale (g)	Total Consumption (h)	System Losses (i)	Company Use (j)	Gross Energy	PECO DSM Energy Impact	Net Energy For Load (k)
-6	1991	9,947	5,136	15,967	1,028	723	32,801	2,585	36	35,422	0	35,423
-5	1992	9,522	5,222	15,559	960	730	31,993	2,439	36	34,468	0	34,468
-4	1993	10,264	5,623	15,714	770	765	33,136	3,024	36	36,196	0	35,729
-3	1994	10,412	5,954	15,622	789	784	33,561	2,606	36	36,203	0	36,207
-2	1995	10,660	6,222	15,869	859	784	34,394	2,408	36	36,838	0	36,838
-1	1996	10,550	6,315	14,826	857	753	33,301	2,311	35	35,647	0	35,647
0	1997	10,546	6,410	15,146	856	0	32,957	2,318	35	35,310	8	35,302
1	1998	10,625	6,506	15,106	853	0	33,090	2,325	35	35,450	30	35,420
2	1999	10,651	6,604	15,118	850	0	33,224	2,332	35	35,590	47	35,543
3	2000	10,678	6,703	15,096	848	0	33,325	2,339	35	35,698	64	35,634
4	2001	10,705	6,803	15,199	846	0	33,554	2,346	35	35,934	82	35,852
5	2002	10,731	6,905	15,180	844	0	33,661	2,353	35	36,048	91	35,957
6	2003	10,758	7,009	15,161	842	0	33,770	2,360	35	36,165	91	36,074
7	2004	10,785	7,114	15,141	840	0	33,880	2,367	35	36,282	87	36,195
8	2005	10,812	7,221	15,125	838	0	33,996	2,374	35	36,405	80	36,326
9	2006	10,839	7,329	15,109	836	0	34,113	2,382	35	36,529	73	36,456
10	2007	10,866	7,439	15,097	834	0	34,235	2,389	35	36,659	67	36,592
11	2008	10,893	7,551	15,085	831	0	34,360	2,396	35	36,791	64	36,727
12	2009	10,921	7,664	15,073	829	0	34,487	2,403	35	36,924	63	36,861
13	2010	10,948	7,779	15,064	827	0	34,618	2,410	35	37,063	60	37,003
14	2011	10,975	7,896	15,056	825	0	34,752	2,417	35	37,204	58	37,146
15	2012	11,003	8,014	15,049	823	0	34,889	2,425	35	37,348	51	37,297
16	2013	11,030	8,134	15,044	821	0	35,030	2,432	35	37,496	40	37,45[illegible]
17	2014	11,058	8,256	15,040	819	0	35,173	2,439	35	37,647	30	37,617
18	2015	11,085	8,380	15,039	817	0	35,322	2,447	35	37,803	21	37,782

* 'Other' sales include public street and highway lighting, other sales to public authorities, sales to railroads and railways and interdepartmental sales.

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Company Name: **PECO Energy**

IRP-ELEC 1A. Historical and Forecast Energy Demand (GWh)

Load Growth Scenario: HIGH

Index Year (a)	Actual Year (b)	Residential (c)	Commercial (d)	Industrial (e)	Other* (f)	Sales For Resale (g)	Total Consumption (h)	System Losses (i)	Company Use (j)	Gross Energy	PECO DSM Energy Impact	Net Energy For Load (k)
-6	1991	9,947	5,136	15,967	1,028	723	32,801	2,585	36	35,422	0	35,423
-5	1992	9,522	5,222	15,559	960	730	31,993	2,439	36	34,468	0	34,468
-4	1993	10,264	5,623	15,714	770	765	33,136	3,024	36	36,196	0	35,729
-3	1994	10,412	5,954	15,622	789	784	33,561	2,606	36	36,203	0	36,207
-2	1995	10,660	6,222	15,869	859	784	34,394	2,408	36	36,838	0	36,838
-1	1996	10,757	6,969	15,469	911	1,474	35,580	2,421	38	38,039	0	38,039
0	1997	10,855	6,787	15,361	950	0	33,953	2,467	38	36,458	8	36,450
1	1998	10,954	7,066	15,530	1,051	0	34,600	2,505	38	37,143	30	37,113
2	1999	11,053	7,355	15,701	1,102	0	35,211	2,537	38	37,786	47	37,739
3	2000	11,154	7,657	15,810	1,113	0	35,734	2,564	38	38,336	64	38,272
4	2001	11,255	7,971	15,921	1,124	0	36,272	2,600	38	38,910	82	38,828
5	2002	11,358	8,298	16,033	1,135	0	36,824	2,628	38	39,489	91	39,398
6	2003	11,461	8,638	16,145	1,147	0	37,391	2,655	38	40,084	91	39,993
7	2004	11,566	8,992	16,258	1,158	0	37,974	2,683	38	40,694	87	40,607
8	2005	11,671	9,361	16,372	1,170	0	38,573	2,711	38	41,322	80	41,242
9	2006	11,846	9,745	16,486	1,181	0	39,258	2,739	38	42,035	73	41,962
10	2007	12,024	10,144	16,602	1,193	0	39,963	2,768	38	42,768	67	42,701
11	2008	12,204	10,560	16,718	1,205	0	40,687	2,797	38	43,521	64	43,457
12	2009	12,387	10,993	16,835	1,217	0	41,432	2,826	38	44,295	63	44,232
13	2010	12,573	11,444	16,953	1,229	0	42,199	2,855	38	45,091	60	45,031
14	2011	12,761	11,913	17,071	1,242	0	42,987	2,885	38	45,910	58	45,852
15	2012	12,953	12,401	17,191	1,254	0	43,799	2,930	38	46,766	51	46,71[illegible]
16	2013	13,147	12,910	17,311	1,267	0	44,635	2,945	38	47,618	40	47,5[illegible]
17	2014	13,344	13,439	17,432	1,279	0	45,495	2,976	38	48,509	30	48,479
18	2015	13,544	13,990	17,554	1,292	0	46,381	3,007	38	49,426	21	49,405

* 'Other' sales include public street and highway lighting, other sales to public authorities, sales to railroads and railways and interdepartmental sales.

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Company Name: PECO Energy

IRP-ELEC 1B. Historical and Forecast Peak Load (MW)

Load Growth Scenario: BASE

Index Year (a)	Actual Year (b)	Residential (c)	Commercial (d)	Industrial (e)	Other[1] (f)	Sales For Resale (g)	Gross Peak Load Requirements	PECO DSM Peak Impact	Inter-ruptible Load[2]	Net Peak Load Requirements (h)	Annual Load Factor (i)
-6	1991	2,750	1,424	2,703	143	151	7,171	0	75	7,096	56.39%
-5	1992	2,329	1,313	2,689	141	145	6,617	0	0	6,617	59.46%
-4	1993	2,498	1,408	2,884	151	159	7,100	0	0	7,100	57.45%
-3	1994	2,568	1,646	2,701	158	155	7,227	0	0	7,227	57.19%
-2	1995	2,563	1,678	2,679	160	166	7,246	0	0	7,246	58.03%
-1	1996	2,266	1,508	2,590	145	0	6,509	0	204	6,305	62.61%
0	1997	2,466	1,598	2,854	156	0	7,074	2	204	6,868	58.01%
1	1998	2,513	1,666	2,847	157	0	7,183	6	204	6,973	58.01%
2	1999	2,540	1,689	2,891	157	0	7,277	10	204	7,063	58.01%
3	2000	2,562	1,708	2,928	157	0	7,354	15	204	7,135	58.02%
4	2001	2,586	1,732	2,984	157	0	7,458	21	204	7,233	58.04%
5	2002	2,604	1,749	3,026	157	0	7,536	24	204	7,308	58.05%
6	2003	2,615	1,767	3,076	157	0	7,615	24	204	7,387	58.05%
7	2004	2,628	1,785	3,124	157	0	7,694	24	204	7,466	58.05%
8	2005	2,652	1,832	3,135	156	0	7,775	24	204	7,547	58.06%
9	2006	2,662	1,902	3,136	156	0	7,856	23	204	7,629	58.06%
10	2007	2,669	1,921	3,192	156	0	7,938	23	204	7,711	58.07%
11	2008	2,678	1,941	3,247	156	0	8,021	23	204	7,794	58.07%
12	2009	2,681	1,961	3,307	155	0	8,104	22	204	7,878	58.06%
13	2010	2,688	1,980	3,365	155	0	8,189	21	204	7,964	58.06%
14	2011	2,693	2,083	3,343	156	0	8,274	20	204	8,050	58.05%
15	2012	2,699	2,104	3,402	155	0	8,360	18	204	8,138	58.34%
16	2013	2,706	2,125	3,462	154	0	8,447	15	204	8,228	58.04%
17	2014	2,717	2,147	3,517	154	0	8,535	12	204	8,319	58.03%
18	2015	2,745	2,169	3,553	156	0	8,623	8	204	8,411	58.02%

NOTE (1) - 'Other' sales include public street and highway lighting, other sales to public authorities, sales to railroads and railways and interdepartmental sales.

NOTE (2) - 1990-1994 figures are actual interruptions at the system peak.

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Company Name: PECO Energy

IRP-ELEC 1B. Historical and Forecast Peak Load (MW)

Load Growth Scenario: LOW

Index Year (a)	Actual Year (b)	Residential (c)	Commercial (d)	Industrial (e)	Other[1] (f)	Sales For Resale (g)	Gross Peak Load Requirements	PECO DSM Peak Impact	Inter-ruptible Load[2]	Net Peak Load Requirements (h)	Annual Load Factor (i)
-6	1991	2,750	1,424	2,703	143	151	7,171	0	75	7,096	56.39%
-5	1992	2,329	1,313	2,689	141	145	6,617	0	0	6,617	59.46%
-4	1993	2,498	1,408	2,884	151	159	7,100	0	0	7,100	57.45%
-3	1994	2,568	1,645	2,701	158	155	7,227	0	0	7,227	57.19%
-2	1995	2,563	1,678	2,679	160	166	7,246	0	0	7,246	58.03%
-1	1996	2,419	1,610	2,766	165	0	6,950	0	204	6,746	58.86%
0	1997	2,426	1,572	2,807	154	0	6,959	2	204	6,753	57.93%
1	1998	2,438	1,617	2,762	152	0	6,969	6	204	6,759	58.06%
2	1999	2,436	1,620	2,773	151	0	6,980	10	204	6,766	58.21%
3	2000	2,436	1,624	2,783	149	0	6,992	15	204	6,773	58.30%
4	2001	2,428	1,626	2,802	148	0	7,005	21	204	6,780	58.60%
5	2002	2,424	1,628	2,816	146	0	7,015	24	204	6,787	58.72%
6	2003	2,411	1,630	2,836	145	0	7,021	24	204	6,793	58.85%
7	2004	2,401	1,631	2,853	143	0	7,028	24	204	6,800	58.99%
8	2005	2,399	1,658	2,836	142	0	7,035	24	204	6,807	59.15%
9	2006	2,385	1,705	2,811	140	0	7,041	23	204	6,814	59.30%
10	2007	2,369	1,706	2,834	138	0	7,048	23	204	6,821	59.46%
11	2008	2,355	1,707	2,856	137	0	7,054	23	204	6,827	59.63%
12	2009	2,336	1,708	2,881	135	0	7,060	22	204	6,834	59.79%
13	2010	2,320	1,709	2,904	134	0	7,066	21	204	6,841	59.96%
14	2011	2,302	1,781	2,857	132	0	7,072	20	204	6,848	60.13%
15	2012	2,284	1,781	2,880	131	0	7,077	18	204	6,855	60.32%
16	2013	2,268	1,781	2,902	129	0	7,081	15	204	6,862	60.52%
17	2014	2,255	1,782	2,919	128	0	7,084	12	204	6,868	60.72%
18	2015	2,256	1,783	2,921	128	0	7,087	8	204	6,875	60.92%

NOTE (1) - 'Other' sales *include* public street and highway lighting, other sales to public authorities, sales to railroads and railways and interdepartmental sales.

NOTE (2) - 1990-1994 figures are actual interruptions at the system peak.

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Company Name: PECO Energy

IRP-ELEC 1B. Historical and Forecast Peak Load (MW)

Load Growth Scenario: HIGH

Index Year (a)	Actual Year (b)	Residential (c)	Commercial (d)	Industrial (e)	Other[1] (f)	Sales For Resale (g)	Gross Peak Load Requirements	PECO DSM Peak Impact	Inter-ruptible Load[2]	Net Peak Load Requirements (h)	Annual Load Factor (i)
-6	1991	2,750	1,424	2,703	143	151	7,171	0	75	7,096	56.39%
-5	1992	2,329	1,313	2,689	141	145	6,617	0	0	6,617	59.46%
-4	1993	2,498	1,408	2,884	151	159	7,100	0	0	7,100	57.45%
-3	1994	2,568	1,645	2,701	158	155	7,227	0	0	7,227	57.19%
-2	1995	2,563	1,678	2,679	160	166	7,246	0	0	7,246	58.03%
-1	1996	2,698	1,783	2,878	170	0	7,530	0	204	7,326	55.51%
0	1997	2,654	1,762	3,029	168	0	7,612	2	204	7,406	54.67%
1	1998	2,676	1,714	3,141	168	0	7,698	6	204	7,488	55.08%
2	1999	2,711	1,801	3,105	167	0	7,784	10	204	7,570	55.42%
3	2000	2,731	1,822	3,153	166	0	7,872	15	204	7,653	55.60%
4	2001	2,754	1,843	3,200	166	0	7,963	21	204	7,738	55.81%
5	2002	2,773	1,863	3,250	165	0	8,051	24	204	7,823	56.03%
6	2003	2,794	1,882	3,295	165	0	8,137	24	204	7,909	56.27%
7	2004	2,808	1,902	3,350	164	0	8,224	24	204	7,996	56.53%
8	2005	2,823	1,923	3,402	164	0	8,312	24	204	8,084	56.81%
9	2006	2,849	1,984	3,403	163	0	8,400	23	204	8,173	57.19%
10	2007	2,866	2,049	3,412	163	0	8,490	23	204	8,263	57.57%
11	2008	2,878	2,071	3,469	163	0	8,580	23	204	8,353	57.97%
12	2009	2,890	2,092	3,527	162	0	8,671	22	204	8,445	58.38%
13	2010	2,898	2,115	3,589	162	0	8,763	21	204	8,538	58.80%
14	2011	2,909	2,136	3,649	162	0	8,856	20	204	8,632	59.24%
15	2012	2,916	2,249	3,623	162	0	8,949	18	204	8,727	59.71%
16	2013	2,925	2,272	3,684	161	0	9,042	15	204	8,823	60.17%
17	2014	2,937	2,295	3,743	161	0	9,136	12	204	8,920	60.65%
18	2015	2,952	2,319	3,798	161	0	9,230	8	204	9,018	61.15%

NOTE (1) - *'Other' sales include public street and highway lighting, other sales to public authorities, sales to railroads and railways and interdepartmental sales.*

NOTE (2) - *1990-1994 figures are actual interruptions at the system peak.*

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Company Name: PECO Energy

IRP-ELEC 1C. Historical and Forecast Number of Customers (Year End)

Load Growth Scenario: BASE

Index Year (a)	Actual Year (b)	Residential (c)	Commercial (d)	Industrial (e)	Other (f)	Total Customers (j)
-6	1991	1,293,832	137,789	4,087	816	1,436,524
-5	1992	1,302,226	138,018	3,896	831	1,444,971
-4	1993	1,309,218	139,067	3,668	863	1,452,816
-3	1994	1,316,863	140,241	3,527	907	1,461,538
-2	1995	1,321,379	141,653	3,394	943	1,467,369
-1	1996	1,324,448	142,431	3,299	991	1,471,169
0	1997	1,338,000	143,700	3,199	1,011	1,485,910
1	1998	1,346,000	144,700	3,099	1,031	1,494,830
2	1999	1,354,000	145,700	2,999	1,051	1,503,750
3	2000	1,362,000	146,700	2,899	1,071	1,512,670
4	2001	1,369,000	147,700	2,899	1,071	1,520,670
5	2002	1,377,000	148,700	2,899	1,071	1,529,670
6	2003	1,385,000	149,700	2,899	1,071	1,538,670
7	2004	1,393,000	150,700	2,899	1,071	1,547,670
8	2005	1,401,000	151,700	2,899	1,071	1,556,670
9	2006	1,409,000	152,700	2,899	1,071	1,565,670
10	2007	1,417,000	153,700	2,899	1,071	1,574,670
11	2008	1,426,000	154,700	2,899	1,071	1,584,670
12	2009	1,434,000	155,700	2,899	1,071	1,593,670
13	2010	1,442,000	156,700	2,899	1,071	1,602,670
14	2011	1,449,000	157,700	2,899	1,071	1,610,670
15	2012	1,457,000	158,700	2,899	1,071	1,619,670
16	2013	1,466,000	159,700	2,899	1,071	1,629,670
17	2014	1,474,000	160,700	2,899	1,071	1,638,670
18	2015	1,482,000	161,700	2,899	1,071	1,647,670

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Company Name: **PECO Energy**

IRP-ELEC 1C. *Historical and Forecast Number of Customers (Year End)*

Load Growth Scenario: LOW

Index Year (a)	Actual Year (b)	Residential (c)	Commercial (d)	Industrial (e)	Other (f)	Total Customers (j)
-6	1991	1,293,832	137,789	4,087	816	1,436,524
-5	1992	1,302,226	138,018	3,896	831	1,444,971
-4	1993	1,309,218	139,067	3,668	863	1,452,816
-3	1994	1,316,863	140,241	3,527	907	1,461,538
-2	1995	1,321,379	141,653	3,394	943	1,467,369
-1	1996	1,324,448	141,400	3,299	986	1,470,133
0	1997	1,332,000	141,900	3,200	1,006	1,478,106
1	1998	1,337,000	142,400	3,100	1,026	1,483,526
2	1999	1,342,000	142,900	3,000	1,046	1,488,946
3	2000	1,347,000	143,400	2,900	1,066	1,494,366
4	2001	1,352,000	143,900	2,850	1,066	1,499,816
5	2002	1,357,000	144,400	2,800	1,066	1,505,266
6	2003	1,362,000	144,900	2,750	1,066	1,510,716
7	2004	1,367,000	145,400	2,700	1,066	1,516,166
8	2005	1,372,000	145,900	2,650	1,066	1,521,616
9	2006	1,377,000	146,400	2,600	1,066	1,527,066
10	2007	1,383,000	146,900	2,550	1,066	1,533,516
11	2008	1,389,000	147,400	2,500	1,066	1,539,966
12	2009	1,395,000	147,900	2,450	1,066	1,546,416
13	2010	1,401,000	148,400	2,400	1,066	1,552,866
14	2011	1,407,000	148,900	2,350	1,066	1,559,316
15	2012	1,413,000	149,400	2,300	1,066	1,565,766
16	2013	1,419,000	149,900	2,250	1,066	1,572,216
17	2014	1,425,000	150,400	2,200	1,066	1,578,666
18	2015	1,431,000	150,900	2,150	1,066	1,585,116

Company Name: **PECO Energy**

IRP-ELEC 1C. Historical and Forecast Number of Customers (Year End)

Load Growth Scenario: HIGH

Index Year (a)	Actual Year (b)	Residential (c)	Commercial (d)	Industrial (e)	Other (f)	Total Customers (j)
-6	1991	1,293,832	137,789	4,087	816	1,436,524
-5	1992	1,302,226	138,018	3,896	831	1,444,971
-4	1993	1,309,218	139,067	3,668	863	1,452,816
-3	1994	1,316,863	140,241	3,527	907	1,461,538
-2	1995	1,321,379	141,653	3,394	943	1,467,369
-1	1996	1,334,593	143,150	3,350	996	1,482,089
0	1997	1,347,939	144,650	3,300	1,016	1,496,905
1	1998	1,361,418	146,150	3,250	1,036	1,511,854
2	1999	1,375,032	147,650	3,210	1,056	1,526,948
3	2000	1,388,783	149,150	3,185	1,076	1,542,194
4	2001	1,402,670	150,650	3,185	1,076	1,557,581
5	2002	1,416,697	152,150	3,185	1,076	1,573,108
6	2003	1,430,864	153,650	3,185	1,076	1,588,775
7	2004	1,445,173	155,150	3,185	1,076	1,604,584
8	2005	1,459,624	156,650	3,185	1,076	1,620,535
9	2006	1,474,221	158,150	3,185	1,076	1,636,632
10	2007	1,488,963	159,650	3,185	1,076	1,652,874
11	2008	1,503,853	161,150	3,185	1,076	1,669,264
12	2009	1,518,891	162,650	3,185	1,076	1,685,802
13	2010	1,534,080	164,150	3,185	1,076	1,702,491
14	2011	1,549,421	165,650	3,185	1,076	1,719,332
15	2012	1,564,915	167,150	3,185	1,076	1,736,326
16	2013	1,580,564	168,650	3,185	1,076	1,753,475
17	2014	1,596,370	170,150	3,185	1,076	1,770,781
18	2015	1,612,333	171,650	3,185	1,076	1,788,244

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Company Name: *PECO Energy*

IRP-ELEC 2A. Estimated Summer Peak Resources, Loads and Reserves (MW)

		Resources							Peak Load				Reserve		
Index Year (a)	Actual Year (b)	Total Capability (c)	Inoperable Capability* (d)	Operable Capability (e)	*Non-Utility Generators (f)*	*Scheduled Imports (g)*	*Scheduled Exports (h)*	Net Resources (i)	Total Internal Peak Load (j)	Interruptible Load (k)	Load Management (l)	Net Internal Peak Load (m)	Reserve Margin (n)	Scheduled Maintenance (o)	Adjusted Margin (p)
-6	1991	8,814	48	8,766	0	0	677	8,089	6,810	285	0	6,525	1,564	0	1,564
-5	1992	8,814	48	8,766	0	0	370	8,398	6,955	281	0	6,674	1,722	0	1,722
-4	1993	8,884	48	8,836	0	0	400	8,436	6,970	225	0	6,745	1,691	0	1,691
-3	1994	8,877	0	8,877	0	0	400	8,477	6,970	344	0	6,626	1,851	0	[illegible]
-2	1995	8,954	0	8,954	0	0	400	8,554	7,246	325	0	6,921	1,633	0	[illegible]
-1	1996	9,128	1,509	7,619	0	0	205	7,414	6,509	120	0	6,389	1,025	0	[illegible]
0	1997	8,952	642	8,310	0	0	212	8,098	7,074	204	2	6,868	1,230	0	1,230
1	1998	8,882	480	8,402	0	0	179	8,223	7,183	204	6	6,973	1,250	0	1,250
2	1999	8,876	400	8,476	0	0	185	8,291	7,277	204	10	7,063	1,228	0	1,228
3	2000	8,870	308	8,562	0	0	191	8,371	7,354	204	16	7,135	1,236	0	1,236
4	2001	8,989	309	8,680	0	0	197	8,483	7,458	204	21	7,233	1,250	0	1,250
5	2002	8,983	213	8,770	0	0	203	8,567	7,536	204	24	7,308	1,259	0	1,259
6	2003	8,977	113	8,864	0	0	209	8,655	7,616	204	24	7,387	1,268	0	1,268
7	2004	8,971	12	8,959	0	0	215	8,744	7,694	204	24	7,466	1,278	0	1,278
8	2005	8,965	0	8,965	0	0	221	8,744	7,776	204	24	7,547	1,197	0	1,197
9	2006	9,224	69	9,155	0	0	(38)	9,193	7,856	204	23	7,629	1,564	0	1,564
10	2007	9,224	0	9,224	0	0	(38)	9,262	7,938	204	23	7,711	1,551	0	1,551
11	2008	9,224	0	9,224	0	0	(38)	9,262	8,021	204	23	7,794	1,468	0	1,468
12	2009	9,524	70	9,454	0	0	(38)	9,492	8,104	204	22	7,878	1,614	0	1,614
13	2010	9,524	0	9,524	0	0	(38)	9,562	8,189	204	21	7,964	1,598	0	1,598
14	2011	9,524	0	9,524	0	0	(38)	9,562	8,274	204	20	8,060	1,512	0	1,512
15	2012	9,824	58	9,766	0	0	(38)	9,804	8,360	204	18	8,138	1,666	0	1,666
16	2013	9,824	0	9,824	0	0	(38)	9,862	8,447	204	15	8,228	1,634	0	1,634
17	2014	9,824	0	9,824	0	0	(38)	9,862	8,536	204	12	8,319	1,643	0	1,643
18	2015	10,124	31	10,093	0	0	(38)	10,131	8,623	204	8	8,411	1,720	0	1,720

*NOTE: Inoperable Capability is the amount of Installed Capacity above the Summer Net Peak Load with the required Reserve Margin.

Company Name: PECO Energy

IRP-ELEC 2B. Estimated Winter Peak Resources, Loads and Reserves (MW)

		Resources							Peak Load				Reserve		
Index Year (a)	Actual Year (b)	Total Capability (c)	Inoperable Capability* (d)	Operable Capability (e)	Non-Utility Generators (f)	Scheduled Imports (g)	Scheduled Exports (h)	Net Resources (i)	Total Internal Peak Load (j)	Interruptible Load (k)	Load Management (l)	Net Internal Peak Load (m)	Reserve Margin (n)	Scheduled Maintenance (o)	Adjusted Margin (p)
-6	1991	9,212	66	9,146	0	0	785	8,361	5,540	280	0	5,260	3,101	530	2,571
-5	1992	9,212	66	9,146	0	0	350	8,796	5,678	287	0	5,391	3,405	0	3,405
-4	1993	9,317	66	9,251	0	0	400	8,851	5,880	231	0	5,649	3,202	0	3,202
-3	1994	9,186	0	9,186	0	0	400	8,786	5,735	350	0	5,385	3,401	279	3,122
-2	1995	9,222	0	9,222	0	0	400	8,822	5,736	350	0	5,386	3,436	280	3,156
-1	1996	9,426	2,119	7,307	0	0	205	7,102	5,803	104	0	5,648	1,454	0	1,454
0	1997	9,495	642	8,853	0	0	212	8,641	6,007	204	3	5,800	2,841	0	2,841
1	1998	9,545	480	9,065	0	0	179	8,886	6,100	204	11	5,885	3,001	0	3,0[illegible]
2	1999	9,595	400	9,195	0	0	185	9,010	6,179	204	18	5,957	3,053	0	3,0[illegible]
3	2000	9,595	308	9,287	0	0	191	9,096	6,265	204	24	6,037	3,059	0	3,059
4	2001	9,595	309	9,286	0	0	197	9,089	6,338	204	31	6,103	2,986	0	2,986
5	2002	9,595	213	9,382	0	0	203	9,179	6,399	204	34	6,161	3,018	0	3,018
6	2003	9,595	113	9,482	0	0	209	9,273	6,468	204	34	6,230	3,043	0	3,043
7	2004	9,595	12	9,583	0	0	215	9,368	6,534	204	32	6,298	3,070	0	3,070
8	2005	9,595	0	9,595	0	0	221	9,374	6,602	204	29	6,369	3,005	0	3,005
9	2006	9,595	69	9,526	0	0	(38)	9,564	6,671	204	25	6,442	3,122	0	3,122
10	2007	9,595	0	9,595	0	0	(38)	9,633	6,740	204	23	6,513	3,120	0	3,120
11	2008	9,595	0	9,595	0	0	(38)	9,633	6,811	204	21	6,586	3,047	0	3,047
12	2009	9,895	70	9,825	0	0	(38)	9,863	6,881	204	21	6,656	3,207	0	3,207
13	2010	9,895	0	9,895	0	0	(38)	9,933	6,953	204	20	6,729	3,204	0	3,204
14	2011	9,895	0	9,895	0	0	(38)	9,933	7,026	204	19	6,803	3,130	0	3,130
15	2012	10,195	58	10,137	0	0	(38)	10,175	7,099	204	17	6,878	3,297	0	3,297
16	2013	10,195	0	10,195	0	0	(38)	10,233	7,178	204	14	6,960	3,273	0	3,273
17	2014	10,195	0	10,195	0	0	(38)	10,233	7,247	204	11	7,032	3,201	0	3,201
18	2015	10,495	31	10,464	0	0	(38)	10,502	7,322	204	8	7,110	3,392	0	3,392

*NOTE: *Inoperable Capability is the amount of Installed Capacity* above the Summer Net Peak Load with the required Reserve Margin.

Company Name: PECO Energy

IRP-ELEC 3A. Existing Generating Capability (as of January 1, 1997)

Station and Unit No. (a)	Location (b)	Date Installed (c)	Unit Type (d)	Primary Fuel: Fuel Type (e)	Primary Fuel: Transp. Method (f)	Alternate Fuel: Fuel Type (g)	Alternate Fuel: Transp. Method (h)	Net Capability-MW: Summer (i)	Net Capability-MW: Winter (j)	Changes During Past Year: MW (k)	Changes During Past Year: Reason (l)	% Ownership Share (m)	Notes (n)
Chester 7	Chester, PA	2/7/69	GT	OIL	TK			13	18			100.00%	
Chester 8		5/20/69	GT	OIL	TK			13	18			100.00%	
Chester 9		3/6/69	GT	OIL	TK			13	18			100.00%	
Conemaugh 1	Indiana Co., PA	5/21/70	ST	COL	CV			176	176			20.72%	
Conemaugh 2		5/27/71	ST	COL	CV			176	176			20.72%	
Conemaugh D		2/1/70	IC	IC	TK			2.3	2.3			20.72%	
Conowingo 1	Conowingo, MD	3/1/28	HY	WAT				36	36			100.00%	
Conowingo 2		3/1/38	HY	WAT				36	36			100.00%	
Conowingo 3		3/6/28	HY	WAT				36	36			100.00%	
Conowingo 4		4/5/28	HY	WAT				36	36			100.00%	
Conowingo 5		6/1/28	HY	WAT				36	36			100.00%	
Conowingo 6		7/1/28	HY	WAT				36	36			100.00%	
Conowingo 7		6/1/28	HY	WAT				36	36			100.00%	
Conowingo 8		3/10/64	HY	WAT				65	65			100.00%	
Conowingo 9		3/25/64	HY	WAT				65	65			100.00%	
Conowingo 10		3/25/64	HY	WAT				65	65			100.00%	
Conowingo 11		5/4/64	HY	WAT				65	65			100.00%	
Cromby 1	Phoenixville, PA	7/23/54	ST	COL	RR			144	147			100.00%	
Comby 2		9/26/55	ST	NG/OIL	PL			201	211			100.00%	
Cromby D		6/6/67	IC	OIL	TK			2.7	2.7			100.00%	
Croydon 11	Croydon, PA	5/18/74	GT	OIL	WA			47	60			100.00%	
Croydon 12		6/18/74	GT	OIL	WA			47	60			100.00%	
Croydon 21		6/18/74	GT	OIL	WA			45	59			100.00%	
Croydon 22		6/18/74	GT	OIL	WA			47	60			100.00%	
Croydon 31		8/6/74	GT	OIL	WA			47	60			100.00%	
Croydon 32		8/8/74	GT	OIL	WA			45	59			100.00%	
Croydon 41		7/24/74	GT	OIL	WA			47	60			100.00%	
Croydon 42		7/24/74	GT	OIL	WA			45	59			100.00%	
Delaware 7	Philadelphia, PA	8/28/53	ST	OIL	WA			126	128			100.00%	
Delaware 8		4/1/53	ST	OIL	WA			124	128			100.00%	

Company Name: PECO Energy

IRP-ELEC 3A. Existing Generating Capability (as of January 1, 1997)

Station and Unit No. (a)	Location (b)	Date Installed (c)	Unit Type (d)	Primary Fuel: Fuel Type (e)	Primary Fuel: Transp. Method (f)	Alternate Fuel: Fuel Type (g)	Alternate Fuel: Transp. Method (h)	Net Capability-MW: Summer (i)	Net Capability-MW: Winter (j)	Changes During Past Year: MW (k)	Changes During Past Year: Reason (l)	% Ownership Share (m)	Notes (n)
Delaware 9		7/24/70	GT	OIL	TK			17	20			100.00%	
Delaware 10		5/7/69	GT	OIL	TK			15	18			100.00%	
Delaware 11		4/19/69	GT	OIL	TK			15	18			100.00%	
Delaware 12		5/2/69	GT	OIL	TK			15	18			100.00%	
Delaware D		6/6/67	IC	OIL	TK			2.7	2.7			100.00%	
Eddystone 1	Eddystone, PA	2/5/60	ST	COL	RR			279	288			100.00%	
Eddystone 2		10/7/60	ST	COL	RR			302	311			100.00%	
Eddystone 3		9/24/74	ST	NG/OIL	PL/WA			380	380			100.00%	
Eddystone 4		6/29/76	ST	NG/OIL	PL/WA			380	380			100.00%	
Eddystone 10		5/20/67	GT	OIL	TK			14	18			100.00%	
Eddystone 20		10/11/67	GT	OIL	TK			14	18			100.00%	
Eddystone 30		3/7/70	GT	OIL	TK			17	20			100.00%	
Eddystone 40		6/21/70	GT	OIL	TK			17	20			100.00%	
Falls 1	Falls Twp., PA	5/22/70	GT	OIL	TK			17	20			100.00%	
Falls 2		6/10/70	GT	OIL	TK			16	20			100.00%	
Falls 3		6/28/70	GT	OIL	TK			17	20			100.00%	
Keystone 1	Armstrong Co., PA	8/24/67	ST	COL	CV			178.5	178.5			20.99%	
Keystone 2		7/23/68	ST	COL	CV			178.5	178.5			20.99%	
Keystone D		11/23/68	IC	OIL	TK			2.3	2.3			20.99%	
Limerick 1	Limerick, PA	2/1/86	NB	UR	TK			1105	1123			100.00%	
Limerick 2		1/8/90	NB	UR	TK			1115	1133			100.00%	
Moser 1	Pottstown, PA	6/9/70	GT	OIL	TK			16	20			100.00%	
Moser 2		5/29/70	GT	OIL	TK			16	20			100.00%	
Moser 3		6/11/70	GT	OIL	TK			16	20			100.00%	
Muddy Run 1	Drumore Twp., PA	4/10/67	PS	WAT				110	110			100.00%	
Muddy Run 2		4/10/67	PS	WAT				110	110			100.00%	
Muddy Run3		6/1/67	PS	WAT				110	110			100.00%	
Muddy Run 4		6/1/67	PS	WAT				110	110			100.00%	
Muddy Run 5		10/11/67	PS	WAT				110	110			100.00%	
Muddy Run 6		10/11/67	PS	WAT				110	110			100.00%	

Company Name: ***PECO Energy***

IRP-ELEC 3A. Existing Generating Capability (as of January 1, 1997)

Station and Unit No. (a)	Location (b)	Date Installed (c)	Unit Type (d)	Primary Fuel: Fuel Type (e)	Primary Fuel: Transp. Method (f)	Alternate Fuel: Fuel Type (g)	Alternate Fuel: Transp. Method (h)	Net Capability-MW: Summer (i)	Net Capability-MW: Winter (j)	Changes During Past Year: MW (k)	Changes During Past Year: Reason (l)	% Ownership Share (m)	Notes (n)
Muddy Run 7		2/10/68	PS	WAT				110	110			100.00%	
Muddy Run 8		2/10/68	PS	WAT				110	110			100.00%	
Peach Bottom 2	Peach Bottom, PA	7/5/74	NB	UR	TK			464	476			42.49%	
Peach Bottom 3		12/23/74	NB	UR	TK			464	476			42.49%	
Richmond 91	Philadelphia, PA	6/7/73	GT	OIL	TK			48	66			100.00%	
Richmond 92		6/7/73	GT	OIL	TK			48	66			100.00%	
Salem 1	Salem, NJ	6/30/77	NP	UR	TK			471	477			42.59%	
Salem 2		10/13/81	NP	UR	TK			471	477			42.59%	
Salem 3		6/17/71	GT	OIL	TK			16	20			42.59%	
Schuylkill 1	Philadelphia, PA	7/25/58	ST	OIL	PL			166	175			100.00%	
Schuylkill 10		5/30/69	GT	OIL	TK			15	18			100.00%	
Schuylkill 11		6/11/71	GT	OIL	TK			17	20			100.00%	
Schuylkill D		7/6/67	IC	OIL	TK			2.8	2.8			100.00%	
Southwark 3	Philadelphia, PA	6/14/67	GT	OIL	TK			13	18			100.00%	
Southwark 4		10/9/67	GT	OIL	TK			14	18			100.00%	
Southwark 5		7/26/67	GT	OIL	TK			13	18			100.00%	
Southwark 6		11/7/68	GT	OIL	TK			14	18			100.00%	
Fairless Hills A	Fairless Hills, PA	1/1/97	ST	OIL				30	30			100.00%	(1)
Fairless Hills B		1/1/97	ST	OIL				30	30			100.00%	(1)
Pennsbury 1		1/1/97	GT	MTH				3	3			100.00%	(1)
Pennsbury 2		1/1/97	GT	MTH				3	3			100.00%	(1)
MERMCI 1	Plymouth, PA	1/1/97						28	28			100.00%	(1)

Notes:

'(1) On 1/1/97, PECO Energy claimed installed capacity credit for these units.

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Company Name: **PECO Energy**

IRP-ELEC 7A. Distribution of Net Generating Capability by Fuel Type (MW)

Summer

Index Year (a)	Actual Year (b)	Coal (c)	Oil/Gas Steam (d)	Nuclear (e)	Hydro (f)	Pumped Storage (g)	Oil CT/ICE (h)	Gas CT/ICE (i)	Total Capability (j)	Operable Capability (k)	Net Transactions (l)	Net Resources (m)
-6	1991	1,392	1,377	3,938	410	880	817		8,814	8,766	(677)	8,089
-5	1992	1,392	1,377	3,938	410	880	817		8,814	8,766	(370)	8,396
-4	1993	1,434	1,377	3,938	410	880	845		8,884	8,836	(400)	8,436
-3	1994	1,399	1,377	3,938	470	880	813		8,877	8,877	(400)	8,477
-2	1995	1,434	1,377	3,938	512	880	813		8,954	8,954	(400)	8,554
-1	1996	1,434	1,377	4,090	512	880	835		9,128	7,619	(205)	7,414
0	1997	1,434	1,377	4,098	512	880	834		9,135	8,310	(212)	8,098
1	1998	1,434	1,377	4,098	512	880	834		9,135	8,402	(179)	8,223
2	1999	1,434	1,377	4,098	512	880	834		9,135	8,476	(185)	8,291
3	2000	1,434	1,377	4,098	512	880	834		9,135	8,562	(191)	8,371
4	2001	1,434	1,377	4,098	512	880	834		9,135	8,680	(197)	8,483
5	2002	1,434	1,377	4,098	512	880	834		9,135	8,770	(203)	8,567
6	2003	1,434	1,377	4,098	512	880	834		9,135	8,864	(209)	8,655
7	2004	1,434	1,377	4,098	512	880	834		9,135	8,959	(215)	8,744
8	2005	1,434	1,377	4,098	512	880	834		9,135	9,056	(221)	8,835
9	2006	1,434	1,377	4,098	512	880	834		9,135	9,155	38	9,193
10	2007	1,434	1,377	4,098	512	880	834		9,135	9,235	38	9,273
11	2008	1,434	1,377	4,098	512	880	834		9,135	9,235	38	9,273
12	2009	1,434	1,677	4,098	512	880	834		9,435	9,454	38	9,492
13	2010	1,434	1,677	4,098	512	880	834		9,435	9,535	38	9,573
14	2011	1,434	1,677	4,098	512	880	834		9,435	9,535	38	9,573
15	2012	1,434	1,977	4,098	512	880	834		9,735	9,766	38	9,804
16	2013	1,434	1,977	4,098	512	880	834		9,735	9,835	38	9,873
17	2014	1,434	1,977	4,098	512	880	834		9,735	9,835	38	9,873
18	2015	1,434	2,277	4,098	512	880	834		10,035	10,093	38	10,131

Company Name: PECO Energy

IRP-ELEC 7A. Distribution of Net Generating Capability by Fuel Type (MW)

Winter

Index Year (a)	Actual Year (b)	Coal (c)	Oil/Gas Steam (d)	Nuclear (e)	Hydro (f)	Pumped Storage (g)	Oil CT/ICE (h)	Gas CT/ICE (i)	Total Capability (j)	Operable Capability (k)	Net Transactions (l)	Net Resources (m)
-6	1991	1,413	1,402	3,966	512	880	1,039		9,212	9,146	(785)	8,361
-5	1992	1,413	1,402	3,966	512	880	1,039		9,212	9,146	(350)	8,796
-4	1993	1,455	1,402	3,966	512	880	1,102		9,317	9,251	(400)	8,851
-3	1994	1,419	1,336	3,966	512	880	1,073		9,186	9,186	(400)	8,786
-2	1995	1,455	1,336	3,966	512	880	1,073		9,222	9,222	(400)	8,822
-1	1996	1,455	1,402	4,101	512	880	1,076		9,426	7,307	(205)	7,102
0	1997	1,455	1,402	4,170	512	880	1,076		9,495	8,670	(212)	8,458
1	1998	1,455	1,402	4,170	512	880	1,076		9,495	8,762	(179)	8,583
2	1999	1,455	1,402	4,170	512	880	1,076		9,495	8,836	(185)	8,651
3	2000	1,455	1,402	4,170	512	880	1,076		9,495	8,922	(191)	8,731
4	2001	1,455	1,402	4,170	512	880	1,076		9,495	9,040	(197)	8,843
5	2002	1,455	1,402	4,170	512	880	1,076		9,495	9,130	(203)	8,927
6	2003	1,455	1,402	4,170	512	880	1,076		9,495	9,224	(209)	9,015
7	2004	1,455	1,402	4,170	512	880	1,076		9,495	9,319	(215)	9,104
8	2005	1,455	1,402	4,170	512	880	1,076		9,495	9,416	(221)	9,195
9	2006	1,455	1,402	4,170	512	880	1,076		9,495	9,515	38	9,553
10	2007	1,455	1,402	4,170	512	880	1,076		9,495	9,595	38	9,633
11	2008	1,455	1,402	4,170	512	880	1,076		9,495	9,595	38	9,633
12	2009	1,455	1,702	4,170	512	880	1,076		9,795	9,814	38	9,852
13	2010	1,455	1,702	4,170	512	880	1,076		9,795	9,895	38	9,933
14	2011	1,455	1,702	4,170	512	880	1,076		9,795	9,895	38	9,933
15	2012	1,455	2,002	4,170	512	880	1,076		10,095	10,126	38	10,164
16	2013	1,455	2,002	4,170	512	880	1,076		10,095	10,195	38	10,233
17	2014	1,455	2,002	4,170	512	880	1,076		10,095	10,195	38	10,233
18	2015	1,455	2,302	4,170	512	880	1,076		10,395	10,453	38	10,491

Company Name: PECO Energy

IRP-ELEC 7B. Scheduled Imports and Exports (MW)

Summer

Participant Type Code	Name of Participant	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
P	BG&E	0	0	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)
P	DP&L (1)	(206)	(212)	(217)	(223)	(229)	(235)	(241)	(247)	(253)	(259)	0	0	0	0	0	0	0	0	0	0
C		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
G	GFCP	0	0	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160
G	MMLP	0	0	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
I		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
M		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Totals	(206)	(212)	(179)	(185)	(191)	(197)	(203)	(209)	(215)	(221)	38	38	38	38	38	38	38	38	38	38

Notes:
(1) DP&L is our only long term firm contract for operational capacity and energy for 1996.

Company Name: **PECO Energy**

IRP-ELEC 7B. Scheduled Imports and Exports (MW)

Winter

Participant Type Code	Name of Participant	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
P	BG&E	0	0	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)	(140)
P	DP&L	(205)	(212)	(217)	(223)	(229)	(235)	(241)	(247)	(253)	(259)	0	0	0	0	0	0	0	0	0	0
C		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
G	GFCP	0	0	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
G	MMLP	0	0	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
I		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
M		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Totals	(205)	(212)	(179)	(185)	(191)	(197)	(203)	(209)	(215)	(221)	38	38	38	38	38	38	38	38	38	38

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Company Name: PECO Energy

IRP-ELEC 8B. Scheduled Imports and Exports (GWH)

Participant Type Code	Name of Participant	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
PU	BG&E	0	0	(1,165)	(1,165)	(1,165)	(1,168)	(1,165)	(1,165)	(1,165)	(1,168)	(1,165)	(1,165)	(1,165)	(1,168)	(1,165)	(1,165)	(1,165)	(1,168)	(1,165)	(1,165)
PU	DP&L	(1,414)	(1,764)	(1,806)	(1,856)	(1,911)	(1,956)	(2,006)	(2,056)	(2,111)	(2,155)	0	0	0	0	0	0	0	0	0	0
C		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
G	GFLP	0	0	1,248	1,248	1,248	1,252	1,248	1,248	1,248	1,252	1,248	1,248	1,248	1,252	1,248	1,248	1,248	1,252	1,248	1,248
G	MMLP	0	0	233	233	233	234	233	233	233	234	233	233	233	234	233	233	233	234	233	233
I		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
M		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Totals	(1,414)	(1,764)	(1,490)	(1,640)	(1,595)	(1,638)	(1,690)	(1,740)	(1,795)	(1,837)	316	316	316	318	316	316	316	318	316	316

Pa PUC Revised Apr 97

Company Name: **PECO Energy**

IRP-ELEC 9. Summary of Demands, Resources and Energy for the Past Year

	Peak Day Summer 1996	Peak Day Winter 1996/7	Calendar Year 1996	Notes
01 Installed Generating Capacity (MW)	8736	8844		
02 Forced Outages (MW)	987	1281		
03 Planned/Maintenance Outages (MW)	227	697		
04 Units in Cold Reserve (MW)	0	0		
05 Miscellaneous Unavailable Capacity (MW)	207	269		
06 Total Capacity Not Available at Time of Peak (MW) (02+03+04+05)	1421	2147		
07 Firm Capacity Commitments from Others (MW)	460	208		
08 Firm Capacity Commitments to Others (MW)	852	763		
09 Reliable Capacity for Load (MW) (01-06+07-08)	6923	5940		
10 Peak Load in Season (MW)	6509	5798		
11 Operating Reserve at Time of Peak (MW) (09-10)	414	144		
12 Date and Hour of Peak	8/23/96 @1600	1/17/97 @1900		
13 Energy Produced by Company (Net MWH)			37,121,321	
14 Energy Received from Interconnection or Affiliated Company (MWH)			19,537,838	
15 Energy Delivered to Interconnection or Affiliated Company (MWH)			21,178,037	
16 System Losses and Company Use (MWH)			2,535,669	
17 Energy Delivered to Company Customers (MWH) (13+14-15-16)			32,945,461	

Pa.PUC Revised Apr-97

Company Name: PECO Energy

IRP-ELEC 10A. Conservation and Load Management Program Description

Program Name: Smart Choice
Customer Class: Residential
Status: Existing X Proposed ____________

Contact Person: Albert J. McDevitt Phone No: 215-841-6198

Program Objective:

To encourage builders to construct houses to high standards of energy efficiency and comfort, resulting in more manageable energy bills and improved comfort levels.

Details of Activity and Implementation Schedule:

Smart Choice is a program for new-home builders that emphasizes customer comfort and reduced energy bills. In addition to complying with the current Pennsylvania Act 222, the Building Energy Conservation Act, the builder must also adhere to stringent standards related to air infiltration, duct system design, efficiencies of heating and cooling equipment, and domestic water heaters. The Smart Choice program includes a comfort and energy bill guarantee for the customer.

Actual and/or Anticipated Results:

Year	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Savings: Electric (KWH)	Energy Savings: Gas (CCF)	Energy Savings: Oil (Gallons)	Energy Savings: Coal (Tons)	Other Results
1995	464.75		1216875	168750			
1996	358.56		912656	126562			

Monetary and Personnel Resources:

Estimated Workhours	Payroll	Advertising	Customer Grants	Other	Total
	Categorized Program Expenses ($)				
2080	$75,000	$395,000	$715,000		$1,185,000
1560	$56,000	$295,000	$645,000		$996,000

PA.PUC Revised Apr-97

Company Name: PECO Energy

IRP-ELEC 10A. Conservation and Load Management Program Description

Program Name: Low-Income Usage Reduction Program
Customer Class: Residential
Status: Existing X Proposed ______

Contact Person: Lana A. Watkins Phone No: 215-841-4581

Program Objective:

To implement fair, effective, and efficient usage-reduction strategies for low-income customers. The program is designed to reduce uncollectible accounts and associated collection and termination expenses by enabling low-income customers to reduce inefficient energy use.

Details of Activity and Implementation Schedule:

The program has three essential elements: financial assistance, referrals, installation of energy-reduction measures, and conservation education. During program intake, low-income customers are carefully interviewed to determine eligibility for financial assistance, including PECO's Customer Assistance Program. They receive a free, detailed home energy survey to determine what energy-saving measures might be installed. PUC regulations require the installation of any conservation measures which has a maximum simple payback of seven years.

Actual and/or Anticipated Results:

Year	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Savings: Electric (KWH)	Energy Savings: Gas (CCF)	Energy Savings: Oil (Gallons)	Energy Savings: Coal (Tons)	Other Results
1995	32		201,740	33,730			
1996	32		201,740	33,730			

Monetary and Personnel Resources:

Estimated Workhours	Payroll	Advertising	Customer Grants	Other	Total
23,650	$709,500			$2,390,500	$3,100,000
23,650	$709,500			$2,390,500	$3,100,000

PA PUC Revised Apr-97

Company Name: PECO Energy

IRP-ELEC 10A. Conservation and Load Management Program Description

Program Name: New Industrial and Commercial Construction
Customer Class: Industrial and Commercial
Status: Existing X Proposed ____________

Contact Person: Dennis Murphy Phone No: 215-841-4023

Program Objective:

To promote and incent new equipment purchases and construction practices that enable customers to become more efficient, productive, and competitive through the use of high efficiency equipment and energy efficient designs.

Details of Activity and Implementation Schedule:

Provide building owners and builders with information to incorporate energy efficient equipment and construction techniques. All new non-residential construction and major renovation projects will be targeted to promote the use of high efficiency heat pumps, high efficiency lighting and motors, and electric thermal storage systems. Customers will receive grants for feasibility studies, engineering and design.

Actual and/or Anticipated Results: No direct impacts.

Year	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Savings: Electric (KWH)	Energy Savings: Gas (CCF)	Energy Savings: Oil (Gallons)	Energy Savings: Coal (Tons)	Other Results
1995		1,500					
1996		3,000					

Monetary and Personnel Resources:

Estimated Workhours	Categorized Program Expenses ($): Payroll	Advertising	Customer Grants	Other	Total
2,000	$75,000	$30,000	$85,000	$140,000	$215,000
1,000	$40,000	$0	$350,000	$0	$40,000

PA PUC Revised Apr-93

Company Name: PECO Energy

IRP-ELEC 10A. Conservation and Load Management Program Description

Program Name: Commercial and Industrial Rate Incentives
Customer Class: Industrial and Commercial
Status: Existing X Proposed ____

Contact Person: Paul D. Corey Phone No: 215-841-5499

Program Objective:

To serve as consultants to our customers by providing information and advice on energy conservation and demand-side management.

Details of Activity and Implementation Schedule:

The following rate options have been designed to encourage commercial and industrial customers to manage their energy demands and usage consistent with system capabilities: Night Service Rider (Rates GS and HT); Curtailment Rider (Rate HT); Cooling Thermal Storage Rider (HT); and the Large Interruptible Load Rider (HT). Note: PECO has asked the Pa PUC to approve a "freeze" of the existing LILR and a new interruptible rider to take its place.

Actual and/or Anticipated Results:

Year	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Savings: Electric (KWH)	Energy Savings: Gas (CCF)	Energy Savings: Oil (Gallons)	Energy Savings: Coal (Tons)	Other Results
1995	334,000						
1996	189,000						

Monetary and Personnel Resources:

Estimated Workhours	Payroll	Advertising	Customer Grants	Other	Total
	Categorized Program Expenses ($)				
39,520	$988,000			$0	$988,000
37,440	$936,000			$0	$936,000

PA.PUC Revised Apr-97

Company Name: PECO Energy

IRP-ELEC 10A. Conservation and Load Management Program Description

Program Name: Gas Cooling
Customer Class: Commercial
Status: Existing X Proposed ______

Contact Person: Gary Stockbridge Phone No: 215-841-4972

Program Objective:

The program is designed to encourage the use of natural gas cooling equipment, increase the probability of incorporating this equipment in architectural and engineering designs, and to educate the customer on the benefits of gas cooling equipment.

Details of Activity and Implementation Schedule:

This program promotes the design and installation of gas cooling technologies, as well as the retrofit of existing electric units with gas cooling systems. The program focus will be on gas absorption, gas engine-driven, and gas-fired desiccant systems and their application in all market segments. Technology transfers, direct-mail and educational literature targeting customers, architects and engineers, as well as financial incentives, are planned.

Actual and/or Anticipated Results:

Year	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Savings Electric (KWH)	Energy Savings Gas (CCF)	Energy Savings Oil (Gallons)	Energy Savings Coal (Tons)	Other Results
1995	3,138		3,138,000	(378,500)			
1996	6,496		6,495,660	(780,216)			

Monetary and Personnel Resources:

Estimated Workhours	Payroll	Advertising	Customer Grants	Other	Total
	Categorized Program Expenses ($)				
2,080	$48,990			$350,000	$398,990
2,080	$55,000	$100,000	$250,000	$281,000	$686,000

Company Name: PECO Energy

IRP-ELEC 10A. Conservation and Load Management Program Description

Program Name: Energy Conservation Displays and Exhibits
Customer Class: Residential and Commercial
Status: Existing X Proposed

Contact Person: Skip Sindoni Phone No: 215-841-4160

Program Objective:

To present information on energy conservation to our customers through home shows, exhibits and conferences.

Details of Activity and Implementation Schedule:

PECO has numerous displays and exhibits on conservation and the efficient use of energy. In 1994 these included 44 curriculum workshops, 4,000 teachers contacted, 13 youth debates, 10 special mailings, 75 special events, 12 student and teacher grants.

Actual and/or Anticipated Results: No direct impacts.

Year	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Savings Electric (KWH)	Gas (CCF)	Oil (Gallons)	Coal (Tons)	Other Results
1995							
1996							

Monetary and Personnel Resources:

Estimated Workhours	Categorized Program Expenses ($) Payroll	Advertising	Customer Grants	Other	Total
1,000	$31,000			$200,000	$231,000
1,000	$32,000			$235,000	$267,000

PA.PUC Revised Apr-97

Company Name: PECO Energy

IRP-ELEC 10A. Conservation and Load Management Program Description

Program Name: Residential Conservation Impact Measurement and Analysis
Customer Class: Residential
Status: Existing X Proposed ______

Contact Person: *Hillary N. McAndrews* *Phone No:* 215-841-6470

Program Objective:

To analyze energy conservation impacts, as well as to identify opportunities for new conservation programs and opportunities for improvement of existing programs.

Details of Activity and Implementation Schedule:

PECO activities in this area involve supplementing existing data sources with market research and energy consumption *studies in an effort to determine factors which affect energy* conservation. Analysis of a survey of 4,500 residential customers was conducted to determine appliance ownership and demographic characteristics.

Actual and/or Anticipated Results: No direct impacts.

Year	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Savings: Electric (KWH)	Energy Savings: Gas (CCF)	Energy Savings: Oil (Gallons)	Energy Savings: Coal (Tons)	Other Results
1995							
1996							

Monetary and Personnel Resources:

Estimated Workhours	Categorized Program Expenses ($): Payroll	Advertising	Customer Grants	Other	Total
200	$6,000			$0	$6,000
200	$7,000			$0	$7,000

PA.PUC Revised Apr-97

Company Name: PECO Energy

IRP-ELEC 10A. Conservation and Load Management Program Description

Program Name: Energy Efficient Management
Customer Class: Industrial and Commercial
Status: Existing X Proposed ______

Contact Person: Dennis Murphy Phone No: 215-841-4023

Program Objective:

To promote the use of advanced high efficiency end-use technologies by our existing industrial *and commercial customers.*

Details of Activity and Implementation Schedule:

Program promotes the use of high efficiency heat pumps, high efficiency lighting and motors and *electric thermal storage systems.* This program offers assistance and grants for feasibility studies, engineering, design and installation of the high efficiency equipment.

Actual and/or Anticipated Results:

Year	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Savings: Electric (KWH)	Energy Savings: Gas (CCF)	Energy Savings: Oil (Gallons)	Energy Savings: Coal (Tons)	Other Results
1995		1,500					
1996		3,000					

Monetary and Personnel Resources:

Estimated Workhours	Categorized Program Expenses ($): Payroll	Advertising	*Customer* Grants	Other	Total
2,000	$75,000	$30,000	$50,000	$153,000	$228,000
2,000	$75,000	$18,000	$185,000	$222,000	$297,000

Company Name: PECO Energy

IRP-ELEC 10A. Conservation and Load Management Program Description

Program Name: Natural Gas Vehicles
Customer Class: *Commercial/Industrial*
Status: Existing X Proposed ____

Contact Person: Paul Dwyer Phone No: 215-841-8471

Program Objective:

To promote the use of natural gas vehicles (NGVs) to fleet operators and create a practical refueling infrastructure; to conserve gasoline and diesel fuel.

Details of Activity and Implementation Schedule:

1. Expand refueling infrastructure by installing fueling stations, providing portable refueling units, and assisting gasoline retailers in installing stations.
2. Conduct symposiums, training sessions, advertising, education, personal sales.
3. Expand PECO's NGV fleet.
4. Competitively price natural gas.
5. Develop financial incentive programs with the Department of Environmental Protection.
6. Work with state and local governments.

In 1995, 50 additional NGVs were added to the regional fleet and one natural gas refueling facility were built.

Actual and/or Anticipated Results:

Year	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Savings: Electric (KWH)	Energy Savings: Gas (CCF)	Energy Savings: Gasoline (Gallons)	Energy Savings: Coal (Tons)	Other Results
1995					250,000		
1996					125,000		

Monetary and Personnel Resources:

Estimated Workhours	Categorized Program Expenses ($): Payroll	Advertising	Customer Grants	Other	Total
4,000	$124,000			$200,000	$324,000
4,000	$135,000			$180,000	$315,000

Company Name: PECO Energy

IRP-ELEC 10A. Conservation and Load Management Program Description

Program Name: Customer Assistance Program (CAP)
Customer Class: *Residential*
Status: Existing X Proposed

Contact Person: Marcia Keaton Phone No: 215-841-4475

Program Objective:

To assist limited income customers who have a verified inability to pay.

Details of Activity and Implementation Schedule:

Any PECO Energy customer who provides financial information indicating an inability to pay, and has an income below *150% of the federal poverty level is referred to PECO Energy's* Customer Assistance Program and Low-Income Usage Reduction Program.

Actual and/or Anticipated Results:

Year	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Savings: Electric (KWH)	Energy Savings: Gas (CCF)	Energy Savings: Oil (Gallons)	Energy Savings: Coal (Tons)	Other Results
1995			9,350,754				
1996			3,350,754				

Monetary and Personnel Resources:

Estimated Workhours	Categorized Program Expenses ($): Payroll	Advertising	Customer Grants	Other	Total
65,000	$1,606,000			$394,000	$2,000,000
73,000	$1,804,000			$364,000	$2,168,000

Note: the Customer Assistance Program has been subcontracted for 1995

Company Name: PECO Energy

IRP-ELEC 10A. Conservation and Load Management Program Description

Program Name: Energy Conservation Literature
Customer Class: Residential
Status: Existing X Proposed ______

Contact Person: Mark Selverian Phone No: 610-941-1726

Program Objective:

To provide a series of "how-to" booklets on energy conservation tips, measures, and techniques to all PECO customers who call a toll-free hotline (1-800-521-5353). The program helps customers control their energy consumption and better manage their energy bills.

Details of Activity and Implementation Schedule:

Any customer who calls the toll-free hotline will be able to receive the literature kit. In addition, PECO distributes conservation literature at trade shows and similar events. Approximately 20,000 kits were distributed in 1994.

Actual and/or Anticipated Results: no direct impacts.

Year	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Savings: Electric (KWH)	Gas (CCF)	Oil (Gallons)	Coal (Tons)	Other Results
1995							
1996							

Monetary and Personnel Resources:

Estimated Workhours	Categorized Program Expenses ($): Payroll	Advertising	Customer Grants	Other	Total
150	$3,800			$25,000	$28,800
60	$1,600			$69,506	$71,106

PA.PUC Revised Apr-97

Company Name: **PECO Energy**

IRP-ELEC 108. Conservation and Load Management Program Summary

Customer Class	Program Name	Peak Load Reduction (KW)	Load Shifted to Off-Peak (KW)	Energy Use Change (KWH)	Allocated Workhours	Categorized Program Expenses ($) Payroll	Advertising	Customer Grants	Other	Total
Residential										
	Smart Choice	359		(912,856)	1,560	$56,000	$295,000	$645,000	$0	$996,000
	Low Income Usage Reduct. Prog.	32		(210,740)	23,860	$709,400			$2,390,600	$3,100,000
	Conservation Displays & Exhibits				1,000	$32,000			$235,000	$267,000
	Conservation Impact Analysis				200	$7,000			$0	$7,000
	Customer Assistance Program			(3,350,754)	73,000	$1,804,000			$364,000	$2,168,000
	Energy Conservation Literature				80	$1,600			$69,506	$71,106
	Conservation Information				48	$1,480			$20,000	$21,480
	Conservation Exhibits				800	$20,700			$80,000	$100,700
Commercial/ Industrial										
	New Construction		3,000		1,000	$40,000	$0	$350,000	$0	$390,000
	Rate Incentives	189,000			37,440	$936,000			$0	$936,000
	Gas Cooling	3,138		(3,138,000)	2,080	$48,990			$350,000	$398,990
	Energy Efficient Management		3,000		2,000	$75,000	$18,000	$185,000	$222,000	$500,000
	Natural Gas Vehicles				4,000	$136,000			$180,000	$316,000
Totals		192,529	6,000	(7,612,150)	146,838	$3,867,270	$313,000	$1,180,000	$3,911,006	$9,271,276

PA.PUC Revised Apr 97

Company Name: PECO Energy

IRP-ELEC 10C. Conservation and Load Management Program Cost Benefit Analysis Inputs

Program Name: Smart Choice
Customer Class: Residential
Year From: 1995
Year To: 1996

t	Year	No. of Part.	Annual Energy Savings (E) KWH	Cumulative Energy Savings (CE) KWH	Energy Shift (ES) KWH	Participant Demand Savings (D) KW	Utility Capacity Savings (G) KW	Participant Cost (PC) $	Incentive Costs (I) $	Utility Costs (UC) $	Discount Rates: Part. (d) %	Discount Rates: Non Part. (d) %	Discount Rates: Ratepayer (d) %	Discount Rates: Utility (d) %	Average Energy Cost (ACE) $/KWH	Average Demand Cost (ACD) $/KW	Avoided Energy Cost (MCE) $/KWH	Avoided Capacity Cost (MCD) $/KW	System Sales (S) MWH
1	1995	1,376	1,108,817	2,217,634		465	667	664	687,500	210,487	9.3%	9.3%	9.3%	9.3%	0.0679		0.0239	3.87	48,489,000
2	1996	1,376	912,666	3,130,290		389	437	664	687,500	210,487	9.3%	9.3%	9.3%	9.3%	0.0679		0.0277	3.99	50,206,000
3	1997																		
4	1998																		
5	1999																		
6	2000																		
7	2001																		
8	2002																		
9	2003																		
10	2004																		
11	2005																		
12	2006																		
13	2007																		
14	2008																		
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23	2017																		
24	2018																		
25	2019																		
26	2020																		
27	2021																		
28	2022																		
29	2023																		
30	2024																		

PA PUC Revised Apr-97

Company Name: PECO Energy

IRP-ELEC 10C. Conservation and Load Management Program Cost Benefit Analysis Inputs

Program Name: Low Income Usage Reduction Program
Customer Class: Residential
Year From: 1995
Year To: 1996

I	Year	No. of Part.	Annual Energy Savings (E) KWH	Cumulative Energy Savings (CE) KWH	Energy Shift (ES) KWH	Participant Demand Savings (D) KW	Utility Capacity Savings (G) KW	Participant Cost (PC) $	Incentive Costs (I) $	Utility Costs (UC) $	Discount Rates Part. (d) %	Discount Rates Non Part. (d) %	Discount Rates Ratepayer (d) %	Discount Rates Utility (d) %	Average Energy Cost (ACE) $/KWH	Average Demand Cost (ACD) $/KW	Avoided Energy Cost (MCE) $/KWH	Avoided Capacity Cost (MCD) $/KW	System Sales (S) MWH
1	1995	3,300	201,740	622,297		32	39	0	0	837,000	9.3%	9.3%	9.3%	9.3%	0.0679		0.0239	3.87	48,489,000
2	1996	3,300	201,740	724,037		32	39	0	0	837,000	9.3%	9.3%	9.3%	9.3%	0.0679		0.0227	3.99	50,205,000
3	1997																		
4	1998																		
5	1999																		
6	2000																		
7	2001																		
8	2002																		
9	2003																		
10	2004																		
11	2005																		
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29	2023																		
30	2024																		

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Company Name: PECO Energy

IRP-ELEC 10D. Conservation and Load Management Program Cost Benefit Analysis Results

Program Name: Smart Choice
Present Values Calculated for Year: 1995
Period of Analysis: Beginning Year: 1995
Ending Year: 2009

Participant Test

Utility Benefits (Bup) $	Utility Costs (Cup) $	Revenue Reduction Cost (Crp) $	Incentive Costs (Clp) $	Sales Ratio (I) $	Participant Revenue Requirement (Rp) $	Total Participant Benefits (Bp) $	Total Participant Costs (Cp) $	Net Present Value (NPVp) $	Benefit Cost Ratio (BCRp)	Discounted Payback Period (yrs)
						$1,244,116	$913,000	$331,116	1.36	6.08

Nonparticipant Test

Utility Benefits (Bunp) $	Utility Costs (Cunp) $	Revenue Reduction (Crnp) $	Incentive Costs (Clnp) $	Rate Impact Non-Part. (RIMnp) $/MWH	Net Present Value (NPVnp) $	Benefit Cost Ratio (BCRnp)
$486,209	$711,647	$742,956			($968,395)	0.33

All Ratepayers Test

Total Ratepayers Benefits (Bua) $	Total Ratepayers Costs (Ca) $	Net Present Value (NPVa) $	Benefit Cost Ratio (BCRa)
$486,209	$1,123,487	($637,279)	0.43

Utility Revenue Requirement Test

Increased Revenue (Ruu) $	Total Utility Benefits (Buu) $	Total Utility Costs (Cuu) $	Incentive Costs (Ciu) $	Net Present Value (NPVu) $	Benefit Cost Ratio (BCRu)
	$486,209	$711,647		($225,439)	0.68

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Company Name: PECO Energy

IRP-ELEC 10D. Conservation and Load Management Program Cost Benefit Analysis Results

Program Name: Low-Income Usage Reduction Program
Present Values Calculated for Year: 1995
Period of Analysis: Beginning Year: 1995
Ending Year: 2009

Participant Test

Utility Benefits (Bup) $	Utility Costs (Cup) $	Revenue Reduction Cost (Crp) $	Incentive Costs (Cip) $	Sales Ratio (I) $	Participant Revenue Requirement (Rp) $	Total Participant Benefits (Bp) $	Total Participant Costs (Cp) $	Net Present Value (NPVp) $	Benefit Cost Ratio (BCRp)	Discounted Payback Period (yrs)
						$195,714	$0	$195,714	n/a	n/a

Nonparticipant Test

Utility Benefits (Bunp) $	Utility Costs (Cunp) $	Revenue Reduction (Crnp) $	Incentive Costs (Cinp) $	Rate Impact Non-Part. (RIMnp) $/MWH	Net Present Value (NPVnp) $	Benefit Cost Ratio (BCRnp)
$101,435	$837,000	$195,714			($931,279)	0.1

All Ratepayers Test

Total Ratepayers Benefits (Bua) $	Total Ratepayers Costs (Ca) $	Net Present Value (NPVa) $	Benefit Cost Ratio (BCRa)
$101,435	$837,000	($735,565)	0.12

Utility Revenue Requirement Test

Increased Revenue (Ruu) $	Total Utility Benefits (Buu) $	Total Utility Costs (Cuu) $	Incentive Costs (Ciu) $	Net Present Value (NPVu) $	Benefit Cost Ratio (BCRu)
	$101,435	$837,000		($735,565)	0.12

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Company Name: PECO Energy

IRP-ELEC 10E. Assessment of Conservation and Load Management Potential

Index Year (a)	Actual Year (b)	Residential KW (c)	Residential KWH (d)	Commercial KW (e)	Commercial KWH (f)	Industrial KW (g)	Industrial KWH (h)	Other KW (i)	Other KWH (j)	Total KW (k)	Total KWH (l)	Utility Program Goals KW (m)	Utility Program Goals KW (n)
-6	1991	36,583	42,715,800	0	0	334,000				370,583	42,715,800		
-5	1992	35,917	47,027,600	740	1,440,000	334,000				370,657	48,467,600		
-4	1993	36,512	62,819,400	2,220	5,400,000	334,000				372,732	68,219,400		
-3	1994	37,106	74,511,200	3,700	8,460,000	334,000				374,806	82,971,200		
-2	1995	38,331	86,203,000	5,550	11,520,000	334,000				377,881	97,723,000		
-1	1996	40,186	98,714,800	7,770	14,760,000	334,000				381,956	113,474,800		
0	1997	40,150	103,846,600	8,880	16,380,000	334,000				383,030	120,226,600		
1	1998	38,225	101,598,400	8,880	16,380,000	334,000				381,105	117,978,400		
2	1999	36,299	96,070,200	8,880	15,660,000	334,000				379,179	111,730,200		
3	2000	34,374	88,082,000	8,880	14,400,000	334,000				377,254	102,482,000		
4	2001	31,819	80,093,800	8,510	13,140,000	334,000				374,329	93,233,800		
5	2002	29,893	72,925,600	8,510	12,060,000	334,000				372,403	84,985,600		
6	2003	27,968	68,217,400	8,510	11,520,000	334,000				370,478	79,737,400		
7	2004	25,412	65,149,200	8,140	11,340,000	334,000				367,552	76,489,200		
8	2005	22,857	60,441,000	7,770	10,800,000	334,000				364,627	71,241,000		
9	2006	20,302	56,552,800	7,400	10,440,000	334,000				361,702	66,992,800		
10	2007	17,116	48,564,600	6,660	9,180,000	334,000				357,776	57,744,600		
11	2008	13,301	37,296,400	5,550	7,200,000	334,000				352,851	44,496,400		
12	2009	9,485	26,848,200	4,440	5,400,000	334,000				347,925	32,248,200		
13	2010	5,040	17,220,000	2,960	3,780,000	334,000				342,000	21,000,000		

Note: Values shown are cumulative amounts.

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Company Name: PECO Energy

IRP-ELEC 12. Transmission Line Projection

Transmission Line Name (a)	Location (b)	Design Voltage (kV) (c)	Length (Miles) (d)	Construction Start Date (e)	In Service Date (f)	Line Cost (Millions) (g)
Middletown - Morton	Delaware County Middletown Township Upper Providence Township Nether Providence Township Springfield Township	230	4.2	1994	7/1/96	N/A
Newtown Square - Goshen Tap	Delaware County Chester County	69	7.2	1/96	6/97	N/A

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MAY 23 1997

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PETITION OF PECO ENERGY COMPANY FOR APPROVAL OF A RETAIL ACCESS PILOT PROGRAM	:	Docket No. P-00971170

COMMENTS OF PECO ENERGY COMPANY
TO THE COMMISSION'S MAY 8, 1997
PRELIMINARY OPINION AND ORDER

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Counsel

PECO Energy Company
Philadelphia, PA 19103
(215) 841-4256

DATED: May 22, 1997

DOCKETED
OCT 22 1997

B. Proposed Revisions Which PECO Opposes And Which Require Further Evidentiary Development

1. Market Price/ Stranded Cost Recovery (Order, pp. 17-23)

What PECO Proposed: PECO unbundled its retail rates by determining the revenue requirements, by rate class, of production (less fuel and variable operating maintenance expenses), transmission, distribution, customer-related functions, and forecast market generation. The sum of these cost functions was subtracted from the revenue requirement, by rate class, and the remainder became the proposed competitive transition charge (CTC).

The costs of transmission, distribution, and customer-related functions were derived from the then-most recent cost of service study (1990) and from PECO's Open Access Tariff. The market generation forecasts were derived from analysis and modeling of the PJM system by ICF Resources, Inc. ("ICF"), an independent consultant hired by PECO. The forecasts of the market value of energy and capacity were then adjusted for Gross Receipts Tax, class average line losses, and class average load factors.

What the Preliminary Order Said: The Commission received comments from several intervenors, who claimed that a higher market generation credit was needed to stimulate customer interest in participating in the Pilot Program. However, these commenters did not offer any alternative studies of the expected market prices for energy and capacity in 1997 and 1998. In response to these comments, the Preliminary Order sets the market rate for energy and capacity, including the Gross Receipts Tax, at 3.0¢/kWh for PECO -- indeed, for every

Competitive Wholesale Generation Price Projection in PJM: Update

Report

Prepared for:

PECO Energy

Prepared by:

ICF Resources Incorporated

May 19, 1997

TABLE OF CONTENTS

CHAPTER ONE
INTRODUCTION

BACKGROUND

ICF Resources was requested by PECO Energy Company (Hereafter "PECO") in May 1996 to provide an independent assessment and forecast of the competitive price of wholesale generation in the Penn-Jersey-Maryland (PJM) System to aid PECO in the calculation of a Competitive Transition Charge (CTC) that will be levied as part of a retail pilot program in Pennsylvania. The CTC is a charge (in cents/kWh) that those electing to participate in the retail pilot will pay even if they source their energy and capacity needs from other suppliers. The CTC represents the difference between PECO Energy's embedded cost of generation and the estimated competitive price of wholesale generation. This number will change from period to period. For the purpose of the retail pilot, ICF Resources was asked to forecast the competitive price of generation applicable to November and December 1997 and the calendar year 1998.

The purpose of this report is to present the results of the competitive price of wholesale generation projection in PJM and to describe the key assumptions and methodology underlying ICF Resources' assessment. This chapter provides the reader with background information related to ICF Resources' assessment.

ICF'S ROLE IN THE ANALYSIS AND THE FORMULATION OF ASSUMPTIONS

ICF Resources' competitive price of wholesale electric generation forecast is based on separate forecasts of the competitive price of wholesale electric energy and the competitive price of electric capacity.

The competitive price of capacity is dependent upon the supply and demand balance in PJM. ICF Resources' forecast of the competitive price of capacity is based upon (i) the projected capacity and load balance in PJM and (ii) market information available from recent capacity sales and purchases entered into by PJM utilities.

Competitive energy price projections were prepared using ICF Resources' Integrated Planning Model (IPM©) representation of the PJM system. ICF Resources' IPM© is an analytic tool that can be used to model the PJM system on a multi-area basis. The IPM© can be used both to represent behavioral factors, such as how utilities within a power pool respond to load growth, and to mimic the manner in which a single utility or power pool dispatches its capacity to meet load.

The IPM© has been used by many ICF clients to address a wide range of questions including, for example, to understand the reasons for long-term dispatch patterns within power pools, to estimate the dispatchability of specific units, to assess the impact of different variables on dispatch patterns and energy-related measures, such as the buyback tariffs for QFs in New York, the PJM billing rate, or the as-available energy rate in Florida, and to forecast marginal energy prices in nearly every US market.

The projections presented in this report, like all projections, are based upon a large number of assumptions. These assumptions have been obtained from various sources, but ICF can make no assurances as to their accuracy. Some of these represent technical assumptions, based upon a substantial body of empirical experience. For example, our assumptions dealing with the technical and operating characteristics of the existing PJM electric generating units, such as heat rates and minimum loads, are based upon analysis of their actual performance for historical years. Other assumptions, such as future oil prices, electricity load growth rates, and how the electric markets will respond to load growth, represent economic forecasts.

CHAPTER TWO
ICF Resources' Analytic Approach

This chapter provides an overview of the methodology used by ICF Resources to develop a competitive generation price projection.

THE PENN-JERSEY-MARYLAND (PJM) MARKET

ICF's forecast of marginal energy and capacity prices in PJM is predicated on the assumption that the operation of the restructured PJM marketplace will not differ significantly from operations under the current PJM Interconnection Agreement and, more importantly, that the fundamental determinants of marginal prices will remain unchanged. ICF believes this assumption to be valid given that:

1. under the PJM Interconnection Agreement all member utilities' resources are operated and dispatched as a tight pool (as if they were one system, to achieve the highest *practicable degree of reliability and economy*), and
2. there has long been an active competitive capacity market in PJM as member systems trade installed capacity credits to meet reserve margin requirements.

Marginal energy and capacity prices under a restructured PJM pool, operated by an Independent System Operator (ISO), should not differ from those experienced under the current pool structure.

In PJM, as in other centrally dispatched systems or "tight pools", incremental electricity demand by one member utility's customers is met by using the cheapest feasible source of power available to the entire system. In tight pools, a central entity called the "dispatcher," acting on behalf of the member systems, exercises control over the dispatch (i.e., determination of how much electric energy is to be generated by each unit on the system). Decisions made by the dispatcher are based on minimizing the total operating (or variable) cost of producing electric energy, subject, of course, to certain practical reliability and operating limitations.

In the case of PJM, this means, for example, that incremental demands posed by the customers of Public Service Electric and Gas in New Jersey might be met by increasing generation from the cheapest available coal unit on the system belonging to, for example, Pennsylvania Power and Light ("PP&L"). As a result, PJM utilities are either buying from or selling to other members of the system almost every instant. Over the long-term, the member utilities coordinate their capacity expansion plans.

The goal of the system dispatcher is then to minimize the variable cost of generating electricity. The factors that determine the cost of generating a kWh of electricity by a given generating unit are: the unit's heat rate or efficiency (expressed in BTU/kWh); the unit's delivered cost of fuel ($/MMBtu); and the variable component of the unit's operation and maintenance costs (in mills/kWh). The fuel component of the variable cost is the product of the heat rate and the fuel cost, and when added to the variable O&M cost gives the total variable cost. In a "pure economic dispatch" the dispatcher would simply "stack" the available units in order of increasing total variable cost (merit order), and meet incremental demand by dispatching the cheapest unit with excess available capacity. However, due to a number of engineering, reliability, and transmission constraints, actual dispatch patterns may show some deviation from the "pure economic dispatch."

At any given point in time, the dispatcher knows which unit is on the margin, i.e., which of the units operating at that point in time has the highest total variable cost. As load varies slightly up or down, the output of the marginal unit will also vary to follow the load.[1] If the additional load is greater than can be met by the unit on the margin, then the dispatcher "turns on" the next cheapest unit available to the system, and this unit will now become the marginal unit. Similarly, as load falls, the dispatcher will turn the most expensive units off.

As noted, certain practical reliability and operating limitations result in deviations in dispatch patterns from "pure economic dispatch." *In particular:*

- Must-Run Units: Certain units located close to large load centers 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 unit.

- Minimum Turndowns: 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.

- Transmission Constraints: Transmission capacity and other types of system stability constraints sometimes act to restrict the level of power that can be transmitted between broad regions (or areas) within PJM. Transmission constraints were developed for this study based on conversations with transmission engineers at a number of PJM utilities as well as an examination of actual power flows within PJM in previous years. As discussed below, an important aspect of developing transmission constraints is the division of PJM into regions.

When modeling the PJM system with IPM, the unit operating characteristics and cost components and the constraints discussed above are all represented. Constraints related to must-run units and minimum turndowns are based on available information from public and industry sources and reported performance data.

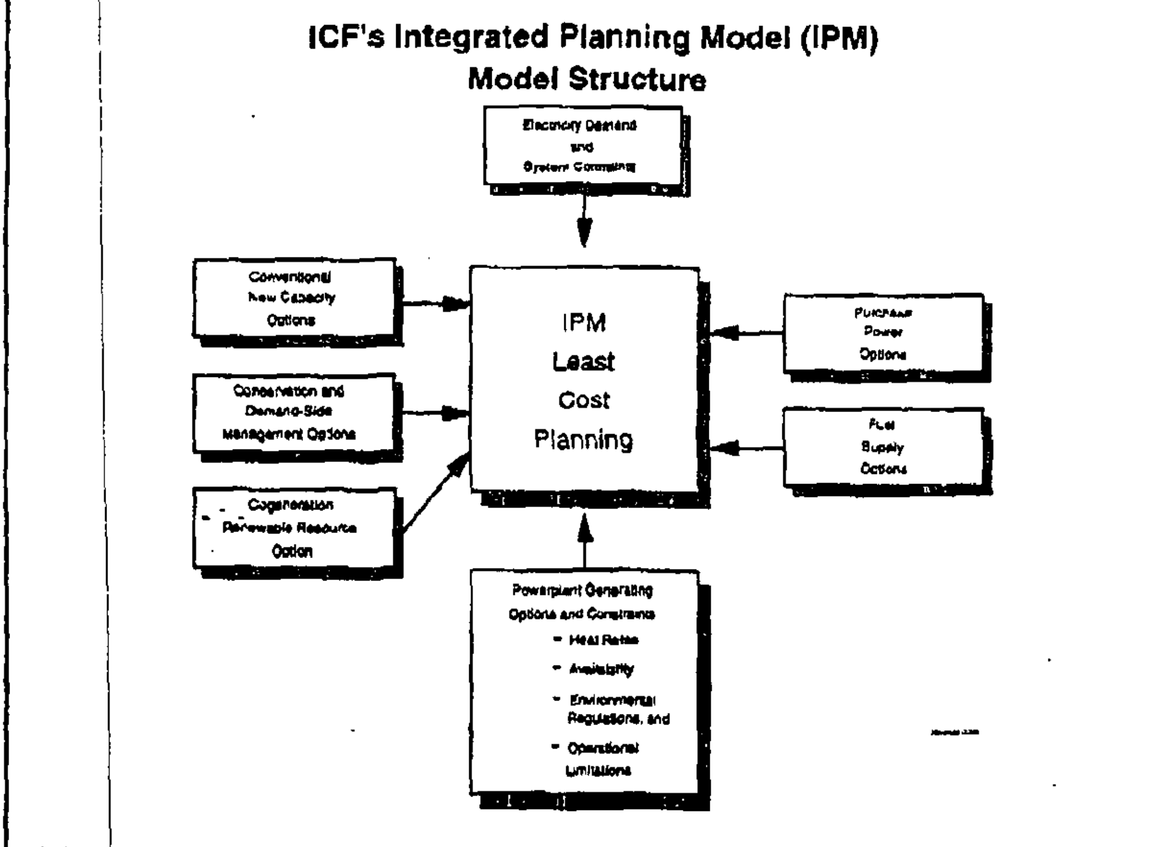
[1] In practice, a block of units (rather than a single unit) may be called on to increase their output

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 2-2). 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. 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.

Figure 2-2



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.

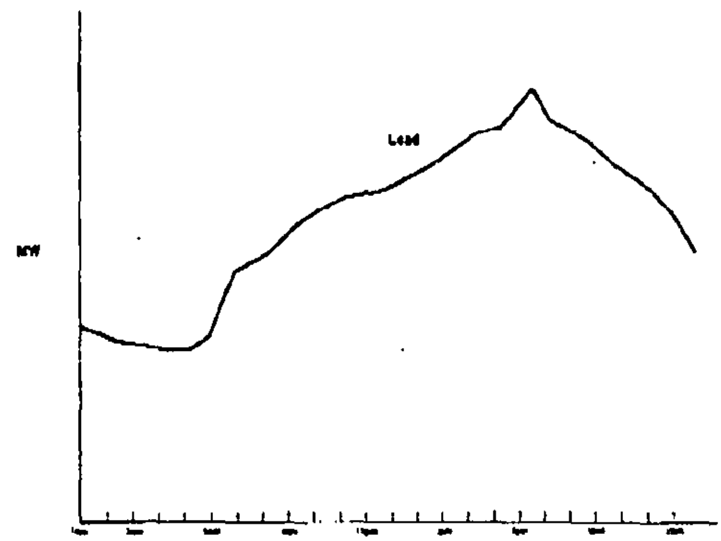
In the real-world, utility loads vary literally every instant. In our analytic approach, this complexity is represented by means of a Load Duration Curve made up of ten analytic segments. Furthermore, separate Load Duration Curves are developed for each of three seasons. This approach has many advantages:

- 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 2-3 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 2-4). 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.

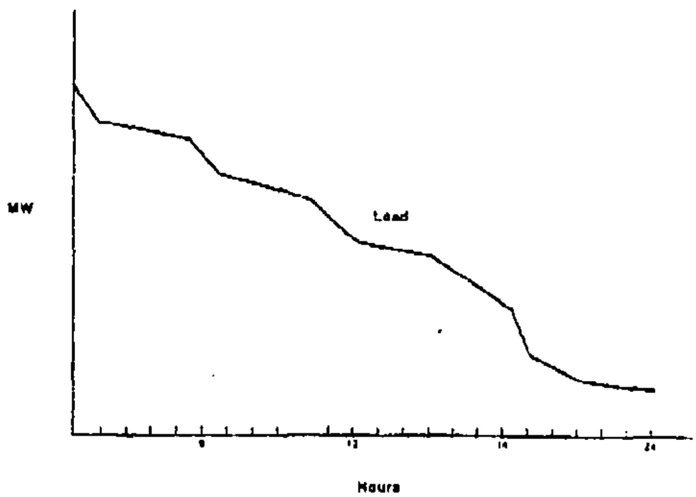
Figure 2-3
Typical Daily Load Shape



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 2-5 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 2-4
Typical Daily Load Duration Curve



In addition to operating constraints on PJM, such as the must-run constraints discussed above, 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.

MODELING THE PJM SYSTEM USING IPM

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.[2]

- 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:

<u>Generating Capacity</u>: 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.

<u>Transmission Constraints</u>: 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

[2] The PJM utilities also use the concept of regions or areas within PJM, to capture the impact of transmission constraints. PECO Energy, in particular, has used a three-area approach for formulating its least cost plan.

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.

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 2-3 shows the combination of months represented in each season.

TABLE 2-3
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%

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.

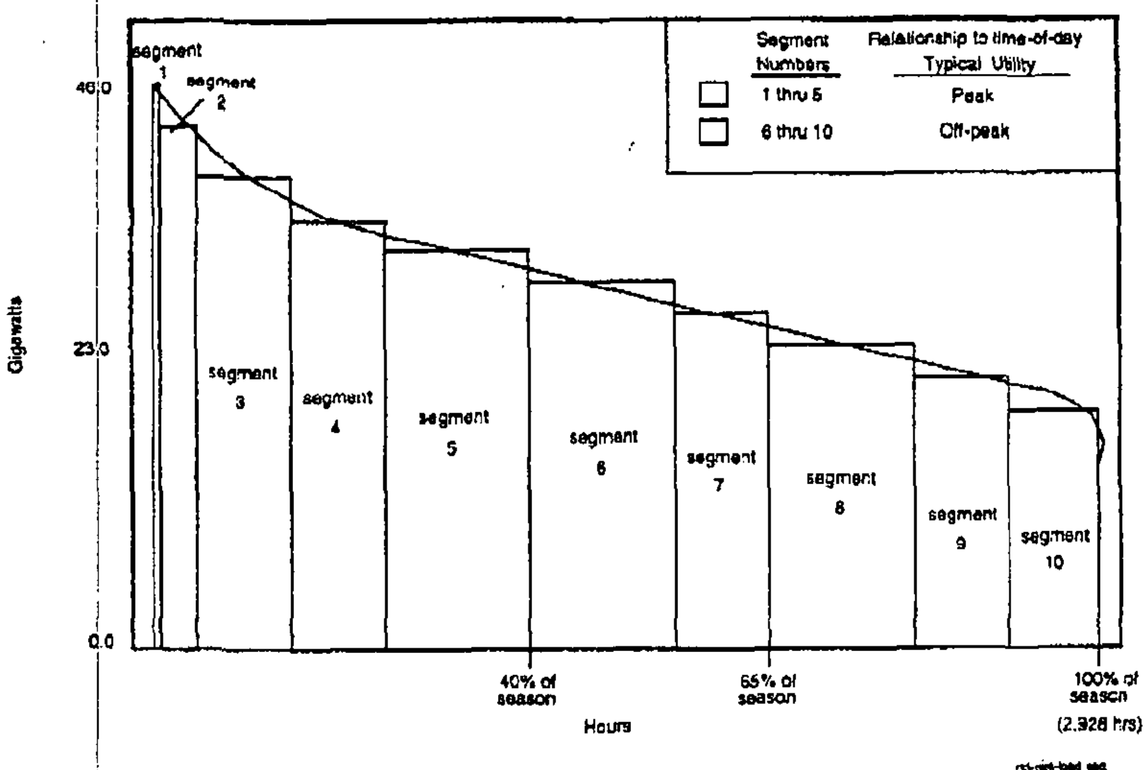
An example of the segmentation of the PJM poolwide load duration curve is shown in Figure 2-5. Several points about Figure 2-5 are worth noting:

- 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.

Figure 2-5
Illustration of Segmentation of the PJM Poolwide Load Duration Curve (Summer Season)



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.

ICF Resources analyzed the hourly observations contained in the seasonal load duration curves such as the one shown in Figure 2-5 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.

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.

The treatment of acid rain compliance for purposes of this study is further discussed in Chapter Three.

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.

CHAPTER THREE
Formulating Key Assumptions

INTRODUCTION

ICF Resources was requested by PECO Energy to provide an independent forecast of the competitive price of wholesale generation in the PJM system This chapter focuses on the key assumptions underlying the analysis. Five economic variables in particular are major determinants of marginal energy costs on the PJM system:

- Load Growth
- Capacity Additions
- Fuel Prices
- Acid Rain Compliance
- Nuclear Performance

Assumptions concerning these variables are summarized in Table 3-1 and are discussed more fully below.

LOAD GROWTH

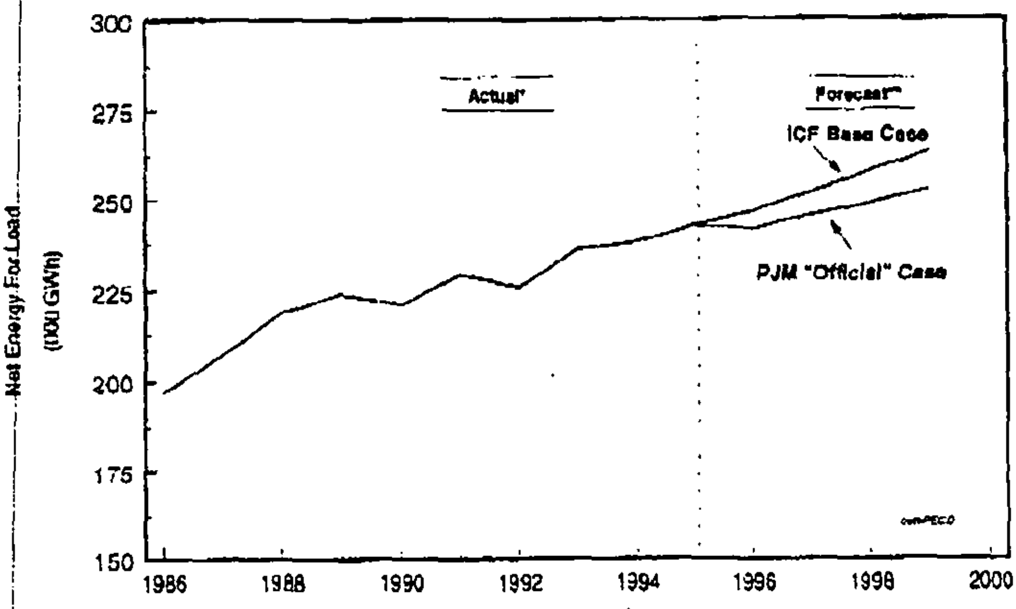
Load growth is an important determinant of marginal energy costs. As loads increase. PJM must turn to increasingly expensive units on the margin, thereby increasing the marginal energy cost on the pool. Between 1985 and 1995, PJM energy requirements and peak loads increased at about 2.75 percent per year. PJM utility forecasts during this period called for annual average growth rates of less than 1.5 percent. Current PJM forecasts also anticipate significantly lower than experienced load and generation growth at about 1.2 percent per annum through 2005.

ICF Resources believes that the PJM forecast is too conservative to be the basis of a realistic Base Case. The eventual introduction of retail competition may provide the impetus for greater load management efforts and reduced load growth. Hence, future growth rates may be lower than experienced in the recent past. Nonetheless, we believe that growth rates will be higher than currently projected by PJM utilities. Our Base Case assumption, therefore, is for load and generation growth of 2.3 percent per year through 1999. Projected peak load and energy requirements for the Base Case through 1999 as well as recent historical data are shown in Figures 3-1 and 3-2.

Table 3-1
Overview of Key Assumptions

Parameter	Value
Net Internal Demand	1997 Forecast 45,738 MW 1998 Forecast 46,372 MW
Net Energy for Load	1997 Forecast 246,608 GWh 1998 Forecast 250,390 GWh
Poolwide Planning Reserve Margin	18%
Response to Load Growth	Lower load growth does not necessitate additional capacity
Generating Unit Non-Fuel Variable O&M Costs	$1.0 to $2.0 / MWh
Seasonal Henry Hub Gas Prices ($/mmBtu)	Season Year / Summer / Winter / Shoulder 1997 / 1.77 / 2.09 / 1.89 1998 / 1.77 / 2.09 / 1.89
Seasonal Gas Transportation ($/mmBtu)	Season Year / Summer / Winter / Shoulder 1997 / 0.32 / 0.63 / 0.45 1998 / 0.32 / 0.63 / 0.45
Examples of Delivered Oil Prices ($/mmBtu)	1% Resid / Distillate 1997 3.09 / 4.06 1998 3.08 / 4.06
Examples of Delivered Coal Prices ($/mmBtu)	Cromby 1 1997 1.48 1998 1.45
Coal Plant Availability	Average coal unit availability of about 82.4%
Acid Rain Legislation	Units assumed to scrub are: Cromby 1, England 2, Eddystone 1-2, and Conemaugh 1-2.
Nuclear Performance	Annual Capacity Factor 1997 75.1% 1998 75.1%
Salem Nuclear	Unit 2 is assumed to be back on-line by 1997. Unit 1 is assumed to be off-line throughout the forecast horizon.
Power Purchases by individual utilities and the PJM Pool	Explicit consideration given to power purchase agreements that affect the energy market: PEPCO and OES/APS (450 MW), and Economy energy available from the ECAR region.
Schuylkill, Cromby 2, & Delaware Retirement	End of 1998

Figure 3-1
Projected Electric Energy Requirements for PJM on a Pool-Wide Basis



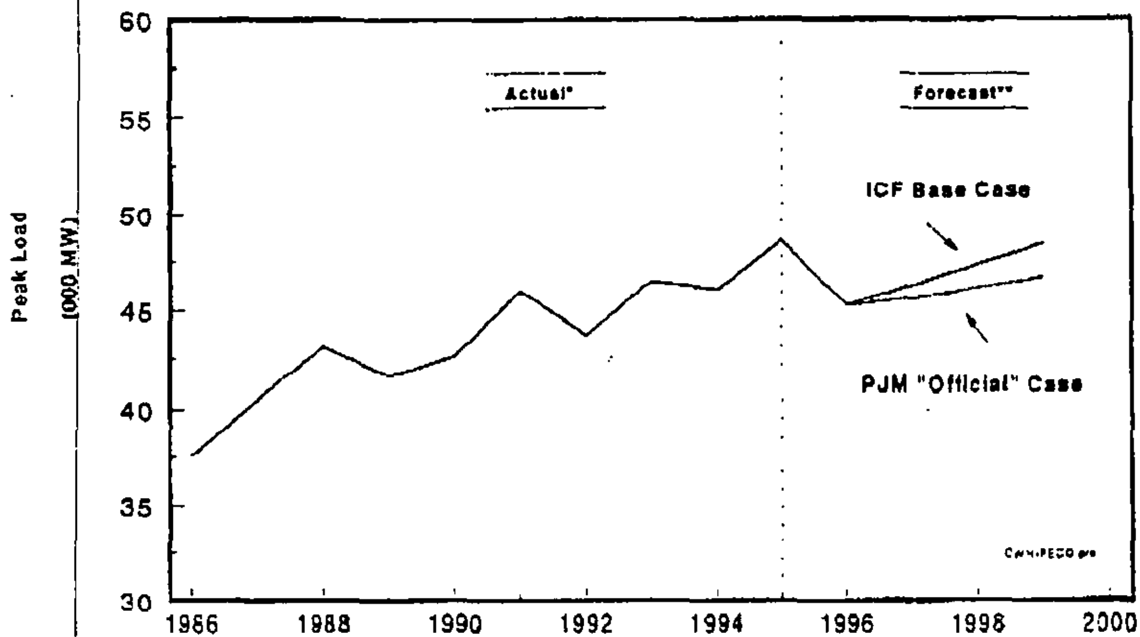
* Actuals are not weather-adjusted.
** All forecasts assume a "normal year" with respect to weather.

Responding to Load Growth: The Addition of New Capacity

Lower-than-expected electricity sales combined with the completion of previously planned coal and nuclear plants produced a situation of excess capacity nationwide in the electric utility industry in the early 1980s. In the PJM region, the completion of several nuclear power plants (e.g., PECO Energy's Limerick 1 and 2, Pennsylvania Power and Light's Susquehanna 2, and Public Service Electric and Gas' Hope Creek 1) had created excess capacity by the mid-1980s. In fact, the presence of this excess capacity helped utilities meet increasing loads in the late 1980s without serious problems.

The completion of plants that appeared in hindsight to be unnecessary, and at costs that substantially exceeded earlier projections, prompted regulators to deny the pass-through of portions of the capital invested. These actions have heightened utility concerns about the risks of undertaking large capital expenditures. Current publicly announced plans of electric utilities in PJM continue to reflect a reluctance to commit to large capital expenditures.

Figure 3-2
Projected Summer Peak Loads for PJM on a Pool-Wide Basis



* Actuals are not weather-adjusted.
** All forecasts assume a "normal year" with respect to weather.

Utility plans call for additional incremental capacity needs to be met with a combination of unit uprates and as yet unspecified purchases. This strategy minimizes the capital at risk and allows utilities to take a "wait-and-see" approach in the short-term. In general, there is an unwillingness to commit to bringing on-line substantial amounts of new baseload capacity. Through the mid-1980s, PJM utilities did, however, sign contracts for substantial amounts of QF capacity, as discussed below.

The capacity additions undertaken over the forecast period in this study can be categorized as follows:

<u>Must-Run QF Capacity:</u> Our short-term projection (through 1998) of must-run QF capacity is based on ongoing research that draws upon utility filings at state commissions, state-level surveys, QF filings at FERC, and trade press reports. We use an assumption that is very close to the 1995 PJM/MAAC forecast with the exception that we do not include several units which are still "on the books" but which have been recently bought-out or otherwise terminated.

<u>Dispatchable QF Capacity:</u> A number of PJM QFs are dispatchable. Because the contractual terms of all these QFs are not readily available, we have treated some as dispatchable QFs and others as must-run.

Firmly Scheduled Utility Capacity: This category refers to utility-owned baseload capacity which utilities are committed to build. For PJM, there are currently no large projects in the "firmly scheduled pipeline".

Currently Planned Utility Capacity: Utilities also have plans to bring on-line additional units in the future, although these plans are, as of now, flexible (i.e., they are not in the "firmly scheduled pipeline"). For example, JCPL has plans to add substantial amounts of gas turbine capacity in the late 1990s and beyond. We have included in our forecast only those utility planned builds that have gained regulatory approval. In addition, near term load growth under the ICF Base Case creates a need for additional capacity to meet pool-wide reserve margin requirements by 1998 . Due to the short lead time, this requirement is met with about 750 MW of combustion turbine capacity.

FUEL PRICES

Base Case fuel prices are based on ICF's *Bulk Power Service 1997 Fuel Markets Outlook*. Note that all prices shown are in 1996 dollars.

OIL PRICES

Delivered residual oil prices are based on ICF's forecast of commodity prices plus a transportation adder of $1.00/bbl. The underlying forecast price of crude oil is virtually static through the forecast period at $18.47/bbl in 1997 to $18.43/bbl in 1998 ($1996). Product prices were derived based on inter-grade differentials, developed by ICF.

GAS PRICES

The gas prices used in this analysis are based on ICF's long-term forecast. This forecast shows commodity gas prices increasing at 2.3% between the 1996 value of 1.77$/mmBtu and the 1997 value of 1.81 $/mmBtu. Seasonal variation at Henry is assumed to be about 8%. The delivered gas price forecast for PJM units is based on the addition of applicable seasonal interruptible transportation rates to forecasted commodity prices.

COAL PRICES

Coal price forecasts are based on ICF's commodity price forecast plus plant specific transportation adders. Coal prices are expected to decrease on a real basis from current levels due to continued improvements in coal mining productivity.

NUCLEAR PERFORMANCE

Nuclear capacity currently accounts for about 25 percent of utility capacity and, in 1995, about 37 percent of total generation in the PJM region. While its capital cost is high, the variable cost of nuclear power is low (about 10-15 mills/kWh) and this, combined with the high cost of shutting down and restarting a nuclear reactor, means that PJM's nuclear plants generally will be fully utilized when available. Because it is a low variable cost source, good nuclear performance acts to decrease the dispatchability of more expensive units.

Annual nuclear capacity factors tend to vary substantially from year to year. While part of this variability results from the scheduling of down-time for refueling and scheduled maintenance, which does not tend to follow an annual cycle, there is nonetheless an underlying element of unpredictability, even in the short term. A large part of this unpredictability results from the relatively long down-time required for unscheduled maintenance, either to prevent developing problems or to respond to Nuclear Regulatory Commission (NRC) requirements. While economic incentives may increasingly make it desirable for PJM to employ preventative maintenance to avoid forced outages, some degree of unpredictability will almost certainly remain.

PJM nuclear performance has been improving rapidly over the past several years. Between 1991 and 1994 nuclear capacity factors in PJM averaged 75.2 percent. Increased market competition should provide an impetus for increased utility efforts aimed at improving nuclear performance. ICF Resources' Base Case assumption is that the trend toward improved performance will continue such that near-term nuclear performance in PJM will be 75.0 percent during the forecast horizon. The PJM Official Forecast Case assumes nuclear performance of 75.1% in 1997 and 77.1% in 1998.

In early May, 1995, the 1,106-megawatt Salem Nuclear Unit 1, located in New Jersey, was removed from service due to maintenance problems at the unit. The second unit was also shut down in June due to maintenance problems. Based on current ICF Resources' research, we assume that Unit 2 will return to service in the third quarter of 1997, while, Unit 1 remains unavailable during the forecast horizon.

PURCHASES

PJM utilities have entered into a number of power sales agreements with other regions and utilities. These transactions, which are handled explicitly by IPM, effect poolwide marginal energy cost and therefore also effect the dispatchability of other sources of electric energy on the PJM pool. For this analysis, the following power purchase agreements with entities outside PJM have been explicitly included:

- A 450 MW purchase of energy and capacity by Potomac Electric from Ohio Edison, which continues throughout the study horizon.

- A 50 MW purchase of energy and capacity by Jersey Central Power & Light of Niagara Mohawk NUG capacity beginning in 1997 and ending in 2004.

- Economy electric energy from ECAR of up to 22,000 GWh/year at a variable cost of 18 mills/kWh (1996$) is assumed to be available to PJM utilities. This economy energy is dispatchable from a PJM perspective. Each PJM utility is assumed to get a pro-rata share of this economy energy that is purchased by the pool.

CHAPTER FOUR
DISCUSSION OF RESULTS

ICF Resources' competitive price of wholesale electric generation projections are based on separate projections of the competitive price of electric capacity and the competitive price of electric energy. This section presents and discusses the results of ICF's projections and the key factors underlying these results.

COMPETITIVE ENERGY PRICE PROJECTIONS

As discussed in Chapter Two, the PJM system operates as a tight pool. The PJM dispatch center dispatches, on a real-time basis, units to meet loads at the lowest variable cost, subject to various constraints such as minimum turndowns and *transmission constrains discussed in* Chapter Two. IPM determines the dispatch order for each season, segment, and year using the Load Duration Curve. By overlaying hourly load data onto this dispatch pattern, model calculates a marginal energy cost for each hour.

To more accurately represent the transmission situation and regional generation mixes within PJM, it was necessary to divide the PJM system into three regions. Because of these differences, the marginal energy cost forecast for each of the three regions will vary. To derive an estimate of poolwide marginal energy prices for the evaluation of PECO's Competitive Transition Charge, ICF calculated the generation weighted average of the three individual regions.

During the development of the IPM representation of the PJM system, the model was calibrated by backcasting to an actual historical year. Historical information, such as nuclear performance, hydroelectric generation levels, actual fuel prices at utility units as reported to the Federal Energy Regulatory Commission (FERC), purchased power from non-utility generators, peak load, and net generation were used as inputs for the calibration year of 1993. The model was calibrated to both energy outputs by unit type and marginal energy costs. The calibration *marginal energy price results for a single region -- the Eastern region of PJM -- are presented in* Table 4-1.

TABLE 4-1
1993 Historical and IPM Backcast East PJM Marginal Energy Cost (1993$/MWH)

Source	Peak[2]	Off-Peak	Annual Average
PJM Reported Lambda[1]	27.4	18.7	21.8
IPM Backcast	25.2	18.9	21.1

[1] FERC Form 714 for East PJM
[2] *Peak hours are 8 a.m. to 7.59 p.m., Monday through Friday.*

Table 4-2 provides ICF Resources' Base Case projections of the competitive poolwide energy price in PJM.

Table 4-2
Poolwide PJM Competitive Energy Price Projections (1996$/MWh)

	ICF Base Case		
	Peak[1]	Off-Peak	All Hours
1995[2]	26.6	18.2	21.2
1997[3]	26.1	20.6	22.6
1998	24.8	19.1	21.2

[1] Peak hours are 8 a.m. to 7.59 p.m., Monday through Friday.
[2] Based on actual PJM system lambda filings (adjusted to 1996 dollars)
[3] Average for November and December 1997.

As shown in the above table, poolwide marginal energy costs are projected to remain near 1995 levels in the near-term. Between 1995 and the beginning of the forecast period, the relatively modest increase in the price of natural gas and electricity demand in PJM are for the most part offset by declining real oil and coal prices. In addition, Salem 2 is assumed to return to service in late 1997, contributing a significant amount of low-variable cost energy. As a result of these factors, poolwide marginal energy costs do not increase above 1995 levels in the ICF Base Case. Note that the relatively higher prices shown for 1997 do not reflect average prices for the entire year, but for only two months, November and December, when gas transportation prices and marginal energy prices are expected to be slightly higher than annual average.

Competitive Capacity Price Projections

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. 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 annualized cost of a new 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 in part to the positive benefit additional capacity creates by lowering the probability of a supply shortage.

Currently, the PJM system is experiencing an excess capacity situation, which is reflected in capacity being priced well below the cost of a new turbino. Based on the analysis of recent market activity, the supply and demand balance within PJM, and communications with bulk power representatives of PECO Energy, ICF Resources' projects a competitive pure capacity value of $18.0 per kW per year for 1997 and $19.5 per kW per year for 1998. The projected increase in the competitive capacity value between 1997 and 1998 reflects the tightening supply and demand balance between these years. Because capacity has greatest value during peak hours it is appropriate to create a time-of-day value of capacity. The allocation of the annual price of capacity to peak hours is shown in Table 4-3.

Table 4-3
Competitive Capacity Price Projection
(1996 Dollars)

Year	Capacity Value	Capacity Factor	Time-of-Day Capacity Value
1997	$18.0 /kW-yr	35.71%	$5.57/MWh
1998	$19.5 /kW-yr	35.71%	$6.23/MWh

COMPETITIVE WHOLESALE GENERATION PRICE PROJECTION

As discussed in an earlier section, the competitive wholesale generation price is equal to the sum of the competitive price of wholesale energy and the competitive price of wholesale capacity. ICF Resources' projections of the competitive price of wholesale generation are presented in Table 4-4.

Table 4-4
Poolwide PJM Competitive Wholesale Generation Price Forecast (1996$/MWh)

	ICF Base Case		
	Peak[1]	Off-Peak	All Hours
1997[2]	31.7	20.6	24.6
1998	31.0	19.1	23.4

[1] Peak hours are 8 a.m. to 7.59 p.m., Monday through Friday.
[2] Average for November and December 1997.

VERIFICATION

I, Judah Rose, hereby declare that I am Vice President, ICF Resources, Inc.; that as such I am authorized to make this verification on its behalf; that the facts in the foregoing document are true to the best of my knowledge, information and belief, and that I make this verification subject to the penalties of 18 Pa. C.S. § 4904 pertaining to false statements to authorities.

Date: May 21, 1997

Judah Rose, Vice President