Electric Power Outlook For Pennsylvania 2002 – 2007

August 2003

Pennsylvania Public Utility Commission

Bureau of Conservation, Economics & Energy Planning

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EXECUTIVE SUMMARY

Each public utility which produces, generates, distributes, or furnishes electricity must annually submit to the Commission information concerning its future plans to meet its customers' demands. 66 Pa.C.S. § 524. The law requires the Commission to prepare a report summarizing and discussing the data provided on or before September 1. The Commission is required to submit the report to the General Assembly, the Governor, the Office of Consumer Advocate and each affected public utility. The Commission adopted regulations at Title 52 §§ 57.141 – 57.154, Annual Resource Planning Report, in order to comply with the requirements of the public utility law.

This report concludes that there is sufficient generation, transmission and distribution capacity to meet the needs of Pennsylvania consumers for the foreseeable future.

Both generation adequacy and the reserve margins of the Pennsylvania-New Jersey-Maryland Interconnection, Inc. (PJM) and the East Central Area Reliability Council (ECAR) have been maintained. While sufficient generation capacity is expected for the next five years, the Pennsylvania Public Utility Commission will continue its current policy of encouraging generation adequacy within PJM.

With respect to transmission adequacy, the transmission system in the Mid-Atlantic region has sufficient capacity to meet demand. However, the system is often congested during periods of high demand. Both the Mid-Atlantic Area Council (MAAC) and ECAR are planning transmission expansions and upgrades over the next five years to relieve congestion. Current initiatives at the federal level, such as the Federal Energy Regulatory Commission's Standard Market Design rulemaking, may also help improve the overall reliability and efficiencies of the transmission system.

While the data provided reflects distribution adequacy, the Commission acknowledges the report of the Legislative Budget and Finance Committee issued in June 2002. As agreed, the Commission is considering the recommendations set forth in the report and is taking the appropriate corrective measures. Amendments to the Commission's reliability regulations were issued on June 26, 2003, with a 60-day comment period.

To summarize the relevant statistics in this report, electricity demand in Pennsylvania has grown at a rate of 1.7% annually in the past five years. This is an aggregate figure for all sectors, including industrial, commercial and residential. The current projections for 2002-2007 show electricity demand growth at 1.0% annually. This includes a residential growth of 0.7%, a commercial growth of 1.7% and an industrial growth of 0.7%.

Regionally, generating resources are projected to be adequate for the next several years. In MAAC, the 2007 reserve margin is expected to be 17.1%, with a net internal demand of 59,537 MW and committed resources totaling 69,745 MW. ECAR's 2007 reserve margin is projected to be 17.8%, with a net internal demand of 106,451 MW and 125,434 MW of committed resources.

As this report concludes, our electric system is adequate to meet the demand of Pennsylvania's consumers for the foreseeable future. Pennsylvania needs to maintain its commitment to the basics of energy production and to encourage new initiatives in demand side response, renewable energy, and other new technologies so we can continue as a national leader in these areas.

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Section 1

Purpose

Electric Power Outlook for Pennsylvania 2002-2007 is a statistical report summarizing and discussing the current and future electric power supply and demand situation for the eight major investor-owned jurisdictional electric distribution companies (EDCs) operating within the Commonwealth and the entities responsible for maintaining the reliability of the bulk electric supply system within the region. Any comments or conclusions contained in this report do not necessarily reflect the views or opinions of the Commission or individual commissioners. Although this report has been issued by the Commission, it is not to be considered or construed as approval or acceptance by the Commission of any of the plans, assumptions or calculations made by the EDCs or regional reliability entities and reflected in the information submitted.

The Bureau of Conservation, Economics and Energy Planning prepares this report, pursuant to Title 66, Pennsylvania Consolidated Statutes, Section 524. This report is submitted annually to the General Assembly, the Governor, the Office of Consumer Advocate and each affected public utility. The report is also made available to the general public on the Commission's web site at http://puc.paonline.com/electric/electric_main.asp.

The information contained in this report includes a brief description of the existing generation, transmission and distribution system for each EDC, highlights of the past year, information on EDCs' projections of peak load and a discussion of historical trends in electric utility forecasting. Since the eight largest EDCs operating in Pennsylvania represent approximately 99% of jurisdictional electricity sales, the smaller companies have not been included in this report.

The report also provides a regional perspective with statistical information on the projected resources and aggregate peak loads for the regional reliability councils.

Informational sources include data submitted by jurisdictional investor-owned EDCs, which is filed annually pursuant to the Commission's regulations in Title 52 of the Pennsylvania Code, Sections 57.141-57.154. Sources also include data submitted by regional reliability councils to the North American Electric Reliability Council (NERC) which is subsequently forwarded to the federal Energy Information Agency (EIA).

Regional Reliability Councils & Regional Transmission Organization

In Pennsylvania, all major electric utilities are interconnected with neighboring systems extending beyond state boundaries. These systems are organized into regional entities – regional reliability councils – which are responsible for ensuring the reliability of the electric system. The regional reliability councils in Pennsylvania are the Mid-Atlantic Area Council (MAAC) and the East Central Area Reliability Council (ECAR).

MAAC and ECAR are members of the North American Electric Reliability Council (NERC), a national organization which oversees 10 regional reliability organizations. NERC establishes criteria, standards and requirements for its members and all control areas. All control areas must operate in a manner such that system instability, uncontrolled system separation and cascading outages will not occur as a result of the most severe single contingency.

For the past 35 years, MAAC and ECAR have been instrumental in maintaining a high level of electric service reliability. Through the establishment of reliability standards and operational protocols (under NERC's guidance), these councils require their member companies to provide sufficient generating capacity and transmission facilities to ensure adequate system resources for efficient operation. MAAC and ECAR also are responsible for coordinating the planning of new generation and transmission facilities.

MAAC and ECAR set forth the criteria which individual utilities and systems must follow in planning adequate levels of generating capability. Among the factors which are considered in establishing these levels are load characteristics, load forecast error, scheduled maintenance requirements and the forced outage rates of generating units.

The MAAC reliability standards require that sufficient generating capacity be installed to ensure that the probability of system load exceeding available capacity is no greater than one day in ten years. Load serving entities that are members of MAAC have a capacity obligation determined by evaluating individual system load characteristics, unit size and operating characteristics.

MAAC member companies include Metropolitan Edison Company, Pennsylvania Electric Company, PPL Electric Utilities Corporation, PECO Energy Company and UGI Utilities, Inc.

ECAR's standard for evaluating the reliability of the generation component of the bulk power supply involves the computation of the number of days per year that the ECAR Region is expected to rely on (a) generating resources outside of ECAR and (b) reducing area load to the extent that such resources are not available. This measure of performance, the Dependence on Supplemental Capacity Resources (DSCR), is used to identify critical bulk power supply situations for appropriate response by the member companies.

ECAR members include Duquesne Light Company, Pennsylvania Power Company and West Penn Power Company.

The PJM Interconnection, L.L.C. (PJM) is a formal power pool, independent system operator and Regional Transmission Organization (RTO) in the Northeast Region of NERC and consists of the members of MAAC. PJM is the largest centrally dispatched system in North America and the third largest in the world. PJM coordinates the operation of 540 electric generating units and operates a regional bid-based energy market. PJM also monitors, evaluates and coordinates the operation of over 8,000 miles of transmission lines.

On April 1, 2002, PJM West became operational, broadening the regional scope of the electric grid operator for the Mid-Atlantic region, to include Allegheny Power (and West Penn Power Company) and marking the first time, nationally, that two separate control areas are operated under a single energy market and a single governance structure. The PJM West offices located at Greensburg, Pennsylvania, will provide transmission and generation coordination for the PJM West area. Allegheny expects its customers to benefit from enhanced reliability and expanded wholesale markets.

Although Allegheny is now in PJM West, it continues to be a member of ECAR.

Duquesne Light Company anticipates joining the PJM West RTO in the near future. Duquesne's inclusion in this RTO will put the region's transmission facilities under common control to enhance reliability to customers.

Some companies in the Midwest ISO have petitioned FERC to join the PJM RTO. These include American Electric Power, Commonwealth Edison, Dayton Power & Light and Illinois Power. Recently, FERC conditionally approved their requests, thereby ensuring just and reasonable transmission rates across the region and protecting reliability.

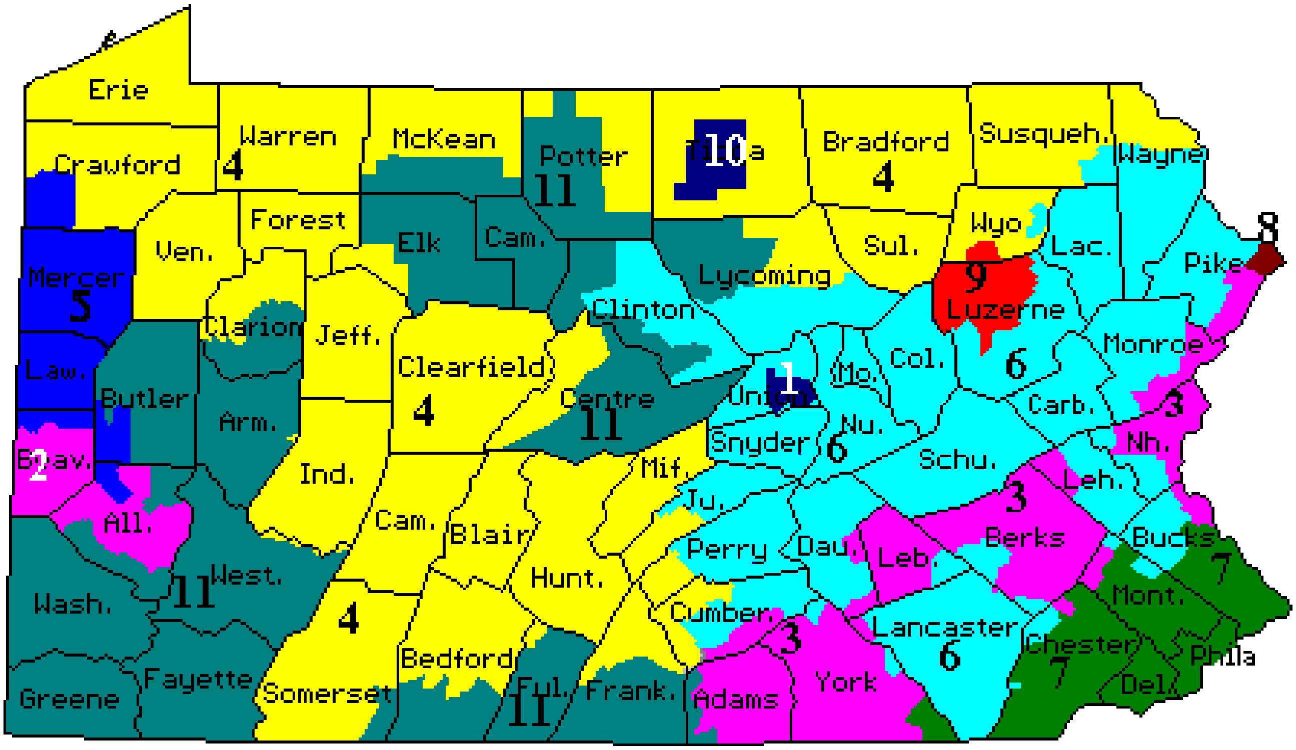
MAAC's capacity mix is 20.6% nuclear and 24.1% coal, whereas ECAR's mix is 6.3% nuclear and 68.3% coal. Natural gas is expected to be a major fuel source for new generating capacity additions, increasing to 12.8% of the total for MAAC and 38.0% for ECAR by 2007.

Regionally, generating resources are projected to be adequate for the next several years. In MAAC, the 2007 reserve margin is expected to be 17.1%, with a net internal demand of 59,537 MW and committed resources totaling 69,745 MW. ECAR's 2007 reserve margin is projected to be 17.8%, with a net internal demand of 106,451 MW and 125,434 MW of committed resources.

Electric Distribution Companies

Eleven electric distribution companies (EDCs) currently serve the electrical energy needs of the majority of Pennsylvania's homes, businesses and industries. Cooperatives and municipal systems provide service to several rural and urban areas. The eleven jurisdictional EDCs (nine systems) are:

1. **Citizens' Electric Company**
2. **Duquesne Light Company**
3. **Metropolitan Edison Company (FirstEnergy)**
4. **Pennsylvania Electric Company (FirstEnergy)**
5. **Pennsylvania Power Company (FirstEnergy)**
6. **PPL Electric Utilities Corporation**
7. **PECO Energy Company**
8. **Pike County Light & Power Company (Orange & Rockland Utilities, Inc.)**
9. **UGI Utilities, Inc.**
10. **Wellsboro Electric Company**
11. **West Penn Power Company (Allegheny Energy, Inc.)**



Due to the deregulation of electric generation, local generating resources are now available to the competitive wholesale market. The EDCs have either entered into long-term contracts for power from traditional resources with affiliates or other generation suppliers or expect to purchase power from the wholesale market to fulfill their “provider-of-last-resort” obligations.

It is the responsibility of each load-serving entity to make provisions for adequate generating resources to serve its customers. Furthermore, section 2807(e)(3) of the Public Utility Code requires that, at the end of the transition period (the period in which the EDC recovers its stranded costs), the local EDC or Commission-approved alternate supplier must acquire electric energy at prevailing market prices for customers who contract for power which is not delivered, or for customers who do not choose an alternate supplier. EDCs must also assume the role of provider-of-last-resort for customers choosing to return to the EDC.

The Commission is in the process of developing regulations to address the EDCs’ responsibilities concerning provider-of-last-resort service after the end of the transition period.

Demand Side Response Initiative

Through a collaborative process, the Commission, utility representatives and other interested parties are currently addressing ways to encourage customers to respond to peak period wholesale prices by reducing their demand for electricity. The working group is addressing existing and proposed demand side response programs, consumer education programs and appropriate methods to measure program results.

The Commission hosted a roundtable to discuss the issues related to decreasing electricity demand during peak periods. Many experts have called for developing such a demand-side response to benefit the performance of wholesale and retail electricity markets, electric reliability, and the environment.

The challenge that underlies this effort is extreme price volatility in the wholesale market during periods of peak consumption. When wholesale prices escalate during peak periods, there is a significant, lingering impact on retail prices. These price spikes and their aftermath dampen competition in retail markets because it becomes difficult for suppliers to obtain power at competitive prices.

Demand side response will increase the efficiency of the market. In other words, the price volatility in wholesale power markets has been greatly amplified by the lack of price-responsive retail demand.

Currently, most retail customers do not have a strong incentive to use less electricity during peak periods, even though wholesale prices are climbing. The reason for this is that the retail customer pays an average rate. A retail customer pays the same price for a kilowatthour of electricity on a high-demand day in the summer as the customer does on a low-demand day in the fall. During days when wholesale prices rise, inelastic retail demand exacerbates wholesale price increases.

PJM DSR Initiatives

In 2002, PJM received final approval from the FERC for an Emergency Load Response Program and for an Economic Load Response Program.

The Emergency Load Response Program is designed to provide a method by which end-use customers may be compensated by PJM for voluntarily reducing load during an emergency event. This program became effective on June 1, 2002. The PJM Market Monitoring Unit will review the program following each summer period.

The Economic Load Response Program is designed to provide an incentive to customers or curtailment service providers to enhance the ability and opportunity for customers to reduce consumption when PJM Locational Marginal Prices (LMP) are high. Program participants have the choice of two options: a Day Ahead Option or Real Time Option. The Day Ahead Option will provide a mechanism by which any qualified market participant may offer customers the opportunity to reduce the load they draw from the PJM system in advance of real time operations and receive payments based on day ahead time LMP[1] for the reductions. The Real Time Option will provide a mechanism by which any qualified market participant may offer customers the opportunity to commit to a reduction of the load they draw from the PJM system during times of high prices and receive payments based on real time LMP for the reductions.

[1] LMP is the hourly integrated market clearing price for energy at the location the energy is delivered or received.

The program became effective on June 1, 2002, and will remain in effect until December 1, 2004. At that time, the program will be terminated unless it is extended by a majority vote from the PJM Members Committee.

Pennsylvania EDC Results

In the summer of 2002, the reported energy demand reduction attributable to EDCs' demand side response programs was 1,303 MWH and the average reduction was 25.4 MW. The aggregate, non-coincident reduction at system peak was 34.5 MW.

In the short term, the purpose of Pennsylvania's demand side response initiative is to reduce peak demand and educate customers about peak price fluctuations. In the long term, the intention is to improve overall energy efficiency, maintain the integrity of the region's transmission system and mitigate the escalation of wholesale energy prices during times of peak demand.

The following is a summary of initiatives taken by the EDCs to implement demand-side response programs. Additional information is provided in individual company sections.

Overview of EDC Demand Side Response Programs: 2002, 2003

EDC	*Program*	Description
Allegheny Power	-- Voluntary Generation Buy-Back -- Energy Pricing Pilot -- Distributed Generation Price Pilot Program	-- Allegheny Power buys-back or displaces firm load. (Large C&I) -- Allegheny Power calls curtailment events for temperature setbacks.(Res/Sm Comm) -- Customers run standby generation during peak hours. (R).
Duquesne	-- Voluntary Contract Load Reduction Program -- Direct Load Control	-- Customers make their generators or curtailable load available for peak load reductions. (Large C&I). -- Duquesne cycles A/C compressor off and on. (Res/Sm Comm)
First Energy (Met-Ed, Penelec)	-- Voluntary Load Reduction Programs -- Seasonal Savings Programs -- Time of Use Pilot -- Rider E / Rule 20 -- Direct Load Control -- Distributed Generation	--Customers reduce specified level of hourly load. (C&I) --Customers contract to reduce specified level of hourly load. (C&I) --Residential customers shift usage from high-cost summer weekday periods. --Existing tariff provisions allow mandatory/semimandatory load reductions. (C&I) --Ongoing development for residential and small commercial customers. -- The companies will explore the use of distributed generation on an individualized basis.
PECO	-- Interruptible Rider-2 "Smart Returns" -- "GoodWatts" Pilot	-- PECO notifies customer to reduce load at certain times to receive credits; or PECO compensates customer for reducing load. (Large C&I) -- PECO shifts air conditioning loads to off-peak periods.
First Energy (PennPower)	-- Real time Pricing (RTP) -- Experimental Power Curtailment Program	-- Customers respond to day-ahead hourly signals. (C&I) -- Customer curtails firm load. (C&I)
PPL	-- Demand Side Initiative Rider (DSI) -- Proposed 2002 Experimental DSR Rate Rider	-- Customers may respond to changes in the electric generation market by adjusting their load requirements. (C& I) -- Time of Use Pilot Program available to 200 residential customers in summer of 2002. (Res)
UGI	-- Voluntary Load Reduction Pilot Program -- Time-of-Use (Rate RTU)	-- Customers receive a monetary incentive to curtail load. (C&I) -- May change rate spreads. (Res)

Section 2

2002: A Year in Review

The eight largest EDCs operating in Pennsylvania delivered approximately 99% of the jurisdictional companies' electrical energy needs. Aggregate sales in 2002 totaled approximately 137.7 billion kilowatthours (KWH), a 2.6% increase from that of 2001 and approximately 4.0% of the United States' total sales. Industrial sales continued to lead the Pennsylvania market capturing 33.7% of the total sales, followed by residential (33.6%) and commercial (30.1%). Aggregate non-coincident peak load rose to 27,975 MW in 2002, up 3.6% from 2001. See Tables 2.1 and 2.2 below.

Table 2.1. Energy Demand, Peak Load and Customers Served (2002)

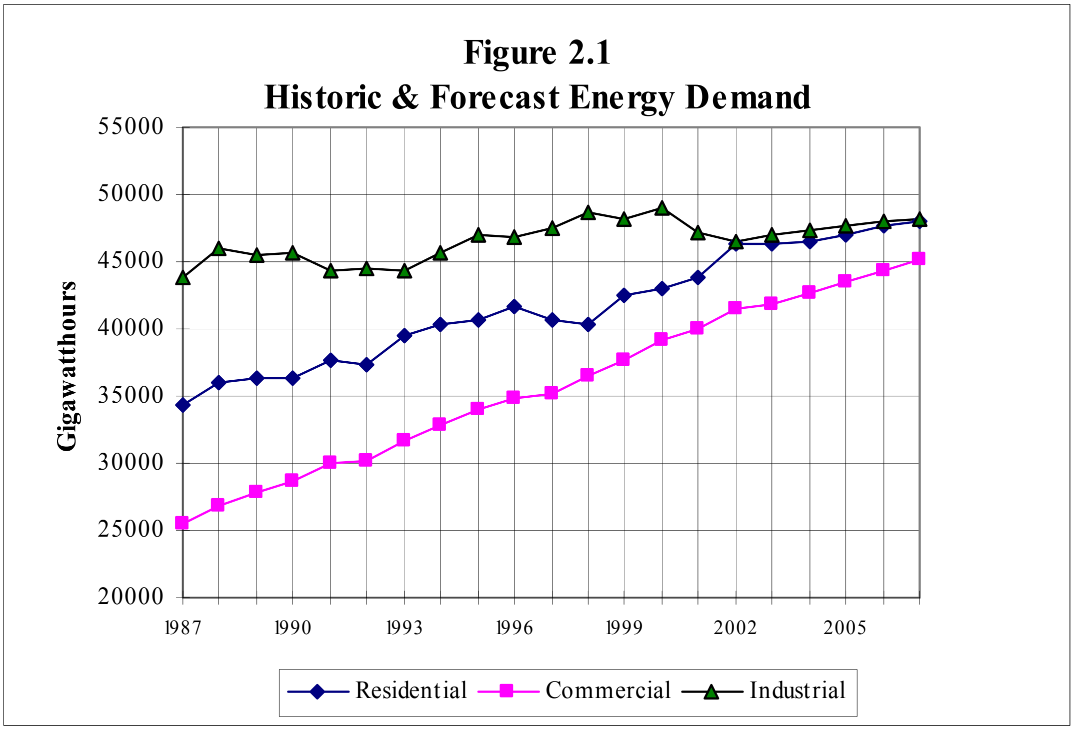
EDC	Total Customers Served	Residential (MWH)	Commercial (MWH)	Industrial (MWH)	Other (MWH)	Sales For Resale (MWH)	Total Consumption (MWH)	System Losses (MWH)	Company Use (MWH)	Net Energy For Load (MWH)	Peak Load (MW)
Duquesne	587,439	3,924,096	6,457,535	3,328,366	70,133	194,493	13,974,623	815,365	33,043	14,823,031	2,886
Met-Ed	510,093	4,720,617	3,984,966	4,012,022	34,844	607	12,753,056	1,204,631	n/a	13,957,687	2,616
Penelec	584,923	4,167,102	4,696,659	4,314,670	41,301	515	13,220,247	1,000,896	n/a	14,221,143	2,693
Penn Power	155,112	1,533,300	1,268,200	1,504,700	6,200	5,200	4,317,600	252,000	6,950	4,576,563	869
PECO	1,530,390	12,335,116	8,019,454	15,322,901	952,745	174,918	36,805,134	2,576,359	98,651	34,130,123	8,164
PPL	1,306,443	12,639,799	12,116,751	9,852,700	499,174	1,007,282	36,115,706	2,611,213	109,571	38,836,490	6,970
UGI	61,719	495,113	337,855	112,070	4,981	46	950,065	58,163	1,866	1,010,094	195
West Penn	692,644	6,458,857	4,496,820	7,957,010	52,133	618,825	19,583,645	1,438,860	n/a	21,022,505	3,582
Total	5,428,763	46,274,000	41,378,240	46,404,439	1,661,511	2,001,886	137,720,076	9,957,487	250,081	142,577,636	27,975
% of Total		33.60%	30.05%	33.69%	1.21%	1.45%	100.00%				
2002 v 2001	0.69%	5.86%	3.82%	-1.48%	39.31%	-15.36%	2.60%	11.06%	9.52%	3.07%	3.63%

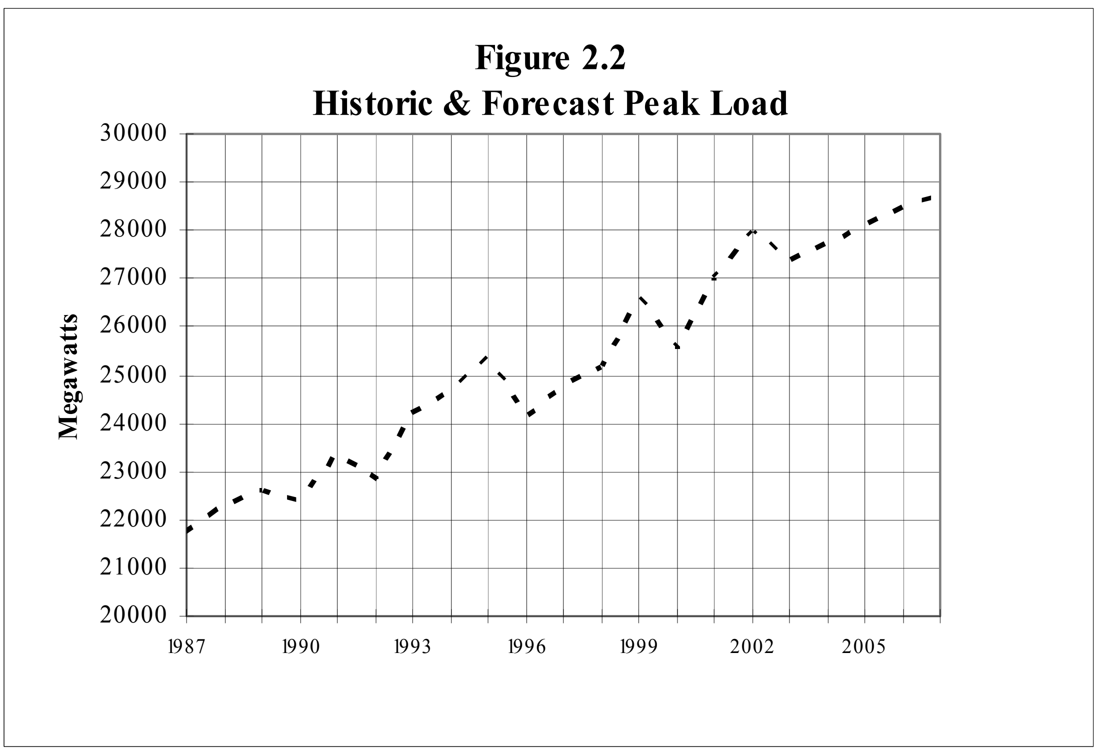
Table 2.2. Energy Demand, Peak Load and Customers Served (2001)

EDC	Total Customers Served	Residential (MWH)	Commercial (MWH)	Industrial (MWH)	Other (MWH)	Sales For Resale (MWH)	Total Consumption (MWH)	System Losses (MWH)	Company Use (MWH)	Net Energy For Load (MWH)	Peak Load (MW)
Duquesne	586,494	3,583,859	6,169,688	3,282,731	71,445		13,107,723	772,262	28,106	13,908,091	2,771
Met-Ed	502,801	4,495,607	3,855,416	4,185,931	32,932	867	12,570,753	1,023,692	n/a	13,594,445	2,486
Penelec	582,638	3,991,249	4,537,511	4,391,809	41,489	227,325	13,189,383	1,310,019	n/a	14,499,402	2,337
Penn Power	151,962	1,391,000	1,220,000	1,539,000	6,000	474,000	4,630,000	261,000	6,950	4,897,950	1,011
PECO	1,525,653	11,177,726	7,603,638	15,311,815	772,839	161,243	35,027,261	2,451,908	94,805	32,480,548	7,948
PPL	1,293,973	12,268,633	11,778,371	10,319,004	210,688	921,072	35,497,768	2,109,975	96,550	37,704,293	6,583
UGI	61,510	481,258	331,258	114,046	4,987	22	931,571	44,902	1,924	978,397	181
West Penn	686,517	6,324,916	4,359,918	7,955,272	52,312	580,669	19,273,087	991,785	n/a	20,264,872	3,677
Total	5,391,548	43,714,248	39,855,800	47,099,608	1,192,692	2,365,198	134,227,546	8,965,543	228,335	138,327,998	26,994
% of Total		32.57%	29.69%	35.09%	0.89%	1.76%	100.00%				

Between 1987 and 2002, the state's energy demand grew at an average rate of 1.7% annually. Residential sales grew at an annual rate of 2.0%, commercial at 3.3% and industrial at 0.4%.

The current aggregate 5-year projection of growth in energy demand is 1.0%. This includes a residential growth rate of 0.7%, a commercial rate of 1.7% and an industrial rate of 0.7%. See Figure 2.1 below. Gigawatthours are a measure of energy sales over time and megawatts are a measure of the instantaneous peak usage of electricity.





In 2002, Pennsylvania's EDCs purchased nearly 18 million MWH from independent power producers (IPPs). Table 2.3 below shows the amount of purchased energy by each EDC, the percentage of net energy for load represented by the purchases and contracted capacity, both online and future.

Table 2.3. Purchases from IPPs or QFs by Pennsylvania EDCs

Company	2002 Purchased Energy (MWH)	Percent of Net Energy For Load	On Line Contract Capacity (MW)	Future Contract Capacity (MW)
Duquesne	0	0.00%	0	0
Met-Ed	2,255,675	16.16%	295	295
Penelec	3,098,419	21.79%	401	401
Penn Power	203	0.00%	0	0
PPL	2,452,160	6.50%		
PECO	7,541,591	23.22%	223	223
West Penn	1,126,065	5.56%	136	136
Pennsylvania	16,474,114	11.94%	1,055	1,055

Also, in 2002, electric generation suppliers (EGSs) provided 15 million MWH to Pennsylvania customers, or about 11.1% of total resources. See Table 2.4 below.

Table 2.4. Summary of Resources (MWH)

Company	EDC Purchases	IPP & QF Purchases	EGS Resources	Net Resources
Duquesne	11,458,784	0	3,346,121	14,804,905
Met-Ed	7,146,051	2,255,675	1,818,229	11,219,955
Penelec	7,332,590	3,098,419	860,075	11,291,084
Penn Power	4,492,272	203	173,814	4,666,289
PPL	33,975,651	2,452,160	1,285,095	37,712,906
PECO	20,215,298	7,541,591	7,270,372	35,027,261
West Penn	18,622,118	1,126,065	259,501	20,007,684
Pennsylvania	103,242,764	16,474,114	15,013,207	134,730,085

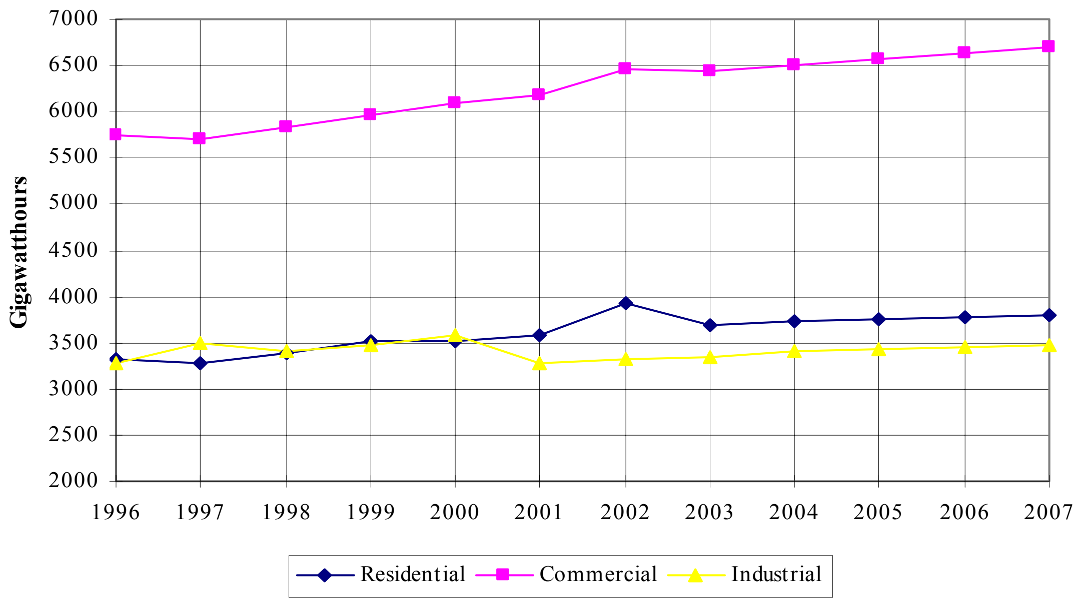
Summary of EDC Data

Duquesne Light Company

Duquesne Light Company (Duquesne) provides service to 587,439 electric utility customers in southwestern Pennsylvania. In 2002, Duquesne had energy sales totaling nearly 14 billion kilowatthours (KWH) -- up 6.6% from 2001. Commercial sales continued to dominate Duquesne's market with 46.2% of the total sales, followed by residential (28.1%) and industrial (23.8%).

Between 1987 and 2002, Duquesne's total energy demand increased about 1.6% per year. The 2002 industrial energy demand was 14.1% greater than the 1987 level, still far behind the peak level achieved in 1981 (49.4%). Residential demand grew at an annual rate of 1.7% over the past 15 years, with an increase in commercial energy demand at an average of 1.9% per year.

Figure 3.1
Historic & Forecast Energy Demand

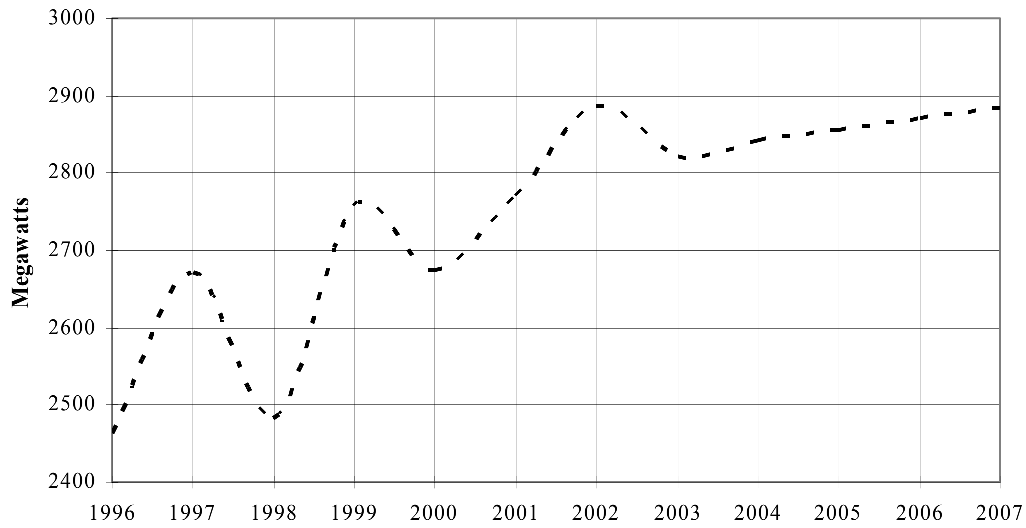


The current 5-year projection of average growth in total energy consumption is about 0.4% per year. This includes a residential growth rate of -0.7% (due to the high demand in 2002), a commercial growth rate of 0.7% and an industrial growth rate of 0.8%.

Duquesne's summer peak load, occurring on August 1, 2002, was 2,886 megawatts (MW), representing an increase of 4.2% from last year's peak of 2,771 MW. The 2002/2003 winter peak load was 2,120 MW or 6.5% higher than that of the previous year.

The actual average annual peak load growth rate over the past fifteen years was 1.5%. Duquesne's forecast shows the peak demand staying relatively consistent, moving from 2,886 MW in the summer of 2002 to 2,884 MW in 2007.

Figure 3.2
Historic & Forecast Peak Load



Tables 3.1-3.4 on pages 13 and 14 provide Duquesne's forecasts of peak load and residential, commercial and industrial energy demand from 1993 through 2002.

Duquesne anticipates joining a regional transmission organization, as part of its pending POLR III (Provider of Last Resort) proposal, to ensure a stable, plentiful supply of electricity for its customers.

Duquesne has implemented a Voluntary Load Reduction Program available to commercial and industrial customers with the flexibility to curtail load or utilize on-site generating facilities during periods of peak market prices. A peak load reduction of 16.8 MW and 61.7 million KWH in energy savings are anticipated for 2003. This represents 0.6% of the 2002 peak load and 4.4% of annual sales. Also, a Direct Load Control Program is being implemented for residential and commercial customers in which air conditioning units will be shut off or cycled during periods of high heat.

Table 3.1

Year	Actual Peak Demand	Projected Peak Load Requirements (Megawatts)									
		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	2499	2423									
1994	2535	2461	2324								
1995	2666	2466	2352	2355							
1996	2463	2497	2351	2346	2537						
1997	2671	2521	2373	2390	2599	2583					
1998	2484	2564	2392	2401	2634	2614	2614				
1999	2756	2613	2412	2413	2652	2632	2632	2715			
2000	2673	2655	2442	2433	2671	2653	2653	2736	2638		
2001	2771	2700	2472	2452	2690	2677	2677	2757	2661	2661	
2002	2886	2745	2501	2472	2709	2702	2702	2776	2682	2682	2850
2003			2533	2490	2728	2727	2727	2798	2702	2702	2884
2004				2511	2749	2754	2754		2723	2723	2912
2005					2769	2782	2782			2743	2934
2006						2810	2810				2953
2007							2839				

Table 3.2

Year	Actual Energy Demand	Projected Residential Energy Demand (Gigawatthours)									
		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	3231	3267									
1994	3219	3302	3234								
1995	3379	3338	3279	3190							
1996	3321	3374	3303	3207	3175						
1997	3274	3411	3324	3221	3167	3228					
1998	3382	3447	3350	3237	3171	3234	3234				
1999	3526	3484	3371	3254	3176	3240	3240	3366			
2000	3509	3522	3396	3271	3181	3249	3249	3383	3610		
2001	3584	3559	3425	3288	3187	3258	3258	3400	3643	3643	
2002	3924	3597	3453	3305	3192	3267	3267	3415	3681	3681	3671
2003			3483	3322	3198	3276	3276	3432	3716	3716	3726
2004				3339	3204	3287	3287		3759	3759	3772
2005					3210	3297	3297			3780	3810
2006						3210	3307				3846
2007							3318				

Table 3.3

Year	Actual Energy Demand	Projected Commercial Energy Demand (Gigawatthours) 1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	5490	5675									
1994	5563	5829	5570								
1995	5729	5909	5748	5703							
1996	5737	6028	5850	5818	5732						
1997	5703	6148	5949	5908	5757	5858					
1998	5826	6270	6033	6017	5824	5945	5945				
1999	5954	6393	6117	6131	5910	6039	6039	5983			
2000	6092	6516	6209	6247	6005	6159	6159	6073	6113		
2001	6170	6627	6299	6359	6102	6301	6301	6157	6231	6231	
2002	6458	6740	6385	6469	6198	6450	6450	6236	6336	6336	6324
2003			6477	6577	6295	6606	6606	6327	6438	6438	6467
2004				6693	6400	6773	6773		6540	6540	6570
2005					6505	6944	6944			6628	6653
2006						7118	7118				6729
2007							7296				

Table 3.4

Year	Actual Energy Demand	Projected Industrial Energy Demand (Gigawatthours) 1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	3046	3208									
1994	3256	3315	3149								
1995	3237	3336	3293	3362							
1996	3285	3429	3342	3423	3349						
1997	3501	3486	3401	4367	3717	3431					
1998	3412	3576	3451	4335	3941	3690	3690				
1999	3481	3674	3484	4398	4013	3828	3828	3771			
2000	3581	3736	3519	4461	4086	3919	3919	3836	3537		
2001	3283	3817	3554	4526	4160	3988	3988	3901	3576	3576	
2002	3328	3902	3591	4591	4236	4059	4059	3964	3615	3615	3315
2003			3631	4655	4313	4130	4130	4027	3651	3651	3382
2004				4717	4393	4202	4202		3695	3695	3445
2005					4474	4276	4276			3742	3491
2006						4351	4351				3530
2007							4427				

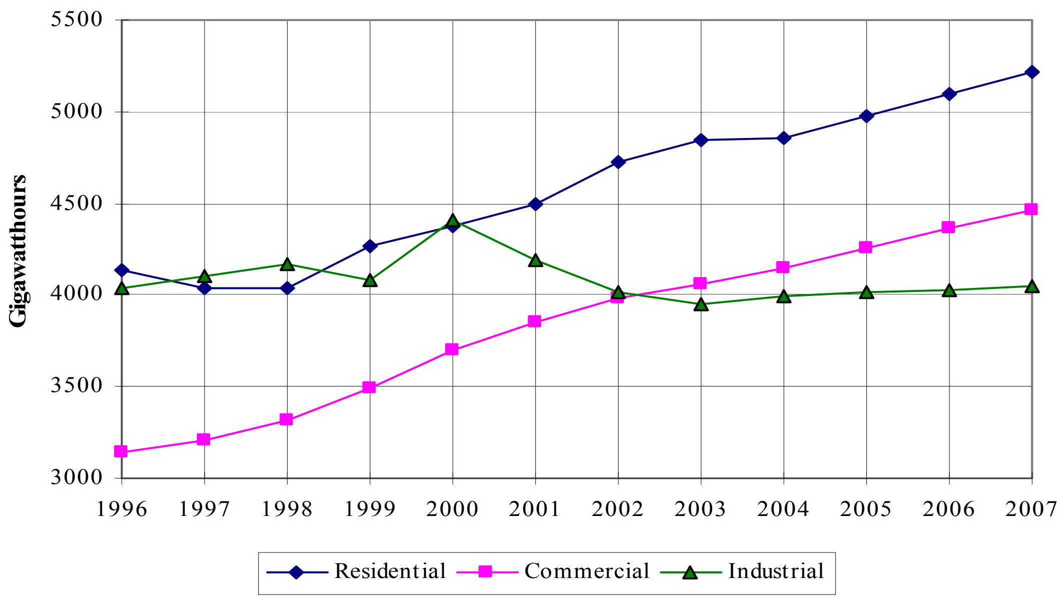
Metropolitan Edison Company

Metropolitan Edison Company (Met-Ed) provides service to over 510,000 electric utility customers in eastern and south central Pennsylvania. In 2002, Met-Ed had total energy sales of 12.8 billion kilowatthours (KWH) - - up 1.5% from 2001. Residential sales dominated Met-Ed's market with 37.0% of the total sales, followed by industrial (31.5%) and commercial (31.2%).

Between 1987 and 2002, Met-Ed's energy demand grew at an average rate of 2.6% per year. Residential and commercial sales have maintained relatively steady growth over the period (3.1% for residential and 4.2% for commercial), while industrial sales have fluctuated considerably. Industrial sales grew at an average rate of about 0.9%.

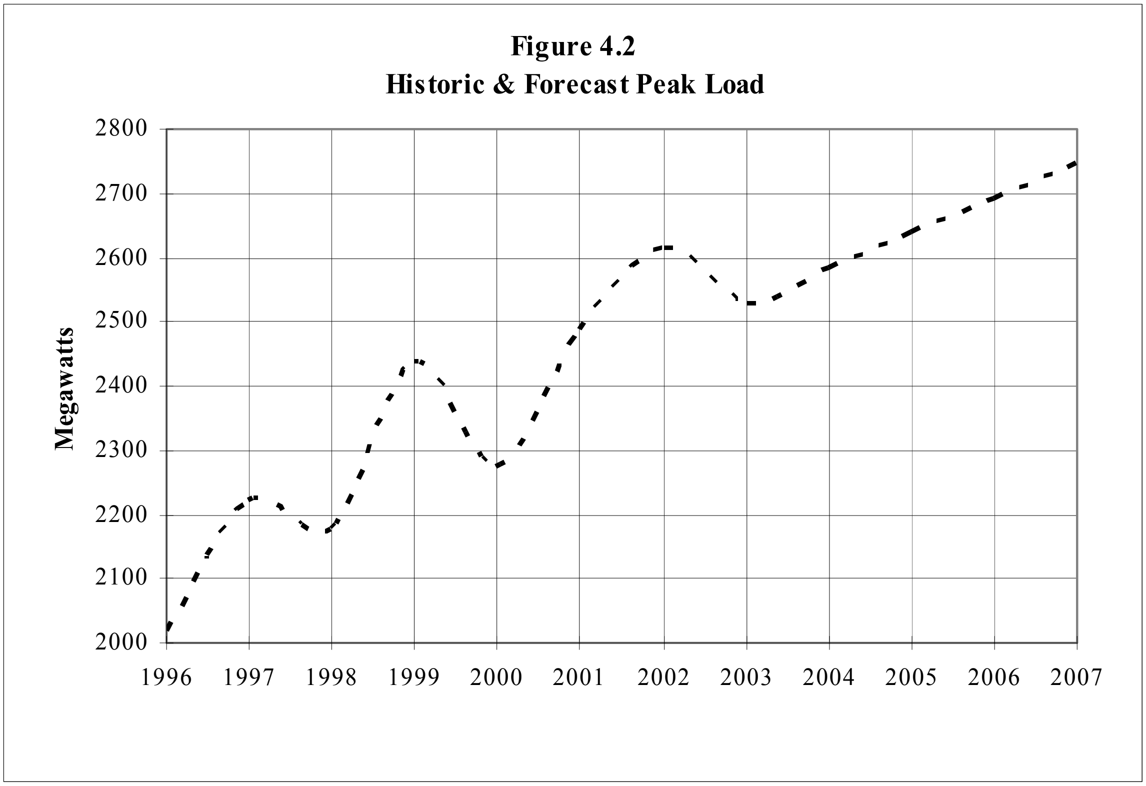
The current five-year projection of growth in total energy demand is 1.5%. This includes a residential growth rate of 2.0%, a commercial growth rate of 2.3% and an industrial rate of 0.2%.

Figure 4.1
Historic & Forecast Energy Demand



Met-Ed's summer peak load, occurring on August 14, 2002, was 2,616 megawatts (MW), an all-time system peak. This represents an increase of 5.2% from last year's peak of 2,486 MW. The 2002/03 winter peak load was 2,394 MW or 15.8% higher than the previous year's winter peak of 2,067 MW.

The actual average annual peak load growth rate over the past fifteen years was 2.7%. Met-Ed's forecast shows its peak load increasing from 2,616 MW to 2,747 MW by 2007, or an average annual growth rate of 1.0%.



Tables 4.1-4.4 on pages 17 and 18 provide Met-Ed's forecasts of peak load and residential, commercial and industrial energy demand from 1993 through 2002.

Met-Ed was a wholly owned subsidiary of GPU until November 7, 2001, when GPU was merged with FirstEnergy Corporation, a holding company registered under the Public Utility Holding Company Act of 1935. Met-Ed is a member of the PJM Interconnection and the Mid-Atlantic Area Council.

The final restructuring settlement between Met-Ed and various intervenors was approved by the Commission on October 16, 1998. The settlement provided that 100% of customers could choose another energy supplier beginning January 1, 1999. Met-Ed retains Provider of Last Resort (PLR) responsibility for those customers who choose not to shop. Beginning in June 2000, 20% of Met-Ed's PLR obligation were to be met by competitive default suppliers (CDS) chosen by competitive bid. The amount of PLR load served by CDS was to increase by 20% increments each year up to 80% of the load in June 2003. The CDS bid process failed for June 2000. Met-Ed increased the load available for CDS bid in June 2001 to 40%; again, however, no bids were received.

GPU has divested most of its generation facilities and negotiated short-term contracts with the new owners: Edison Mission Energy, Sithe Energy (now Reliant) and Amergen. These contracts ended in 2001, except for an agreement with Reliant for capacity only through May 31, 2002. Met-Ed currently retains ownership of the York Haven generating station, which has a combined generating capacity of 19.4 MW.

In 2002, Met-Ed purchased approximately 2.3 billion KWH from cogeneration and small power production projects. Contract capacity (defined as PJM installed capacity credits) is 295 MW.

For calendar year 2002, eight electric generation suppliers sold a total of over 1.8 billion KWH to retail customers in Met-Ed's service territory, or about 14.3% of total consumption.

Met-Ed's only active conservation program is a low-income weatherization program (LIURP), which includes the installation of a variety of weatherization measures in the homes of customers with electric heat and/or electric water heating and/or high baseload use. In addition, 95 time-of-day conversions were made. Over $1.8 million was spent in 2002 for a peak load reduction of 142 KW, a load shift of 71 KW and energy savings totaling 1.2 million KWH.

Table 4.1

Year	Actual Peak Demand	Projected Peak Load Requirements (Megawatts) 1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	1954	1980									
1994	2000	2019	1999								
1995	2186	2065	2041	2042							
1996	2017	2100	2086	2080	2094						
1997	2224	2129	2129	2113	2139	2139					
1998	2176	2161	2170	2147	2176	2176	2194				
1999	2439	2191	2216	2192	2205	2205	2233	2263			
2000	2274	2223	2255	2229	2228	2228	2268	2318	2404		
2001	2486	2253	2293	2263	2264	2264	2305	2373	2456	2455	
2002	2616	2284	2331	2299	2303	2303	2343	2429	2508	2504	2503
2003			2367	2333	2345	2345	2386	2486	2559	2553	2554
2004				2369	2388	2388	2429		2612	2602	2611
2005					2432	2432	2472			2652	2668
2006						2475	2515				2725
2007							2559				

Table 4.2

Year	Actual Energy Demand	Projected Residential Energy Demand (Gigawatthours) 1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	3800	3701									
1994	3921	3796	3894								
1995	3925	3894	4007	3892							
1996	4135	3984	4114	3972	3961						
1997	4034	4071	4203	4047	4028	4028					
1998	4040	4150	4287	4121	4041	4041	4122				
1999	4266	4224	4364	4203	4095	4095	4204	4264			
2000	4377	4293	4446	4286	4152	4152	4264	4352	4344		
2001	4496	4360	4522	4359	4222	4222	4328	4442	4430	4430	
2002	4721	4427	4597	4438	4292	4292	4391	4533	4516	4501	4607
2003			4677	4508	4361	4361	4451	4624	4602	4577	4708
2004				4582	4430	4430	4513		4687	4651	4804
2005					4499	4499	4575			4724	4892
2006						4571	4636				4988
2007							4697				

Table 4.3

Year	Actual Energy Demand	Projected Commercial Energy Demand (Gigawatthours) 1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	2794	2754									
1994	2921	2859	2878								
1995	3011	2958	2961	2959							
1996	3144	3015	3055	3037	3026						
1997	3209	3065	3146	3117	3106	3106					
1998	3209	3135	3237	3209	3179	3179	3224				
1999	3487	3204	3328	3304	3258	3258	3306	3414			
2000	3699	3293	3427	3397	3338	3338	3389	3518	3518		
2001	3855	3386	3518	3497	3420	3420	3473	3622	3622	3751	
2002	3985	3490	3608	3611	3512	3512	3567	3732	3732	3860	3976
2003			3700	3724	3607	3607	3663	3841	3837	3970	4096
2004				3835	3703	3703	3762		3947	4079	4216
2005					3805	3805	3864			4189	4336
2006						3912	3972				4456
2007							4083				

Table 4.4

Year	Actual Energy Demand	Projected Industrial Energy Demand (Gigawatthours) 1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	3665	3643									
1994	3861	3718	3757								
1995	3957	3781	3821	3888							
1996	4033	3807	3891	3956	3985						
1997	4097	3900	3974	4019	4064	4064					
1998	4173	4003	4078	4110	4132	4132	4136				
1999	4085	4081	4182	4205	4197	4197	4229	4239			
2000	4412	4132	4277	4291	4294	4294	4305	4307	4313		
2001	4186	4196	4367	4376	4389	4389	4370	4365	4352	4312	
2002	4012	4255	4458	4463	4468	4468	4448	4435	4410	4409	4263
2003			4547	4552	4535	4535	4560	4506	4459	4490	4341
2004				4644	4627	4627	4664		4508	4567	4419
2005					4724	4724	4776			4645	4498
2006						4810	4876				4577
2007							4964				

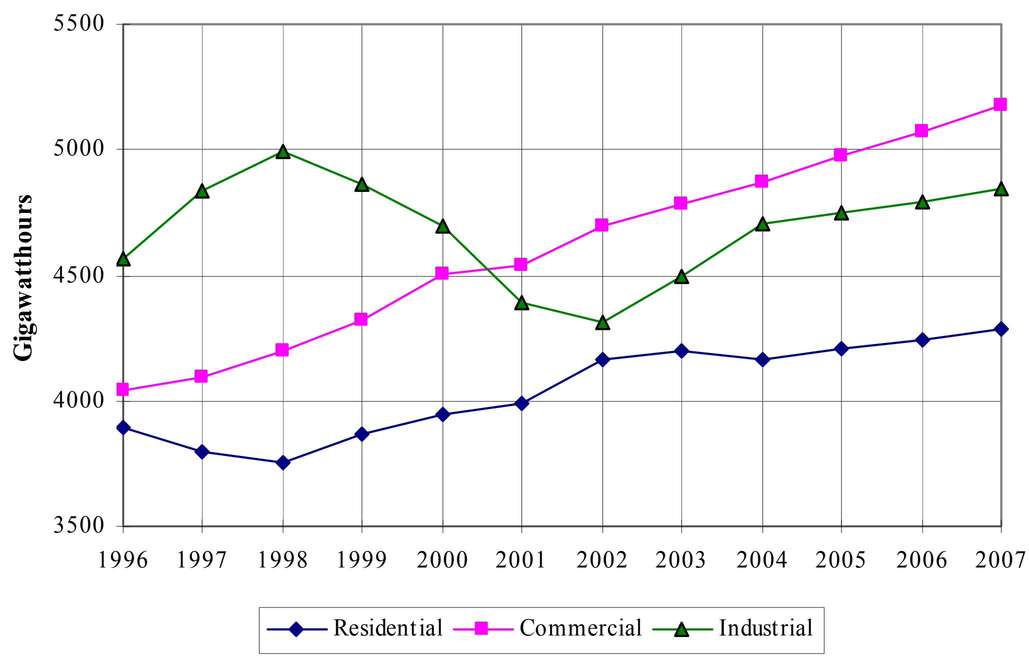
Pennsylvania Electric Company

Pennsylvania Electric Company (Penelec) provides service to nearly 585,000 electric utility customers in western and northern Pennsylvania. In 2002, Penelec had energy sales totaling 13.2 billion kilowatthours (KWH) - - up 0.2% from 2001. Commercial sales dominated Penelec's market with 35.5% of the total sales, followed by industrial (32.6%) and residential (31.5%).

Between 1987 and 2002, Penelec's energy demand grew at an average rate of 1.5% per year. Residential and commercial sales have maintained relatively steady growth over the period (1.5% for residential and 3.2% for commercial), while industrial sales have fluctuated greatly. Industrial sales for 2002 were 11.9% less than the 1987 level, or an average annual decrease of 0.7%.

The current five-year projection of growth in total energy demand is 1.7%. This includes a residential growth rate of 0.6%, a commercial growth rate of 2.0% and an industrial growth rate of 2.3%.

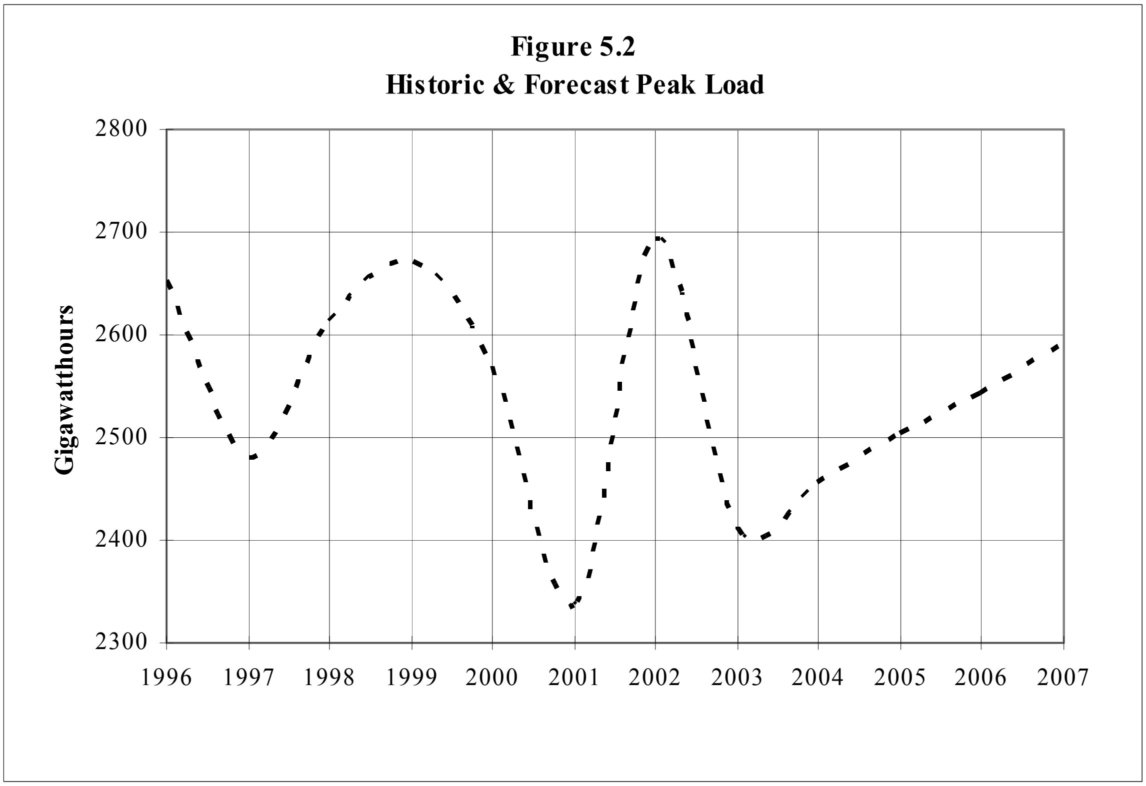
Figure 5.1
Historic & Forecast Energy Demand



Penelec's 2002 summer peak load, occurring on July 29, 2002, was 2,693 megawatts (MW), representing an increase of 15.2% from last year's summer peak of 2,337 MW. The 2002/03 winter peak load was 2,663 MW or 28.5% higher than the previous year's winter peak of 2,073 MW.

The actual average annual peak load growth rate over the past fifteen years was 1.0%. Penelec's forecast shows its peak load decreasing from 2,693 MW in 2002 to

2,592 MW in 2007. Penelec expects its winter peak load to slightly exceed its summer peak load beginning in 2003.



Tables 5.1-5.4 on pages 23 and 24 provide Penelec's forecasts of peak load and residential, commercial and industrial energy demand from 1993 through 2002.

Penelec was a wholly owned subsidiary of GPU. On November 7, 2001, GPU was merged with FirstEnergy Corporation, a holding company registered under the Public Utility Holding Company Act of 1935. Penelec is a member of the PJM Interconnection and the Mid-Atlantic Area Council.

The final restructuring settlement between Penelec and various intervenors was approved by the Commission on October 16, 1998. The settlement provided that 100% of customers could choose another energy supplier beginning January 1, 1999. Penelec retains Provider of Last Resort (PLR) responsibility for those customers who choose not to shop. Beginning in June 2000, 20% of Penelec's PLR obligation was to be met by competitive default suppliers (CDS) chosen by competitive bid. The amount of PLR load served by CDS was to increase by 20% increments each year up to 80% of the load in June 2003. There were no bidders for the first 20% increment. Penelec increased the load available for CDS bid in June 2001 to 40%; again, however, no bids were received.

GPU has divested most of its generation facilities and negotiated short term contracts with the new owners: Edison Mission Energy, Sithe Energy (now Reliant) and Amergen. These contracts ended in 2001, except for an agreement with Reliant for capacity only through May 31, 2002.

In 2002, Penelec purchased approximately 3.1 billion KWH from cogeneration and small power production projects. Contract capacity (defined as PJM installed capacity credits) is 401 MW.

For calendar year 2002, ten electric generation suppliers sold a total of 1.9 billion KWH to retail customers in Penelec's service territory, or about 6.5% of total consumption, down from 14.3% in 2001.

Penelec's only active conservation program is a low-income weatherization program, which includes the installation of a variety of weatherization measures in the homes of customers with electric heat and/or electric water heating and/or high baseload use. In addition, 28 time-of-day conversions were made. Nearly $1.7 million was spent in 2002 for a peak load reduction of 264 KW and energy savings totaling 1.7 million KWH.

Table 5.1

Year	Actual Peak Demand	Projected Peak Load Requirements (Megawatts)									
		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	2514	2425									
1994	2538	2482	2519								
1995	2589	2541	2578	2584							
1996	2652	2582	2651	2641	2706						
1997	2481	2615	2727	2758	2743	2751					
1998	2613	2639	2717	2790	2728	2742	2688				
1999	2583	2663	2775	2795	2769	2795	2730	2672			
2000	2569	2688	2808	2893	2818	2855	2772	2704	2651		
2001	2337	2713	2842	2916	2867	2904	2813	2737	2675	2321	
2002	2693	2737	2875	2967	2914	2951	2853	2770	2700	2347	2337
2003			2507	3056	2527	2564	2472	2804	2737	2373	2375
2004				2526	2567	2604	2506		2760	2399	2405
2005					2606	2643	2540			2425	2437
2006						2682	2573				2465
2007							2606				

Table 5.2

Year	Actual Energy Demand	Projected Residential Energy Demand (Gigawatthours)									
		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	3716	3624									
1994	3773	3665	3719								
1995	3765	3710	3770	3772							
1996	3897	3751	3817	3820	3813						
1997	3801	3789	3859	3876	3853	3853					
1998	3756	3820	3893	3920	3890	3890	3870				
1999	3864	3847	3928	3961	3921	3921	3922	3894			
2000	3949	3868	3961	3999	3948	3948	3950	3931	3881		
2001	3991	3887	3986	4030	3982	3982	3979	3968	3915	3977	
2002	4167	3905	4008	4064	4015	4015	4009	4007	3951	4021	4043
2003			4036	4084	4046	4046	4039	4045	3984	4065	4089
2004				4126	4077	4077	4069		4017	4109	4134
2005					4109	4109	4099			4154	4180
2006						4139	4129				4226
2007							4160				

Table 5.3

Year	Actual Energy Demand	Projected Commercial Energy Demand (Gigawatthours)									
		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	3650	3567									
1994	3794	3651	3713								
1995	3922	3734	3809	3828							
1996	4044	3756	3901	3934	4031						
1997	4098	3807	3979	4041	4156	4156					
1998	4198	3862	4054	4131	4282	4282	4283				
1999	4319	3915	4122	4212	4388	4388	4408	4347			
2000	4509	3968	4193	4292	4495	4495	4531	4459	4387		
2001	4538	4034	4242	4389	4600	4600	4658	4571	4473	4472	
2002	4697	4108	4291	4486	4695	4695	4784	4684	4558	4549	4613
2003			4333	4586	4795	4795	4908	4797	4643	4626	4730
2004				4682	4898	4898	5031		4728	4704	4846
2005					4995	4995	5152			4781	4962
2006						5099	5270				5078
2007							5386				

Table 5.4

Year	Actual Energy Demand	Projected Industrial Energy Demand (Gigawatthours)									
		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	4346	4318									
1994	4449	4561	4425								
1995	4463	4631	4537	4538							
1996	4563	4664	4678	4632	4809						
1997	4836	4703	4783	4796	5054	5054					
1998	4996	4737	4863	4854	5172	5172	4836				
1999	4866	4779	4929	4912	5235	5235	4894	5047			
2000	4698	4797	4989	4960	5309	5309	4948	5114	5004		
2001	4392	4824	5037	5008	5363	5363	5002	5205	5093	4857	
2002	4315	4847	5077	5057	5411	5411	5057	5293	5177	5144	4670
2003			5116	5107	5460	5460	5113	5383	5239	5214	4783
2004				5158	5515	5515	5169		5306	5244	4846
2005					5570	5570	5226			5274	4887
2006						5637	5284				4928
2007							5342				

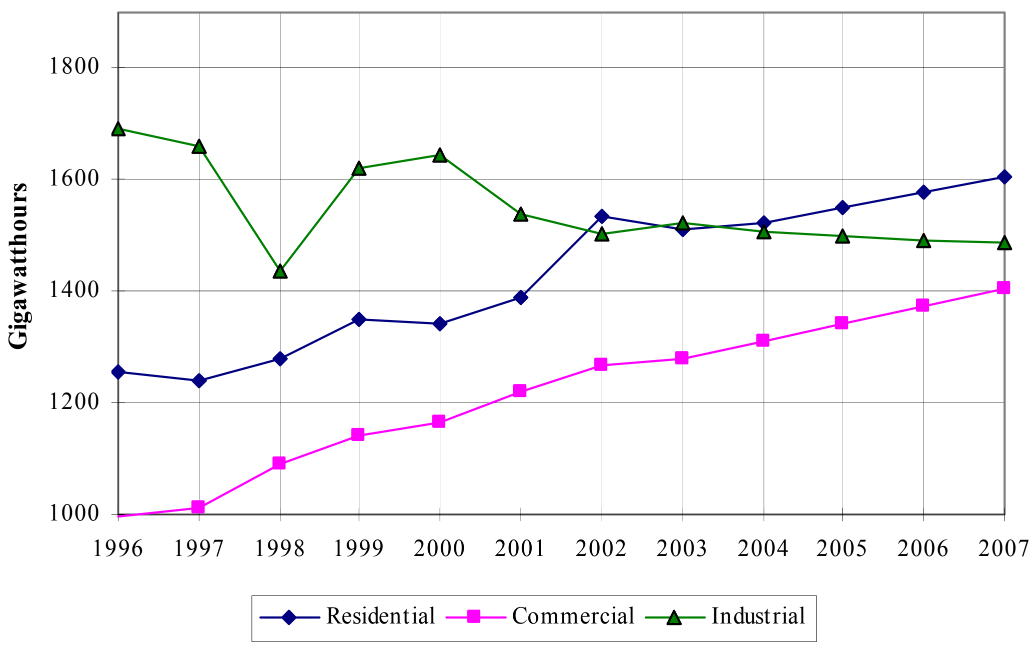
Pennsylvania Power Company

Pennsylvania Power Company (Penn Power) provides service to over 155,000 electric utility customers in western Pennsylvania. In 2002, Penn Power had energy sales totaling 4.3 billion kilowatthours (KWH) - - a decrease of 6.7% from the 2001 figure. Residential sales lead Penn Power's market with 35.5% of the total sales, followed by industrial (34.9%) and commercial (29.4%).

Between 1987 and 2002, Penn Power's energy demand grew at an average rate of 1.7% per year. Residential and commercial sales have maintained relatively steady growth over the period at rates of 3.2% and 4.8%, respectively. Industrial sales have fluctuated considerably and, in 2002, were only 89.4% of the 1987 level, or an average annual decline of 1.0%.

The current five-year projection of growth in total energy demand is 0.9%. This includes a residential growth rate of 0.9%, a commercial growth rate of 2.1% and an industrial rate of -0.2%.

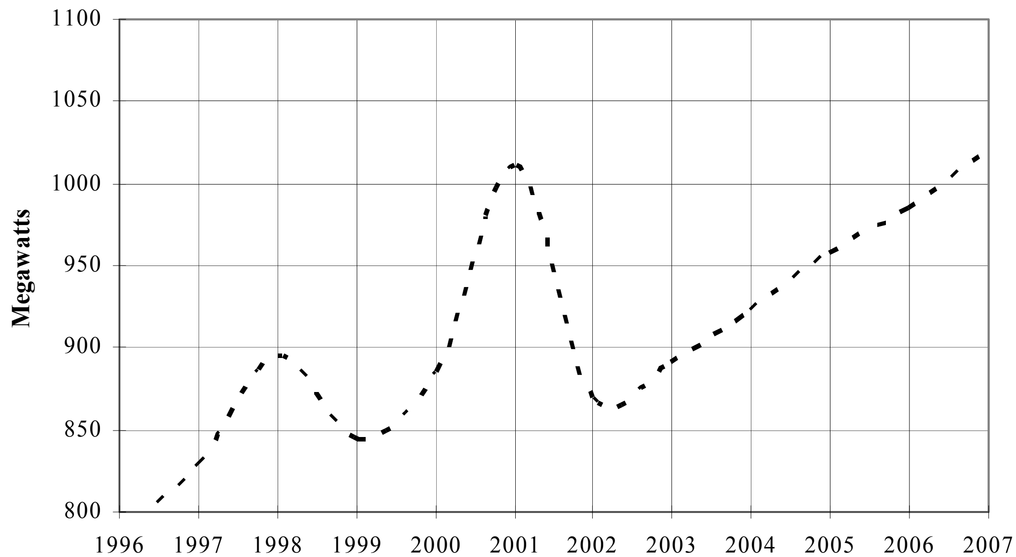
Figure 6.1
Historic & Forecast Energy Demand



Penn Power's 2002 summer peak load, occurring on July 29, 2002, was 869 megawatts (MW), representing a decrease of 14.0% from last year's peak of 1,011 MW. The 2002/03 winter peak load of 839 MW was 0.2% higher than the previous year's winter peak of 837 MW.

The actual average annual peak load growth rate over the past fifteen years was 2.4%. Penn Power's forecast shows its peak load increasing from 869 MW in the summer of 2002 to 1,020 MW by 2007, or an average annual growth rate of 3.5%. Penn Power's peak load represents about 7.0% of FirstEnergy's peak load.

Figure 6.2
Historic & Forecast Peak Load



Tables 3.1-3.4 on pages 25 and 26 provide Penn Power's forecasts of peak load and residential, commercial and industrial energy demand from 1993 through 2002.

The electrical systems of Penn Power and the other FirstEnergy operating companies are interconnected and fully integrated. As of January 1, 2003, Penn Power owned 1,237 MW of the First Energy system's generating capacity.

For calendar year 2002, four electric generation suppliers sold a total of nearly 14.5 million KWH to retail customers in Penn Power's service territory or about 0.3% of total consumption, down from 3.8% in 2001. Penn Power purchased 203 million KWH from an independent power producer in 2002.

While Penn Power is open to economic load reduction opportunities mutually beneficial to the customer and the company, it does not administer any load management or energy conservation programs on a generic basis. Penn Power now offers an Experimental Power Curtailment Program (APX) and an Experimental Day Ahead Real Time Pricing Program (RTP) as experimental tariffs.

APX allows the customer to offer curtailed load for sale to Penn Power that can be sold in an open market. RTP provides the customer the option to manage its load by reacting to market-driven day ahead prices on an hourly basis, where the customer can reduce its load during periods of high energy prices, increase load to take advantage of market conditions or shift loads to periods of lower prices.

Table 6.1

Year	Actual Peak Demand	Projected Peak Load Requirements (Megawatts)									
		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	688	603									
1994	706	608	655								
1995	835	625	670	717							
1996	784	641	680	752	759						
1997	829	654	689	792	781	781					
1998	895	677	703	807	804	804	902				
1999	845	693	717	825	831	830	919	880			
2000	885	711	732	844	858	858	937	897	935		
2001	1011	729	747	862	892	892	958	919	957	883	
2002	869	749	763	879	928	928	980	941	980	904	918
2003			777	897	962	962	1003	963	1003	930	947
2004				914	997	997	1026	983	1025	956	983
2005					1019	1019	1050			982	1022
2006						977	1012				1058
2007							1036				

Table 6.2

Year	Actual Energy Demand	Projected Residential Energy Demand (Gigawatthours)									
		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	1105	1081									
1994	1178	1094	1103								
1995	1195	1105	1126	1166							
1996	1254	1113	1130	1179	1211						
1997	1238	1122	1132	1189	1238	1238					
1998	1278	1139	1142	1195	1265	1265	1300				
1999	1351	1151	1152	1201	1292	1292	1318	1300			
2000	1341	1162	1162	1220	1320	1320	1336	1319	1390		
2001	1391	1175	1179	1235	1373	1373	1355	1339	1412	1360	
2002	1533	1188	1196	1251	1430	1430	1374	1360	1434	1395	1447
2003			1207	1267	1459	1459	1398	1381	1457	1430	1483
2004				1283	1488	1488	1423	1403	1479	1451	1520
2005					1502	1502	1445			1473	1558
2006						1516	1467				1597
2007							1494				

Table 6.3

Year	Actual Energy Demand	Projected Commercial Energy Demand (Gigawatthours) 1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	831	812									
1994	891	832	850								
1995	938	870	881	893							
1996	996	905	897	903	936						
1997	1013	941	914	928	970	970					
1998	1090	978	934	953	1010	1010	1042				
1999	1143	1015	955	976	1054	1054	1074	1110			
2000	1164	1052	977	1008	1103	1103	1108	1145	1204		
2001	1220	1089	999	1039	1167	1167	1143	1181	1242	1162	
2002	1268	1124	1021	1070	1238	1238	1182	1221	1284	1206	1270
2003			1042	1101	1314	1314	1221	1262	1327	1251	1327
2004				1131	1395	1395	1262	1304	1372	1293	1387
2005					1436	1436	1304			1335	1449
2006						1478	1348				1514
2007							1392				

Table 6.4

Year	Actual Energy Demand	Projected Industrial Energy Demand (Gigawatthours) 1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	1212	1152									
1994	1293	1104	1170								
1995	1558	1132	1163	1499							
1996	1693	1178	1187	1703	1894						
1997	1659	1218	1208	1902	1967	1967					
1998	1436	1255	1242	1935	2002	2002	1677				
1999	1619	1293	1273	1966	2043	2043	1716	1483			
2000	1643	1329	1305	2002	2082	2082	1759	1520	1563		
2001	1539	1373	1337	2039	2138	2138	1803	1558	1596	1618	
2002	1505	1413	1377	2077	2184	2184	1847	1596	1635	1644	1514
2003			1409	2114	2230	2230	1890	1633	1673	1677	1516
2004				2149	2273	2273	1933	1670	1711	1716	1517
2005					2314	2314	1981			1758	1519
2006						2357	2029				1520
2007							2076				

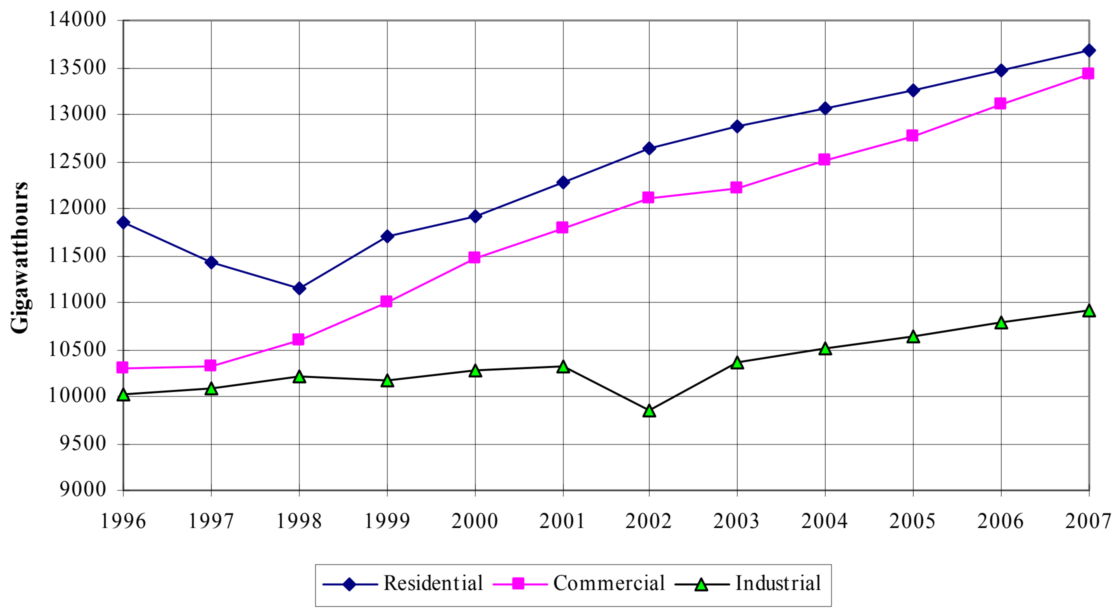
PPL Electric Utilities Corporation

PPL Electric Utilities Corporation (PPL) provides service to over 1.3 million homes and businesses over a 10,000 square mile area in 29 counties of central eastern Pennsylvania. In 2002, PPL had energy sales totaling 36.1 billion kilowatthours (KWH) -- up 1.7% from 2001. Residential sales continued to dominate PPL's market with 35.0% of the total sales, followed by commercial (33.6%) and industrial (27.3%).

Between 1987 and 2002, PPL's energy demand grew an average of 2.2% per year. Residential energy sales grew at an annual rate of 2.2%, commercial at a 3.3% rate and industrial at 1.0%.

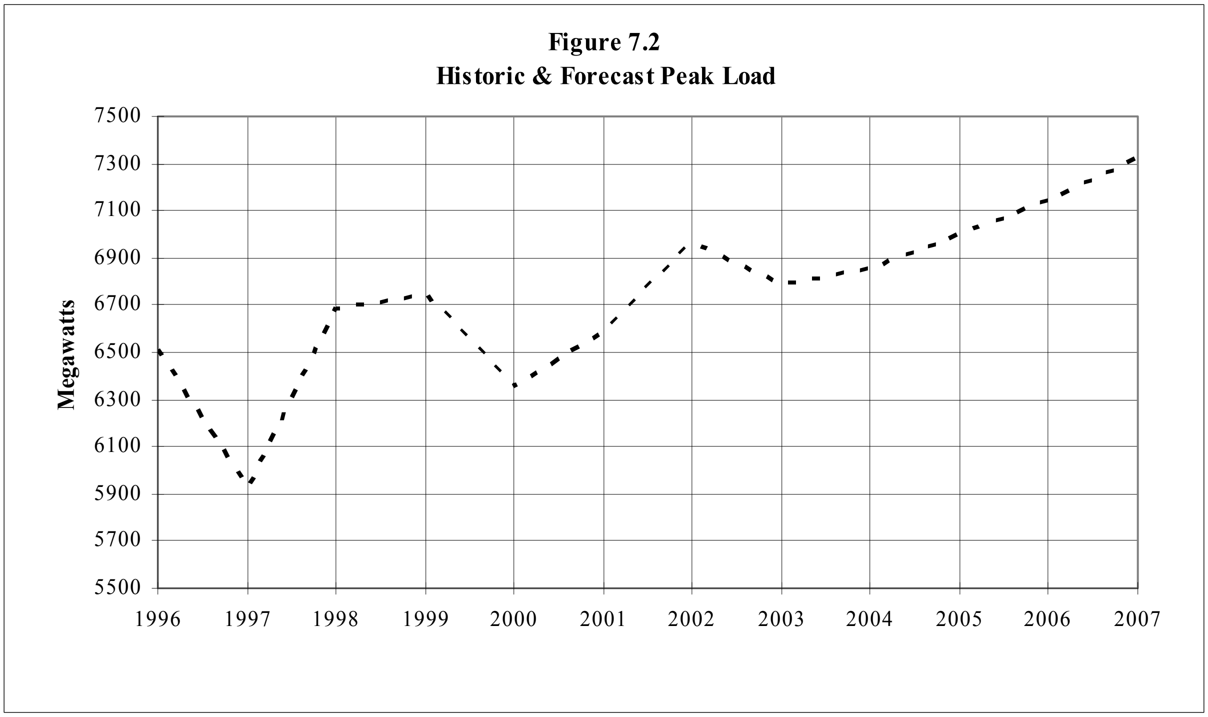
The current five-year projection of average growth in energy demand is 1.9%. This includes growth rates of 1.6% for residential, 2.1% for commercial and 1.9% for industrial.

Figure 7.1
Historic & Forecast Energy Demand



PPL's 2002/03 winter peak load, occurring on January 23, 2003, was 6,970 megawatts (MW), representing an increase of 13.6% from last year's peak of 6,131 MW. The 2002 summer peak load was 6,906 MW or 4.9% above the previous summer's peak of 6,583 MW. PPL expects to be a summer-peaking utility by 2005.

The actual average annual peak load growth rate over the past fifteen years was 1.5%. PPL's five-year winter peak load forecast scenario shows the peak load increasing from 6,970 MW in 2002/03 to 7,090 MW in the winter of 2007/08 at an average annual rate of 0.3%. The summer peak load is projected to increase from 6,906 MW in 2002 to 7,320 MW in 2007.



Tables 7.1-7.4 on pages 29 and 30 provide PPL's forecasts of peak load and residential, commercial and industrial energy demand from 1993 through 2002.

Net operable generating capacity of 7,994 MW (summer rating) includes 47.0% coal-fired capacity and 24.9% nuclear capacity. Independent power producers also provided 294 MW to the system. In 2002, PPL purchased nearly 2.5 billion KWH from cogeneration and independent power production facilities.

For calendar year 2002, fourteen electric generation suppliers sold a total of approximately 1.3 billion KWH to retail customers in PPL's service territory, or about 3.6% of total consumption, up from 2.9% in 2001.

For 2002, PPL reported a peak load reduction of 246.5 MW and energy savings of 2.6 million KWH, resulting from its Interruptible Service – Economic Provisions tariff schedule. Interruptible Service – Emergency Provisions reduced load by 260.5 MW and saved 4.8 million KWH. Customers reducing load for either economic or emergency conditions receive significant rate discounts. The combined peak load reduction from these two programs represents approximately 7.3% of the 2002 summer peak load.

PPL's Price Response Service permits customers to respond to market price signals by reducing a portion of their loads. In 2002, an estimated 1,100 KW peak load reduction was achieved, with energy savings totaling 29,600 KWH.

PPL is a member of PJM and MAAC.

Table 7.1

Year	Actual Peak Demand	Projected Peak Load Requirements (Megawatts)									
		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	6403	6280									
1994	6508	6345	6406								
1995	6607	6430	6531	6435							
1996	6506	6565	6581	6500	6830						
1997	5925	6668	6711	6625	6920	6910					
1998	6688	6813	6846	6760	7055	6935	6910				
1999	6746	6938	6991	6895	7190	7030	6935	6815			
2000	6355	7063	7126	7040	7315	7120	7030	6905	6580		
2001	6583	7188	7251	7175	7450	7130	7120	7006	6680	6850	
2002	6970	7308	7396	7310	7590	7250	7130	7040	6770	6960	7000
2003			7526	7455	7725	7350	7250	7140	6860	7060	7070
2004				7585	7860	7470	7350		6960	7170	7040
2005					8040	7580	7470			7270	7120
2006						7690	7580				7200
2007							7690				

Table 7.2

Year	Actual Energy Demand	Projected Residential Energy Demand (Gigawatthours)									
		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	11043	10990									
1994	11444	11480	11220								
1995	11300	11700	11420	11290							
1996	11848	11920	11630	11450	11475						
1997	11434	12140	11850	11620	11640	11690					
1998	11156	12360	12070	11800	11815	11760	11690				
1999	11704	12570	12290	11980	11980	11830	11760	11740			
2000	11923	12780	12500	12160	12145	11910	11830	11850	12031		
2001	12269	12980	12700	12330	12320	12020	11910	11980	12150	12176	
2002	12640	13170	12910	12510	12495	12160	12020	12120	12280	12324	12391
2003			13110	12690	12680	12290	12160	12260	12421	12478	12514
2004				12870	12865	12430	12290		12562	12634	12650
2005					13040	12570	12430			12799	12803
2006						12710	12570				12955
2007							12710				

Table 7.3

	Actual Energy	Projected Commercial Energy Demand (Gigawatthours)									
Year	Demand	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	9373	9320									
1994	9715	9660	9540								
1995	9948	9920	9770	9830							
1996	10288	10210	10010	10090	10100						
1997	10309	10480	10260	10355	10350	10490					
1998	10597	10760	10520	10625	10610	10740	10490				
1999	11002	11030	10780	10910	10885	11000	10740	10740			
2000	11477	11300	11045	11200	11165	11280	11000	10980	11090		
2001	11778	11560	11315	11490	11445	11560	11280	11240	11275	11291	
2002	12117	11820	11585	11780	11725	11870	11560	11500	11444	11431	11850
2003			11855	12065	11995	12140	11870	11760	11612	11561	12033
2004				12345	12265	12410	12140		11782	11699	12219
2005					12525	12680	12410			11848	12411
2006						12940	12680				12602
2007							12940				

Table 7.4

	Actual Energy	Projected Industrial Energy Demand (Gigawatthours)									
Year	Demand	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	9100	8790									
1994	9536	8910	9390								
1995	9845	9020	9570	9685							
1996	10016	9130	9565	9675	9900						
1997	10078	9240	9695	9885	10150	10070					
1998	10220	9350	9830	10070	10405	10110	10070				
1999	10179	9450	9965	10260	10600	10270	10110	10190			
2000	10280	9550	10100	10445	10795	10440	10270	10350	10543		
2001	10319	9650	10240	10635	10990	10610	10440	10520	10836	10963	
2002	9853	9750	10380	10830	11190	10790	10610	10690	11077	11255	10780
2003			10520	11040	11400	10960	10790	10860	11295	11521	11135
2004				11245	11615	11140	10960		11498	11777	11425
2005					11825	11320	11140			12010	11702
2006						11510	11320				11970
2007							11510				

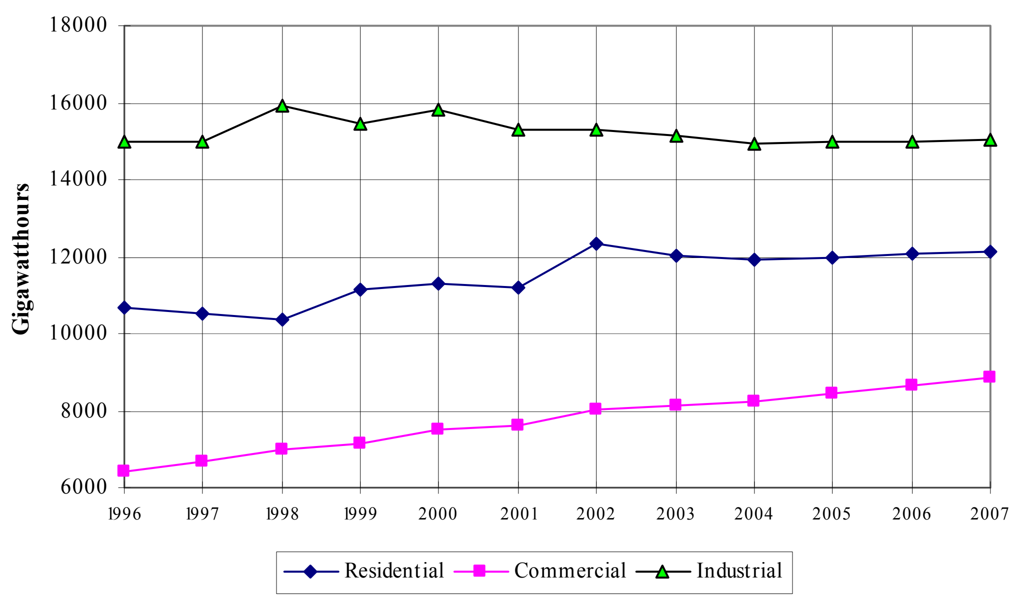
PECO Energy Company

PECO Energy Company (PECO) provides service to over 1.5 million electric utility customers in southeastern Pennsylvania. In 2002, PECO had total retail energy sales of 36.8 billion kilowatthours (KWH) -- up 5.1% from 2001. Industrial sales continued to dominate PECO's market with 41.6% of the total sales, followed by residential (33.5%) and commercial (21.8%).

Between 1987 and 2002 PECO's energy demand grew an average of 1.3% per year. Residential energy sales grew at an annual rate of 1.8%, commercial at a 4.2% rate and industrial at -0.2%.

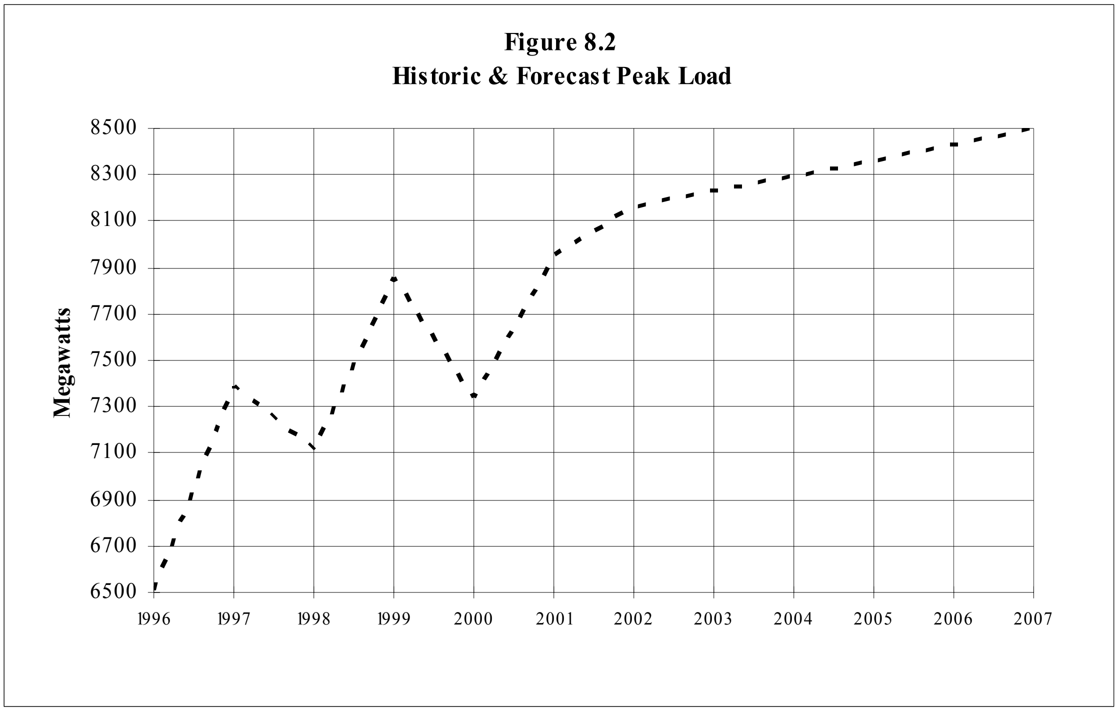
The current five-year projection of growth in energy demand is 0.2%. This includes an annual growth rate of -0.3% for residential, 2.0% for commercial and -0.4% for industrial.

Figure 8.1
Historic & Forecast Energy Demand



PECO's 2002 summer peak load, occurring on August 14, 2002, was 8,164 megawatts (MW), representing an increase of 2.7% from last year's peak of 7,948 MW. The 2002/03 winter peak demand was 6,346 MW or 5.8% above the previous winter's peak of 5,997 MW.

The actual average annual peak demand growth rate over the past fifteen years was 1.5%. PECO's current forecast shows the peak load increasing from the actual 2002 summer peak load of 8,164 MW to 8,496 MW in the summer of 2007, or an annual growth rate of 0.8%.



Tables 8.1-8.4 on pages 33 and 34 provide PECO's forecasts of peak load and residential, commercial and industrial energy demand from 1993 through 2002.

Net operable capacity of 9,463 MW includes 45.6% nuclear capacity and 15.2% coal-fired capacity. This capacity is owned by Exelon. PECO has entered into a Purchased Power Agreement with Exelon Generation to provide its provider-of-last-resort load throughout the forecast period.

In 2002, PECO purchased over 353 million KWH from cogeneration and independent power production facilities.

For calendar year 2002, electric generation suppliers sold a total of 3.3 billion KWH to retail customers in PECO's service territory or about 8.9% of total consumption, down from 20.8% in 2001. On the summer peak day, electric generation suppliers represented a load of 640 MW.

PECO has developed commercial and industrial rate incentive programs to encourage customers to manage their energy demands and usage consistent with system capabilities. During 2002, the peak load reduction resulting from this rate option was 180 MW, with energy savings of nearly 1.3 million KWH.

PECO is a member of the PJM Interconnection and MAAC.

Table 8.1

Year	Actual Peak Demand	Projections of Peak Load Requirements (Megawatts)									
		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	7100	6626									
1994	7227	6705	6645								
1995	7246	6777	6731	6671							
1996	6509	6845	6815	6599	6811						
1997	7390	6910	6897	6677	6868	6868					
1998	7108	6975	6975	6751	6973	6973	6973				
1999	7850	7046	7052	6825	7063	7063	7063	7063			
2000	7333	7125	7135	6905	7135	7135	7135	7135	7339		
2001	7948	7206	7226	6989	7233	7233	7233	7233	7398	7392	
2002	8164	7295	7317	7077	7308	7308	7308	7308	7457	7451	8012
2003			7411	7166	7387	7387	7387	7387	7517	7510	8076
2004				7256	7466	7466	7466		7577	7570	8140
2005					7547	7547	7547			7631	8205
2006						7629	7629				8271
2007							7711				

Table 8.2

Year	Actual Energy Demand	Projected Residential Energy Demand (Gigawatthours)									
		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	10264	10311									
1994	10412	10418	10245								
1995	10660	10531	10348	10423							
1996	10657	10646	10457	10387	10576						
1997	10515	10761	10570	10472	10653	10653					
1998	10376	10877	10680	10581	10732	10732	10515				
1999	11132	10994	10794	10696	10812	10812	10516	10516			
2000	11304	11112	10909	10812	10894	10894	10600	10600	10600		
2001	11178	11230	11024	10934	10976	10976	10685	10685	10685	11278	
2002	12335	11349	11141	11055	11059	11059	10770	10770	10770	11385	11634
2003			11261	11177	11142	11142	10856	10856	10856	11488	11733
2004				11300	11225	11225	10943		10943	11592	11855
2005					11310	11310	11031			11697	11957
2006						11394	11119				12059
2007							11208				

Table 8.3

Year	Actual Energy Demand	Projected Commercial* Energy Demand (Gigawatthours)									
		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	5623	5455									
1994	5954	5571	5678								
1995	6222	5714	5820	6241							
1996	6410	5859	5955	6403	6523						
1997	6689	6006	6148	6593	6667	6667					
1998	7012	6155	6342	6787	7044	7044	6643				
1999	7154	6305	6538	6983	7346	7346	6597	6597			
2000	7481	6456	6738	7182	7650	7650	6649	6649	6649		
2001	7604	6610	6940	7385	7955	7955	6703	6703	6702	7315	
2002	8019	6765	7146	7591	8262	8262	6756	6756	6756	7446	7732
2003			7354	7799	8572	8572	6810	6810	6810	7578	7963
2004				8011	8882	8882	6865		6864	7711	8099
2005					9195	9195	6920			7844	8265
2006						9510	6975				8436
2007							7031				

* Small Commercial & Industrial

Table 8.4

Year	Actual Energy Demand	Projected Industrial* Energy Demand (Gigawatthours)									
		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	15714	15994									
1994	15622	16216	15819								
1995	15869	16337	15899	15805							
1996	14976	16488	16003	15766	15249						
1997	14992	16700	16155	15791	15299	15299					
1998	15929	16853	16270	15923	15259	15259	15456				
1999	15477	17013	16402	16040	15271	15271	15919	15919			
2000	15828	17178	16521	16145	15248	15248	16047	16047	16047		
2001	15312	17351	16642	16253	15353	15353	16175	16175	16175	15405	
2002	15323	17531	16766	16363	15333	15333	16304	16304	16305	15406	15324
2003			16893	16473	15314	15314	16435	16435	16435	15408	15417
2004				16588	15294	15294	16566		16567	15409	15429
2005					15278	15278	16699			15409	15442
2006						15262	16832				15458
2007							16967				

* Large Commercial & Industrial

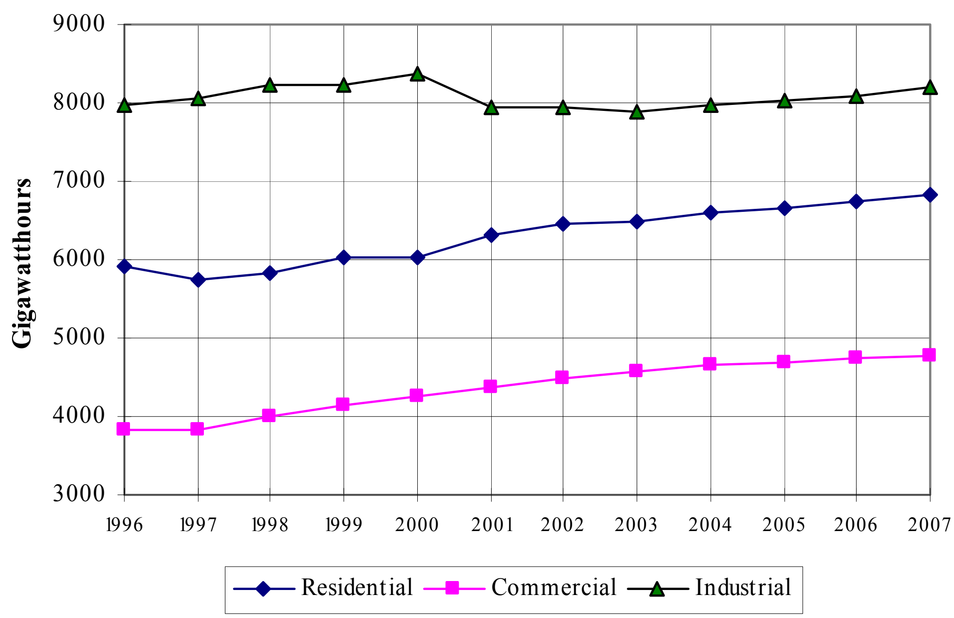
West Penn Power Company

West Penn Power Company (West Penn) provides service to nearly 693,000 electric utility customers in western, north and south central Pennsylvania. In 2002, West Penn had total retail energy sales of 19.6 billion kilowatthours (KWH) – up 1.6% from 2001. Industrial sales continued to dominate West Penn's market with 40.6% of the total sales, followed by residential (33.0%) and commercial (23.0%).

Between 1987 and 2002, West Penn's energy demand grew an average of 1.9% per year. Sales for all sectors have maintained relatively steady growth during the period. Residential sales grew at an annual rate of 1.8%, commercial sales at 2.9% and industrial sales at 1.5% over the past 15 years.

The current five-year projection of growth in energy demand is 0.9%. This includes a residential growth rate of 1.1%, a commercial rate of 1.2% and an industrial rate of 0.6%.

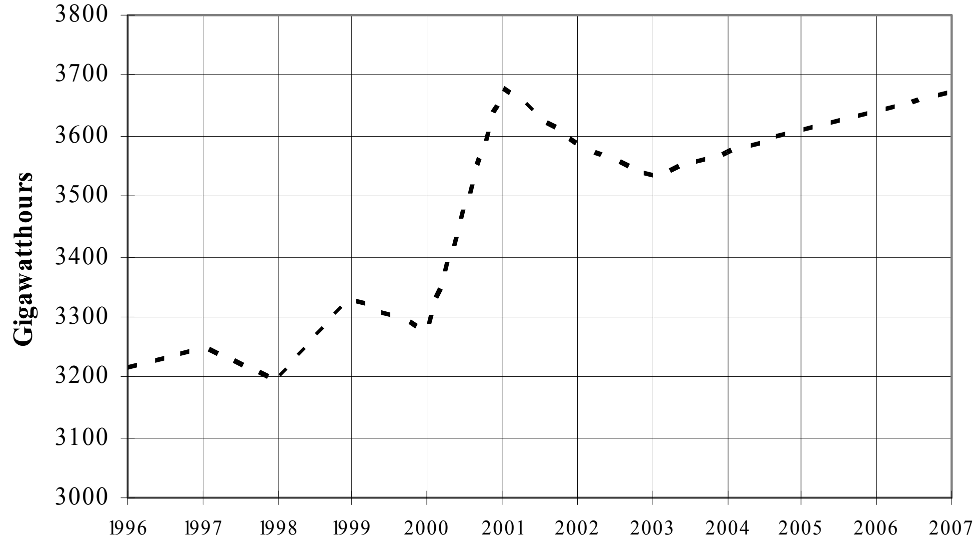
Figure 9.1
Historic & Forecast Energy Demand & Peak Load



West Penn's 2002 summer peak load, occurring on August 14, 2002, was 3,582 megawatts (MW), representing a decrease of 2.6% from last year's summer peak of 3,677 MW. The 2002/03 winter peak load was 3,470 MW or 10.1% above the previous year's winter peak of 3,151 MW.

The actual average annual peak load growth rate over the past fifteen years was about 2.0%. West Penn's load forecast scenario shows the annual peak load increasing from 3,582 MW in 2002 to 3,674 MW in 2007, or an average annual growth rate of 0.5%.

Figure 9.2
Historic & Forecast Peak Load



Tables 9.1-9.4 on pages 37 and 38 provide West Penn's forecasts of peak load and residential, commercial and industrial energy demand from 1993 through 2002.

Effective in November 1999, all of West Penn's generation assets were transferred to Allegheny Energy Supply Company, LLC (AESC), an unregulated subsidiary of Allegheny Energy. West Penn subsequently entered into a Power Sales Agreement with AESC for providing default service load requirements. The power provided by AESC will come from owned generation and market purchases. West Penn will remain an electric distribution company, providing transmission and distribution service to its customers and providing default service, or Provider of Last Resort service, for those customers who do not choose an alternate supplier.

In 2002, West Penn purchased over 1.1 billion KWH from cogeneration and independent power production facilities. Contract capacity for these facilities was 136 MW.

In 2002, West Penn expended over $2.5 million on its Low Income Usage Reduction Program, resulting in a peak load reduction of 884 KW and energy savings totaling 2.8 million KWH. West Penn has also developed a Generation Buy-Back program, intended as a way for West Penn to buy back or displace firm load from large commercial and industrial customers that have on-site generation or operational flexibility. This program was implemented in 2001. A total of 39 customers signed up with a potential load reduction of 231.5 MW. In 2002, the estimated load reduction was 250 MW.

Another program implemented in 2001 was Coincident Peak Pricing, a program designed to enable customers to make informed decisions about their energy consumption, while mitigating and reducing system peak loads. The estimated load reduction for 2002 is 642 MW.

In April 2002, Allegheny Power joined PJM Interconnection, LLC (PJM) through the creation of PJM West. As a PJM member, Allegheny Power is responsible for following the reliability standards of the PJM markets as are defined in the PJM Tariffs and PJM West Reliability Assurance Agreement.

Table 9.1

Year	Actual Peak Demand	Projections of Peak Load Requirements (Megawatts) 1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	3068	3128									
1994	3179	3191	3075								
1995	3242	3263	3147	3117							
1996	3215	3314	3214	3207	3235						
1997	3251	3362	3270	3279	3315	3315					
1998	3192	3415	3335	3329	3371	3371	3379				
1999	3328	3464	3396	3372	3417	3417	3442	3279			
2000	3277	3511	3440	3410	3462	3462	3496	3360	3284		
2001	3311	3563	3503	3454	3506	3506	3545	3425	3304	3141	
2002	3582	3617	3560	3500	3547	3547	3578	3484	3341	3445	3458
2003			3624	3554	3586	3586	3617	3519	3380	3465	3505
2004				3609	3630	3630	3668		3415	3501	3542
2005					3679	3679	3723			3536	3586
2006						3722	3769				3622
2007							3812				

Table 9.2

Year	Actual Energy Demand	Projected Residential Energy Demand (Gigawatthours) 1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	5680	5729									
1994	5740	5847	5697								
1995	5819	5938	5763	5826							
1996	5913	6022	5843	5897	5844						
1997	5757	6106	5932	5979	5923	5923					
1998	5823	6189	6016	6081	6020	6020	6127				
1999	6020	6267	6096	6166	6118	6118	6250	5873			
2000	6022	6335	6163	6260	6223	6223	6381	6013	6061		
2001	6325	6404	6238	6313	6282	6282	6446	6077	6172	6192	
2002	6459	6484	6317	6391	6371	6371	6518	6165	6256	6260	6374
2003			6405	6460	6445	6445	6604	6165	6339	6329	6471
2004				6567	6546	6546	6699	6231	6445	6436	6596
2005					6624	6624	6763			6521	6680
2006						6722	6864				6775
2007							6976				

Table 9.3

Year	Actual Energy Demand	Projected Commercial Energy Demand (Gigawatthours) 1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	3523	3621									
1994	3624	3721	3640								
1995	3782	3824	3706	3741							
1996	3836	3911	3826	3834	3856						
1997	3833	3989	3935	3942	3950	3950					
1998	3993	4067	4034	4049	4055	4055	4080				
1999	4137	4151	4128	4147	4161	4161	4163	4039			
2000	4265	4222	4199	4223	4271	4271	4270	4215	4182		
2001	4360	4285	4256	4272	4347	4347	4339	4313	4225	4326	
2002	4497	4366	4340	4350	4430	4430	4393	4401	4275	4395	4458
2003			4450	4434	4501	4501	4457	4443	4329	4449	4543
2004				4556	4588	4588	4557		4397	4517	4624
2005					4664	4664	4630			4571	4684
2006						4756	4707				4749
2007							4779				

Table 9.4

Year	Actual Energy Demand	Projected Industrial Energy Demand (Gigawatthours) 1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1993	7115	7392									
1994	7426	7549	7604								
1995	7858	7733	7854	7659							
1996	7974	7995	7985	7981	8204						
1997	8046	8143	8235	8232	8427	8427					
1998	8226	8304	8426	8429	8755	8755	8608				
1999	8237	8396	8618	8502	8855	8855	8808	8575			
2000	8383	8499	8781	8609	8976	8976	8997	8830	7942		
2001	7955	8621	8934	8664	9052	9052	9070	8975	8120	8481	
2002	7957	8727	9191	8767	9156	9156	9136	9167	8230	8597	8006
2003			9322	8874	9241	9241	9264	9161	8353	8663	8116
2004				9010	9367	9367	9448		8477	8729	8188
2005					9450	9450	9561			8799	8230
2006						9566	9660				8290
2007							9768				

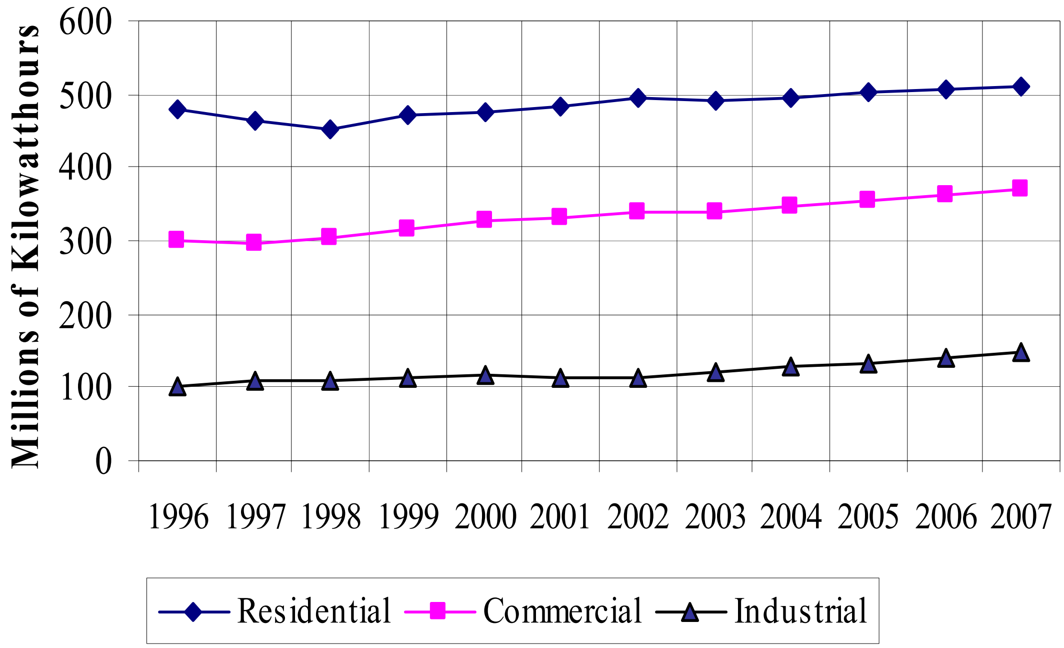
UGI Utilities, Inc.

The Electric Division of UGI Utilities, Inc. (UGI) provides electric service to nearly 62,000 customers in northwestern Luzerne and southern Wyoming counties, Pennsylvania. In 2002, UGI had energy sales totaling 950.1 million kilowatthours (KWH) -- up 2.0% from 2001. Residential sales continued to dominate UGI's market with 52.1% of the total sales, followed by commercial (35.6%) and industrial (11.8%).

Between 1987 and 2002, UGI experienced an average growth in total sales of 1.8%, which includes a residential growth rate of 1.3%, a commercial rate of 2.5% and an industrial rate of 2.6%.

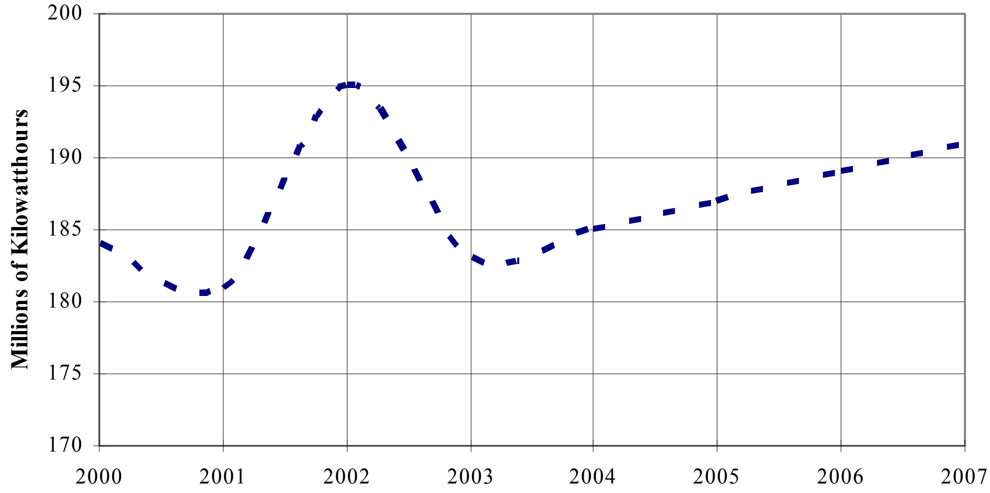
Over the five-year planning horizon, UGI expects growth in energy demand to average 1.8%. This includes a residential growth rate of 0.7%, a commercial rate of 1.9% and an industrial rate of 5.8%. The five-year peak load forecast indicates an average growth rate of -0.4%. Peak load is projected to decrease from 195 MW to 191 MW by the winter of 2007/08.

Figure 10.1
Historic & Forecast Energy Demand



Peak demand on the UGI system occurred on January 23, 2003, and totaled 195 megawatts (MW), or 10.8% above the December 2001 winter peak load of 176 MW and 6.0% above the 2002 summer peak load of 184 MW, which occurred on August 13, 2002.

Figure 12.2
Historic & Forecast Peak Load



In 2002, two electric generation suppliers provided nearly 1.2 million KWH to UGI's retail customers who chose an alternate supplier. This represents about 0.1% of total sales, down from 1.0% in 2001. UGI does not own electric generation supply and will meet its customers' energy requirements by making wholesale purchases in various markets.

As of December 31, 2002, 72 UGI customers were taking generation service from two different suppliers. Of those, approximately 96% were residential customers, with the remaining 4% commercial.

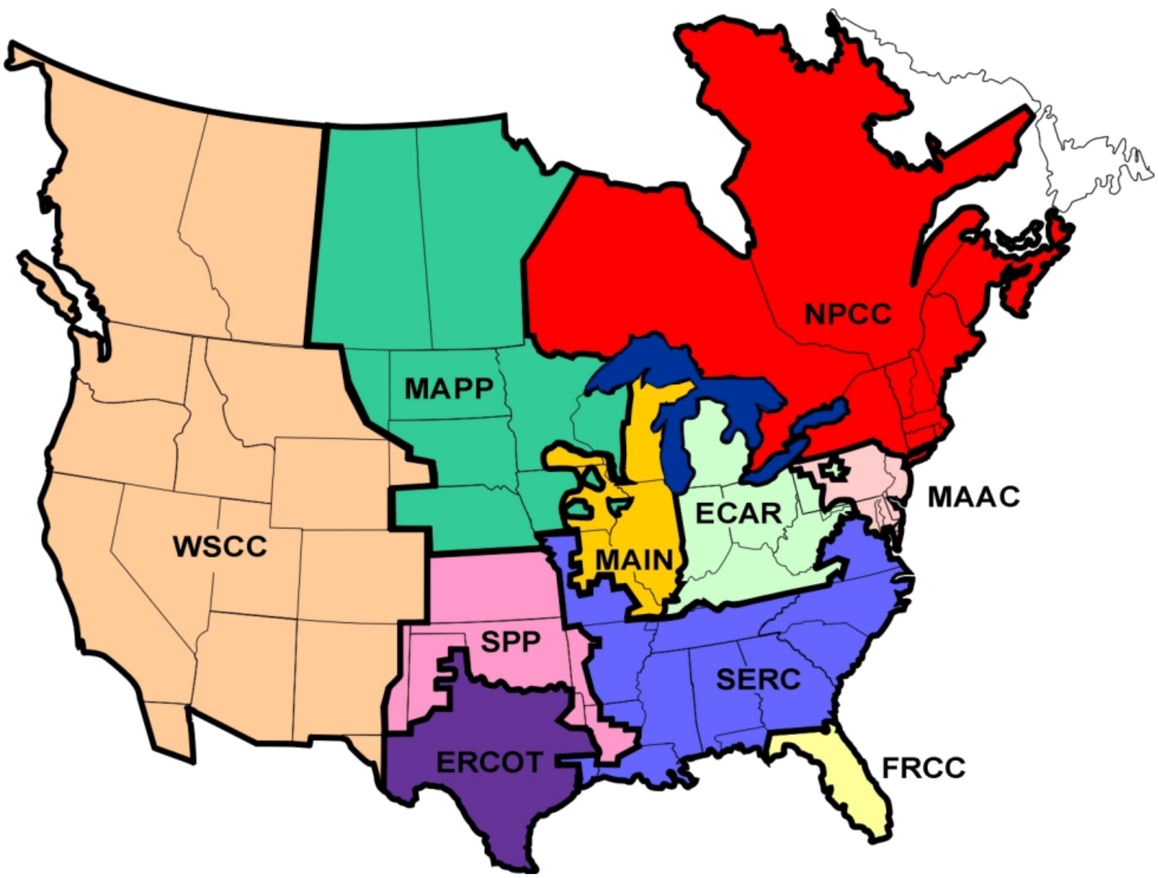
During the summer of 2002, UGI offered its Voluntary Load Reduction program to all of its commercial and industrial customers. The program centers on a customer's ability to reduce its demand during peak periods, thereby enhancing system reliability and increasing the economic efficiency of the wholesale and retail markets. One commercial customer and one industrial customer participated in the program, resulting in a total load reduction of 16.12 MWH.

Section 3

Regional Reliability Assessments

The passage of the Pennsylvania Electricity Generation Customer Choice and Competition Act substantially changed the Commission's jurisdiction as well as our ability to compile data from the generation sector. At this time, all information on generation and transmission capacity is regional. Therefore, this section summarizes the regional reliability assessments of MAAC, ECAR and PJM for generation and transmission capability. The regional reports find that there is sufficient generation and transmission capacity in PA to meet the needs of electric consumers for the foreseeable future.

NERC



Source: http://www.nerc.com

In 1968, electric utilities formed the North American Electric Reliability Council (NERC) to promote the reliability of the electricity supply for North America. Since its formation, NERC has operated as a voluntary organization, dependent on reciprocity and mutual self-interest. Due to the restructuring of the electric utility industry, NERC is being transformed from a voluntary system of reliability management to one that is mandatory, with the backing of U.S. and Canadian governments. The mission of the new North American Electric Reliability Organization (NAERO) will be to develop, promote and enforce reliability standards.

NERC's members are the ten regional reliability councils. Members of these regional councils include investor-owned utilities, federal, rural electric cooperatives, state/municipal and provincial utilities, independent power producers and power marketers. The regional councils operating in Pennsylvania are the Mid-Atlantic Area Council (MAAC) and the East Central Area Reliability Council (ECAR).

Electric system reliability is addressed by considering two basic and functional aspects of the electric system: adequacy and security. *Adequacy* is the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. *Security* is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Resource adequacy can be expressed in terms of either reserve margin or capacity margin. *Reserve margin* is the difference between available resources and net internal demand, expressed as a percent of net internal demand. *Capacity margin* is the difference between available resources and net internal demand, expressed as a percent of available resources.

Compliance Standards

On March 30, 2001, NERC changed its governance to a new, ten-member independent Board of Trustees, replacing a 47-member Board, which comprised both stakeholders and independent members. Additionally, NERC has initiated an Agreement for Regional Compliance and Enforcement Programs under which the Regional Councils will monitor and enforce certain NERC reliability standards, including the imposition of financial penalties.

NERC believes that compliance with reliability standards must be mandatory. The number and complexity of transactions are increasing, due to an increase in the expanse of competitive markets. Compliance with NERC standards is necessary to maintain system reliability to protect the public welfare and ensure a robust competitive market.

Reliability Assessment

According to NERC's *Reliability Assessment 2002-2011* report, the average annual peak demand growth rate over the next ten years is projected to be 2.0% in the United States, about the same as last year's forecast. Over the next 10 years, capacity adequacy in North America will be highly dependent upon the response of merchant power plant developers to market signals to construct new generating facilities in areas experiencing declining capacity margins. Merchant developers have announced plans for more than 286,000 MW of new capacity during the 10-year period, a potential 30.6% increase.

Projected capacity margins show a sharp increase from 2002 to 2005, reaching over 24% in 2005, then decreasing to about 18% as demand continues to grow and reported capacity additions dwindle. Near term generation adequacy is deemed by NERC to be satisfactory throughout most of North America, provided new generating facilities are constructed as planned.

About 10,100 new circuit miles of transmission facilities (230 kV and Higher) are planned for construction throughout North America over the next 10 years. Most of these additions are intended to address local transmission concerns or to connect proposed new generators to the transmission grid. Transmission systems are expected to perform reliably in the near term; however, portions of the transmission systems are reaching their limits as customer demand increases and the systems are subjected to new loading patterns resulting from increased electricity transfers.

Coal remains the predominant fuel for electric generation; however, nearly all recently built power plants and those proposed use natural gas as their primary fuel. With a majority of the new generation fueled by natural gas, there is the question of whether the availability of natural gas and the infrastructure to move it to the generating stations will be adequate. Also, there is a concern about the potential reliability impacts associated with environmental policies and compliance implementation.

MAAC

The Mid-Atlantic Area Council (MAAC) is one of ten regional reliability councils comprised of investor-owned electric utilities, power marketers and independent power producers. MAAC serves over 22 million people in a nearly 50,000 square mile area, which includes all of Delaware and the District of Columbia, major portions of Pennsylvania, New Jersey and Maryland, and a small part of Virginia. MAAC comprises less than 2% of the land area of the contiguous United States but serves about 8% of the electrical load.

MAAC was established in December 1967 to augment the reliability of the bulk electric supply systems of its members through coordinated planning of generation and transmission facilities. PJM Interconnection, L.L.C., (PJM) is the only control area in MAAC. The MAAC signatory systems operate on a "free flowing ties" basis under the PJM Operating Agreement and in accordance with the PJM Open Access Transmission Tariff filed at FERC.

MAAC signatories participate in the PJM energy and capacity market, obtain transmission service through the PJM OASIS, enter into bilateral transactions coordinated between PJM and other control areas and participate in PJM emergency procedures. Under the MAAC Agreement and the PJM Operating Agreement, MAAC and PJM members are obligated to comply with MAAC and NERC operating and planning principles and standards.

A new MAAC Agreement went into effect on January 1, 2001, whereby all members of the PJM Interconnection became members of MAAC. As of May 2003, MAAC had 247 members. Funding for MAAC and NERC will now be collected under a new schedule of the PJM Open Access Transmission Tariff. Full members include Allegheny Electric Cooperative, Inc., Baltimore Gas and Electric Company, Citizens Power Sales, Conectiv, Dynegy Power Marketing, Inc., GPU Energy, PECO Energy Company, Potomac Electric Power Company, PPL, Inc., Public Service Electric and Gas Company, UGI Utilities, Inc. U.S. Generating Company and Vineland Municipal Electric Utility. Operation of the MAAC region is coordinated from the PJM Interconnection Control Center located near Valley Forge, Pennsylvania.

The 2002 MAAC aggregate coincident system summer peak load of 55,569 MW, which occurred on August 14, 2002, was 2.9% higher than the 2001 summer peak of 54,014 MW. Net energy for load in 2002 increased 10,065 GWH (3.8%) from 2001. The regional total internal summer peak demand (including direct control load management and interruptible demand) is projected to increase to 59,537 MW by 2007 at an average annual growth rate of about 1.9%.

Compliance Standards

The MAAC reliability standards require that sufficient generating capacity be installed to ensure that the probability of system load exceeding available capacity is no greater than one day in 10 years. Load serving entities that are members of MAAC have a capacity obligation determined by evaluating individual system load characteristics and unit size and operating characteristics. These obligation reserves must be met by all load-serving entities in PJM as signatories to the Reliability Assurance Agreement.

Net capacity resources are projected to increase from 63,619 MW in 2002 to 69,783 MW in 2007, an increase of 6,164 MW or 9.7%. The reserve margin is expected to peak at 23.1% in 2003. (These figures do not include PJM West, which is a part of ECAR.) The majority of the capacity additions are expected to be natural gas-fueled combined-cycle units. It must be noted that some of this capacity is speculative and may never be built.

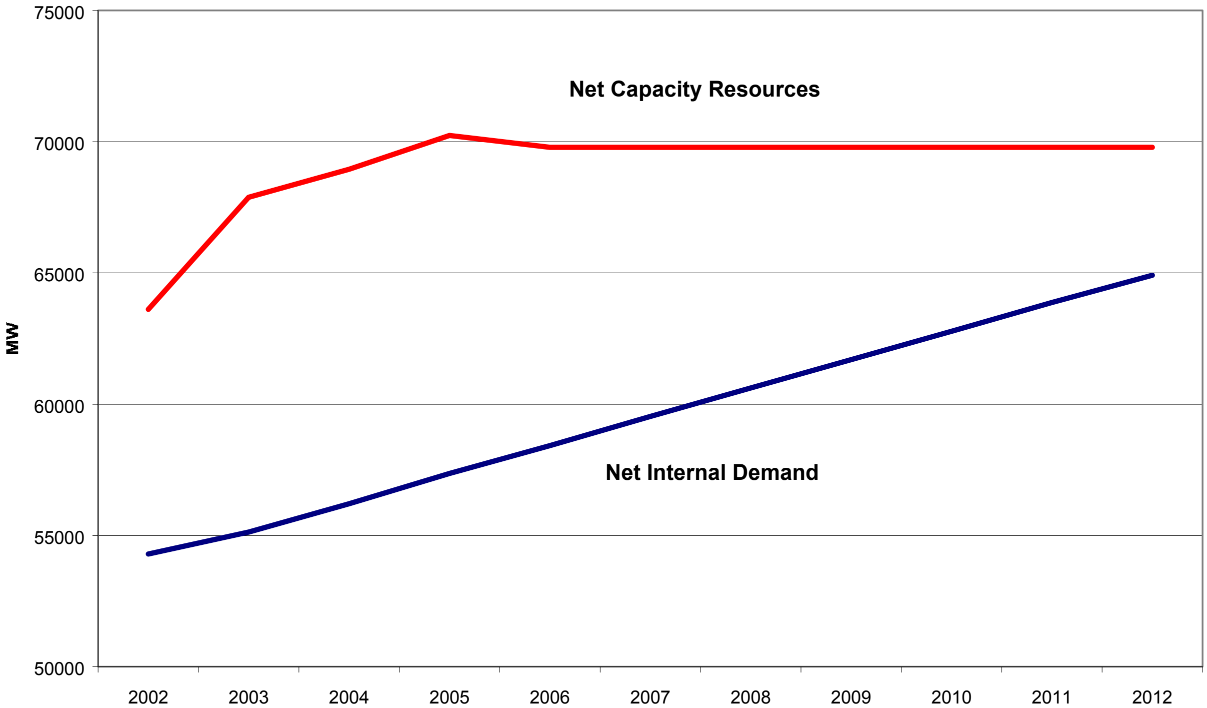
Table 11.1 provides a five-year forecast of loads, resources and reserve margins for MAAC, based on MAAC's Response to the 2003 NERC Data Request (formerly the MAAC EIA-411).

Table 11.1. MAAC 5-Year Load, Resource & Reserve Margin Forecast

		2002	2003	2004	2005	2006	2007
MAAC	Demand (MW)	54296	55128	56211	57361	58424	59537
	Capacity (MW)	63619	67889	68948	70233	69783	69783
	Reserve (%)	17.2	23.1	22.7	22.4	19.4	17.2

Figure 11.1 graphically shows the projected generating capacity and demand for the summer of 2002 through the summer of 2012.

Figure 11.1 -- MAAC Projected Capacity and Demand - Summer



In 2002, the MAAC region's mix of generating capacity was as follows: 24.1% coal, 20.6% nuclear, 10.7% oil, 4.6% hydroelectric (including pumped storage) and 6.0% natural gas. Dual fueled units represent 32.2% of the total. Natural gas generation is expected to increase significantly, rising to 12.8% of the total by 2007.

Reliability Assessment

MAAC's self assessment contained in NERC's *Reliability Assessment 2002-2011 Report* states that generation resources are expected to be adequate to maintain regional reliability over the next ten years. Although not all of this capacity will be built, MAAC believes that sufficient generating capacity will be added to meet the MAAC adequacy objective.

Over the next five years, MAAC expects there will be adequate transmission capability to meet MAAC's criteria requirements. Several transmission reinforcement projects are expected to be in service by 2005.

One concern that MAAC has is the potential adverse impact of Environmental Protection Agency regulations which require abatement of NO_x by 2003 in all states within the MAAC Region. These regulations may result in retirement of existing generating units or extended outages of existing units for capital modifications. Another concern is the effect of off-system sales on the availability of resources for load-serving entities, particularly during peak periods.

See Appendix A for additional data on MAAC capacity and demand projections.

PJM Interconnection L.L.C.

PJM coordinates with its member companies to meet the load requirements of the region. PJM's members also uses bilateral contracts and the spot energy market to secure power to meet electric load. In order to reliably meet its load requirement, PJM must monitor and assess its 8,000 miles of transmission lines for congestion concerns or physical capability problems.

On March 15, 2001, PJM and Allegheny Energy jointly submitted a filing with FERC to establish PJM as the Regional Transmission Organization (RTO) for Allegheny pursuant to an arrangement known as "PJM West." PJM West will continue to be a separate control area, within the ECAR Region, but will operate under the direction of the PJM Board of Managers. This will expand the scope of PJM's operations in Pennsylvania, Maryland and Virginia and extend PJM's operations into West Virginia and Ohio. The expansion of PJM's operations will provide greater resources to maintain both short-term and long-term reliability at a lower overall cost and environmental impact. Duquesne Light Company anticipates joining PJM West after certain issues are resolved concerning the impact of RTO participation on its provider-of-last-resort requirement. PJM West became operational on April 1, 2002. Table 11.2 provides the combined statistics for PJM and PJM West.

Table 11.2. PJM and PJM West Statistics	
Generating Units	594
Generating Capacity	72,400 MW
Peak Load	63,762 MW (August 14, 2002)
Annual Energy	329,000 GWH
Transmission Miles	13,000
Area	79,000 square miles
Number of Customers	11 million
Population Served	25.1 million

Dominion Resources, Inc. and PJM announced on June 25, 2002, that the companies have executed an agreement to have Dominion's 6,000 miles of transmission lines operated on a regional basis by PJM. Under the terms of the agreement, Dominion would establish PJM South and would allow Dominion's control area to be operated separately under the single PJM energy market, similar to PJM West. Dominion, headquartered in Richmond, Virginia, has nearly 24,000 MW of generating capacity and serves 3.9 million electric and natural gas customers in five states.

On July 31, 2002 , FERC conditionally approved the requests of AEP, Com Ed, DPL , and DVP (collectively, the Market Growth Participants) to join PJM. FERC 's conditions include resolution of certain operational and transmission rate matters to be approved by the FERC prior to the Market Growth Participants' integration into PJM.

In 2002, PJM and the Midwest ISO announced that they executed a "Letter of Intent" to develop a single wholesale market for electricity producers and consumers in all parts of 27 mid-west and mid-Atlantic states, the District of Columbia and the Canadian province of Manitoba. The Letter of Intent states, "Such a Market, extending over a large geographic area, will be designed and operated to serve the needs of the public, the individual states and governmental entities, to benefit the economies in the regions encompassed by the Market." The Midwest ISO serves 17.5 million customers and operates 122,000 MW of generating capacity and 111,000 miles of transmission lines.

In addition to the direct connect transmission facilities associated with new generating capacity, several transmission reinforcement projects are expected to be in service by 2006. These projects were evaluated by PJM through the PJM Regional Transmission Expansion Planning Process. PJM conducted a comprehensive load flow analysis of the ability of the PJM system as planned for 2006 to meet single contingency, second contingency and multiple facility outage contingency tests. Five areas of the system as planned through 2006 were found to be non-compliant with applicable NERC and MAAC reliability standards without additional reinforcement.

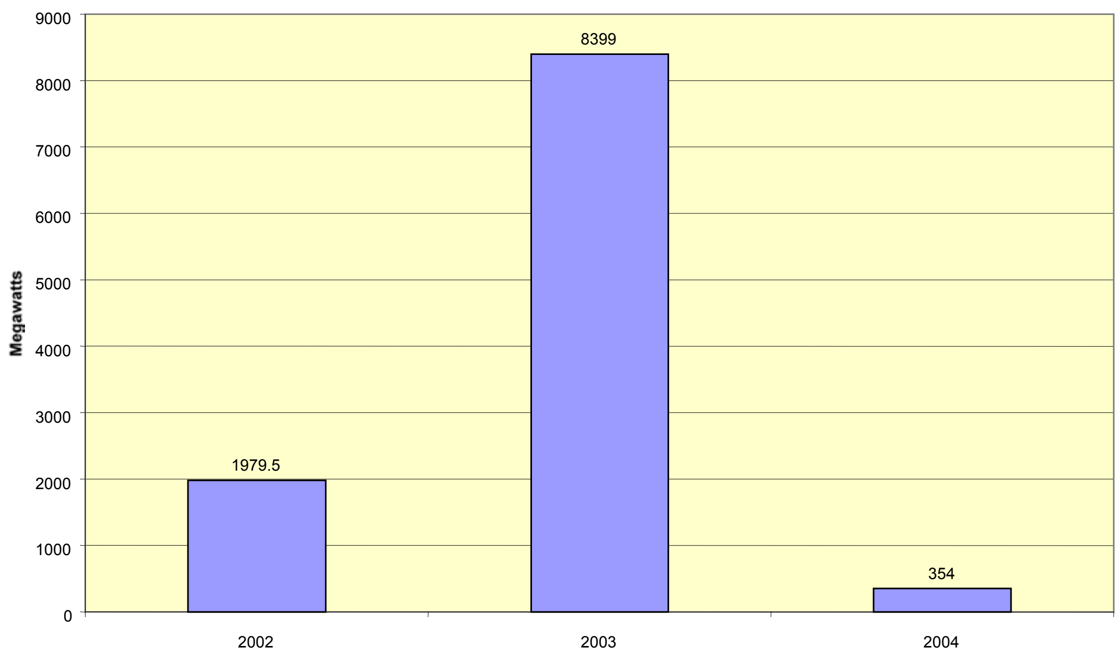
See Appendix C for a listing of planned transmission line additions and upgrades for Pennsylvania's EDCs.

According to the PJM State of the Market Report – 2002, PJM's Demand-Side Response (DSR) program resulted in a maximum hourly reduction in load of 1,833 MWH during 2002. In 2002, the total resources in the Economic Program were 343 MW; the total resources in the Emergency Program were 548 MW; and the total resources in the ALM Program were 1,569 MW. The total DSM reduction for that hour was 515 MW. The impact of this load reduction was to lower average hourly LMP by about $16 per MWH to $110 per MWH.

PJM Generation Adequacy

For 2002, PJM expects to have about 2,000 MW of capacity additions and expects nearly 8,800 MW of capacity additions during 2003 and 2006. See Figure 11.2.

Figure 11.2. PJM Generation Additions



Four activities conducted by PJM decide the future construction or expansion of an existing power plant in the region:

- Proposals are submitted to PJM and entered in a calendar-based queue. (Appendix D provides tables of the status of PJM new power plant queues.)
- Feasibility studies are conducted by queue to estimate interconnection costs and construction time, and provide feedback to project owners.
- Impact studies are conducted next to develop specific recommendations for system additions and costs. Permitting of plants begins at this stage. (Appendix E provides a chart of transmission network upgrades for new PA power plants.)
- The Board of Managers grants approvals after public review with PJM committee members.

Table 11.3. PJM Proposed Projects and Capacity

Projects			***MW***		
Total Original Projects	373	100%	Total Original Projects	119,644	100%
Projects Withdrawn	185	49.6%	Projects Withdrawn	71,476	59.7%
Projects Remaining	122	32.7%	Project Remaining	42,072	35.2%
Projects in Service	66	17.7%	Projects in Service	6,096	5.1%

PJM-West has 10,136 MW of capacity and a load of 8,127 MW, or a reserve margin of about 24.6%. PJM-East this summer had an installed capacity of 63,619 MW and a load of 54,296 MW, a 17.2% reserve margin. PJM-East and PJM-West have a combined capacity of 72,703 MW. The system heavily depends on PJM-West's capacity for reliability purposes. PJM-East imports approximately 3% of its power supply from neighboring systems in the summer months. PJM-East this summer had 636 MW of Direct Control Load Management and 637 MW of Interruptible Demand. It is important to state however, that PJM-East can benefit from its expanded markets at PJM-West and the merger of the Midwest-ISO. Figure 11.3 illustrates a historic increase in PJM East's installed capacity during the past 34 months. The significant increases occurred during the most recent 17 months. This is included to demonstrate how capacity has risen in the short term for PJM East. Figure 11.4 shows the PJM load forecast as compared to existing and planned generating capacity.

Figure 11.3.

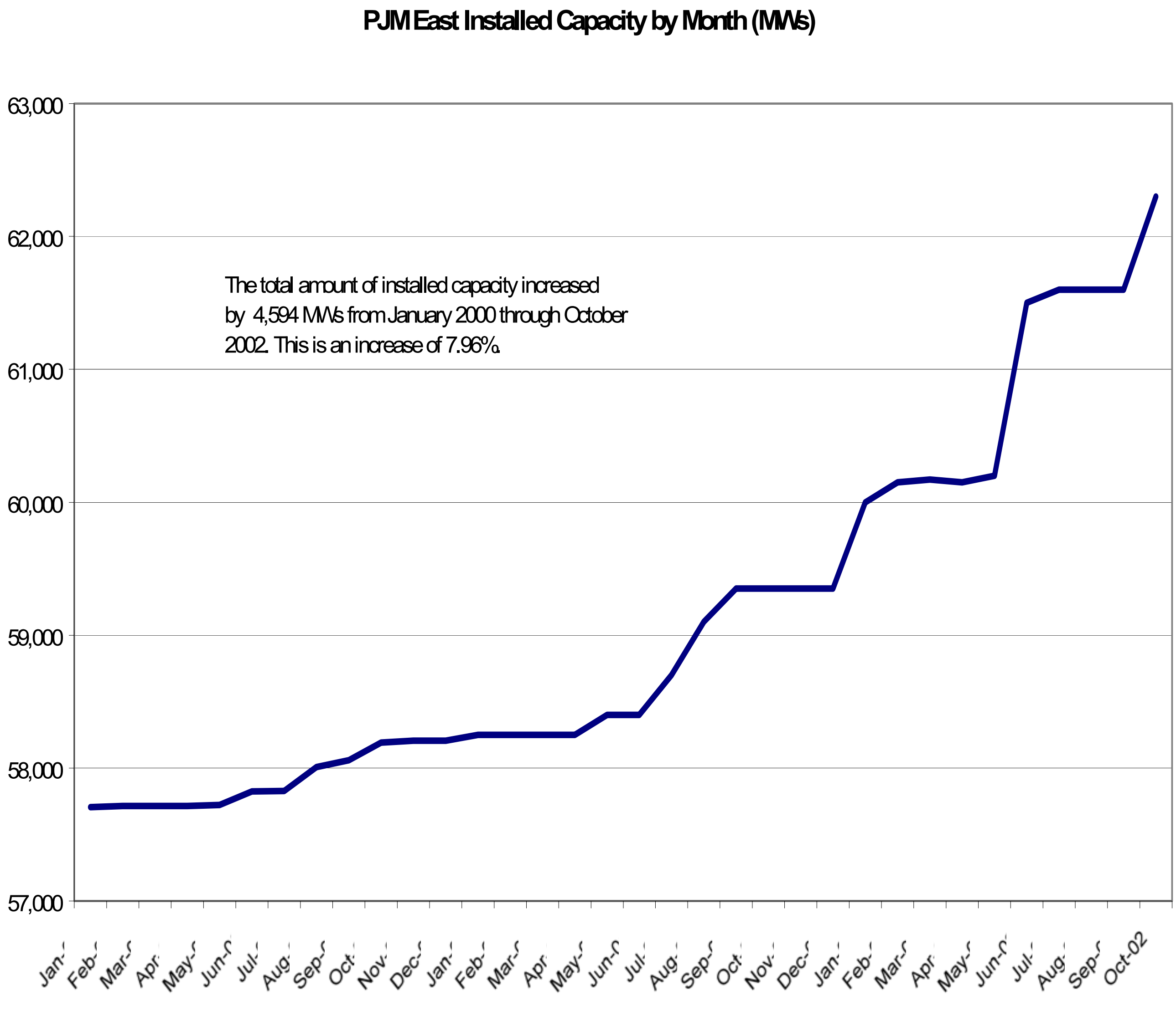
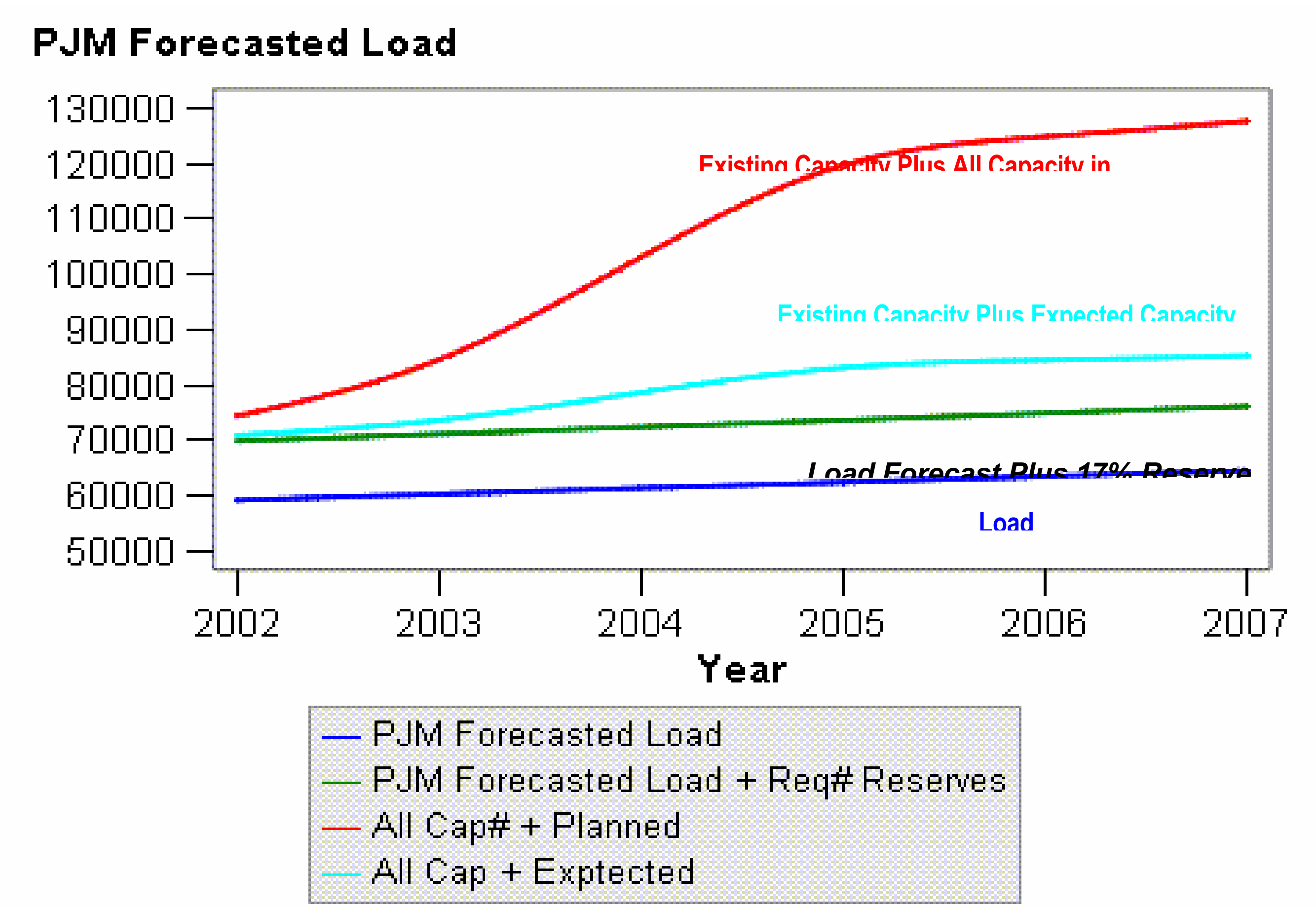


Figure 11.4



Projects Placed In-Service 1/1/02-9/30/02 - 2,813 MW
Projects In Testing Phase - 1,322 MW
Expected In-Service By 12/31/02 - 915 MW

Expected Slow-Down in Power Plant Construction in PJM

In the 1960s and early 1970s, the annual growth in electricity demand was around seven percent. There was a need to construct new power plants. As a result of the load growth, new generating capacity was constructed to meet that demand. In the early 1980s, the load growth that caused the construction of the base load generating capacity disappeared due to the worldwide inflation and recession of 1981-1984. Several electric utilities in Pennsylvania were left with excess capacity from 1984 through 2000. The power plants constructed in the late 1960s and 1970s are over 30 years old, some of which are approaching the end of their useful lives.

The load growth that occurred during the strong economic conditions in the US in the 1990s was moderate in Pennsylvania due to the restructuring and transition of the state's economy. The state's economy has been moving from heavy steel and manufacturing industry to service oriented industries in the last twenty years. As a result of this transformation, the load growth has been modest for almost fifteen years. During this period, the load has grown between one to three percent. In such a low-growth environment, Pennsylvania has maintained a fairly adequate reserve margin of around 20%.

However, although both PJM-East and PJM-West maintain adequate reserves, the Commission is concerned about the adequacy of the transmission lines between these two locations. Dependency on transmission transfers to supplement capacity and/or reserves during peak times may create reliability issues in the future. Transmission constraints and development are some of the largest issues facing a power plant developer. The cost to upgrade a transmission system, and associated feasibility studies, factor largely into power plant site selection, along with many other issues. Appendix E is a summary of transmission network upgrades for new power plant construction or expansion within Pennsylvania. These are based on PJM's queues and are the projects most likely to become a reality in future years. This transmission information coincides, to a large degree, with new plant construction.

Also, PJM has limited information on the retirement of generating units. Older units may not be economically viable in the future. NOx legislation will have an impact on some PJM units. Some nuclear units have reached their planned life span, and some Pennsylvania nuclear units are considering, or undergoing review for Nuclear Regulatory Commission (NRC) re-licensing of their plants which may offer continued service from those plants, recognizing any delays for required maintenance, upgrades, re-rating, etc. Pennsylvania plants are noted in bold in the chart in Appendix F.

Pennsylvania

As we enter the 21st Century, many Pennsylvania aging coal and nuclear generating power plants may face retirement due to high maintenance and strict environmental regulations. Reserve margins in PJM are already declining, approaching 17% in the next two years. Clearly there is a need for new construction of power plants in the PJM region.

Serious financial problems have engulfed the energy industry nationwide, and have significantly limited the industry's ability to finance the construction of new generation. Many power plant projects have been canceled due to the financial problems faced by energy companies.

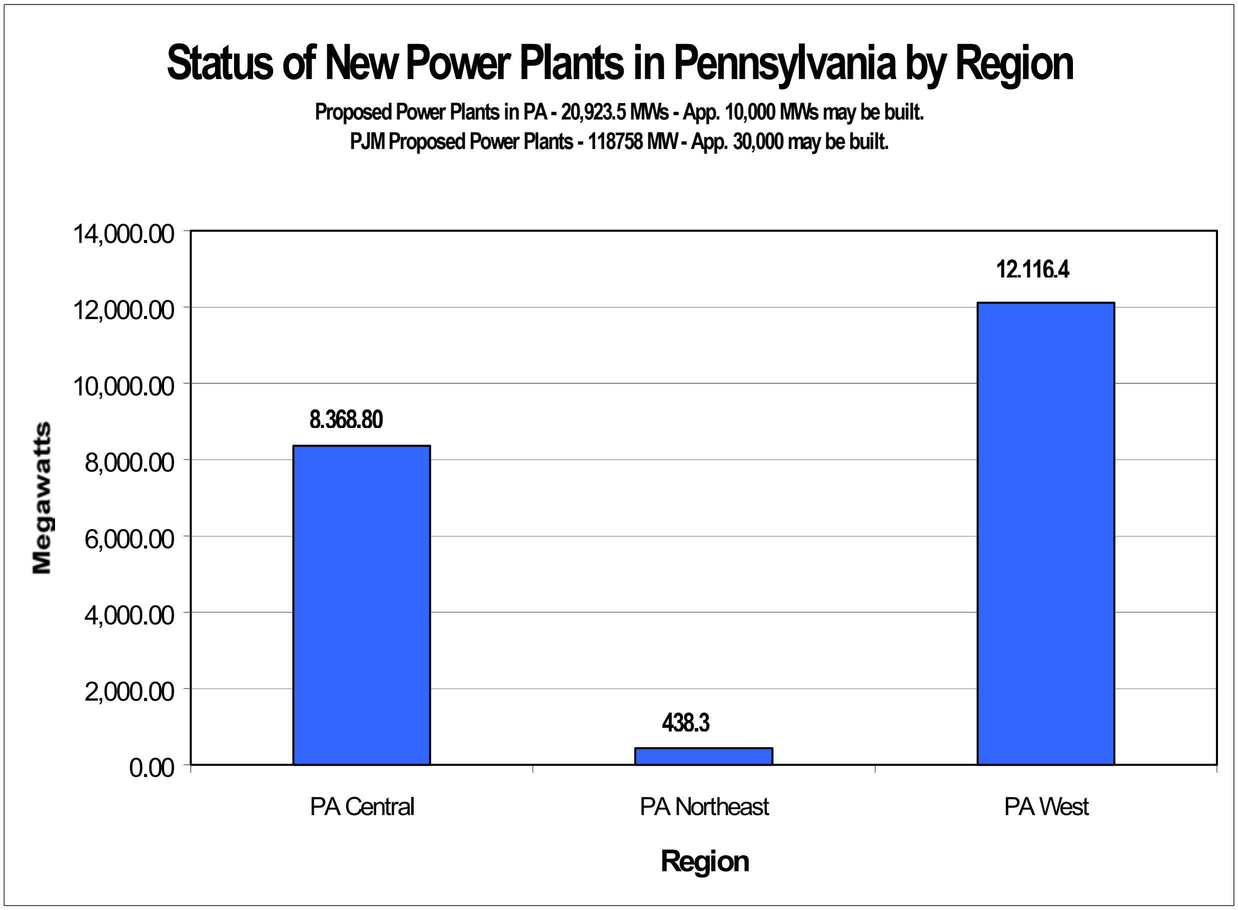
The following two charts summarize Pennsylvania's projects and capacity in service, as well as the status of new power plants in the state by region. Most plants are being developed in the western and central regions of the Commonwealth.

Table 11.7 and Figure 11.7 provide a summary of the status of new power plants in Pennsylvania, broken down by region. Of the 21,000 MW of proposed plants, it is estimated that approximately one-half will eventually be built.

Table 11.7. Summary of Pennsylvania Projects and Capacity

Total Projects			***Total MW***		
Central PA	26	34.7%	Central PA	8368.8 MW	40.0%
Northeast PA	14	18.7%	Northeast PA	438.3MW	2.1%
Western PA	35	46.7%	Western PA	12,116.4 MW	57.9%
Total Projects	**75**	**100.0%**	**Total MW**	**20,923.5 MW**	**100%**
			Projects In Service	**3,000 MW or 14.34%**	

Figure 11.7


Status of New Power Plants in Pennsylvania by Region
Proposed Power Plants in PA - 20,923.5 MWs - App. 10,000 MWs may be built.
PJM Proposed Power Plants - 118758 MW - App. 30,000 may be built.
14,000.00
12,000.00
10,000.00
8,000.00
6,000.00
4,000.00
2,000.00
0.00
Megawatts
8.368.80
438.3
12.116.4
PA Central
PA Northeast
PA West
Region

ECAR

The East Central Area Reliability Council (ECAR) augments bulk power supply reliability through coordination of planning and operation of member companies' generation and transmission facilities. Full members currently includes 20 systems serving either all or parts of the states of Indiana, Kentucky, Maryland, Michigan, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia, serving more than 36 million people.

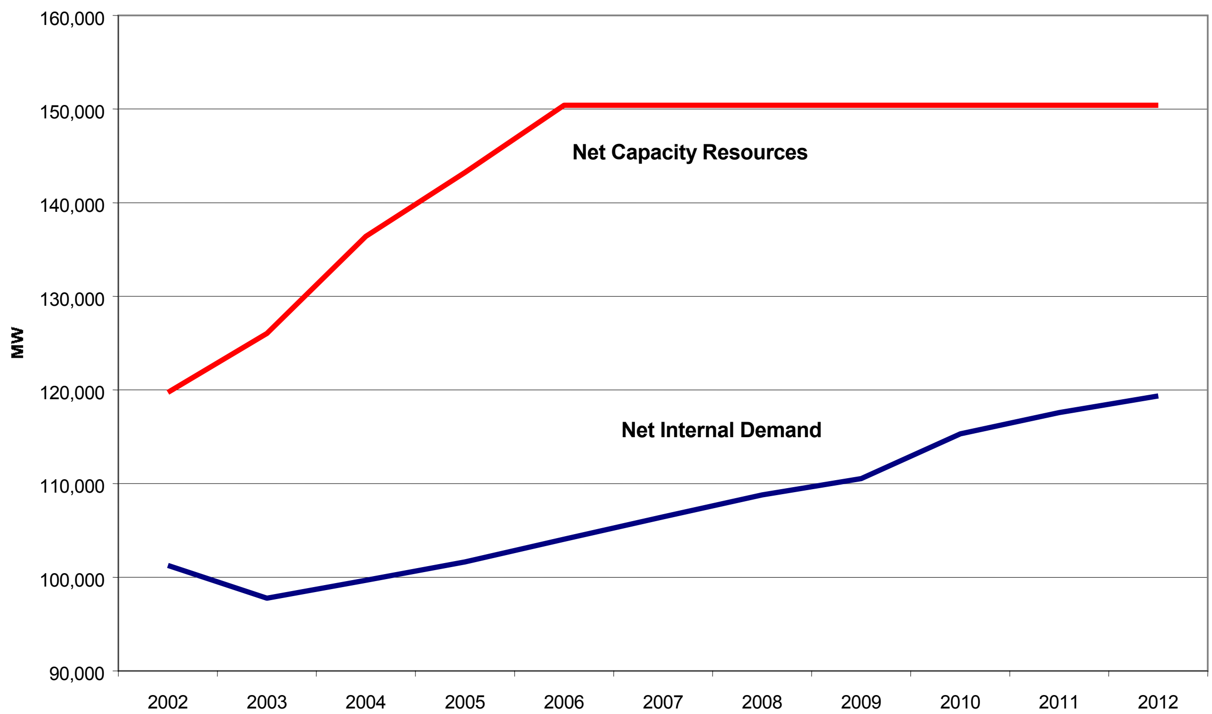
Control of the generating units and the bulk power transmission networks within the ECAR region is directed by 19 Power Control Centers which include Allegheny Power (of which West Penn Power Company is a subsidiary), Duquesne Light Company and FirstEnergy (of which Pennsylvania Power Company is a subsidiary).

The 2002 aggregate (non-coincident) summer peak load of 102,996 MW was 2,761 MW or 2.8% higher than the summer peak of 2001. This load was also 3,650 MW or 3.7% higher than the forecast. Net generating capacity resources at the time of the peak was 119,736 MW. Net energy for load in 2002 was 567.9 billion KWH or 4.0% higher than that of the previous year.

The regional non-coincident internal peak load is projected to increase to 109,533 MW by the summer of 2007 at an average annual growth rate of 1.3%. Peak load reductions from direct load control programs and interruptible customers are expected to reach 2,867 MW by 2007. Energy demand is expected to grow at a rate of 1.4% per year.

ECAR's members project additions of 30,749 MW of new generating capacity by 2007, which includes 26,911 MW of uncommitted resources. A majority of this new capacity is projected to be short lead-time, gas-fired combustion turbine and combined cycle units (78.5%). Capacity margins for net internal demand are expected to be between 22.4% and 30.8% in the 2003-2007 timeframe. See Figure 11.8.

Figure 11.8 ECAR Capacity and Demand - Summer



Compliance Standards

ECAR's standard for evaluating the reliability of the generation component of the bulk power supply involves the computation of the number of days per year that the ECAR Region is expected to rely on (a) generating resources outside of ECAR and (b) reducing area load to the extent that such resources are not available. The member companies use this measure of performance, the Dependence on Supplemental Capacity Resources (DSCR), to identify critical bulk power supply situations for appropriate response.

Reliability Assessment

ECAR's self assessment contained in NERC's *Reliability Assessment 2002-2011* report states that resources planned for the ECAR Region should be adequate. The system is expected to meet the forecasted demand obligations, assuming proposed projects are completed as planned.

See Appendix A for additional data on capacity and demand projections.

Section 4

Conclusions

For many years, Pennsylvania has benefited from a high level of electric service reliability.

The Mid-Atlantic Area Council (MAAC) and the East Central Area Reliability Council (ECAR) regions covering Pennsylvania continue to have sufficient generating resources to maintain a high level of reliability during the summer of 2002 and beyond. Load growth in the mid-Atlantic is expected to be moderate. Thousands of megawatts of new capacity are proposed to be in service between 2002 and 2007, and it is anticipated that total generation capacity will match or somewhat outstrip demand. New capacity will help to ensure the reliability of electric service in the state and will increase the robustness of the competitive energy markets. Figure 12.1 shows the actual and projected PJM East reserve margin from 1990 to 2006. Figure 12.2 depicts projected growth in installed capacity for PJM East.

Figure 12.1

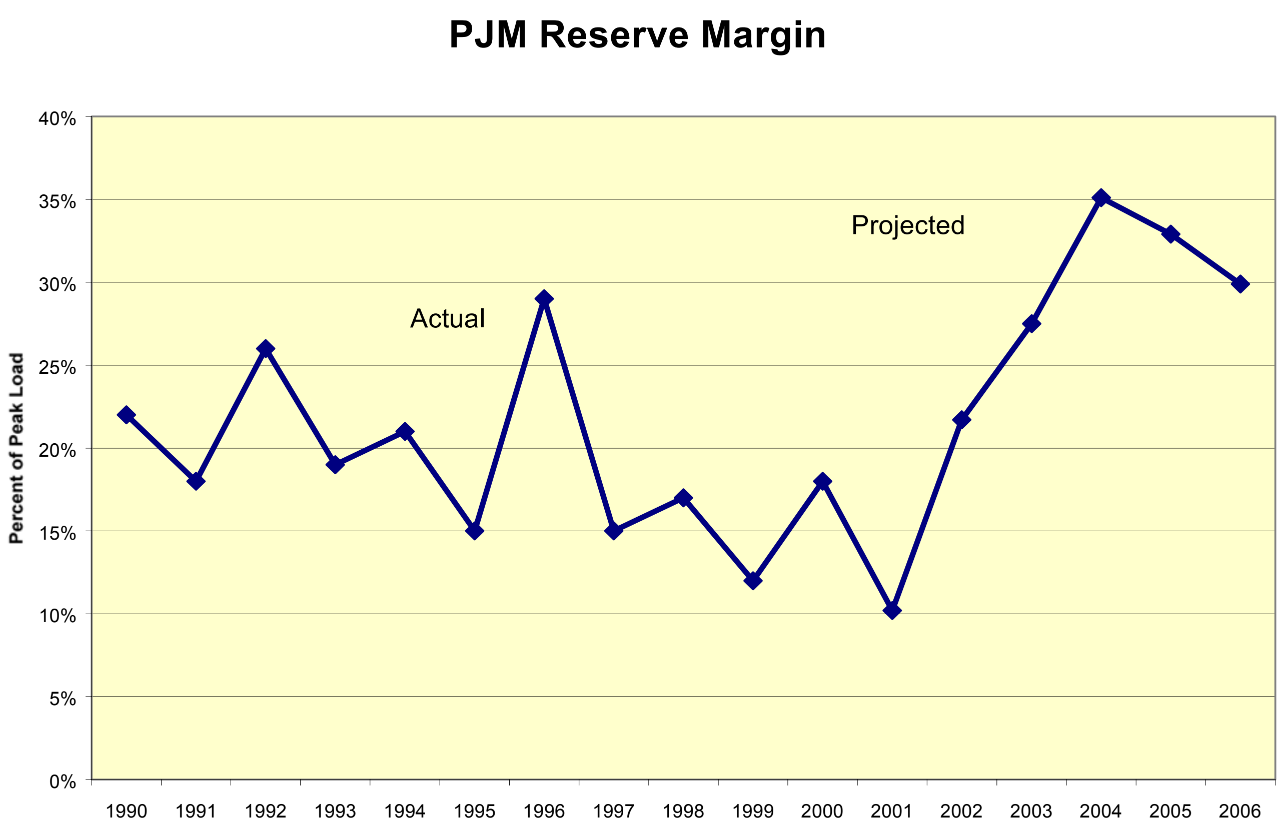
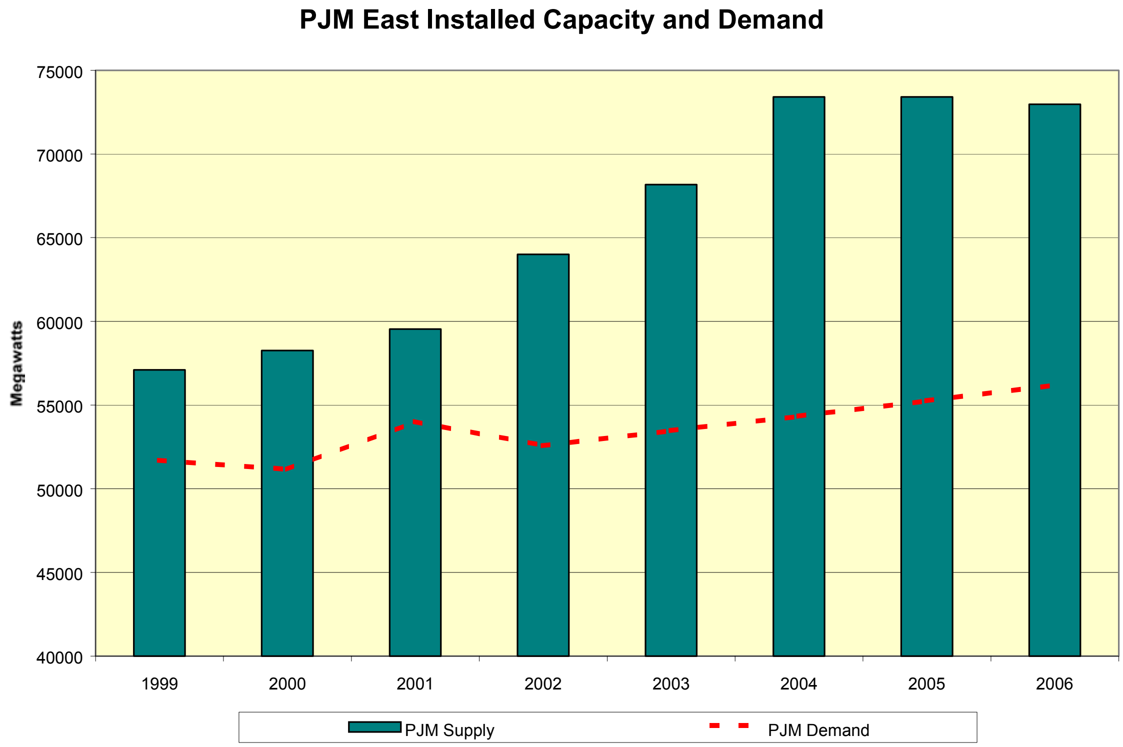


Figure 12.2



Thus, the regional reliability councils report that there is sufficient generation, transmission and distribution capacity in Pennsylvania to meet the needs of electric consumers for the foreseeable future. The Commission has also launched a demand side response initiative to address ways to encourage customers to respond to peak period wholesale prices by reducing their demand. In the long term, this initiative will improve overall energy efficiency.

* * *

To summarize the relevant statistics in this report, aggregate Pennsylvania sales in 2002 totaled 134.4 billion kilowatthours (KWH), a 2.6% increase from that of 2001 and represents 4.0% of the United States' total. Industrial sales accounted for 34.6% of the total sales, followed by residential (34.5%) and commercial (30.9%).

Between 1987 and 2002, the state's energy demand grew an average of 1.7% annually. Residential sales grew at an annual rate of 2.0%, commercial at 3.3% and industrial at 0.4%. The current aggregate 5-year projection of growth in energy demand is 1.0%. This includes a residential growth rate of 0.7%, a commercial rate of 1.7% and an industrial rate of 0.7%.

The 2002 MAAC/PJM aggregate coincident system summer peak load of 55,569 MW, which occurred on August 14, 2002, was 2.9% higher than the 2001 summer peak of 54,014 MW. Energy consumption in 2002 increased 10.1 billion KWH (3.8%) from 2001. The regional total internal summer peak demand (including direct control load management and interruptible demand) is projected to increase to 59,537 MW by 2007 at an average annual growth rate of about 1.9%.

Committed resources are projected to grow from 63,132 MW in 2002 to 69,745 MW in 2007, an increase of 6,613 MW or 10.5%. The reserve margin is expected to peak at 22.3% in 2003, declining to 17.1% by 2007. (These figures do not include PJM West, which is a part of ECAR.) The majority of the capacity additions are expected to be natural gas-fueled combined-cycle units.

The regional non-coincident internal peak demand is projected to increase to 106,451 MW by the summer of 2007 at an average annual growth rate of 1.0%. Peak load reductions from direct load control programs and interruptible customers are expected to reach 2,867 MW by 2007. Energy demand is expected to grow at a rate of 1.4% per year.

ECAR's members project additions of 30,749 MW of new generating capacity by 2007, which includes 26,911 MW of uncommitted resources. A majority of this new capacity is projected to be short lead-time, gas-fired combustion turbine and combined cycle units (78.5%). Reserve margins for net internal demand are expected to be between 28.3% and 17.8% in the 2003-2007 timeframe.

Appendix A

Capacity and Demand Projections
Of ECAR and MAAC

Source: ECAR and MAAC Responses to the 2001 NERC Data Request
(formerly the EIA-411)

ECAR Actual and Projected Energy and Peak Demand

Actual Data: 2002	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Peak Hour Demand - MW	79,963	80,476	80,834	77,743	81,624	98,300	101,988	102,996	97,427	81,544	75,971	82,887
Net Energy - GWH	48,240	43,586	45,847	42,678	43,139	48,983	55,193	54,146	47,301	44,837	44,684	49,263

Reporting Year: 2003	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Peak Hour Demand - MW	87,300	80,558	76,220	69,633	80,554	95,538	100,714	100,016	90,167	72,743	76,104	82,616
Net Energy - GWH	51,098	44,942	46,671	42,378	44,417	48,398	53,424	52,064	45,555	45,158	44,709	49,408

Next Year: 2004	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Peak Hour Demand - MW	86,120	82,489	77,669	70,986	82,455	97,355	102,737	102,160	91,868	74,165	77,704	84,293
Net Energy - GWH	52,291	46,441	47,808	43,268	45,408	49,600	54,325	53,130	46,336	45,903	45,686	50,462

Actual Previous Year and	Actual	Projected									
10 Year Projection:	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Peak Hour Demand - MW - Summer	102,996	100,714	102,737	104,716	107,169	109,533	111,884	113,659	118,470	120,645	122,335

Actual Previous Year and	Actual	Projected									
10 Year Projection:	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12
Peak Hour Demand - MW - Winter	87,300	86,120	87,556	88,532	90,443	92,334	95,042	98,843	100,365	100,664	120,214

Actual Previous Year and	Actual	Projected									
10 Year Projection:	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Net Energy - GWH	567,897	568,222	580,658	590,121	599,955	608,977	618,362	627,723	637,854	647,171	657,741

Peak demands are sum of monthly company peaks (non-coincicent).

MAAC Actual and Projected Energy and Peak Demand

Actual Data: 2002	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Peak Hour Demand - MW	39,458	38,812	38,634	44,336	42,547	52,490	55,302	55,569	46,828	41,809	37,039	42,379
Net Energy - GWH	22,880	20,130	21,271	20,247	20,563	23,885	27,970	27,985	22,330	21,340	21,074	24,232

Reporting Year: 2003	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Peak Hour Demand - MW	44,031	42,756	40,652	37,252	42,700	53,112	56,257	54,610	48,267	37,708	39,421	43,203
Net Energy - GWH	24,840	21,934	22,293	20,059	20,619	23,423	26,531	26,088	22,022	20,850	21,412	24,045

Next Year: 2004	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Peak Hour Demand - MW	44,748	43,467	41,333	37,886	43,568	54,160	57,330	55,652	49,202	38,373	40,122	43,970
Net Energy - GWH	25,334	22,488	22,743	20,416	21,102	23,846	27,013	26,512	22,414	21,175	21,692	24,492

Actual Previous Year and	Actual	Projected									
10 Year Projection:	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Peak Hour Demand - MW - Summer	55,569	56,257	57,330	58,480	59,543	60,656	61,746	62,821	63,903	64,996	66,032

Actual Previous Year and	Actual	Projected									
10 Year Projection:	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Peak Hour Demand - MW - Winter	46,551	44,748	45,522	46,213	46,909	47,627	48,338	49,070	49,796	50,527	51,245

Actual Previous Year and	Actual	Projected									
10 Year Projection:	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Net Energy - GWH	273,906	274,116	279,227	283,818	288,237	292,599	297,199	301,656	306,126	310,826	315,594

ECAR Projected Capacity and Demand - Summer

Demand in Megawatts	Actual 2002	Projected 2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Internal Demand	102,996	100,714	102,737	104,716	107,169	109,533	111,884	113,659	118,470	120,645	122,335
Standby Demand											
Total Internal Demand	102,996	100,714	102,737	104,716	107,169	109,533	111,884	113,659	118,470	120,645	122,335
Direct Control Load Management	116	125	145	169	193	215	237	247	248	249	139
Interruptible Demand	1,629	2,831	2,917	2,916	2,905	2,867	2,864	2,876	2,898	2,806	2,828
Net Internal Demand	101,251	97,758	99,675	101,631	104,071	106,451	108,783	110,536	115,324	117,590	119,368

Capacity in Megawatts	Actual 2002	Projected 2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Committed Resources	121,596	125,434	125,434	125,434	125,434	125,434	125,434	125,434	125,434	125,434	125,434
Uncommitted Resources	0	0	12,905	19,741	26,911	26,911	26,911	26,911	26,911	26,911	26,911
Total Capacity	121,596	125,434	138,339	145,175	152,345	152,345	152,345	152,345	152,345	152,345	152,345
Nuclear	7,703	7,706	7,706	7,706	7,706	7,706	7,706	7,706	7,706	7,706	7,706
Hydro	1,052	1,052	1,052	1,135	1,215	1,215	1,215	1,215	1,215	1,215	1,215
Pumped Storage	2,117	2,117	2,117	2,117	2,117	2,117	2,117	2,117	2,117	2,117	2,117
Geothermal	0	0	0	0	0	0	0	0	0	0	0
Steam -- Coal	83,083	82,861	83,411	84,284	86,384	86,384	86,384	86,384	86,384	86,384	86,384
Steam -- Oil	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570
Steam -- Gas	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354	2,354
Steam -- Dual Fuel	0	0	0	0	0	0	0	0	0	0	0
Combustion Turbine -- Oil	1,799	1,799	1,799	1,799	1,799	1,799	1,799	1,799	1,799	1,799	1,799
Combustion Turbine -- Gas	17,890	18,655	23,541	24,501	25,901	25,901	25,901	25,901	25,901	25,901	25,901
Combustion Turbine -- Dual Fuel	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle -- Oil	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle -- Gas	3,312	6,594	13,968	17,768	19,428	19,428	19,428	19,428	19,428	19,428	19,428
Combined Cycle -- Dual Fuel	0	0	0	0	0	0	0	0	0	0	0
Other	716	726	821	1,941	3,871	3,871	3,871	3,871	3,871	3,871	3,871
Inoperable Capacity	1,860	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
Net Operable Capacity	119,736	123,502	136,407	143,243	150,413	150,413	150,413	150,413	150,413	150,413	150,413
Capacity Purchases - Total		3,557									
Full Responsibility Purchases											
Capacity Sales - Total		1,015									
Full Responsibility Sales											
Adjustment to Purchases and Sales											
Net Capacity Resources	119,736	126,044	136,407	143,243	150,413	150,413	150,413	150,413	150,413	150,413	150,413

ECAR Projected Capacity and Demand - Winter

Demand in Megawatts	Actual	Projected									
	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Internal Demand	87,300	86,120	87,556	88,532	90,443	92,334	95,042	98,843	100,365	100,664	120,214
Standby Demand											
Total Internal Demand	87,300	86,120	87,556	88,532	90,443	92,334	95,042	98,843	100,365	100,664	120,214
Direct Control Load Management	146	148	150	153	155	158	159	161	163	168	150
Interruptible Demand	2,310	2,310	2,295	2,280	2,227	2,206	2,206	2,213	2,220	2,222	2,271
Net Internal Demand	84,844	83,662	85,111	86,099	88,061	89,970	92,677	96,469	97,982	98,274	117,793

Capacity in Megawatts	Actual	Projected									
	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Committed Resources	125,757	133,053	133,053	133,053	133,053	133,053	133,053	133,053	133,053	133,053	133,053
Uncommitted Resources	0	0	11,599	19,882	23,772	23,772	23,772	23,772	23,772	23,772	23,772
Total Capacity	125,757	133,053	144,652	152,935	156,825	156,825	156,825	156,825	156,825	156,825	156,825
Nuclear	7,842	7,845	7,845	7,845	7,845	7,845	7,845	7,845	7,845	7,845	7,845
Hydro	1,091	1,091	1,091	1,254	1,254	1,254	1,254	1,254	1,254	1,254	1,254
Pumped Storage	2,117	2,117	2,117	2,117	2,117	2,117	2,117	2,117	2,117	2,117	2,117
Geothermal	0	0	0	0	0	0	0	0	0	0	0
Steam -- Coal	83,875	83,653	85,076	87,176	87,176	87,176	87,176	87,176	87,176	87,176	87,176
Steam -- Oil	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585
Steam -- Gas	2,221	2,221	2,221	2,221	2,221	2,221	2,221	2,221	2,221	2,221	2,221
Steam -- Dual Fuel	0	0	0	0	0	0	0	0	0	0	0
Combustion Turbine -- Oil	2,101	2,101	2,101	2,101	2,101	2,101	2,101	2,101	2,101	2,101	2,101
Combustion Turbine -- Gas	20,826	21,701	26,672	26,672	28,072	28,072	28,072	28,072	28,072	28,072	28,072
Combustion Turbine -- Dual Fuel	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle -- Oil	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle -- Gas	3,383	10,013	15,123	20,023	20,583	20,583	20,583	20,583	20,583	20,583	20,583
Combined Cycle -- Dual Fuel	0	0	0	0	0	0	0	0	0	0	0
Other	716	726	821	1,941	3,871	3,871	3,871	3,871	3,871	3,871	3,871
Inoperable Capacity	1,934	1,934	1,934	1,934	1,934	1,934	1,934	1,934	1,934	1,934	1,934
Net Operable Capacity	123,823	131,119	142,718	151,001	154,891	154,891	154,891	154,891	154,891	154,891	154,891
Capacity Purchases - Total		2,914									
Full Responsibility Purchases											
Capacity Sales - Total		715									
Full Responsibility Sales											
Adjustment to Purchases and Sales											
Net Capacity Resources	123,823	133,318	142,718	151,001	154,891	154,891	154,891	154,891	154,891	154,891	154,891

MAAC Projected Capacity and Demand - Summer

Demand in Megawatts	Actual 2002	Projected 2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Internal Demand	55,569	56,257	57,330	58,480	59,543	60,656	61,746	62,821	63,903	64,996	66,032
Standby Demand	0	0	0	0	0	0	0	0	0	0	0
Total Internal Demand	55,569	56,257	57,330	58,480	59,543	60,656	61,746	62,821	63,903	64,996	66,032
Direct Control Load Management	636	617	617	617	617	617	617	617	617	617	617
Interruptible Demand	637	512	502	502	502	502	502	502	502	502	502
Net Internal Demand	54,296	55,128	56,211	57,361	58,424	59,537	60,627	61,702	62,784	63,877	64,913

Capacity in Megawatts	Actual 2002	Projected 2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Committed Resources	63,132	67,401	68,460	69,745	69,745	69,745	69,745	69,745	69,745	69,745	69,745
Uncommitted Resources	0	0	0	0	0	0	0	0	0	0	0
Total Capacity	63,132	67,401	68,460	69,745	69,745	69,745	69,745	69,745	69,745	69,745	69,745
Nuclear	13,030	13,203	13,203	13,203	13,203	13,203	13,203	13,203	13,203	13,203	13,203
Hydro	1,169	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205
Pumped Storage	1,745	1,745	1,745	1,745	1,745	1,745	1,745	1,745	1,745	1,745	1,745
Geothermal	0	0	0	0	0	0	0	0	0	0	0
Steam -- Coal	15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217
Steam -- Oil	2,521	2,521	2,521	2,521	2,521	2,521	2,521	2,521	2,521	2,521	2,521
Steam -- Gas	78	78	78	78	78	78	78	78	78	78	78
Steam -- Dual Fuel	10,857	10,857	10,857	10,857	10,857	10,857	10,857	10,857	10,857	10,857	10,857
Combustion Turbine -- Oil	4,242	4,242	4,242	4,242	4,242	4,242	4,242	4,242	4,242	4,242	4,242
Combustion Turbine -- Gas	999	2,459	2,459	2,558	2,558	2,558	2,558	2,558	2,558	2,558	2,558
Combustion Turbine -- Dual Fuel	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825
Combined Cycle -- Oil	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle -- Gas	2,711	5,241	6,270	6,270	6,270	6,270	6,270	6,270	6,270	6,270	6,270
Combined Cycle -- Dual Fuel	4,674	4,674	4,674	5,860	5,860	5,860	5,860	5,860	5,860	5,860	5,860
Other	1,064	1,134	1,164	1,164	1,164	1,164	1,164	1,164	1,164	1,164	1,164
Inoperable Capacity	0	0	0	0	0	0	0	0	0	0	0
Net Operable Capacity	63,132	67,401	68,460	69,745	69,745	69,745	69,745	69,745	69,745	69,745	69,745
Capacity Purchases - Total	488	488	488	488	38	38	38	38	38	38	38
Full Responsibility Purchases	0	0	0	0	0	0	0	0	0	0	0
Capacity Sales - Total	0	0	0	0	0	0	0	0	0	0	0
Full Responsibility Sales	0	0	0	0	0	0	0	0	0	0	0
Adjustment to Purchases and Sales	0	0	0	0	0	0	0	0	0	0	0
Net Capacity Resources	63,620	67,889	68,948	70,233	69,783	69,783	69,783	69,783	69,783	69,783	69,783

MAAC Projected Capacity and Demand - Winter

Demand in Megawatts	Actual 02/03	Projected 03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Internal Demand	46,551	44,748	45,522	46,213	46,909	47,627	48,338	49,070	49,796	50,527	51,245
Standby Demand	0	0	0	0	0	0	0	0	0	0	0
Total Internal Demand	46,551	44,748	45,522	46,213	46,909	47,627	48,338	49,070	49,796	50,527	51,245
Direct Control Load Management	55	55	55	55	55	55	55	55	55	55	55
Interruptible Demand	337	313	303	303	303	303	303	303	303	303	303
Net Internal Demand	46,159	44,380	45,164	45,855	46,551	47,269	47,980	48,712	49,438	50,169	50,887

Capacity in Megawatts	Actual 02/03	Projected 03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Committed Resources	65,655	70,679	72,169	72,268	72,268	72,268	72,268	72,268	72,268	72,268	72,268
Uncommitted Resources	0	0	0	0	0	0	0	0	0	0	0
Total Capacity	65,655	70,679	72,169	72,268	72,268	72,268	72,268	72,268	72,268	72,268	72,268
Nuclear	13,174	13,347	13,347	13,347	13,347	13,347	13,347	13,347	13,347	13,347	13,347
Hydro	1,179	1,215	1,215	1,215	1,215	1,215	1,215	1,215	1,215	1,215	1,215
Pumped Storage	1,749	1,749	1,749	1,749	1,749	1,749	1,749	1,749	1,749	1,749	1,749
Geothermal	0	0	0	0	0	0	0	0	0	0	0
Steam -- Coal	15,309	15,309	15,309	15,309	15,309	15,309	15,309	15,309	15,309	15,309	15,309
Steam -- Oil	2,609	2,609	2,609	2,609	2,609	2,609	2,609	2,609	2,609	2,609	2,609
Steam -- Gas	79	79	79	79	79	79	79	79	79	79	79
Steam -- Dual Fuel	11,024	11,024	11,024	11,024	11,024	11,024	11,024	11,024	11,024	11,024	11,024
Combustion Turbine -- Oil	5,103	5,103	5,103	5,103	5,103	5,103	5,103	5,103	5,103	5,103	5,103
Combustion Turbine -- Gas	1,080	2,540	2,540	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639
Combustion Turbine -- Dual Fuel	5,613	5,613	5,613	5,613	5,613	5,613	5,613	5,613	5,613	5,613	5,613
Combined Cycle -- Oil	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle -- Gas	2,822	6,077	7,567	7,567	7,567	7,567	7,567	7,567	7,567	7,567	7,567
Combined Cycle -- Dual Fuel	4,925	4,925	4,925	4,925	4,925	4,925	4,925	4,925	4,925	4,925	4,925
Other	989	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089
Inoperable Capacity	0	0	0	0	0	0	0	0	0	0	0
Net Operable Capacity	65,655	70,679	72,169	72,268	72,268	72,268	72,268	72,268	72,268	72,268	72,268
Capacity Purchases - Total	488	488	488	488	38	38	38	38	38	38	38
Full Responsibility Purchases	0	0	0	0	0	0	0	0	0	0	0
Capacity Sales - Total	0	0	0	0	0	0	0	0	0	0	0
Full Responsibility Sales	0	0	0	0	0	0	0	0	0	0	0
Adjustment to Purchases and Sales	0	0	0	0	0	0	0	0	0	0	0
Net Capacity Resources	66,143	71,167	72,657	72,756	72,306	72,306	72,306	72,306	72,306	72,306	72,306

ECAR Transmission Line Circuit Miles

		Voltage Class (kV)				
		230	345	500	765	Total
Existing	12/31/2002	1,273	12,074	852	2,223	16,422
Under Construction	First 5 Years	17	13	0	92	122
Committed or Planned	Second 5 Years	0	0	0	0	0
		======	======	======	======	======
Total	12/31/2009	1,290	12,087	852	2,315	16,544

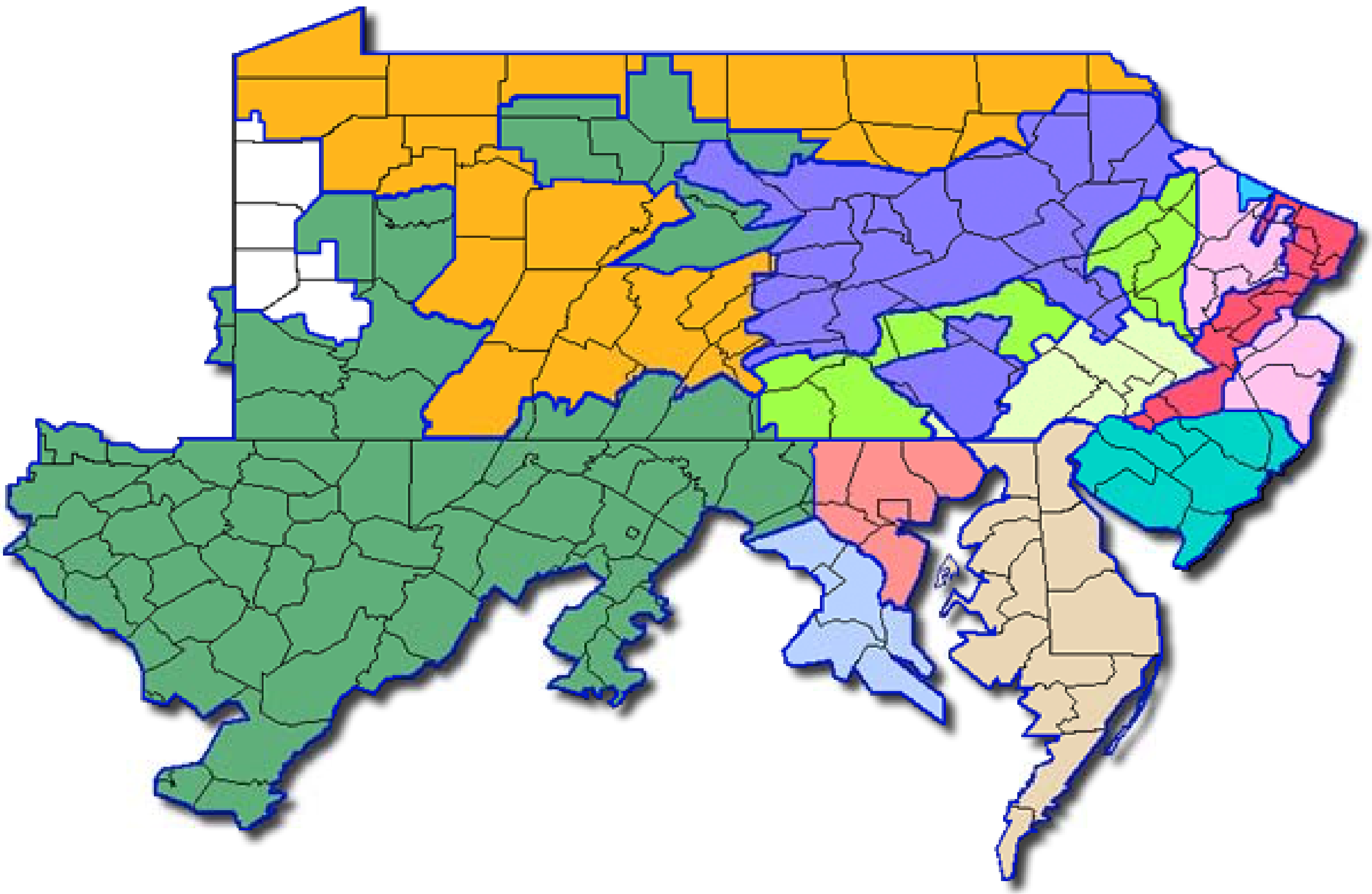
MAAC Transmission Line Circuit Miles

		Voltage Class (kV)				
		230	345	500	765	Total
Existing	12/31/2002	5,190	165	1,676	0	7,031
Under Construction	First 5 Years	70	0	0	0	70
Committed or Planned	Second 5 Years	0	0	0	0	0
		======	======	======	======	======
Total	12/31/2010	5,260	165	1,676	0	7,101

Appendix B

PJM Transmission Zones

Source: http://www.pjm.com



Delmarva Power & Light
Atlantic Electric
Pennsylvania Electric
Metropolitan Edison
Jersey Central Power & Light
Baltimore Gas & Electric
Public Service Electric & Gas
Allegheny Power
Peco Energy
Pennsylvania Power & Light
Potomac Electric Power
Rockland Electric

Appendix C

Transmission Line Projections

Transmission Line Projections (over 100 kV)

Company	Transmission Line	County	Design Voltage	Length	Construction Start Date	In-Service Date	Line Cost
Duquesne	Cheswick - North	Allegheny	138 kV	3.5 mi.	Jun-04	Jun-05	$1,750,000
Duquesne	Dravosburg - Wilmerding	Allegheny	138 kV	0.1 mi.	Jan-03	Mar-03	$150,000
Duquesne	Carson - Oakland	Allegheny	138 kV	1.0 mi.	Feb-05	May-05	$500,000
Duquesne	Collier - Carson	Allegheny	345 kV	0.1 mi.	Mar-05	Apr-05	$250,000
Met-Ed	Collins - Newberry	Lanc/York	115 kV	2.0 mi.	2001	2002	n/a
Met-Ed	Conewago Tap	York	115 kV	2.0 mi.	2003	2004	n/a
Penelec	North Meshoppen	Susquehanna	230 kV	0.4 mi.	2002	2003	n/a
PPL	Otter Creek - Yorkana	York	230 kV	12.0 mi.	Jun-03	May-04	$11,673,000
PPL	Manor-S. Akron	Lancaster	230 kV	25.2 mi.	Jun-05	Nov-06	$22,614,000
PPL	Martins Creek - Gilbert	Northampton	230 kV	0.3 mi.	Oct-03	Nov-03	$703,000
PPL	Steel City - Quarry	Northampton	230 kV	2.0 mi.	May-02	May-03	$1,925,000
PPL	Jenkins	Luzerne	230 kV	0.6 mi.	Jan-06	Nov-06	$300,000
PPL	Susquehanna	Luzerne	230 kV	0.6 mi.	Jan-06	Nov-06	$300,000
PPL	Lackawanna	Lackawanna	138 kV	8.0 mi.	Jan-06	Sep-07	$4,130,300
PPL	Hauto-Frack	Carbon	138 kV	0.7 mi.	Jan-07	May-07	$277,000
PPL	W. Hempfield	Lancaster	138 kV	1.6 mi.	Oct-02	May-04	$2,079,000
PPL	Derry-Millville	Lycoming	138 kV	12.0 mi.	Apr-09	Nov-10	$9,497,000
PPL	North Shamokin	Northumberland	138 kV	0.2 mi.	Jun-09	Sep-09	$497,000
PPL	Springfield	Bucks	230 kV	1.2 mi.	Aug-10	Sep-11	$3,586,000
PPL	Replace Sumner-Central	Lehigh	138 kV	1.3 mi.	Apr-06	Sep-06	$2,949,000
PPL	Seidersville-Quakertown	Northampton	138 kV	13.5 mi.	Sep-07	Nov-09	$33,898,000
PPL	Devonshire	Dauphin	138 kV	0.1 mi.	May-04	Nov-04	$50,000
PPL	Linglestown	Dauphin	138 kV	3.9 mi.	Apr-03	Nov-03	$929,000
PECO	Linwood-Phillips Island	Marcus Hook	230 kV	0.8 mi.	Sep-02	Jun-03	n/a
PECO	Emilie-Ford Mill	Bucks	230 kV	6.5 mi.	Jun-03	Oct-03	n/a
PECO	Emilie-Rolling Mill	Bucks	138 kV	9.25 mi.	Feb-03	Jun-03	n/a
PECO	Richmond-Holmesburg	Philadelphia	230 kV	6.25 mi.	Aug-03	Oct-03	n/a
West Penn	South Fayette Substation	Allegheny	138 kV	0.5 mi.	Apr-04	Jun-04	$117,000
West Penn	Springdale - Butler	Allegheny	138 kV	0.4 mi.	Apr-03	Nov-03	$595,000
West Penn	Glade Run Loop	Armstrong	138 kV	6.6 mi.	Oct-04	Jun-05	$3,976,000
West Penn	Saxonburg Substation	Butler	138 kV	3.5 mi.	Sep-03	Jun-04	$2,288,000
West Penn	Saxonburg - Silverville	Butler	138 kV	8.0 mi.	Sep-07	Jun-08	$10,113,000
West Penn	Dale Substation Loop	Centre	230 kV	0.02 mi.	Sep-01	Jul-03	$211,000
West Penn	Carbon Center Jct.	Elk/McKean	138 kV	14.4 mi.	Jan-07	Nov-07	$2,719,000
West Penn	Elko - Carbon Center	Elk	230 kV	5.7 mi.	Nov-04	Jun-06	$6,240,000
West Penn	Ronco Loop	Fayette	500 kV	0.2 mi.	Dec-02	Dec-02	$65,000
West Penn	Manifold Loop	Washington	138 kV	1.0 mi.	Nov-03	May-04	$1,200,000
West Penn	Gordon - Van Kirk Jct.	Washington	138 kV	2.7 mi.	Jul-03	Dec-03	$1,453,000
West Penn	Hickory Loop	Washington	138 kV	0.5 mi.	Sep-07	Nov-07	$2,379,000
West Penn	Vanceville	Washington	138 kV	0.1 mi.	Sep-08	Nov-08	$45,000
West Penn	Springdale - White Valley	Westmoreland	138 kV	10.1 mi.	Sep-02	Dec-02	$1,683,000
West Penn	Ethel Springs	Westmoreland	138 kV	2.7 mi.	Sep-04	Jun-05	$1,022,000
West Penn	Unity Substation Loop	Westmoreland	138 kV	0.1 mi.	May-06	Nov-06	$29,000

Appendix D

Status of Pennsylvania's New Power Plants

Status of Central Pennsylvania's New Power Plants

PJM Queues A-H Project

Queues	Project	MW	In-Service Date	Status
A01	South Lebanon	655	2002	In-Service
A18	North Temple	557	2002	In-Service
A34	Brunner Island	14	2002	In-Service
A36	Hunterstown	830	2003	Under Construction
A54	TMI	45	2002	Under Construction
B33	Steelton	500	2004	Facility Study in Progress
B35	South Akron	350	2003	Facility Study Completed
B36	South Akron	100	2003	Facility Study Completed
C02	S. Lebanon	47	2004	Awaiting Plant upgrade
D01	Engleside	1.6	2004	In-Service
D19	TMI-Peach Bottom	550	2004	Facilities study in progress
D20	TMI-Peach Bottom	550	2004	Facilities study in progress
E02	North Lebanon	1.20	2004	In-Service
G04	Brunner Island #2	14	2004	Impact Study Executed
G04	Brunner Island #1	14	2004	Impact Study Executed
G32	TMI-Juniata	1200	2004	Impact Study Executed
G36	Holtwood	5	2004	Impact Study Executed
G48	Birdsboro	10	2004	Impact Study Executed
H14	TMI-Peach Bottom	1060	2004	Impact Study Executed
H21	Ironwood	100	2004	Impact Study Executed
A12	Martins Creek	600	2003	Under Construction
B03	Hosensack	750	2003	Under Construction
B23	Northampton	5	2003	In-Service
D18	Hosensack	350	2003	Facilities Study in Progress
F03	Martins Creek	30	2003	In-Service
G06	Martins Creek	30	2003	Impact Study Executed
Total Queues **26**		**Total MW** **8,368.80**		

Status of Northeast Pennsylvania's New Power Plants
PJM – A-H

Queue s	Project	MW	In-Service Date	Status
A08	Susquehanna 230 kV	50	2003	In-Service: Partial
A09	Susquehanna 500 kV	50	2003	In-Service: Partial
A11	Harwood	35	2003	In-Service
A31	Peckville	44	2003	In-Service
A32	Montour #1	14	2003	In-Service
A33	Montour #2	14	2003	In-Service
B26	Hunlock Creek	44.7	2003	In-Service
D03	Harwood	66	2003	In-Service
D05	East Carbondale	70E	2003	Facilities Study in Progress
E06	Bear Creek	15.6E	2003	Construction Pending
E07	Montour	7	2003	In-Service
H02	Susquehanna 230 kV	9	2003	Impact Study Executed
H03	Susquehanna 500 kV	9	2003	Impact Study Executed
H23	Bear Creek	10	2003	Facility Issued
Total Queues 14		**Total MW 438.3**		

Status of Western Pennsylvania's New Power Plants

PJM – A-H

Queues	Project	MW	In-Service Date	Status
B05	Wayne – H.C.	250	2003	In-Service
B14	Arnold	14W	2003	In-Service
B34	Seward	304	2004	Under Construction
C10	Erie East	100	2005	Construction Pending
D06	Eclipse	5	2001	In-Service
D21	Hunterstown –	550	2004	Facilities Agreement Pending
D22	Hunterstown –	550	2004	Facilities Agreement Pending
E13	Somerset	10E	2004	In-Service
F04	Somerset	30E	2003	Facilities Study In-Progress
F09	Central City West	9	2003	Facilities Agreement Pending
G09	Homer City	547.5	2003	Impact Agreement
G21	Myersdale, N	48E	2003	Impact Agreement Executed
G31	Johnstown	610	2003	Impact Agreement Executed
H09	H'ville & Johnstown	550	2003	Feasibility Study Pending
H15	C'pman-Mosha	520	2003	Feasibility Study Pending
H22	Erie South	300	2003	Feasibility Study Pending
H24	Forest	535	2003	Feasibility Study Pending
H25	Hooversville	500	2003	Feasibility Study Pending
D06/W17	Friendsville	432	2003	Facilities Agreement Pending
E04/W20	Guilford	88	2003	In-Service
E17/W26	Taylorstown	1595	2005	Facilities Agreement Pending
E17/W27	Hatfield Ferry	620	2003	Under Construction
E17/W29	Yukon	640	2004	Facilities Agreement Pending
G00/W40	Warren 138 kV	264	2004	Impact Study Executed
G02/W43	Tallmansville	450	2004	Impact Study Executed
G30/W51	Fort Martin	600	2004	Impact Study Executed
530/W52	Oak Grove 138 kV	54	2005	Impact Study Executed
G30/W53	South Bend	104	2004	Impact Study Executed
G30/W55	Kempton	500	2004	Impact Study Executed
G5/W60	Hatfield Ferry	525	2004	Impact Study Executed
G51/W63	Upton 34.5 kV	9.9	2004	Facilities Study Complete
H04/W64	Henry 138 kV	150E	2004	Impact Study Executed
H21/W68	Greenland Gap	300E	2004	Impact Study executed
H23/W70	Kelso Gap 138 kV	100E	2004	Impact Study Executed
H27/W71	McConnelsburg	252	2004	Impact Study Executed
Total Queues 35		**Total MW 12,116.4**		

Summary of PJM's Interconnection Queue
October 18, 2002

	Projects Original Queue	Projects With drawn	Projects Remaining	Projects In Service	MW Original Queue	MW Withdrawn	MW Remaining	MW In Service
A	62	31	14	17	27,121	16,847	7,540	2,734
B/C	85	51	19	15	25,234	16,131	6,626	2,427
D/E/F	91	49	22	19	28,612	19,328	8,632	654
G	76	40	23	13	24,369	15,429	8,669	270
H	36	13	22	1	9,287	3,732	5,547	9
I	24	1	22	1	4,135	9	5,058	2
Total	**374**	**185**	**122**	**66**	**118,758**	**71,116**	**42,072**	**6,096**

Appendix E

PJM Transmission Network Upgrades
For New Power Plants in Pennsylvania

PJM Transmission Network Upgrade for New Power Plants in PA
(Source: PJM data)

A01 – South Lebanon	**655**	
• Install reactor in Brunner – West Hempfield, 230kV • Replace 230kV breaker at South Manheim, 230kV • Install underlying system voltage support		$2.98 M $0.396 M $0.136 M
A18 – North Temple	***557***	
• Install reactor in Brunner – West Hempfield, 230KV • Replace 230KV breaker at South Manheim, 230KV • Install underlying system voltage support		$2.98 M $0.396 M $0.136 M
A34 – Brunner Island	**14**	
• Install reactor in Brunner – West Hempfield, 230KV • Replace 230KV breaker at South Manheim, 230KV • Install underlying system voltage support		$2.98 M $0.396 M $0.136 M
A36 – Hunterstown	**830**	
• Replace Hunterstown 230/115KV transformer • Replace 2 Grays Ferry 230KV breakers		$4.6 M $97.8 K
A54 – TMI	**45**	
• No upgrades required		$0
B33 – Steelton	**500**	
• No upgrades required		$0
B35 – South Akron	**350**	
• No upgrades required		$0
B36 – South Akron	**100**	
• No upgrades required		$0

C02 – South Lebanon	**47**	
• No upgrades required		$0
D01 – Engleside	**1.6**	
• No upgrades required		$0
D19 – TMI-Peach Bottom	**550**	
• Upgrade or replace 11 500KV breakers at Peach Bottom		$1.4 M

D20 – TMI-Peach Bottom	**550**	
• Upgrade or replace 11 500KV breakers at Peach Bottom		$1.1 M
E02 – North Lebanon	**1.2**	
• No upgrades required		$0
A12 – Martin Creek	**600**	
• Upgrade Martins Creek grounding • Eliminate CT Saturation at Martins Creek		$140 K $150 K
B03 – Hosensack	**750**	
• Upgrade Martins Creek grounding • Eliminate CT Saturation at Martins Creek • Update Martins Creek – Gilbert to 160 deg C Op Temp • Install ungrounded transformer at Martins Creek		$140 K $150 K $0 $250 K
D18 – Hosensack	**350**	
• Upgrade Martins Creek – Gilbert to 6-wire Circuit • Install 2nd Steel City – Quarry, 230KV Circuit		$6.5 M $5.8 M
F03 – Martins Creek	**30**	
• No upgrades required		$0
A08 – Susquehanna 230kV	**50**	
• No upgrades required		$0

A09 – Susquehanna 500kV	**50**	
• No upgrades required		$0
A11 – Harwood	**35**	
• No upgrades required		$0
A31 – Peckville/Varden	**44**	
• No upgrades required		$0
A32 – Montour #1	**14**	
• No upgrades required		$0
A33 – Montour #2	**14**	
• No upgrades required		$0

B26 – Hunlock Creek	**44.7**	
• No upgrades required		$0
D03 – Harwood	**66**	
• No upgrades required		$0
D04 – Peckville	**1**	
• No upgrades required		$0
D05 – East Carbondale	**70**	
• No upgrades required		$0
E06 – Bear Creek	**15.6**	
• No upgrades required		$0
E07 – Montour		
• No upgrades required		$0

B05 – Wayne-Homer City	**250**	
• No upgrades required		$0
B14 – Arnold	**14**	
• No upgrades required		$0
B34 – Seward	**304**	
• Install 230/115kV transformer at Seward		$4.66 M
C10 – Erie East	**100**	
• No upgrades required		$0
D06 – Eclipse	**5**	
• No upgrades required		$0
D21 – Hunterstown-Conemaugh	**550**	
• No upgrades required		$0
D22 – Hunterstown-Conemaugh	**550**	
• No upgrades required		$0

E13 – Somerset	**10**	
• No upgrades required		$0
F04 – Somerset	**30**	
• No upgrades required		$0
F09 – Central City West	**9**	
• No upgrades required		$0

Appendix F

NRC Re-Licensing Application Process

Nuclear Regulatory Commission Re-licensing Application Process

Completed Applications: (Includes Application, Review Schedule, Supplemental Environmental Impact Statement and Safety Evaluation Report)	♦ Calvert Cliffs, Units 1 & 2 ♦ Oconee Nuclear Station, Units 1, 2, & 3 ♦ Arkansas Nuclear, Unit 1 ♦ Edwin I Hatch Nuclear Plant, Unit 1 & 2 ♦ Turkey Point Nuclear Plant, Units 3 & 4
Applications Currently Under Review:	♦ North Anna, Units 1 & 2, and Slurry, Units 1&2 - Joint application received May 29, 2001 ♦ McGuire, Units 1 & 2, and Catawba, Units 1 & 2 - Joint application received June 14, 2001 ♦ **Peach Bottom, Units 2 & 3 - application received July 2, 2001** ♦ St. Lucie, Units 1 & 2 - application received November 30, 2001 ♦ Fort Calhoun, Unit 1 - Application received January 11, 2002 ♦ HB Robinson, Unit 2 - application received June 17, 2002 ♦ RE Ginna Nuclear Power Plant, Unit 1 - application received August 1, 2002 ♦ VC Summer Nuclear Station, Unit 1 - application received August 6, 2002
Future Submittals of Applications*:	♦ Dresden, Units 2 and 3 - January 2003 ♦ Quad Cities, Units 1 and 2 - January 2003 ♦ Not Publicly Announced - July 2003 ♦ Farley, Units 1 and 2 – September 2003 ♦ Arkansas Nuclear One, Unit 2 - September 2003 ♦ Nine Mile Point, Units 1 and 2 - October 2003 (Unit 2 requires exemption) ♦ D.C. Cook, Units 1 and 2 - November 2003 ♦ Browns Ferry, Units 2 and 3 - December 2003 ♦ Millstone, Units 2 and 3 - January 2004 (Unit 3 requires exemption) ♦ Brunswick, Units 1 and 2 - January-March 2004 ♦ **Beaver Valley, Units 1 and 2 - September 2004** ♦ Not Publicly Announced - October 2004 ♦ Davis-Besse, Unit 1 – December 2004 ♦ Pilgrim, Unit 1 – December 2004 ♦ Not Publicly Announced - December 2004 ♦ **Susquehanna, Units 1 and 2 - January-March 2005** ♦ Not Publicly Announced - January-March 2005

* This list of future submittals is based on the November 4, 2002, public meeting between the NRC and the NEI License Renewal Working Group and will be updated on a periodic basis. SOURCE: www.nrc.gov

Appendix G

Pennsylvania’s Existing Electric Generating Facilities

Pennsylvania's Electric Generating Facilities
(Source: Electric Power Generation Association)

Station	Owner/Operator	MW
AES Beaver Valley	AES	120.0
Allegheny Lock & Dam	Sithe Energies	13.0
Allegheny Lock & Dam	Sithe Energies	17.4
Archbald Power	PEI POWER	70.0
Armstrong Generating	Allegheny Energy Supply Co	326.4
Beaver Valley Power	FirstEnergy Nuclear	1,846.8
Bradford	Penntech Paper	52.0
Bristo	Rohm and Haas	1.50
Bruce Mansfield	Pennsylvania Power	40.0
Brunot Island Generating	Orion Power Holdings	291.6
Cambria County	Cambria Cogen	98.0
Chambersburg Power	Chambersburg Borough Electric	7.27
Cheswick Generating	Orion Power Holdings	570.0
Clairton	Exelon Generation Co	60.0
Clairton USX B	Mid-Atlantic Energy	219.7
Colver Power	A/C Power-Colver	102.0
Conemaugh Power	Reliant Energy Wholesale	1,883.2
Conemaugh	National Renewable Resources	15.0
Cromby Generating	Exelon Generation Co	420.2
Delaware County WTE	American Ref-Fuel	90.0
Delaware Generating	Exelon Generation Co	392.4
Ebensburg	Power Systems	48.5
Eddystone Generating	Exelon Generation Co	1,569.0
Elrama Generating	Orion Power Holdings	510.3
EME Homer City	Mid-West Generation	2,012.0
Erie Works	General Electric	36.0
Exelon Power Distributed Generation	Exelon Generation Co	1,048.0
FR Phillips Generating	Orion Power Holdings	411.3
Grays Ferry Power	Trigen Energy	173.6
Grove City	General Electric	10.6
Grows	Exelon Generation Co	6.60
Harrisburg WTE	City of	8.20
Hatfield's Ferry Power	Allegheny Energy Supply Co	1,728.0
Hunlock Power	UGI Development	94.0
John B Rich Power	Gilberton Power	79.4
Keystone Generating	Reliant Energy Wholesale	1,883.2
Lancaster County Resource	Covanta Energy	35.7
Limerick Nuclear Generating	Exelon Generation Co	2,230.5
Marcus Hook	General Chemical	4.50

Station	Owner/Operator	MW
Mehoopany	Proctor & Gamble	45.0
Mitchell Generating	Allegheny Energy Supply Co	448.8
Montgomery County	Montenay Power	32.0
Mount	Foster Wheeler Energy	46.5
Muddy Run Hydroelectric	Exelon Generation Co	800.0
NEPC	Tractebel Power	59.0
New Castle Generating	Orion Power Holdings	352.9
North East	Conectiv Operating	81.8
Northampton Generating	PG&E National Energy	110.0
Northeast WWTP	Calpine	11.4
Northumberland Cogeneration	Viking Energy of	16.2
Panther Creek Energy	Constellation Power	95.0
Peach Bottom Atomic Power	Exelon Generation Co	2,304.0
Pennsylvania House Power	Trigen Energy	0.10
Philadelphia Container	Smurfit-Stine	10.0
Piney Creek	Mid-Atlantic Energy	30.0
Portland Generating	Reliant Energy Wholesale	620.3
Pottstown	Bio-Energy	6.40
PPL Brunner Island	PPL Generation	1,566.9
PPL Holtwood	PPL Generation	108.2
PPL Martins Creek	PPL Generation	2,113.5
PPL Montour	PPL Generation	1,624.5
PPL Susquehanna	PPL Generation	2,304.0
Ringgol	Cogentrix Energy	18.0
Safe Harbor Hydroelectric	Safe Harbor Water Power	417.5
Schuylkill Generating	Exelon Generation Co	233.0
Scrubgrass Generating	PG&E National Energy	83.0
Seneca Pumped Storage	Clevelnad Electric	422.0
Seward Generating	Reliant Energy Wholesale	218.2
Shawville Generating	Reliant Energy Wholesale	631.0
Southwest WWTP	Calpine	11.5
Sunbury Generating	WPS Power	462.4
Three Mile Island Nuclear	AmerGen Energy Co	872.0
Titus Generating	Reliant Energy Wholesale	260.6
Warren Power	Reliant Energy Wholesale	137.7
West Point (PA) Merck	Merk & Co	30.2
Wheelabrator Falls	Wheelabrator	53.0
Wheelabrator Frackville Energy	Wheelabrator	42.0
WPS Westwood Generation	WPS Power	30.0
York County	Montenay Power	35.0
York Solar	Solar Turbines	70.0
Total Pennsylvania Generating		**35,339.8**