Electric Power Outlook For Pennsylvania 2004 – 2009

August 2005

Pennsylvania Public Utility Commission

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Published annually by the
Pennsylvania Public Utility Commission
P.O.Box 3265, Harrisburg, PA 17105-3265

Produced by the
Bureau of Conservation, Economics and Energy Planning

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 Mid-Atlantic Area Council (MAAC) and the East Central Area Reliability Council (ECAR) have been maintained. While sufficient generation capacity is expected for the next five years, the Commission will continue its current policy of encouraging generation adequacy within the region.

With respect to transmission adequacy, the transmission system in the Mid-Atlantic region has sufficient capacity to meet demand. Both MAAC and ECAR are planning transmission expansions and upgrades over the next five years to reinforce the bulk power grid. Current initiatives at the federal level may also help improve the overall reliability and efficiencies of the transmission system.

To summarize the relevant statistics in this report, electricity demand in Pennsylvania has grown at a rate of 1.5% annually in the past 15 years. This is an aggregate figure for all sectors, including industrial, commercial and residential. The current projections for 2004-2009 show electricity demand growth at 1.5% annually. This includes a residential growth rate of 1.6%, a commercial growth rate of 2.4% and an industrial growth rate of 0.8%.

Regionally, generating resources are projected to be adequate for the next several years. In MAAC, the 2009 reserve margin is expected to be 12.2%, with a net internal demand of 61,204 MW and generating resources totaling 68,698 MW. ECAR's 2009 reserve margin is projected to be 23.0%, with a net internal demand of 111,082 MW and 136,630 MW of projected resources.

As this report concludes, the regional electric system is adequate to meet the demand of Pennsylvania's consumers for the foreseeable future.

Pennsylvania must 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.

To this end, the Commission is in the process of implementing the requirements of Act 213 (the Alternative Energy Portfolio Standards Act), signed by Governor Edward Rendell on November 30, 2004. Generally, Act 213 requires that an annually increasing percentage of electricity sold to retail customers be derived from alternative energy resources, including solar, wind, low-impact hydropower, geothermal, biologically-derived methane gas, fuel cells, biomass, coal mine methane, waste coal, demand-side management, distributed generation, large-scale hydropower, by-products of wood-pulping and wood manufacturing, and municipal solid waste.

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SECTION 1 - INTRODUCTION

Purpose

Electric Power Outlook for Pennsylvania 2004-2009 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.[1]

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.[2] 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).

[1] See http://www.puc.state.pa.us/general/publications_reports/pdf/EPO_2005.pdf.

[2] 52 Pa. Code §§ 57.141-57.154.

Regional Reliability Organizations

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 covering 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 nearly 38 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, First Energy (Pennsylvania Power Company) and Allegheny Power (West Penn Power Company).

The PJM Interconnection, L.L.C. (PJM) is a regional transmission organization (RTO) that ensures the reliability of the largest centrally dispatched control area in North America. PJM coordinates the operation of over 160,000 MW of generating capacity and over 56,000 miles of transmission lines. The PJM RTO coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

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 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, provide transmission and generation coordination for the PJM West area.

On May 1, 2004, PJM began managing the flow of wholesale electricity over Commonwealth Edison's 5,000 miles of transmission lines in Illinois, making PJM the world's largest grid operator, meeting a peak demand of 87,000 MW. On October 1, 2004, PJM began managing American Electric Power's (AEP's) eastern control area, including nearly 22,300 miles of high-voltage transmission lines within a seven-state area and 23,800 MW of generating capacity. At the same time, Dayton Power and Light integrated into the PJM RTO with 1,000 miles of transmission lines and 4,450 MW of generation. Also, about 20 municipal electric companies, cooperatives and generators in the AEP area have joined PJM. On January 1, 2005, PJM began managing the wholesale flow of electricity for Duquesne, with 3,400 MW of capacity and 620 miles of transmission lines

These entities, including Allegheny, now comprise PJM West.

Dominion Virginia Power (Dominion) was integrated into the PJM RTO on May 1, 2005. Dominion's control area, covering parts of Virginia and North Carolina, will operate separately under the single PJM energy market as PJM South, including an additional 6,100 miles of transmission lines and nearly 23,000 MW of generating capacity.

The Midwest Independent System Operator (Midwest ISO) is the nation's first RTO approved by the Federal Energy Regulatory Commission (FERC). The Midwest ISO is based in Carmel, Indiana, and is responsible for monitoring the electric transmission system, ensuring equal access to the transmission system and maintaining and improving electric system reliability in the Midwest.

The Midwest ISO was founded on February 12, 1996, and was configured to comply with FERC's concept of an independent organization that will ensure the smooth regional flow of electricity in a competitive wholesale marketplace. The Midwest ISO began selling transmission service under its open access transmission tariff on February 1, 2002. Utilities with more than 100,000 miles of transmission lines covering 1.1 million square miles from Manitoba, Canada, to Kentucky have committed to participate in the Midwest ISO.

During 2004, preparations were made for the start of day-ahead and real-time locational margin price (LMP) energy markets that began April 1, 2005.

The Midwest ISO "footprint" currently contains about 130,000 MW of generating capacity. The generator fuel mix is dominated by coal-fired resources, accounting for almost 60% of the capability. Most of the recent investment has been in natural gas resources, which currently account for 20% of the capability in the region. The Midwest ISO system-wide peak in July 2004 was 104,000 MW.

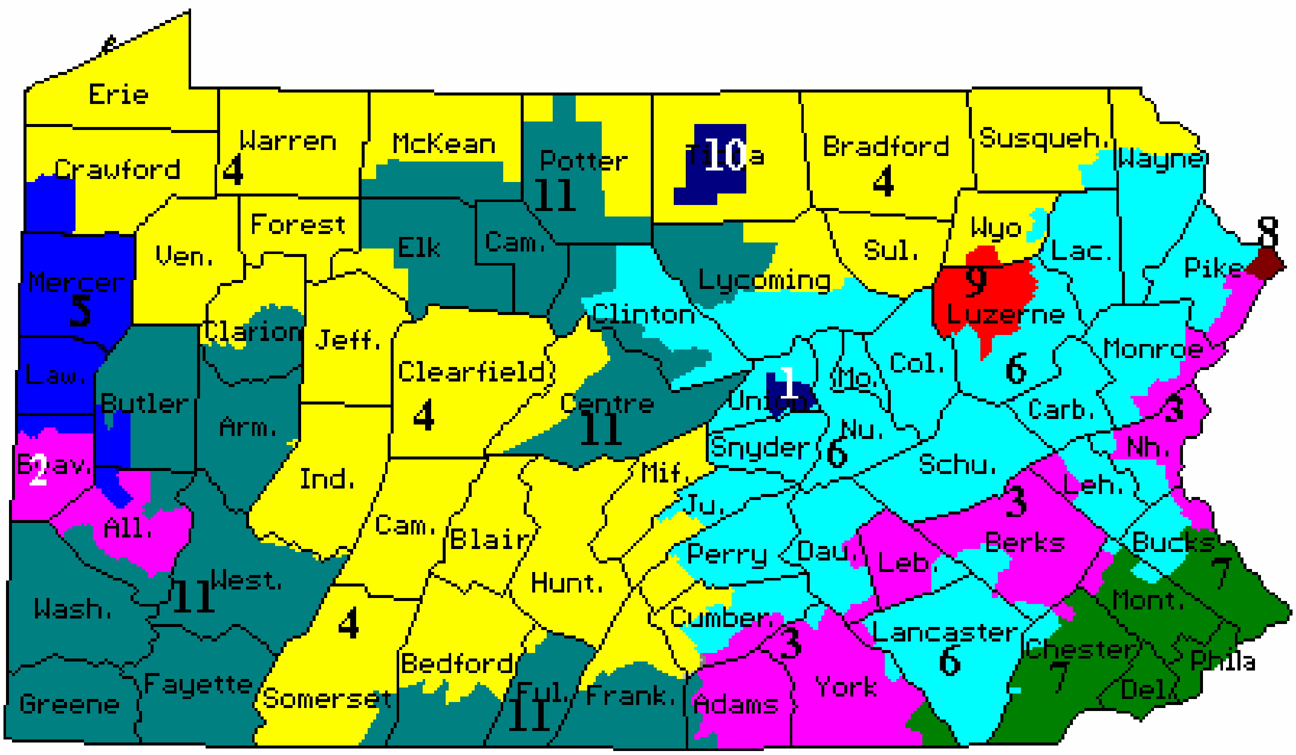
The integration of Commonwealth Edison and AEP into PJM in 2004 resulted in changes to regional dispatch patterns. A joint operating agreement between PJM and the Midwest ISO includes protocols to coordinate power flows that affect both systems.

See Appendix B for maps of the expanded PJM RTO and the Midwest ISO.

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 (Exelon)**
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.[3]

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.[4]

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. On December 16, 2004, the Commission initiated a proposed rulemaking proceeding defining the obligation of EDCs to serve retail customers. The proposed rulemaking was published in the *Pennsylvania Bulletin* on February 26, 2005, (35 Pa.B. 4121) with comments due April 27, 2005.[5] Comments and reply comments have been received and are under review.

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 (DSR) 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.

[3] Also referred to as "obligation to serve" and "default service."
[4] 66 Pa.C.S. § 2807(e)(3).
[5] 35 Pa.B. 4121.

These price spikes and their aftermath dampen competition in retail markets because it becomes difficult for suppliers to obtain power at competitive prices.

DSR 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.

Hourly pricing or real-time pricing of electricity is also an incentive to modify usage patterns, as the cost of electricity reflects the cost of supply at the time of consumption. Although this pricing scheme is not considered a DSR program, its implementation may have the same effect as other initiatives.

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 FERC has extended these programs until December 31, 2007.

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.

During the summer of 2004 there was no activity in the Emergency Program due to mild weather and associated load levels. As of September 30, 2004, there were 1,385 MW of resources active in the Emergency Program.[6]

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 provides 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[7] for the

[6] PJM, *2004 State of the Market Report*, March 8, 2005.
[7] LMP is the hourly integrated market clearing price for energy at the location the energy is delivered or received.

reductions. The Real Time Option provides 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.

As of September 30, 2004, there were 106 currently active sites in the Economic Program with an associated 724 MW. In 2004, the total load reduction level was 48,622 MWH, with total payments averaging $31 per MWH. About 96% of the MWH reductions, 87% of payments and 93% of curtailed hours resulted from the real-time rate option. Only 4% of the MWH reductions, 1% of payments and 1% of curtailed hours resulted from the day-ahead option. The maximum hourly load reduction attributable to the Economic Program was 168 MW in the nine-month period ended September 30, 2004. During the summer of 2004, a reduction of 1,000 MW would have created a $5 per MW LMP decrease.[6]

The PJM Subcommittee on Special Membership has proposed to increase participation in the Real Time Economic Load Response Program by removing the full membership obligation for Curtailment Service Providers, which has been a major barrier to participation.

Pennsylvania EDC Results

In 2004, the reported energy demand reduction attributable to EDCs' demand side response programs was 119,897 MWH and the aggregate peak load reduction was 459 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 that have been taken by the EDCs to implement demand-side response programs. Additional information is provided in individual company sections.

Summary of EDC Demand Side Response Programs

EDC	*Program*	Description
Allegheny Power	-- Voluntary Generation Buy-Back -- Real Time 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 -- "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)	-- Customers respond to day-ahead hourly signals. (C&I)
PPL	-- Demand Side Initiative Rider (DSI) -- Demand Side Response Rider -- Interruptible Service – Economic Provisions -- Interruptible Service – Emergency Provisions -- Price Response Service	-- Customers may respond to changes in the electric generation market by adjusting their load requirements. (C& I) -- Eligible residential customers may shift energy usage away from peak demand hours. (Res) -- Permits PPL to request customers to reduce load for economic conditions. -- Permits PPL to request customers to reduce load for emergency conditions. -- Permits customers to respond to market price signals with a portion of their load.
UGI	-- Voluntary Load Reduction Pilot Program -- Time-of-Use (Rate RTU)	-- Customers receive a monetary incentive to curtail load. (C&I) -- Time differentiated rate where residential customers pay higher prices during pre-defined on-peak hours. (Res)

Alternative Energy Portfolio Standards

On November 30, 2004, Governor Edward Rendell signed into law the Alternative Energy Portfolio Standards Act (Act 213).[8] Generally, Act 213 requires that an annually increasing percentage of electricity sold to retail customers be derived from alternative energy resources. This applies to both electric distribution companies and electric generation suppliers.

These alternative energy resources are categorized as "Tier One" and "Tier Two" resources. Tier One resources include solar, wind, low-impact hydropower, geothermal, biologically-derived methane gas, fuel cells, biomass and coal mine methane. Tier Two resources include waste coal, demand-side management, distributed generation, large-scale hydropower, by-products of wood-pulping and wood manufacturing, and municipal solid waste.

Act 213, which took effect on February 28, 2005, requires that, within two years of the effective date, at least 1.5% of the electric energy sold to retail customers must be generated from Tier One resources. The percentage of electric energy derived from Tier One resources shall increase by at least 0.5% each year so that, by the 15th year, at least 8% of the energy sold to retail customers in each service territory will come from these resources. Energy sold from Tier Two resources shall increase to 10% of the total retail sales by the 15th year. The Act sets forth a 15-year schedule for complying with its mandates. The compliance schedule is as follows:

		Tier I % (incl. Solar)	Tier II	Solar PV %
Year 1:	June 1, 2006 through May 31, 2007	1.5%	4.2%	.0013%
Year 2:	June 1, 2007 through May 31, 2008	1.5%	4.2%	.0013%
Year 3:	June 1, 2008 through May 31, 2009	2.0%	4.2%	.0013%
Year 4:	June 1, 2009 through May 31, 2010	2.5%	4.2%	.0013%
Year 5:	June 1, 2010 through May 31, 2011	3.0%	6.2%	.0203%
Year 6:	June 1, 2011 through May 31, 2012	3.5%	6.2%	.0203%
Year 7:	June 1, 2012 through May 31, 2013	4.0%	6.2%	.0203%
Year 8:	June 1, 2013 through May 31, 2014	4.5%	6.2%	.0203%
Year 9:	June 1, 2014 through May 31, 2015	5.0%	6.2%	.0203%
Year 10:	June 1, 2015 through May 31, 2016	5.5%	8.2%	.2500%
Year 11:	June 1, 2016 through May 31, 2017	6.0%	8.2%	.2500%
Year 12:	June 1, 2017 through May 31, 2018	6.5%	8.2%	.2500%
Year 13:	June 1, 2018 through May 31, 2019	7.0%	8.2%	.2500%
Year 14:	June 1, 2019 through May 31, 2020	7.5%	8.2%	.2500%
Year 15:	June 1, 2020 through May 31, 2021	8.0%	10.0%	.5000%

[8] 73 P.S. §§ 1647.1–1647.8.

Companies are exempt from these requirements for the duration of their cost recovery periods. The current expiration dates for the cost recovery period in each EDC service territory and their compliance start dates for compliance is as follows:

	Exemption expires	Compliance begins
Pike County Power and Light	December 31, 2005	February 28, 2007
Citizens Electric of Lewisburg	December 31, 2007	January 1, 2008
Wellsboro Electric Company	December 31, 2007	January 1, 2008
UGI Utilities Inc. – Electric Division	December 31, 2006	February 28, 2007
Pennsylvania Power Company	December 31, 2006	February 28, 2007
Duquesne Light Company	December 31, 2007	January 1, 2008
West Penn Power Company	December 31, 2010	January 1, 2011
PPL Electric Utilities, Inc.	December 31, 2009	January 1, 2010
Pennsylvania Electric Company	December 31, 2010	January 1, 2011
Metropolitan Edison Company	December 31, 2010	January 1, 2011
PECO Energy Company	December 31, 2010	January 1, 2011

The Commission is required to establish regulations governing the verification and tracking of energy efficiency and demand-side management measures, pursuant to Act 213, including benefits to all customer classes. On June 23, 2005, the Commission released its initial proposal in the form of a Tentative Order governing the participation of DSR in the alternative energy market.[9] The Commission proposes to use two means to establish qualifications for Alternative Energy Credits – a catalog approach for standard energy saving measures and general guidelines for metered and custom energy saving measures. Comments on the proposal are due August 23, 2005.

The Commission must also develop technical and net metering interconnection rules for customer-generators intending to operate renewable onsite generators in parallel with the electric utility grid, consistent with rules defined in other states within the service region of the regional transmission organization that manages the transmission system in any part of the Commonwealth. Regulations are currently being drafted to separately address technical and net metering issues.

Working Groups were established to facilitate a stakeholder process in compliance with Act 213.

[9] Docket No. M-00051865.

SECTION 2 – HISTORIC AND FORECAST DATA

2004: A Year in Review

The eight largest EDCs operating in Pennsylvania deliver approximately 99% of the jurisdictional companies' electrical energy needs. Aggregate sales in 2004 totaled approximately 141.1 billion kilowatthours (KWH), a 2.3% increase from that of 2003 and approximately 4.0% of the United States' total sales. Residential sales led the Pennsylvania market capturing 34.0% of the total sales, followed by industrial (33.3%) and commercial (30.4%). Aggregate non-coincident peak load increased to 26,958 MW in 2004, up 0.5% from 2003. See Tables 2.1 and 2.2 below.

Table 2.1. Energy Demand, Peak Load and Customers Served (2004)

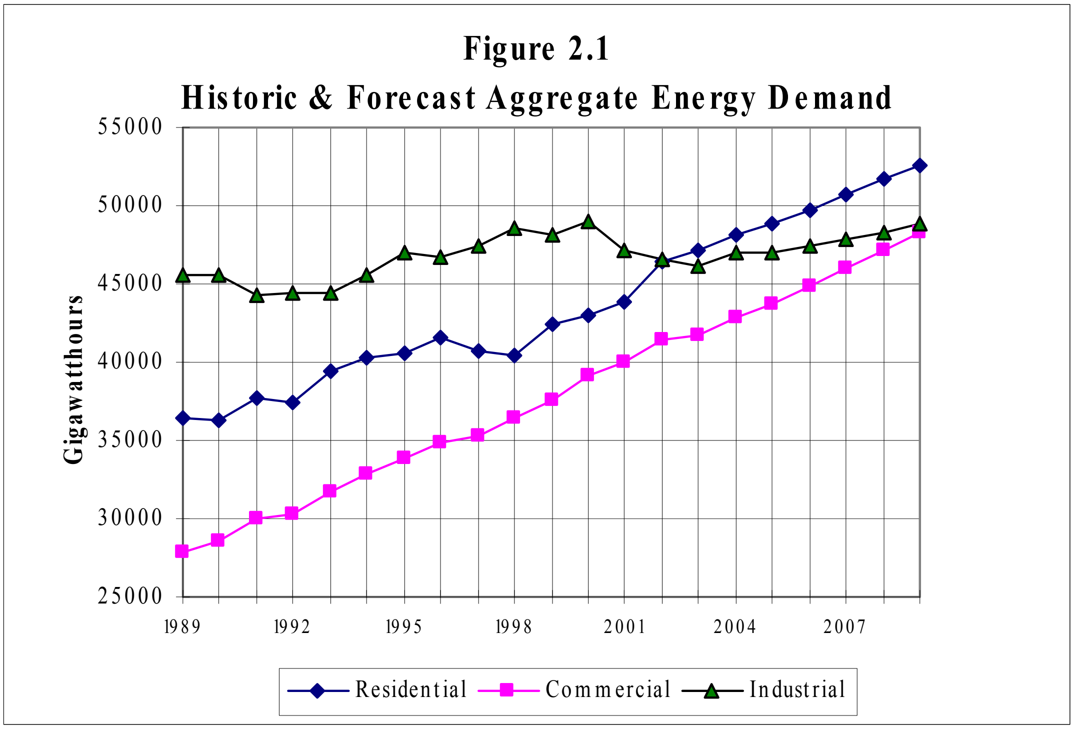
EDC	Total Customers Served	Residential (MWH)	Commercial (MWH)	Industrial (MWH)	Other (MWH)	Sales For Resale (MWH)	Total Consumption (MWH)	System Losses (MWH)	Company Use (MWH)	Net Energy For Load (MWH)	Peak Load (MW)
Duquesne	587,664	3,885,587	6,453,654	3,228,573	69,683	312,103	13,949,600	788,104	30,423	14,768,127	2,646
Met-Ed	520,687	5,070,963	4,251,165	4,041,540	33,569	0	13,397,237	1,088,986	n/a	14,486,223	2,468
Penelec	585,658	4,249,263	4,791,759	4,588,866	39,852	0	13,669,740	1,084,432	n/a	14,754,172	2,425
Penn Power	157,412	1,545,200	1,296,100	1,553,900	6,600	0	4,401,800	308,350	6,950	4,717,100	898
PECO	1,536,754	12,507,039	8,414,312	15,741,001	914,257	78,414	37,655,023	2,635,852	59,353	40,350,228	7,567
PPL	1,351,170	13,441,358	12,576,277	9,610,976	196,971	1,003,448	36,829,031	3,039,253	76,992	39,945,276	7,335
UGI	61,922	521,275	350,564	112,026	5,588	67	989,520	58,562	1,859	1,049,941	212
West Penn	700,630	6,723,588	4,691,157	8,038,797	52,161	672,352	20,178,055	1,436,902	n/a	21,614,957	3,407
Total	5,501,897	47,944,273	42,824,988	46,915,679	1,318,681	2,066,384	141,070,006	10,440,441	175,577	151,686,024	26,958
% of Total		33.99%	30.36%	33.26%	0.93%	1.46%	100.00%				
2004 v 2003	0.69%	1.93%	2.93%	1.94%	-5.45%	8.06%	2.25%	8.30%	-21.10%	2.61%	0.45%

Table 2.2. Energy Demand, Peak Load and Customers Served (2003)

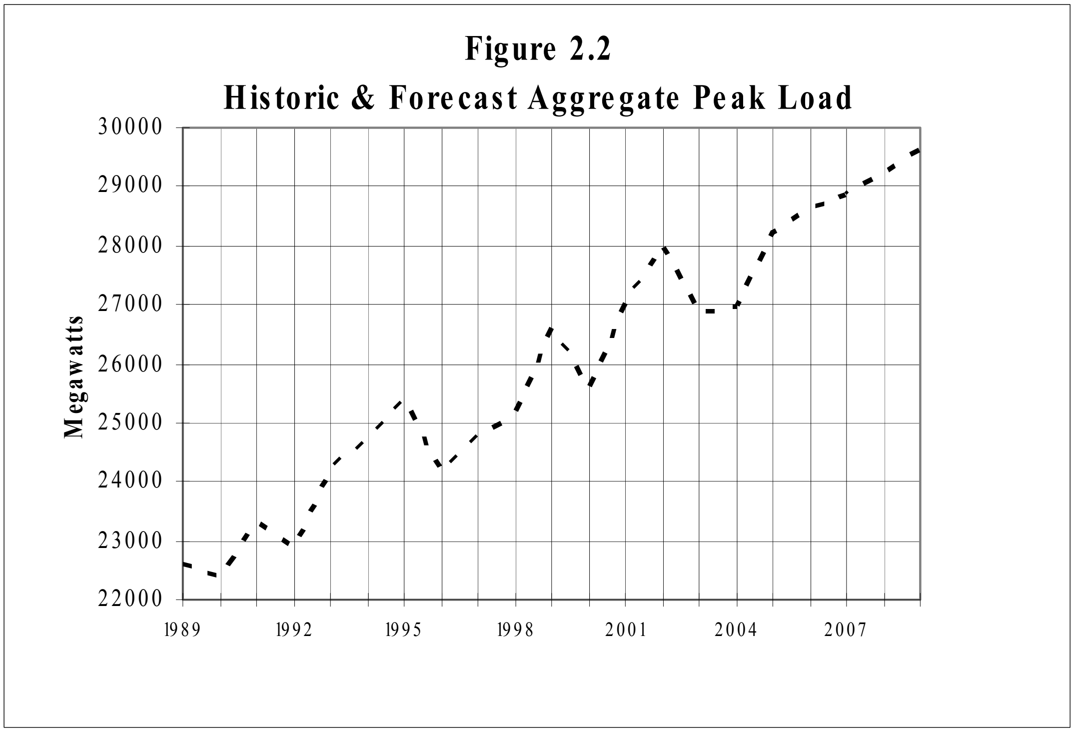
EDC	Total Customers Served	Residential (MWH)	Commercial (MWH)	Industrial (MWH)	Other (MWH)	Sales For Resale (MWH)	Total Consumption (MWH)	System Losses (MWH)	Company Use (MWH)	Net Energy For Load (MWH)	Peak Load (MW)
Duquesne	587,899	3,758,737	6,345,609	3,189,067	69,678	211,764	13,574,855	757,915	31,687	14,364,457	2,686
Met-Ed	516,559	4,894,672	4,017,843	3,985,660	35,604	633	12,934,412	1,074,482	n/a	14,008,894	2,438
Penelec	585,112	4,186,693	4,727,317	4,391,097	41,344	699	13,347,150	1,038,655	n/a	14,385,805	2,308
Penn Power	155,929	1,513,000	1,291,100	1,480,800	6,400	5,200	4,296,500	250,950	6,950	4,554,400	855
PECO	1,530,505	12,258,656	8,077,251	15,518,212	896,922	14,400	36,765,442	2,573,581	89,975	39,428,998	7,696
PPL	1,329,781	13,266,164	12,273,458	9,598,860	287,041	1,037,543	36,463,066	2,684,861	92,028	39,239,955	7,197
UGI	61,780	516,201	345,335	111,986	5,538	64	979,124	57,377	1,898	1,038,399	201
West Penn	696,855	6,640,582	4,529,422	7,747,364	52,213	641,890	19,611,471	1,202,523	n/a	20,813,994	3,455
Total	5,464,420	47,034,705	41,607,335	46,023,046	1,394,740	1,912,193	137,972,020	9,640,344	222,538	147,834,902	26,836
% of Total		34.09%	30.16%	33.36%	1.01%	1.39%	100.00%				

Between 1989 and 2004, the state's energy demand grew at an average rate of 1.5% annually. Residential sales grew at an annual rate of 1.9%, commercial at 2.9% and industrial at 0.2%.

The current aggregate 5-year projection of growth in energy demand is 1.6%. This includes a residential growth rate of 1.8%, a commercial rate of 2.4% and an industrial rate of 0.8%. 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.



Over the past 15 years, the average aggregate non-coincident peak load increased 1.2% per year. The combined forecast of the EDCs' peak load shows the load increasing from 26,958 MW in 2004 to 29,632 MW in 2009.



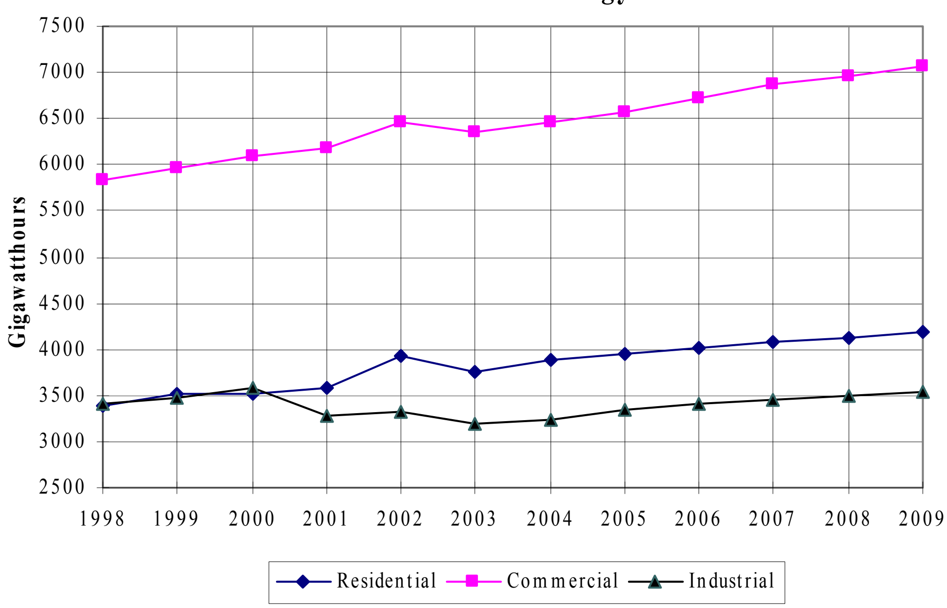
Summary of EDC Data

Duquesne Light Company

Duquesne Light Company (Duquesne) provides service to 587,664 electric utility customers in southwestern Pennsylvania. In 2004, Duquesne had energy sales totaling 13.9 billion kilowatthours (KWH) -- up 2.8% from 2003. Commercial sales continued to dominate Duquesne's market with 46.3% of the total sales, followed by residential (27.9%) and industrial (23.1%).

Between 1989 and 2004, Duquesne's total energy demand increased about 1.1% per year. Residential and commercial demand grew at an annual rate of 1.5% over the past 15 years. Industrial energy demand increased at an average rate of 0.02 percent for the period.

Figure 3.1
Historic & Forecast Energy Demand

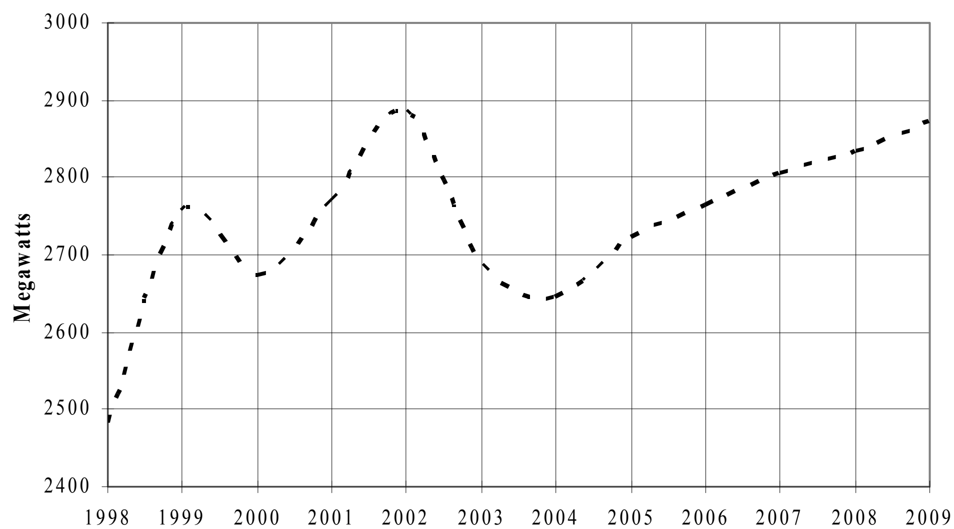


The current 5-year projection of average growth in total energy consumption is about 1.8% per year. This includes a residential growth rate of 1.6%, a commercial growth rate of 1.9% and an industrial increase in energy demand of 1.9% per year.

Duquesne's summer peak load, occurring on June 9, 2004, was 2,646 megawatts (MW), representing a decrease of 1.5% from last year's peak of 2,686 MW. The 2004/2005 winter peak load was 2,135 MW or 2.9% higher than that of the previous year.

The actual average annual peak load growth rate over the past fifteen years was 0.7%. Duquesne's forecast shows the peak load increasing from 2,646 MW in the summer of 2004 to 2,873 MW in 2009, or an average annual growth rate of 1.7%.

Figure 3.2
Historic & Forecast Peak Load



Tables 3.1-3.4 provide Duquesne's forecasts of peak load and residential, commercial and industrial energy demand from 1995 through 2005.

On January 1, 2005, PJM began managing the flow of wholesale electricity for Duquesne. While Duquesne's integration into PJM involves transferring control of 670 miles of high voltage transmission lines, ownership remains with Duquesne. PJM is now the regional reliability coordinator for Duquesne.

For calendar year 2004, six electric generation suppliers (EGSs) sold a total of 4.8 billion KWH to retail customers in Duquesne's service territory, or about 34.6% of total consumption. There were no instances in 2004 where EGSs failed to supply scheduled load.

Duquesne 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 31.5 MW and 115.7 million KWH in energy savings were experienced in 2004. This program ended on December 31, 2004.

A Pilot Direct Load Control Program was implemented in 2004 for residential and commercial customers in which air conditioning units will be shut off or cycled during periods of high temperature. Customers receive a credit on the monthly bill, based on the program option selected. The amount of load curtailed as a result of this program is not significant.

Duquesne is a member of ECAR, MAAC and PJM.

Table 3.1

Year	Actual Peak Demand	Projected Peak Load Requirements (Megawatts)										
		1995	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**
1995	2666	2355										
1996	2463	2346	2537									
1997	2671	2390	2599	2583								
1998	2484	2401	2634	2614	2614							
1999	2756	2413	2652	2632	2632	2715						
2000	2673	2433	2671	2653	2653	2736	2638					
2001	2771	2452	2690	2677	2677	2757	2661	2661				
2002	2886	2472	2709	2702	2702	2776	2682	2682	2850			
2003	2686	2490	2728	2727	2727	2798	2702	2702	2884	2822		
2004	2646	2511	2749	2754	2754		2723	2723	2912	2841	2719	
2005			2769	2782	2782			2743	2934	2855	2740	2722
2006				2810	2810				2953	2870	2771	2765
2007					2839					2884	2801	2805
2008											2831	2835
2009												2873

Table 3.2

Year	Actual Energy Demand	Projected Residential Energy Demand (Gigawatthours)										
		1995	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**
1995	3379	3190										
1996	3321	3207	3175									
1997	3274	3221	3167	3228								
1998	3382	3237	3171	3234	3234							
1999	3526	3254	3176	3240	3240	3366						
2000	3509	3271	3181	3249	3249	3383	3610					
2001	3584	3288	3187	3258	3258	3400	3643	3643				
2002	3924	3305	3192	3267	3267	3415	3681	3681	3671			
2003	3759	3322	3198	3276	3276	3432	3716	3716	3726	3697		
2004	3886	3339	3204	3287	3287		3759	3759	3772	3721	3811	
2005			3210	3297	3297			3780	3810	3744	3832	3941
2006				3210	3307				3846	3767	3879	4018
2007					3318					3791	3925	4088
2008											3978	4125
2009												4198

Table 3.3

Year	Actual Energy Demand	Projected Commercial Energy Demand (Gigawatthours)										
		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	5729	5703										
1996	5737	5818	5732									
1997	5703	5908	5757	5858								
1998	5826	6017	5824	5945	5945							
1999	5954	6131	5910	6039	6039	5983						
2000	6092	6247	6005	6159	6159	6073	6113					
2001	6170	6359	6102	6301	6301	6157	6231	6231				
2002	6458	6469	6198	6450	6450	6236	6336	6336	6324			
2003	6346	6577	6295	6606	6606	6327	6438	6438	6467	6436		
2004	6454	6693	6400	6773	6773		6540	6540	6570	6505	6428	
2005			6505	6944	6944			6628	6653	6570	6479	6568
2006				7118	7118				6729	6636	6597	6711
2007					7296					6703	6713	6870
2008											6841	6949
2009												7076

Table 3.4

Year	Actual Energy Demand	Projected Industrial Energy Demand (Gigawatthours)										
		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	3237	3362										
1996	3285	3423	3349									
1997	3501	4367	3717	3431								
1998	3412	4335	3941	3690	3690							
1999	3481	4398	4013	3828	3828	3771						
2000	3581	4461	4086	3919	3919	3836	3537					
2001	3283	4526	4160	3988	3988	3901	3576	3576				
2002	3328	4591	4236	4059	4059	3964	3615	3615	3315			
2003	3189	4655	4313	4130	4130	4027	3651	3651	3382	3349		
2004	3229	4717	4393	4202	4202		3695	3695	3445	3415	3031	
2005			4474	4276	4276			3742	3491	3437	2990	3347
2006				4351	4351				3530	3453	3033	3407
2007					4427					3471	3075	3458
2008											3123	3501
2009												3542

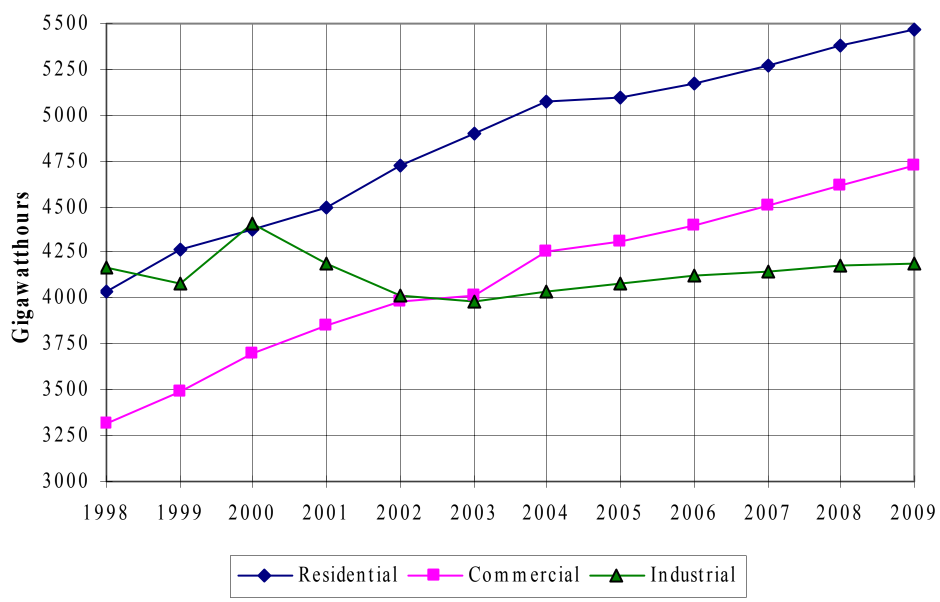
Metropolitan Edison Company

Metropolitan Edison Company (Met-Ed) provides service to nearly 521,000 electric utility customers in eastern and south central Pennsylvania. In 2004, Met-Ed had total energy sales of 13.4 billion kilowatthours (KWH) - - up 3.6% from 2003. Residential sales dominated Met-Ed's market with 37.9% of the total sales, followed by commercial (31.7%) and industrial (30.2%).

Between 1989 and 2004, Met-Ed's energy demand grew at an average rate of 2.4% per year. Residential and commercial sales have maintained relatively steady growth over the period (2.8% for residential and 3.9% for commercial), while industrial sales have fluctuated considerably. Industrial sales grew at an average rate of about 0.8%.

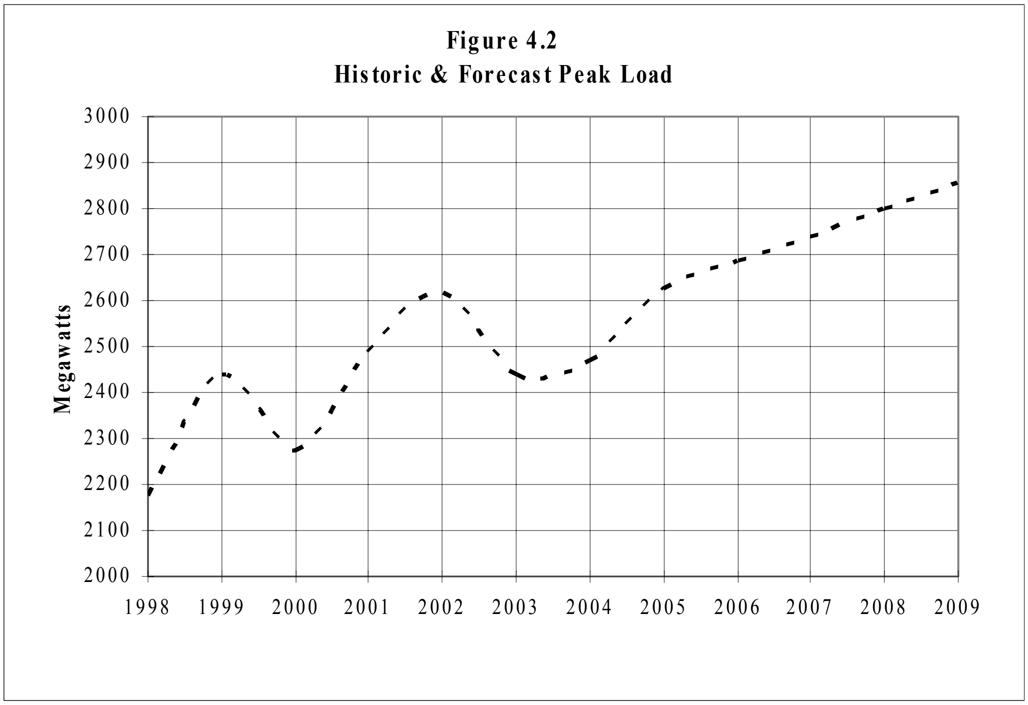
The current five-year projection of growth in total energy demand is 1.5%. This includes a residential growth rate of 1.5%, a commercial growth rate of 2.1% and an industrial rate of 0.7%.

Figure 4.1
Historic & Forecast Energy Demand



Met-Ed's summer peak load, occurring on August 3, 2004, was 2,468 megawatts (MW), representing an increase of 1.2% from last year's system peak of 2,438 MW. The 2004/05 winter peak load was 2,411 MW or 2.2% higher than the previous year's winter peak of 2,359 MW.

The actual average annual peak load growth rate over the past fifteen years was 1.9%. Met-Ed's forecast shows its peak load increasing from 2,468 MW to 2,857 MW by 2009, or an average annual growth rate of 3.0%.



Tables 4.1-4.4 provide Met-Ed's forecasts of peak load and residential, commercial and industrial energy demand from 1995 through 2005.

Met-Ed is a wholly owned subsidiary of FirstEnergy Corporation. Met-Ed is a member of the PJM Interconnection and the Mid-Atlantic Area Council.

Met-Ed retains Provider of Last Resort (PLR) responsibility for those customers who do not choose an alternate energy supplier.

Met-Ed divested most of its generation facilities in 1999. Met-Ed currently retains ownership of the York Haven generating station, which has a combined generating capacity of 19.4 MW.

In 2004, Met-Ed purchased approximately 2.2 billion KWH from cogeneration and small power production projects. Contract capacity (defined as PJM installed capacity credits) is 295 MW. For calendar year 2004, seven electric generation suppliers sold a total of 950 million KWH to retail customers in Met-Ed's service territory, or about 7.1% 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, 57 time-of-day conversions were made. Over $1.7 million was spent in 2004 for a peak load reduction of 105 KW, a load shift of 43 KW and energy savings totaling 768,157 KWH.

Met-Ed is a member of MAAC and PJM. FirstEnergy is a member of ECAR and the Midwest ISO.

Table 4.1

Year	Actual Peak Demand	Projected Peak Load Requirements (Megawatts)										
		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	2186	2042										
1996	2017	2080	2094									
1997	2224	2113	2139	2139								
1998	2176	2147	2176	2176	2194							
1999	2439	2192	2205	2205	2233	2263						
2000	2274	2229	2228	2228	2268	2318	2404					
2001	2486	2263	2264	2264	2305	2373	2456	2455				
2002	2616	2299	2303	2303	2343	2429	2508	2504	2503			
2003	2438	2333	2345	2345	2386	2486	2559	2553	2554	2527		
2004	2468	2369	2388	2388	2429		2612	2602	2611	2584	2570	
2005			2432	2432	2472			2652	2668	2639	2634	2625
2006				2475	2515				2725	2691	2702	2689
2007					2559					2747	2756	2740
2008											2817	2801
2009												2857

Table 4.2

Year	Actual Energy Demand	Projected Residential Energy Demand (Gigawatthours)										
		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	3925	3892										
1996	4135	3972	3961									
1997	4034	4047	4028	4028								
1998	4040	4121	4041	4041	4122							
1999	4266	4203	4095	4095	4204	4264						
2000	4377	4286	4152	4152	4264	4352	4344					
2001	4496	4359	4222	4222	4328	4442	4430	4430				
2002	4721	4438	4292	4292	4391	4533	4516	4501	4607			
2003	4895	4508	4361	4361	4451	4624	4602	4577	4708	4846		
2004	5071	4582	4430	4430	4513		4687	4651	4804	4860	4885	
2005			4499	4499	4575			4724	4892	4980	4977	5097
2006				4571	4636				4988	5094	5083	5176
2007					4697					5211	5190	5276
2008											5300	5376
2009												5472

Table 4.3

Year	Actual Energy Demand	Projected Commercial Energy Demand (Gigawatthours)										
		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	3011	2959										
1996	3144	3037	3026									
1997	3209	3117	3106	3106								
1998	3209	3209	3179	3179	3224							
1999	3487	3304	3258	3258	3306	3414						
2000	3699	3397	3338	3338	3389	3518	3518					
2001	3855	3497	3420	3420	3473	3622	3622	3751				
2002	3985	3611	3512	3512	3567	3732	3732	3860	3976			
2003	4018	3724	3607	3607	3663	3841	3837	3970	4096	4057		
2004	4251	3835	3703	3703	3762		3947	4079	4216	4144	4170	
2005			3805	3805	3864			4189	4336	4258	4281	4310
2006				3912	3972				4456	4363	4388	4400
2007					4083					4464	4498	4506
2008											4601	4616
2009												4721

Table 4.4

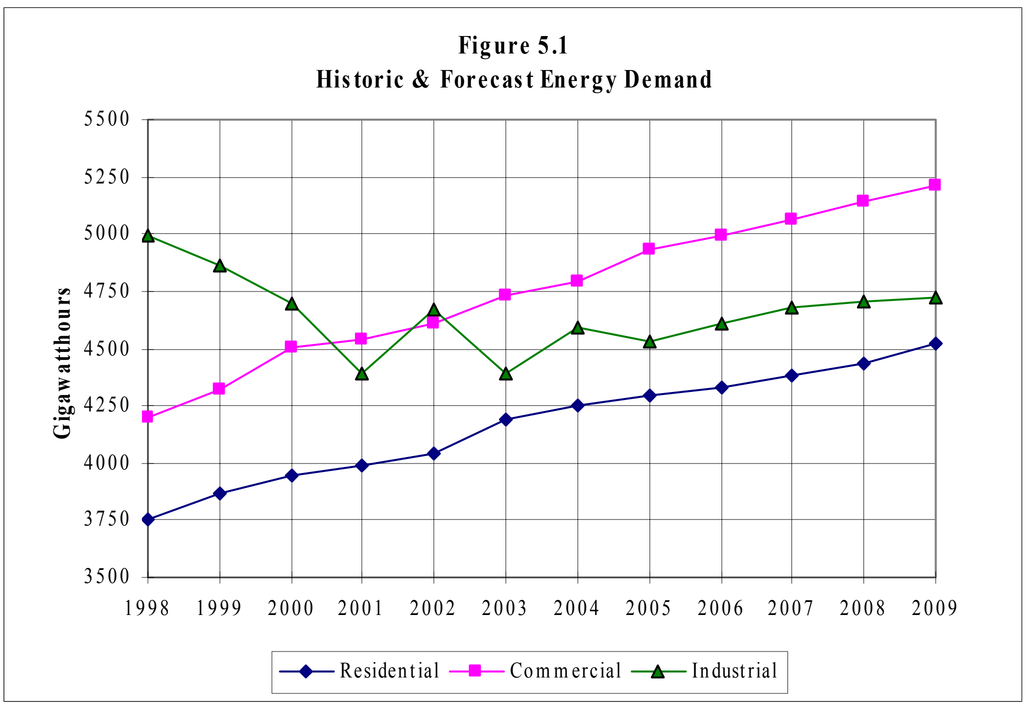
Year	Actual Energy Demand	Projected Industrial Energy Demand (Gigawatthours)										
		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	3957	3888										
1996	4033	3956	3985									
1997	4097	4019	4064	4064								
1998	4173	4110	4132	4132	4136							
1999	4085	4205	4197	4197	4229	4239						
2000	4412	4291	4294	4294	4305	4307	4313					
2001	4186	4376	4389	4389	4370	4365	4352	4312				
2002	4012	4463	4468	4468	4448	4435	4410	4409	4263			
2003	3986	4552	4535	4535	4560	4506	4459	4490	4341	3954		
2004	4042	4644	4627	4627	4664		4508	4567	4419	3989	4080	
2005			4724	4724	4776			4645	4498	4010	4136	4077
2006				4810	4876				4577	4030	4162	4119
2007					4964					4050	4206	4145
2008											4237	4175
2009												4195

Pennsylvania Electric Company

Pennsylvania Electric Company (Penelec) provides service to nearly 586,000 electric utility customers in western and northern Pennsylvania. In 2004, Penelec had energy sales totaling 13.7 billion kilowatthours (KWH) - - up about 2.4% from 2003. Commercial sales dominated Penelec's market with 35.1% of the total sales, followed by industrial (33.6%) and residential (31.1%).

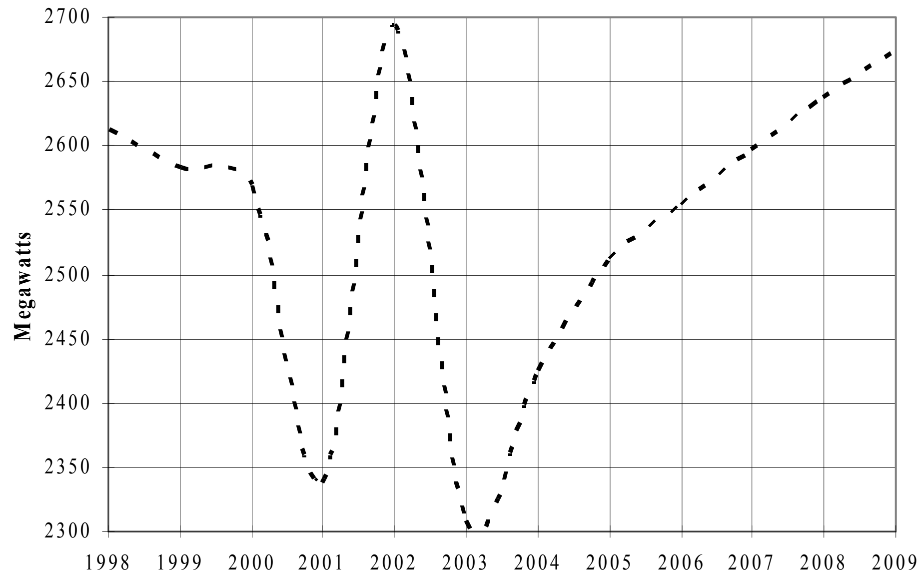
Between 1989 and 2004, Penelec's energy demand grew at an average rate of 1.2% per year. Residential and commercial sales have maintained relatively steady growth over the period (1.4% for residential and 3.0% for commercial), while industrial sales have fluctuated greatly. Industrial sales for 2004 were 7.0% less than the 1989 level, or an average annual decrease of 0.5%.

The current five-year projection of growth in total energy demand is 1.2%. This includes a residential growth rate of 1.3%, a commercial growth rate of 1.7% and an industrial growth rate of 0.6%.



Penelec's 2004 summer peak load, occurring on June 9, 2004, was 2,337 megawatts (MW), representing an increase of 1.3% from last year's summer peak of 2,308 MW. The 2004/05 winter peak load was 2,425 MW or 5.9% higher than the previous year's winter peak of 2,290 MW.

The actual average annual peak load growth rate over the past fifteen years was 1.2%. Penelec's forecast shows its winter peak load increasing from 2,425 MW in 2004/2005 to 2,523MW in 2009/2010, or an average increase of 0.8%. Penelec's summer peak load is expected to increase from 2,337 MW in 2004 to 2,674 MW in 2009, or an average increase of 2.9%.



Tables 5.1-5.4 provide Penelec's forecasts of peak load and residential, commercial and industrial energy demand from 1995 through 2005.

Penelec is a wholly owned subsidiary of FirstEnergy Corporation. Penelec is a member of the PJM Interconnection and the Mid-Atlantic Area Council.

Penelec retains Provider of Last Resort (PLR) responsibility for those customers who do not choose an alternate energy supplier.

Penelec divested all of its generation facilities in 1999.

In 2004, Penelec purchased approximately 3.2 billion KWH from cogeneration and small power production projects. Contract capacity (defined as PJM installed capacity credits) is 396.45 MW.

For calendar year 2004, out of 22 electric generation suppliers, six sold a total of 1.2 billion KWH to retail customers in Penelec's service territory, or about 8.7% of total consumption, down from 14.1% in 2003.

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, 7 time-of-day conversions were made. Nearly $1.7 million was spent in 2004 for a peak load reduction of 231 KW and energy savings totaling 1.5 million KWH.

Penelec is a member of MAAC and PJM. FirstEnergy is a member of ECAR and the Midwest ISO.

Table 5.1

Year	Actual Peak Demand	Projected Peak Load Requirements (Megawatts)										
		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	2589	2584										
1996	2652	2641	2706									
1997	2481	2758	2743	2751								
1998	2613	2790	2728	2742	2688							
1999	2583	2795	2769	2795	2730	2672						
2000	2569	2893	2818	2855	2772	2704	2651					
2001	2337	2916	2867	2904	2813	2737	2675	2321				
2002	2693	2967	2914	2951	2853	2770	2700	2347	2337			
2003	2308	3056	2527	2564	2472	2804	2737	2373	2375	2410		
2004	2425	2526	2567	2604	2506		2760	2399	2405	2456	2438	
2005			2606	2643	2540			2425	2437	2505	2481	2511
2006				2682	2573				2465	2544	2525	2554
2007					2606					2592	2565	2598
2008											2604	2637
2009												2674

Table 5.2

Year	Actual Energy Demand	Projected Residential Energy Demand (Gigawatthours)										
		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	3765	3772										
1996	3897	3820	3813									
1997	3801	3876	3853	3853								
1998	3756	3920	3890	3890	3870							
1999	3864	3961	3921	3921	3922	3894						
2000	3949	3999	3948	3948	3950	3931	3881					
2001	3991	4030	3982	3982	3979	3968	3915	3977				
2002	4167	4064	4015	4015	4009	4007	3951	4021	4043			
2003	4187	4084	4046	4046	4039	4045	3984	4065	4089	4194		
2004	4249	4126	4077	4077	4069		4017	4109	4134	4162	4135	
2005			4109	4109	4099			4154	4180	4203	4186	4295
2006				4139	4129				4226	4245	4236	4333
2007					4160					4287	4287	4385
2008											4339	4438
2009												4524

Table 5.3

Year	Actual Energy Demand	Projected Commercial Energy Demand (Gigawatthours)										
		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	3922	3828										
1996	4044	3934	4031									
1997	4098	4041	4156	4156								
1998	4198	4131	4282	4282	4283							
1999	4319	4212	4388	4388	4408	4347						
2000	4509	4292	4495	4495	4531	4459	4387					
2001	4538	4389	4600	4600	4658	4571	4473	4472				
2002	4697	4486	4695	4695	4784	4684	4558	4549	4613			
2003	4727	4586	4795	4795	4908	4797	4643	4626	4730	4782		
2004	4792	4682	4898	4898	5031		4728	4704	4846	4874	4825	
2005			4995	4995	5152			4781	4962	4976	4912	4928
2006				5099	5270				5078	5076	4986	4990
2007					5386					5178	5060	5064
2008											5136	5140
2009												5213

Table 5.4

Year	Actual Energy Demand	Projected Industrial Energy Demand (Gigawatthours)										
		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	4463	4538										
1996	4563	4632	4809									
1997	4836	4796	5054	5054								
1998	4996	4854	5172	5172	4836							
1999	4866	4912	5235	5235	4894	5047						
2000	4698	4960	5309	5309	4948	5114	5004					
2001	4392	5008	5363	5363	5002	5205	5093	4857				
2002	4315	5057	5411	5411	5057	5293	5177	5144	4670			
2003	4391	5107	5460	5460	5113	5383	5239	5214	4783	4492		
2004	4589	5158	5515	5515	5169		5306	5244	4846	4708	4561	
2005			5570	5570	5226			5274	4887	4749	4666	4527
2006				5637	5284				4928	4797	4737	4612
2007					5342					4845	4791	4679
2008											4815	4708
2009												4725

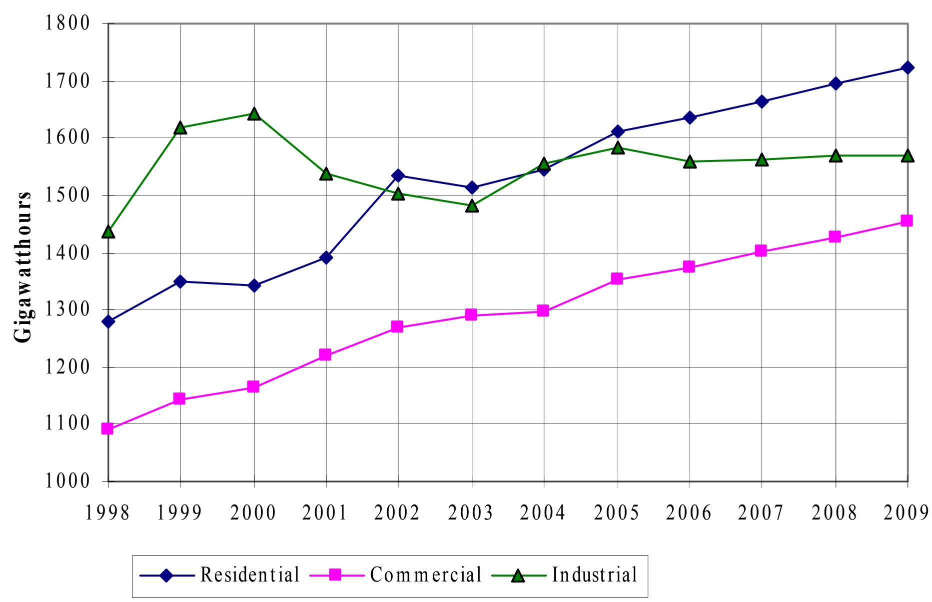
Pennsylvania Power Company

Pennsylvania Power Company (Penn Power) provides service to over 157,000 electric utility customers in western Pennsylvania. In 2004, Penn Power had energy sales totaling 4.4 billion kilowatthours (KWH) - - an increase of 2.5% from the 2003 figure. Residential sales lead Penn Power's market with 35.2% of the total sales, followed by industrial (35.3%) and commercial (29.4%).

Between 1989 and 2004, Penn Power'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 at rates of 2.8% and 4.2%, respectively. Industrial sales have fluctuated considerably and, in 2004, were only 85.9% of the 1989 level, or an average annual decline of 1.0%.

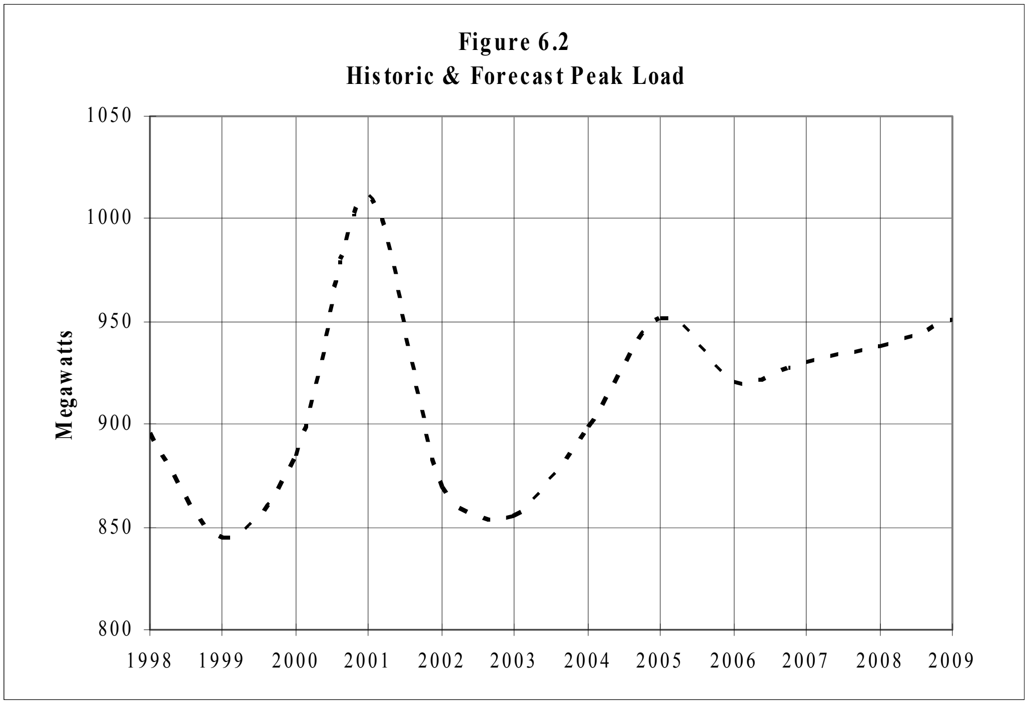
The current five-year projection of growth in total energy demand is 1.5%. This includes a residential growth rate of 2.2%, a commercial growth rate of 2.3% and an industrial rate of 0.2%.

Figure 6.1
Historic & Forecast Energy Demand



Penn Power's 2004 summer peak load, occurring on June 15, 2004, was 898 megawatts (MW), representing an increase of 5.0% from last year's peak of 855 MW. The 2004/05 winter peak load of 952 MW was 10.2% higher than the previous year's winter peak of 864 MW.

The actual average annual peak load growth rate over the past fifteen years was 2.0%. Penn Power's forecast shows its peak load increasing from 898 MW in the summer of 2004 to 951 MW by 2009, or an average annual growth rate of 1.2%. Penn Power's peak load represents about 7.9% of FirstEnergy's peak load.



Tables 6.1-6.4 provide Penn Power's forecasts of peak load and residential, commercial and industrial energy demand from 1995 through 2005.

The electrical systems of Penn Power and the other FirstEnergy operating companies are interconnected and fully integrated. As of January 1, 2005, Penn Power owned 1,237 MW of the First Energy system's generating capacity, located in Pennsylvania and Ohio. Competitive bidding for generation supply will begin in 2007, at the expiration of the generation rate cap in 2006.

For calendar year 2004, two electric generation suppliers sold a total of over 5.8 million KWH to retail customers in Penn Power's service territory or about 0.1% of total consumption, down from 0.2% in 2003. Penn Power purchased 60,270 KWH from an independent power producer in 2004.

FirstEnergy is a member of ECAR and the Midwest ISO.

Table 6.1

Year	Actual Peak Demand	Projected Peak Load Requirements (Megawatts)										
		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	835	717										
1996	784	752	759									
1997	829	792	781	781								
1998	895	807	804	804	902							
1999	845	825	831	830	919	880						
2000	885	844	858	858	937	897	935					
2001	1011	862	892	892	958	919	957	883				
2002	869	879	928	928	980	941	980	904	918			
2003	855	897	962	962	1003	963	1003	930	947	891		
2004	898	914	997	997	1026	983	1025	956	983	923	865	
2005			1019	1019	1050			982	1022	958	884	952
2006				977	1012				1058	985	900	921
2007					1036					1020	916	930
2008											929	938
2009												951

Table 6.2

Year	Actual Energy Demand	Projected Residential Energy Demand (Gigawatthours)										
		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	1195	1166										
1996	1254	1179	1211									
1997	1238	1189	1238	1238								
1998	1278	1195	1265	1265	1300							
1999	1351	1201	1292	1292	1318	1300						
2000	1341	1220	1320	1320	1336	1319	1390					
2001	1391	1235	1373	1373	1355	1339	1412	1360				
2002	1533	1251	1430	1430	1374	1360	1434	1395	1447			
2003	1513	1267	1459	1459	1398	1381	1457	1430	1483	1512		
2004	1545	1283	1488	1488	1423	1403	1479	1451	1520	1523	1542	
2005			1502	1502	1445			1473	1558	1552	1571	1612
2006				1516	1467				1597	1579	1599	1636
2007					1494					1607	1629	1665
2008											1657	1695
2009												1723

Table 6.3

Year	Actual Energy Demand	Projected Commercial Energy Demand (Gigawatthours) 1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	938	893										
1996	996	903	936									
1997	1013	928	970	970								
1998	1090	953	1010	1010	1042							
1999	1143	976	1054	1054	1074	1110						
2000	1164	1008	1103	1103	1108	1145	1204					
2001	1220	1039	1167	1167	1143	1181	1242	1162				
2002	1268	1070	1238	1238	1182	1221	1284	1206	1270			
2003	1291	1101	1314	1314	1221	1262	1327	1251	1327	1279		
2004	1296	1131	1395	1395	1262	1304	1372	1293	1387	1310	1309	
2005			1436	1436	1304			1335	1449	1342	1339	1353
2006				1478	1348				1514	1373	1370	1374
2007					1392					1405	1402	1400
2008											1429	1427
2009												1453

Table 6.4

Year	Actual Energy Demand	Projected Industrial Energy Demand (Gigawatthours) 1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	1558	1499										
1996	1693	1703	1894									
1997	1659	1902	1967	1967								
1998	1436	1935	2002	2002	1677							
1999	1619	1966	2043	2043	1716	1483						
2000	1643	2002	2082	2082	1759	1520	1563					
2001	1539	2039	2138	2138	1803	1558	1596	1618				
2002	1505	2077	2184	2184	1847	1596	1635	1644	1514			
2003	1481	2114	2230	2230	1890	1633	1673	1677	1516	1521		
2004	1554	2149	2273	2273	1933	1670	1711	1716	1517	1507	1529	
2005			2314	2314	1981			1758	1519	1500	1555	1582
2006				2357	2029				1520	1493	1570	1558
2007					2076					1489	1580	1563
2008											1583	1568
2009												1569

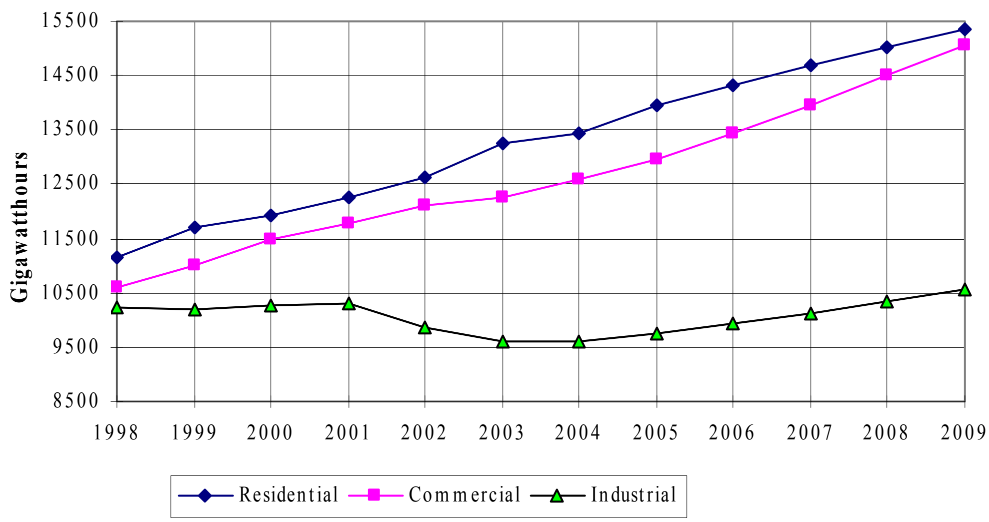
PPL Electric Utilities Corporation

PPL Electric Utilities Corporation (PPL) provides service to 1.35 million homes and businesses over a 10,000 square mile area in 29 counties of central eastern Pennsylvania. In 2004, PPL had energy sales totaling 36.8 billion kilowatthours (KWH) -- up 1.0% from 2003. Residential sales continued to dominate PPL's market with 36.4% of the total sales, followed by commercial (33.7%) and industrial (26.3%).

Between 1989 and 2004, PPL's energy demand grew an average of 1.8% per year. Residential energy sales grew at an annual rate of 2.0%, commercial at a 2.8% rate and industrial at 0.6%.

The current five-year projection of average growth in energy demand is 2.8%. This includes growth rates of 2.7% for residential, 3.7% for commercial and 1.9% for industrial.

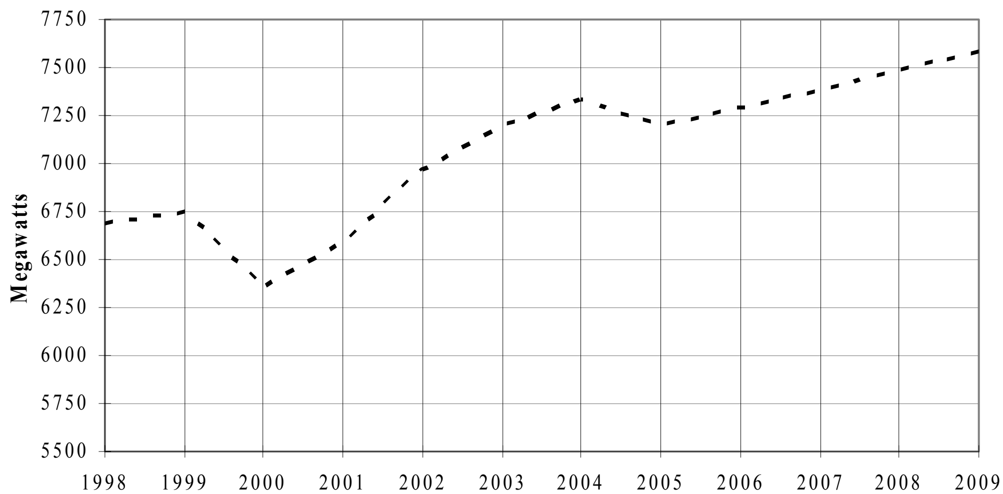
Figure 7.1
Historic & Forecast Energy Demand



PPL's 2004/05 winter peak load, occurring on December 20, 2004, was 7,335 megawatts (MW), representing an increase of 1.9% from last year's peak of 7,197 MW. The 2004 summer peak load was 6,434 MW compared to the previous summer's peak of 6,433 MW.

The actual average annual peak load growth rate over the past fifteen years was 1.3%. PPL's five-year winter peak load forecast scenario shows the peak load increasing from 7,335MW in 2004/05 to 7,580 MW in the winter of 2009/10 at an average annual rate of 0.7%. The summer peak load is projected to increase to 7,400 MW by 2009.

Figure 7.2
Historic & Forecast Peak Load



Tables 7.1-7.4 provide PPL's forecasts of peak load and residential, commercial and industrial energy demand from 1994 through 2004.

Net operable generating capacity of 8,601 MW (summer rating) includes 43.7% coal-fired capacity and 23.5% nuclear capacity. Natural gas and dual fuel units account for 26.2% of the total. Independent power producers also provided 293 MW to the system. In 2004, PPL purchased nearly 2.4 billion KWH from cogeneration and independent power production facilities, or about 6.4% of total sales.

For calendar year 2004, nine electric generation suppliers sold a total of approximately 1.0 billion KWH to retail customers in PPL's service territory, or about 2.8% of total consumption, up from 2.4% in 2003.

For 2004, 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. Customers reducing load for economic conditions receive significant rate discounts. The peak load reduction from this program represents approximately 3.8% of the 2004 summer peak load.

PPL's Price Response Service permits customers to respond to market price signals by reducing a portion of their load. In 2004, an estimated 1,100 KW peak load reduction was achieved, with energy savings totaling about 29,600 KWH. The Residential Demand Side Response Rider, which provides for the option of shifting load from on peak hours, reduced the peak by 104 KW and saved 60,435 KWH. Industrial Service – Economic Provisions permits PPL to request customers to reduce load for economic conditions. In 2004, 246.5 MW of peak load was reduced with savings of 2,607 MWH.

PPL is a member of PJM and MAAC.

Table 7.1

Year	Actual Peak Demand	Projected Peak Load Requirements (Megawatts) 1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	6607	6435										
1996	6506	6500	6830									
1997	5925	6625	6920	6910								
1998	6688	6760	7055	6935	6910							
1999	6746	6895	7190	7030	6935	6815						
2000	6355	7040	7315	7120	7030	6905	6580					
2001	6583	7175	7450	7130	7120	7006	6680	6850				
2002	6970	7310	7590	7250	7130	7040	6770	6960	7000			
2003	7197	7455	7725	7350	7250	7140	6860	7060	7070	6790		
2004	7335	7585	7860	7470	7350		6960	7170	7040	6860	7200	
2005			8040	7580	7470			7270	7120	7000	7300	7200
2006				7690	7580				7200	7140	7410	7290
2007					7690					7320	7510	7390
2008											7610	7490
2009												7580

Table 7.2

Year	Actual Energy Demand	Projected Residential Energy Demand (Gigawatthours) 1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	11300	11290										
1996	11848	11450	11475									
1997	11434	11620	11640	11690								
1998	11156	11800	11815	11760	11690							
1999	11704	11980	11980	11830	11760	11740						
2000	11923	12160	12145	11910	11830	11850	12031					
2001	12269	12330	12320	12020	11910	11980	12150	12176				
2002	12640	12510	12495	12160	12020	12120	12280	12324	12391			
2003	13266	12690	12680	12290	12160	12260	12421	12478	12514	12868		
2004	13441	12870	12865	12430	12290		12562	12634	12650	13062	13308	
2005			13040	12570	12430			12799	12803	13259	13505	13950
2006				12710	12570				12955	13462	13728	14311
2007					12710					13671	13962	14675
2008											14198	15019
2009												15349

Table 7.3

Year	Actual Energy Demand	Projected Commercial Energy Demand (Gigawatthours)										
		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	9948	9830										
1996	10288	10090	10100									
1997	10309	10355	10350	10490								
1998	10597	10625	10610	10740	10490							
1999	11002	10910	10885	11000	10740	10740						
2000	11477	11200	11165	11280	11000	10980	11090					
2001	11778	11490	11445	11560	11280	11240	11275	11291				
2002	12117	11780	11725	11870	11560	11500	11444	11431	11850			
2003	12273	12065	11995	12140	11870	11760	11612	11561	12033	12212		
2004	12576	12345	12265	12410	12140		11782	11699	12219	12507	13275	
2005			12525	12680	12410			11848	12411	12757	13601	12967
2006				12940	12680				12602	13101	13975	13436
2007					12940					13418	14286	13946
2008											14631	14517
2009												15068

Table 7.4

Year	Actual Energy Demand	Projected Industrial Energy Demand (Gigawatthours)										
		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	9845	9685										
1996	10016	9675	9900									
1997	10078	9885	10150	10070								
1998	10220	10070	10405	10110	10070							
1999	10179	10260	10600	10270	10110	10190						
2000	10280	10445	10795	10440	10270	10350	10543					
2001	10319	10635	10990	10610	10440	10520	10836	10963				
2002	9853	10830	11190	10790	10610	10690	11077	11255	10780			
2003	9599	11040	11400	10960	10790	10860	11295	11521	11135	10355		
2004	9611	11245	11615	11140	10960		11498	11777	11425	10503	9938	
2005			11825	11320	11140			12010	11702	10641	10035	9749.9
2006				11510	11320				11970	10795	10155	9925.9
2007					11510					10924	10253	10136
2008											10346	10349
2009												10577

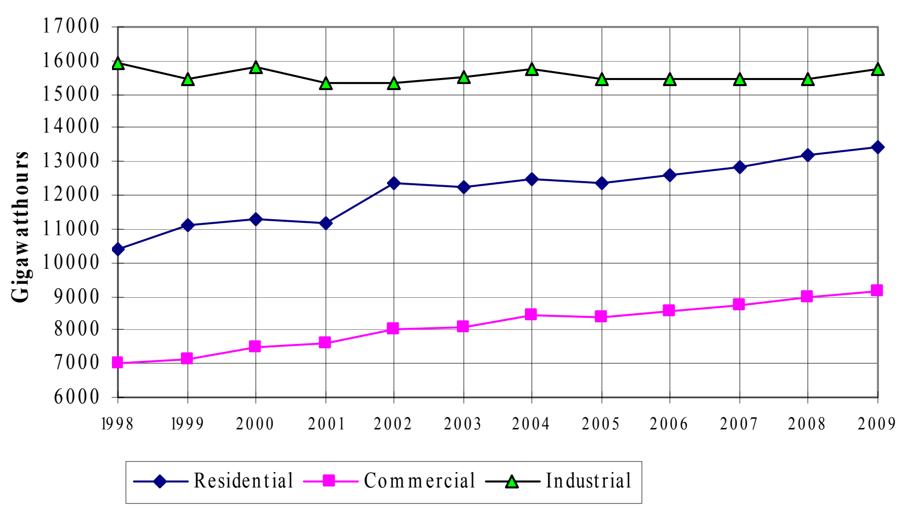
PECO Energy Company

PECO Energy Company (PECO) provides service to over 1.5 million electric utility customers in southeastern Pennsylvania. In 2004, PECO had total retail energy sales of 37.7 billion kilowatthours (KWH) -- up 2.4% from 2003. Industrial sales continued to dominate PECO's market with 41.8% of the total sales, followed by residential (33.2%) and commercial (22.3%).

Between 1989 and 2004 PECO's energy demand grew an average of 1.1% per year. Residential energy sales grew at an annual rate of 1.8% and commercial at a 3.8% rate. Industrial sales declined at an average rate of 0.3%.

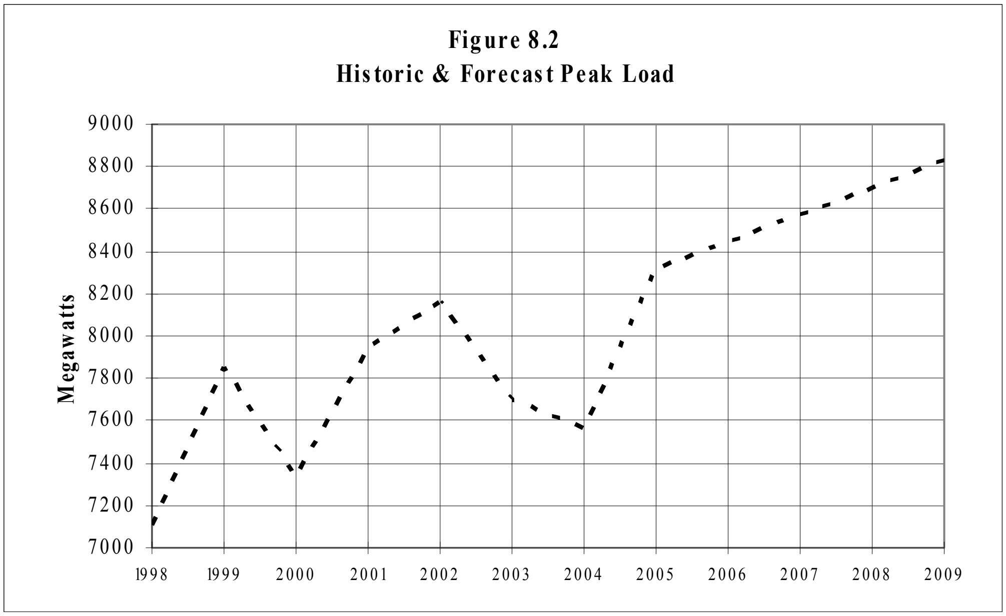
The current five-year projection of growth in energy demand is 0.9%. This includes an annual growth rate of 1.5% for residential, 1.7% for commercial and 0.02% for industrial.

Figure 8.1
Historic & Forecast Energy Demand



PECO's 2004 summer peak load, occurring on August 20, 2004, was 7,567 megawatts (MW), representing a decrease of 1.7% from last year's peak of 7,696 MW. The 2004/05 winter peak demand was 6,838 MW or 6.9% above the previous winter's peak of 6,396 MW.

The actual average annual peak demand growth rate over the past fifteen years was 1.1%. PECO's current forecast shows the peak load increasing from the actual 2004 summer peak load of 7,567 MW to 8,831 MW in the summer of 2009, or an annual growth rate of 3.1%.



Tables 8.1-8.4 provide PECO's forecasts of peak load and residential, commercial and industrial energy demand from 1995 through 2005.

PECO has entered into a Purchased Power Agreement with Exelon Generation to provide energy and capacity for its provider-of-last-resort load throughout the forecast period. Other resources may be obtained through purchases from the wholesale markets.

In 2004, PECO purchased about 892 million KWH from cogeneration and independent power production facilities, or about 2.4% of total energy consumption. Contract capacity totaled 178 MW.

For calendar year 2004, electric generation suppliers sold a total of 4.6 billion KWH to retail customers in PECO's service territory or about 12.2% of total consumption, up from 9.4% in 2003. On the summer peak day, electric generation suppliers represented a load of 1,120 MW, or 14.8%.

PECO has developed commercial and industrial rate incentive programs to encourage customers to manage their energy demands and usage consistent with system capabilities. During 2004, the peak load reduction resulting from this rate option was 180 MW, with energy savings of 1.5 million KWH.

PECO is a member of MAAC and PJM.

Table 8.1

Year	Actual Peak Demand	Projections of Peak Load Requirements (Megawatts) 1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	7246	6671										
1996	6509	6599	6811									
1997	7390	6677	6868	6868								
1998	7108	6751	6973	6973	6973							
1999	7850	6825	7063	7063	7063	7063						
2000	7333	6905	7135	7135	7135	7135	7339					
2001	7948	6989	7233	7233	7233	7233	7398	7392				
2002	8164	7077	7308	7308	7308	7308	7457	7451	8012			
2003	7696	7166	7387	7387	7387	7387	7517	7510	8076	8229		
2004	7567	7256	7466	7466	7466		7577	7570	8140	8295	8129	
2005			7547	7547	7547			7631	8205	8362	8320	8320
2006				7629	7629				8271	8428	8445	8445
2007					7711					8496	8571	8571
2008											8700	8700
2009												8831

Table 8.2

Year	Actual Energy Demand	Projected Residential Energy Demand (Gigawatthours) 1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	10660	10423										
1996	10657	10387	10576									
1997	10515	10472	10653	10653								
1998	10376	10581	10732	10732	10515							
1999	11132	10696	10812	10812	10516	10516						
2000	11304	10812	10894	10894	10600	10600	10600					
2001	11178	10934	10976	10976	10685	10685	10685	11278				
2002	12335	11055	11059	11059	10770	10770	10770	11385	11634			
2003	12259	11177	11142	11142	10856	10856	10856	11488	11733	12020		
2004	12507	11300	11225	11225	10943		10943	11592	11855	11905	12250	
2005			11310	11310	11031			11697	11957	11981	12385	12385
2006				11394	11119				12059	12054	12592	12592
2007					11208					12128	12839	12839
2008											13179	13179
2009												13443

Table 8.3

Year	Actual Energy Demand	Projected Commercial* Energy Demand (Gigawatthours)										
		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	6222	6241										
1996	6410	6403	6523									
1997	6689	6593	6667	6667								
1998	7012	6787	7044	7044	6643							
1999	7154	6983	7346	7346	6597	6597						
2000	7481	7182	7650	7650	6649	6649	6649					
2001	7604	7385	7955	7955	6703	6703	6702	7315				
2002	8019	7591	8262	8262	6756	6756	6756	7446	7732			
2003	8077	7799	8572	8572	6810	6810	6810	7578	7963	8135		
2004	8414	8011	8882	8882	6865		6864	7711	8099	8233	8140	
2005			9195	9195	6920			7844	8265	8434	8349	8349
2006				9510	6975				8436	8637	8550	8550
2007					7031					8839	8755	8755
2008											8965	8965
2009												9144

Table 8.4

Year	Actual Energy Demand	Projected Industrial* Energy Demand (Gigawatthours)										
		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	15869	15805										
1996	14976	15766	15249									
1997	14992	15791	15299	15299								
1998	15929	15923	15259	15259	15456							
1999	15477	16040	15271	15271	15919	15919						
2000	15828	16145	15248	15248	16047	16047	16047					
2001	15312	16253	15353	15353	16175	16175	16175	15405				
2002	15323	16363	15333	15333	16304	16304	16305	15406	15324			
2003	15518	16473	15314	15314	16435	16435	16435	15408	15417	15130		
2004	15741	16588	15294	15294	16566		16567	15409	15429	14959	15477	
2005			15278	15278	16699			15409	15442	14980	15448	15449
2006				15262	16832				15458	15001	15448	15448
2007					16967					15022	15448	15448
2008											15448	15448
2009												15757

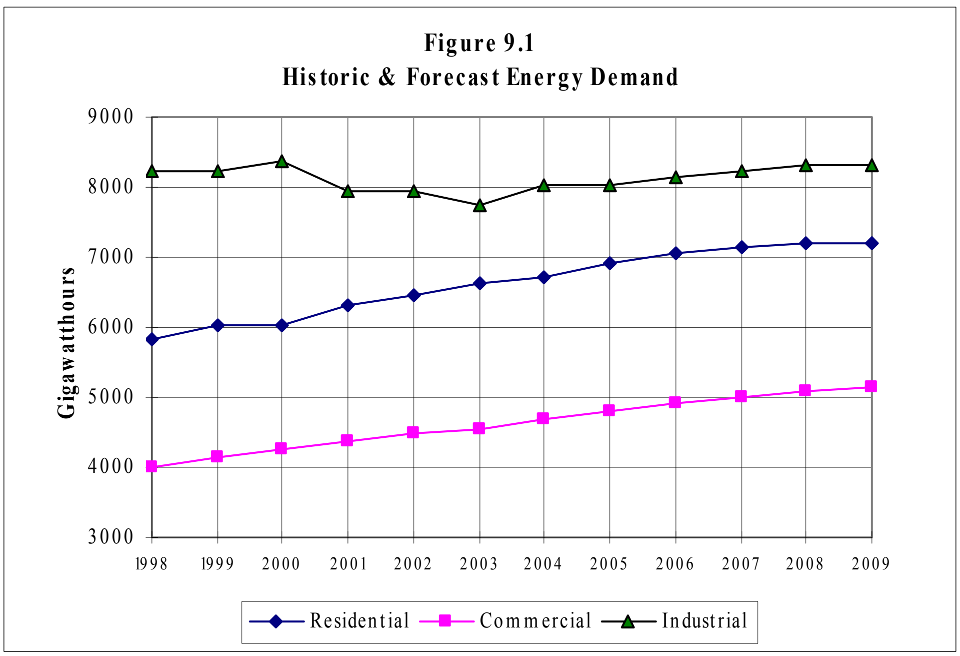
* Large Commercial & Industrial

West Penn Power Company

West Penn Power Company (West Penn) provides service to nearly 701,000 electric utility customers in western, north and south central Pennsylvania. In 2003, West Penn had total retail energy sales of about 20.2 billion kilowatthours (KWH) – up 2.9% from 2003. Industrial sales continued to dominate West Penn's market with 39.8% of the total sales, followed by residential (33.3%) and commercial (23.2%).

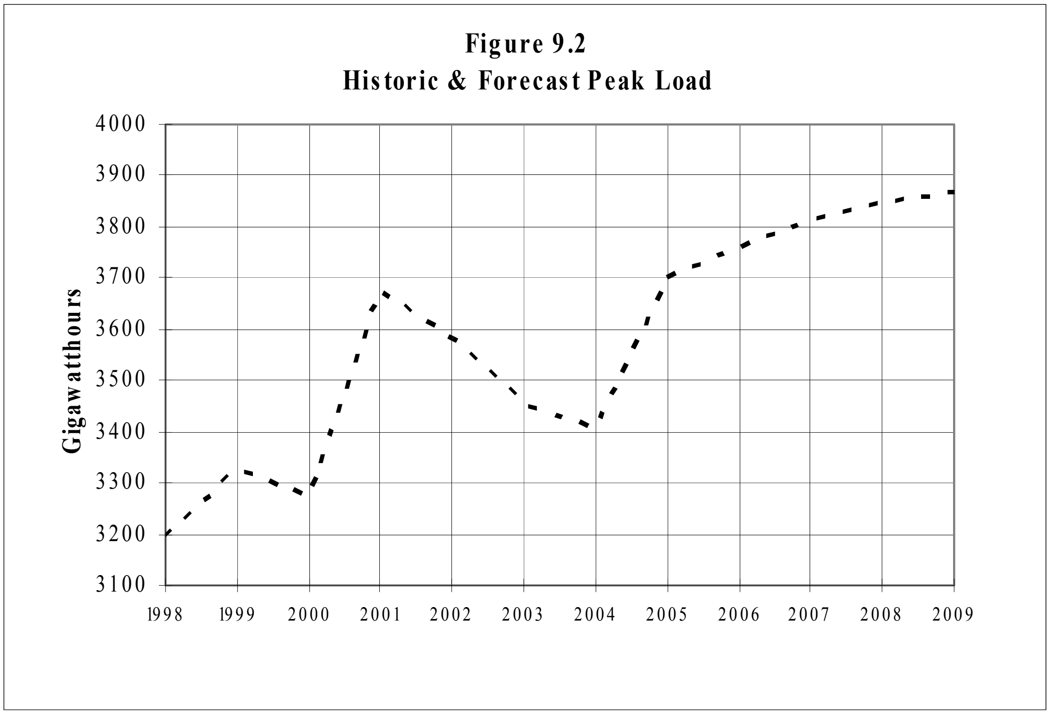
Between 1989 and 2004, West Penn's energy demand grew an average of 1.8% per year. Sales for all sectors have maintained relatively steady growth during the period. Residential sales grew at an annual rate of 1.8%, commercial sales at 2.7% and industrial sales at 1.4% over the past 15 years.

The current five-year projection of growth in energy demand is 1.2%. This includes a residential growth rate of 1.3%, a commercial rate of 1.8% and an industrial rate of 0.7%.



West Penn's 2004 summer peak load, occurring on August 3, 2004, was 3,407 megawatts (MW), representing a decrease of 1.4% from last year's summer peak of 3,455 MW. The 2004/05 winter peak load was 3,539 MW or 3.4% higher than the previous year's winter peak of 3,424 MW.

The actual average annual peak load growth rate over the past fifteen years was about 1.2%. West Penn's load forecast scenario shows the peak load increasing from 3,407 MW in the summer of 2004 to 3,866 MW in 2009, or an average annual growth rate of 2.6%.



Tables 9.1-9.4 provide West Penn's forecasts of peak load and residential, commercial and industrial energy demand from 1995 through 2005.

Effective January, 2000, all of West Penn's generation assets were transferred to its affiliate, Allegheny Energy Supply Company, LLC (AESC). West Penn subsequently entered into a Power Sales Agreement with AESC for providing default service load requirements. The power provided by AESC comes from owned generation and market purchases. As a part of PJM West, West Penn has access to an increased amount of energy resources within the expanded PJM market. West Penn remains 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 2004, West Penn purchased nearly 1.1 billion KWH from cogeneration and independent power production facilities. Contract capacity for these facilities was 136 MW.

West Penn implemented a Generation Buy-Back program in 2001, 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. A total of 39 West Penn customers signed up with a potential load reduction of 231.5 MW. In 2004, the program was not implemented due to mild weather and the lack of price volatility. In 2005, there are 34 customers and a potential load reduction of 155 MW.

West Penn has also implemented two pilot programs. The Price Response Pilot Program involves smart thermostat technology and, eventually, will include real-time pricing. The Residential Distributed Generation Pilot is being conducted to test Internet programmable thermostats, natural gas generators, other equipment controlling devices and real-time hourly pricing.

On April 21, 2005, the Commission approved an Amended Joint Petition for Settlement and for Modification of the 1998 Restructuring Settlement[10] in which West Penn agrees to use a Request For Proposal process to obtain its energy supply for years 2009 and 2010. This process brings competitive market forces to bear on the cost of West Penn's energy supply in these years. The process will be conducted to procure, from the wholesale market, supply necessary to serve those retail customers who do not take service from competitive retail suppliers.

On July 22, 2005, Allegheny Power announced that it has awarded contracts for its 2009 and 2010 generation supply needs in Pennsylvania. Under these contracts, the successful bidder, Allegheny Energy Supply Company, LLC, is expected to realize generation prices of about $45.50 per MWH in 2009 and $52.50 per MWH in 2010.

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. West Penn remains a member of ECAR.

[10] Docket Nos. R-00039022 and R-00973981.

Table 9.1

Year	Actual Peak Demand	Projections of Peak Load Requirements (Megawatts) 1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	3242	3117										
1996	3215	3207	3235									
1997	3251	3279	3315	3315								
1998	3192	3329	3371	3371	3379							
1999	3328	3372	3417	3417	3442	3279						
2000	3277	3410	3462	3462	3496	3360	3284					
2001	3677	3454	3506	3506	3545	3425	3304	3141				
2002	3582	3500	3547	3547	3578	3484	3341	3445	3458			
2003	3455	3554	3586	3586	3617	3519	3380	3465	3505	3535		
2004	3407	3609	3630	3630	3668		3415	3501	3542	3572	3621	
2005			3679	3679	3723			3536	3586	3610	3670	3702
2006				3722	3769				3622	3639	3705	3763
2007					3812					3674	3738	3812
2008											3766	3845
2009												3866

Table 9.2

Year	Actual Energy Demand	Projected Residential Energy Demand (Gigawatthours) 1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	5819	5826										
1996	5913	5897	5844									
1997	5757	5979	5923	5923								
1998	5823	6081	6020	6020	6127							
1999	6020	6166	6118	6118	6250	5873						
2000	6022	6260	6223	6223	6381	6013	6061					
2001	6325	6313	6282	6282	6446	6077	6172	6192				
2002	6459	6391	6371	6371	6518	6165	6256	6260	6374			
2003	6641	6460	6445	6445	6604	6165	6339	6329	6471	6486		
2004	6724	6567	6546	6546	6699	6231	6445	6436	6596	6599	6818	
2005			6624	6624	6763			6521	6680	6671	6890	6923
2006				6722	6864				6775	6744	6965	7047
2007					6976					6821	7041	7136
2008											7132	7194
2009												7189

Table 9.3

Year	Actual Energy Demand	Projected Commercial Energy Demand (Gigawatthours)										
		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	3782	3741										
1996	3836	3834	3856									
1997	3833	3942	3950	3950								
1998	3993	4049	4055	4055	4080							
1999	4137	4147	4161	4161	4163	4039						
2000	4265	4223	4271	4271	4270	4215	4182					
2001	4360	4272	4347	4347	4339	4313	4225	4326				
2002	4497	4350	4430	4430	4393	4401	4275	4395	4458			
2003	4529	4434	4501	4501	4457	4443	4329	4449	4543	4577		
2004	4691	4556	4588	4588	4557		4397	4517	4624	4653	4701	
2005			4664	4664	4630			4571	4684	4695	4780	4791
2006				4756	4707				4749	4739	4832	4907
2007					4779					4776	4878	5006
2008											4936	5098
2009												5135

Table 9.4

Year	Actual Energy Demand	Projected Industrial Energy Demand (Gigawatthours)										
		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1995	7858	7659										
1996	7974	7981	8204									
1997	8046	8232	8427	8427								
1998	8226	8429	8755	8755	8608							
1999	8237	8502	8855	8855	8808	8575						
2000	8383	8609	8976	8976	8997	8830	7942					
2001	7955	8664	9052	9052	9070	8975	8120	8481				
2002	7957	8767	9156	9156	9136	9167	8230	8597	8006			
2003	7747	8874	9241	9241	9264	9161	8353	8663	8116	7885		
2004	8039	9010	9367	9367	9448		8477	8729	8188	7973	7814	
2005			9450	9450	9561			8799	8230	8023	7913	8027
2006				9566	9660				8290	8087	7998	8137
2007					9768					8187	8069	8220
2008											8140	8311
2009												8313

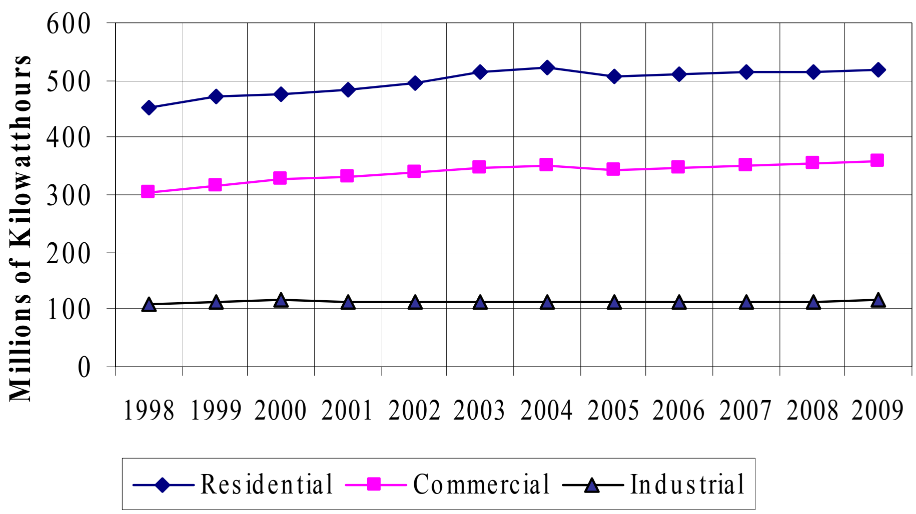
UGI Utilities, Inc.

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 2004, UGI had energy sales totaling 989.5 million kilowatthours (KWH) -- up 1.1% from 2003. Residential sales continued to dominate UGI's market with 52.7% of the total sales, followed by commercial (35.4%) and industrial (11.3%).

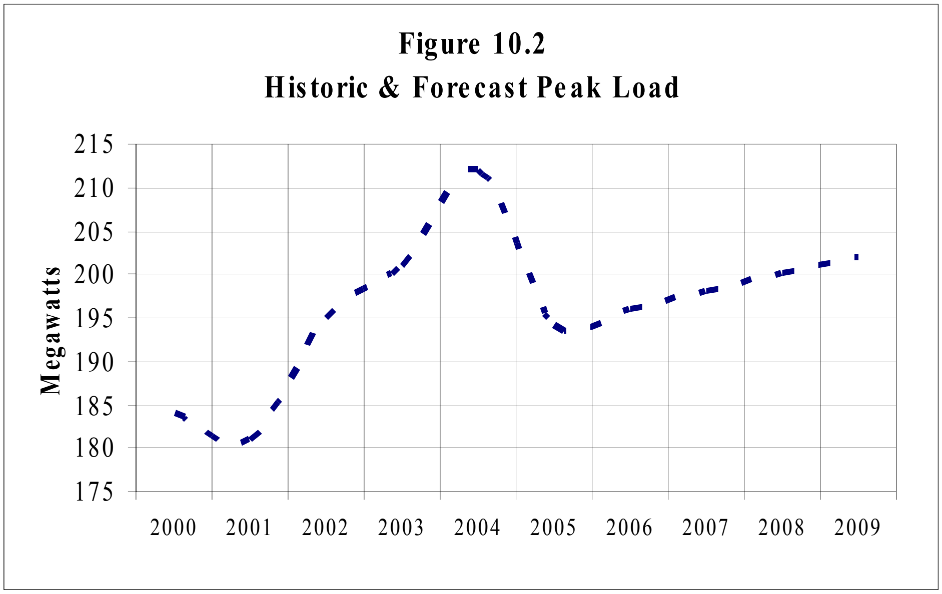
Between 1989 and 2004, UGI experienced an average growth in total sales of 1.5%, which includes a residential growth rate of 1.2%, a commercial rate of 2.0% and an industrial rate of 1.5%.

Over the five-year planning horizon, UGI expects growth in energy demand to average 0.1%. This includes an average decline in residential sales of 0.2%, a commercial growth rate of 0.4% and an industrial growth rate of 0.6%. The five-year peak load forecast indicates an average annual decline of 1.0%. Peak load is projected to decrease from 212 MW in 2004/2005 to 202 MW by the winter of 2009/10.

Figure 10.1
Historic & Forecast Energy Demand



Peak demand on the UGI system occurred on December 12, 2004, and totaled 212 megawatts (MW), or 5.5% above the 2003/2004, winter peak load of 201 MW and 24.0% above the 2004 summer peak load of 171 MW, occurring on June 9, 2004.



In 2004, one electric generation supplier provided 429,000 KWH to UGI's retail customers who chose an alternate supplier. This represents about 0.04% of total sales, down from 0.05% in 2003. UGI does not own electric generation supply and will meet its customers' energy requirements by making wholesale purchases in various markets.

In May, 1999, the number of shopping customers reached a peak of 2,604. As of December 31, 2004, 45 UGI customers were taking generation service from an alternate generation supplier, comprising an aggregate load of 0.1 MW. Of those, approximately 96% were residential customers, with the remaining 4% small commercial.

Under a settlement agreement, adopted May 24, 2004, UGI will provide provider-of-last-resort service to all customers under rates that cannot increase by more than 4.5% through 2005.

During the summer of 2004, UGI offered a modified version of its Voluntary Load Reduction program to commercial and industrial customers with the ability to reduce their demand during peak periods, thereby enhancing system reliability and increasing the economic efficiency of the wholesale and retail markets. Each of the program participants had a PJM Locational Marginal Price (LMP) threshold of $200/MWH. Since the real-time LMP's in UGI's zone never reached or surpassed this level, the program was never utilized.

UGI is a member of MAAC and PJM.

SECTION 3 – REGIONAL RELIABILITY

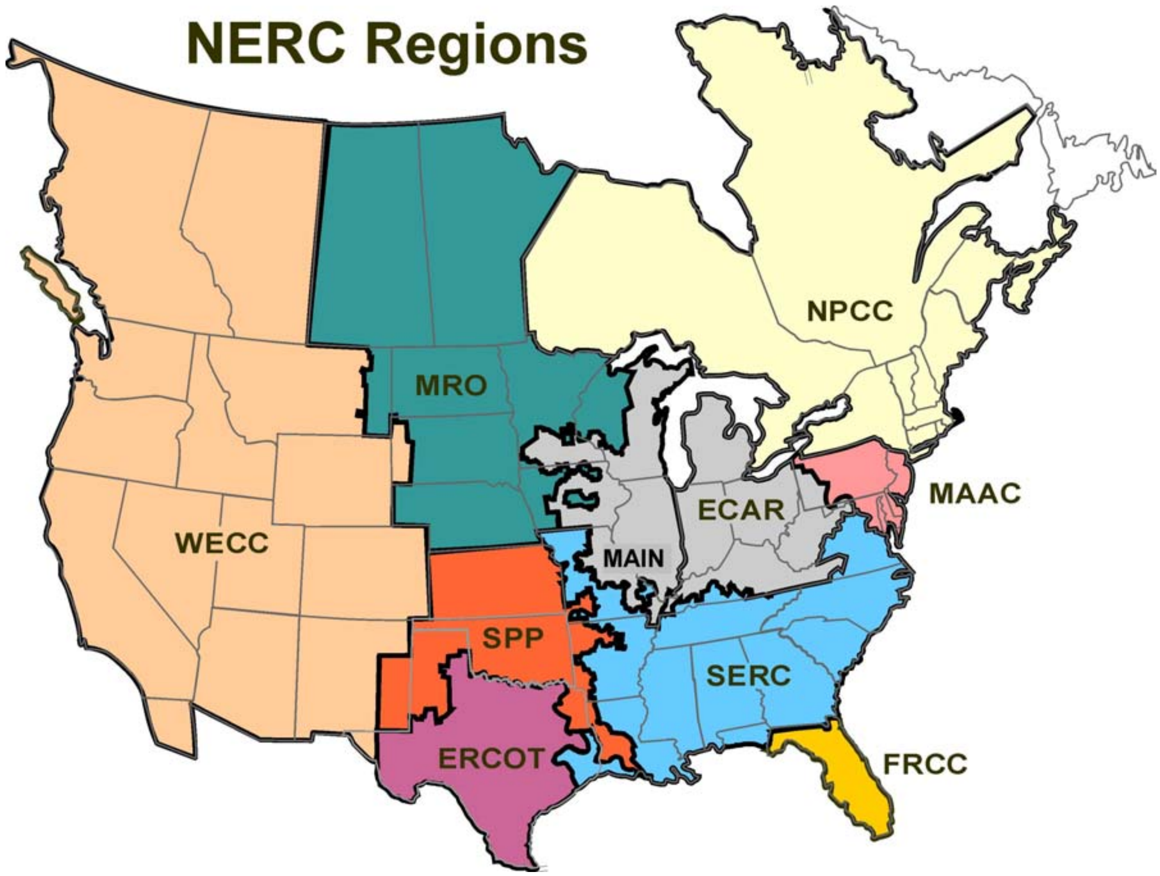
Regional Reliability Assessments

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 Pennsylvania to meet the needs of electric consumers for the foreseeable future.

North American Electric Reliability Council

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 organization will be to develop, promote and enforce reliability standards.

NERC's members include 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).



Source: http://www.nerc.com

ECAR

East Central Area Reliability Coordination Agreement

ERCOT

Electric Reliability Council of Texas

FRCC

Florida Reliability Coordinating Council

MAAC

Mid-Atlantic Area Council

MAIN

Mid-America Interconnected Network, Inc.

MRO

Midwest Reliability Organization

NPCC

Northeast Power Coordinating Council

SERC

Southeastern Electric Reliability Council

SPP

Southwest Power Pool

WECC

Western Electricity Coordinating Council

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.

On February 8, 2005, the NERC Board of Trustees adopted a comprehensive set of reliability standards for the bulk electric system. The new reliability standards incorporate the existing NERC operating policies, planning standards and compliance requirements into an integrated and comprehensive set of measurable reliability standards. The new reliability standards became effective on April 1, 2005.[11]

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.

On April 21, 2005, the U.S. House of Representatives passed the "Energy Policy Act of 2005."[12] Section 1211 of the Act would amend the Federal Power Act to grant the FERC regulatory jurisdiction over an Electric Reliability Organization (ERO). This ERO would develop and enforce reliability standards that provide for an adequate level of reliability of the bulk power system. Reliability standards would be approved by the FERC. The ERO would have the authority to impose a

[11] See: http://www.nerc.com/~filez/standards/Reliability_Standards.html.
[12] H. R. 6, 109th Congress.

penalty on a user, owner or operator of the bulk power system for a violation of an approved reliability standard. The House Bill was received by the U.S. Senate on April 26, 2005.

Reliability Assessment[13]

Resource adequacy in the near-term (2004 - 2008) will be satisfactory throughout North America, provided new generating facilities are constructed as anticipated. Through the summer of 2008, electricity demand is expected to grow by about 69,000 MW. Projected resource additions during this period total about 67,300 MW. The average annual peak demand growth rate over the assessment period is projected to be 2.0% for the United States and 1.1% for Canada, compared to 2.2% and 1.6% for past 10 years.

Projected 2006 U.S. summer capacity margins are about 13.3% lower this year than last year's projection for 2006. The projected margin continues to decline to about 12.3% as projected demand continues to grow while the number of proposed and/or announced new generating units decline.

More than 5,600 miles of new transmission (230 kV and higher) are proposed for construction through 2008, with a total of 10,275 miles added over the 2004 – 2013 timeframe. 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.

Mid-Atlantic Area Council

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 23 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

[13] NERC, *2004 Long-Term Reliability Assessment*, September 2004.

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, 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.

All members of the PJM Interconnection are members of MAAC. As of April 26, 2005, MAAC had 359 members. Funding for MAAC and NERC are now 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, Duquesne Light Company, Dynegy Power Marketing, Inc., Metropolitan Edison Company, Pennsylvania Electric Company, PECO Energy Company, Potomac Electric Power Company, PPL Electric Utilities Corporation, 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.

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.

Reliability Assessment

Generation resources within the MAAC Region are expected to be adequate to maintain regional reliability over the next ten years. PJM is currently evaluating generator interconnection requests for almost 18,000 MW of new generating capacity through 2009. Although not all of this capacity will be built, MAAC believes that sufficient generating capacity will be added to meet the MAAC adequacy objective.[14]

The 2004 MAAC aggregate coincident system summer peak load of 52,049 MW was 1,517 MW or 2.8% lower than the 2003 peak load of 53,566 MW. Last summer's demand was lower due to below normal temperatures in the region. The

[14] Id.

weather normalized summer peak for 2004 was 56,441 MW. The 2005 summer total internal demand is forecast to be 57,631 MW, which is 2,062 MW or 3.7% above the MAAC all-time summer peak of 55,569 MW, which occurred on August 14, 2002. The regional total internal summer peak demand (including direct control load management and interruptible demand) is projected to increase to 62,276 MW by 2009.[15]

By mid-July 2005, MAAC expects its summer generating capacity to increase by a net of 3,001 MW to 67,506 MW. At the time of the peak, the regional reserve margin is expected to be 18.8%[16], compared with the PJM reserve requirement of 15%.[17] In the summer of 2009, capacity resources are projected to total 68,698 MW, with a reserve margin of 12.2%.[18]

The MAAC region's mix of generating capacity includes 23% coal, 20% nuclear, 10% oil, 10% natural gas and 5% hydroelectric (including pumped storage). Dual fueled units represent 30% of the total.

Over the next five years, MAAC expects there will be adequate transmission capability to meet MAAC's criteria requirements. The bulk transmission is expected to perform adequately over a wide range of system conditions. Several transmission reinforcement projects are expected to be in service by 2009.

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 use bilateral contracts and the spot energy market to secure power to meet the electric load of nearly 45 million people. In order to reliably meet its load requirement, PJM must monitor and assess 50,000 miles of transmission lines for congestion concerns or physical capability problems. As of April 26, 2005, there were 359 members of PJM.

PJM was formed in 1927 with the interconnection of three utilities to realize the benefits and efficiencies of sharing resources. In 1997, PJM became the first fully functioning independent system operator. Today, PJM is the world's largest centrally dispatched grid operator and administers the world's largest competitive wholesale electricity market.

[15] NERC, *2005 Summer Reliability Assessment*, May 2005, p. 25.
[16] The projected capacity margin is 15.8%.
[17] These figures do not include PJM West.
[18] The projected capacity margin is 10.9%.

For a summary of PJM's recent history, see page 3.

Compliance Standards

The PJM reliability standards are the same as the standards for the MAAC region. Sufficient generating capacity must be installed to ensure that the probability of system load exceeding available capacity is no greater than one day in 10 years. Currently, a reserve margin of 15% of the net internal demand is considered adequate.

PJM also evaluates the adequacy of the planned transmission system's ability to meet customer energy and demand requirements in light of reasonably expected outages to system facilities. Generation plans, transmission plans and load forecasts provide the basis for system models upon which the analysis is performed. The PJM Open Access Transmission Tariff contains certain technical requirements and standards applicable to generation interconnections with transmission providers.

In addition, PJM sets forth member responsive actions to emergency conditions. An emergency in the PJM Control Area is defined as:

- an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property,

- a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel or

- a condition that requires implementation of emergency procedures.

Emergency procedures include: reductions of load of interruptible customers, voltage reductions, voluntary load curtailments, public appeals to reduce load, automatic load shedding and manual load dumping.

Reliability Assessment

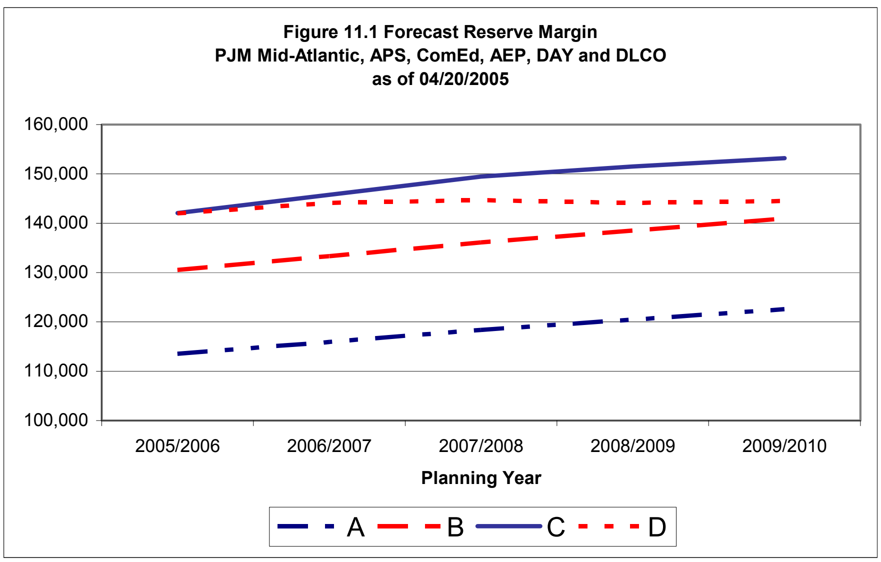
The PJM Mid-Atlantic weather normalized summer peak for 2004 was 56,441 MW, an increase of 1.3% from the 2003 normalized summer peak. The 2005 summer projection is 57,631 MW, an increase of 2.1%. Summer peak load growth for PJM Mid-Atlantic is projected to average 1.8% over the next 10 years.[19]

[19] 2005 PJM Load Forecast Report.

The PJM RTO[20] weather normalized summer peak is forecast to increase at an average rate of 1.7% per year over the next 10 years, reaching 136,549 MW in 2015.[21]

Existing installed capacity of PJM RTO as of April 20, 2005, was 143,406 MW. Of the total installed capacity, 41.5% was coal, 28.4% was natural gas, 19.1% was nuclear, 7.0% was oil, 3.7% was hydroelectric and 0.3% was solid waste. In 2004, coal and nuclear units generated 88.9% of the total electricity. Coal was 52.1% and nuclear was 36.9%.[6]

Figure 11.1 compares the PJM RTO capacity obligation (line B) with existing installed capacity plus expected additions (line D). The forecasted reserve margin varies from 25.1% in the 2005/2006 planning year to 17.9% in the 2009/2010 planning year.



"A": PJM Total Demand - Active Load Management. Forecast is calculated as a diversified sum of zonal forecasts.
"B": "A" multiplied by the reserve requirment of 15%.
"C": Existing Installed Capacity + Total Queue Generation - Announced Retirements.
"D": Existing Installed Capacity + Expected Queue Generation - Announced Retirements.

Source: PJM

[20] The PJM RTO forecast includes forecasts for the AEP, APS, ComEd, Dayton and Duquesne zones.
[21] Id.

East Central Area Reliability Council

The East Central Area Reliability Council (ECAR) was established in 1967 to augment bulk power supply reliability through coordination of planning and operation of member companies' generation and transmission facilities. ECAR promotes the reliable and efficient operation of the interconnected bulk power systems in East Central North America through the establishment of reliability standards, assessments and enforcement of compliance with these standards. As of May 9, 2005, there were 24 full members and 19 associate members. Member systems serve more than 36 million people in all or parts of the states of Indiana, Kentucky, Maryland, Michigan, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia.

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). Although Allegheny Power and Duquesne Light Company are now members of PJM West, they remain members of ECAR.

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.

ECAR's one-to-ten-days DSCR[22] has been determined to be consistent with a Loss of Load Expectation (LOLE) of one-day-in-ten-years. This LOLE criterion is used to assess the adequacy of ECAR capacity margins that include the import capability.

The ECAR Reliability Compliance and Enforcement Program is used to assess and enforce compliance with ECAR reliability standards in such a way that this reliability objective is achieved. Actions taken by ECAR for non-compliance with ECAR standards and/or NERC planning and operating standards may include the imposition of sanctions.

[22] This DSCR index is currently consistent with marginal, but satisfactory, regional power supply adequacy for the assessment period.

Reliability Assessment

The bulk electric systems within the ECAR region are expected to reliably serve the forecasted demand obligations over a wide range of anticipated system conditions, as long as established operating limits and procedures are followed and proposed projects are completed on schedule. ECAR's criteria for resource adequacy will be satisfied through at least 2008, assuming the availability of up to 9,500 MW of capacity resources outside the ECAR region.[13]

The 2004 ECAR aggregate (non-coincident) summer peak load of 95,300 MW was 3,194 MW or 3.2% lower than the 2003 peak load of 98,487. The 2005 summer net internal demand forecast is 101,171 MW. This demand forecast is derived from the aggregate demand forecasts of the ECAR member companies, based on expected summer weather. Demand-side management programs and interruptible demand contracts are expected to total 2,508 MW at the time of the summer peak. Net capacity resources for the summer of 2005 are expected to be 125,634 MW, which equates to a projected capacity margin of 19.5%.[23] [24]

The regional non-coincident internal peak load is projected to increase to 111,082 MW by the summer of 2009 at an average annual growth rate of 3.3%. Peak load reductions from direct load control programs and interruptible customers are expected to reach 2,592 MW by 2009. In the summer of 2009, capacity resources are projected to total 136,630 MW, with a capacity margin of 18.7%.[25] [13]

The ECAR region's mix of generating capacity includes 63% coal, 24% natural gas, 6% nuclear, 3% oil and 3% hydroelectric (including pumped storage). Natural gas may be used as much as 30% of the capacity by 2013. ECAR is monitoring the natural gas supply for indications of possible supply constraints.

Transmission networks in ECAR are expected to meet adequacy and security criteria over a wide range of anticipated system conditions. Although, local transmission overloads are possible during some generation and transmission contingencies, certain operating procedures can be used to mitigate such overloads. About 173 miles of transmission lines (230 kV and above) are planned to be added to the system through the summer of 2009.

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

[23] The projected reserve margin is 24.2%.
[24] NERC, *Summer Reliability Assessment*, May 2005, p. 16.
[25] The projected reserve margin is 23.0%.

Pennsylvania

The Pennsylvania outlook reflects the projections of both ECAR and MAAC. Since transmission and generation are not regulated by the Commission, we must look to these two entities for data concerning the status of the electric system on a regional basis. While we can determine the aggregate load for the State's consumers, we do not know, with complete certainty, what generating facilities will be available to serve these consumers.

Planning the enhancement and expansion of transmission capability on a regional basis is one of the primary functions of regional transmission organizations. PJM implements this function pursuant to the Regional Transmission Expansion Planning Protocol (RTEPP) set forth in Schedule 6 of the PJM Operating Agreement. A key part of this regional planning protocol is the evaluation of both generation interconnection and merchant transmission interconnection requests, the procedures for which are codified under Part IV of the PJM Open Access Transmission Tariff.

Although transmission planning is performed on a regional basis, most transmission additions and upgrades in Pennsylvania are planned to support the local delivery system and new generating facilities.

All new generation, anticipated to interconnect and operate in parallel with the PJM transmission grid and participate in the PJM capacity and/or energy markets, must submit an interconnection request to PJM. These requests are placed in queues, or waiting lists, for the performance of feasibility studies and other technical reviews.

Proposed new generating plants and increased capacity of existing plants located in Pennsylvania total 8,605 MW. These facilities are either under study, under construction, partially in-service or in-service. This additional capacity may be used to serve Pennsylvania customers or out-of-state customers. Appendix C provides the status of new power plant queues for Pennsylvania.

Appendix D lists the existing power plants located in Pennsylvania, along with the operating companies' names and fuel types. The generating capacity of these plants total 46,520 MW. As stated earlier, the output of some of these facilities may serve loads outside of Pennsylvania.

SECTION 4 - CONCLUSIONS

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 2005 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 2005 and 2009, and it is anticipated that total generating capacity will exceed demand by a reliable margin. New capacity will help to ensure the reliability of electric service in the state and will maintain or increase the robustness of the competitive energy markets.

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 continues to pursue demand side response initiatives 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. Furthermore, the implementation of the Alternative Energy Portfolio Standards Act will serve as a catalyst for the development of alternative energy resources. Through demand-side measures and overall improvements in energy efficiency, EDCs and all customer classes will benefit from this effort.

* * *

To summarize the relevant statistics in this report, aggregate Pennsylvania sales in 2004 totaled approximately 141.1 billion kilowatthours (KWH), a 2.3% increase from that of 2003 and represents 4.0% of the United States' total. Residential sales accounted for 34.0% of the total sales, followed by industrial (33.3%) and commercial (30.4%).

Between 1989 and 2004, the state's energy demand grew an average annual rate of 1.5%. Residential sales grew at an annual rate of 1.9%, commercial at 2.9% and industrial at 0.2%. The current aggregate 5-year projection of growth in energy demand is 1.6%. This includes a residential growth rate of 1.8%, a commercial rate of 2.4% and an industrial rate of 0.8%.

The 2004 MAAC aggregate coincident system summer peak load of 52,049 MW was 2.8% lower than the 2003 summer peak of 53,566 MW. The regional total internal summer peak demand (including direct control load management and interruptible demand) is projected to increase to 62,276 MW by 2009 at an average annual growth rate of about 2.1%, using the weather normalized summer peak of 56,441 MW for 2004.

MAAC committed resources are projected to grow from 64,505 MW in 2004 to 68,698 MW in 2009, an increase of 4,193 MW or 6.5%. The reserve margin is expected to be 18.8% in the summer of 2005, declining to 12.2% in 2009. The majority of the capacity additions are expected to be natural gas-fueled combined-cycle units.

ECAR's regional non-coincident internal peak demand is projected to increase to 111,082 MW by the summer of 2009 at an average annual growth rate of 3.3%. Peak load reductions from direct load control programs and interruptible customers are expected to reach 2,592 MW by 2009.

ECAR's members project additions of 12,875 MW of new generating capacity by 2009, which includes 10,167 MW of uncommitted resources, bringing total net capacity resources to 136,630 MW. A majority of this new capacity is projected to be short lead-time, gas-fired combustion turbine and combined cycle units (51%). Capacity margins for net internal demand are expected to range between 20.8% in 2005 to 18.7% in 2009.

APPENDIX A – CAPACITY AND DEMAND PROJECTIONS

Sources for Appendix A: ECAR and MAAC Responses to the 2005 NERC Data Request
(formerly the EIA-411)

ECAR Energy and Peak Demand Projections

Actual Data: 2004	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Peak Hour Demand - MW	86,854	81,131	76,543	71,732	83,453	94,311	96,333	96,467	85,638	69,295	74,843	88,795
Net Energy - GWH	51,698	46,026	45,239	41,588	44,673	46,002	49,451	48,469	45,257	42,464	42,995	49,374

Reporting Year: 2005	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Peak Hour Demand - MW	88,289	85,219	80,579	73,321	82,272	99,518	103,679	103,430	90,378	74,523	79,410	85,969
Net Energy - GWH	51,117	45,633	46,439	42,164	44,053	48,451	53,069	52,301	45,833	44,397	44,611	50,463

Next Year: 2006	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Peak Hour Demand - MW	90,464	86,953	82,292	74,843	84,616	102,544	106,753	106,654	94,857	76,833	81,552	88,275
Net Energy - GWH	52,128	46,357	47,530	42,930	44,856	49,291	53,950	53,392	46,836	45,301	45,332	51,216

Actual Previous Year and	Actual	Projected									
10 Year Projection:	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Peak Hour Demand - MW - Summer	95,300	103,679	106,753	108,749	110,942	112,867	114,598	116,432	118,241	119,880	121,783

Actual Previous Year and	Actual	Projected									
10 Year Projection:	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15
Peak Hour Demand - MW - Winter	91,800	90,464	92,492	93,978	95,841	97,045	98,483	99,826	101,179	102,465	104,418

Actual Previous Year and	Actual	Projected									
10 Year Projection:	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Net Energy - GWH	553,236	568,531	579,119	587,454	597,775	606,813	615,282	624,427	634,154	643,155	653,020

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

ECAR Capacity and Demand Projections - Summer

		Actual	Projected									
Line	**Category**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
01	**Internal Demand**	95,300	103,679	106,753	108,749	110,942	112,867	114,598	116,432	118,241	119,880	121,783
02	**Standby Demand**		0	0	0	0	0	0	0	0	0	0
03	**Total Internal Demand (01+02)**	95,300	103,679	106,753	108,749	110,942	112,867	114,598	116,432	118,241	119,880	121,783
04	**Direct Control Load Management**		198	229	261	288	305	321	336	340	340	340
05	**Interruptible Demand**		2,310	2,294	2,238	2,231	2,215	2,154	2,059	2,063	2,067	2,071
06	**Net Internal Demand (03-04-05)**	95,300	101,171	104,230	106,250	108,423	110,347	112,123	114,037	115,838	117,473	119,372
07	**Total Net Operable Capacity**	129,636										
07a	**Uncommitted Capacity**		0	780	1,234	541	0	732	0	0	0	0
07b1	**Reliability Derating Unit Spec. Subtotal**											
07b2	**Reliability Derating Group Subtotal**											
07c	**Other Generation**	3,187										
07d	**Subtotal Committed Capacity (7-7a-7b1-7b2-7c)**	126,449	126,943	126,943	126,943	126,943	126,943	126,943	126,943	126,943	126,943	126,943
08	**Generator Capacity, <1MW (8a+8b)**	0	0	0	0	0	0	0	0	0	0	0
08a	**Distributed Generator Capacity < 1 MW**											
08b	**Other Capacity < 1 MW**											
09	**Total Net Generator Capacity (7d+8)**	126,449	126,943	126,943	126,943	126,943	126,943	126,943	126,943	126,943	126,943	126,943
9b	**Distributed Generator Capacity >= 1 MW**		0									
10	**Capacity Purchases - Total**	1,470	3,419	1,445	1,445	1,445	1,445	1,445	1,445	1,445	1,445	1,445
10a	**Full Responsibility Purchases**											
11	**Capacity Sales - Total**	0	1,662	62	62	62	62	62	62	62	62	62
11a	**Full Responsibility Sales**											
12	**Net Capacity Resources (9+10-11)**	127,919	128,700	128,326	128,326	128,326	128,326	128,326	128,326	128,326	128,326	128,326

ECAR Capacity and Demand Projections - Winter

		Actual	Projected									
Line	**Category**	**04/05**	**05/06**	**06/07**	**07/08**	**08/09**	**09/10**	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**
01	**Internal Demand**	91,800	90,464	92,492	93,978	95,841	97,045	98,483	99,826	101,179	102,465	104,418
02	**Standby Demand**		0	0	0	0	0	0	0	0	0	0
03	**Total Internal Demand (01+02)**	91,800	90,464	92,492	93,978	95,841	97,045	98,483	99,826	101,179	102,465	104,418
04	**Direct Control Load Management**		158	158	158	158	158	158	158	158	158	158
05	**Interruptible Demand**		1,868	1,808	1,788	1,768	1,703	1,703	1,703	1,703	1,703	1,542
06	**Net Internal Demand (03-04-05)**	91,800	88,438	90,526	92,032	93,915	95,184	96,622	97,965	99,318	100,604	102,718
07	**Total Net Operable Capacity**	134,667										
07a	**Uncommitted Capacity**		0	780	1,234	541	0	732	0	0	0	0
07b1	**Reliability Derating Unit Spec. Subtotal**											
07b2	**Reliability Derating Group Subtotal**											
07c	**Other Generation**	3,390										
07d	**Subtotal Committed Capacity (7-7a-7b1-7b2-7c)**	131,277	131,860	131,860	131,860	131,860	131,860	131,860	131,860	131,860	131,860	131,860
08	**Generator Capacity, <1MW (8a+8b)**	0	0	0	0	0	0	0	0	0	0	0
08a	**Distributed Generator Capacity < 1 MW**											
08b	**Other Capacity < 1 MW**											
09	**Total Net Generator Capacity (7d+8)**	131,277	131,860	131,860	131,860	131,860	131,860	131,860	131,860	131,860	131,860	131,860
9b	**Distributed Generator Capacity >= 1 MW**											
10	**Capacity Purchases - Total**	0	3,154	1,445	1,445	1,445	1,445	1,445	1,445	1,445	1,445	1,445
10a	**Full Responsibility Purchases**											
11	**Capacity Sales - Total**	90	1,062	62	62	62	62	62	62	62	62	62
11a	**Full Responsibility Sales**											
12	**Net Capacity Resources (9+10-11)**	131,187	133,952	133,243	133,243	133,243	133,243	133,243	133,243	133,243	133,243	133,243

MAAC Energy and Peak Demand Projections

Actual Data: 2004	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Peak Hour Demand - MW	45,625	41,170	39,626	36,212	48,571	51,631	50,483	52,049	44,128	34,614	37,114	47,849
Net Energy - GWH	26,806	23,107	22,440	21,235	23,268	23,925	26,712	26,535	22,889	20,978	21,150	24,601

Reporting Year: 2005	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Peak Hour Demand - MW	45,905	43,516	41,790	37,901	44,116	55,209	57,631	56,663	49,502	38,591	40,186	44,355
Net Energy - GWH	25,455	22,356	22,843	20,677	21,369	23,925	27,336	27,189	22,355	21,381	21,911	24,708

Next Year: 2006	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Peak Hour Demand - MW	46,785	44,482	42,516	38,571	44,996	56,303	58,785	57,774	50,480	39,264	40,876	45,117
Net Energy - GWH	25,918	22,764	23,312	21,094	21,721	24,387	27,841	27,703	22,773	21,813	22,328	25,183

Actual Previous Year and	Actual	Projected									
10 Year Projection:	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Peak Hour Demand - MW - Summer	52,049	57,630	58,784	59,909	61,025	62,136	63,244	64,368	65,496	66,619	67,751

Actual Previous Year and	Actual	Projected									
10 Year Projection:	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15
Peak Hour Demand - MW - Winter	45,905	46,784	47,560	48,334	49,106	49,857	50,619	51,370	52,124	52,866	53,590

Actual Previous Year and	Actual	Projected									
10 Year Projection:	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Net Energy - GWH	283,646	281,505	286,837	292,475	298,160	303,309	308,688	314,108	319,017	323,788	328,769

MAAC Capacity and Demand Projections - Summer

Line	Category	Actual 2004	Projected 2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
01	**Internal Demand**	52,049	57,630	58,784	59,909	61,025	62,136	63,244	64,368	65,496	66,619	67,751
02	**Standby Demand**	0	0	0	0	0	0	0	0	0	0	0
03	**Total Internal Demand (01+02)**	52,049	57,630	58,784	59,909	61,025	62,136	63,244	64,368	65,496	66,619	67,751
04	**Direct Control Load Management**	0	429	429	429	429	429	429	429	429	429	429
05	**Interruptible Demand**	0	384	374	364	364	364	364	364	364	364	364
06	**Net Internal Demand (03-04-05)**	52,049	56,817	57,981	59,116	60,232	61,343	62,451	63,575	64,703	65,826	66,958
07	**Total Net Operable Capacity**	70,007										
07a	**Uncommitted Capacity**	0	0	0	0	0	0	0	0	0	0	0
07b1	**Reliability Derating Unit Spec. Subtotal**	2,610										
07b2	**Reliability Derating Group Subtotal**	0										
07c	**Other Generation**	395										
07d	**Subtotal Committed Capacity (7-7a-7b1-7b2-7c)**	67,002	67,812	69,817	69,168	71,761	71,761	71,761	71,761	71,761	71,761	71,761
08	**Generator Capacity, <1MW (8a+8b)**	0	0	0	0	0	0	0	0	0	0	0
08a	**Distributed Generator Capacity < 1 MW**											
08b	**Other Capacity < 1 MW**											
09	**Total Net Generator Capacity (7d+8)**	67,002	67,812	69,817	69,168	71,761	71,761	71,761	71,761	71,761	71,761	71,761
9b	**Distributed Generator Capacity >= 1 MW**											
10	**Capacity Purchases - Total**	495	488	38	38	38	38	38	38	38	38	38
10a	**Full Responsibility Purchases**											
11	**Capacity Sales - Total**	1,330	0	0	0	0	0	0	0	0	0	0
11a	**Full Responsibility Sales**											
12	**Net Capacity Resources (9+10-11)**	66,168	68,300	69,855	69,206	71,799	71,799	71,799	71,799	71,799	71,799	71,799

MAAC Capacity and Demand Projections - Winter

Line	Category	Actual 04/05	Projected 05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15
01	**Internal Demand**	45,905	46,784	47,560	48,334	49,106	49,857	50,619	51,370	52,124	52,866	53,590
02	**Standby Demand**											
03	**Total Internal Demand (01+02)**	45,905	46,784	47,560	48,334	49,106	49,857	50,619	51,370	52,124	52,866	53,590
04	**Direct Control Load Management**	0	0	0	0	0	0	0	0	0	0	0
05	**Interruptible Demand**	340	340	330	330	330	330	330	330	330	330	330
06	**Net Internal Demand (03-04-05)**	45,565	46,444	47,230	48,004	48,776	49,527	50,289	51,040	51,794	52,536	53,260
07	**Total Net Operable Capacity**	73,448										
07a	**Uncommitted Capacity**		0	0	0	0	0	0	0	0	0	0
07b1	**Reliability Derating Unit Spec. Subtotal**	3,910										
07b2	**Reliability Derating Group Subtotal**											
07c	**Other Generation**	422										
07d	**Subtotal Committed Capacity (7-7a-7b1-7b2-7c)**	69,116	70,311	71,341	72,525	73,736	73,736	73,736	73,736	73,736	73,736	73,736
08	**Generator Capacity, <1MW (8a+8b)**	0	0	0	0	0	0	0	0	0	0	0
08a	**Distributed Generator Capacity < 1 MW**											
08b	**Other Capacity < 1 MW**											
09	**Total Net Generator Capacity (7d+8)**	69,116	70,311	71,341	72,525	73,736	73,736	73,736	73,736	73,736	73,736	73,736
9b	**Distributed Generator Capacity >= 1 MW**											
10	**Capacity Purchases - Total**	488	488	38	38	38	38	38	38	38	38	38
10a	**Full Responsibility Purchases**											
11	**Capacity Sales - Total**	0	0	0	0	0	0	0	0	0	0	0
11a	**Full Responsibility Sales**											
12	**Net Capacity Resources (9+10-11)**	69,604	70,799	71,379	72,563	73,774	73,774	73,774	73,774	73,774	73,774	73,774

ECAR Transmission Line Circuit Miles

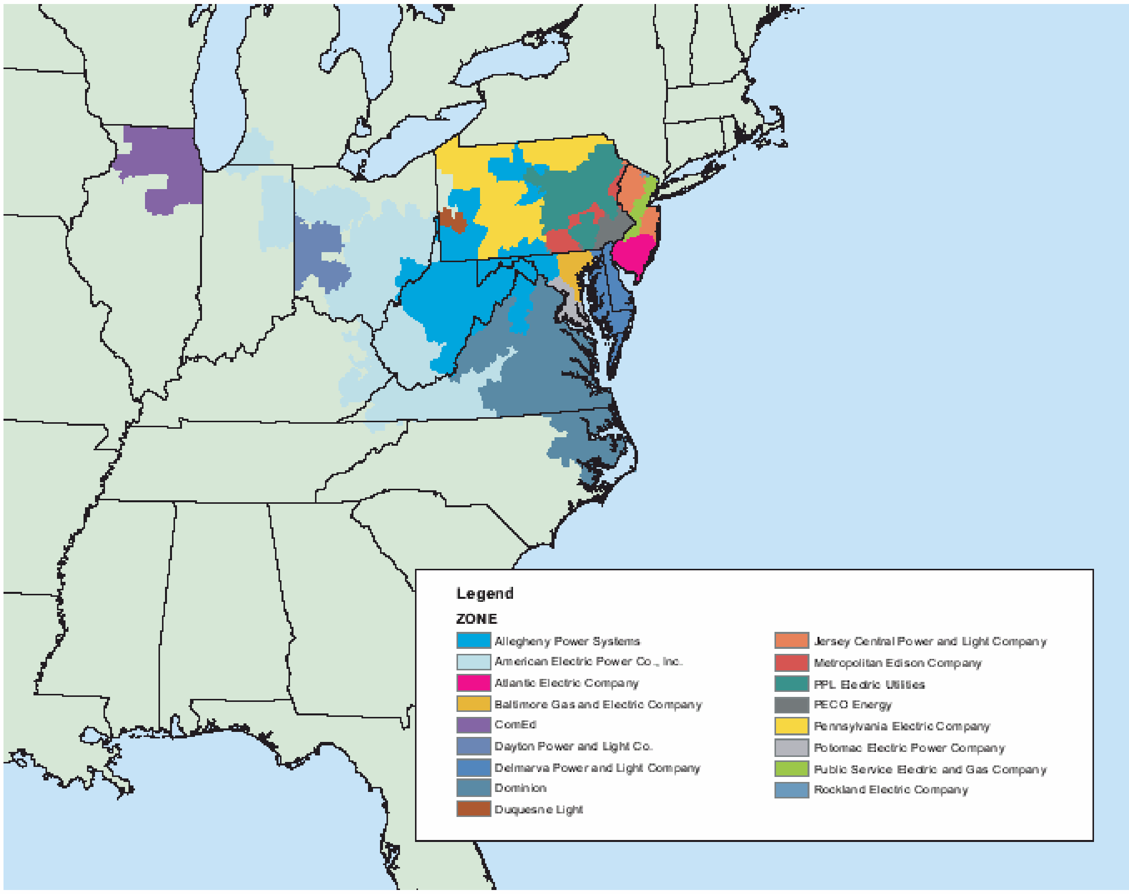
	Voltage Class (kV)				Total
	230	345	500	765	
Existing 12/31/2004	1,278	12,136	852	2,224	16,490
Planned First Five Years	42	88	0	91	221
Planned Second Five Years	0	0	0	0	0
	======	======	======	======	======
Total 12/31/2004	1,320	12,224	852	2,315	16,711

MAAC Transmission Line Circuit Miles

	Voltage Class (kV)				Total
	230	345	500	765	
Existing 12/31/2004	5,216	165	1,676	0	7,057
Planned First Five Years	134	0	0	0	134
Planned Second Five Years	0	0	0	0	0
	======	======	======	======	======
Total 12/31/2004	5,350	165	1,676	0	7,191

APPENDIX B – REGIONAL MAPS

PJM Service Territory



Source: PJM

Midwest ISO

Source: Midwest ISO

APPENDIX C – STATUS OF NEW POWER PLANTS

Status of Pennsylvania's New Power Plants

Queue	Project	MW	In-Service	Status	Fuel
A12	Martins Creek	600	2004	In-Service	Natural Gas
A21	Chichester	725	2004	In-Service	Natural Gas
A59	Emilie	540	2004	In-Service	Natural Gas
B30	Emilie	605	2004	In-Service	Natural Gas
B34	Seward	304	2005	Partially In-Service	Coal
C02	South Lebanon	47	2005	Under Study	Natural Gas
C10	Erie East	100	2006	Under Construction	Natural Gas
D18	Hosensack	350	2004	In-Service	Natural Gas
G05	Brunner Island #1	14	2004	In-Service	Coal
G06	Martins Creek #4	30	2005	Under Study	Coal
G46	Peach Bottom	70	2007	Partially In-Service	Nuclear
G51_W60	Hatfield Ferry	525	2006	Under Study	Coal
H02	Susquehanna	9	2004	In-Service	Nuclear
H06	Chichester	25	2004	In-Service	Natural Gas
I12	Grand Point	30.5	2004	In-Service	Diesel
I13	Hooversville	30	2005	Under Study	Wind
I14	Upton	4.1	2004	In-Service	Methane
J09	Harrisburg Authority	26	2006	Under Construction	Methane
K02	East Towanda-Moshannon	14	2005	Under Study	Wind
K13	Hooversville	6.8	2005	Under Study	Wind
K18	Arnold	2.08	2005	In-Service	Wind
K20	Mill Run	3	2005	Under Study	Wind
K21	East Carbondale	13	2004	In-Service	Wind
K22	Somerset	1.8	2005	In-Service	Wind
K23	Meyersdale North	6	2004	In-Service	Wind
L03	Morgantown	0.8	2005	Under Construction	Methane
L07	Jenkins-Harwood #2	8.6	2005	Under Study	Wind
L13	Rockwood	8	2005	Under Study	Wind
L17	Rolling Hills	6	2005	In-Service	Natural Gas
L18	Bear Creek	6.8	2005	Under Construction	Wind
L19	Karthaus	290	2008	Under Study	Coal
M02	Jenkins-Harwood #2	8.1	2005	Under Study	Wind
M06	Grand Point	30.5	2005	Under Study	Diesel
M07	Peckville	6.3	2004	In-Service	Natural Gas
M11	Susquehanna #1	111	2008	Under Study	Natural Gas
M12	Susquehanna #2	107	2008	Under Study	Natural Gas
M15	Union City	301.5	2006	Under Study	Natural Gas
M20	Chestnut Valley	5	2005	Under Study	Methane
M22	Cambria Slope	125	2007	Under Study	Coal
M25	South Reading	2	2006	Under Study	n/a
M26	Champion	300	2008	Under Study	Coal
M27	Eddystone	7	2004	In-Service	Coal
N01	Graceton-Nottingham	550	2008	Under Study	Natural Gas
N02	Peach Bottom	550	2008	Under Study	Natural Gas
N06	Hamilton	0.047	2005	Under Construction	Methane

Status of Pennsylvania's New Power Plants (contd)

Queue	Project	MW	In-Service	Status	Fuel
N13	Beaver Valley	1642	2005	In-Service	Nuclear
N14	Frackville-Hauto	4.8	2005	Under Study	Wind
N26	Daleville	1.6	2005	Under Study	n/a
N28	Cambria Slope	40	2007	Under Study	Coal
N30	Grand Point	5	2005	Under Study	Methane
N31	Freemansburg	5	2005	Under Study	Methane
N32	Gans	12	2006	Under Study	Wind
N35	South Reading-Birdsboro	9	2005	Under Study	Methane
N36	Gold-Sabinsville	10	2006	Under Study	Wind
N37	Windsor	10	2006	Under Study	Wind
N39	Johnstown-Altoona	16	2006	Under Study	Wind
N40	Champion	300	2009	Under Study	Coal
N50	Eldred	18	2006	Under Study	Wind
N51	Harwood	20	2006	Under Study	Wind
O01	Letort	3.2	2005	Under Study	Methane
O02	Glendon	3.2	2005	Under Study	Methane

Natural Gas (53.7%)
Coal (22.5%)
Nuclear (20.0%)
Wind (2.3%)
Methane (0.7%)
Diesel (0.7%)
N/A (0.04%)

Source: PJM

APPENDIX D – EXISTING GENERATING FACILITIES

Pennsylvania’s Existing Electric Generating Facilities

COMPANY NAME	ST.	PLANT NAME	FUEL TYPE	ALT. FUEL TYPE	TECH. TYPE	MW
A/C Power-Colver Operations	PA	Colver Power Project	Waste Coal			102
AES Corporation	PA	Ironwood	Gas		CC	705
AES Corporation	PA	Beaver Valley	Coal			120
Allegheny Electric Cooperative*	PA	Raystown Hydroelectric Project (Matsen)	Water			21.7
Allegheny Energy Supply*	PA	Armstrong Generating Station	Coal			356
Allegheny Energy Supply*	PA	Chambersburg Generating Facility	Gas		SC	88
Allegheny Energy Supply*	PA	Gans Generating Facility	Gas			88
Allegheny Energy Supply*	PA	Hatfield's Ferry Power Station	Coal			1710
Allegheny Energy Supply*	PA	Lake Lynn Hydroelectric Project	Water			52
Allegheny Energy Supply*	PA	Mitchell Generating Station	Coal	Oil		370
Allegheny Energy Supply*	PA	Springdale, Units 1,2,3,4 & 5	Gas		CC	628
AmerGen Energy Co. LLC	PA	Three Mile Island	Nuclear			850
American Ref-Fuel Co.	PA	Delaware Valley Resource Recovery Facility	Other			90
BioEnergy Partners	PA	Pottstown Plant	Other			6.4
Calpine Corporation	PA	Ontelaunee Energy Center	Gas		CC	545
Calpine Corporation	PA	Philadelphia Water Project	Gas			23
Cambria Cogen Co.	PA	Cambria County Cogen	Waste Coal			85
Chambersburg Borough Electric Dept	PA	Chambersburg Power Plant	Gas		IC	7.27
City of Harrisburg	PA	Harrisburg WTE Plant	Other			8.2
Conectiv Energy	PA	North East Cogeneration Plant	Gas		CC	81.8
Conectiv Energy	PA	Bethlehem Plant	Gas		CC	1,100
Constellation Power Inc.	PA	Panther Creek Energy Facility	Waste Coal			80
Constellation Power Inc.	PA	Handsome Lake Plant	Gas		SC	250
Covanta Energy Corporation	PA	Lancaster County Resource Recovery Facility	Other			35.7
Dominion Generation	PA	Armstrong County	Gas	Oil	CT	600
Dominion Generation	PA	Fairless Energy	Gas			1180
Duke Energy	PA	Fayette County	Gas		CC	620
Exelon Generation Co. LLC*	PA	Clairton USX (Fairless Hills)	Other		ST/S	60
Exelon Generation Co. LLC*	PA	Cromby Generating Station	Coal	Oil/Nat. Gas		388
Exelon Generation Co. LLC*	PA	Croydon Plant	Gas			370
Exelon Generation Co. LLC*	PA	Eddystone Generating Station	Coal	Oil/Nat. Gas		1340
Exelon Generation Co. LLC*	PA	Falls Plant	Gas			50
Exelon Generation Co. LLC*	PA	Delaware Generating Station (Retiring)	Oil			250
Exelon Generation Co. LLC*	PA	Exelon Power Dist. Gen. Group (47 Units)	Oil	Gas		795
Exelon Generation Co. LLC*	PA	Grows Landfill	Other			6.6
Exelon Generation Co. LLC*	PA	Limerick Nuclear Generating Station	Nuclear			2286
Exelon Generation Co. LLC*	PA	Moser Plant	Oil			48
Exelon Generation Co. LLC*	PA	Muddy Run Hydroelectric Plant	Water			1072
Exelon Generation Co. LLC*	PA	Peach Bottom Atomic Power Station	Nuclear			2186
Exelon Generation Co. LLC*	PA	Pennsbury Plant	Oil			48
Exelon Generation Co. LLC*	PA	Schuylkill Generating Station	Oil			166
Exelon Generation Co. LLC*	PA	Southwark Plant	Oil			54
FirstEnergy Generation Corp.*	PA	Bruce Mansfield Plant	Coal			2360
FirstEnergy Generation Corp.*	PA	York Haven	Water			19
FirstEnergy Generation Corp.*	PA	Seneca Pumped Storage Plant	Water			435
FirstEnergy Nuclear Operating Co.*	PA	Beaver Valley Power Station	Nuclear			1630
FPL Energy	PA	Marcus Hook Plant	Gas		CC	750
FPL Energy	PA	Mill Run Wind (FPL)	Wind			15
FPL Energy	PA	Somerset Wind Farm (FPL)	Wind			9
FPL Energy	PA	Moosic Mountain Wind Farm (FPL)	Wind			50
General Chemical Corp.	PA	Marcus Hook Cogen	Oil			4.5
General Electric Co.	PA	Erie Works Plant	Coal			36
General Electric Co.	PA	Grove City Plant	Oil			10.6
Gilberton Power Co.	PA	John B Rich Power Station	Waste Coal			80
Indiana University of Pennsylvania	PA	S.W. Jack Cogeneration Plant	Gas			24
Kimberly Clark	PA	Chester Operations	Waste Coal			60
Merck & Co., Inc.	PA	West Point (PA) Merck Plant	Gas			30.25
Mid-Atlantic Energy Co.	PA	Piney Creek LP	Waste Coal			32
Midwest Generation LLC	PA	Homer City (EME) Generation	Coal			2012
Montenay Power Corp.	PA	Montgomery County	Other			31
Montenay Power Corp.	PA	Yourk County WTE	Other			35
Mount Carmel Power	PA	Mount Carmel	Waste Coal			40

Pennsylvania's Existing Electric Generating Facilities

National Renewable Resources Assoc.	PA	Conemaugh Saltsburg	Water			15
PEI Power Corp.	PA	Archbald Power Station	Gas		CT	70
Penntech Paper Inc.	PA	Bradford (PA) Plant	Coal			52
PG&E National Energy Group	PA	Northhampton Generating Station	Waste Coal			107
PG&E National Energy Group	PA	Scrubgrass Generating Plant	Waste Coal			83
Power Systems Operations	PA	Ebensburg Plant	Waste Coal			50
PPL Generation LLC*	PA	PPL Bruner Island	Coal			1434
PPL Generation LLC*	PA	PPL Martins Creek	Coal	Oil		1920
PPL Generation LLC*	PA	PPL Montour LLC	Coal			1526
PPL Generation LLC*	PA	PPL Holtwood	Water			109
PPL Generation LLC*	PA	PPL Lower Mt. Bethel	Gas		CC	575
PPL Generation LLC*	PA	PPL Susquehanna LLC	Nuclear			2352
PPL Generation LLC*	PA	PPL Wallenpaupack	Water			44
PPL Generation LLC*	PA	PPL Allentown CTG	Oil		CT	78
PPL Generation LLC*	PA	PPL Fishbach CTG	Oil		CT	36
PPL Generation LLC*	PA	PPL Harrisburg CTG	Oil		CT	72
PPL Generation LLC*	PA	PPL Harwood	Oil		CT	36
PPL Generation LLC*	PA	PPL Jenkins CTG	Oil		CT	36
PPL Generation LLC*	PA	PPL Lock Haven CTG	Oil		CT	18
PPL Generation LLC*	PA	PPL West Shore CTG	Oil		CT	36
PPL Generation LLC*	PA	PPL Williamsport CTG	Oil		CT	36
Procter & Gamble	PA	Mehoopany Plant	Gas			45
Reliant Energy Wholesale Group*	PA	Blossburg Plant (Mothball Pending)	Gas			19
Reliant Energy Wholesale Group*	PA	Cheswick Generating Station	Coal			577
Reliant Energy Wholesale Group*	PA	Conemaugh Power Plant	Coal	Gas		1883
Reliant Energy Wholesale Group*	PA	Elrama Generating Station	Coal			474
Reliant Energy Wholesale Group*	PA	Hamilton CT	Oil			20
Reliant Energy Wholesale Group*	PA	FR Philips Generating Station	Coal			411.3
Reliant Energy Wholesale Group*	PA	Keystone Generating Station	Coal	Oil		1883
Reliant Energy Wholesale Group*	PA	Mountain Plant	Gas	Oil		40
Reliant Energy Wholesale Group*	PA	New Castle Generating Station	Coal	Oil		303
Reliant Energy Wholesale Group*	PA	Orrtanna Plant	Oil			20
Reliant Energy Wholesale Group*	PA	Piney	Water			27
Reliant Energy Wholesale Group*	PA	Portland Generating Station	Coal	Gas		570
Reliant Energy Wholesale Group*	PA	Seward Generating Station	Waste Coal			521
Reliant Energy Wholesale Group*	PA	Shawville Generating Station	Coal	Oil		603
Reliant Energy Wholesale Group*	PA	Titus Generating Station	Coal	Gas		274
Reliant Energy Wholesale Group*	PA	Tolna Station	Oil			40
Reliant Energy Wholesale Group*	PA	*Warren Power Plant*	Gas	Oil		
Reliant Energy Wholesale Group*	PA	Brunot Island Generating Station	Gas	Oil		343
Reliant Energy Wholesale Group*	PA	Liberty Plant	Gas		CC	578
Reliant Energy Wholesale Group*	PA	Hunterstown Plant	Gas		CC	795
Reliant Energy Wholesale Group*	PA	*Wayne*	Oil			
Reliant Energy Wholesale Group*	PA	Shawnee CT	Oil			20
Rohm and Haas Co.	PA	Bristol	Oil			1.5
Safe Harbor Water Power Corp.	PA	Safe Harbor Hydroelectric Plant	Water			417.5
Schuylkill Energy Resources	PA	Shenandoah Plant	Waste Coal			80
Sithe Energies Inc.	PA	Allegheny Lock & Dam No. 8	Water			13
Sithe Energies Inc.	PA	Allegheny Lock & Dam No. 9	Water			17.4
Smurfit-Stone Corp.	PA	Philadelphia Container Plant	Oil			10
Solar Turbines Inc.	PA	York Solar Plant	Gas			70
Temple University	PA	Temple Univ. Standby Electric Gen. Facility	Gas			16
Tractebel Power Inc.	PA	NEPCO	Waste Coal			50
Tractebel Power Inc.	PA	Northumberland Cogeneration Facility	Other			16.2
Trigen Energy Corp.	PA	Grays Ferry Power Plant	Gas		CC	173.6
Trigen Energy Corp.	PA	Pennsylvania House Power Plant	Other			0.1
UGI Development Co.*	PA	Hunlock Creek Power Station	Coal	Oil		50
UGI Development Co.*	PA	Hunlock Creek Power Station	Gas		CT	50
Wheelabrator Technologies Inc.	PA	Frackville Energy Co.	Waste Coal			42
Wheelabrator Technologies Inc.	PA	Wheelabrator Falls WTE	Other			53
Wind Developers	PA		Wind			250
WPS Power Development	PA	Sunbury Generating Station	Coal	Oil		462.5
WPS Power Development	PA	WPS Westwood Generation	Waste Coal			30
Total MW in PA						**46520**
* = Verified Data						
Revised 9/9/04						
Source: http://www.epga.org/GeneratingFacilities.html						

Coal (45.4%)
Gas (21.3%)
Nuclear (20.0%)
Water (4.8%)
Oil (4.0%)
Waste Coal (3.1%)
Wind (0.7%)
Other (0.7%)