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POWER PLANT

CUMULATIVE ENVIRONMENTAL

IMPACT REPORT

FOR

MARYLAND

MARCH 1986

Maryland Department of Natural Resources

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should be addressed to:

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JOHN R. GRIFFIN
DEPUTY SECRETARY

March 13, 1986

The Honorable Harry Hughes
Governor
State of Maryland
State House
Annapolis, MD 21401

Dear Governor Hughes:

I am pleased to forward the Fifth Cumulative Environmental Impact Report prepared pursuant to the Maryland Power Plant Siting Act. This report describes the results of studies of the environmental and economic impacts of power plants on Maryland's natural and human environments.

Coal-fired power plants now supply the majority of the electricity generated in the State. Studies to determine the environmental impacts of existing and proposed coal-fired plants have shown that, in general, the potential adverse effects of coal use can be reduced, although not eliminated, with proper design and operation. One particular area of substantial uncertainty remains - the causes and consequences of acid deposition in Maryland. Continuing research and monitoring efforts in this Department and elsewhere in the State are essential to provide the information necessary for an informed State policy in this area.

Environmental surveillance in the vicinity of nuclear power facilities within and adjacent to Maryland has indicated that these plants continue to be in compliance with their operating license restrictions. Concentrations of radionuclides in the environment, although measurable, would result in maximum offsite radiation exposures of less than 15% of the applicable limits.

Maryland's generating capacity is adequate for the needs of its citizens at this time. Because of the long lead time necessary for planning, licensing, and construction of power plants, planning is now underway for new plants which would need to begin operation in the 1990's, and for which licensing is expected to occur in the late 1980's. The recommendations made in this report focus on assessment of alternatives to construction of larger conventional coal-fired power plants, which may provide economic or environmental advantages

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for the State. This broad perspective will ensure that the long-range objective of the Power Plant Siting Act is met: the assurance that Maryland's citizens continue to have an adequate supply of electricity at reasonable cost, with minimal depreciation of the State's natural resources and human environment.

Sincerely,

Torrey C. Brown

Torrey C. Brown, M.D.
Secretary

FOREWORD

The Cumulative Environmental Impact Report is issued biannually as required by the Maryland Power Plant Siting Act. It is a compilation of all studies relating to the cumulative impact of power plants in Maryland and adjacent states on Maryland's environment. Topic areas addressed in this edition are those studied by the Maryland Power Plant Siting Program during 1983 and 1984. In some cases, more current data and result are available and have been used to improve the usefulness of this publication. The reader is directed to earlier editions for coverage of topics in areas where impacts have changed little or no new information exists.

Chapters were prepared under contract, with principal responsibility of content vested in a member of the Power Plant Siting Program staff. Principal authors and their PPSP staff counter parts are herewith acknowledged for their contribution to this effort:

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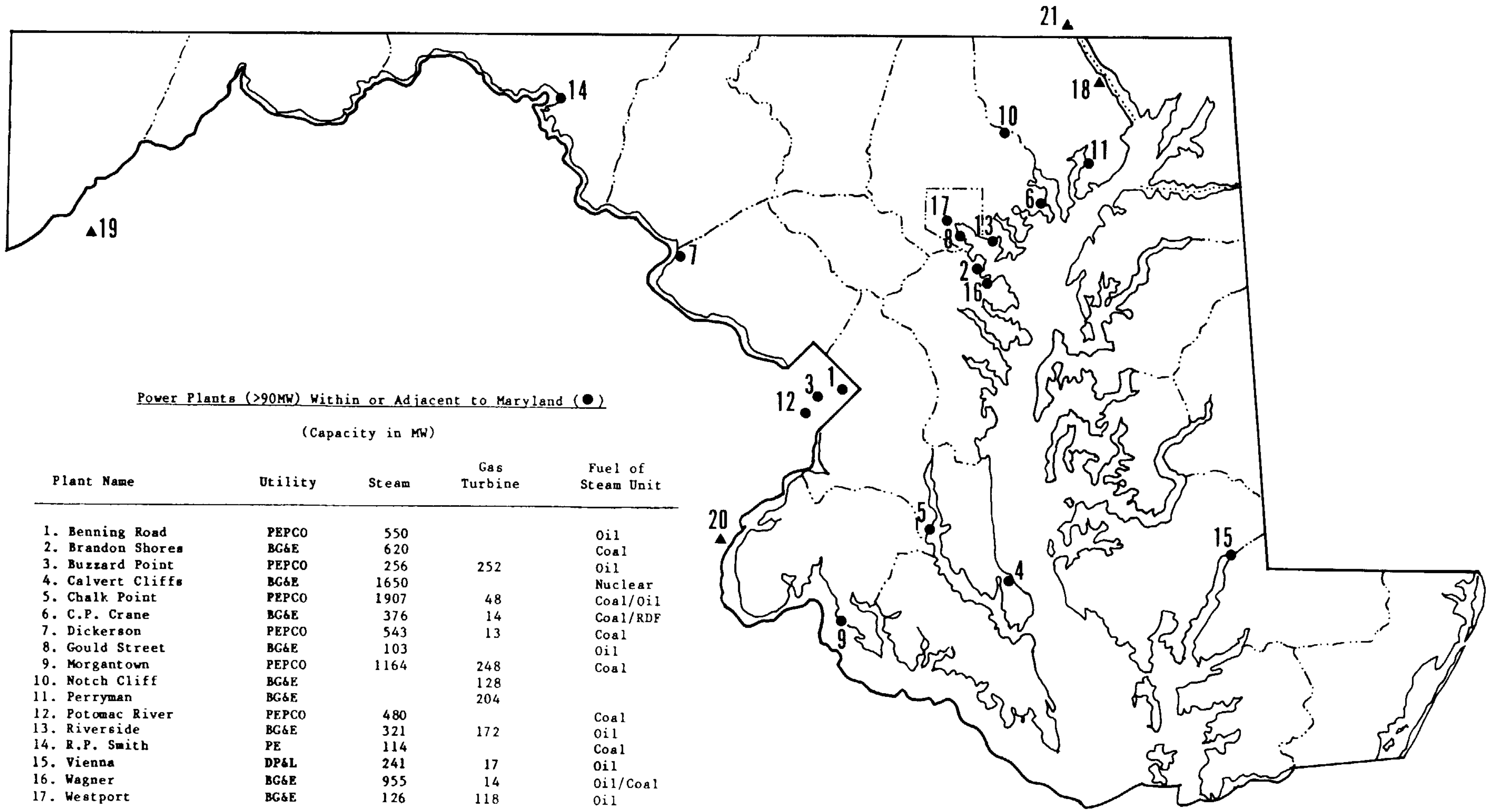
I gratefully acknowledge Mr. Jorgen Jensen for his contributions in putting this publication together; Elaine Patterson, Patricia Hammack, and Rosalee Anderson for their competent and cheerful typing of numerous drafts; and the many reviewers without whose contribution this publication could never have been completed.

Thank you.



Power Plants (>90MW) Within or Adjacent to Maryland (●)

(Capacity in MW)

Plant Name	Utility	Steam	Gas Turbine	Fuel of Steam Unit
1. Benning Road	PEPCO	550		Oil
2. Brandon Shores	BG&E	620		Coal
3. Buzzard Point	PEPCO	256	252	Oil
4. Calvert Cliffs	BG&E	1650		Nuclear
5. Chalk Point	PEPCO	1907	48	Coal/Oil
6. C.P. Crane	BG&E	376	14	Coal/RDF
7. Dickerson	PEPCO	543	13	Coal
8. Gould Street	BG&E	103		Oil
9. Morgantown	PEPCO	1164	248	Coal
10. Notch Cliff	BG&E		128	
11. Perryman	BG&E		204	
12. Potomac River	PEPCO	480		Coal
13. Riverside	BG&E	321	172	Oil
14. R.P. Smith	PE	114		Coal
15. Vienna	DP&L	241	17	Oil
16. Wagner	BG&E	955	14	Oil/Coal
17. Westport	BG&E	126	118	Oil

Plant Owned by Out-of-State Utilities (▲)

Plant Name	Utility	Steam	Gas Turbine	Fuel of Steam Unit
18. Conowingo	PECO	512		Hydro
19. Mount Storm	VEPCO	1695	16	Coal
20. Possum Point	VEPCO	1121	26	Coal
21. Peach Bottom	PECO	1800		Nuclear

Frontispiece. Location of Power Plants in Maryland.

SUMMARY

Chapter I - The Electric Utility Industry in Maryland

Important changes have occurred during the past several years in energy markets which have important implications for the electric utility industry. Consumption of oil and gas has declined, and the rate of growth of electricity demand has slowed considerably. Since this slowdown was not fully anticipated, many electric utilities have been left with excess generating capacity. Maryland has generally followed these national trends.

The industry's financial condition and profitability have improved considerably during the past few years except for those utilities engaged in large construction programs. Maryland's major electric utilities have shared in that improvement, and in fact, all are above the industry average in financial strength. Retail electric price trends in Maryland have also been favorable, with electric rates during the last few years rising less rapidly than both the nationwide average and inflation.

Electric service in Maryland is provided principally by four major investor-owned utilities. In addition, several small towns and rural areas in the State (approximately 15 percent of Maryland households) are served by rural electric cooperatives, municipally-owned systems and one small investor-owned utility. The service areas, historical load patterns and plans for new power plants are described in detail. Nearly 60 percent of the electric power produced by Maryland's electric utilities is coal-fired, with nuclear, gas and oil, and hydroelectricity accounting for the remainder in descending order of importance.

Maryland's major electric utilities do not operate in a completely independent manner. All four participate in power pooling arrangements either with the PJM Interconnection, or in the case of Potomac Edison, as part of the Allegheny Power System. Off-system sales and purchases of energy are very important aspects of their operations.

Chapter II - Need for Power

This chapter assesses the ability of Maryland's utilities to meet the power demands of their customers between now and the year 2000. This assessment requires a comparison of expected growth in peak demand and plans for installed generating capacity.

Load forecasts, using econometric models or other sophisticated methods, have been prepared by each utility and by PPSP (for BG&E and DP&L). The utilities are projecting relatively slow growth over the next 15 years -- 0.9 to 1.9 percent per year. The PPSP projections are somewhat more rapid, 2.6 percent per year for BG&E and 1.6 percent for DP&L.

A number of new generation facilities are planned to meet this load growth. APS will bring into service 840 megawatts of the Bath County Pumped Storage Project during the winter of 1985/1986, and BG&E has scheduled the

620-megawatt coal-fired Brandon Shores Unit 2 for 1992. Between 1995 and 2000, Maryland utilities plan to bring eight additional coal-fired generating units into service, ranging in size from 200 to 400 megawatts.

It appears that generating capacity will be adequate through at least the early 1990s under both PPSP and company forecasts. If, however, company load forecasts are too low, then it may be necessary to advance the in-service dates of some of the generating units scheduled for the late 1990s. Even using its own load forecast, PEPCO's reserves fall to lower than desired levels in the late 1990s. Based upon available regional projections, it appears that purchased power from other utilities will be available through the mid-1990s. This will contribute to reliability of service.

Utilities are also considering conservation and load management programs as methods to help serve customer demands. PEPCO's Energy Use Management program is the most extensive and ambitious of these programs.

Chapter III - Air Impact

Power plants contribute about two-thirds of the sulfur oxides, one-third of the total nitrogen oxides, and one-tenth of the particulates emitted by all sources in Maryland. Only negligible amounts of carbon monoxide and hydrocarbons come from power plants. Total emissions and power plant emissions of sulfur dioxide (SO_2), total suspended particulate matter (TSP), and nitrogen oxides (NO_x) decreased during the period 1975 to 1981, but no corresponding improvements in observed ambient air quality were found. This lack of correlation probably indicates that Maryland Air Management Administration's monitoring stations are not strongly influenced by the sources that have experienced emissions reductions.

Air quality models are becoming increasingly important in evaluating potential impact of new sources and source modifications. For example, recent advances in air quality modeling techniques are being used to evaluate the impact on ambient air quality of current and proposed future operations at Dickerson power plant. Federal regulations limiting credit for tall stacks at power plants produce an anomalous situation at this site in which model predictions of GLCs are much higher than those actually anticipated to occur. Any proposed expansion at the site will involve application of extensive modeling and monitoring studies in order to determine what can or should be done at the site.

No changes were promulgated in either the federal or state ambient air quality standards or the new source review programs during the 1983-1984 period. However, new regulations were proposed during this period: to impose a new National Ambient Air Quality Standard for inhalable particles (PM_{10}); to require several states adjoining Maryland to prepare visibility protection programs; and to limit the amount of stack height credit which may be taken in conducting modeling to determine Prevention of Significant Deterioration (PSD) increment consumption. Also, in 1985, regulations were proposed to require new source review for PM_{10} emissions under the PSD and nonattainment new source review (NSR) programs. The new PM_{10} National Ambient Air Quality Standard

(NAAQS) will probably not affect existing power plants located outside the Baltimore area. The other regulatory changes will primarily affect new construction, requiring additional preconstruction monitoring and ambient air impact analysis for many projects.

The coal conversion at Crane power plant was completed during 1983. Preliminary analyses of ambient air quality monitoring data obtained through 1984 indicates that the conversion produced increases in ambient air concentrations of TSP generally comparable to those projected by air quality models during the licensing process. However, on a few occasions, TSP concentrations exceeded expected values at isolated monitoring sites. Work is continuing to evaluate the technical and regulatory significance of these events.

Chapter IV - Aquatic Impact

Steam and hydroelectric power generation affects water quality and aquatic biota by: 1) entrainment of organisms, mainly early developmental life stages of fish, through condenser and turbine systems; 2) impingement of fish and crabs on intake screens protecting internal plant structures; 3) habitat modifications and changes in water quality associated with release of discharges; and 4) prevention of fish passage. Impacts from steam electric generating facilities are of major concern when spawning and nursery areas of commercially and recreationally important species occur near intake structures, and large numbers of early life stages are entrained or impinged.

There is a low probability of cumulative impact of power plant operations on biota in mesohaline habitats. Entrainment losses to early developmental stages of commercially and recreationally important fish are small and have little economic or ecological significance. Entrainment losses to phytoplankton, zooplankton, and early developmental stages of forage fish are large; however, no nearfield depletions have been found for these biota. Large number of fish and crabs are impinged at power plants located in the mesohaline zone. Impingement and entrainment losses have little consequence because factors other than entrainment and impingement are controlling population levels. Discharge effects in mesohaline habitats are small and localized and do not have regional impacts. The dilution capacity of the mesohaline zone is large relative to the volume of power plant effluents released into it at all Maryland power plants.

Entrainment losses at power plants in tidal fresh-oligohaline habitats affect spawning and nursery activities of striped bass and white perch. However, these impacts are small and do not adversely impact baywide populations. Impingement losses in the tidal fresh-oligohaline zone are small, as are discharge effects.

Long-term changes in water quality of Maryland rivers from development in the watersheds appear to have far greater environmental impacts on aquatic organisms than changes associated with power plant operations, which are localized and of little regional consequence. Dam operations at the Conowingo hydroelectric facility control water level, flow, and dissolved oxygen concentration in aquatic habitats down-stream of the dam and adversely affect aquatic biota. Maintenance of minimum flows during summer reduces many of the discharge effects associated with dam operations, but does little to improve dissolved oxygen concentration in downstream habitats. Conowingo Dam denies anadromous fish access to spawning habitats upstream of the dam. Studies are currently being conducted to determine the most appropriate method of restoring anadromous runs to these upstream habitats. The impacts of small-scale hydroelectric facilities upon Maryland streams and rivers are suspected to be small, mainly because environmental problems are addressed in the planning stages. However, this speculation can not be verified until ongoing preoperational/postoperational studies are completed and the cumulative impacts of multiple projects on the same stream have been assessed.

Chlorine injection is the major means used to control biofouling at Maryland power plants, and it will continue to be so for a least the next decade. Alternatives to chlorine are either not sufficiently developed for implementation or have consequences similar to chlorine. However, current chlorine discharge limits are sufficiently strict to protect spawning and nursery habitats and ecosystem integrity. Organotin antifouling paints may be an effective means of controlling biofouling in some power plant applications in the future. However, the environmental consequences of use of the organotin paints are uncertain and need to be evaluated.

A wide variety of intake control technologies and operating practices that reduce entrainment and impingement impacts in Maryland have been identified. Barrier nets are a cost-effective method for reducing impingement at many Maryland power plants. Fine-mesh wedgewire screens effectively reduce both entrainment and impingement and appear to be more cost-effective than closed-cycle cooling or planned plant outages.

Long-term power plant effects have been found in the nearfield region of several estuarine power plants; however, these effects are generally localized and do not affect ecosystem stability or food-web dynamics. This is probably because plant-related alterations to the estuarine environment are small and generally do not exceed specifications defined in Maryland regulations, or tolerances of most biota. Relative to long-term changes in the water quality of Chesapeake Bay, power plant effects are small.

Chapter V - Radiological Impact

Nuclear power plants with a potential for environmental impact in Maryland include Calvert Cliffs, located on the western shore of the Chesapeake Bay in Maryland, and Three Mile Island and Peach Bottom, located in Pennsylvania on the Susquehanna River. Radiological surveillance of the atmospheric, terrestrial, and aquatic environments conducted by PPSP, DHMH, and the various utilities has indicated that these plants are in compliance with their operating license restrictions, imposed and regulated by the U.S.NRC. to assure no adverse human health or environmental impact.

At Calvert Cliffs, low levels of plant-related Co-58 and Co-60 have been detected in sediments of the Chesapeake Bay. In addition to these nuclides, Zn-65 and Ag-110m have been detected at low levels in Bay biota, with the exception of edible finfish. Of edible biota, oysters in the discharge vicinity have contained the highest levels of Zn-65 and Ag-110m, a function of the organism's ability to concentrate metals. These radionuclide concentrations fluctuate over time, depending upon the quantity of radioactivity released by Calvert Cliffs and variations in oyster assimiliation and depuration rates.

Consumption of seafood containing the highest concentrations detected during the period would result in a plant-related radiation dose of less than 5% of the allowable limit (10 CFR 50, Appendix I), and less than 1% of the radiation dose acquired through consumption of natural radioactivity.

At Peach Bottom, low levels of plant-related Zn-65, Cs-134, Cs-137 have been detected in sediments and biota of the Conowingo Pond, the lower Susquehanna River and Upper Chesapeake Bay. The maximum hypothetical annual total body radiation dose resulting from the ingestion of finfish containing the maximum radionuclide concentrations for this period is estimated to be less than 1 mrem. This represents about 10% of the allowable limit (10 CFR 50, Appendix I), or less than 3% of the annual radiation dose received through the ingestion of natural radioactivity.

During the subject period, releases of I-131 to the atmosphere by the Peach Bottom Atomic Power Station produced detectable concentrations of this radionuclide in sampled cows' milk on several occasions. These sporadically detected concentrations were very low and resulted in a maximum hypothetical dose for 1983 via this pathway estimated to be 0.4 mrem to an infant thyroid, or 1.3% of the allowable limit (10 CFR 50, Appendix I). For 1984, releases of this nuclide are estimated to have resulted in a dose of 0.11 mrem, or 0.4% of the allowable limit.

Because the Three Mile Island Nuclear Station was not operating during 1983 and 1984, only very minute quantities of radioactivity were released. No radioactivity attributable to this facility has been detected during the subject period, or previously, in the Maryland environment.

Chapter VI - Groundwater Impacts

Maryland's geology is quite varied, being separated into five distinct physiographic provinces based on underlying geological materials and structure. The geological character of each region has a pronounced effect upon the occurrence of ground water and the potential for contamination of ground water supplies from the operation of power plants within the province. This chapter presents a generalized picture of the nature of and interrelationships between geology and ground water occurrence within the regions. In this way, the potential for adverse impacts on ground water resulting from the operation of power plants can be more easily understood.

Potential adverse environmental impacts are associated with power plant operations, construction activities, oil and coal handling and storage operations, combustion by-product disposal, and the utilization of ground water resources for various plant operations. However, plant-related by-products and wastes are less toxic than those of many industrial activities. Investigations by the PPSP have indicated that only minor on-site ground water contamination has occurred at abandoned and at presently operating ash sites in the State of Maryland.

Chapter VII - Acid Deposition

In the last few years there has been increasing public concern over the possible ecological and economic implications of acidic deposition. The mean annual pH of precipitation in Maryland is about 4.0, which is roughly 10 times as acidic as natural rain. This acidity is consistent with average pH values for the northeastern United States. Studies of effects on ecological systems in other areas of the country have identified potentially sensitive resources such as lakes and forests in Maryland.

The U.S. EPA and ten other federal agencies are currently funding the comprehensive National Acid Precipitation Assessment Program. This program seeks to establish the relationship between emissions of SO_2 (and other pollutants) and deposition of acidic materials to sensitive receptors, and also to assess environmental effects attributable to acid deposition. Maryland has many concerns which are unique to the Chesapeake Bay region and are not being addressed in studies supported by other programs such as NAPAP. Therefore, the State is supporting additional studies to address these issues.

The Maryland Interagency Working Group on Acid Deposition recommended that studies be funded to evaluate the nature and amount of acidic materials deposited in Maryland, to identify and evaluate the sensitivity of Maryland resources, and to measure the water quality of headwater streams. Studies to address these recommendations have been implemented. Projects currently underway, or recently completed, in the State are located primarily in the Coastal Plain and fall into three general categories: watershed; biotoxicity; and remedial action. Results available thus far suggest that small freshwater streams in the coastal plain are sensitive to acid deposition. Anadromous fish (e.g. blueback herring) which use such streams for spawning are very sensitive to low pH and high dissolved aluminum concentrations; such conditions have been observed in the field. The early life stages of striped bass are also very sensitive to these chemical conditions.

Numerous bills have been introduced in the Congress to amend the Clean Air Act to also control acid deposition. The bills generally attempt to achieve approximately 50 percent reduction in deposition rates by requiring an 8-12 million ton reduction in sulfur dioxide emissions over a 10-12 year period. Costs to Maryland of a hypothetical control scenario have been estimated in a recent study. For Maryland's four major utilities, the total estimated 15 year cost of a 12 million ton national reduction was 3.8 billion dollars.

Chapter VIII - Alternative Power Supply Technologies

A number of developments have occurred in recent years to encourage the development of alternatives to conventional central station power plants. These generation sources are typically small in scale, customer rather than utility-owned and often based upon renewable types of energy. Of particular importance in encouraging this development is federal law which requires that utilities must purchase the electricity supplied by these non-utility facilities and pay prices for the power reflecting the utility's "avoided cost" (i.e., the cost the utility saves by purchasing rather than producing the power).

Six types of alternative power are considered -- municipal solid waste, cogeneration, solar energy, small-scale hydro, wind energy, and wood. At present, power supply capacity from these sources (excluding utility-owned hydro) is approximately 162 megawatts, which compares to peak demand in the State of more than 8,000 megawatts. Virtually all of this power is from municipal solid waste, cogeneration and small-scale hydro. Additional municipal solid waste power plants are being planned, and there appears to be some potential for increasing the amount of small-scale hydro. However, the development of alternative power supplies in Maryland has lagged that in the nation as a whole.

RECOMMENDATIONS

1. **The State should evaluate methods for encouraging the use of conservation and "alternative energy sources" as alternatives or supplements to conventional large scale generation of electricity.**

Although pollution control equipment has reduced the impacts of conventional coal-burning power plants, some environmental impacts are unavoidable. In addition, large capital costs and long lead times have made the construction of large central station electric generating plants increasingly difficult to plan and accomplish. These facts have led utilities to investigate the use of alternative energy sources and demand reduction as alternatives to constructing additional power plants. The State should encourage continued emphasis on such efforts because of their role in conserving natural resources, protecting the environment, and providing electricity in the most economical fashion.

The extent to which such alternatives can or should substitute for additional power plants is not obvious, however. The State has determined that some alternative technologies, e.g., wind power, hold little promise for Maryland. Others, e.g., small-scale hydropower, are characterized by environmental drawbacks that may outweigh their advantages. The State should evaluate all alternative energy supply technologies to determine which seem most appropriate for use here, and to identify appropriate methods for emphasizing their use. This evaluation should extend to demand reduction techniques such as conservation and load management.

2. **The State should support the use of new, so-called "clean coal" technologies for generation of electricity in Maryland wherever they will provide environmental advantages over traditional technologies.**

Maryland utilities have been among the nation's leaders in consideration of new clean coal technologies for generating electricity. While the environmental impact of these technologies is currently undergoing evaluation, they appear to offer the potential for significant environmental advantages over traditional pulverized coal plants. Their use in future generation plans should be investigated by all Maryland utilities and the State should encourage their use where environmental benefits will be realized at a reasonable cost.

3. **The State should determine the ability of utility transmission systems in Maryland to accommodate increases in bulk power supply.**

Among the alternatives to construction of new power plants is the option of buying power from plants in neighboring states. This option recently has received increased emphasis because of a proposal to build power plants in coal rich states, such as West Virginia, and sell the power to utilities in other states. There is, however, serious question that the existing transmission system in Maryland is adequate to accommodate such bulk power transfers. It is also conceivable that Maryland utilities could lose any extra transmission capacity if ordered by the Federal Energy Regulatory Commission to wheel power from one region to another. Evaluation of the transmission system should take place on a routine basis so that the long lead time involved in siting, licensing, and constructing new transmission lines will not adversely affect the State's ratepayers should the state determine that such bulk power transfer is required.

TABLE OF ACRONYMS

A&N	Accomack and North Hampton Electric Cooperative
AES	Atomic Energy Station
AESP	Alternative Energy Sources Program
AFUDC	Allowance for Funds Used During Construction
AGC	Allegheny Generating Corporation
AMS	American Meteorological Society
ANSP	Academy of Natural Sciences of Philadelphia
APS	Allegheny Power System
BACT	Best Available Control Technology
BEA	Bureau of Economic Analysis
BEAP	Baltimore Energy Alliance Program
BG&E	Baltimore Gas and Electric Company
BRESCO	Baltimore Southwest Resource Recovery Facility
CBO	Community Based Organizations
CCNP	Calvert Cliffs Nuclear Power Plant
CDA	Community Development Administration
CDMQC	Climatological Dispersion Model
CEIR	Cumulative Environmental Impact Report
CETA	Comprehensive Employment Training Act
CFR	Code of Federal Regulations
COMAR	Code of Maryland Regulations
CRSTER	Crash Terrain Model
DECD	Department of Economic and Community Development
DHMH	Department of Health and Mental Hygiene
DEMEC	Delaware Municipal Electric Corporation
DNR	Department of Natural Resources
DOE	Department of Energy
DP&L	Delmarva Power and Light Company
DPS	Dry Plate Scrubber
DSP	Department of State Planning
ECAR	East Central Area Reliability Coordination Agreement
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESFF	Electrostatically Augmented Fabric Filter
EUM	Energy Use Management Program
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
GAO	General Accounting Office
GBF	Moving Bed Granular Filter
GEP	Good Engineering Practice
GPU	General Public Utilities
HC	Hydrocarbons
ISCST	Industrial Source Complex Model
LLW	Low Level Radioactive Wastes
MAAC	Mid-Atlantic Area Council
MAMA	Maryland Air Management Administration
MEFA	Maryland Energy Financing Administration
MP	Monongahela Power Company

MPTER	Multiple Point Gaussian Dispersion Algorithm with Terrain Adjustment
MSW	Municipal Solid Waste
NAAQS	National Ambient Air Quality Standards
NAPAP	National Acid Precipitation Assessment Program
NEDS	National Emissions Data System
NERC	North American Electric Reliability Council
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGPA	National Gas Policy Act
NOAA	National Oceangraphic and Atmospheric
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NSR	New Source Review Program
NSWS	National Surface Water Survey
OAQPS	Office of Air Quality Planning and Standards
OVEC	Ohio Valley Electric Corporation
PBAPS	Peach Bottom Atomic Power Station
PCB	Poly-Chlorinated Biphenyls
PDF	Probability Density Function
PE	Potomac Edison Company
PECO	Philadelphia Electric Company
PEPCO	Potomac Electric Power Company
PJM	Pennsylvania-New Jersey-Maryland Power Pool
PPSP	Power Plant Siting Program
PSC	Public Service Commission
PDS	Prevention of Significant Deterioration
PURPA	Public Utility Regulatory Policies Act
QF	Qualifying Facility
RAM	Real Time Air Quality Simulation Model
RCS	Residential Conservation Service
RFD	Refuse Derived Fuel
RIS	Representative Important Species
RTDM	Rough Terrain Dispersion Model
SAV	Submerged Aquatic Vegetation
SIP	State Implementation Plan
SMECO	Southern Maryland Electric Cooperative
TMINS	Three Mile Island Nuclear Station
TSP	Total Suspended Particulate Matter
USGS	United States Geological Survey
VEPCO	Virginia Electric Power Company
WMATA	Washington Metro Area Transit Authority
WPP	West Penn Power Company

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CHAPTER I

THE ELECTRIC UTILITY INDUSTRY IN MARYLAND

The primary purpose of this chapter is to present an overview of the electric utility industry in Maryland. Chapter II of this report presents a comprehensive evaluation of the adequacy of electric service between now and the end of this century. In exploring the current status of the electric utility industry in Maryland it is useful to examine energy markets generally and the utility industry at the national level.

A. Trends in National Energy Markets

Prices and supplies of competing sources of energy are determined by regional, national and even international markets. National policy decisions influence the operations of these markets, and as a consequence, they shape energy options in Maryland. It is therefore helpful to consider the national energy framework within which Maryland energy markets and utilities must operate. Further, it is important to understand, or at least consider, future energy trends since these trends have implications for energy planning.

Prior to the early 1970s, energy usage in the U.S. grew steadily, encouraged by energy prices that in inflation-adjusted terms were stable or even declining. Other factors contributing to the growth in energy demands during this time period include a rapidly growing economy, increased adoption of air conditioning and the expansion of certain energy-intensive industries such as aluminum, paper and chemicals. The favorable energy price trends were due to productivity advances by energy producers, the discovery of new energy resources and the importation of inexpensive foreign oil. During the period 1960 to 1973, primary energy consumption in the U.S. increased by 4.2 percent per year, while the price of petroleum declined by 0.9 percent per year (1).

This situation changed dramatically with the 1973 Arab oil embargo and subsequent developments. The price of oil and other fossil fuels increased sharply and, in conjunction with the severe 1974-1975 recession, brought about an interruption in the growth of energy demand. Another sharp increase in oil prices occurred during the 1979-1980 period. Major increases in natural gas prices occurred in response to the oil price increases and partially due to the phased decontrol mandated by the Natural Gas Policy Act (NGPA) of 1978. Between 1973 and 1984, almost no increase in total energy consumption occurred in the U.S. During this same period oil prices increased by 10.6 percent per year and natural gas prices increased by 16.9 percent per year in inflation-adjusted terms. Coal prices (in inflation-adjusted terms) increased by a far slower though still significant annual rate of 3.5 percent (1).

After almost a decade of rapidly rising energy prices and occasionally short supplies, many experts were predicting that energy prices would continue to outstrip inflation for the indefinite future. Indeed, during the early 1980s (up until 1984), natural gas prices continued to increase sharply due to a complex set of circumstances involving a transition to decontrol and the fact that gas prices were "catching up" to oil prices. With the exception of the unique circumstances of natural gas (and some electric utilities adding expensive new plants), the predictions of ever-increasing energy prices have proven to be incorrect. The rapid run-up in prices over the previous decade served not only to slow demand, but it also encouraged an increase in supply. It is now generally acknowledged that there is considerable excess production capacity for most forms of energy, and these surpluses will continue to exert downward pressure on prices for the near term.

The U.S. Department of Energy, Energy Information Administration (EIA), prepares forecasts of U.S. energy consumption, production and prices. EIA projects that energy consumption will grow moderately (1.7 percent per year) over the next decade. Energy prices are expected to remain stable for the near term, but by the 1990s they are projected to begin increasing again at rates somewhat above that of inflation. EIA also projects that over the next ten years imports will account for an increasing percentage of U.S. oil consumption (2).

B. Energy Trends in Maryland

Trends in Maryland energy consumption have paralleled nationwide patterns. From the period 1960 to 1973 (the year of the Arab oil embargo), energy usage grew steadily in all major consuming sectors. That trend ended in the mid-1970s. Total end-use energy consumption in 1983 was actually 18 percent below levels experienced in 1973, with the majority of the decline occurring in Maryland's shrinking industrial sector. In addition to the reduction in total energy usage in Maryland, there was a sharp reduction in petroleum consumption in all sectors except transportation. The shares of energy type by major consuming sector in Maryland in 1983 are presented on Figure I-1.

Table I-1 presents a comparison of energy usage in Maryland in 1973 and 1983. That table also includes Maryland's share of total energy consumption in the U.S. and the Mid-Atlantic region. The Mid-Atlantic region has been defined to include Maryland, Pennsylvania, Delaware, New Jersey and the District of Columbia. This approximates the area encompassed by the Pennsylvania-New Jersey-Maryland (PJM) Interconnection, the regional power pool that most of Maryland's major electric utilities participate in.

Maryland's share of U.S. energy consumption was 1.7 percent in 1973 declining to 1.6 percent in 1983. For comparative purposes, Maryland's share of U.S. population is 1.8 percent, indicating that Maryland uses slightly less energy per capita than the nation as a whole. The largest difference between Maryland and the U.S. (and the largest change over time) is in the industrial sector. Maryland's industrial sector accounted for 2.3 percent of U.S. industrial energy consumption in 1973 but only 1.3 percent in 1983.

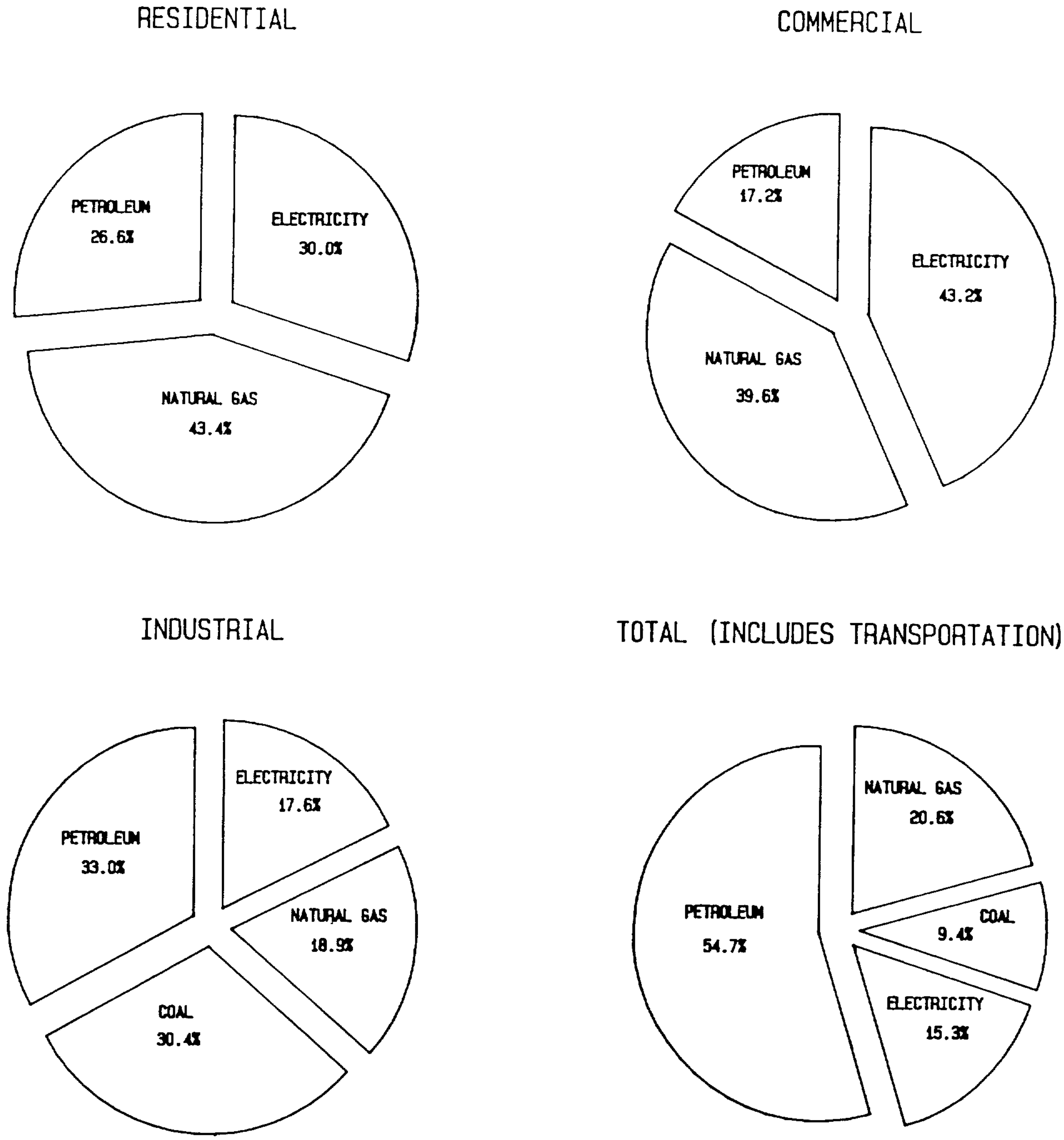

Figure I-1 Shares of Total Energy Consumption in Maryland for Major Sectors, 1983

Table I-1. End-Use Energy Consumption in Maryland Vs. U.S. and Mid-Atlantic Region, 1973 and 1983(a) (Trillion BTUs)

	1973			1983		
	Maryland	% of U.S.	% of Region	Maryland	% of U.S.	% of Region
Residential(b)						
Petroleum	60.7	2.2%	11.6%	40.9	2.9%	13.8%
Natural Gas	74.3	1.5	13.9	66.7	1.5	13.4
Electricity	33.0	1.7	17.8	46.0	1.8	20.6
Total(c)	168.0	1.7	13.5	153.6	1.8	15.1
Commercial(b)						
Petroleum	37.5	2.4	12.5	13.7	1.5	10.9
Natural Gas	30.2	1.1	13.2	31.7	1.3	12.6
Electricity	27.0	1.8	19.0	34.5	1.6	17.9
Total(c)	94.7	1.7	14.1	79.9	1.5	14.0
Industrial						
Coal	158.6	3.9	16.1	76.8	3.1	18.8
Petroleum	177.9	2.0	15.8	83.3	1.1	14.3
Natural Gas	61.7	0.6	12.1	47.7	0.7	11.8
Electricity	34.5	1.5	12.8	44.5	1.7	17.3
Total(c)	432.7	2.3	15.0	252.3	1.3	15.2
Transportation(d)	303.9	1.6	17.2	309.3	1.6	16.4
Totals(c)						
Coal	158.7	3.9	16.2	76.8	3.1	18.8
Petroleum	577.5	1.8	15.5	447.2	1.5	15.5
Natural Gas	168.6	0.9	13.3	168.6	1.2	14.6
Electricity	94.6	1.6	15.9	125.1	1.7	18.6
GRAND TOTALS	999.4	1.7	15.2	817.7	1.6	16.0

(a) Data from Ref. (3). Losses incurred in converting boiler fuels to electricity are excluded. The Mid-Atlantic region is defined here to include Maryland, Pennsylvania, New Jersey, Delaware and the District of Columbia.
(b) Master-metered apartments are included in the commercial sector.
(c) Totals include only those energy sources listed above.
(d) Transportation energy is almost entirely petroleum.

Maryland has reduced its usage of petroleum (and coal) even more than the nation as a whole, with petroleum accounting for most of the decline in total energy consumption during this period. Despite the nationwide decline in gas demand and the moratorium on new gas hookups during much of this period, natural gas usage in Maryland remained unchanged. Electricity consumption in Maryland grew slowly during this period in all major sectors, even in the industrial sector. The fact that electricity is accounting for an ever-increasing share of both U.S. and Maryland energy consumption is not surprising given that electricity prices have risen less rapidly than the prices of most other forms of energy.

As Table I-1 indicates, energy usage in Maryland has been growing more rapidly than in the Mid-Atlantic region. In 1983, Maryland accounted for 16.0percent of the region's total energy usage compared to 15.2 percent in 1973. Despite the rather sharp decline in Maryland's industrial sector discussed earlier, industrial energy consumption in the entire region has declined even more sharply. Over the decade, Maryland's industrial sector actually slightly increased its share of the region's total industrial energy consumption.

C. The Electric Utility Industry

Electricity accounts for less than 15 percent of the energy consumed at end-use in the U.S. Nonetheless, it is a critical part of our energy supply. According to EIA projections, electric power will account for a disproportionate share of the future growth in U.S. energy usage. Over the decade 1984 to 1995, EIA projects end-use energy demand to increase by 7.7 quads (i.e., quadrillion BTUs), with electricity accounting for about 40percent of that growth (2). Moreover, in many key applications, such as lighting, motors and electronic devices, other forms of energy cannot effectively substitute for electricity.

The years following the Arab oil embargo were very difficult ones for electric utilities due to a number of factors. Although electricity sales have increased almost continually, the industry did experience a rather sharp and largely unexpected slowdown. During the period 1960 through 1973, electricity sales grew at an annual rate of 7.3 percent. Since then, annual growth has slowed to 2.7 percent, and EIA is projecting a rate of growth only slightly higher for the next ten years (2).

The major problem for the industry has not been the slowdown in sales per se, but the fact that this marked reduction in sales growth was not foreseen.[1] The result has been a serious and widespread problem of excess capacity which may worsen over the next few years for some utilities, as new generating plants currently in the final stages of construction enter service. A common measure of excess capacity is the extent to which installed generating capacity exceeds annual peak demand. For the U.S. as a whole, 1985 summer peak demand is expected to be 465,112 megawatts compared with a generating capacity of 619,143 (4). This leaves a reserve margin for that year of 33 percent. The industry

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[1]As recently as 1979, the industry was projecting annual load growth in excess of 5 percent (4).

projects that margin to decline gradually to 31 percent by the summer of 1990 (4). It is, of course, desirable to maintain some margin of safety to take account of outages at generating units and load growth uncertainty, and the appropriate level of such reserves varies by utility. However, compared to a typical industry standard of 20 percent, it is clear that there is considerable excess capacity at present. If industry capacity and demand projections are accurate, this condition will persist into the early 1990s.

The excess capacity problem is also present in this region of the country. The Mid-Atlantic Area Council (to which three of Maryland's four largest electric utilities belong) projects a reserve margin of 34 percent in 1985 and 33 percent by 1990. Even by 1994 the reserve margin is expected to be 28 percent (4). One of the reasons why the reserve margins remain so high is that the utilities in the region are projecting peak load to increase by only 1.1 percent per year over the next ten years. The situation is similar for the East Central Area Reliability Coordination Agreement (ECAR), a region that includes principally Ohio and some neighboring states but extends into Western Maryland. For the winter of 1985/1986, the reserve margin is projected to be 44 percent, declining to 32 percent by 1994/1995. This latter reserve margin is based upon a projected growth in peak load of 1.8 percent per year (4).

Maryland utilities have also experienced excess capacity in recent years, and with one major exception, PEPCO, this condition is expected to continue for the next several years. A complete description of the load and capacity balance expected for Maryland utilities over the next 15 years is presented in Chapter II. The regional supply/demand capacity balance is important to Maryland utilities because it indicates the extent to which a Maryland utility can rely upon other utilities in the region for purchased power (assuming the adequacy of transmission capacity). For example, a utility may be able to operate reliably with very low reserves if neighboring systems have excess capacity.

The effect of excess capacity on ratepayers varies from one utility to the next depending on specific circumstances. In general, excess capacity will cause rates to be higher than they otherwise would be as ratepayers are charged the costs (i.e., equity return, interest expense, taxes, depreciation and maintenance) of the unneeded capacity. This has made excess capacity a particularly sensitive issue. There are a number of instances, however, when the unneeded capacity addition benefits the utility system by displacing expensive oil or gas generation, thus lowering fuel costs. These lowered fuel costs may offset most or possibly even all of the added carrying costs of the capacity. This is particularly true in the Mid-Atlantic and Northeast part of the U.S. where large quantities of oil and gas are consumed to generate power.[1]

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[1]Even if a utility cannot use a new, excess generating unit to displace oil or gas on its system, it may be able to sell the power from that plant to another utility and displace high-cost generation on that system. Fuel clauses in Maryland and most other states pass the profits from such sales back to the retail ratepayers.

Finally, in some instances, regulators have required shareholders to bear some or all of the costs of the excess capacity rather than passing them on to retail ratepayers. Although such regulatory treatment has not occurred in Maryland, both investors and utility management are well aware of these instances. It is today regarded as one of the risks associated with new plant construction, and it therefore, influences the planning process.

The industry has responded to the excess capacity problem by scaling back or postponing construction plans. Within the past couple of years, BG&E, Potomac Edison and Delmarva Power & Light Company have announced postponements in the in-service dates of planned coal-fired plants because of lower load growth estimates. In a number of cases in the last few years, utilities in other states have cancelled partially constructed plants. A 1983 study published by EIA (5) states that as of 1982, 100 nuclear generating units have been cancelled. The reasons most commonly cited for the cancellations by the utility were lower load growth than originally anticipated and financial inability to complete construction. The study also found that regulators usually required the utilities to bear a portion of the cost of the cancelled plant. Maryland's utilities have not in recent years cancelled partially completed plants and thus have avoided this problem. However, given this industrywide experience, investors recognize that this risk will be present with any utility constructing new capacity. It is quite likely that managements at Maryland utilities factor this risk perception into their capacity planning process.

In addition to the problems created by the existence of excess capacity there has been a great degree of concern over the industry's financial condition. The financial condition of the industry is a matter of concern not just to investors but to regulators and policymakers as well. This is because financial health affects both a utility's ability and willingness to construct new plant as well as the type of plant it will build. Financial criteria receive considerable weight in the planning process.

Prior to 1983, the industry's financial strength and profitability were seriously impaired by rapid inflation, high interest rates and "regulatory lag." The latter problem refers to the tendency of rate increases to lag behind costs due to the length of time that utility commissions require to rule on rate requests. During the late 1970s and early 1980s, few utilities were able to earn their authorized rates of return. A second major consequence of inflation and high interest rates was that it became much more difficult than in the past to fund new power plant construction due to the high cost of new plant. For example, a recent source estimates the average eventual cost of the nuclear power plants currently under construction will be $3,140 per kilowatt (6).[1]

Within the past three years, the financial condition of most of the industry, including Maryland utilities, has improved considerably. This improvement can be traced to at least four major changes or trends:

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[1]For a typical 1,000-megawatt unit, this would be an installed cost of approximately $3.1 billion.

(1) Capital spending industrywide has been slowing as many utilities have completed plant construction and brought those plants into rate base.

(2) Federal tax legislation, particularly the Economic Recovery Tax Act of 1981, has helped to enhance the cash flow of utilities with new plant in service.

(3) Inflation has slowed considerably from the double-digit rates that prevailed as recently as 1981. This has eased the problem of regulatory lag and made it easier for utilities to earn their authorized rates of return.

(4) Interest rates and capital costs have eased making it less expensive for utilities to obtain needed financing.

The result has been a dramatic improvement in profitability and cash flow. The industry is presently financing approximately 75 percent of its construction from internal funds compared to approximately 40 to 50 percent just a few years ago (7).

Ironically, in the midst of this prosperity, a large segment of the industry is suffering from severe financial distress, and for a few companies, even threats of bankruptcy. Approximately a dozen major utilities across the country have reduced or eliminated dividend payments. Prior to 1984, that was an almost unheard of occurrence in the utility industry. The firms facing this distress are those experiencing difficulties financing power plant construction or companies that must bear the cost of plant cancellations. No Maryland utility is in this distressed group, but these developments affect investor attitudes toward the entire industry.

Table I-2 presents data on the financial condition of the electric utility industry and the four major electric utilities that operate in Maryland. The "industry" consists of the 100 companies followed by the investment banking firm of Salomon Brothers and represents most of the privately-owned electric utility industry. The table lists four financial indicators that are generally considered important by investors in assessing the financial strength of a utility. The data are from calendar 1984, except for the internal cash ratio (projected 1984-1986) and the bond ratings which are mid-1985.

Three of the four Maryland utilities are rated Aa1 by Moody's Investors Service, the upper end of the double A category. APS is a holding company and does not issue long-term debt. However, all three APS operating subsidiaries, including Potomac Edison, are in the double A category. The median bond rating for the industry is single A.

Table I-2. Financial Indicators for Electric Utility Industry in Maryland and the U.S., 1984(a)

	PEPCO	BG&E	APS	Delmarva	U.S. Average
Bond Rating(b)	Aal	Aal	Aa	Aal	A
Coverage Ratio(c)	4.3x	4.0x	3.5x	4.5x	2.9x
AFUDC Ratio(d)	6%	19%	20%	4%	39%
Internal Cash to Construction Ratio(e)	85%	71%	42%	119%	77%

(a) Ref (7). U.S. average is the median value for the 100 electric utilities followed by Salomon Brothers.

(b) Moody's bond ratings. Aal designation is the top of the double A category. The double A designation for APS refers to the bonds of its operating subsidiaries. The median bond rating for the Salomon Brothers 100 is a single A.

(c) The coverage ratio is the pretax coverage ratio excluding AFUDC earnings.

(d) AFUDC ratio is the percentage of earnings accounted for by AFUDC, a noncash item.

(e) This is the projected ratio for the period 1984 to 1986.

The three quantitative measures in the table include the pretax coverage ratio excluding allowance for funds used during construction (AFUDC),[1] AFUDC as a percentage of earnings, and the ratio of internally generated cash-to-construction expenditures projected over the period 1984-1986. The coverage ratio directly indicates the number of times (pretax) earnings "covers" interest payment obligations and therefore the degree of protection afforded bond investors. The AFUDC ratio, the percentage of earnings accounted for by this noncash item, is often described as a "quality of earnings" measure. From the point of view of the utility, the more of its earnings that is in the form of cash, the stronger is its financial condition. The final ratio measures the extent to which construction may be funded from internally generated cash as opposed to issuance of new securities.

These ratios in almost all cases indicate that the four Maryland utilities are well above the industry average even though the industry as a whole has been improving. The internal cash ratios for APS and BG&E do appear to be below average, but that is misleading. With the Bath County plant entering service in late 1985 and therefore allowed into the utility rates in 1986, the cash flow for APS will improve while construction expenditures (at least in the near term) decrease. BG&E should be able to fund nearly all of its construction expenditures over the next few years from internal funds (8).

The financial strength of the Maryland utilities compared to the industry is certainly due in part to their relatively modest construction expendituresand near-term outlook for construction spending. Consequently, a resumption of a major construction program in the future could reverse the present situation. Perhaps of even more significance are factors which are totally beyond the control of the industry, particularly the general economic climate. A resumption of rapid inflation and high interest rates could be very damaging to the industry's financial health, and Maryland utilities would not escape that damage.

Even with the construction slowdown referred to earlier, EIA projects that the industry will add 128,400 megawatts of capacity over the period 1984 to 1995 (a 1.6 percent annual rate of growth). Of that, 64,400 megawatts is projected to be coal-fired and 47,900 megawatts is projected to be nuclear. Almost all of the remainder will be hydroelectric or combustion turbine (2). The Maryland utilities are expecting to add 2,261 megawatts of capacity over this same time frame[2] and plan to retire 126 megawatts. These changes result in an average annual increase in installed capacity over this period of 1.3

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[1]AFUDC is an accounting method used in the utility industry. Plant under construction is often not permitted in rate base. However, to reflect the fact that there is a cost of financing construction, a noncash return is imputed and then added to the book cost of the plant under construction. This imputed return is considered to a form of earnings on the utility's income statement, but it is "paper" earnings rather than cash earnings.

[2]This includes new capacity added in 1984 and 1985 and non-utility capacity to be sold to the Maryland utilities. Two plants, Brandon Shores 1 and 2, and the Bath County Project represent more than 90 percent of the total.

percent. The increase is expected to be largely coal-burning and hydroelectric plants. Unlike the rest of the utilities in the U.S., Maryland utilities during this period will not be adding any nuclear capacity.

Figure I-2 presents the electric utility industry's capacity and generation profiles for 1973 and 1984 and as projected by EIA for 1995. The capacity profile indicates the percentage breakdown of generating capacity by fuel type. The generation profile represents the percentage breakdown of kilowatt-hours generated from the various types of fuels. These data indicate a strong historical trend away from using oil and gas to generate electricity and toward coal and nuclear. Oil and gas fell from 35.2 percent of generation in 1973 to 18.3 percent in 1984. Over the next ten years, nuclear is expected to increase its share while the shares of coal, gas and oil will decline modestly.

It is interesting to note that oil and gas represent a larger percentage of capacity than generation. For example, in 1984 gas and oil-fired plants were more than 32 percent of capacity but only 18.3 percent of generation. This reflects the practice in the industry known as "economic dispatch," whereby utilities attempt to maximize usage of efficient, inexpensive-to- operate generating units and utilize their expensive-to-operate units only when necessary to serve loads.

Table I-3 compares the generation profiles of the U.S., MAAC, ECAR and each of Maryland's major electric utilities. The U.S. and Maryland figures are 1984 actuals, and the MAAC and ECAR figures are projections for 1985. As the table indicates, there are major differences among the Maryland utilities. APS is a virtually completely coal-fired system and is expected to remain so for the forseeable future.[1] APS thus closely resembles the ECAR region except that it has no nuclear generation. BG&E, with the Calvert Cliffs plant, is the most heavily nuclear. With Brandon Shores 2 coal plant and combustion turbine capacity planned for the 1990s, it will move toward a generation mix that more closely resembles the MAAC region. PEPCO generated nearly 90 percent of its energy from coal in 1984, and its mix is not expected to change very much over the next ten years. DP&L's mix most closely resembles that of the U.S., with the exception that it has no hydroelectricity. The Company has the highest percentage of oil generation among the Maryland utilities, but its percentage is roughly equal to the national average. Moreover, the 1984 figure of 18 percent is a dramatic reduction from the 53 percent experienced in 1979.

From the point of view of the customer, the principal concern is the rates that must be paid for electric service. Rate increases over the past decade have been brought about by a number of factors but particularly the addition of expensive new generating plant and rapidly escalating fuel prices. Other factors include general inflation (which affects many types of nonfuel operating costs), increases in interest rates and expenditures on other types of plant such as distribution facilities.

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[1]The Bath County Project, a large pumped storage hydroelectric plant recently brought into service by APS, does not change that fact because the plant supplies only capacity, no net amount of energy. Thus the primary energy source will continue to be almost exclusively coal.

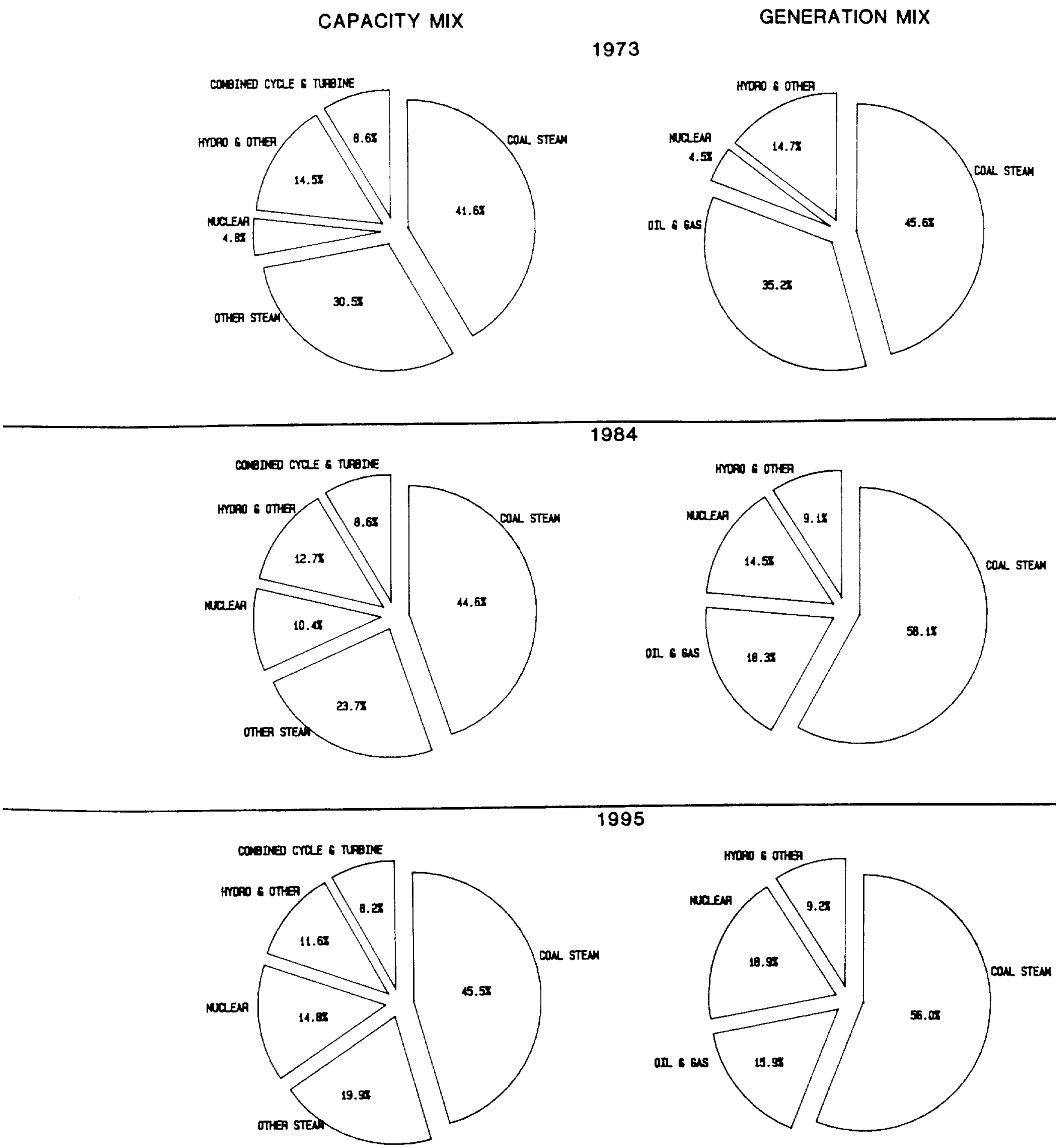

Figure I-2. Generation and Capacity Profiles of the U.S. Electric Utility Industry, 1973, 1984 and 1995. (Ref. 2)

Table I-3. Electricity Generation by Fuel Type, 1984(a)

	Coal	Nuclear	Oil/Gas	Hydro & Other
U.S.	58.1%	14.5%	18.3%	9.1%
MAAC	53.8	32.6	11.0	2.6
ECAR	93.1	6.1	--	0.8 (b)
APS	99.0	--	1.0	--
BG&E	38.0	54.0	4.0	4.0
DP&L	62.0	20.0	18.0	--
PEPCO	89.0	--	11.0	--

(a) Ref. 2, 9, 10, 11, 12. The MAAC and ECAR figures are projections for 1985.

(b) Figure also includes ECAR oil and gas generation.

The average residential rate (in cents per kWh) is shown in Table I-4 for selected years since 1973 for the U.S. and all four Maryland utilities. The cost figures are expressed both in actual year dollars and deflated by the national Consumer Price Index (CPI). On a nationwide basis, residential electric rates have consistently risen at a rate more rapidly than inflation. In fact, electric rates nationwide increased more rapidly than inflation between 1982 and 1984 even though other fuel prices (e.g., coal, petroleum and natural gas) failed to keep pace with inflation (1). Between 1978 and 1984, average residential electric rates in the U.S. increased at a rate of 9.8 percent per year, or 1.7 percent above the rate of inflation.

In general, the rates charged by the Maryland utilities compare favorably with the U.S. average. In 1984, three of the four major Maryland utilities charged rates below the U.S. average, with Potomac Edison's rate being nearly 20 percent below the average. DP&L's residential rate in 1984 was approximately 25 percent above the U.S. average, in part reflecting its use of oil-fired generation (without inexpensive hydro to offset it). However, DP&L's rate of increase since 1978, 9.5 percent, is slightly below the U.S. average. Each of the other three Maryland utilities have actually experienced modest real (i.e., inflation adjusted) declines in their residential rates since 1978.

Table I-4. Residential Electricity Price Trends(a) (cents/kWh)

	1973	1978	1982	1984	Average Annual Rate of Growth 1978-1984
U.S.(b)					
Actual	2.26%	4.16%	6.68%	7.30%	9.8%
CPI Adjusted	1.70	2.13	2.31	2.35	1.7
BG&E					
Actual	2.99	4.98	6.77	7.12	6.1
CPI Adjusted	2.25	2.55	2.34	2.29	-1.8
DP&L					
Actual	3.18	5.32	9.04	9.15	9.5
CPI Adjusted	2.39	2.73	3.13	2.94	1.2
Potomac Edison					
Actual	2.15	3.93	5.83	5.88	7.0
CPI Adjusted	1.62	2.02	2.02	1.89	-1.1
PEPCO					
Actual	2.63	4.94	6.69	6.43	4.5
CPI Adjusted	1.98	2.53	2.31	2.15	-2.7

(a) Figures are computed as average revenue per kWh for the residential class. Data from Ref. 1 and 13. Figures are total company rather than Maryland jurisdiction.

(b) U.S. prices were computed using the data published for a monthly bill of 750 kWh.

Residential rates in Maryland also compare favorably with those in neighboring states. The Department of Energy publication, Typical Electric Bills, reports that a residential monthly bill in Maryland for 1,000 kWh as of January 1984 costs $63.31. The corresponding bill would be $76.24 in Pennsylvania, $85.70 in New Jersey, $67.19 in Virginia, $91.21 in Delaware, $56.02 in West Virginia and $52.42 in the District of Columbia (21).

At the national level, the outlook for future rate increases is quite mixed. In general, the slow inflation and moderating interest rates would appear to suggest a favorable outlook. However, at present and during the next few years, a number of utilities will be bringing into service very expensive new generating plants. There has been considerable discussion of the "rate shock" that will result from these plant additions, and many utility commissions are considering and have considered phase-in plans to moderate the impacts on customers.

Assuming that rapid inflation and fuel price increases do not reemerge, Marylanders should not be facing large electric rate increases during the rest of the 1980s. The only utility with a major rate request pending at the present time is Potomac Edison, which is attempting to place the cost of the Bath County Project in rates. None of the other three Maryland utilities are planning on bringing large new plants on-line during the next several years.

D. Maryland's Electric Utility Industry

Households and businesses in Maryland obtain their electric service from four large and several smaller electric utilities. Each of these utilities fall into one of three main categories:

(1) Municipal utilities -- Several medium-sized and small towns in Maryland operate their own electric distribution systems. Virtually all of their power supply requirements are obtained from either the Potomac Edison Company (for Western Maryland municipals) or Delmarva Power & Light Company (for the Eastern Shore municipals). Only one municipal in Maryland presently generates a significant amount of its electricity. Despite the fact that they are publicly owned, the municipal utilities in Maryland are subject to Public Service Commission regulation.

(2) Rural electric cooperatives -- The cooperatives are operated by and for their members, with financing provided by the Federal Rural Electrification Administration. The cooperatives are also subject to Public Service Commission regulation. Maryland's cooperatives typically serve a sprawling rural and in some cases multistate service area, but they also serve some small to medium-size towns. None of Maryland's cooperatives have any significant amount of generation capacity, although the Eastern Shore cooperatives have plans for acquiring some in the 1990s. At present, almost all of their power needs are supplied by the major investor-owned utilities.

(3) Investor-owned utilities -- Typically, these are large, integrated electric systems engaged in the production, transmission and sale of electricity. Such systems often operate in more than one state and may also sell power at wholesale to smaller distribution utilities. The vast majority of Maryland customers (approximately 85 percent) are served at retail by the four major investor-owned utilities, and these four systems produce nearly all of the power consumed in the State. Three of these four major utilities are multistate.

There has been a resurgence of interest in the last few years in developing non-utility or customer-owned sources of generation. Customers may either sell their generation of power to their local utility or they may use it to serve their own requirements, thus displacing utility-produced power. Currently, the Bethlehem Steel facility at Sparrows Point and the Westvaco Corporation in Luke, Maryland generate much of their own power requirements. A more extensive discussion of non-utility power sources is presented in Chapter VIII.

The areas of Maryland served at retail by the various utilities are shown in Figure I-3. The towns identified on the map are the municipal utilities, and those utilities with no retail customers in Maryland are excluded entirely. The service territories of the Eastern Shore rural cooperatives are diffuse and difficult to show in sharp detail on a map this size. Consequently, there is only a general indication of the regions of Maryland that they serve rather than a sharp delineation of the service area. Finally, several of the utilities have significant service territory outside of Maryland or are part of multistate systems.

The Municipal Utilities and Rural Cooperatives

The municipal utilities and rural electric cooperatives operating in Maryland are listed on Table I-5, along with summary operating data. Taken as a group, these utilities serve approximately 10 percent of Maryland's electric customers. Their 1984 sales were 2.0 million MWh with a combined (noncoincident) peak demand of 455 megawatts. However, it should be noted that one utility, the Southern Maryland Electric Cooperative (SMECO), accounted for over half of that total. These utilities possess only 74 megawatts of capacity, making them highly dependent on outside sources of power. Generation in 1984 totalled 87,000 MWh or less than 5 percent of these utilities' total requirements, and virtually all of that was from Easton Utilities.

Five municipal utilities operate in Maryland as listed in Table I-5. Berlin, located on the Eastern Shore near Ocean City, serves approximately 1,200 customers. It obtains most of its power from DP&L on a wholesale basis, but it also operates combustion turbine capacity for peak shaving purposes. The Eastern Shore towns of St. Michaels and Centreville operated municipal systems at one time but were recently acquired by DP&L.

Easton Utilities provides gas and electric service to its approximately 5,600 customers near the Bay side of the Eastern Shore. Easton owns 48 megawatts of capacity which is well in excess of its peak load. However, it

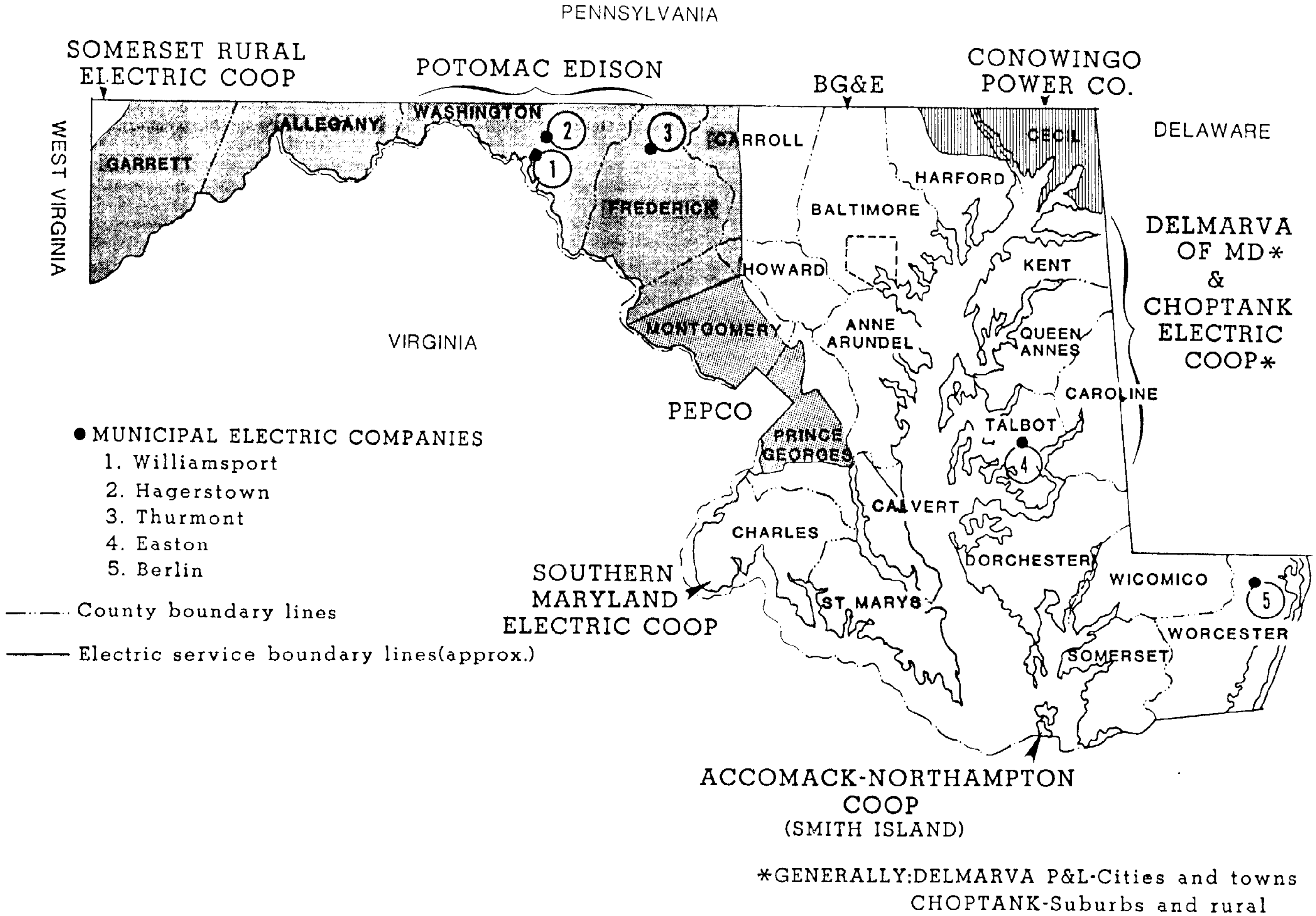

Figure I-3. Service Territories of Maryland Electric Utilities

Table I-5. Municipal Utilities and Rural Electric Cooperatives in Maryland, 1984(a)

Utility	Sales (MWh) Residential	Nonresidential	Total	Peak Demand (MW) (b)	Installed Capacity (MW)	Generation (MWh)	Retail Customers	Power Supply
Municipals								
Berlin	7,727	16,288	24,015	5.4 (w)	3.6	1,424	1,225	DP&L
Easton	70,767	86,588	157,355	27.5 (w)	47.8	85,589	5,592	DP&L & Self
Hagerstown	89,211	143,106	232,317	43.9 (s)	23.0	-0-	17,188	PE
Thurmont	5,666	32,858	38,524	8.2 (w)	-0-	-0-	1,495	PE
Williamsport	7,342	5,143	12,485	3.7 (w)	-0-	-0-	795	PE
Cooperatives								
A&N(c)	53,148	46,001	99,149	22.0 (s)	2.8	8	8,235	DP&L
Choptank	248,309	89,804	338,113	78.0 (w)	-0-	-0-	26,583	DP&L
Somerset(c)	86,550	65,468	152,018	NA	-0-	-0-	9,891	Alleg. Coop
SMECO	736,503	503,306	1,239,809	288.0 (s)	-0-	-0-	69,060	PEPCO
Total(d)	1,165,525	877,093	2,042,618	454.7	74.4	87,013	121,938	

(a) Data from utility annual reports. Data for Berlin are 1982 since 1984 are not available.

(b) "w" denotes winter peak, and "s" denotes summer peak.

(c) Figures for A&N and Somerset include their non-Maryland operations.

(d) Excludes A&N and Somerset.

still purchases substantial amounts of power from DP&L (on an interchange basis) because its own generating units are oil-fired and therefore expensive to operate.

Thurmont and Williamsport both operate very small municipal systems in Western Maryland. Both are full requirements customers of Potomac Edison, although Williamsport is investigating a small-scale hydroelectric project which could displace some of Potomac Edison's power. In 1984, Thurmont served approximately 1,500 customers compared to 800 for Williamsport.

Hagerstown is Maryland's largest municipal utility, serving over 17,000 customers and selling over 230,000 MWh in 1984. The City owns approximately 48 megawatts of generating capacity but does not operate it since it is less expensive to purchase the power wholesale from Potomac Edison.

In addition to the municipals, four rural electric cooperatives operate in Maryland. However, two of the four, A&N which serves Smith Island and Somerset which serves the northwest corner of Garrett County, each have only a few hundred Maryland customers. Those two cooperatives primarily operate in Virginia and Pennsylvania, respectively.

Maryland's two major cooperatives are Choptank Electric Cooperative and the Southern Maryland Electric Cooperative (SMECO). Choptank serves approximately 25,000 customers spread largely over the more rural sections of Maryland's Eastern Shore counties. It is a full requirements customer of DP&L at present, but it plans to participate in Nanticoke No. 1 baseload coal plant expected in service in the mid-1990s. Three cooperatives, Choptank, A&N and Delaware Electric, plan on acquiring a total of 50 megawatts of that plant through their umbrella organization, Old Dominion Electric Cooperative. This capacity will reduce their dependence upon power purchases from DP&L.

SMECO is the largest public power entity in Maryland, although it is considerably smaller than any of the four major investor-owned utilities. In1984, it sold 1.2 million MWh to its 69,000 customers. SMECO is a full requirements customer of PEPCO and has no plans to construct its own generating capacity. However, it is reducing its peak load (or the rate of growth in its load) through load management and in this manner is reducing its dependence on PEPCO. SMECO's load is approximately 7 percent of the PEPCO system.

The Investor-Owned Utilities

Seven investor-owned utilities operate in Maryland. However, two of the seven have no retail customers in Maryland, and one other functions purely as a distribution utility. The other four investor-owned utilities have both generation capacity and extensive retail operations in Maryland. Data for these seven utilities are listed on Table I-6.

Pennsylvania Electric Company (Penn Elec), an operating subsidiary of General Public Utilities (GPU), is a major, integrated utility in Pennsylvania. However, its presence in Maryland is limited to the operation of a small hydroelectric facility located at Deep Creek Lake in Garrett County. The power from that facility is exported out of Maryland into the GPU grid.

Table I-6. Maryland Investor-Owned Utilities, 1984(a)

Utility	Sales (Thousand MWh) Residential	Sales (Thousand MWh) Nonresidential	Sales (Thousand MWh) Total	Generation (Thousand MWh)	Peak Demand (MW)(b)	Installed Capacity (MW)	Customers
APS(c)	9,411	21,655	31,066	39,503	6,035 (w)	7,109	1,180,500
BG&E	6,897	12,338	19,235	20,986	4,230 (s)	5,498	894,177
Conowingo	244	233	477	-0-	99 (w)	-0-	27,108
DP&L	2,249	6,059	8,308	10,691	1,578 (s)	2,225	308,154
Penn Elec	-0-	-0-	-0-	26	-0-	19	-0-
PEPCO	4,645	14,262	18,907	18,537	4,490 (s)	5,375	553,073
Susquehanna	-0-	-0-	-0-	2,085	-0-	512	2
Total	23,446	54,547	77,993	91,828	16,432	20,738	2,963,014

(a) With the exception of Penn Elec, figures include non-Maryland portions of the system. Data from Company annual reports.

(b) "w" denotes winter peak, and "s" denotes summer peak. The APS peak is for the winter of 1984/1985.

(c) Excludes sales to nonaffiliated utilities.

Susquehanna Electric Company, a subsidiary of Philadelphia Electric Company (PECO), operates the 512-megawatt Conowingo hydroelectric facility which it leases from the owner, its corporate affiliate, Susquehanna Power Company. The power from the Dam is then sold at wholesale to PECO, its parent company. Neither Susquehanna company has retail operations in Maryland or anywhere else.

Conowingo Power Company is the Maryland retail subsidiary of Philadelphia Electric Company, serving approximately 27,000 customers in Cecil County. Conowingo functions purely as a distribution utility receiving virtually all of its power from its parent. The rates that it must pay for that power are established by the Federal Energy Regulatory Commission (FERC) rather than the Maryland Public Service Commission and are passed on directly to its customers. In 1984, Conowingo experienced a peak demand of 99 megawatts.

The majority of Maryland households and businesses are served by the remaining four investor-owned utilities -- BG&E, PEPCO, DP&L and Potomac Edison. Moreover, those four also generate and transmit almost all of the electricity consumed in the State. Detailed descriptions of their service territories, operations and expansion plans are presented in the final section of this chapter.

Interactions Among Utilities

Although each utility system in Maryland is a separate entity, there is a high degree of interaction and coordination among the Maryland utilities and between Maryland and non-Maryland utilities. Table I-7 summarizes the wholesale power arrangements in Maryland. BG&E has no wholesale customers, and PEPCO has only one -- SMECO. The situation is more complicated for Potomac Edison and DP&L. Both companies have extensive wholesale arrangements in Maryland and in the non-Maryland portions of their service territories. As indicated earlier, Philadelphia Electric Company has two subsidiaries operating in Maryland, one of which sells power on a wholesale basis to Philadelphia Electric (Susquehanna), and the other purchases wholesale power from Philadelphia Electric (Conowingo). All of these wholesale transactions are regulated by the Federal Energy Regulatory Commission (FERC) rather than by the Maryland Public Service Commission.

Another level of coordination and interaction among the investor-owned utilities is the formation of multi-utility power pools. Potomac Edison and its two corporate affiliates form the APS power pool. The units owned by all three utilities are centrally dispatched, and generation capacity additions are centrally planned. Power exchanges take place among the three utilities on a daily basis as a result of the central dispatch procedures. The goal of this arrangement is to operate all generating units in a coordinated fashion so as to achieve the minimization of fuel costs. The pricing of these power transactions is governed by the APS Power Supply Agreement.

Table I-7. Power Supply Relationships Among Maryland's Electric Utilities

I. Investor Owned

BG&E - no wholesale customers.

DP&L - sells wholesale to Choptank, Berlin, A&N and on an interchange basis with Easton.

PEPCO - sells wholesale to SMECO.

PE - subsidiary of APS; sells wholesale to Hagerstown, Thurmont, and Williamsport.

Conowingo - full requirements customer of Philadelphia Electric.

Penn Elec - exports all of its power out of Maryland.

Susquehanna - sells Conowingo Dam output to Philadelphia Electric.

II. Municipals

Easton - interchange arrangement with DP&L.

Berlin - purchases power from DP&L.

Hagerstown - purchases power from Potomac Edison.

Thurmont - purchases power from Potomac Edison.

Williamsport - purchases power from Potomac Edison.

III. Rural Electric Cooperatives

SMECO - purchases power from PEPCO.

Choptank - purchases power from DP&L.

A&N - purchases power from DP&L.

Somerset - purchases power from several sources including APS.

PEPCO, BG&E and DP&L are all members of the Pennsylvania-New Jersey-Maryland (PJM) Interconnection power pool. In addition to the three Maryland members, the pool includes nearly all electric utilities operating in New Jersey and Pennsylvania. Major exceptions are West Penn Power (which is part of APS), Duquesne Light and Pennsylvania Power Company (a subsidiary of Ohio Edison Company). PJM is considered to be one of the three "tight" power pools in the U.S. (excluding holding companies), the other two being the New York and New England power pools. PJM attempts to provide economic dispatch for the entire multistate region rather than on merely an individual utility basis. Operationally, this means that a member utility at any given hour will purchase increments of energy from the pool if doing so is less costly than generating. In practice, however, there are practical limits to achieving the full potential benefits of economic dispatch, principally as a result of constraints on the transmission grid.

Power pooling is facilitated by the PJM Interconnection Office located in Valley Forge, Pennsylvania. That office stays in continual communication with the dispatch centers of member utilities, collecting load, availability and cost data on all units. It then signals to the dispatchers the PJM "system lambda" which is the pool-wide incremental cost of generating a kilowatt-hour. In this manner fuel cost savings are achieved. Power transactions among the PJM companies are normally priced at the "split savings" rate, i.e., halfway between the running rate (i.e., the cost of generating an additional kilowatt-hour) of the selling utility and the operating cost that the buying utility would have incurred had it generated rather than purchased the power. Unlike APS, the individual PJM companies perform their own planning of new facilities. PJM performs the role of coordination of generation and transmission construction and maintenance. Power pooling thus helps to bring about more economical use of existing generating plant, coordination among members of future capacity additions, and improved power supply reliability.

In addition to participating in power pools, the Maryland utilities are members of regional reliability councils. In 1968, the North American Electric Reliability Council (NERC) was formed in order to promote the reliability of bulk power supply in North America. It presently includes nine regional councils and one affiliate which encompass virtually the entire U.S. and Canada. The regional councils are voluntary associations and are not directly regulated, although they do provide regular reports to the U.S. Department of Energy. Their chief function is to monitor loads and power resources and conduct studies of reliability. The councils also establish certain reliability standards such as spinning reserve requirements. PEPCO, BG&E and DP&L are members of the Mid-Atlantic Area Council (MAAC), and Potomac Edison is a member of East Central Area Reliability Coordination Agreement (ECAR).

The various power systems engage in transactions with other power systems outside the scope of power pooling. For example, APS has been selling large quantities of power to PJM companies for the last several years. This is because APS has had a surplus of low-cost, coal-fired generation which can be used to displace the expensive oil-fired generation of PJM companies. In addition to these economy or opportunistic sales, it has engaged in longer term firm power commitments to Public Service Electric and Gas Company and Atlantic City Electric Company. For the past several years, it has maintained a diversity exchange with Virginia Electric Power Company (VEPCO) whereby APS provides up to 300 megawatts of summer season power in exchange for a like amount of winter season power from VEPCO. This is an advantageous arrangement since APS is winter peaking and VEPCO summer peaking. PEPCO has acquired 150 megawatts of coal-fired power from the Ohio Edison Company using the transmission facilities of APS. The length of the arrangement is indefinite but for a minimum of five years. In general, there has been a great interest in the so-called west-to-east power transfers from the Ohio Valley region as a result of surplus, low-cost power in that region and the high cost of generating additional quantities of energy in this region. The prospects for future power imports are discussed in Chapter II.

Finally, power systems may also interact through joint ventures. APS owns 40 percent of the Bath County Pumped Storage Project which began commercial service in December 1985 with the other 60 percent owned by Virginia Electric Power Company (VEPCO). All of the major Maryland utilities jointly own one or more of their existing generating plants with another utility. Shared ownership is one means for a utility to reduce its dependence on a very few number of generating units and thereby reduce its risk.

The relative importance of these off-system transactions (i.e., sales to or purchases of power from other utilities) to Maryland utilities is demonstrated by Table I-8 below. The term "system sales" refers to the utility's electricity sales to its regular retail and wholesale customers. Interchanges are generally short-term, "opportunity" sales (or purhcases) that utilities make with each other to reduce power costs or for reliability purposes such as in power pooling arrangements. The "purchases" and "other sales" on this table refer to off-system transactions among utilities that are not classified as interchange. As indicated, interchange sales, either interchange imports or exports, are quite large relative to system sales of electricity. DP&L's interchange exports are one-third the size of its electric sales, while PEPCO's interchange imports are 30 percent of the size of its sales. For Potomac Edison, additional sales above and beyond interchanges (classified as sales for resale) are 46 percent of the size of the Company's retail sales. BG&E's off-system sales constitute the smallest percentage, with interchange exports 15 percent the size of system sales. Of these four utilities, only PEPCO was a net power importer in 1984.

It is important to understand that these import and export figures relate to these utility systems rather than whether the State of Maryland itself is an importer or exporter. For example, this table indicates that both DP&L and Potomac Edison are net exporters of power. However, the Maryland customers of these two companies consume far more power than these same two utilities produce in Maryland. On a statewide basis, approximately 38.4 million megawatt-hours was consumed in Maryland in 1984 compared to net generation of 35.7 million megawatt-hours, indicating that Maryland is a net power importer (14). These imports came from power plants owned by Maryland utilities but located outside the State and to a lesser extent by purchases from non-Maryland utilities. Since the next major plant in the State (Brandon Shores 2) is not expected to be in service until the early 1990s and power demands are expected to grow, Maryland's status as a net importer is likely to continue over the next several years.

Table I-8. 1984 Off-System Transactions of Maryland Utilities(a) (Thousand MWh)

	DP&L	BG&E	PEPCO	Potomac Edison
System sales(b)	8,308	19,235	18,907	8,727
Purchases from other utilities	916	2,307	5,665	2,811
Sales to other utilities	2,833	2,794	4,214	3,755
Net exports(c)	(1,917)	(487)	1,451	(944)

(a) Source is company annual reports for 1984 to the Maryland Public Service Commission.

(b) System sales refers to those electricity sales the utility makes to its regular retail and wholesale customers.

(c) Figures in parentheses indicate company is a net exporter. Net exports are defined here as sales to other utilities minus power purchased from other utilities. Other utilities referred to above would not include regular wholesale customers such as the municipal and rural cooperative distribution utilities.

E. Service Areas and Capacity Plans of Maryland's Major Electric Utilities

Baltimore Gas & Electric Company

BG&E serves a population of approximately 2.4 million people in a 2,300-square mile area. This area includes Baltimore City and most or all of Baltimore, Anne Arundel, Harford, Carroll and Howard counties and very small portions of Calvert, Montgomery and Prince George's counties. Thus, the service area roughly corresponds to the Census Bureau's Baltimore Standard Metropolitan Statistical Area. In 1984, BG&E experienced a peak load of 4,230 megawatts compared to 5,498 megawatts of generating capacity.

The economy of this region is diverse. Baltimore City and County contain considerable heavy and light manufacturing activity, and one of the East Coast's largest international ports. Baltimore is also a major commercial center. The Baltimore area economy has been substantially dependent on its heavy manufacturing base but will probably be less so in the future. Manufacturing activity is not expected to grow rapidly; the impetus for growth is instead expected to come from the commercial sector. In 1970, manufacturing accounted for 22 percent of the Baltimore region employment, but this percentage has fallen significantly over the past decade. The Maryland Department of State Planning (DSP) projects that by 1990 manufacturing will comprise only 14 percent of total employment, while the service sector and government will experience significant gains. This relatively stagnant outlook for manufacturing implies slow growth for total nonresidential electric energy demand. This is because energy consumption per employee is generally much greater in the manufacturing sector (particularly heavy manufacturing) than in the commercial sector.

Electricity demand has reflected the changing economic conditions facing businesses and households. Prior to the mid-1970s, electricity consumption grew rapidly in response to rapid growth in the economy and favorable electricity rates. Since then, economic growth has slowed considerably. As shown in Table I-9, electricity demand growth slowed noticeably for each major customer class and for peak demand. The year 1973 is shown on that table as the intermediate point since that was the year of the oil embargo. The most dramatic change has been a decline in peak demand growth from 9.1 percent per year during the earlier period to 2.2 percent per year since then. Load growth between 1973 and 1982 was relatively slow. The 1984 peak, however, is a substantial 7.8 percent above the 1982 figure.

It is also worth noting that the system annual load factor (i.e., the ratio of average hourly demand during the year to the one-hour annual peak demand) has improved somewhat since 1973. The system load factor is an important characteristic of a utility system. The higher the load factor, the less generating capacity (plus reserve margin) needed to reliably serve a given

Table I-9. Growth in Energy and Peak Demand on the BG&E System(a)
(Thousands of MWh)

				Annual Average Growth Rates	
	1966	1973	1984	1966-1973	1973-1984
Residential	2,347	4,618	6,897	10.2%	3.7%
Commercial	1,771	2,582	3,264	5.5	2.2
Industrial	4,365	6,845	9,074	6.6	2.6
Total	8,653	14,341	19,235	7.5	2.7
Peak Demand (MW)	1,817	3,334	4,230	9.1	2.2
Load Factor	58.9%	52.7%	55.2%		

(a) Data from Ref. 15 and 18.

volume of kilowatt-hour sales. In recent years, BG&E's load factor has been improving due to greater adoption of electric space heating, particularly in new homes. This increases winter demands (and thus annual sales), but has no effect on summer demand when the BG&E system experiences its annual peak. The introduction of time-of-day rates (i.e., higher rates during hours of heaviest demand) for large nonresidential customers may have also contributed to the improvement.

Important economic and demographic shifts have taken place within the Baltimore region. The economies of Baltimore City and County, the two largest entities in the area served by BG&E, have been stagnant relative to the rest of the area. Over the past decade and a half, the City has experienced a significant net loss of both employment and population. At the same time the newer, rapidly suburbanizing areas, particularly Anne Arundel and Howard counties, have been growing rapidly, creating a need for new electrical distribution facilities in those areas. To some extent these geographic trends mirror the sector trends. Heavy manufacturing, primarily located in Baltimore City and County, has been gradually declining in comparison to commercial activity, light manufacturing and government.

These economic trends are expected to continue. For example, the latest Maryland Department of State Planning projections expect that Baltimore City's population will continue to decline though at a slower rate than in the past. Howard and Anne Arundel counties are expected to continue to grow considerably more rapidly than the rest of the State, but at a slower rate than in the past. These trends toward a declining heavy manufacturing sector and increased suburbanization tend to offset to some degree the improvement in load factor afforded by increased use of electric space heating. This is because manufacturing traditionally is the sector with the highest load factor of any customer group.

BG&E obtains most of its power from a mixture of nuclear and coal-fired plants. In 1984, the Calvert Cliffs nuclear plant supplied approximately 54 percent of the system generation, compared to 38 percent for coal, and 4 percent each for oil and hydro. The coal percentage is likely to increase in 1985 and future years since the Brandon Shores 1, a 600-megawatt coal unit, entered service in May 1984. It is interesting to note that the Calvert Cliffs plant accounted for 54 percent of generation that year even though it accounted for only 30 percent of installed capacity. This reflects the operation of economic dispatch described earlier, and also the Company's ability to maintain a high level of availability at that plant. The Company's next planned capacity addition involves expansion of the Safe Harbor hydroelectric plant in 1987 and Brandon Shores Unit 2, another 620-megawatt coal-fired plant, expected in service in the early 1990s. Finally, BG&E is planning to add 200 megawatts of combustion turbine capacity and a 400-megawatt coal unit in the late 1990s.

Electric utilities usually seek and obtain increases in electric rates when major new generating plants enter service, and BG&E is no exception. With Brandon Shores 1 entering service in 1984, the Maryland Public Service Commission awarded BG&E an increase in its electric rates of $61 million (approximately a 5 percent increase) (15). The Company had requested an increase of almost twice that amount. Factoring in associated fuel savings, BG&E estimates that Brandon Shores 1 was brought "on line at less than a 2% net increase in our customers' electric bills" (15).

Potomac Electric Power Company

PEPCO serves a population of 1.75 million in a retail service territory of 643 square miles. This encompasses the entire District of Columbia, most of the D.C. suburban Maryland counties of Prince George's and Montgomery and a very small section of Arlington County, Virginia.[1] PEPCO also supplies all of the power requirements of SMECO. Including SMECO, Maryland accounts for slightly more than half of the PEPCO load, and the vast majority of the Company's generating capacity is located in Maryland. On a systemwide basis, PEPCO's 1984 peak demand was 4,490 megawatts compared to 5,375 megawatts of generating capacity.

There are important differences among the three major geographic regions comprising the PEPCO system. The District is a highly urbanized environment of government and commercial office buildings and large apartment complexes. The suburban Maryland region is largely residential with a large retail trade sector. However, a significant amount of commercial and office building type of development is occurring in those suburban areas. The Southern Maryland region, served only indirectly by PEPCO, is largely rural and small town but with some suburban development.

The distinguishing aspect of the PEPCO area economy is the virtual absence of any heavy manufacturing. The small amount of manufacturing that does exist is mainly food processing, publishing and other activities that tend not to be energy-intensive. PEPCO, in fact, is one of the few major investor-owned utilities in the U.S. without a large industrial load. This fact, coupled with the very high air conditioning saturation percentage, accounts for the relatively low annual load factor on the PEPCO system. PEPCO lacks a large base of high load factor customers. The principal "industry" in the PEPCO service area is the federal government and firms supplying services to the federal government. The lack of a large manufacturing base coupled with the relatively stable federal presence tends to insulate this area from the effects of the business cycle. For example, at the height of the last recession in 1982 nationwide unemployment was 9.7 percent, nearly double the 5.5 percent rate in the Washington, D.C. area (16). Other than the effects of weather, serving this type of local economy makes PEPCO's energy sales more stable than in regions that are highly industrialized.

Major increases in employment in the Washington, D.C. area have occurred during the last decade. Over this time period, manufacturing has remained at less than 4 percent of total employment. Government employment has expanded very slowly, and has therefore gradually declined as a share of total employment. The service/financial sector has expanded at an above average rate and is now the largest sector in the local economy (17).

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[1]PEPCO presently is planning to transfer its very small Virginia service area to VEPCO, the utility which serves most of Northern Virginia. However, PEPCO will maintain ownership of all of its generating units located in Virginia.

The rate of growth of power demands on the PEPCO system has fallen off sharply since 1973, as shown below on Table I-10. Prior to that year, sales grew at an annual rate of more than 8 percent per year, compared to less than 3 percent per year since 1973. Peak demand growth has slowed even more dramatically, down from 8.2 percent per year prior to 1973 to 1.8 percent per year since 1973. This pronounced difference in the sales and peak growth rates means that the PEPCO system annual load factor has been slowly but steadily improving. Sales to SMECO has been the most rapidly growing major sector on the PEPCO system as the Southern Maryland region continues to develop.

There are several identifiable factors accounting for the decline in demand growth. Although economic development in the Washington area has occurred in recent years, it has done so at a slower rate than in the past (i.e., prior to the early 1970s). For example, federal employment in the D.C. area has been virtually stagnant over the past decade. Moreover, a disproportionate amount of the growth that has occurred has been in the portions of the Washington area not served by PEPCO -- the suburban sections of northern Virginia and the northern extremities of Prince George's and Montgomery counties. The District, like many inner cities, has been experiencing a population decline.

Table I-10. Growth in Sales and Peak Demand on the PEPCO System(a) (Thousands of MWh)

				Annual Average Growth Rates	
	1966	1973	1984	1966-1973	1973-1984
Residential	1,978	3,529	4,645	8.6%	2.5%
Nonresidential	5,661	9,704	12,956	8.0	2.6
Sales to SMECO	330	755	1,306	12.6	5.1
Total	7,969	13,988	18,907	8.4	2.8
Peak Demand	2,123	3,680	4,490	8.2	1.8
Load Factor	46.5%	46.7%	50.8%	--	--

(a) Data from Ref. 18 and 19.

It should be pointed out that the summary data listed in Table I-10 mask some recent changes that have occurred. Although total sales have increased by only 2.8 percent per year since 1973, increases of 5.7 percent and 4.5 percent occurred in 1983 and 1984, respectively. The 1984 annual peak exceeds the 1982 peak by 8.3 percent. Thus PEPCO's recent growth experience differs significantly from that of the period 1973 to 1982 and may signal a new trend for PEPCO. This reemergence of rapid growth has been accompanied by stable electricity prices. The average cost per kWh of electricity to PEPCO consumers in 1984 was approximately equal to the average cost in 1982 in nominal terms, which means that in inflation-adjusted terms, the cost per kilowatt-hour to customers declined by approximately 7 percent. These favorable price trends have helped to encourage the recent sales growth.

PEPCO meets its power demands principally with coal-fired generation, but it also employs some oil-fired generation and purchased power. As was indicated earlier in this chapter, PEPCO has a long-term contract for 150 megawatts of firm power from the Ohio Edison Company. The Company owns no hydroelectric or nuclear plants. In 1984, 89 percent of PEPCO's generation came from coal and the remaining 11 percent from oil; the coal figure represents a slight decline from 1982 when coal accounted for 92 percent of generation. Although oil accounted for only 11 percent of PEPCO's 1984 generation, it is nearly 44 percent of PEPCO's total generating capacity. This reflects the use of economic dispatch and the Company's ability to substitute purchased power for oil generation.

PEPCO's plans to meet future loads consist of three major elements --delayed unit retirements, load management and new capacity. Over the next several years, PEPCO will be refurbishing its Potomac River coal-fired units under its life-extension program. This program will enable PEPCO to avoid retiring those units and replacing them with new capacity. PEPCO has also recently proposed its Energy Use Management Program (EUM) which consists of amajor expansion of time-of-use rates, direct control of residential air conditioners and water heaters and curtailable rates for large commercial establishments. PEPCO estimates this program will reduce peak demand growth by about 440 megawatts systemwide with little impact on total usage of energy. A more detailed discussion on this program is presented in Chapter II. The proposed program is currently before the Maryland and District Public Service Commissions awaiting approval. Finally, PEPCO expects to construct approximately 300 megawatts of new capacity in the mid-1990s and another 300 megawatts in the late 1990s. This new capacity is likely to be either baseload coal or gasification combined cycle.

Delmarva Power & Light Company

DP&L serves directly or indirectly the Delmarva Peninsula -- a geographic region which includes the entire State of Delaware, the Maryland Eastern Shore and two Virginia counties. This region contains about 5,700 square miles and a population of 860,000. In 1984, DP&L's peak was 1,578 megawatts compared to 2,225 megawatts of installed capacity. Maryland accounts for approximately one-quarter of that load.

Whereas DP&L supplies about 95 percent of the peninsula's bulk power supply, it supplies retail service to only about 70 percent of the population. The rest obtain retail service from one other small, privately-owned utility (Lincoln & Ellendale), nine municipal electric systems and three rural electric cooperatives.[1] All of these utility systems are full requirements customers of DP&L (meaning that DP&L is their only source of power) except for Dover, Delaware and Easton, Maryland. Those entities have their own generation (mostly oil-fired) and buy and sell energy with DP&L on an interchange basis in order to minimize power supply costs. Both municipals are therefore fully integrated with DP&L even though they are not actually dependent upon DP&L.

Some energy is also generated by industrial companies for their own use. Dupont's Seaford, Delaware nylon plant generates most of the power that it consumes and purchases back-up power from DP&L. A small amount of energy from the Texaco joint steam-electricity facility is produced in excess of refinery requirements and is sold to DP&L.[2]

Except for a major manufacturing and urban center in and around Wilmington, Delaware, the peninsula is a largely rural region. Outside of the Wilmington area, a large food processing industry has emerged as a natural complement to the peninsula's agriculture and fishing base. In addition, there are several popular ocean and bay resorts, the largest being Ocean City, Maryland. Maryland is slightly more than one-fourth of DP&L's total load, but virtually all of the peninsula's heavy industry is located in Delaware. The Virginia service territory is quite small and accounts for less than 5 percent of the peninsula's power demands.

Differences in electricity usage among the three states making up the DP&L system are shown below in Table I-11 for 1984. In 1984, Delaware accounted for 70.8 percent of DP&L total sales (including sales for resale) compared to 25.5 percent for Maryland and 3.7 percent for Virginia. There are also important differences in the sectoral or customer class compositions in the three states. In Delaware, the industrial sector predominates as a result of that state's heavy industry, particularly the very energy-intensive chemicals industry. The decline of heavy manufacturing in Delaware is the factor most responsible for the very slow growth in energy sales which has occurred since the mid-1970s. Both Maryland and Virginia have substantial percentages of their work force in manufacturing, but it is principally in food processing, a sector that makes extensive use of labor but is not particularly energy-intensive. The relatively high percentages for the commercial sector in Maryland and Virginia

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[1]This discussion excludes Maryland's Cecil County which is principally served by Conowingo Power Company. It should also be noted that the towns of St. Michaels and Centreville operated municipal distribution systems until a few years ago. They have since been absorbed into the DP&L system and are not served directly at retail by DP&L. DP&L has finalized negotiations to purchase the Lincoln & Ellendale utility and has submitted its request for ownership to the Delaware Public Service Commission.

[2]Delmarva's relationship with the Texaco refinery is a complicated one. The Delaware City units are operated by DP&L but provide steam and electricity to the refinery.

reflect the importance of tourism and the fact that agricultural is often classified as commercial. Sales for resale are also of far greater importance in Maryland and Virginia than in Delaware, reflecting the more rural character of the former two portions of the peninsula. The largest amounts of sales for resale are to the rural electric cooperatives that operate in all three states on the peninsula.

As shown on Table I-12, DP&L has experienced an unusually sharp reduction in its electricity sales growth since 1973. This reduction in the rate of growth has occurred in every sector, but it has been most pronounced in the industrial sector. The State of Delaware, not unlike many other areas of the Northeast and upper Midwest, has experienced stagnation in its heavy industrial sector in recent years. Industrial power consumption in 1984 (a relatively good year for the Delmarva economy) was below that of 1979 and only marginally above 1973 levels. DP&L's nonindustrial sales since 1973 have increased by approximately 3 percent per year. Another important trend to note is that peak demand has been growing even more slowly than energy sales since 1973, leading to a gradually improving annual load factor. This is due principally to the widespread adoption of electric heating in new homes and in many commercial buildings. The annual peak demand figure of 1,578 megawatts listed below is from the summer of 1984. However, in January 1985 the peak reached 1,646 megawatts indicating that the DP&L system under unusual weather conditions can peak in the winter season.

Table I-11. Distribution of Electricity Sales on the DP&L System, 1984(a)

	Delaware	Maryland	Virginia	Total DP&L
Total Sales				
1000's MWh	5,928	2,140	311	8,379
% of DP&L	70.8%	25.5%	3.7%	100%
Customer Class Distribution				
Residential	23.3%	36.5%	28.0%	26.8%
Commercial	23.3	28.9	27.0	24.9
Industrial	39.3	13.3	10.0	31.5
Resale	13.6	20.8	34.6	16.2
Other	0.6	0.5	0.4	0.6

(a) Data from Ref. 11.

Table I-12. Growth in Sales and Peak Demand for the DP&L System(a) (Thousands of MWh)

	1966	1973	1984	Annual Average Growth Rates 1966-1973	1973-1984
Residential	839	1,630	2,249	10.5%	3.0%
Commercial	719	1,360	2,073	9.8	3.9
Industrial	1,510	2,513	2,570	7.6	0.2
Resale & Other	570	1,253	1,416	11.9	1.1
Total	3,638	6,756	8,308	9.2	1.9
Peak Demand (MW)	661	1,489	1,578	10.8	0.5
Load Factor	67.8%	55.8%	64.1%		

(a) Data from Ref. 18 and 20.

At the present time, DP&L has more than sufficient generation resources to meet peak load, with a reserve margin of 37 percent in 1984. Delmarva uses a reserve margin of 18 percent for planning purposes (11). In 1984, DP&L generated 62 percent of its power from coal, 20 percent from nuclear fuel and 18 percent from gas and oil. Of particular significance is the fact that Delmarva has moved away rapidly from dependence on oil-fired capacity over the last few years. For example, in 1979 oil and gas accounted for 53 percent of DP&L's generation. That percentage fell sharply in 1980 when Indian River Unit No. 4, a 412-megawatt coal-fired unit entered service. Delmarva has also converted two of its Edge Moor units from oil to coal since that time and retired two other oil-fired units.

DP&L will not be bringing any new generating capacity on-line for the next few years. In 1981, it obtained licensing authority from the Maryland Public Service Commission to construct a new 500-megawatt coal-fired plant (Nanticoke No. 1) at the Vienna site in Maryland. That unit, which was originally intended for the late 1980s, is now not expected until the mid- 1990s and has been scaled back to 200 megawatts. Other means under consideration for meeting loads include life-extension programs at existing generating units and load management.

The Allegheny Power System

APS is a holding company with three operating utility subsidiaries: the Potomac Edison Company (PE), the Monongahela Power Company (MP) and the West Penn Power Company (WPP). All three utilities operate and plan bulk power supply facilities jointly. These three companies serve a sprawling, largely rural service territory which extends over five states, six regulatory jurisdictions, approximately 86 counties and 29,000 square miles. Although nearly 2.9 million people inhabit this region, the largest city in the APS service territory is Parkersburg, West Virginia with a population of only 44,000.

In the winter of 1984/1985, APS experienced a peak demand of 6,035 megawatts compared to installed capacity of 7,109 megawatts. That capacity figure excludes approximately 300 megawatts of oil-fired steam capacity placed in cold reserve status.

Potomac Edison serves the western Maryland counties, the eastern panhandle of West Virginia and the northwest corner of Virginia. Maryland accounts for about two-thirds of Potomac Edison's sales and about 20 percent of the entire APS load. Monongahela serves the northern half of West Virginia (excluding the eastern panhandle), and West Penn serves the southwest and certain central areas of Pennsylvania.

The breakdown of total system sales among the three utilities is shown on Table I-13 along with customer class sector shares for each company. West Penn is the largest of the three companies, accounting for nearly half the system sales. Potomac Edison and Monongahela are comparable in size, with Potomac Edison's 1984 sales being slightly greater than Monongahela's. The customer class breakdowns reveal similar patterns among the three companies. In each case the industrial sector is extremely large ranging from 46 to 55 percent of total sales, and the commercial sector is relatively modest. This reflects the fact that the service territory contains considerable heavy manufacturing and a virtual absence of major commercial centers. The residential share for Monongahela Power is noticeably below the other two companies, which may reflect the relative availability of low-cost natural gas in that region. Although APS operates in five states, Ohio and Virginia together account for less than 10 percent of total sales.

It should also be noted that APS serves several municipal systems and cooperatives at wholesale, the largest being Hagerstown, Maryland. However, these sales accounted for only about 3 percent of system sales in 1984.

As in the other three Maryland systems (and the rest of the U.S.), electricity sales growth for APS has fallen off sharply since the early 1970s. For APS, it has been unusually severe because of the area's heavy dependence on heavy manufacturing and the relative lack of the more stable commercial activity. Even after several years of relative decline, industrial energy sales were nearly 50 percent of total sales for all three APS utilities in 1984. Thus APS remains very vulnerable to economic downturns which could further damage the industrial sector. These growth trends are shown in Table I-14, which lists sales for APS in 1966, 1973 and 1984 and associated annual growth rates for those periods.

Table I-13. Distribution of Total APS Electricity Sales by Company and Customer Class, 1984(a)

	Potomac Edison	Monongahela Power	West Penn Power	APS
Total Sales				
1000's MWh	8,727	8,056	14,338	31,121
% of APS	28.0%	25.9%	46.1%	100.0%
Customer Class Shares				
Residential	30.2%	26.5%	32.4%	30.2%
Commercial	14.9	16.5	18.5	17.0
Industrial	50.1	55.0	46.2	49.6
Resale & Other	4.8	2.1	2.9	3.2

(a) Data from Ref. 9.

Table I-14. Growth in Sales and Peak Demand for the Allegheny Power System(a) (Thousands of MWh)

	1966	1973	1984	Annual Average Growth Rates 1966-1973	1973-1984
Residential	3,711	6,614	9,411	8.6%	3.3%
Commercial	1,865	3,621	5,274	9.9	3.5
Industrial	8,822	13,760	15,431	6.6	1.1
Resale & Other	314	677	1,005	11.6	3.7
Total	14,712	24,672	31,121	7.7	2.1
Annual Peak (MW)	2,661	4,230	6,035	6.2	3.3
Load Factor	68.7%	71.7%	62.2%	--	--

(a) Data from Ref. 18 and 9. The peaks are for the winter season beginning in year designated. The 1984 winter season peak occurred in January 1985.

Since 1973, total sales have increased by 2.1 percent compared to peak demand growth of 3.3 percent, leading to a significant decline in the annual load factor. This decline is partly explained by unusually severe weather conditions in January 1985. (APS and all three operating utilities are winter peaking.) However, it is also partly attributable to the fact that the high load factor industrial sector has been declining as a percentage of the system. Thus, the decline is partly an aberration but is also partly reflective of a long-term trend. Despite this unusual decline, APS normally experiences the highest load factor of any of the Maryland utilities.

The APS is an almost entirely coal-fired system -- approximately 98 percent from the standpoint of fuel mix. APS has 7,109 megawatts of installed capacity, of which 62 megawatts are run-of-river hydroelectric. Not included in that total are older oil-fired plants, 361 megawatts of capacity, classified as in cold storage. In late 1985, APS brought into service 840 megawatts of the Bath County Pumped Storage Project. The 840 megawatts is 40 percent of the entire Project, with the other 60 percent owned by VEPCO, the utility which constructed the plant. Unlike other APS generating units, this plant will not be owned directly by the three operating subsidiaries. Instead, a new company was created, the Allegheny Generating Corporation (AGC), which owns the capacity and sells the power wholesale to the three utility subsidiaries. In turn, AGC is actually owned by the three APS operating utilities, with ownership shares based upon the relative peak demands of the three utilities. For example, Potomac Edison's ownership share of AGC is 28 percent. Each utility receives power from the Bath plant in accordance with its ownership share, and it is also responsible for supplying the same proportion of the pumping energy. These transactions fall under the jurisdiction of the FERC rather than the individual state commissions since they are wholesale (i.e., interutility) rather than retail sales.

It should be noted that the addition of this capacity, although substantial, will not change the APS fuel mix. This is because a pumped storage plant, unlike thermal plants, does not create any electricity on a net basis. It is merely a device for shifting it from the off-peak period to the on-peak period. Pumping energy will be supplied to the Bath plant by running APS' baseload coal units at a higher level during off-peak hours than they would otherwise be run in the absence of the Bath facility.

APS anticipates that it will require additional capacity during the 1990s. Present plans call for a 300-megawatt coal unit in 1995 and additional units in 1997 and 1998.

Summary of Growth Trends

Table I-15 summarizes and compares the growth trends since 1973 for the four major Maryland utility systems and the U.S. The growth trends are fairly similar among the four utilities, and they compare reasonably well to nationwide trends. A possible exception is in the industrial sector where severe economic downturns in certain key heavy manufacturing industries have been more severe for DP&L and APS than for the nation as a whole. The sluggish industrial sector also explains virtually all of the difference in total sales growth between APS and DP&L and the rest of the nation. PEPCO has no significant manufacturing, and BG&E's sales to industrial customers have increased by 2.6 percent per year compared to 1.9 percent per year nationwide. It is also interesting to note that the annual load factors for all three summer peaking utilities (PEPCO, BG&E and DP&L) have been increasing over time, and in each case due to the growth of a winter season heating load.

Table I-15. Comparisons of Annual Growth Rates of Sales and Peak Demand, 1973-1984(a)

	BG&E	PEPCO	DP&L	APS	U.S.
Residential	3.7%	2.5%	3.0%	3.3%	2.8%
Commercial	2.2	2.6	3.9	3.5	3.7
Industrial	2.6	--	0.2	1.1	1.9
Other	--	5.1	1.1	3.7	3.0
Total	2.7	2.8	1.9	2.1	2.7
Peak Demand	2.2	1.8	0.5	3.3	--
1984 System Annual Load Factor	55.2%	50.8%	64.1%	62.2%	60.9%(b)

(a) See earlier discussion and tables in this chapter.

(b) Figure is a projection for 1984 based on reported summer peak and net energy for load. Since some utilities are winter peaking, this figure may overstate somewhat the national average load factor.

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CHAPTER II

NEED FOR POWER

The previous chapter presented an overview of the electric utility industry in the U.S. and in Maryland. This chapter extends our examination of the Maryland utilities focusing on the ability of those utilities to serve the power demands of their customers, both presently and over the next 15 years. That period of time approximates the planning horizons typically used by large integrated utilities. In order to assess the question of adequacy, it is necessary to explore both the expected growth in power demands and the utilities' resource plans for meeting that growth.

It is important to understand that this analysis cannot be performed at the state level. That is, the ability to serve cannot be assessed by comparing power demands in Maryland with electric power supply resources in Maryland. Instead, than assessment must be performed separately for each individual utility system; and in the case of the multistate electric utilities, it is the entire system that must be considered, not merely the Maryland portion. This is because each utility plans and operates as an integrated system.

This chapter assesses future adequacy of service by comparing the power demand forecasts with the capacity expansion plans of the State's four major utilities -- BG&E, APS (Potomac Edison), PEPCO and DP&L. These four companies serve, either at retail or at wholesale, over 95 percent of Maryland's power demands. In recent years, there has been increased recognition that conservation and other programs for "managing" power demands,can affect demand.

A. Future Growth in Power Demands

An essential part of assessing the future adequacy of service is determining the future growth in power demands. Failure to properly anticipate growth may lead to power shortages and/or excessive, uneconomic reliance on generating units with very high operating costs such as combustion turbines. Alternatively, overforecasting demands may result in constructing plant in advance of need and thus creating costly excess capacity. This latter problem has been widespread over the last decade.

The sharp slowdown in load growth after 1973 caught industry forecasters by surprise, and they responded only gradually to past forecast errors. The North American Electric Reliability Council (NERC) reports the growth paths (i.e., projected annual rate of growth) forecasted by the industry since 1974. These forecasts, listed on Table II-1, indicate that the industry has been continually revising their projections downward over the last ten years. The current industrywide forecast of 2.2 percent is less than half the rate of growth forecast in 1979.

Table II-1 U.S. Electric Utility Industry
Load Forecast History, 1974 to 1985(a)

Year Forecast was Published	Forecast of Annual Growth Rate for the Next Ten Years
1974	7.6%
1975	6.9
1976	6.4
1977	5.7
1978	5.2
1979	4.7
1980	4.0
1981	3.4
1982	3.0
1983	2.8
1984	2.5
1985	2.2

(a) Data from Ref. 1.

The industrywide belief that future load growth will be relatively slow appears to be shared by Maryland utilities. Table II-2 presents the most recent forecasts of annual peak demand and electricity sales filed with the Maryland Public Service Commission for the years 1986 through 2000.[1] (These figures are for the entire multistate system rather than just the Maryland portions.) For the 15-year period, the annual rate of growth of peak demand ranges from 0.9 percent for DP&L to 1.9 percent for BG&E. Thus all four utilities are below the industry average of 2.2 percent.

All three summer peaking utilities (BG&E, DP&L and PEPCO) are predicting gradually improving system load factors, with PEPCO's improvement being the most dramatic. This is evidenced on Table II-2 by the fact that the energy sales growth rates are higher than those of peak demand. The improving load factors are due to the expectation that the winter season electric heating

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[1]In addition to the major Maryland utilities, Conowingo Power, SMECO, Easton Utilities and Hagerstown have also filed load projections. Over the time frame 1985 to 1999, Conowingo projects peak load growth from 103 to 134 megawatts (1 1.9 percent rate of growth); Easton projects growth from 29.3 to 51.2 megawatts (4.1 percent annual growth); and Hagerstown projects growth from 50.5 to 66.6 megawatts (annual growth of 2.0 percent). All three utilities expect total sales to grow at approximately the same rate as the peak. PEPCO already includes a forecast for SMECO's load in its forecast of systemwide loads.

loads will grow faster than the summer loads and that savings will result from load management programs. In the case of APS, little change in expected in the annual load factor over the forecast period.

Table II-2. Projected Growth of System Sales and Peak Demand for Major Maryland Utilities(a) (Thousands MWh and MW)

	APS(b)		BG&E		DP&L		PEPCO	
	Sales	Peak	Sales	Peak	Sales	Peak	Sales	Peak
1985(c)	30,902	6,035	19,723	4,365	--	1,795	19,468	4,682
1986	31,073	5,798	20,235	4,500	8,721	1,713	19,686	4,667
1987	32,098	5,941	20,738	4,550	8,860	1,728	20,155	4,638
1988	32,724	6,058	21,269	4,610	9,058	1,753	20,595	4,627
1989	33,343	6,156	21,845	4,700	9,229	1,776	21,138	4,656
1990	33,949	6,263	22,422	4,780	9,404	1,801	21,666	4,663
1991	34,568	6,354	22,981	4,870	9,564	1,822	22,228	4,706
1992	35,223	6,461	23,521	4,950	9,711	1,841	22,772	4,795
1993	35,678	6,551	24,056	5,040	9,863	1,860	23,358	4,878
1994	36,062	6,636	24,599	5,130	10,043	1,879	23,899	4,970
1995	36,504	6,722	25,140	5,260	10,213	1,899	24,365	5,045
1996	36,961	6,801	25,672	5,390	10,193	1,870	24,816	5,118
1997	37,574	6,899	26,181	5,530	10,287	1,891	25,263	5,190
1998	38,069	7,001	26,638	5,640	10,470	1,911	25,756	5,278
1999	38,331	7,086	27,074	5,750	10,660	1,932	26,210	5,352
2000	38,622	7,170	27,504	5,860	10,838	1,952	26,665	5,430
Annual Rate of Growth 1985-2000	1.5%	1.5%	2.2%	1.9%	1.6%	0.9%	2.2%	1.1%

(a) Data from Ref. 2, 3, 4 and 5. All projections were prepared by the utility.

(b) System is winter peaking. The "year" refers to year in which winter ends. For example, the 1985 peak is for the winter of 1984/1985.

(c) Peak demands are actuals. Sales are projections.

Several important adjustments were incorporated in these forecasts. BG&E, APS and PEPCO include substantial peak load savings from load management programs, ranging from 95 megawatts for BG&E to 459 megawatts for PEPCO by the year 2000. These adjustments are listed in Table II-3, and the programs expected to produce those reductions are described in greater detail later in this chapter. DP&L has included a 50-megawatt downward adjustment to its projected loads beginning in 1996 to reflect the expectation that the Old Dominion Electric Cooperative will acquire a portion of Nanticoke Unit 1. When this happens, DP&L's system load will decline by the 50 megawatts. Finally, PEPCO has adjusted its load forecast (beginning in 1987) for the sale of its Virginia service territory, an adjustment in 1987 of 115 megawatts.

Table II-3. Forecasted Reductions in Peak Demand from Load Management Programs(a)

	1985	1990	1995	2000
BG&E				
Megawatts	44(b)	75	98	95
% of Peak	1.0%	1.6%	1.9%	1.6%
APS				
Megawatts	17	113	206	299
% of Peak	0.3%	1.8%	3.1%	4.2%
PEPCO				
Megawatts	11	327	432	459
% of Peak	0.2%	7.0%	8.6%	8.5%

(a) Data from Ref. 2, 3, and 5. Figures are the adjustments to company-prepared projections of peak demand resulting from load management programs.

(b) Estimate for 1986.

To place these projections in perspective, the projected rates of growth are compared to recent historical growth. These comparisons are shown on Table II-4, which presents the forecasted growth in peak demands along with the actual rates of growth over the last three, five and seven years. To make the comparisons more meaningful, load management and other adjustments have been removed from the projections and from actual 1985 peak loads. The DP&L growth rates (both historical and projected) are based on total system excluding rate Q (interruptible) customers and refinery service. These comparisons indicate that all four utilities are projecting rates of growth that are somewhat lower than the rates which have occurred during the past several years. The largest discrepancy is for PEPCO which is forecasted to grow by 1.8 percent (after removing the adjustments), but since 1978 has grown by 4.2 percent. The differences between historical and projected growth rates serve to emphasize the uncertainty in load forecasting.

Table II-4. Comparison of Historic Load Growth with Projected Load Growth for Maryland Utilities(a) (Average Annual Rates of Growth)

	Historic			Projected
	1982-1985	1980-1985	1978-1985	1986-2000
APS(b)	1.9%	2.8%	2.3%	1.8%
BG&E(b)	3.9	2.1	3.1	1.9
DP&L(c)	3.4	2.2	2.2	1.2
PEPCO(b,d)	3.4	2.5	4.2	1.8

(a) Data to compile growth rates from Ref. 5, 6 and Table II-2.

(b) Load management program effects removed from projections and 1985 actuals.

(c) Based on system excluding rate Q (interruptible) customers and refining service. Projected growth rate assumes no participation in Nanticoke 1 by Old Dominion. On a total company basis DP&L is projecting a peak load rate of growth of 0.9% per year.

(d) Projected rate of growth assumes no transfer of PEPCO's Virginia service territory.

In cooperation with the Maryland Department of State Planning (DSP), PPSP has maintained a program of conducting independent long-range load forecasts. Since 1977 studies have been conducted on each of the four major systems. The program of load forecasting involves updating each study approximately every two years.

The load forecasts were developed through the application of econometric models. This methodology requires two main stages. First, statistical models of the demand for electricity are estimated from historical data. These models describe and quantify the relationships between the demand for electric energy and the various factors (i.e., explanatory variables) that govern it, such as population, income, employment, climate, electric rates and appliance ownership. In the second stage, projected or assumed future values of the explanatory variables are inserted into the estimated model, and the energy sales forecast is then calculated for each year. Peak demand is largely explained by the level of sales occurring in the month in which the annual peak occurs, the customer class mix and peak day weather. Thus the energy sales forecast must first be obtained in order to forecast peak demand.

All PPSP/DSP forecast studies have modeled electricity sales separately for the residential and nonresidential classes of customers and for the summer and winter seasons. In all cases the models were estimated using ordinary least squares regression -- in some cases using quarterly or monthly time-series data and in other cases using pooled time-series/cross-section data.

In each study numerous simulations and scenarios were run by varying the key forecasting assumptions such as economic growth and energy prices. As might be expected, these forecasts are highly sensitive to the particular economic and energy price outlook assumed. These simulation results serve to emphasize the uncertainty in long-term load forecasting. In each study a most likely case set of assumptions was developed based upon economic/demographic projections prepared by federal, state and local agencies along with PPSP's best judgment.

A PPSP forecast study of BG&E and an update of an earlier DP&L forecast study (originally prepared in 1979) were completed in 1985. Forecasts of annual peak demand, along with Company estimates of capacity and resulting reserve margins are shown on Table II-5 for the two companies. In both cases, PPSP's projections exceed those prepared by the companies. Over the period 1986 to 2000, PPSP projects an annual rate of growth in peak demand of 2.6 percent compared to 1.9 percent forecast by BG&E. Peak demand on the DP&L system is forecast to grow by 1.7 percent per year compared to the Company's estimate of 0.9 percent per year. These differences, while not dramatic, are important. For example, in the case of BG&E, PPSP is projecting that peak demand in the year 2000 will be 405 megawatts greater than the Company's projections. Thus even a modest difference in the annual rate of growth will result in a substantial difference in total peak demand over a 15-year period.

Table II-5. Capacity Vs. Peak Load Using PPSP-Prepared Load Forecasts, 1985-2000(a)

	BG&E			DP&L		
	Peak Demand	Capacity	Reserve Margin	Peak Demand(b)	Capacity	Reserve Margin
1985 (actual)	4,365	5,612	28.6%	1,795	2,277	26.9%
1986	4,366	5,662	29.7	1,714	2,277	32.9
1987	4,500	5,662	25.8	1,750	2,277	30.1
1988	4,639	5,662	22.1	1,791	2,277	27.1
1989	4,780	5,662	18.5	1,836	2,277	24.0
1990	4,924	5,662	15.0	1,883	2,277	20.9
1991	5,059	5,662	11.9	1,924	2,277	18.4
1992	5,192	6,176	19.0	1,965	2,277	15.9
1993	5,326	6,176	16.0	2,007	2,277	13.5
1994	5,460	6,176	13.1	2,049	2,277	11.1
1995	5,594	6,176	10.4	2,087	2,277	9.1
1996	5,723	6,176(c)	7.9	2,070	2,427	17.3
1997	5,855	6,276	7.2	2,100	2,427	15.6
1998	5,989	6,376	6.5	2,128	2,427	14.1
1999	6,125	6,776	10.6	2,155	2,427	12.6
2000	6,265	6,776	8.2	2,181	2,427	11.3
Annual Rate of Growth	2.6%	--	--	1.7%	--	--

(a) Forecasts from Ref. 6 and 7. Capacity figures from Table II-7.

(b) PPSP projections for 1996-2000 were adjusted downward by 50 megawatts to account for the anticipated sale of 50 megawatts of Nanticoke 1 to Old Dominion Electric Cooperative.

(c) For 1996-2000 based on summer peaking conditions.

B. Resources for Meeting Load Growth

As mentioned earlier, all four Maryland utilities are presently forecasting very slow load growth over the period 1985 through 2000 -- an annual rate of growth of less than 2 percent per year. However, even that very slow rate of growth means nearly 4,000 megawatts of additional demand over this time frame. Moreover, it is expected that at least some retirements of power plant capacity will also be occurring. The purpose of this section is to identify those new, planned resources and examine the implications for fuel mix.

Like the rest of the utility industry in this country, the Maryland utilities have revised downward their forecasted rates of load growth with some regularity in recent years. They have responded to the lower load growth outlook by altering their schedules for bringing new generating capacity into service.

The major capacity additions expected to take place are identified in this section, with a year-by-year tabulation presented on Table II-6. In summary, the four utilities expect to add approximately 3,500 megawatts of new capacity (net of retirements) by the year 2000 in order to meet the expected growth in load of roughly 4,000 megawatts. This discrepancy means that reserve margins during the latter years of the time frame will be somewhat lower than the current levels. Maryland utilities are also likely to be meeting some of their demands through conservation/load management plans (already partially reflected in the load data) and life-extension programs which reduce plant retirements. For example, no retirements are contemplated until the 1990s, and even then the total amount retired is 496 megawatts, most of which is from oil-fired steam units. These retirements represent approximately 2 percent of the total installed capacity of Maryland utilities in the year 2000.

The Allegheny Power System

APS has the most active capacity expansion program of any of the four utility systems. It has purchased through its generating subsidiary, AGC, a 40 percent interest in the Bath County Pumped Storage Project, which recently began operation.[1] The plant entered service in late 1985 with Potomac Edison receiving approximately 28 percent of the capacity. According to the proposed allocation formula, Potomac Edison's share of the plant (and its output) will change over time if its peak loads change relative to the peak loads of WestPenn Power and Monongahela Power, its sister subsidiaries.

APS plans also call for the construction of four 300-megawatt baseload coal units by the year 2000, with the first unit in service in 1995. It is anticipated that at least some of these units will be constructed at the Limestone Run site (previously referred to as Lower Armstrong). Construction has not yet begun.

APS currently has 361 megawatts of old, oil-fired steam capacity in cold reserve storage, the Springdale and Mitchell plants. It plans to reactivate that capacity during the 1992-1993 time period but then to retire the Mitchell plants (and 86 megawatts of Springdale) in the late 1990s. APS also plans to retire 82 megawatts at the R.P. Smith and Willow Island plants. Total retirements during the 1990s are projected at 370 megawatts. In addition to retirements, APS' diversity exchange agreement with VEPCO (300 megawatts) is due to expire next year, and its allocation of power from Ohio Valley Electric Corporation (OVEC) is scheduled to be phased out over the next three years.

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[1] Recent Company data list 580 megawatts as being in service by the end of 1985 with the remaining 260 megawatts coming on-line in early 1986.

Table II-6. Summary of Projected Capacity Changes of Maryland Utilities, 1985-2000(a) (Megawatts)

	Additions	Retirements
1985		
	75 Increase at Safe Harbor (BG&E)	
	47 Municipal solid waste facility (BG&E)(b)	
	580 Bath County Project (APS)	
1986		
	260 Bath County Project (APS)	
	50 Increase at Safe Harbor (BG&E)	
	59 Harrison 3 uprate (APS)	
1987		
	100 AES Beaver Valley cogeneration (APS)(b)	
1988		
	34 Small-scale hydro (APS)(b)	
1989-1991		
	No changes	
1992		
	620 Brandon Shores 2 (BG&E)	-126 Westport 3 & 4 (BG&E)
	20 Brandon Shores 1 uprate (BG&E)	
	154 Mitchell reactivate (APS)	
1993		
	207 Springdale reactivate (APS)	
1994		
	No changes	
1995		
	300 Coal 1 (APS)	
	300 Coal unit (PEPCO)	
1996		
	200 Nanticoke 1 (DP&L)	
	162 Switch to winter ratings (BG&E)	

	Additions	Retirements
1997		
	300 Coal 2 (APS)	-48 Rivesville 5 (APS)
	100 Combustion turbines (BG&E)	-86 Springdale 7 (APS)
		-27 Smith 3 (APS)
1998		
	100 Combustion turbines (BG&E)	-77 Mitchell 1 (APS)
	300 Coal 3 (APS)	
	300 Coal unit (PEPCO)	
1999		
	400 Coal plant (BG&E)	-77 Mitchell 2 (APS)
		-55 Willow Island (APS)
2000		
	300 Coal 4 (APS)	
TOTAL (1985-2000)		
	4,968	-496

(a) Information from Ref. 2, 3, 4 and 5. Figures do not include changes in purchased power contracts. APS 300-megawatt diversity exchange agreement is due to expire in 1985/1986. OVEC capacity (available to APS) is scheduled as 92, 81 and 40 megawatts in 1985/1986, 1986/1987 and 1987/1988, respectively.

(b) Capacity is non-utility owned but made available to the utility.

Partially offsetting these losses is 100 megawatts expected in 1987 from a cogeneration facility in Pennsylvania (Beaver Valley AES) and 34 megawatts in 1988 from two small-scale hydro projects. None of these three projects will be utility-owned.

Baltimore Gas & Electric Company

BG&E brought Brandon Shores Unit 1, a 600-megawatt coal plant, into service in May 1984. The second unit at Brandon Shores, a 620-megawatt coal unit, had previously been expected in 1987 or 1988. However, with expectations for reduced load growth, the in-service date has now been delayed until 1992. This is the largest project currently under construction or planned by any Maryland utility.

Aside from Brandon Shores, BG&E's plans call for several much smaller projects. The Company is in the process of expanding the capacity of the Safe Harbor hydroelectric facility in which it is a two-thirds owner. This expansion provided BG&E with 75 megawatts of added capacity in 1985, and a further 50 megawatts is expected in 1986. In 1985, BG&E began receiving 47 megawatts of power from a plant fueled by municipal solid waste. BG&E will not own the plant but will be acquiring the power through a long-term contract with the Maryland Northeast Waste Disposal Authority. After Brandon Shores Unit 2, BG&E plans to construct 200 megawatts of combustion turbines to be in service in 1997-1998 and a 400-megawatt coal plant scheduled for 1999. Finally, Company load projections indicate that BG&E will become winter peaking in 1996.[1] This change adds to BG&E's rated capacity at the time of the annual peak (an estimated 162 megawatts) because generating capability is greater in cold weather than hot weather.

In summary, BG&E expects to add 1,270 megawatts of installed capacity, purchase another 47 megawatts and receive another 162 megawatts of capability from a shift to winter peak. Against this must be netted 126 megawatts of retirements in 1992 at the Westport plant.

Delmarva Power & Light Company

DP&L was granted a power plant certification license in 1982 by the Maryland Public Service Commission to construct Nanticoke No. 1, a 500-megawatt coal-fired plant. This plant was scheduled for 1987 with 125 megawatts going to Atlantic City Electric Company and 50 megawatts to the various rural cooperatives on the peninsula. Plans have since been revised, and Delmarva now expects an in-service date of 1996. The plant (renamed Nanticoke No. 1, but at the Vienna site) will be 200 megawatts with 50 going to the cooperatives and the other 150 to DP&L. In addition to meeting future load growth (which has been considerably scaled back since the certification application), the plant will enable Delmarva to substantially reduce its consumption of oil.

Nanticoke No. 1 is the sum total of DP&L's capacity expansion plan over the next 15 years although some other items are worth mentioning. In 1985, DP&L received back 50 megawatts of the Indian River Unit 4 capacity that had been leased to Atlantic City Electric Company for a five-year period. This is coal-fired capacity and may be used to offset oil usage. DP&L currently lists no power plant retirements in its generation plan. Both power plant life-extension programs and load management are currently under review by DP&L.

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[1]PPSP's latest projections also conclude BG&E will become winter peaking. The only disagreement is over the precise year this will happen, with PPSP forecasting the switch will not occur until several years later.

Potomac Electric Power Company

At the present time, PEPCO has the lowest percent reserve margin of any Maryland utility, 14.8 percent in 1985. Despite these relatively low reserves, the Company does not plan to add new capacity until 1995 when a 300-megawatt plant is scheduled for service. A second 300-megawatt plant is scheduled for 1998. It is expected that the plants will either be baseload coal and/or coal gasification combined cycle.

The Company is employing several strategies other than construction to meet load growth. It has proposed an ambitious Energy Use Management program, which is described fully in the last section of this chapter. PEPCO also intends to proceed with a life-extension program which will involve refurbishing the coal-fired Potomac River plants. PEPCO has no plans for retiring any of its generating capacity over the next 15 years. PEPCO has made arrangements to sell its Virginia service territory to VEPCO. This will enable it to shed an estimated 115 megawatts of load beginning in 1987. Finally, PEPCO has been actively involved in the purchased power market arranging for a 150-megawatt long-term purchase from Ohio Edison Company.

Fuel Mix

The combination of capacity additions and load growth is expected to lead to at least modest changes in fuel mix for DP&L and BG&E. APS will continue to generate almost all of its energy from coal, with only a very small amount from hydro and oil (the latter when Mitchell and Springdale return to service). The Bath County Project supplies no net amount of energy, only capacity. PEPCO is also projecting virtually no change in fuel mix. In 1993, it expects coal to account for 90 percent of generation and oil 10 percent compared to an 89 and 11 percent split experienced in 1984. BG&E projects that in 1989 nuclear's percentage will fall slightly and coal's share will rise somewhat as compared to 1984. When Brandon Shores 2 enters service in 1992, coal's share should rise even further. Delmarva's fuel mix will not change significantly until Nanticoke No. 1 enters service in 1996. That unit should result in an increase in the coal percentage with an offsetting decline in oil and gas generation. In summary, the fuel mix of Maryland utilities in the year 2000 will probably not differ very much from the present mix. The percentage of generation from coal will be slightly higher and nuclear and oil slightly lower than at present.

C. Future Adequacy of Service

This section combines the outlook for load growth with the utilities' plans for new capacity in order to assess the ability of Maryland utilities to serve the needs of their customers. This outlook is summarized on Table II-7 which lists projected peak loads and installed capacity for each major Maryland utility from 1985 through 2000. Table II-5 presented earlier in this chapter provides the same information for DP&L and BG&E but using load forecasts prepared by PPSP.

Table II-7. Forecasted Capacity Versus Peak Load for the Maryland Utilities, 1985-2000(a) (Megawatts)

	APS			BG&E			DP&L			PEPCO		
Year	Peak	Capacity	R.M.(b)	Peak	Capacity	R.M.(b)	Peak	Capacity	R.M.(b)	Peak	Capacity	R.M.(b)
1985	6,035	7,088	17.5%	4,365	5,612	28.6%	1,795	2,277	26.9%	4,682	5,375	14.8%
1986	5,798	7,648	31.9	4,500	5,662	25.8	1,713	2,277	32.9	4,667	5,375	15.2
1987	5,941	7,987	34.4	4,550	5,662	24.4	1,728	2,277	31.8	4,638	5,375	15.9
1988	6,058	7,987	31.8	4,610	5,662	22.8	1,753	2,277	29.9	4,627	5,375	16.2
1989	6,156	7,987	29.7	4,700	5,662	20.5	1,776	2,277	28.2	4,656	5,375	15.4
1990	6,263	7,987	27.5	4,780	5,662	18.5	1,801	2,277	26.4	4,663	5,375	15.3
1991	6,354	7,987	25.7	4,870	5,662	16.3	1,822	2,277	25.0	4,706	5,375	14.2
1992	6,461	7,987	23.6	4,950	6,176	24.8	1,841	2,277	23.7	4,795	5,375	12.1
1993	6,551	8,141	24.3	5,040	6,176	22.5	1,860	2,277	22.4	4,878	5,375	10.2
1994	6,636	8,348	25.8	5,130	6,176	20.4	1,879	2,277	21.2	4,970	5,375	8.2
1995	6,722	8,348	24.2	5,260	6,176	17.4	1,899	2,277	19.9	5,045	5,675	12.5
1996	6,801	8,648	27.2	5,390	6,338	17.6	1,870	2,427	29.8	5,118	5,675	10.9
1997	6,899	8,648	25.4	5,530	6,438	16.4	1,891	2,427	28.3	5,190	5,675	9.3
1998	7,001	8,787	25.5	5,640	6,538	15.9	1,911	2,427	27.0	5,278	5,975	13.2
1999	7,086	9,010	27.2	5,750	6,938	20.7	1,932	2,427	25.6	5,352	5,975	11.6
2000	7,170	8,878	23.8	5,860	6,938	18.4	1,952	2,427	24.3	5,430	5,975	10.0

(a) Data from Ref. 2, 3, 4 and 5. All figures are utility-prepared projections. For APS, "year" refers to winter ending in that year. For example, 1985 is the winter of 1984/1985.

(b) "R.M." means percent reserve margins, calculated as capacity minus peak divided by peak.

The key measure to focus on in assessing reliability is the percent "reserve margin," calculated as effective capacity minus the peak divided by the peak. Generally speaking, total reserves may be divided between desired or target levels, and "excess," i.e., reserves above minimum desired levels. It is desirable for a utility to maintain significant levels of reserve so that operational uncertainties will not imperil system reliability. The two principal sources of uncertainty are peak load uncertainty or fluctuations, and unit forced outages, i.e., unanticipated equipment failures at a plant which might either reduce power output or shut down the plant altogether. Utilities tend to plan generation additions to meet projected peak loads with a reserve margin for such contingencies. To achieve a given level of reliability, reserve margins differ from utility to utility. Generally speaking, the appropriate reserve margin will depend upon such factors as weather variability, types and sizes of generating units, forced outage experience, load characteristics, and the strength of interconnections with other utility systems. It is therefore not surprising that the desired reserve margins differ from system to system.

Because it may not be possible to perfectly coordinate capacity additions with load growth, "excess" capacity results. For example, on a slowly growing system, peak load may only be increasing (or projected to increase) by 75 megawatts per year. The utility might conclude that the type of capacity it deems appropriate cannot be economically constructed at a size less than 300 megawatts. Assuming the desired reserve level is not violated prior to the in-service date of this unit, this utility will experience 225 megawatts of "excess" capacity in the first year of the unit, gradually diminishing thereafter. The so-called excess capacity is therefore an inevitable part of planning. In practice, utilities do experience this and attempt to compensate by selling the temporary excess off-system.

The Maryland utilities report the following minimum reserve margins that they use for planning purposes (8, 9, 10 and 11).

APS -- 25 percent
BG&E -- 18 percent
DP&L -- 18 percent
PEPCO -- 16 percent

These minimums may be compared with the reserve margin percentages listed on Table II-5 and Table II-7 to reach some tentative conclusions regarding future adequacy of service and excess capacity.

For the winter of 1985/1986, APS is projecting a reserve margin of 31.9 percent, which exceeds the planned minimum of 25 percent.[1] The reserve margin rises the following year as the remaining 260 megawatts of the Bath County Project is assumed to enter service, and then it gradually declines thereafter. The System's reserve margin between 1990 and the year 2000 is maintained within

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[1]The 31.9 percent reserve margin assumes that the remaining 260 megawatts of the Bath County Project will not be in service at the time of the 1985/1986 peak. It also excludes the 261 megawatts of capacity in cold reserve storage. If those two sources were included in the capacity total for that year, the reserve margin would be approximately 43 percent.

a very narrow range of 23 to 27 percent through the addition of four coal plants and reactivation of the oil-fired steam capacity that is presently in cold storage reserve.

The reliability of the APS is also affected by off-system transactions. The 300-megawatt diversity exchange with VEPCO is scheduled to terminate after the winter of 1985/1986, and the surplus capacity available from the Ohio Valley Electric Corporation (OVEC), 92 megawatts in 1986, is not expected to be available after 1988 (8). APS has entered into a short-term contract with American Electric Power and Ohio Edison to sell 2,102 megawatts of capacity to six eastern utilities (8). APS lists its share as 1,058 megawatts for the winter of 1985/1986. Finally, APS expects to purchase 134 megawatts of cogeneration and small-scale hydro beginning in 1987 and 1988. That capacity, which is not included on Table II-7 (since it is not owned by APS), would add approximately 2 percentage points to the reserve margins.

Accepting the APS desired reserve margin and the realities of capacity planning, the amount of excess capacity is modest and short-lived. An approximate demand supply balance is restored by 1990. Moreover, it is clear that the APS companies are utilizing their excess capacity to engage in off-system sales, the profits from which are flowed back to their retail customers. It would also appear that the Company's plan will adequately meet the power demands of its customers. However, there are two significant caveats to that conclusion. First, the APS is basing its planning on a forecast of very slow load growth, somewhat slower than that experienced in recent years. Second, it is planning an ambitious construction schedule for the late 1990s, four baseload coal plants between 1995 and 2000. To meet the planned date for the first unit, licensing and construction must begin fairly soon. APS' schedule for retirements, however, does provide for some flexibility. If necessary, those retirements can probably be delayed.

BG&E's situation is similar to that of APS. The Company experienced a reserve margin of 28.6 percent in 1985, and expects a reserve margin in excess of its desired minimum throughout the rest of the 1980s. This situation undoubtedly prompted the decision to postpone Brandon Shores Unit 2 to 1992. With the exception of the years immediately after the in-service date of Brandon Shores Unit 2 (1992 and 1993), reserve margins in the 1990s are projected to range from 16 to 21 percent.

A somewhat different picture is encountered using the PPSP load forecast. Reserves are slightly lower though adequate until about the mid-1990s. After 1994, margins fall to or below 10 percent for the remainder of the decade. (See Table II-5.) If load growth begins to exceed Company projections, then BG&E's planning process must be readjusted. That plan includes 200 megawatts of combustion turbines (very short lead time plants) and 126 megawatts of retirement. If necessary, the in-service dates of those plants could be moved up and the retirements postponed. Even if those actions are taken, the PPSP forecast would require a new plant by 1997, rather than 1999, as currently planned.

DP&L projects a reserve margin of nearly 33 percent in 1986, and with its projection of slow growth (0.9 percent per year), reserve margins will average about 30 percent for the remainder of the 1980s. According to its current plans and forecast, the reserve margin declines to 20 percent in 1995, and with Nanticoke Unit 1, it rises to nearly 30 percent in 1996. The reserve margin then declines gradually to 24.3 percent by the year 2000.

The situation differs somewhat using the more rapid PPSP forecast. Under that forecast scenario, reserves decline to 18.4 percent by 1991, indicating a need to advance the in-service date of Nanticoke Unit 1, approximately three years. With the PPSP forecast, DP&L would appear to require additional capacity by the year 2000. Even though PPSP's forecast exceeds DP&L's (1.6 percent versus 0.9 percent), it is still below actual historical growth on the DP&L system. (See Table II-4.)

In the near term, DP&L appears to have more excess capacity than Maryland's other utilities. However, the Company's most recent capacity addition, the coal-fired Indian River 4, has enabled DP&L to substantially reduce its oil consumption. The addition of Nanticoke No. 1, a proposed coal-fired unit, will enable DP&L to further reduce oil consumption.[1]

PEPCO's reserve margins at present and for the remainder of the 1980s are very close to the Company's planning minimum (16 percent). Reserves remain adequate during this time period due to the sale of the Virginia service territory and the Company's ambitious load management plan.[2] After 1990, reserve margins decline below the planning minimum, averaging only 11.2 percent between 1991 and 2000. These very low reserve margins result even with a load forecast of 1.1 percent annual growth (1.8 percent excluding load management and the Virginia sale).

PEPCO's capacity plan appears to be adequate for the remainder of the 1980s but questionable for the 1990s. Even with its forecast of relatively slow growth, reserve margins in the 1990s are quite low. Moreover, this forecast assumes that PEPCO is able to achieve 459 megawatts of capacity savings from its Energy Use Management program. That program is now before the Maryland and District Public Service Commissions and has been challenged by intervenor groups in regulatory proceedings.

A further consideration in assessing the adequacy of service issue is the availability of off-system purchases.[3] Table II-8 presents projections of supply and demand for the Mid-Atlantic Area Council (MAAC) and East Central Area Reliability Coordination Agreement (ECAR) regions. Both regions project substantial excess capacity over the next ten years. MAAC projects reserve

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[1]A PPSP planning study conducted in 1981 concluded that the unit would, under certain assumptions, justify constructing the plant ahead of need. That study, however, assumed oil prices for in excess of actual oil prices today (12).

[2]PEPCO also has available 150 megawatts of purchased power from Ohio Edison which is not included in the capacity figures on Table II-5.

[3]The alternative question is to what extent can Maryland utilities sell any excess capacity off-system with the current regional capacity "glut", to a utility can sell inexpensive (e.g., coal-fired) energy to other utilities to displace expensive oil and gas generation. But the market for "firm" capacity sales is weak.

margins to rise to 38 percent by 1987 and then to decline to 28 percent by 1994. ECAR projects a reserve margin of 32 percent in the winter of 1994/1995. (Unfortunately, data beyond 1994 are not available.) The MAAC utilities, however, are assuming load growth of only 1.1 percent per year. If load growth of 2.0 percent is assumed instead, the reserve margin would fall to approximately 18 percent by 1994, a situation of virtually no excess capacity.

Table II-8. Projected Regional Supply/Demand Balances, 1985-1994(a) (Megawatts)

	MAAC			ECAR(b)		
Year	Peak Demand	Capacity(c)	Reserve Margin	Peak Demand	Capacity(c)	Reserve Margin
1985	35,610	47,859	34.4%	67,349(d)	--	--
1986	36,040	49,049	36.1	66,671	96,310	44.5%
1987	36,350	49,999	37.6	68,042	96,829	42.3
1988	36,790	49,998	35.9	69,728	97,606	40.0
1989	37,150	49,741	32.6	71,496	99,478	39.1
1990	37,540	49,741	32.5	72,958	100,276	37.4
1991	37,910	49,837	31.5	74,501	101,151	35.8
1992	38,340	50,159	30.8	76,047	102,905	35.3
1993	38,800	50,336	29.7	77,529	104,220	34.4
1994	39,300	50,171	27.7	79,065	105,607	33.6
1995	--	--	--	80,544	106,097	31.7
Annual Rate of Growth(e)	1.1%	0.5%	--	2.1%(e)	1.1%(e)	--

(a) Data from Ref. 1.

(b) ECAR is winter peaking. Year refers to winter ending in indicated year. For example, 1985 is the winter of 1984/1985.

(c) Capacity refers to "planned resources."

(d) The 1984/1985 peak figure for ECAR is an actual. All other figures on this table are projections.

(e) Growth rate is calculated from 1986 to 1995.

Thus, the availability of excess capacity in the region after the early 1990s is predicated upon the assumption of very slow load growth. It appears that generating capacity for the region as a whole is adequate up until the mid-1990s, but beyond that, the situation is uncertain. If growth is faster than presently anticipated, some utilities (including those that serve Maryland) must adjust their capacity plans, if adequate levels of reliability are to be maintained.

An underlying assumption of this discussion is that adequate transmission capability will be available to move the power from the surplus areas to the Maryland utilities that might need that surplus in future years. For the Mid-Atlantic region such an assumption appears highly questionable. This region imports a considerable amount of economy energy from the Western Pennsylvania and Ohio areas and is likely to continue to do so in the future. However, it is estimated that the west-to-east transmission paths in this region were 97 percent loaded (i.e., fully utilized during 97 percent of the hours of the year) in both 1983 and 1984 (13).

Although these bottlenecks are well recognized, there are difficulties in constructing additional transmission capability. The North American Electric Reliability Council (NERC) identifies the following impediments (13):

- Difficulty in obtaining public and regulatory recognition of the benefits from additional transmission capacity.

- Protracted licensing procedures.

- Jurisdictional disputes among states, localities and the federal government.

- Lack of economic incentives because the customer receives the benefit while the utility takes on the risk.

Transmission considerations have traditionally been overlooked in discussions of future adequacy of service. However, with purchased power taking on an increasingly important role and serious bottlenecks existing in the Mid-Atlantic region, it is important that transmission be examined along with the adequacy of generating capacity.

D. Programs to Reduce Power Demands

Along with the capacity additions identified in the previous section, the Maryland utilities attempt to meet customers' needs through conservation and load management programs. Conservation refers to programs that attempt to reduce a customer's total electric usage without specific regard for the precise time when that reduction occurs. The term "load management" refers to programs or incentives that induce a customer to alter the timing of his loads rather than reduce total energy consumption. The object of load management programs is to improve the utility system's load factor by shaving peaks or shifting peak loads. Another possible strategy being pursued is the encouragement of electricity generation by the customer, either to substitute for utility-produced power or to be sold back to the utility. This subject is covered in Chapter VIII.

Conservation/Weatherization

The Maryland utilities conduct a wide variety of conservation and weatherization programs including the federally mandated Residential Conservation Service (RCS). It is beyond the scope of this chapter to describe all these programs in detail. Estimates of load savings have not been made for most programs. Given this lack of quantification, it would appear that these programs are generally regarded by the utilities more as a customer service, i.e., a means to help customers reduce their electric bills, rather than as an important alternative to increasing generating capacity.

In 1982 and 1983, PPSP conducted a major, two-phase study of potential utility-sponsored weatherization programs for residential customers. The potential benefits to participating customers were found to be substantial, but savings in generating capacity were only modest -- approximately 1 percent of total system peak demand for the most ambitious and expensive program considered (14).

BG&E conducts a number of residential programs in addition to the RCS program. For the Baltimore Energy Alliance Program (BEAP) the Company provides equipment, free audits and some funding to pay former CETA workers to weatherize homes in Baltimore City. The program is now being expanded to surrounding counties. As of October 1984, approximately 4,600 residences had been audited and weatherized. A program targeted for low to moderate income households directly involving community-based organizations (CBOs) was started in 1983. Under this program, BG&E provides training, materials and workshops for the CBO volunteers. The Company hopes to reach about 3,000 homes with this program in 1985. BG&E participates in the Community Development Administration's low-interest loan weatherization program by providing loan processing assistance. BG&E has a number of other programs of an informational and promotional nature.

PEPCO conducts the required RCS program and in addition provides customers with a do-it-yourself ("Class B") energy audit. The Company has recently initiated programs oriented toward low-income customers. This includes providing training to groups involved with low-income weatherization projects. In 1985, the Company expects to initiate a project involving the direct installation of low-cost conservation measures in the homes of customers with electric space or water heating. PEPCO's Community Conservation Program, begun in 1983, is intended to provide free assistance to senior citizens and low-income customers in installing energy conservation measures. This program intends to provide these services through CBOs in the local areas. In addition to residential programs, PEPCO offers energy management consulting services, including audits, to its nonresidential customers. This assistance is provided without charge.

Aside from the RCS program, DP&L's most important residential conservation programs are the Super E+ Program and its new water heater wrap program. The former is designed to encourage weatherization on the part of builders and customers in newly constructed homes. This is particularly important for DP&L since a large percentage of new homes heat with electricity. The second program involves the promotion of water heater insulation. The Company estimates that approximately two-thirds of its customers with electric water heaters could benefit from insulation. DP&L also conducts a number of workshops and conferences on conservation for both its residential and nonresidential customers.

Potomac Edison has provided the most extensive quantitatiye analysis of its conservation programs. The Company lists eight residential programs and seven nonresidential programs producing measurable peak demand savings. The most important such program (from a load savings standpoint) is the Energy Efficient Home Program which is expected to save more than 8 megawatts by the 1990s. This program is designed to encourage comprehensive weatherization in new electrically heated homes. There is an analogous program for nonresidential customers. Other major programs are designed to encourage the adoption of water heater insulation blankets, energy-efficient appliances, heat pump water heaters and insulation retrofits. Potomac Edison also has a special program to induce its customers to "down-size" their electric furnaces by disconnecting unneeded heating elements. In total, Potomac Edison estimates peak demand reductions of approximately 20 megawatts by the 1990s from these programs.

Load Management

In contrast to conservation, load management is regarded by utilities as an important component of the generation resource plan. There are a number of possible load management programs with time-of-use rates, direct control of household appliances and curtailable service to large nonresidential customers being the most important.

The most ambitious load management program is PEPCO's Energy Use Management (EUM) program, a combination of expanded time-of-use rates, residential load control and curtailable rates. The Company currently bills its largest nonresidential customers (those with billing demands over 1,000 kW) on time-of-use tariffs in the District and Maryland, and under the EUM program, it proposes to extend those rates to the Washington Metropolitan Area Transit Authority (WMATA) and all other nonresidential customers with demands above 25 kilowatts. PEPCO estimates an eventual load reduction from expanded time-of-use rates of 115 megawatts.

The residential load control and curtailment programs follow demonstration projects conducted by PEPCO over the past couple of years. That experience convinces PEPCO that the technology is feasible, that customers would not be greatly inconvenienced by the service interruptions involved and that the load savings would be significant. The residential program will involve the cycling off of air conditioners and electric water heaters for short periods of time when loads are pressing against capacity. The Company installs a radio receiver and a switch on the customer's appliance which it can then control by means of a central FM transmitter. Analyses performed by PEPCO found that the program generates net savings to the Company. It then passes back that savings to the customer in the form of a billing credit, which is a reward for agreeing to permit the Company to control the appliance. The program is completely voluntary which complicates the estimate of load savings. PEPCO estimates that this program will reduce peak demand by 120 megawatts.

The commercial curtailment program uses a somewhat different approach. The customer tells PEPCO how much it can reduce its electric load once PEPCO informs the customer of the need to do so. PEPCO, in turn, does not physically control the load, but when the need arises, PEPCO requests a curtailment. If the customer fails to curtail to at least the full extent agreed upon, that customer is penalized with a surcharge. If the customer complies, he receives a rate discount based upon the kilowatts of curtailment. The curtailable load program is also completely voluntary. The Company estimates that its commercial program will save 205 megawatts of peak load.

Thus PEPCO estimates a total peak savings by the early 1990s of 440 megawatts. That estimate, however, depends not only on the Company's technical analysis, but also on the willingness of customers to participate in these programs. This participation is extremely difficult to predict and adds an important element of uncertainty regarding the impact of EUM.

SMECO is the only utility in the state conducting load control on a nonexperimental basis. The program involves cycling off air conditioners and electric water heaters, the former for 7 minutes out of each 28 and the latter for 2 to 3 hours at a time. It is estimated that the savings is about one kW per switch, and SMECO expects to hook up about 250 switches per month. At the present time, participating customers do not receive a rate discount.

DP&L has sold power to its large Delaware industrial customers under time-of-use rates for the past few years and has recently introduced time-of-use rates in Maryland for customers above 300 kW or taking power at primary voltage. The Company has also recently begun to offer time-of-use rates to its residential customers in Delaware. In 1982, the Company completed a demonstration project in Delaware involving both direct load control and time-of-use rates. Extrapolating from the experimental results the Company estimates potential peak load savings of 35 megawatts.

In the nonresidential sector, Delmarva has 69.2 megawatts of interruptible load (10). This load principally consists of large industrial customers in Delaware. This load has been interrupted on occasion and is deducted from the system peak load for forecasting purposes.

BG&E also expects to obtain savings from load management, principally from time-of-use rates and curtailable load. The Company projects savings to range from 35 megawatts in 1985 to 103 megawatts in 1997, about half of this from curtailable load. Time-of-use rates are also applied to all customers with billing demands over 200 kW. BG&E is currently conducting a time-of-day rate experiment with approximately 140 residential customers on the experimental rates. The Company operates or expects to operate several other load management programs which will have somewhat smaller impacts. At present, 204 residential customers are taking Economy Service in which demand limiters are installed in the customer's residence. The Company also incorporates power factor penalties when a nonresidential customer's power factor falls below 90 percent. Finally, one customer (2.5 megawatts) is on a temperature sensitive interruption rate.

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