CHAPTER 1

PROJECTED ENVIRONMENTAL IMPACT

A. Introduction

The Power Plant and Environmental Review Division (PPER) of the Maryland Department of Natural Resources (DNR) publishes the Cumulative Environmental Impact Report (CEIR) biennially under requirements of the Maryland Power Plant Research Act (Section 3-304 of the Natural Resources Article of the Annotated Code of Maryland). The objective of the CEIR is to summarize the information available on the impacts to the human health and the environment from electrical power generation in Maryland. Most of the information contained in the report is collected as part of ongoing environmental research programs sponsored by PPER and the Chesapeake Bay Research and Monitoring Division (CBRM) of DNR.

This is the seventh CEIR. The topics addressed in this edition were selected by PPER and CBRM staff to provide a thorough understanding of the actual and potential environmental impacts attributable to electric power generation in the state. Understanding environmental impacts requires information about the following two subjects:

- the **sources** of these impacts (the generating facilities that produce electric power in Maryland), and

- the **receptors** of these impacts (air, surface water, ground water, and terrestrial resources).

Four chapters of this report (Chapters 3, 4, 6, and 7) describe the multi-media effects of power generation. Additional chapters discuss the impacts of nuclear power generation (Chapter 5) and acid deposition (Chapter 8) on each environmental resource. In addition, Chapter 2 presents an overview of the electric utility industry in Maryland and a description of utility plans for meeting anticipated growth in demand over the next 15 years. Chapter 9, a new chapter for the CEIR, discusses some of the changes occurring in the utility operating environment that may affect current and future power generation systems.

This first chapter summarizes the cumulative environmental impacts of electric power generation on local and regional environmental media. The chapter orients the reader to the topic of cumulative environmental impact by describing the principal effects of each power generation technology used in Maryland on specific environmental pathways.

B. Electric Power Generation in Maryland

Energy Producers

The vast majority of electricity in this state is produced in conventional central station power plants operated by large investor-owned electric utilities. The four largest utilities are:

- Baltimore Gas and Electric Company (BG&E) -- serving approximately 1,000,000 Maryland retail customers primarily in the Baltimore metropolitan area;

- Delmarva Power and Light Company (DP&L) -- serving the Delmarva Peninsula, including about 118,000 Maryland customers;

- Potomac Edison Company (PE) (a unit of the Allegheny Power System) -- serving Western Maryland and portions of West Virginia and Virginia, and approximately 169,000 Maryland customers; and

- Potomac Electric Power Company (PEPCO) -- serving the District of Columbia, about 421,000 Maryland retail customers in Montgomery and Prince George's Counties, and retail customers of the Southern Maryland Electric Cooperative (SMECO).

Several small utilities, municipal electric systems, and rural electric cooperatives also serve customers in some areas of the State. Table 1-1 summarizes generating capacities of the power plants in Maryland operated by electric utilities. Locations of the power plants are shown in Figure 1-1.

Power Generation Technologies

In Maryland, three main types of generation technologies provide 11,000 MW of generating capacity, where capacity refers to the amount of generation potentially available in a system.

- *Steam Turbines* -- Sixteen oil-fired and 11 coal-fired steam turbine units provide a total combined generating capacity of approximately 7,800 megawatts (MW). In addition, two nuclear-fired units at BG&E's Calvert Cliffs Nuclear Power Plant provide approximately 1,650 MW of generating capacity.

- *Fossil-Fueled Combustion Turbines* -- Forty-six combustion turbines provide a total combined generating capacity of approximately 1,200 MW.

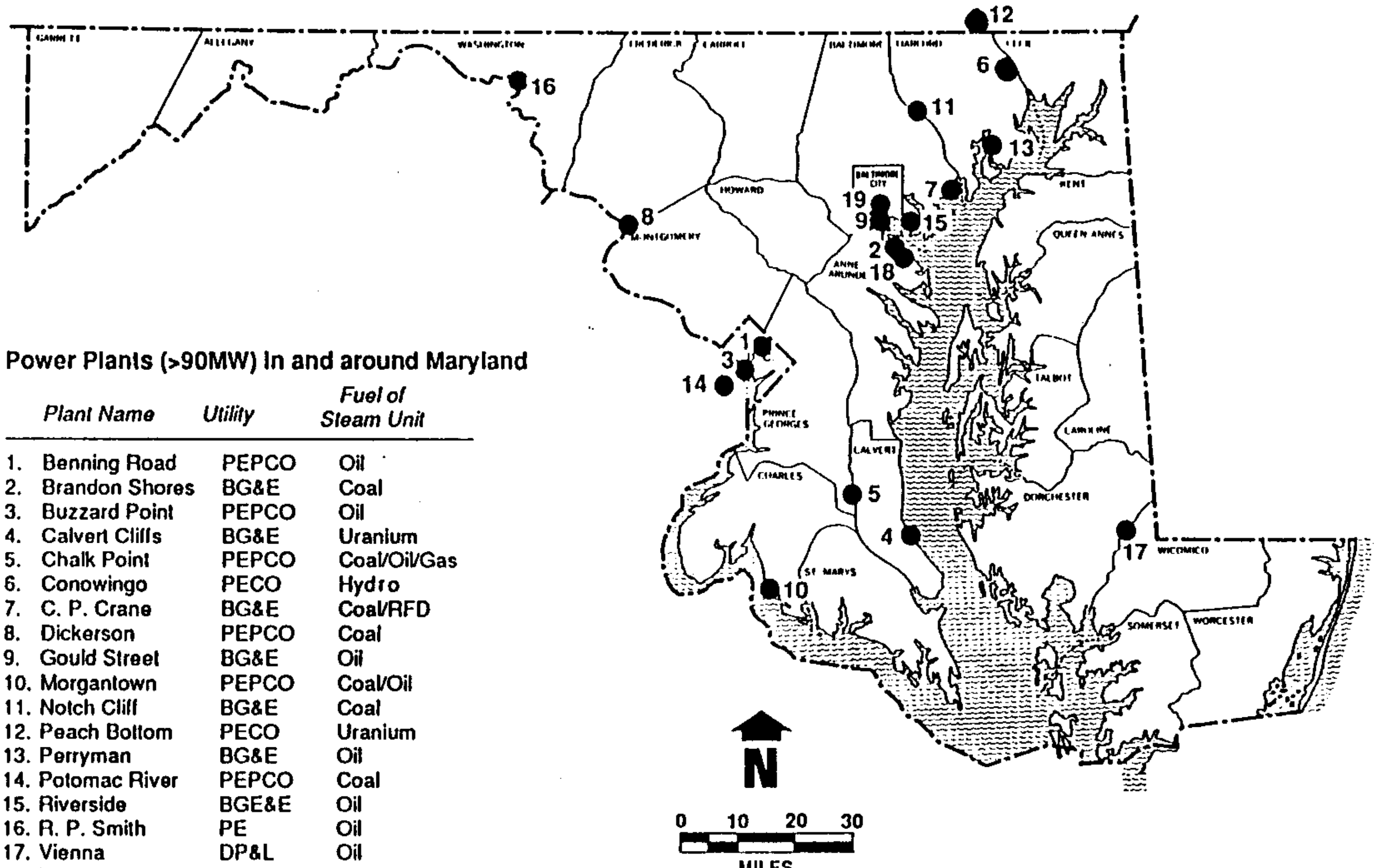
- *Hydroelectric Power* -- Eleven units of Philadelphia Electric Company's (PECO's) Conowingo Hydroelectric Power Plant provide approximately 512 MW.

Table 1-1

Current and planned generating capacity in Maryland*

Utility	Plant Name	Capacity: Existing MW	Capacity: Planned Additions MW
BG&E	Brandon Shores	620	640
	Calvert Cliffs	1,650	--
	C.P. Crane	390	--
	Gould Street	103	--
	Notch Cliff	128	--
	Perryman	204	800
	Riverside	493	--
	Wagner	1,002	--
	Westport	244	--
	Philadelphia Road	64	--
Subtotal		4,898	1,440
PEPCO	Chalk Point	1,955	376
	Dickerson	556	750
	Morgantown	1,412	--
Subtotal		3,923	1,126
PECO (Susquehanna)	Conowingo	512	--
Penelec	Deep Creek Lake	32	--
APS/PE	R.P. Smith	114	--
DP&L	Vienna	150	--
	Nanticoke	--	600
	Crisfield	10	--
Subtotal		160	600
SMECO	SMECO (at Chalk Point)	--	84
Easton	Easton	47	46
Berlin	Berlin	4	5
Hagerstown	Hagerstown	25	--
TOTAL		9,715	3,301

* Utility-owned capacity only
-- No planned change



(●) Power Plants (>90MW) in and around Maryland

	Plant Name	Utility	Fuel of Steam Unit
1.	Benning Road	PEPCO	Oil
2.	Brandon Shores	BG&E	Coal
3.	Buzzard Point	PEPCO	Oil
4.	Calvert Cliffs	BG&E	Uranium
5.	Chalk Point	PEPCO	Coal/Oil/Gas
6.	Conowingo	PECO	Hydro
7.	C. P. Crane	BG&E	Coal/RFD
8.	Dickerson	PEPCO	Coal
9.	Gould Street	BG&E	Oil
10.	Morgantown	PEPCO	Coal/Oil
11.	Notch Cliff	BG&E	Coal
12.	Peach Bottom	PECO	Uranium
13.	Perryman	BG&E	Oil
14.	Potomac River	PEPCO	Coal
15.	Riverside	BGE&E	Oil
16.	R. P. Smith	PE	Oil
17.	Vienna	DP&L	Oil
18.	Wagner	BG&E	Oil/Coal
19.	Westport	BG&E	Oil

Figure 1-1. Location of power plants in and around Maryland

Steam turbine power plants account for about 85 percent of the total generating capacity in Maryland. A steam turbine is an enclosed rotary device in which the energy of high-temperature, high-pressure steam is converted to mechanical energy by passing through rows of radial blades attached to a central rotor. The turbine is attached to a generator where the rotational motion is used to generate electricity. Steam turbine plants in Maryland use either fossil fuel (coal, oil, or natural gas) or nuclear fission to generate steam. As shown in Figure 1-2, steam electric stations in Maryland burn mostly pulverized coal, reflecting the national trend during the 1970s and 1980s toward coal and away from oil as the primary fuel.

Combustion turbines are the second most common power generation technology in use in Maryland. Combustion turbines use compressors to draw in air from the atmosphere and pressurize it. The compressed air is then directed to the combustor where it is mixed with fuel (oil or natural gas) and ignited. The energy of the combustion product is converted to mechanical energy by expansion in a turbine. This mechanical energy is used to drive generators which produce electricity. Combustion turbines in the state are primarily used to provide peak power -- that is, to help meet short-term demands for electricity when demand is highest.

The third major generation technology in Maryland is hydroelectric power, which uses the energy of moving water to produce electricity. Potential energy in the form of stored water behind a dam is converted to kinetic energy when drawn by gravity through the dam's conduits. In this system, flowing water pushes against turbine blades to drive generators and produce electricity.

Fuels Mix

As illustrated in Figure 1-2a, coal accounts for nearly 60 percent of the generating capacity of Maryland utility power plants. Capacity refers to the amount of generation potentially available, not the amount of electricity actually generated within a given time period. For example, on hot summer days when utility system demand is at its peak, power will be generated by power plants using the wide mix of fuels shown in Figure 1-2a. However, the great majority of electricity generated by Maryland utilities over the course of each year is from coal and nuclear power, as shown in Figure 1-2b. Coal-fired and nuclear plants, while more expensive to construct, are less expensive to operate than oil-fired and gas-fired plants. Therefore, utilities will operate the larger coal and nuclear plants for more hours each year than the gas- and oil-fired plants.

Demand for Power

The demand for power grew rapidly during the late 1960s and into the 1970s throughout Maryland and across the United States, largely in response to relatively low fossil fuel costs and electricity prices. Energy demand growth slowed significantly in response to the oil embargo of 1973-1974, the oil price

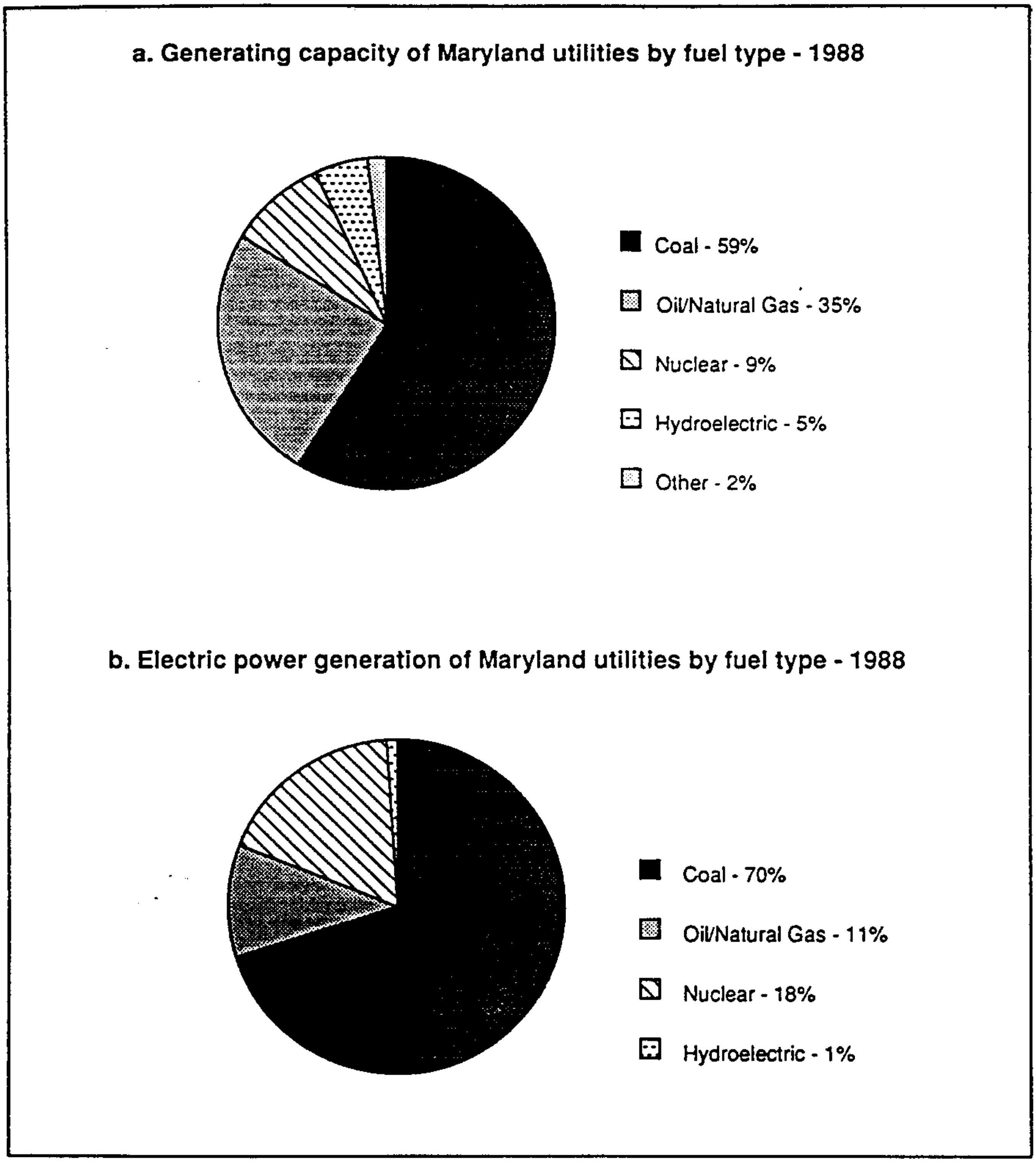


Figure 1-2. Generating capacity (a) and actual power generation (b) by fuel type

increases in 1978, and the recession of the early 1980s. Since the mid-1980s, energy use in Maryland and the United States, particularly electricity, has begun to accelerate again.

Power demands on three of Maryland's largest investor-owned utilities, BG&E, DP&L, and PEPCO, grew far more rapidly than anticipated in the late 1980s. In response to increased economic growth and declining real (inflation-adjusted) electric rates, utility load growth has accelerated sharply since the mid-1980s, increasing by five to eight percent per year for these three utilities. The unanticipated rapid load growth in recent years has led to a problem of low generating reserves, at least in the short run. Using utility company projections, 1990 reserve margins are expected to be only about 13 percent for the three companies. Similar PPER projections indicate that reserves could be even lower.

Each of the utilities is taking actions, however, to ensure adequacy of supply. BG&E, PEPCO, and DP&L each plan to have new power generating units on line by 1991. Allegheny Power System (APS), the parent company of PE, is relying heavily over the next five years on electricity generation by independent companies to serve load growth. At present, such non-utility generation (NUG) plays only a minor role in PEPCO's and BG&E's resource plans, while DP&L plans to acquire substantial NUG capacity in the mid-1990s. Chapters 2 and 9 present more detailed discussions on NUG in Maryland.

In general, resource plans submitted by the utilities to the Maryland Public Service Commission (PSC) in 1989 indicate that power generating reserves will be adequate through 2003. The adequacy of service, however, depends on a number of factors in addition to the present and future availability of generating capacity. The extended outlook for electric power supply and demand in Maryland is discussed in detail in Chapter 2.

C. Local Cumulative Impacts from Maryland Power Plants

PPER and CBRM conduct research and monitoring programs and review information from utilities and other agencies to evaluate the impact of electric power generation on the environment. Data collected from these programs are used to assess the local impact attributable to each power plant as well as to evaluate the regional effect on each environmental medium. The results are also used to evaluate the cumulative effects of power generation in Maryland and form the basis for this report.

This subsection briefly summarizes the information presented in the rest of the CEIR on the cumulative environmental impacts of power plants on the state's air, surface water, ground water, and terrestrial resources. The next subsection summarizes regional and global impacts of power plants.

Air Impacts

- Impacts from Fossil Fuel-Powered Plants

Until the past few years, air quality concerns dealt primarily with the pollutants commonly referred to as "criteria" pollutants, or those pollutants for which the U.S. Environmental Protection Agency has developed air quality standards. There are currently six federally regulated criteria pollutants: sulfur dioxide (SO_2), particulate matter (PM), carbon monoxide, nitrogen oxides (NO_x), ozone, and lead. Information on emissions of criteria pollutants from power plants has led to some encouraging conclusions.

- It appears that power plant-induced ground level concentrations of SO_2 and NO_x, even considering future increases in electric generation and the combined impacts of all power plants, are generally too small to be of major concern with regard to human health. Increases in SO_2 and NO_x emissions from new power plants will tend to be low because new sources are subject to more stringent pollution control technology requirements. Impacts from power plant emissions of SO_2 and NO_x are also discussed below under Acid Deposition.

- Hydrocarbon emissions from power plants are relatively small. However, hydrocarbon concentrations in the atmosphere play a role in the extremely complex phenomenon of ozone formation. Most current strategies for reducing ozone formation have centered on reducing hydrocarbon emissions. However, in some locations, NO_x reductions may be just as important in reducing ozone formation.

- Ground level concentrations of PM due to emissions from power plant stacks are usually low and of little concern. However, in certain problem areas of the state, both new and existing power plants may be subject to additional restrictions on PM emissions. In contrast to stack emissions, "fugitive" emissions of PM from coal-fired facilities could be significant, depending on the controls used and the location of the sources. Fugitive particulate sources from new coal-fired plants could be a significant issue during plant licensing because of the uncertainties in estimating the magnitude of fugitive emissions, and the cost of emission controls.

More recently, emissions of "non-criteria" or toxic pollutants have been receiving increasing attention from the community at large as well as from regulators. Amendments to the Clean Air Act as proposed at the time of this writing address the issue of toxic air pollutant emissions.

- Because much of the toxic material originating from power plants is found in particulate matter, air pollution control strategies for reducing stack and fugitive PM emissions will reduce toxic emissions as well. Although preliminary evidence indicates that inhalation of toxics originating at power plants is not a significant issue, the effects on humans of ingesting power plant toxics are more uncertain.

- Acid Deposition

Research has shown that when sulfur and nitrogen oxides are released to the atmosphere, they can be transported through the upper atmosphere, react with water vapor, sunlight, and other atmospheric pollutants, and form what is commonly referred to as acid rain. Control of acid deposition is also addressed in the proposed amendments to the Clean Air Act.

- In Maryland, the mean annual pH of rainfall is between 4.2 and 4.3, or roughly 10 times as acidic as natural rainfall. Acid deposition has reportedly adversely affected terrestrial and aquatic ecosystems and contributed to the deterioration of physical resources and the incidence of human health problems particularly those related to respiratory ailments.

- In Maryland, power plants accounted for approximately 78 percent of the total 320,000 tons of SO_2 emissions in 1987; industrial sources accounted for most of the rest.

- Power plants contributed about 40 percent of the total 210,000 tons of NO_x emitted across the state in 1987; automobiles and other mobile sources accounted for about 45 percent. Data indicate that the bulk of the power plant SO_2 and NO_x emissions in Maryland comes from older facilities, built between 1950 and 1975.

Acidic deposition can affect both local and regional environmental resources. Locally, PPER and CBRM continue to evaluate the impacts of acid deposition on the state's streams, aquatic life, and local forest resources. Regional impacts are discussed elsewhere in the chapter.

- Atmospheric Radionuclide Distributions

Nuclear power plants release limited quantities of radioactivity to the atmosphere as part of routine operations. Three nuclear power plants whose releases can produce an environmental impact in Maryland are the Three Mile Island and Peach Bottom power plants located in Pennsylvania, and the Calvert Cliffs Nuclear Power Plant in Maryland. PPER, the Maryland Department of the Environment (MDE), and the utilities each conduct environmental surveillance programs in the vicinity of these power plants to assess radiological impacts.

Recent monitoring and surveillance programs have been affected by the fact that two of the plants, Calvert Cliffs and Peach Bottom, were shut down for extended periods over the last two years. Peach Bottom was shut down in March 1987, and started up again in 1989. Calvert Cliffs was shut down in May 1989, and remains shut down at the time of this writing.

- According to results of the latest available environmental surveillance programs, radioactivity released during operations of the Three Mile Island plant was not detected in Maryland in 1987 or 1988, nor has there been evidence of releases into Maryland in previous years. No impact on Maryland's public health or the environment from radioactivity from Three Mile Island is indicated.

- Monitoring in the vicinity of Calvert Cliffs indicated that no radioactivity attributable to the plant was detected in particulate or precipitation samples collected weekly from on-site and distant locations during 1987. In 1988, very low concentrations of I-131 were detected on two occasions in air iodine samples collected from the immediate vicinity of the Calvert Cliffs plant. Although no environmental or health related impact is indicated, the detection of this radionuclide in air samples is significant because I-131 attributable to plant operation has not been detected previously.

- No radioactivity attributable to releases by Peach Bottom was detected in the atmosphere in 1987-1988. PECO reported that quantities of radionuclides released in 1987 were significantly lower than in previous years due to the March 1987 shutdown.

Surface Water Impacts

- Steam Electric Facilities

The most significant impacts to surface waters from steam electric facilities result from withdrawing local water to use as plant cooling water and discharging thermal and chemical effluent from plant operations.

- Availability of water for cooling is found to be generally good in Maryland, and consumptive use of fresh water by power plants is likely to be substantially less than previously projected. Earlier projections by the U.S. Army Corps of Engineers indicated that fresh water consumption in the Susquehanna River basin would be 328 million gallons per day (mgd) by the year 2000; however, average consumptive use in the basin is now expected to remain at 71 mgd at least through 2001. There may, however, be increasing pressure to locate future power generating sites on estuaries or the ocean in order to conserve fresh water.

- Water withdrawals can affect aquatic organisms by entrainment and impingement. Studies thus far have shown that, in general, entrainment and impingement impacts have been localized. There is no evidence thus far of long-term consequences to aquatic biota in the state's surface waters. However, the significance of entrainment losses of forage fish such as the bay anchovy remains a major unresolved issue; future synergistic interactions of power plant impacts with impacts from other sources cannot be ruled out.

- Numerous technologies have been developed for reducing entrainment and impingement impacts. Two intake control technologies, barrier nets and wedge-wire screens, have been identified and field tested in Maryland and appear to be effective at reducing impingement and entrainment impacts.

- Thermal and chemical discharges have affected surface water quality in the vicinity of several power plants, although no regional effects have been detected. To date, power plants have not been implicated as major sources of contaminants to the Chesapeake Bay or its tributaries.

- Radionuclides contained in liquid effluents discharged by the Peach Bottom plant to the Susquehanna River and by the Calvert Cliffs plant to the Chesapeake Bay can be taken up by aquatic biota (such as finfish, shellfish, and aquatic vegetation) or bind with particulate material and bottom sediment. Radionuclide concentrations measured in a variety of biota and sediments collected from the Susquehanna River and Chesapeake Bay during 1987 and 1988 are generally similar to or lower than those detected during previous years. Although radionuclide concentrations do fluctuate seasonally and annually, there is no evidence of accumulation or build-up of plant-related radioactivity in these aquatic systems. Consumption of seafood containing plant-related radioactivity would produce an extremely small radiation dose increment, well within regulatory limits.

- Hydroelectric Facilities

The Conowingo Power Plant, operated by PECO, is by the far the largest hydroelectric facility in Maryland. Evidence of three major types of impacts have been attributed to the development and operation of Conowingo: flow cessation and fluctuation of water levels, alterations of water quality, and prevention of fish passage.

- Viable aquatic habitat in the Susquehanna River below Conowingo was lost in the past because flows were commonly reduced to virtually zero for extended periods of time. As part of a settlement agreement between PECO and the State, a minimum flow was instituted for the period March through November. This has helped fish populations below the dam to become healthier and more productive.

- Hydroelectric releases have violated the state's water quality standards for dissolved oxygen in the past. Physical modification of the dam is underway to improve the situation. Preliminary results indicate that turbine venting is an effective aeration technique that should allow compliance with the state's dissolved oxygen standard.

- The physical presence of the dam at Conowingo and the other three main stream dams has denied anadromous fish access to spawning areas upstream. However, construction of a permanent fish lift at Conowingo began in 1990 after approval of final design plans. Construction is expected to be completed in the spring of 1991. Until fish passage can be provided around the upstream dams, fish must still be sorted and trucked upstream. Studies are continuing to investigate the movement patterns of adult fish and behavior and success of outmigrating juveniles.

Ground Water Impacts

Power plants can adversely impact both the quantity and quality of local ground water resources. Available data indicate that power plant withdrawals have not created adverse impacts to other ground water users. However, there has been some minimal damage from coal storage and fly ash landfilling. Power plants in the state that use ground water resources for plant operations can cause aquifer drawdown if too much water is withdrawn. Local ground water can also be affected if chemicals leach from coal storage piles or fly ash landfills, or if there are spills or leaks of petroleum hydrocarbon products.

- The Calvert Cliffs, Chalk Point, Morgantown, and Vienna power plants rely on ground water resources from the Aquia, Magothy, Columbia, and Patapsco aquifers, respectively. During 1987 and 1988, these four facilities combined withdrew an average of approximately 1.3 mgd, which was 0.5 mgd less than in 1985 and 1986.

- Power plant withdrawals continue to contribute to long-term regional water level declines of some heavily used Coastal Plain aquifers, including the Aquia and Magothy. Available data indicate, however, that past and current power plant withdrawals have not created adverse impacts to other ground water users. Furthermore, current ground water management practices implemented by the Water Resources Administration appear to minimize the impact of power plant water withdrawals.

- Results of PPER evaluations of coal storage and fly ash landfilling practices in southern Maryland demonstrate that leachate from these sources has affected ground water quality locally in shallow (water table) aquifers. However, the degradation that has occurred is localized and has not caused adverse impacts to ground water users. This is primarily because of engineering designs, management practices, and site-specific hydrogeologic conditions combined with the lack of potential users in the immediate vicinity of the sites.

Terrestrial Impacts

The construction and operation of power plants may affect terrestrial ecosystems directly by habitat alteration or indirectly through air emissions that are later deposited on the land or water surfaces.

- Direct alterations of habitat due to existing power plants are localized in extent and have had no impact on critical or unique habitats. There is a potential for impacts from new construction of power plants and their associated facilities; however, in most cases, adverse effects of construction can be avoided by careful site location and planning.

- While there appears to be a potential for damage to some ecosystems from atmospheric releases of pollutants, there is no evidence that such damage has actually occurred in Maryland. However, it has been observed elsewhere that atmospheric emissions leading to acid deposition can adversely affect terrestrial and aquatic resources.

D. Regional and Global Cumulative Impacts from Power Generation

Many of the impacts to environmental resources attributable to electric power generation are localized. For example, ground water withdrawals in general affect local ground water reserves only, and direct impacts to terrestrial resources also affect a relatively small area. Studies have shown that the adverse impacts of power plants to aquatic biota in surface waters are generally localized. Even some emissions to the atmosphere from power plants affect local air quality only. However, power plant operations can also contribute to regional and global environmental impacts, primarily through releases of pollutants to the atmosphere. Although the CEIR focuses primarily on impacts to Maryland, two larger-scale issues have been examined briefly in this report: regional impacts of acid deposition and potential global impacts of the greenhouse effect. Chapters 3 and 8 provide more detailed discussions of these issues.

- Acid Deposition

Because of the atmospheric transport mechanisms involved, acid deposition can affect regional as well as local resources. As previously discussed, acid deposition precursors (SO_2 and NO_x) are abundant in fossil fuel power plant emissions. When these pollutants are emitted high enough in the atmosphere, they have a greater probability of being transported long distances before being deposited to the ground. For example, CBRM reports that as much as two-thirds of all acid deposition in Maryland originates from out-of-state sources. Modeling studies have shown that the primary source regions of acid deposition precursors for Maryland are from the states to the west and southwest.

Clean Air Act (CAA) Amendments of 1990 were signed into law in November of 1990. A key component of the CAA bill is the implementation of an acid deposition control program. The plan calls for an annual, nationwide reduction of SO_2 emissions by 10 million tons and NO_x emissions by 2 million tons below a baseline by the year 2000.

- Greenhouse Effect and Global Climate Change

In recent years, there has been increasing concern internationally over global climate change and its relationship to the "greenhouse effect". Researchers are actively investigating the causes of global warming and the potential environmental, health, and economic impacts from global climate change.

The earth continually intercepts the radiant energy emitted by the sun. A portion of this energy is reflected back into space, but some of it is absorbed by compounds in the atmosphere known as greenhouse gases. This natural "greenhouse effect" warms the lower atmosphere and the earth's surface. Without this effect, the earth's atmosphere would in fact be much too cold to support life.

The important greenhouse gases include carbon dioxide (CO_2), methane, chlorofluorocarbons, nitrous oxide, and ozone. Carbon dioxide currently contributes about 50 percent of the greenhouse gas effect. It is thought that human activities contribute a small but significant fraction of the CO_2 in the atmosphere. The combustion of fossil fuels is the largest human-generated source of CO_2. Across the United States, the utility industry accounts for roughly 35 percent of the fossil fuel-derived CO_2 emissions, which translates to only about 6 to 7 percent of the total worldwide, human-generated CO_2 emissions. In Maryland, utilities generated about 22 million tons of CO_2 in 1984, less than 0.1 percent of the worldwide CO_2 emissions attributable to human activities. As information from the Federal Energy Regulatory Commission (FERC) presented in Chapter 3 indicates, utility emissions of CO_2 in Maryland have risen slightly since 1980.

Our understanding of the phenomenon of the greenhouse effect and how it behaves is not factually well supported. There is considerable uncertainty in the scientific and economic research communities over the rate of warming and its consequences. Despite the uncertainties, policies are being formulated to address the environmental and economic concerns of global climate change. Control of utility CO_2 emissions, whether through energy conservation or use of alternate fuels, could significantly affect the utility operating environment in the future.

E. The Changing Utility Operating and Regulatory Environment

Significant changes are taking place in the electric utility industry, which could restructure the way electricity is generated and distributed in the United States. Much of the change has resulted from the fact that regulatory and institutional forces are introducing more competition into the electric power supply industry. Operation of the electric utility industry will also continue to be affected by local, regional, and global environmental concerns.

Until very recently, utilities across the United States provided electricity by constructing large, central station coal and nuclear generating units. These units were expensive to install, but relatively inexpensive to operate. Today, many utilities, including those in Maryland, are beginning to emphasize flexibility and diversity in power generation. For example, utilities are tending to install smaller generating units than in the past to cut down on large financial commitments. Utilities also continue to explore the use of alternate fuels and generating technologies, both to diversify their generation mix and to respond to increasingly restrictive environmental regulations.

One of the most significant changes in the industry, however, comes from the fact that non-utility generation is becoming an integral part of the power supply mix nationwide. The trend toward increased reliance on NUG supply is in its very early stages in Maryland, but is expected to increase in importance over time. The emergence of NUG as an important resource raises many issues. Some of these issues, which are explored further in Chapter 9, include the fact that, whether because of financial consideration or requirements of current rules and regulations:

- Proposed NUG projects in Maryland are not subject to the same extensive environmental review and PSC licensing procedures as proposed utility projects, despite the fact that NUG facilities can be larger, or may have combined environmental consequences greater than electric utility plants.

- Unlike the utilities, NUG units are located in accordance with the generator's own needs and opportunities. This may or may not coincide with existing electric system supplies (transmission lines) or even with areas that need the power.

At present, the State has no formal, consolidated mechanism to look at the potential impacts of the increasing reliance on NUG supplies. The electric utilities, the PSC, and NUG developers should cooperate to examine these issues to ensure that NUG is a viable and reliable alternative energy source.

CHAPTER 2

THE OUTLOOK FOR ELECTRIC POWER SUPPLY AND DEMAND IN MARYLAND

A. Introduction

This chapter presents an overview of the electric utility industry in Maryland and examines the load growth projections and capacity expansion plans of the four major electric utilities that serve the state. Section B of this chapter outlines the electric utility industry structure and includes a classification and description of each utility. Section C describes Maryland utilities' associations with regional reliability councils and power pools: multi-utility organizations that enhance the reliability and improve the operating costs of electric service. The next section examines the outlook for growth in power demand in Maryland, using both utility and PPER demand forecasts. Section D also outlines each utility's resource plan and examines its adequacy to maintain reliable service. Section E addresses the need for power plant sites in Maryland and the social costs and benefits associated with constructing them.

B. Maryland's Electric Utility Industry

Each of Maryland's electric utilities falls into one of three main categories, all subject to the regulatory authority of the Maryland Public Service Commission (PSC):

- Investor-owned utilities (IOUs) -- Typically, these are large, integrated electric systems engaged in the production, transmission, and retail distribution of electricity. Maryland's IOUs have multistate retail operations and sell power on a wholesale basis to the distribution utilities (the one exception is Baltimore Gas & Electric Company, which has retail operations only in Maryland). The four major IOUs distribute electricity to approximately 85 percent of Maryland's customers and generate (or otherwise supply) nearly all of the bulk power consumed in the state.

- Rural electric cooperatives -- The cooperatives are-operated by and for their member customers, with most of the capital financing provided by the federal Rural Electrification Administration (REA). The Maryland cooperative's principal service is the distribution of power purchased from the IOU; only one of the cooperatives, the Southern Maryland Electric Cooperative (SMECO), owns any significant generating capacity. SMECO recently constructed an approximately 80 MW gas-fired combustion turbine, which began operation in mid-1990.

- Municipal utilities -- Several medium-sized and small towns operate their own electric distribution systems. All of these municipal utilities are located either in Western Maryland or on the Eastern

Shore. Presently, only Easton Utilities generates a significant percentage of the electricity it sells.

In addition to utility-produced electricity, there has been increased interest in power from non-utility generation (NUG). This type of power is often derived from the waste heat or from other by-products of industrial processes, and may be either sold to the utility or used to serve the generator's own requirements, substituting for utility purchases. The emerging role of NUG is discussed more fully in Chapter 9.

Service Areas of Maryland Electric Utilities

The areas of Maryland served at retail by the various utilities are shown on Figure 2-1. The five towns shown on the map -- Berlin, Easton, Hagerstown, Thurmont, and Williamsport -- are the municipal distribution utilities. Delmarva Power & Light Company (DP&L) and Choptank Electric Cooperative both serve large areas of Maryland's Eastern Shore, and their respective service areas cannot be clearly delineated on a map this size. The map does not show electric utilities lacking retail service areas (i.e., generation-only utilities), nor does it show the service areas outside of Maryland served at retail by these utilities. As the map indicates, Baltimore Gas & Electric Company (BG&E) serves the Baltimore metropolitan area, stretching from the northern part of Calvert County to the Pennsylvania border. The Potomac Electric Power Company (PEPCO) serves most of the Maryland suburbs of Washington, D.C. Taken together, these two areas account for more than 80 percent of the state's population.

Table 2-1 gives an overview of the Maryland utilities' operations in 1989. The table shows retail sales, installed generating capacity, and the amount of electrical energy generated in Maryland. The figures for annual peak demand are based on the total system, including the demands of non-Maryland system customers. Three utilities, PEPCO, DP&L, and Potomac Edison, have substantial retail operations outside of Maryland that are not included on this table (except for peak demand). Also excluded from Table 2-1 are the Somerset Electric and A&N Cooperatives, which serve a very small number of Maryland customers in the extreme northwest corner of Garrett County and on Smith Island, respectively. Two IOUs, Susquehanna Electric Company and Pennsylvania Electric Company (Penelec), operate generating units but have no retail operations in Maryland. Susquehanna and Penelec own the Conowingo (512 MW) and Deep Creek Lake (19 MW) hydroelectric plants, respectively, whose power primarily serves customers in Pennsylvania.

As Table 2-1 indicates, investor-owned utilities, particularly PEPCO and BG&E, dominate Maryland's electric utility industry. They account for virtually all of the electric power generated in the state and the vast majority of the retail sales. The two rural cooperatives have substantial sales (though no generation), but the operations of the municipals are relatively small.

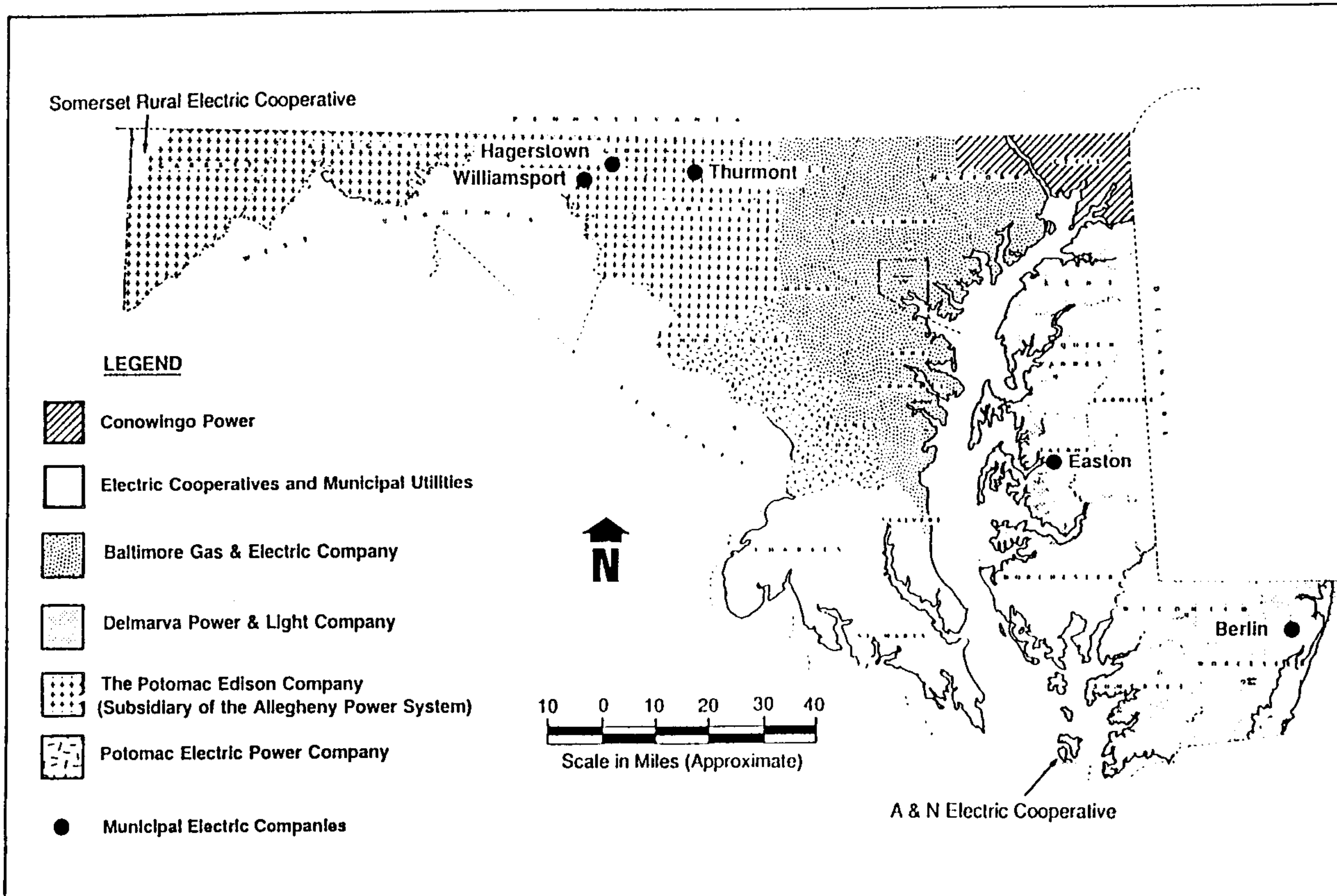


Figure 2-1. Service areas of Maryland electric utilities

Table 2-1

Overview of Maryland electric utilities in 1989 (Maryland-only operations)

Utility	Generation (MWH)	Residential Sales (MWH)	Total Retail Sales (MWH)	Retail Customers	Peak Demand[a] (MW)	Installed Capacity (MW)
Municipals						
Berlin [b]	0	825	2,522	1,477	7	4
Easton	73,835	59,450	176,222	6,822	41	57
Hagerstown	0	107,015	282,354	17,139	61	0
Thurmont	0	18,924	48,180	1,739	11	0
Williamsport	0	10,098	5,644	823	2	0
Subtotal	73,835	196,312	514,922	28,000	122	61
Cooperatives						
Choptank	0	335,881	457,676	31,156	116	0
SMECO	0	1,156,771	1,881,998	87,751	463	0
Subtotal	0	1,492,652	2,339,674	118,907	579	0
Investor-Owned						
BG&E	14,613,054	9,450,984	24,791,062	1,002,418	5,304	5,146
DP&L	559,001	1,034,042	2,172,648	118,273	2,181	176
Potomac Edison	577,498	1,943,441	6,858,848	168,638	2,124	114
PEPCO	18,811,261	4,604,482	11,885,944	421,019	5,241	3,923
Conowingo	0	334,286	653,270	32,759	162	0
Subtotal	34,560,814	17,367,235	46,361,772	1,743,107	15,012	9,359
Grand Total	34,634,649	19,056,199	49,216,368	1,890,014	15,713	9,420

Source: PSC 1989 and requests for data from each utility.

[a] Total system, including peak demand contribution of non-Maryland system customers (for DP&L, PEPCO, and Potomac Edison). All other figures on this table are Maryland only.

[b] 1988 data.

Table 2-1 also indicates that 1989 retail sales exceeded generation in Maryland, meaning that Maryland is a net importer of electric power (49 million MWH sales versus 35 million MWH generation). This results primarily from the fact that Maryland utilities operate power plants in neighboring states. (Table 2-2 compares total system and Maryland-only operations for the four major utilities.) DP&L and Potomac Edison account for most of these imports; only a small percentage of the energy they sell is generated in Maryland. However, in 1989, BG&E was also a major net importer because of the extended outages of the Calvert Cliffs nuclear power plant. Also, some of BG&E's generating capacity is located in Pennsylvania. PEPCO, on the other hand, with most of its base load capacity located in Maryland, produces far more energy in the state than it provides to Maryland retail customers (and SMECO). The excess is exported to PEPCO's retail customers in the District of Columbia. A small amount of PEPCO's generation (about 15 percent) comes from its power plants located in the District and nearby Northern Virginia.

The Municipals and Cooperatives

At present, five municipal electric systems and four rural electric cooperatives operate in Maryland. Together they account for approximately eight percent of Maryland's electric customers and six percent of total retail sales, but less than one percent of its total generating capacity. They instead rely heavily on power purchases from the investor-owned utilities.

Two of the five municipals, Berlin and Easton, are located on the Eastern Shore. Berlin obtains nearly all of its power from DP&L, although it maintains a small amount of capacity to assist in meeting peak demands. Easton is self-sufficient in that it has sufficient capacity to serve its peak load, but it purchases substantial amounts of power from DP&L to save fuel expense. The three Western Maryland municipals of Hagerstown, Thurmont, and Williamsport obtain all of their power from Potomac Edison.

The two major cooperatives are Choptank Electric Cooperative and SMECO. Neither system generates any power at present, but both plan to do so in the future. Choptank (along with other cooperatives on the Eastern Shore) intends to acquire a portion of DP&L's next coal-fired power plant (anticipated in the late 1990s). Choptank's participation would take place indirectly through the Old Dominion Electric Cooperative. SMECO, which currently purchases all its power from PEPCO, is constructing an 84 MW combustion turbine peaking capacity plant, which will be operated and dispatched by PEPCO.

The Investor-Owned Utilities

Seven IOUs operate in Maryland, five of which provide retail service. Penelec, which operates the Deep Creek Lake hydroelectric plant, is a subsidiary of General Public Utilities, a public utility holding company. Deep Creek Lake is its only operation in Maryland. Susquehanna Electric Company operates the Conowingo hydroelectric plant and exports virtually all of the power from that plant to its parent, Philadelphia Electric Company (PECO).

Table 2-2

Overview of Maryland's investor-owned utilities in 1989
(Maryland jurisdiction vs. total system)

Utility	Generation (MWH)	Residential Sales (MWH)	Total Retail Sales (MWH)	Retail Customers	Peak Demand (MW)	Installed Capacity* (MW)
BG&E:						
MD only	14,613,054	9,450,984	24,791,062	1,002,418	5,304	5,146
Total System	18,295,469	9,450,984	24,791,062	1,002,418	5,304	5,744
DP&L:						
MD only	559,001	1,034,042	2,172,648	118,273	N/A	176
Total System	10,352,583	3,049,882	8,997,823	357,286	2,175	2,393
Potomac Edison:						
MD only	577,498	1,943,441	6,858,848	168,638	N/A	114
Total System	11,509,562	3,466,647	10,129,151	316,977	2,124	2,059
PEPCO:						
MD only	18,811,261	4,604,482	11,885,944	421,019	N/A	3,923
Total System	22,566,190	6,071,019	21,538,657	632,403	5,241	5,375

Source: PSC (1989) and requests for data from each utility.

* Installed capacity does not include non-affiliated purchased power. The Potomac Edison figures include the Company's share of the Bath County pumped storage plant. The BG&E capacity figures include Safe Harbor.

Conowingo Power Company, also a wholly-owned subsidiary of PECO, provides retail service to nearly 33,000 customers in Cecil County, Maryland. Conowingo Power has no generating capacity of its own, obtaining all of its required power from its parent through wholesale purchase. It is the smallest of the investor-owned electric utilities in Maryland.

BG&E has the largest Maryland operations of all the investor-owned electric utilities. Its service area is urban and suburban, and it serves a substantial industrial (i.e., manufacturing) load. Although the industrial portion of the local economy has been declining gradually since the early 1970s, BG&E's annual peak demands for the past several years have increased faster than had been forecast. In 1989, BG&E experienced a record peak demand of 5,304 MW. BG&E's current 5,744 MW installed capacity (excluding purchased power) is a mixture of nuclear, coal, oil, gas, and hydroelectric power. BG&E's supply-side resources in 1989, including capacity purchases, totalled 6,168 MW. The Calvert Cliffs nuclear plant accounts for nearly 30 percent of the company's installed capacity and, during normal years, for more than 40 percent of its generation.

The Potomac Edison Company (PE) serves the Western Maryland region and contiguous areas in Virginia and West Virginia. PE is a subsidiary of the Allegheny Power System (APS), a holding company that also owns Monongahela Power Company (MP) and West Penn Power Company (WPP). MP serves northern West Virginia and a small area in Ohio, and WPP serves southwestern Pennsylvania. PE sells more than two-thirds of its energy to its Maryland customers; these sales account for about 20 percent of all APS sales. The APS service area contains no large metropolitan areas; it is primarily rural and suburban, with a substantial amount of heavy industry. Unlike Maryland's other major utilities, both PE and APS are winter-peaking. The information in this chapter refers mostly to APS rather than to PE specifically, because APS operates the three companies as a single system for purposes of bulk power supply planning.

During the winter of 1989/1990, the APS and PE peak demands were 6,489 MW and 2,124 MW, respectively, compared to their total supply-side resources of 7,756 MW and 2,273 MW. APS generates almost all its electric power from coal-fired plants. It also owns 840 MW of the 2,100 MW Bath County Project, a pumped storage hydroelectric plant operated by Virginia Power Company, which APS uses primarily to meet its peaking needs.

DP&L serves directly or indirectly virtually all of the power requirements on the Delmarva Peninsula. The only other entities on the peninsula that generate significant amounts of electric power are the municipal utilities of Dover, Delaware and Easton, Maryland. The region includes the entire state of Delaware, the Maryland Eastern Shore counties, and the two Virginia counties of Accomack and Northampton. DP&L's service area is very heterogeneous. In the northern part of Delaware, DP&L serves the Wilmington metropolitan area, a large urban/suburban complex with substantial heavy industry. Most of the rest of the peninsula is rural, with small towns, light manufacturing, and ocean resorts. Maryland accounts for approximately 25 percent of the DP&L system power demands. DP&L's peak demand in 1989 was 2,175 MW, compared to installed capacity of 2,393 MW. DP&L's capacity is a mix of nuclear, coal, and gas/oil. Its nuclear capacity consists of small ownership percentages of the Peach Bottom and Salem generating stations, which are operated by other utilities.

PEPCO is approximately the same size as BG&E on a system-wide basis, but Maryland accounts for only about 60 percent of PEPCO's operations, the District of Columbia accounting for the remaining 40 percent. Like BG&E's, PEPCO's service area is a mixture of urban and suburban customers, with the suburban portion growing more rapidly. One important difference is that PEPCO serves virtually no heavy manufacturing loads. In 1989, PEPCO's peak demand (system wide) was 5,241 MW with generating capacity of 5,825 MW (including purchased power). During the past several years, approximately 85 to 90 percent of PEPCO's generation has come from its coal-fired units, with the remainder being oil- and gas-fired generation. In 1987, PEPCO entered into a 19-year purchased power contract with the Ohio Edison Company, providing PEPCO with up to 450 MW through 2006.

C. Inter-utility Operations

Inter-utility organizations and cooperation between utilities enhance the reliability and reduce the cost of electric service for participating utilities. Maryland utilities participate in both regional reliability councils and multi-utility power pool systems.

Regional Reliability Councils

The North American Electric Reliability Council (NERC), formed by the electric utilities in 1968, coordinates utilities' generation and transmission systems and assesses the reliability of electric service. NERC is divided into nine regional reliability councils, which monitor loads and power resources, conduct reliability studies, and establish appropriate reliability standards. Each of Maryland's inventor-owned utilities belongs to one of two regional reliability councils. Potomac Edison and the APS system belong to the East Central Area Reliability Agreement (ECAR); and BG&E, DP&L, and PEPCO belong to the Mid-Atlantic Area Council (MAAC).

As of 1989, ECAR reported an overall reserve margin of 29 percent, while MAAC reported an 18 percent margin. By 1998, the reserve margins are projected to fall to 21 percent for ECAR and to rise to 22 percent for MAAC (NERC 1989). These projections, of course, are subject to uncertainties. Since the projected reserve margins are at or below desired levels, they suggest that there is little or no surplus generating capacity in this region. Hence, there appears to be little opportunity for Maryland utilities to rely on other utilities in the region to serve the growth in Maryland power demands.

ECAR's capacity and transmission network are capable of handling currently predicted loads. However, unexpected demand growth or delays in planned additions to generating capacity could diminish the system's reliability. In the MAAC region, planned capacity additions will satisfy projected future demands, but operating conditions will be tight during the next ten years. The region has experienced higher-than-anticipated demand growth recently, and demand forecasts and capacity addition plans have been revised accordingly. However, if demand growth continues above anticipated levels, capacity shortfalls may occur in the MAAC region during the 1990s. For example, during the summers of 1988 and 1989, the region experienced voltage reductions due to tight supplies of generation capacity.

MAAC's transmission grid also faces constraints in importing emergency power from neighboring regions, particularly the west and south. The Council is currently undertaking studies to determine its future transmission system needs and options to upgrade transfer capability and reliability.

Power Pools

In order to realize fully the efficiency and reliability benefits of power transactions, the Maryland utilities participate in multi-utility power pools. PE and its two utility affiliates form the APS power pool. All the units owned by the three members are centrally dispatched in order to minimize fuel costs. APS also performs all generation planning centrally, taking into account the power needs of the entire system. The APS Power Supply Agreement governs the pricing of power transactions and the assignment of cost responsibility for generating reserves among the members.

PEPCO, BG&E, and DP&L are members of the Pennsylvania-New Jersey-Maryland Interconnection (PJM) power pool, which also includes most of the electric utilities in Pennsylvania, New Jersey, Delaware, and the District of Columbia. By centralizing the operations of the pool members, PJM facilitates the most efficient possible usage of the generating units and provides greater supply reliability for all pool members.

The PJM pool employs an operating procedure known as "economic dispatch" in order to minimize fuel costs for all members collectively. With economic dispatch, a utility system minimizes fuel expense by making maximum use of its lowest-operating-cost generating units (i.e., base load coal or nuclear) and only dispatching the higher-cost units (i.e., oil or gas) when the base load units are running at their maximum levels. PJM implements this process by collecting plant operating data on all member plants and continuously determining the pool-wide cost of generating an additional kilowatt-hour (the incremental cost). It operates all of the members' units as a single system, in which generation is added from the most economical source available -- regardless of ownership -- to meet the next increment of load. These intercompany power flows are referred to as interchanges. Interchange accountants later determine how much each company bought from or sold to other members of the pool. Through this system of economic dispatch and after-the-fact accounting, PJM realizes and distributes the economies of operation.

Unlike APS, the individual PJM companies perform their own planning for new generation and transmission facilities. PJM establishes criteria or standards for generating reserves and also performs an enforcement role. For example, PJM may assess a member utility a penalty for failure to maintain sufficient generating reserves. Power pooling thus helps to bring about more economical use of existing generating plant, coordination of future capacity additions by members, and improved power supply reliability.

Power Purchase Agreements

All of the investor-owned Maryland utilities participate in power purchase agreements with other utilities, both within the APS and the PJM power pools and with other utility systems. APS is a major net exporter of power, though Potomac Edison imports power from its APS affiliates, WPP and MP. BG&E has recently entered into a power purchase agreement with Pennsylvania Power & Light Company (PP&L), which is part of PJM, to meet rapidly increasing demands. PEPCO will also rely on imported power during the next 15 years. PEPCO began receiving 150 MW of power from the Ohio Edison Company in 1987; this amount increased to 450 MW in 1989. DP&L entered into a 20-year agreement to purchase 100 MW from Duquesne Light Company beginning in 1990, but this purchase was rejected by the Delaware Public Service Commission in March 1990. Because DP&L was unable to obtain regulatory approval in Delaware, the purchase agreement was cancelled.

Power purchase agreements among utilities can facilitate economic use of all available generating resources. APS, for example, is particularly well-suited to power exchanges. As the only winter-peaking system among the Maryland utilities, it tends to have surplus capacity during the summer when the other utilities may need to purchase power.

D. Projected Load Growth and Resources for Meeting Growth

This section reviews the anticipated growth in power demand over the next 15 years for Maryland's major electric utilities and their resource plans for meeting those needs. Resource plans are broad in scope, including conventional power plants, load management programs, purchased power agreements, and the development of non-utility power. The Maryland utilities employ "least cost" planning methods, in which the least cost resource plan is generally the one requiring the minimum present value of the utility's revenues after appropriate consideration for quality of service, reliability, flexibility, and environmental impacts.

The planning environment in Maryland changed substantially during the latter half of the 1980s, inducing the utilities to alter their resource plans in important ways. With the exception of the APS service area, power demands in the state grew far more rapidly than the utilities anticipated. From the late 1970s through 1984, load growth was relatively slow, increasing at a compound rate of approximately two percent per year (or less) for DP&L, PEPCO, and BG&E. Load growth has accelerated sharply since the mid-1980s, increasing by five to eight percent per year for the three companies. This rapid growth is attributable to very strong service area economies, and to the fact that electric rates have either fallen or increased less rapidly than inflation. The emergence of this rapid load growth and the perceived need for new capacity has also stimulated utility interest in load management programs.

A second and related change is slower growth or even decline in fuel prices, particularly for oil and gas. The increased growth rate in power demands has led the utilities to accelerate their schedules for new capacity resources. The lower oil prices that currently prevail (compared to the early 1980s), combined with the relatively low cost of constructing combustion turbine units and the utility industry's desire for smaller increments of generation to minimize financial risk, have increased the attractiveness of combustion turbine peaking plants (as opposed to base load coal plants).

Another resource that has increased in importance in recent years is non-utility generation (NUG) capacity. NUG capacity includes power produced by independent power producers (IPPs) and qualifying facilities (QFs). QFs are either cogenerators or facilities that produce power using renewable resources, wastes, or biomass. The federal Public Utilities Regulatory Policy Act of 1978 (PURPA) requires that utilities purchase all power offered by QFs at rates reflecting the utilities' "avoided cost." APS anticipates nearly 600 MW of non-utility generation on its system by the mid-1990s. NUG is discussed more fully in Chapter 9.

With the acceleration in load growth referred to earlier, PEPCO and DP&L have revised their load forecasts upwards. In 1985, PEPCO projected a year 2000 peak demand of 5,430 MW, and DP&L projected its peak demand for that year at 1,952 MW. Their current projections for year 2000 are 6,961 MW and 2,601 MW, respectively. BG&E has increased its year 2000 forecast peak from 6,070 MW to 6,590 MW, even though its current forecast assumes much larger load management savings than the forecast published in 1985.

The outlook for growth in power demands and the resource plans designed to meet that growth are described below for APS, BG&E, DP&L, and PEPCO, based on the 15-year integrated resource plans filed by each with the PSC, and other information. APS is used rather than PE because resource planning and reliability are addressed for the entire APS system. Later in this section, load projections prepared by PPER are presented for comparative purposes.

<u>The Allegheny Power System</u>

After reducing demand estimates to account for its demand-side management programs, APS projects that its peak demand growth rates will increase by approximately 1.8 percent per year over the next 15 years. This amounts to an increase of about 1,700 MW by the year 2005 (see Table 2-3). Projected low growth rates in personal income and industrial production in the APS service area are responsible for this continuing modest growth trend. (Recall that APS has a very large industrial load.)

Table 2-3

Allegheny Power System
Projected peak demand, capacity and reserves
(megawatts)

Year[a]	Annual Peak Demand[b]	Net Capacity Additions	Capacity Sale[c]	Total Capacity	Reserve Margin	Resource Change
1991	6,412	85	-300	7,841	22.3%	+85 Hatfield rerate
1992	6,567	-	-200	7,941	20.9	-
1993	6,678	131	-200	8,072	20.9	+131 NUG purchases
1994	6,788	154	-200	8,226	21.2	+154 Mitchell reactivate
1995	6,921	201	+100	8,727	26.1	+80 NUG; +121 Springdale reactivate
1996	7,051	310	+100	9,037	28.2	+310 NUG purchases
1997	7,165	86	0	9,023	25.9	+86 Springdale reactivate
1998	7,276	129	0	9,152	25.8	+129 CT
1999	7,393	129	0	9,281	25.5	+129 CT
2000	7,509	129	0	9,410	25.3	+129 CT
2001	7,619	129	0	9,539	25.2	+129 CT
2002	7,744	258	0	9,797	26.5	+258 CT
2003	7,868	129	0	9,926	26.2	+129 CT
2004	7,992	129	0	10,055	25.8	+129 CT
2005	8,109	330	0	10,385	28.1	+330 coal plant

Source: 1990 Long-Range Plan submitted by the Potomac Edison Company.

(a) "Year" refers to winter ending in the designated year. For example, 1990 is the winter of 1989/1990.
(b) Annual peak demand is company projection after netting out demand-side management savings.
(c) "Capacity sale" refers to sale to Old Dominion Electric Cooperative through 1994. The "+100" figures in 1995 and 1996 represent unspecified winter season capacity exchanges.

CT = combustion turbine.

Slow demand growth and APS' 840 MW share of the Bath County power plant (installed in 1985) have given the utility more capacity than it requires to meet its load. APS has therefore entered into an agreement with the Old Dominion Electric Cooperative (ODEC), through which ODEC may purchase up to 300 MW of capacity from APS through 1994.

APS plans to rely primarily on new NUG capacity through 1998 to meet its demand growth. Currently, APS purchases 160 MW yearly from QFs, and it anticipates that an additional 521 MW of NUG capacity will become available between 1990 and 1996. APS' 1989 plan had included substantially more NUG capacity, 695 MW of post-1990 additions. As a result of this loss, APS now plans to accelerate plans to reactivate Springdale and Mitchell, oil-fired steam units now in cold storage, which will provide an additional 361 MW of capacity. This is now scheduled for the period 1994 to 1997. These WPP-owned units are located in Pennsylvania.

Between 1998 and 2005, APS plans to install 1,362 MW of capacity in the form of eight combustion turbines, which will provide a total of 1,032 MW, and a 330 MW pulverized coal plant. Two major changes in the APS resource plan since the last CEIR include load reductions from the extension of demand management programs beyond 1995 and delayed plant retirements. The present APS plan assumes approximately 400 MW of savings from demand-side programs over the 15-year period (which is reflected in the load projections on Table 2-3).

Table 2-3 also shows the projected APS reserve margin, calculated as available installed capacity minus annual peak demand, divided by peak demand. Reserves are needed because of generating unit down time and uncertainties in projecting power demands. APS utilizes a minimum planning reserve margin of 25 percent. During the period 1990 to 2005, reserves are projected to range between 21 and 28 percent, according to the current plan.

In summary, due to anticipated slow load growth, demand management, capacity in cold storage reserve, and the abundance of non-utility generation projects in the region, APS has no plans to construct any new capacity until 1998. When construction does occur, it will be in the form of oil-fired combustion turbines, at least until 2005.

Baltimore Gas & Electric Company

BG&E's system peak demand has increased rapidly in recent years due to the unexpectedly rapid economic growth in its service territory. Thus, despite introducing new load management programs, it has had to revise its load forecasts upward. Table 2-4 presents BG&E's demand and capacity forecasts for the next 15 years; the load data incorporate anticipated load reductions from demand-side management plans. BG&E is projecting a convergence of its summer and winter peaks and expects to become winter-peaking by 2003. BG&E will meet much of its increased demand requirements by accelerating

Table 2-4

Baltimore Gas & Electric Company
Projected peak demand, capacity and reserves
(megawatts)

Year	Annual Peak Demand(a)	Net Capacity Additions	Total Capacity(b)	Reserve Margin	Resource Change(c)
1990	5,540	17	6,185	11.6%	+43 misc. uprating; -26 purchased power
1991	5,600	468	6,653	18.8	+642 Brandon Shores 2; -174 PP&L purchases
1992	5,670	125	6,778	19.5	+125 PP&L purchases
1993	5,780	42	6,820	18.0	+42 PP&L purchases
1994	5,880	118	6,938	18.0	+118 PP&L
1995	5,970	107	7,045	18.0	+134 Perryman CT; -27 PP&L purchases
1996	6,100	153	7,198	18.0	+134 Perryman CT; +19 PP&L
1997	6,220	142	7,340	18.0	+134 Perryman CT; +8 PP&L
1998	6,340	141	7,481	18.0	+134 Perryman CT; +7 PP&L
1999	6,460	142	7,623	18.0	+118 Perryman CC; +24 PP&L
2000	6,590	153	7,776	18.0	+118 Perryman CC; +35 PP&L
2001	6,690	165	7,941	18.7	+516 Perryman CC & CT; -351 PP&L purchases
2002	6,810	414	8,355	22.7	+414 coal plant
2003	6,930	0	8,355	20.6	-
2004	7,070	0	8,355	18.2	-

Source: BG&E Integrated Resource Plan 1990-2004 (base case forecast and plan).

(a) Company forecast of peak demand net of demand-side programs.
(b) Total capacity includes 169 MW from Bethlehem Steel.
(c) BG&E has a flexible arrangement for peaking capacity from PP&L, which permits the year-to-year changes shown above. The 125 MW in 1992 is base load. Both the peaking and base load purchases terminate in 2001.

construction of the approximately 640 MW coal-fired Brandon Shores Unit 2, now scheduled for service in May 1991.

A 12-year purchased power agreement with Pennsylvania Power and Light Company (PP&L), to last from 1990 through 2001, will provide BG&E with much of the additional capacity it requires. An initial one-year agreement allowed BG&E to purchase 200 MW from PP&L between June 1, 1989 and May 31, 1990. Subsequently, BG&E will receive a 125 MW share of the Susquehanna nuclear plant and the associated transmission path to the BG&E grid. BG&E will also have the option to take up to 600 MW of peaking capacity (275 MW after October 1991). This is a very flexible arrangement, which provides BG&E with 400 MW of total purchased power from PP&L until 2001.

BG&E recently filed an application with the PSC to construct a series of combustion turbine and combined cycle units at its Perryman site in Harford County. This project will potentially provide up to 800 MW of capacity during the next 15 years, with initial combustion turbine increments entering service in the mid-1990s.

Delmarva Power & Light Company

In 1989, DP&L brought on line two 105 MW gas-fired turbines, known as Hay Road Nos. 1 and 2. Following a more rapid growth in peak demand than expected, DP&L accelerated its plans to increase capacity in the early 1990s. The reserve margin fell to just 8.5 percent in 1988, well below the target reserve margin of 15 percent. Consequently, DP&L plans to expand net capacity by 398 MW between 1989 and 1993, in an effort to achieve its desired level of reliability and meet its PJM reserve obligation. That expansion will be composed of 210 MW from new combustion turbines, 48 MW from a NUG purchase, 150 MW from the Hay Road No. 4 combined cycle, and 30 MW from upgrades of its existing units. DP&L will also lose 40 MW of capacity from the transfer of Delaware City No. 3 unit to a private developer.

While the 105 MW Hay Road No. 1 combustion turbine has been operational since July 1989, for presentation purposes it is considered to be a 1990 resource. A third 105 MW gas-fired combustion turbine at Hay Road is scheduled to come on line in 1991.

In 1989, DP&L signed a 20-year agreement to receive 100 MW of purchased power from Duquesne Light Company beginning in 1990. This contract was rejected by the Delaware Public Service Commission and subsequently cancelled by DP&L. To make up the capacity shortfall, DP&L now proposes to advance the in-service date of the Hay Road No. 4 combined cycle plant from 1994 to 1993.

Also in 1989, DP&L requested bids from NUGs for 100 MW of peaking capacity beginning in 1992. Proposals for 830 MW of capacity were received, and a bid from Star Enterprises for 48 MW was accepted. DP&L has received PSC approval for the purchased power contract. An additional solicitation is planned to add 129 MW of base load capacity from NUGs in 1996.

These proposed expansion plans are expected to increase DP&L's reserve margin to the target level of 15 percent by 1991. After that, construction of a 150 MW combined cycle addition at Hay Road and three base load coal-fired generators are expected to maintain DP&L's reserve margin at or above 15 percent through 2004. The additional 129 MW of base load NUG capacity planned for 1996 and expansions of demand-side management programs will also assist in meeting peak demands through 2004. Table 2-5 presents the company's peak demand forecasts and expected capacity between 1990 and 2004.

The Maryland PSC is currently conducting a proceeding to review various planning issues. DP&L specifically has sought approval for its planned 1996 competitive bid solicitation; the decision to construct a combined cycle plant at its Hay Road site in Delaware; and a general review of its resource planning process, including its approach to demand-side management. This proceeding is expected to be completed in late 1990. During the hearings in that proceeding held in September 1990, DP&L modified its plans, indicating a preference for a 300 MW pulverized coal plant in 1998 to replace the capacity additions of 1998 and 2001 indicated in Table 2-5.

Potomac Electric Power Company

PEPCO experienced higher than expected growth in peak demand during the late 1980s due to extremely high summer temperatures and strong growth in Washington, D.C. area population and employment. Peak demand has grown much faster than PEPCO's installed capacity, and therefore reserve margins fell below 9 percent in 1988, well below PEPCO's target reserve level of 16 percent. PEPCO plans to meet increasing demand through a combination of increased purchases of capacity, new plant construction, and more aggressive use of demand-side management programs.

Table 2-6 presents PEPCO's latest load forecast and capacity projections through the year 2003. Immediate relief of the current tight capacity situation was obtained in 1989, by adding the last 250 MW increment of the purchased power contract with the Ohio Edison Company. This completed the phase-in of the total 450 MW of annual capacity purchases from Ohio Edison, which began in July 1987. In addition to fulfilling PEPCO's near-term capacity requirements, this purchase will displace generation from PEPCO's higher-operating-cost units through the life of the contract, which expires in the year 2005. The power is transmitted from Ohio to the PEPCO service territory through the APS transmission grid. PEPCO plans to meet near-term load increases by installing combustion turbines at its Chalk Point site and will receive 84 MW from a SMECO-owned combustion turbine (sited at Chalk Point and operated by PEPCO). These units are expected to add about 460 MW of capacity by 1991. Beginning in 1992, PEPCO plans to install an approximately 750 MW combined cycle coal gasification plant (Station H), adding capacity in 127 MW increments, as demand growth warrants. This plant is to be sited at the Company's Dickerson Station in upper Montgomery County. Construction of the final stage, the coal gasifier, will

Table 2-5

Delmarva Power & Light Company
Projected peak demand, capacity and reserves
(megawatts)

Year	Annual Peak Demand[a]	Net Capacity Additions	Total Capacity	Reserve Margin (percent)	Resource Additions[b]
1990	2,228	111	2,505	12.4	+105 Hay Road 1; +6 miscellaneous
1991	2,276	120	2,625	15.3	+105 Hay Road 3; +15 miscellaneous
1992	2,294	17	2,642	15.2	+17 miscellaneous
1993	2,337	150	2,792	19.5	+150 Hay Road 4
1994	2,383	0	2,792	17.2	-
1995	2,427	0	2,792	15.0	-
1996	2,472	129	2,921	18.2	+129 NUG purchase
1997	2,517	0	2,921	16.1	-
1998	2,519	100	3,021	19.9	+100 coal plant
1999	2,563	0	3,021	18.0	-
2000	2,601	0	3,021	16.3	-
2001	2,645	150	3,171	20.0	+150 coal plant
2002	2,688	0	3,171	18.3	-
2003	2,727	0	3,171	16.8	-
2004	2,768	150	3,321	15.3	+150 coal plant

Source: DP&L, Updated Integrated Resource Plan, June 1990 update.

(a)Company forecast of peak demand net of demand side management savings.
(b)Miscellaneous in early years refers to unit uprates. In 1992, there is a +48 MW NUG purchase and -40 MW from loss of Delaware City 3. The 1998 coal plant is 150 MW, with Old Dominion Electric Cooperative taking a 50 MW share. Hence, DP&L's net capacity addition is 100 MW.

Table 2-6

Potomac Electric Power Company
projected peak demand, capacity and reserves
(megawatts)

Year	Annual Peak Demand*	Net Capacity Additions	Total Capacity	Reserve Margin (percent)	Resource Change
1989	5,241	250	5,875	12.1	+250 Ohio Edison purchase
1990	5,383	84	5,959	10.7	+84 SMECO combustion turbine
1991	5,494	376	6,335	15.3	+375 Chalk Point combustion turbines
1992	5,558	127	6,462	16.3	+127 Station H
1993	5,587	127	6,589	17.9	+127 Station H
1994	5,625	50	6,639	18.0	+50 Montgomery County Municipal Solid Waste Incinerator
1995	5,672	-	6,639	17.1	-
1996	5,725	127	6,766	18.2	+127 Station H
1997	5,779	-	6,766	17.1	-
1998	5,834	127	6,893	18.2	+127 Station H
1999	5,895	-	6,893	16.9	-
2000	6,961	140	7,033	18.0	+140 Station H
2001	6,037	-	7,033	16.5	-
2002	6,129	140	7,173	17.0	+140 Station H
2003	6,234	-	7,173	15.1	-

Source: PEPCO 1990 Energy Plan.

*PEPCO's Fall 1989 forecast net of demand-side management savings, including programs not yet approved.

depend on oil/gas being sufficiently more expensive than coal so as to justify the gasification plant investment.

PEPCO has been forced to modify its 1989 plan to accommodate two important changes. First, load growth has proven to be more rapid than reflected in PEPCO's 1988 forecast (the basis of its 1989 resource plan). This has induced PEPCO to move up the in-service dates for the Chalk Point and Station H (initial increment) combustion turbines to 1991 and 1992, respectively. Second, PEPCO has encountered licensing delays in the District for its planned Benning Road combustion turbine units and has requested authority to site those units at Chalk Point for a 1991 in-service date. This means that the company is now planning to install four combustion turbines at Chalk Point by 1991, in addition to the SMECO turbine. PEPCO's Chalk Point application has been approved by the PSC.

PEPCO plans to add 50 MW of NUG capacity from the Montgomery County waste-to-energy facility at Dickerson and a 60 MW natural gas-fired cogeneration unit in the District of Columbia, although the D.C. facility is not yet included in the company's official resource plan. In past Energy Plans, PEPCO has identified more than 500 MW of possible NUG capacity additions, but the availability of this capacity is uncertain. If much of this capacity emerges by the mid-1990s, it may become feasible to defer certain portions of Station H.

Demand-side Programs

Demand-side management (DSM) programs have become an integral part of the resource planning process in recent years for all four of Maryland's major electric utilities. For the most part, these programs are designed to reduce demand at the time of the annual peak or to shift demand from the peak periods (when demands are high) to off-peak periods.

Table 2-7 presents the utilities' year-by-year estimates of their annual peak demand reductions from demand-side programs, and Figure 2-2 is a graphic comparison of these projected reductions. The company load forecasts presented earlier in this chapter incorporate the reductions shown on this table. In addition, PEPCO's load forecast, listed in Table 2-6, includes approximately 700 MW of recently approved or proposed DSM savings which are not shown in Table 2-7.

With the exception of Potomac Edison's plans, the programs shown on Table 2-7 emphasize three major areas: (1) direct control of residential water heaters and/or air conditioners; (2) expanded use of time-of-day rates; and (3) curtailable rates for commercial and industrial customers. These programs are generally referred to as "peak shaving" because their primary purpose is to permit a short duration reduction on load on peak days (e.g., the hottest days of the year). However, the peak shaving programs have no appreciable impact on total energy use. Their primary purpose is to provide savings to participating customers and to substitute for new peaking (i.e., combustion turbine) capacity.

Table 2-7

Peak demand reductions from demand-side management programs (megawatts)

Year	APS	PE	BG&E	DP&L	PEPCO[a]
1990	85	62	174	39	215
1991	108	73	220	65	277
1992	131	85	277	91	327
1993	154	96	332	104	352
1994	177	108	368	110	372
1995	200	119	403	117	384
1996	223	131	431	123	397
1997	246	142	466	127	411
1998	269	154	487	132	425
1999	293	165	501	136	438
2000	316	177	514	140	450
2001	339	188	525	145	464
2002	362	200	536	148	479
2003	385	211	546	154	491
2004	409	223	557	158	505

Sources: 1990 Long Range Plan of the Potomac Edison Company, BG&E Integrated Resource Plan 1990-2004, DP&L Challenge 2000 Integrated Resource Planning Study, PEPCO 1990 Energy Plan.

(a) In the fall of 1989, PEPCO received PSC approval of several new programs which, if successful, could increase DSM savings by up to 200 MW by 2004. These new programs are not included on this table. Several other new programs are under consideration at this time.