Chapter 8

Electricity

The United States electric power industry began in the late 1800s when Thomas Edison formed the Edison Electric Illuminating Company in New York City with a power load of about 10 KW serving 85 customers. From this small plant, the industry has grown to a generating capacity of over 650,000 MW nationally. The electric industry forecasts the need to add over 75,000 MW of additional capacity between 1988 and 1997.[1]

The industry comprises about 3,400 utility companies nationwide that furnish electric power to more than 80 million households, commercial establishments, and industrial operations. While electricity heats about 30 percent of the nation's households, other more diversified uses of electricity have also been developed such as mass transit railways, complex computer systems that perform vital functions, and sophisticated communication systems.

To satisfy New Jerseyans' demand for electricity in 1990, electricity suppliers imported 29 percent of all electricity consumed in-state and generated electricity from the following fuels: nuclear (40 percent), coal (22 percent), petroleum (3 percent) and natural gas (6 percent). (See Figure 8-1.)[2]

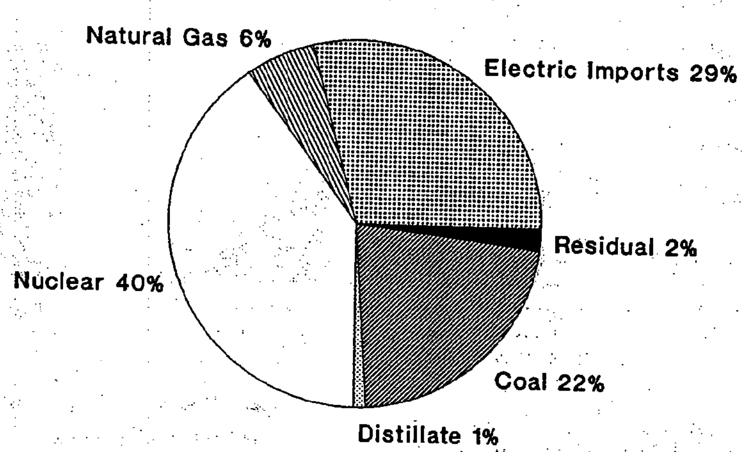
Historically, the growth in electric energy paralleled the growth in gross national product (GNP) until about 1970. (See Figure 8-2.) This growth in energy use was primarily influenced by the electrification of the country. As the price of other fuels increased, the cost of electricity remained relatively low. This economic competitiveness was further improved by the increase in the heat rate and level of fuel efficiency at which power plants generated electricity and by the advantage gained in building large generating facilities.

Until the early 1970s marginal electricity costs were lower than average costs, since the new plants were more efficient than the older ones. Since then, marginal costs have been higher so that expanded capacity raises rates.

During the 1960s the peak demand grew at a compounded annual rate of over 7 percent. In order to meet continually increasing demand, utilities began to plan and construct large baseload plants. This growth and the Clean Air Act of 1970 led utilities to rely more on building nuclear plants instead of coal-fired plants in the belief that nuclear plants could be operated in a safe and environmentally acceptable way. In 1971 the full cost of both coal and nuclear plants ranged between $400 and $500

FIGURE 8-1

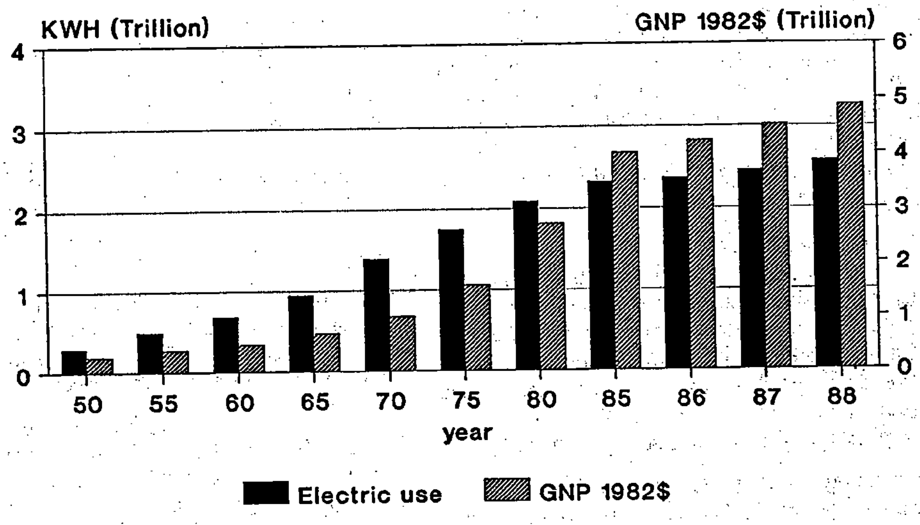
Generation of Electricity for New Jersey
Source for 66,328 GWH in 1990



Note: Net gigawatthours (GWH) generated or imported as % of 1990 net system req.
Source: DEPE, NJ Energy Data System.

FIGURE 8-2

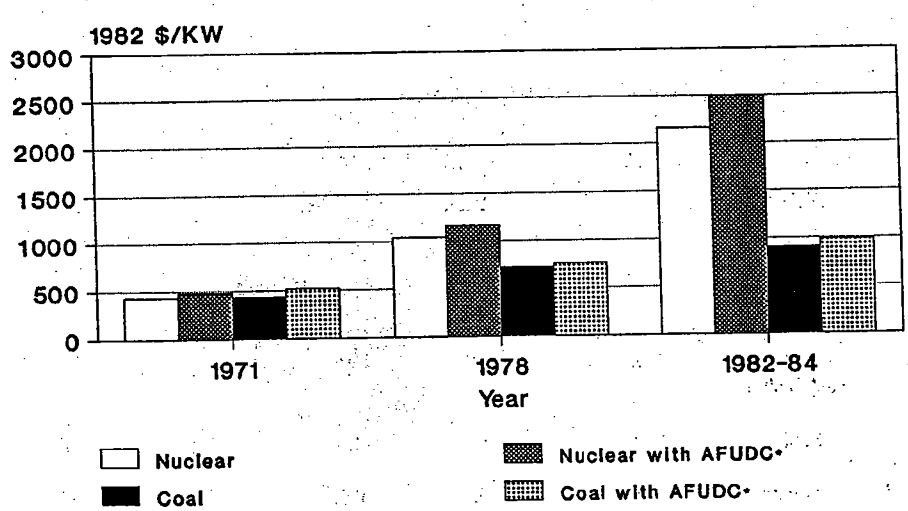
Relation of Electric Use to GNP
United States 1950-1988



Source: EIA, Annual Energy Review, 1989 T.92
1990 Statistical Abstract, T.690

FIGURE 8-3

Electric Powerplant Cost Escalation
1971-1984



*Allow. for Funds Used During Construct.
Source: OTA, New Elec. Power Technology Problems and Prospects for the 1990's.

per KW. (See Figure 8-3.) By 1982 nuclear plants were much more expensive to build than coal plants.

The 1973-74 Arab oil embargo caused an unprecedented change in the operation of the electric power industry. Forecasts of electric demand growth and costs, based solely on past trends, proved virtually useless. Utility executives found themselves caught in a complicated and uncertain maze of financial, regulatory, and technological considerations.

On average, utilities paid 240 percent more for oil and 385 percent more for natural gas in real dollars in 1984 than in 1972. Due to these price escalations, the utilities began to *back out* oil and gas use and intensified development of coal and nuclear plants. On a nationwide basis oil dropped from 16 to 5 percent in the utility fuel mix and gas from 22 to 12 percent between 1972 and 1984.

Meanwhile construction costs of new power plants, particularly nuclear, rose dramatically during this period. Many factors contributed: increased attention to environmental and safety issues that extended construction lead times and added equipment costs; the changing regulatory environment; inflation-driven doubling of the cost of capital; and poor management.[3]

While in the late 1940s and 1950s utilities were seeking reductions in rates, for the first time in the 1970s utilities sought higher rates. Additionally, most utilities seriously misinterpreted the price elasticity of electric demand, the relationship between a change in price and change in use. Growth in demand dropped from 7 percent a year to less than 2.5 percent by the end of the decade, as consumers used electricity more efficiently. As shown in Figure 8-2, the ratio of electric use to GNP started to drop after the 1979 Iranian crisis, indicating that the economy produced more goods and services with fewer kilowatt hours.

These lower growth rates in peak and energy brought some electric utilities to the brink of bankruptcy when forced to cancel large, unneeded power plants. The combined effects of erosion in rate base and declining demand growth, coupled with the increasingly costly construction programs already underway, left the industry struggling financially as bond ratings and stock prices fell precipitously.

In 1979, the accident at Three Mile Island Unit 2 (TMI-2) substantially altered the outlook towards the nuclear power in this country, clouded the utility capacity planning process and further burdened the financial capabilities of utilities with heavy commitments to nuclear power. After the accident, the Nuclear Regulatory Commission (NRC) imposed a moratorium on the licensing of nuclear reactors. In addition, the NRC required retrofitting commercially operating reactors to take into account the lessons learned at TMI. These events contributed to a subsequent escalation of nuclear plant construction costs.

Even prior to the TMI Unit 2 accident, lower growth in demand rates and rising costs led to a reevaluation of the continued commitment to certain nuclear projects. Since 1972, orders for 117 nuclear power plant in the United States have been cancelled, and every project on which construction started after 1973 was eventually cancelled.[4] After the accident at Chernobyl in 1986, public concern about nuclear power safety increased. While some countries continue to pursue aggressive nuclear power plant construction programs, in the United States there have been no new orders since 1978.[5]

At the inception, nuclear power was thought to have indisputable advantages over other forms of energy in its production cost. Today the economic viability of nuclear power is in question. The capital cost of constructing new nuclear power plants has skyrocketed since the early

TABLE 8-1

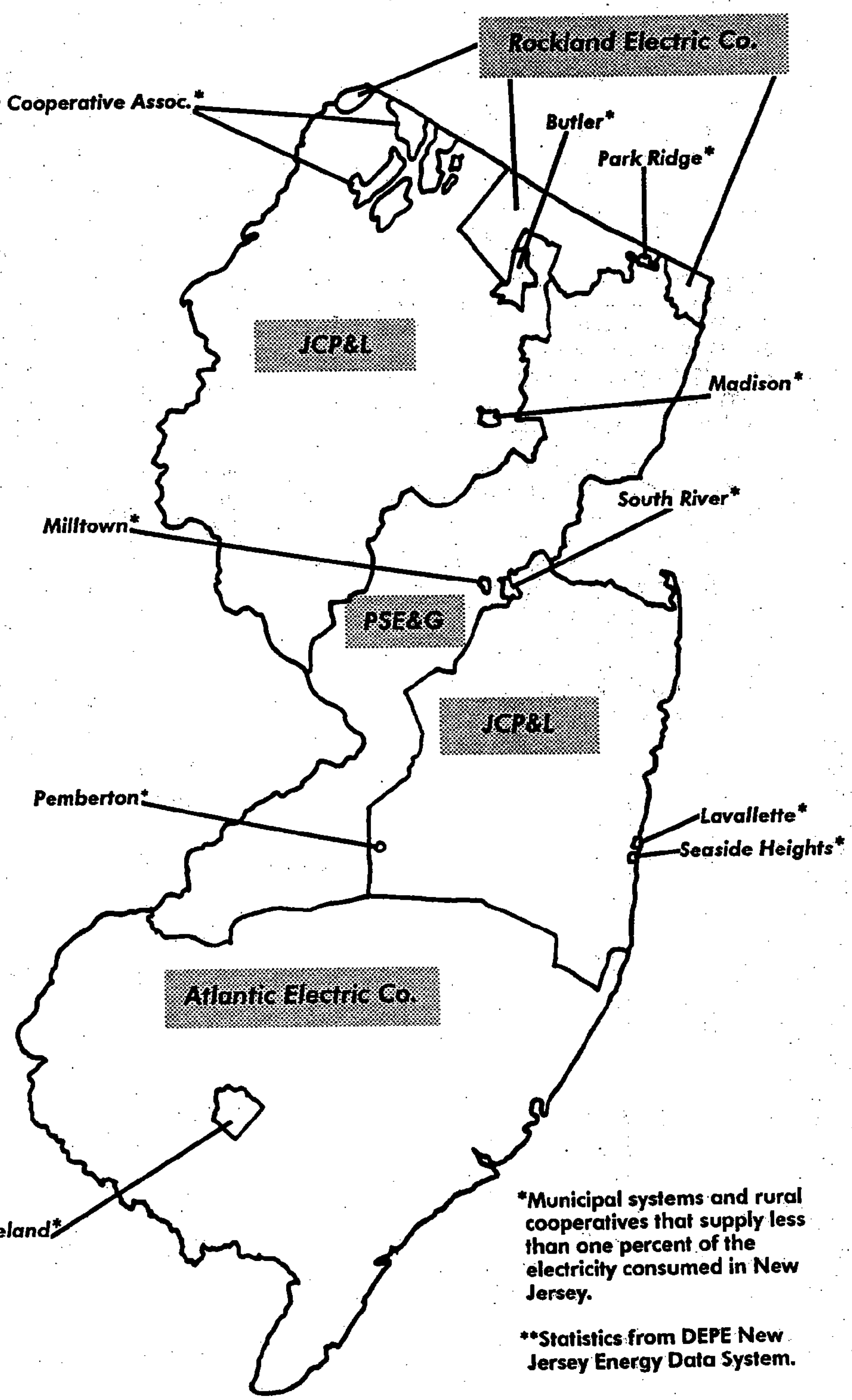
Profiles of New Jersey Electric Utilities

Utilities	Area Served	Number of Municipalities	Customers (thousand)	Percent of Sales: Residential	Commercial	Industrial
PSE&G	Northest to West Central	225	1,892	27%	47%	25%
JCP&L	Northwest to East Central	232	880	39%	37%	23%
AE	South	124	450	42%	39%	18%
Rockland	Northern Bergen, Passaic and Sussex	6	62	41%	30%	29%

Source: Utility company annual reports and tariffs 1990, New Jersey Energy Data System.

FIGURE 8-4

Service Territories of Electric Companies Operating in New Jersey



1990 Utility Profiles**

Atlantic Electric Co.

Customers:	450,000
Revenues:	$720 million
Sales:	7,757 GWH

Jersey Central Power & Light (JCP&L)

Customers:	880,000
Revenues:	$1.5 billion
Sales:	16,465 GWH

Public Service Electric & Gas (PSE&G)

Customers:	1,892,000
Revenues:	$3.3 billion
Sales:	36,723 GWH

Rockland Electric Co.

NJ customers:	62,000
NJ Revenues:	$125 million
NJ Sales:	1,176 GWH

*Municipal systems and rural cooperatives that supply less than one percent of the electricity consumed in New Jersey.

**Statistics from DEPE New Jersey Energy Data System.

1970s. The installed cost of nuclear generation per KW increased from $388 in 1971 to $2,693 in 1985. With inflation factored out, the real increase is approximately sixfold.[6] Utility executives are now more wary about risks of constructing new generating stations. Data Resources, Inc. (DRI) forecast in 1988 that utility spending would decline from $26.4 billion in 1988 to $24.3 billion in 1990.[7] This decrease in spending was projected to extend even to those utilities that were experiencing growth in their service areas and that had excess cash relative to their capital expenditure programs.

During the late 1960s in response to the increasing growth in peak load and energy, New Jersey electric utilities followed the national trend— construction of nuclear power plants. At one time, New Jersey utilities planned to build more than 10 nuclear reactors. Siting plants offshore or on an artificial island were among the proposals. However, most of these projects never reached fruition.

As a result of the TMI-2 accident, which threatened JCP&L with bankruptcy, JCP&L cancelled its Forked River unit after an expenditure of $384 million. PSE&G's Hope Creek 1067 MW Unit No. 1 came on line at the end of 1987 with a price tag of $4.5 billion or $4,200/KW. Over $1.2 billion of this cost was due to interest during construction. Originally conceived in 1968 when growth in electricity had averaged 7 percent per year, Hope Creek was to have included two 1,000 MW units and cost $500 million total. Faced with the cash demands of building both units, PSE&G cancelled Unit No. 2 in 1983 after spending $300 million. At the time the decision to cancel was made, electricity growth rates had dropped to about 2 percent, with little increase forecast for the next decade.

During the late 1980s peak demand growth again began to exceed forecasts. In 1987 and particularly in 1988, electricity use and peak demand increased to levels that forecasters had not expected for several years, possibly a decade.[8] In 1988, two separate stretches of extremely hot, humid weather caused voltage reductions on June 22 and August 15 as the state's utilities were unable to obtain relief normally available from other power pools. In 1989, New Jersey utilities imposed three separate 5 percent voltage reductions on June 1, June 26 and July 25. The utilities successfully avoided the need to impose voltage reductions in 1990.

Current Electric System

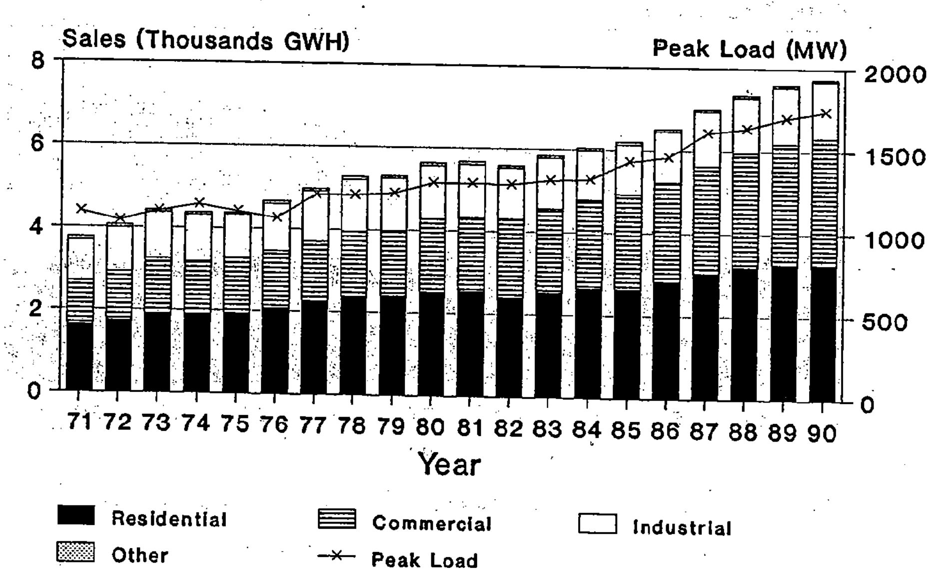
New Jersey Electric Utilities

Three major electric utilities supply more than 90 percent of New Jersey's electricity: Atlantic Electric (AE), Jersey Central Power and Light Company (JCP&L), and Public Service Electric and Gas Company (PSE&G).

Other companies divide the remaining 10 percent. These include Rockland Electric Company, a subsidiary of the New York-based Orange and Rockland Utilities. In 1990, Rockland Electric had annual revenues in New Jersey of approximately $125 million on sales of 1,176 gwh and served approximately 62,000 customers, about 54,000 of which are residential, in parts of Bergen, Passaic, and Sussex counties.[9] Vineland Electric, serving the City of Vine-

FIGURE 8-5

Atlantic Electric Sales & Peak Load
1971-90



Source: NJEDS

land, is the largest of ten municipally- owned systems. A number of rural electric cooperatives and small public systems supply less than 1 percent of New Jersey's electricity. (See Table 8-1 and Figure 8-4).

Atlantic Electric

AE serves the southern third of New Jersey and is experiencing high growth in both energy and peak demand, with 1990 revenues of $720 million for 7,757 gwh sold to 450,000 customers.[10] (See Figures 8-5 through 8-7.)

The residential sector accounts for about 42 percent of the company's energy sales and over half of the revenues. While the commercial sector has exhibited the fastest growth, the industrial sector has shown a corresponding steady decline. Since 1980, the company has increased its reliance upon coal, nuclear, and out-of-state purchases while decreasing its dependence upon oil. Out-of-state purchases consist of PJM interchange and firm purchases from Pennsylvania utilities that principally depend on nuclear and coal generation.

In response to increasing demand, AE placed an 81 MW combustion turbine on line in 1990; a second turbine began commercial operation in 1991. To continue to meet its incremental capacity and energy needs into the mid-1990s, AE is relying primarily upon approximately 500 MW of non-utility cogeneration capacity from three projects in the western portion of its territory and an 80 MW resource recovery facility located in Delaware County, Pennsylvania. The resource recovery facility began operating in July of 1991 and construction on two of the cogeneration projects was already underway as of October 1991. Should all or some of these projects not come to fruition, AE has filed a Notice of Intent with the Board to construct a 220 MW gas-fired combined cycle facility in Millville, New Jersey as part of its contingency planning. In May of 1990, the Board issued its early assessment report concerning this proposal. The utility filed for a contingent certificate of need in November 1990 and as of October 1991 its application was pending hearings at the Office of Administrative Law (OAL).

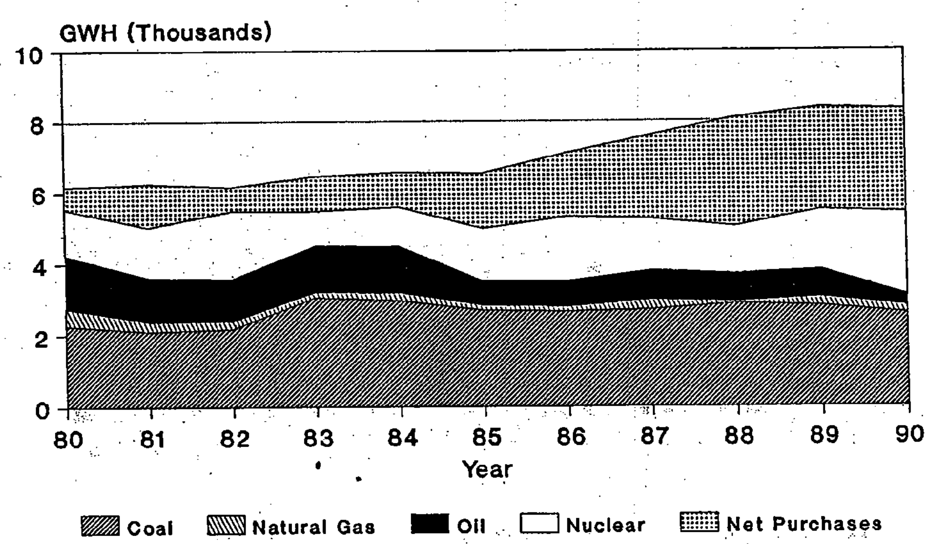
Jersey Central Power and Light Company

JCP&L serves the east-central and northwestern portions of New Jersey, split by PSE&G. In calendar year 1990, JCP&L had revenues of $1.5 billion for 16,465 gwh sold to 880,000 customers.[11] (See Figures 8-8 through 8-10.) The utility's sales growth since the early 1980s has resulted primarily from population growth and rapid expansion of the commercial sector within JCP&L service territory.

Since the TMI-2 accident in 1979, JCP&L has relied heavily upon out-of-state purchases from companies with excess capacity to meet its net system requirements. Energy purchases increased from almost 60 percent to about 70 percent in both 1983 and 1984. TMI Unit No. 1's return to full service in 1986 eased the supply situation somewhat; however, in 1990, purchases still represented approximately half of JCP&L's energy supply. Tapping

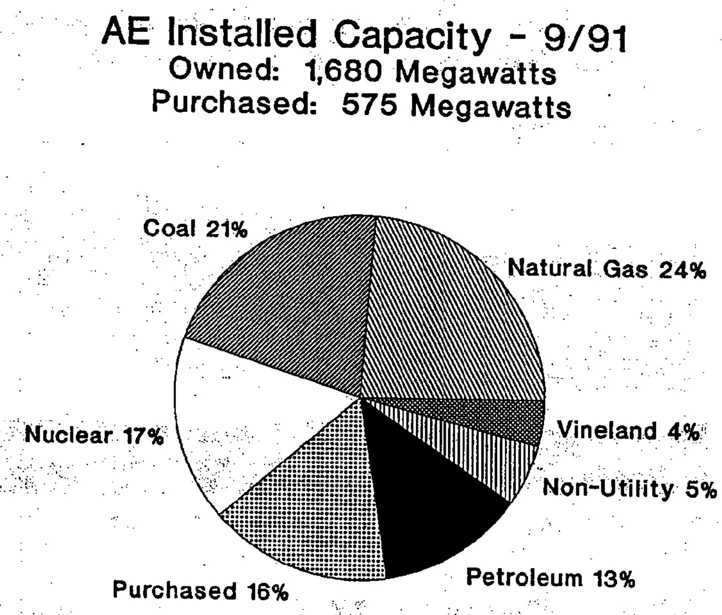
FIGURE 8-6

Atlantic Electric Net System Requirement
Net GWH Generated, by Source 1980-1990



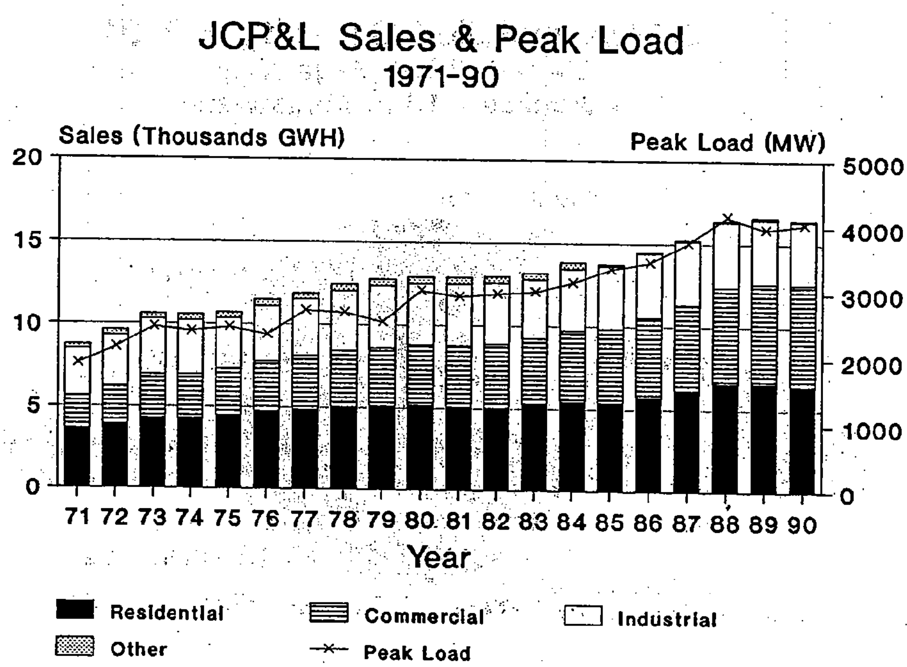
Note: GWH - Gigawatthours generated.
Source: DEPE, NJ Energy Data System.

FIGURE 8-7



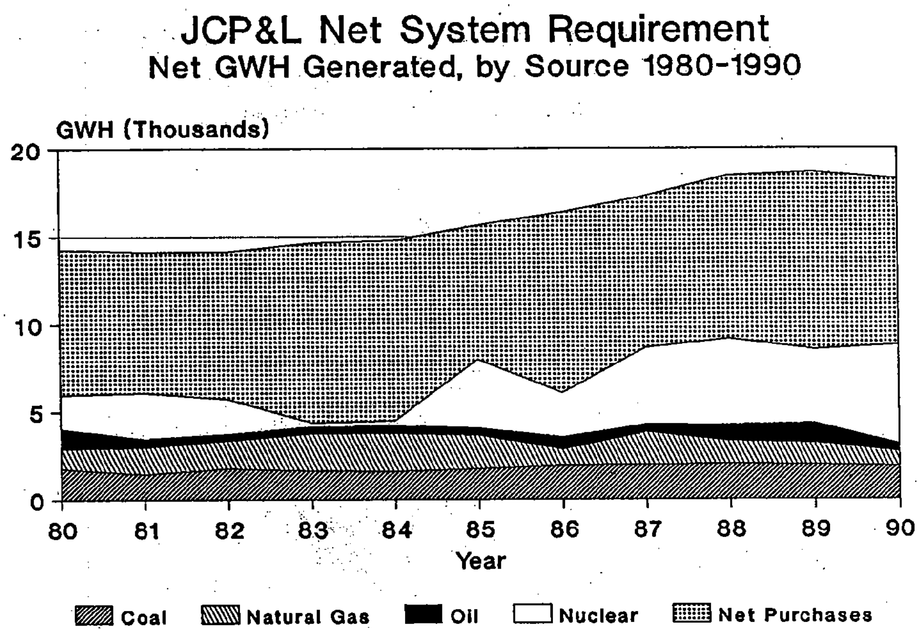
Source: MAAC Regional Reliability Council, 4/1/91, see Appendix A-8-1

FIGURE 8-8



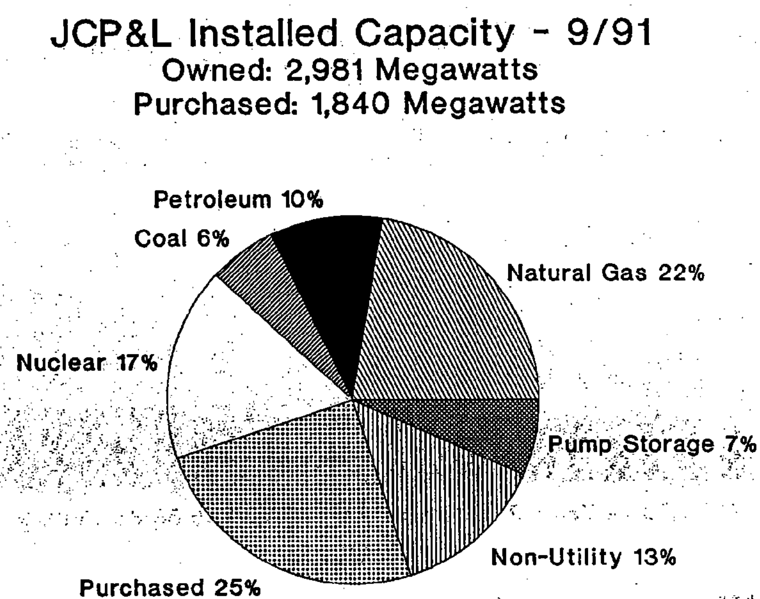
Source: NJEDS

FIGURE 8-9



Note: GWH - Gigawatthours generated
Source: DEPE, NJ Energy Data System.

FIGURE 8-10



Source: MAAC Regional Reliability
Council, 4/1/91, see Appendix A-8-2

excess Midwest capacity, JCP&L has been able to enter into contracts for both capacity and energy at attractive rates for the near term at least. The utility also added a 78 MW combustion turbine to their system in 1989 in Lacey Township, New Jersey.

JCP&L also purchases approximately 718 MW from non-utility cogeneration and small power and producers and has entered into long-term contracts for an additional 522 MW of non-utility power projected to come on line by 1996. General Public Utilities Corporation (GPU), JCP&L's holding and parent company, has signed an agreement to purchase 150 MW from an existing Duquesne Light Company 300 MW coal-fired facility and has allocated a portion of the power for JCP&L. The agreement also stipulates that the two companies, jointly, will construct a new transmission line capable of carrying approximately 1500 MW from western to eastern Pennsylvania. As of October 1991, the agreements were the subject of hearings at the OAL.

Public Service Electric and Gas Company

PSE&G serves a diagonal east-west central portion of New Jersey. The service territory includes many older, fully developed areas. PSE&G is the largest electric utility in the state, supplying over 60 percent of all the electricity sold in New Jersey. In 1990, PSE&G had electric operating revenues just under $3.3 billion for 36,723 gwh sold to 1,892,000 customers.[12] (See Figures 8-11 through 8-13.)

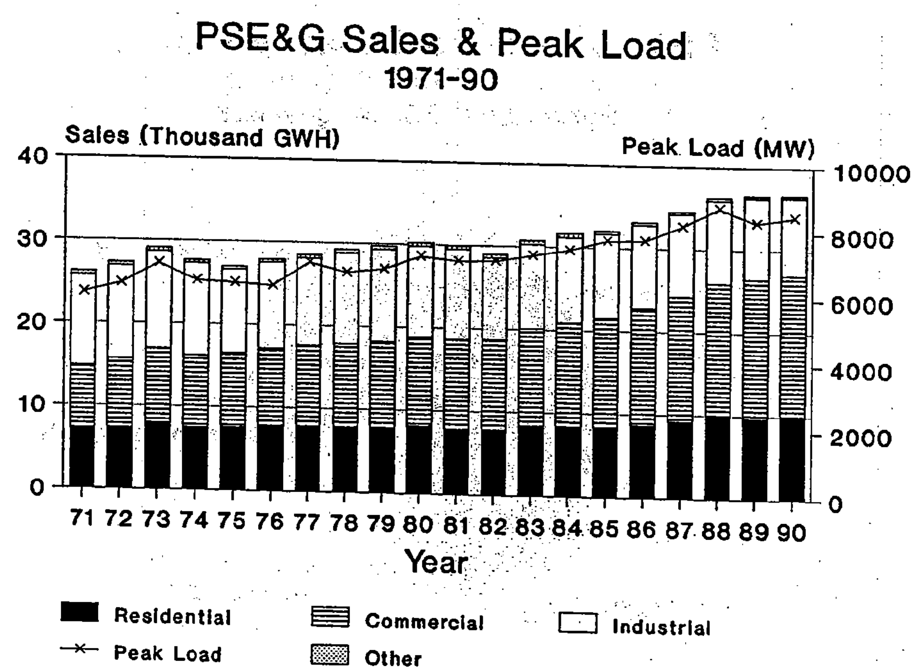
Only the commercial sector has shown continuous growth, while the industrial sector has steadily declined and the residential sector has remained relatively constant. Throughout the 1980s generation from coal supplied approximately 30 percent of the net system requirement; the share of electricity generated from oil has dropped from about 18 percent to less than 10 percent as the share of electricity from nuclear generation increased significantly. Some of the reduction in oil-fired generation can be accounted for by conservation, increased nuclear generation, and displacement by natural gas which has become available and economic for electric generation.

PSE&G purchases approximately 300 MW from non-utility cogeneration and small and independent power producers and has entered into long term contracts for an additional 369 MW of non-utility power projected to come on line by 1996. PSE&G is also in the process of upgrading its Bergen generating facility to a gas-fired combined cycle facility.

The PJM Interconnection

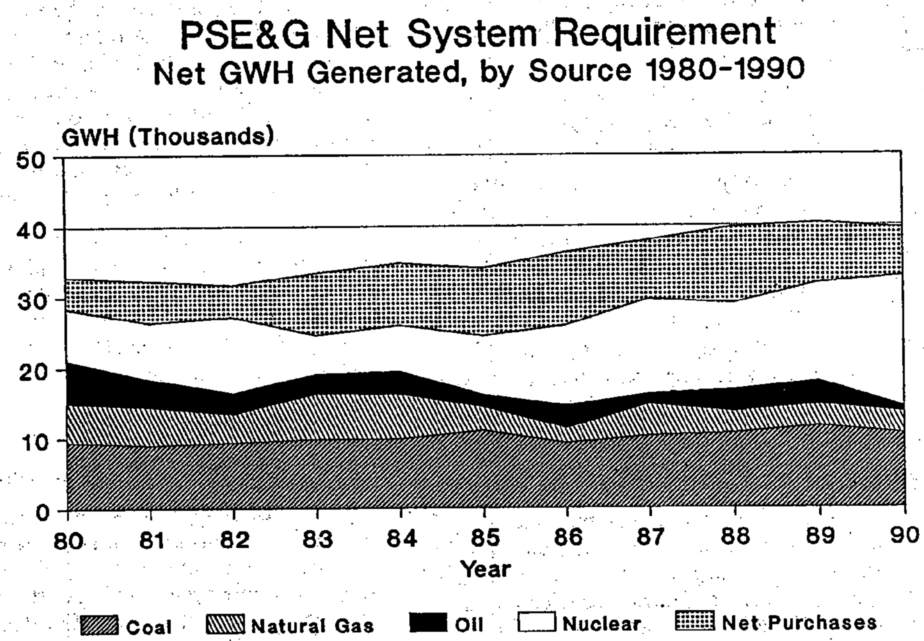
The Pennsylvania-New Jersey-Maryland Interconnection (PJM), is the country's oldest integrated power pool. PJM comprises eight investor-owned utility systems and operates as a single system to meet the needs of the Mid-Atlantic area, which includes most of Pennsylvania, almost all of New Jersey, Delaware, the District of Columbia, more than half of Maryland and a portion of Virginia. (See Figure 8-14.) The PJM Interconnection serves some 21 million people in an area of just under 49,000 square miles, utilizing over 6,300 miles of bulk power transmission lines.

FIGURE 8-11



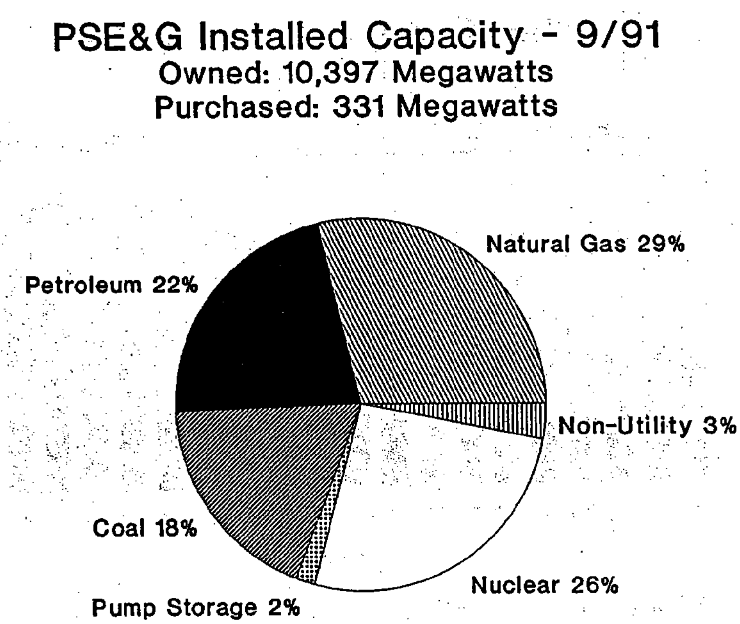
Source: NJEDS

FIGURE 8-12



Note: GWH - Gigawatthours generated.
Source: DEPE, NJ Energy Data System.

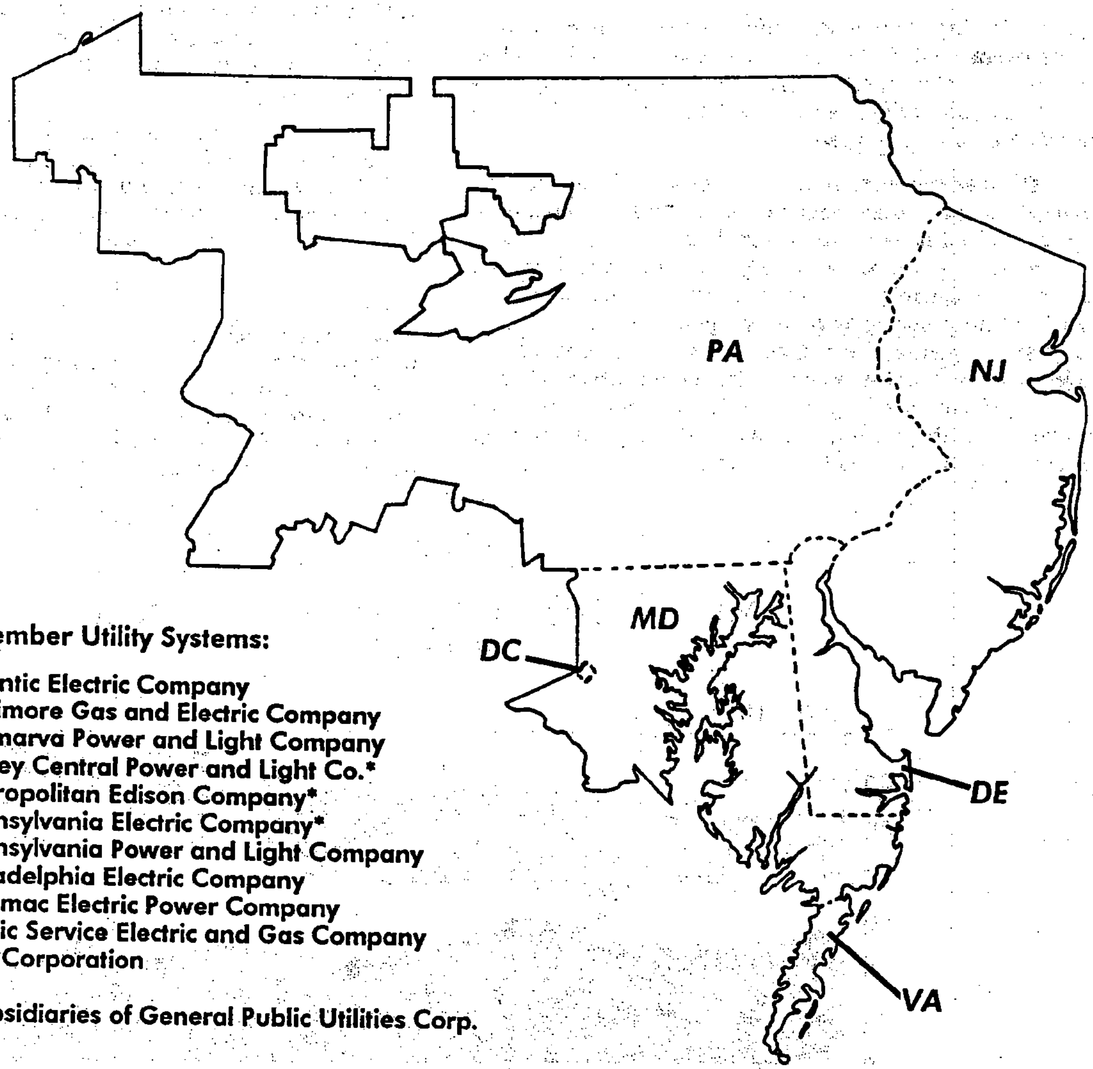
FIGURE 8-13



Source: MAAC Regional Reliability Council, 4/1/91, see Appendix A-8-3

FIGURE 8-14

Pennsylvania-New Jersey-Maryland Interconnection: The PJM Power Pool



PJM Member Utility Systems:

- Atlantic Electric Company
- Baltimore Gas and Electric Company
- Delmarva Power and Light Company
- Jersey Central Power and Light Co.*
- Metropolitan Edison Company*
- Pennsylvania Electric Company*
- Pennsylvania Power and Light Company
- Philadelphia Electric Company
- Potomac Electric Power Company
- Public Service Electric and Gas Company
- UGI Corporation

*Subsidiaries of General Public Utilities Corp.

The PJM Interconnection, from its control center in Valley Forge, Pennsylvania, coordinates the operation of the entire system and dispatches the units with the lowest incremental operating costs. The most economical units required to meet PJM loads are selected on the basis of information provided by the member companies on unit cost and availability of generating units. The electricity produced by the generating units is transported over the bulk power transmission system. Real time monitoring and security analysis programs prevent unsafe conditions that could result as PJM-scheduled generation and interchange with other power pools vary with load.

The PJM Interconnection Office is responsible for providing overall reliability and economy of service as well as accounting for the hourly energy interchange among member systems and scheduled transactions between PJM and neighboring power systems.

If each member were required to have sufficient reserve to meet its own peak demand, each utility's generating capacity would have to be higher than it is with access to PJM power. Operating as a single system, members can rely on the capacity of transmission ties between each other and neighboring systems and pools to meet demand. Therefore, a member incurring a loss of a generator can have its needs met by another unit or an interconnected system without affecting service. In addition, the entire system avoids the necessity of any single company running expensive marginal units for its own security.

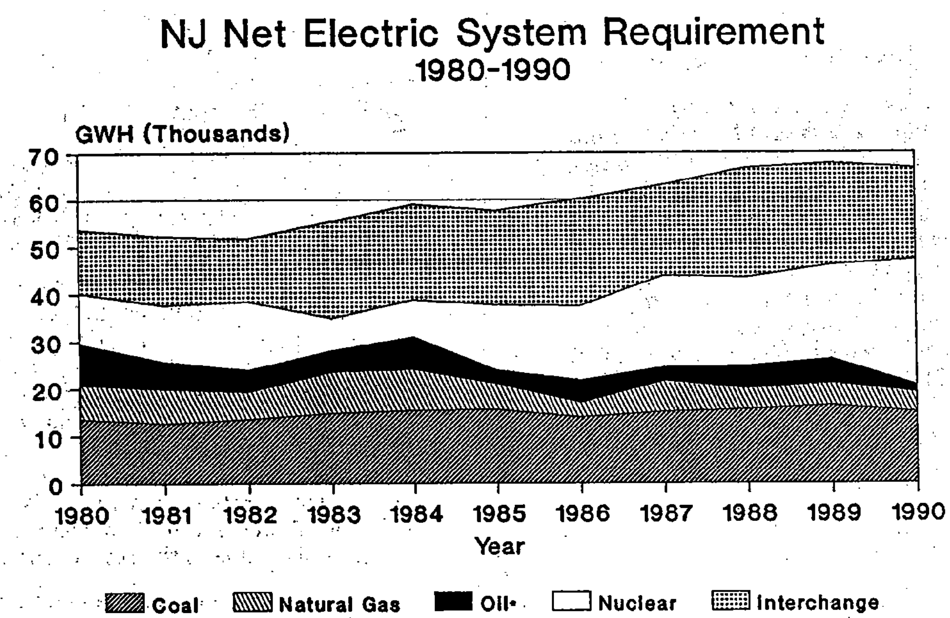
New Jersey's utilities rely upon almost 300 circuit miles of 500 KV volt transmission lines to import power from outside of the state. This system is fully integrated into the 500 KV grid operated by PJM. New Jersey utilities also have several links with New York utilities. In addition, nearly 1,000 miles of 230 KV transmission deliver power within the state.[13]

The system has evolved into the means of importing economy energy, (lower cost electricity), to the state. Presently, the transmission system is loaded on average to more than 90 percent of its design limits. On the hottest days, west-to-east transmission limitations can prevent PJM from relieving localized voltage problems. If PJM cannot generate and import sufficient energy, it must resort to customer voluntary reductions and voltage reduction to maintain the system.

Within New Jersey some utilities have been experiencing problems with delivering electricity to the load centers that have shifted from urban to suburban areas. Utilities are now either considering or constructing smaller, localized capacity to ensure reliability in these new load centers.

Given existing west-to-east transmission constraints, it may become necessary for PJM to cost-effectively upgrade its high voltage transmission system in order to improve west-to-east power flow. New Jersey's electric utilities must review and evaluate how better to utilize existing lines or improve the capability of the transmission system. As the load centers shift and new generation comes on

FIGURE 8-15

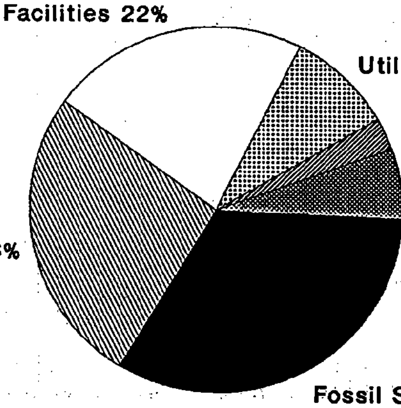


Note: • Includes residual & distillate.
GWH - Gigawatthours generated.
Source: NJ Energy Data System.

FIGURE 8-16

New Jersey Utility Generation Capacity

1991 Total Capacity - 17,806 Megawatts



Source: MAAC Regional Reliability Council, 4/1/91, see Appendix A-8-1,2,3

line, new transmission may become necessary. Any analysis of the need to upgrade the present transmission system should address public health concerns with respect to these lines.

Net System Requirements

Figure 8-15 and 8-16 present data on the New Jersey electric net system requirements (NSR)—the amount of electricity sold to New Jersey customers, plus losses—and installed capacity respectively. (See also Appendix: Electric Generation Summary.) NSR consists of electricity generated by New Jersey electric utilities and electricity purchased from out-of-state utilities. New Jersey generation is broken down by fuel type: coal, natural gas, residual oil, distillate oil, and nuclear. Pumped storage accounts for less than 1 percent of NSR.

The amount of electricity produced from oil decreased dramatically between 1973 and 1987. While oil accounted for over 50 percent of electric generation in 1973, it accounted for only 6.7 percent in 1987. This trend was due in part to the rise in oil prices over the last 15 years, but regulatory changes also were important. In 1978, the Natural Gas Policy Act (NGPA) became effective, which made natural gas in New Jersey competitive with oil. Beginning in 1979, natural gas became a noticeable fuel component for New Jersey electric generation. In that year, natural gas accounted for approximately 7 percent of generation, while oil accounted for approximately 22 percent. By 1980, generation by natural gas accounted for about 18 percent, with oil at roughly 22 percent.

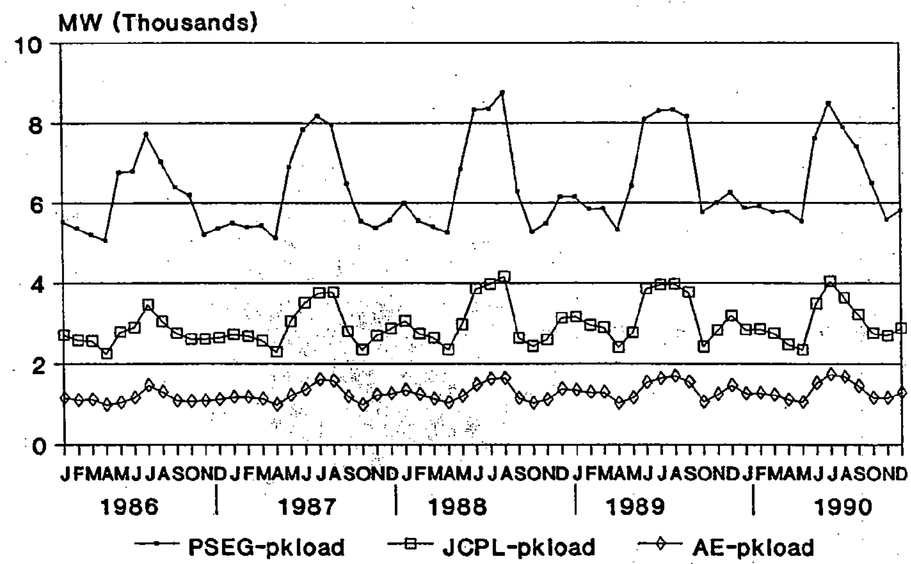
The drop in generation by oil was supplanted by increases in coal generation. Notably, purchased power, which jumped from 0.18 percent to 25.2 percent of New Jersey generation between 1978-79, consisted primarily of out-of-state coal generation. Additional impetus for increased purchased power in New Jersey came from the 1979 Three Mile Island nuclear accident. Following the accident, JCP&L, a part owner, was forced to purchase large amounts of power to meet its electric load.

Between 1982 and 1983, New Jersey nuclear generation decreased from approximately 27 percent to 12 percent of net system requirement. By 1985, nuclear generation returned to 24 percent. The 1983-84 drop in nuclear generation as a percent of net system requirement was largely attributable to the Salem nuclear power plant outages in 1983 and 1984. Purchased power, which rose from 26 percent to 37 percent between 1982 and 1983, compensated for the nuclear shortfall. Generation from oil rose from approximately 5 percent to 8 percent between 1985 and 1986, most likely due to the concurrent drop in oil prices.

In order to meet the peak demand and energy requirements of New Jersey residents, electric utilities rely on a combination of power plants owned by them located in New Jersey, partially-owned power plants located in Pennsylvania, firm purchases of power from utilities outside New Jersey, and non-utility generation. Figure 8-16 pro-

FIGURE 8-17

Peakload at Major New Jersey Utilities
1986-1990



Source: DEPE, NJ Energy Data System

vides the breakdown of units owned by New Jersey utilities as of April, 1990. See appendix tables A-8-1, A-8-2 and A-8-3 for a listing of each utility's generating plants with capacity, in-service date, installed cost and operating expenses. Over the last several years, peak demand has grown 5 to 6 percent each year. (See Figure 8-17.)

Regulatory Overview

The current regulatory framework under which New Jersey's utilities operate evolved between 1907 and 1920, paralleling developments in other states. Enabling legislation was enacted in New Jersey in 1911.

Electric utilities across the country have a similar structure. A single entity—the electric utility company—owns and operates generation, transmission, distribution, and customer service facilities.

This vertical integration has characterized investor-owned electric utilities but is not the only model extant. In some regions a significant amount of power is generated by public agencies (*e.g.*, the Tennessee Valley Authority, the Bonneville Power Authority, the New York Power Authority) for sale by other public agencies (*e.g.*, rural electrification co-ops, municipal power companies) and/or private companies.

In contrast, the gas industry (see Chapter 4) is traditionally less integrated, consisting of separate producers, transporters (pipeline companies), and local distribution companies. Parenthetically, the divestiture of AT&T represents a shift of telecommunications from electric-like vertical integration to gas-like layering, in response to pressures to allow more competition.

Prior to 1970 the electric utility industry experienced tremendous growth that some industry observers believe resulted from economies of scale.[14] While the demand for electricity increased, plants became larger and more efficient, which lowered cost and resulted in more growth.

In general, electric utilities are allowed to operate as monopolies, based on the theory that it is more efficient (and in the public interest) for one company to serve a designated area than it is for several competitors to do so. A single utility thus avoids redundant facilities while regulation is intended to guarantee ratepayers reasonable rates and reliable service.

In order for this utility concept to work, a *franchise* to serve all customers within the designated area is granted. The utility can neither discriminate between like customers nor charge different rates for identical service. The utility is allowed to install its equipment, using local streets and existing and/or new rights-of-way. While its facilities are exempted from real estate taxes, the utility pays a franchise tax and is required to provide a certain level of service and to set prices at a reasonable level.

Federal Regulation

In 1935, the federal Public Utility Holding Company Act (PUHCA) modified the entire regulatory system. The act was designed to end abuses and subsequent collapses associated with the labyrinth-like utility holding companies of that era.

The 1935 PUHCA requires that electric utilities classified as holding companies register with and follow the antitrust and regulatory rules of the SEC. The holding company must therefore operate a single integrated utility system and maintain relatively simple corporate and financial structures. The acquisition and sale of securities and assets are governed by SEC rules. In addition, the SEC regulates internal operating practices, proxy solicitations and contracts for services, sales, and construction. While not a direct regulator, the Financial Accounting Standards Board (FASB) has accounting representation and presentation oversight over the public accounting profession, and thereby influences reporting requirements.

In addition to the constraints imposed by PUHCA, several federal agencies also have regulatory responsibilities. These include the Federal Energy Regulatory Commission (FERC), the Securities and Exchange Commission (SEC) and the Nuclear Regulatory Commission (NRC).

Serious debate is now taking place in Congress over amending PUHCA to remove barriers to increased competition for so-called electric wholesale generators. The broadened debate includes such issues as open transmission access, affiliate transactions and the jurisdiction of state commissions over wholesale transactions.

The FERC approves and sets sales standards for interstate and wholesale transactions; administers the Public Utilities Regulatory Policies Act (PURPA) which concerns small power producers and cogenerators; and approves rates related to the Federal Power Marketing Administration.

The regulatory system tries to balance economic efficiency with the need for adequate and reliable service for ratepayers and equity for shareholders. The regulatory mechanism attempts to approximate what would occur in a competitive market. The state commissions generally have ratemaking authority over wholesale transactions except in those concerning allocations of costs within registered holding companies.

State Regulation

In New Jersey, the Board of Regulatory Commissioners (BRC or Board) is responsible for the economic regulation of the state's utilities. [The regulatory body was previously constituted as the Board of Public Utilities; Governor Florio issued Reorganization Plan #002-1991 effective August 19, 1991 and recast the body as the BRC *in but not of* the Department of Environmental Protection and Energy. (See Chapter 2.)] Historically, the Board has used a rate-base, rate-of-return method. The rate base is the capital investment in plant and equipment needed to serve customers. The rate of return is the profit that the utility should make it if is serving the customers efficiently and prudently. The Board determines rates using those guiding principles in a base rate case.

The Board, like other public utility regulators across the country, adopted a second rate adjustment mechanism as a result of utility experiences with the volatile fuel market of the 1970s. During that decade, supply disruptions caused primary fuel prices to spiral. Utilities were unable to recover fuel costs outside the detailed and often lengthy process of mounting a base rate case. Responding to this situation, the Board adopted the levelized energy adjustment clause (LEAC) process to calculate interim rate adjustments based solely on fluctuations in fuel costs. As a result of this expedited LEAC process, utilities can recover actual reasonable fuel costs in a timely manner and customers can be compensated for overcollections when actual costs fall below projections.

The Board establishes the rates for each class of customer (residential, commercial, and industrial) in line with its legislative mandate to assure safe, adequate, and proper service.

In Docket No. ER85121163, the Board disallowed as unreasonable $431 million of the construction costs of Hope Creek Nuclear Plant. State regulatory agencies throughout the country have taken similar actions. These large cost disallowances and other changes such as the introduction of competition in the generation sector of the industry have fundamentally changed the New Jersey regulatory environment. Consequently, utilities are more cautious about large-scale capital expenditures and now view independent power production as an acceptable means to help meet customers' needs with lower risk, albeit with lower profit opportunities.

Regulated Conservation Programs

Energy conservation became a broad-based regulatory policy of the Board in 1982 with the creation of the Conservation and Load Management Docket (BPU Docket No. 8211-1032) that required the state's electric and natural gas public utilities to develop comprehensive conservation, cogeneration and load management plans. Prior to this docket, energy conservation as a regulatory tool had been limited in application to programs launched by JCP&L after the Three Mile Island Unit II incident and to federally mandated Residential Conservation Service (RCS) programs. Through the Conservation and Load Management Docket, the Board sought to defer the need for new large-scale central station (coal or nuclear) power plants.

Throughout the 1980s, the state's utilities offered customers ways to increase energy efficiency through energy audit, loan and rebate programs targeting the residential, commercial and industrial sectors and through direct investment programs for low income customers. Certain core programs were required in all utility conservation plans although each utility was able to develop additional programs with the Board's approval. Rate base dollars provided funding for the initiatives based on Board screening and approval of specific program costs.

Conservation as a cost-effective planning and regulatory tool was rigorously reviewed within a consultant study known as the New Jersey Conservation Analysis Team (NJCAT) study. The goal of this study was to review in depth the effectiveness of the 1982 Docket programs and provide both the Board and the utilities with guidance in the design and enhancement of future programs. The NJCAT study examined the cost-effectiveness of core utility-sponsored energy conservation programs including the residential and small business energy audit programs, subsidized loan programs, seal-up and weatherization programs and programs that offered rebates on the purchase of high efficiency appliances.

The results of the NJCAT study were released in August of 1990. The study concluded that some programs achieved good cost/benefit results but that others achieved unanticipated poor results. Overall, the measured benefits of the programs averaged approximately 70 cents for each dollar spent. However, the results presented in the NJCAT study reflected only direct energy savings and did not consider other external benefits such as reduced environmental degradation, increased comfort and increased value of homes—factors that are important but difficult to quantify. The study noted that inclusion of such factors would likely change the study results. Study results are sensitive to changes in fuel prices: increased fuel costs would alter the benefit/cost ratio to reflect more favorably upon programs.

Future utility-sponsored program enhancements will be structured: (1) to ensure that conservation opportunities will continue to be made available to those most in need of reducing their energy costs and (2) to foster the proliferation of cost-effective conservation projects as efficiency gains assume an expanding role in meeting the state's future energy needs.

The Board initiated a rulemaking proceeding and held a public hearing in June of 1990 to consider incentive mechanisms that would enable utilities to profit on investments in conservation that yield measurable energy savings. The Board then formulated proposed regulations and held a hearing in December of 1990. Numerous industry, business and public interest groups and individuals came forward in response to the proposed regulations. Upon review of issues raised in the hearing, the Board modified the rule proposal and held a hearing in May 1991. Based on input from the hearing and a series of meetings with concerned parties, the Board developed and adopted on September 25, 1991 performance-based conservation incentive rules (Docket No. EX90040304). For a more detailed discussion of the rules, see the section *Conservation Incentives* under the heading of *Regulatory Issues* that appears later in this chapter.

Alternative Power Production

Alternative power producers (APPs) which include independent power producers, PURPA-defined qualifying cogenerators and qualifying small power producers (QFs), and self-generators continue to make inroads into the formerly traditional area of electricity generation. Electric utilities now find themselves competing with the APPs, a situation that did not exist only a few short years ago. In short, electric generation is no longer a natural monopoly.

PURPA - 1978

In 1978 Congress passed the Public Utility Regulatory Policies Act (PURPA), which sets forth federal policies for the regulation of utilities that generate and sell electricity. This law, in effect, created the cogeneration and small power industries that we will refer to as cogenerators. After various challenges, the court upheld the regulations put in place by the Federal Energy Regulatory Commission (FERC) and in areas of the country with high electricity rates cogeneration became an important option for industrial companies.

PURPA Section 201 defines qualifying facilities (QFs) to include small power production facilities as well as cogeneration facilities that meet standards established by the FERC. Section 202 requires utilities to purchase power from QFs interconnect so long as it is in the public interest, would conserve energy or capital, optimize efficiency in facilities and resources, improve reliability, and meet the review requirements of Section 212 of the Federal Power Act (FPA). Section 210 establishes just and reasonable rates for back-up electricity sales to cogenerators by utilities and requires utilities to purchase electricity offered by QFs at the *incremental cost of alternative electric energy*, later known as *avoided cost*. Under PURPA, QFs must be certified by the FERC and meet minimum efficiency standards.

Subsequent to the passage of PURPA, the FERC issued a rulemaking to implement the law. The result of the rulemaking was new regulations, FERC Section 292.101 *et seq.*, which specified the criteria that QFs must meet to enjoy the benefits of PURPA. The most important criteria for cogeneration facilities were efficiency standards and ownership limitations. Minimum efficiencies were established for topping cycles at 42.5 percent and for bottoming cycles at 45 percent. To prevent utilities from dominating the market, the regulations limited utility involvement to 50 percent for a QF to be exempt from public utility regulation.

Board Order - 1981

Due to the legal challenges to PURPA at the federal level, the Board did not establish its policy for non-utility cogeneration and small power production until October 14, 1981, in its Decision and Order Docket No. 8010-687. The Order contained the ground rules that utilities had to follow when dealing with QFs. The most important finding was that the avoided cost rate, *i.e.*, what utilities pay QFs, should be the PJM billing rate plus 10 percent for energy and the PJM capacity deficiency rate for capacity. (In the case of JCP&L, the actual cost of a peaking unit was deemed to be more appropriate.) PJM is the interstate power pool of which PSE&G, AE, and JCP&L are members. The PJM rates were considered to be the *incremental cost* as required by the FERC. The 10 percent adder on the energy cost was meant to reflect the *excess value* or societal benefits that non-utility power had over conventional electricity supply as well as to help promote the technology.

Board Order of Clarification - 1983

The Order of Clarification was issued December 7, 1983, due to utility arguments that the avoided cost set in the 1981 Order was only a starting point for negotiation. The Board reiterated that QFs were entitled to those rates unless they specifically chose to negotiate price for other favorable contract terms. Under the guidelines of the Board's 1981 and 1983 PURPA orders, utilities negotiated power purchase agreements individually with potential QFs. In 1986 and 1987, the process evolved to where AE and JCP&L made standard pricing offers available to prospective contract QFs.

FERC Notices of Proposed Rulemaking - 1988

On March 16, 1988, the FERC issued three Notices of Proposed Rulemaking (NOPRs) dealing with the implementation of PURPA for comment by interested parties. Due to much controversy surrounding the NOPR, it is uncertain what, it any, actions will be taken by the FERC regarding the proposed rules. The three NOPRs are:

(1) Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities (ADFAC NOPR) - The ADFAC NOPR addresses utility questions about inappropriate methods of determining avoided cost and a lack of consideration of dispatchability or reliability criteria in many states' avoided cost calculations. It contains proposed clarifications that would have benefited QFs, including mandating backup power for a cogeneration facility and the thermal customer served by the facility, and includes any savings from line loss reductions in the avoided cost.

(2) Regulations Governing Bidding Programs (Bidding NOPR) - The Bidding NOPR would have provided the standards for the solicitation and evaluation of bids and state certification of the bids to avoid anti-trust problems. The NOPR proposed that the solicitation of bids describe the need for capacity and energy, the participation criteria, and the selection criteria. The evaluation would be based on the solicitation criteria, and the state would approve the price and selection.

(3) Regulations Governing Independent Power Producers (IPP NOPR) - The IPP NOPR would open up the marketplace to any non-utility generator willing to provide competitively priced electricity and works toward deregulation of the electricity supply or generating function. The crucial aspect of this NOPR is the concept of market power that separates a public utility from an independent power producer (IPP). A project would be an IPP if it had no significant market power and does not control the transmission line. The NOPR would exempt IPPs from cost of service regulation.

The FERC proposed the NOPRs to clarify existing rules as well as to introduce some new concepts to the way the cogeneration industry is regulated. The most important new concept is the introduction of competition to the electricity generation industry.

The NOPRs are controversial. Some state public utility commissions that already have bidding in place felt their systems were not compatible with the FERC's view. The three original NOPRs raised so many questions that a fourth was issued on July 29, 1988, called *Regulations Governing the Public Utility Regulatory Policies Act of 1978*, to address procedural and technical rules dealing with QF status. The major proposed revisions were to remove the 50 percent ownership limit on utility subsidiaries, to expand self-certification of QF status, and to liberalize the evaluation of efficiency criteria. As of October 1991, the FERC had not taken any formal actions concerning this rulemaking.

Board Cogeneration Stipulation - 1988

The 1981 Board Order specified that it would revisit its QF policy within five years. As a result, in 1987 the Board produced an assessment of the QF activity in New Jersey that called for changes to the policies outlined in the 1981 Order.

The Board thereafter convened a settlement conference on December 18, 1987, in which Board staff participated along with utilities, APP representatives, and other interested parties. The culmination of the process was a Stipulation of Settlement issued on July 1, 1988 that instituted a competitive bidding system through which utilities would procure blocks of APP capacity and large conservation projects.

The major provisions are:

1. Bidding to provide capacity and energy to electric utilities commenced on October 1, 1988, and will recur on September 1 each year thereafter.
2. Utilities will advertise solicitations locally and nationally.
3. The utility's incremental need will determine the block size, but existing utility capacity is exempt from consideration.
4. The utility may include IPPs.
5. Conservation investments over 400 KW shall be considered along with energy and capacity sales in the bid process.
6. The utility will determine the bid ceiling price using the differential revenue requirements method.
7. The evaluation will be primarily based on:
   a. Economic/price factors—maximum weight 55 percent
      i. Price
      ii. Dispatchability
      iii. Security
   b. Project status and viability factors—minimum weight 25 percent—
      i. FERC certification
      ii. Scheduling
      iii. Engineering

   iv. Liquidated damages
   c. Non-economic factors—minimum weight 20 percent—
      i. Promotion of QFs
      ii. Fuel type, location, environmental benefits, and fuel efficiency

8. Levelization up to 120% of avoided cost for oil and gas projects and up to 135% for solid fuel projects is allowed without requiring security. If an APP desires payments greater than 120 or 135% of avoided cost, security is required to insure that ratepayers will receive the benefits of payments less than avoided cost in the later years of a contract in exchange for providing the developers with payments greater than avoided cost in the early years of the contract.
9. Performance penalties will be based on average availability factors for non-nuclear utility units with a cap at 80 percent for solid fuel and 85 percent for all others.
10. *Force majeure* is defined so that no misunderstanding occurs about when performance guarantees apply.
11. Standard offers are provided to small projects of 10 MW or less with the price being the bid cap price. Also long term energy only contracts are available as are sales to utilities in accordance with tariffs based on short term avoided cost.
12. Resource recovery projects will receive the bid cap price for the first three years so long as the facility is in the county solid waste plan, has a vendor selected, has QF status, does an interconnection study, and agrees to allow 90 percent of electricity revenues to go to reduce tipping fees.
13. Utilities agree to wheel power from QFs that win a bid to other in-state utilities.
14. Utility affiliates cannot bid in their parent's solicitation for three years.
15. The utilities submit detailed backup on how they determined avoided cost and capacity block.
16. A complete schedule for the procurement process is established.
17. The bidder's fee will be $5,000 for those participating in the selective procurement process.
18. A detailed liquidated damages schedule provides for penalties if APP capacity is delayed or cancelled.
19. A regulatory risk provision allows APP to terminate the power purchase contract if a change in governmental policy damages the economics of the contract.

As of mid-1990, about 400 MW of APP capacity was grid-connected and actually on line in New Jersey. Approximately 2000 MW of additional APP capacity is in various stages of development, including more than 600 MW to be procured by JCP&L, PSE&G and O&R under the first round of the new bidding procedure.

Under the bidding procedure, utility subsidiaries are prohibited from bidding to sister utilities in the first three years of the process. Starting with the round of bidding that will be initiated in September 1991, subsidiaries would have been able to bid to sister utilities unless the Board took specific action to extend the prohibition. The Board approved a joint stipulation in the summer of 1991 extending the prohibition for an additional year. The Board will review the appropriateness of the prohibition prior to the September 1992 round of bidding.

One of the reasons utilities were initially reluctant to contract with some APPs was a lack of dispatchability. Utilities wanted more control over when the power was delivered, and some APPs wanted to provide baseload power only. This issue is largely economic, since electricity is more valuable on-peak and especially during the summer peak. Utilities do not want to take more power than they need. The utilities are also concerned about the interconnection of the various APPs to the system. For non-utility cogeneration facilities specifically, the dispatchability issue often complicates the efforts to properly match steam loads. However, the cogeneration industry believes that the problems can be handled.[15]

Cogeneration, which represents the bulk of present APP facility capacity, has an average availability of approximately 89 percent.[16] Nuclear plants, on a national basis, have a capacity factor in the mid-60 percent range. Since these plants are base loaded, their capacity factor reflects their availability factor.[17] Thus by comparison cogenerators can be as reliable and, in many cases, more reliable than the large plants that the utilities have on line. The relatively small size of most APP units provides supply diversity, which can help prevent brownouts or blackouts that could occur if several large utility plants are off line simultaneously. The smaller size of APP units also enables adding smaller increments of generation capacity than with conventional power plants, and the time needed to plan and construct them shorter.[18]

APP facilities, especially those that employ cogeneration, are generally close to load centers, resulting in lower loads on the transmission system and a corresponding lower risk of localized brownouts or blackouts. Connecticut has specifically provided for the implementation of line loss credits based on the avoided cost of transmission and distribution equipment.[19] New Jersey purchases approximately 32 percent of its electricity from out-of-state utilities and has been on 5 percent voltage reduction during some summer hours due in part to limitations on transmission capacity.

The installation of additional electric generating capacity in New Jersey would allow the west-to-east electric transmission system to provide more on-peak electricity and reduce the need for imported electricity and for voltage reductions. This additional capacity would also reduce electricity costs to consumers by obviating new transmission facilities.

Regulatory Issues

Restructuring the Industry

Uncertainties abound in today's electricity industry due to fuel prices, growth forecasts, demand-side opportunities, and changes in the regulatory environment. The general deregulation climate of the 1980s may affect the vertically-integrated utilities during the 1990s. Two themes have emerged to date: *de-integration*, and alternatives to traditional rate-base, rate-of-return regulation.

PURPA and the evolution of QFs and IPPs have shown that electricity generation is not a natural monopoly. For generation, no insurmountable capital barriers prohibit new entrants, many of whom are eager to bid for the right to sell power to the grid. Utility responses to this situation vary. In New Jersey, the 1988 Cogeneration and Small Power Production Stipulation of Settlement (Docket No. 8010-687B) supports the rights of alternative power producers, while allowing utilities to reserve the right to add unspecified amounts of their own capacity.

The development and proliferation of APPs has undoubtedly introduced a much larger degree of competition into the electric generation market than had previously existed, yet the transition to a fully competitive industry is far from complete. The industry is now at a crossroads as regulators and industry participants examine the continued appropriateness of treating the maturing APP sector under a set of standards different from those applied to utilities.

Currently, APPs bid to supply blocks of power to satisfy part of the utilities' incremental capacity needs as projected annually by each utility. The APP assumes risks associated with potential changes in construction, operating and production costs, construction delays, changes in government regulations, etc. APP earnings are not subject to regulatory oversight.

In contrast, utility ratemaking procedures dictate a much different—essentially *cost plus*—approach to utility owned and operated facilities. Through rate base/rate of return regulation, utilities can recover from ratepayers all *prudently incurred* (as determined by Board review) investment and operating costs associated with new facilities. In return for this risk protection, utility earnings are regulated.

Utilities are required to obtain a Certificate of Need from the Board prior to commencing construction of facilities over 100 MW. Utilities must demonstrate that no more economic or environmentally sound alternative exists in order to receive the Certificate of Need.

The Certificate of Need regulations do not apply to non-utility generators. Power purchase agreements with non-utility generators are deemed prudent by virtue of winning the competitive bid solicitation. This is also the case for large scale conservation projects that are awarded contracts by virtue of winning the competitive bid solicitation.

Inter-utility power purchase agreements are subject to prudency reviews by the Board on a case-by-case basis. This is true for both short- and long-term power purchase agreements. Utility conservation plans are subject to biennial review by the Board. In September 1991 the Board approved a rule that is intended to provide utilities with incentives to invest in conservation.

In reviewing utility construction plans, non-utility power purchase and power savings agreements, inter-utility power purchase agreements and utility conservation plans, the Board attempts to compare all options according to the same standards. A utility must demonstrate that the option it proposes to use to meet its capacity needs is the most beneficial option based on an evaluation of price and non-price factors such as reliability and environmental impact.

Because there is no apparent technical basis upon which to distinguish between utility generation and non-utility generation, (*i.e.*, there is no inherent reason why an APP should be any more or less able than a utility to construct a reliable generating facility at a reasonable cost), the current debate must focus on the regulatory treatment of various segments of the industry. New Jersey should strive to remove distinctions between utility and non-utility generators and between utility and non-utility conservation projects.

A system under which all capacity options—utility construction, non-utility construction, utility conservation programs, non-utility conservation programs and inter-utility power purchase agreements—are reviewed according to a similar set of standards is needed. To this end, the Board will implement a generic proceeding to develop a system for evaluating all potential sources of capacity and energy. All-source bidding should be carefully examined as a means of choosing future sources of capacity and energy.

Under such an approach, if a utility project were to be chosen, it might be appropriate to require the utility to commit to a fixed price of delivery. In return for the guarantee of a fixed price, the utility's earnings on that investment could be exempted from regulatory oversight.

Another model that may be appropriate to consider in bringing greater continuity to the treatment of utility and non-utility generators is tighter regulation of APPs, more akin to the standard ratemaking model. Under such an approach, APPs would receive greater protection from project risk in exchange for regulatory oversight of earnings. However, legal and regulatory impediments may challenge the use of this approach.

A third possible approach would be a refined, more integrated version of the current approach whereby there are specifically identifiable utility and non-utility segments of the generation mix. Regulators might decide that is it best to have some limited and predetermined portion of electric supply needs specifically set-aside to be met by traditional utility facilities, thus giving the state a diversified portfolio of electric generation.

Utilities are currently given different rate treatment depending on which option a utility chooses for meeting capacity needs. A utility can earn a profit by receiving a rate of return on its investment if it opts to construct a facility. However, if it chooses to purchase power from a non-utility generator or another utility, it receives a pass-through of all costs but earns no profit.

Utilities should opt for sources of capacity and energy that provide the maximum benefits consistent with least-cost planning principles. Utility decisions should not be biased by the different regulatory treatment currently afforded to utility costs depending on which option a utility chooses for meeting its capacity and energy needs.

Unbundling

Changes in the industry described above have led some to propose the complete unbundling generation to create a competitive industry. Transmission could then function as a regulated common carrier, giving access on behalf of distribution companies to least-cost providers. The primary challenges to such divestiture involve the following concerns:

Reliability: Reliability ensures that sufficient generation capacity exists to cover scheduled and forced outages, reduced capability, and deviations from forecast load. This installed capacity is further affected by the design and performance characteristics of the generating equipment, type of load served, and availability of capacity from other systems. Statistics support the conclusion that once an APP facility is up and operating, from a technical and operational standpoint, it is at least as reliable as utility-owned facilities. One concern often cited is the continued availability of non- utility generation should an APP project encounter financial difficulties.

If economic conditions warrant, private developers may simply abandon the project. Adequate assurances must be provided that, if necessary, the utility can take over the operation and/or ownership of the facility under such circumstances. Contractual safeguards such as the lender's ability to appoint an operator and the provision of second liens to purchasing utilities, as well as the knowledge that financial lender thoroughly reviews project economics prior to financing provide some comfort in this regard. The Board should explore whether contractual terms such as selection of the utility as operator in the event of default and the provision of second lien rights to the utility should be required. The issue of utility recovery of costs associated with such a transition would also have to be addressed.

DEPE Permitting: Permit applications for proposed electric generating stations frequently require the performance of complex modeling, monitoring and/or other types of detailed reviews by the DEPE to ensure the protection of human health and the environment at large. Such necessary reviews are often quite extensive and time-consuming. As a result, the DEPE permitting process can become the critical path for timely project development.

Legislation has been proposed that would establish a licensing fee mechanism whereby applicant fees could be assessed to fund the procurement of outside consultants to expedite these reviews. Such a mechanism which enhances the ability of the DEPE to process applications without compromising environmental protection should be supported.

Transmission: Transmission must be sufficient to move electricity from the generators to users as well as to accommodate transactions with neighboring utilities and/or power pools.

Dispatch: Maintaining control to meet changing system requirements through dispatch is essential. Present PJM dispatch may be expandable. At minimum, capacity and energy contracts would be separately negotiated, with allowances for operation as *spinning reserve*.

Flexibility: Flexibility includes fuel and technology diversity and ability to meet changed conditions. Regulators and the industry must learn many lessons, including the full cost of take-or-pay contracts formerly common in the gas industry.

Transition: In a transition period, is there need for special arrangements for existing power plants that are carried on the rate base at higher value than they can be sold for in a free market? Should special provisions (*excess payments*) be provided for wholesale purchases from divested plants of this type, or should the owners be compelled to write down the excess value? During and following the telephone divestiture, there were extensive equipment writeoffs, a possible parallel.

These important issues must be addressed as the debate over the future direction of the industry continues.

Market-based Pricing

An alternative to the model for full unbundling of the generation industry would be a transition to an optional system in which retail electricity prices would be regulated instead of profits.[20]

Under the system an exogenous index (*e.g.* consumer or producer price index) would annually mediate electricity price caps (cents/kwh). The utility would be permitted to charge any price below the cap according to market forces. By regulating price instead of profit (as in rate base systems), proponents maintain that utilities would gain efficiency incentives, since they would be assured of capturing the profits. In this manner, proponents argue, utilities would be provided the financial incentive to pursue least-cost options, be they supply or demand-side measures, be they utility or non-utility projects, in order to minimize costs and therefore maximize profits. While price caps might adequately protect all ratepayers, difficult problems would have to be overcome to enable a smooth transition from the present system.[21] Such problems include the selection of a proper index, assurances that the caps appropriately reflect changes in industry costs and technology, arguments concerning which components of the utility's cost, if any, would be set aside for automatic adjustments and design of safeguards to ensure that the utility could not practice discriminatory pricing on captive customers in order to subsidize marketing efforts aimed at selected customers. An appropriate forum for further review of the market-based pricing concept may be in a Board response to a specific utility proposal that presents a mechanism which addresses the aforementioned concerns.

Self-Generation

In New Jersey, which has relatively high retail electricity rates, self-generation remains an option even if utilities do not need to sign up capacity. Self-generation can be economic in a variety of circumstances. A consultant or in-house staff can take the first step, which is to determine the facility's internal heat and electric load and the types of equipment that are available to meet either or both. The economics of the project should be evaluated and compared to the electricity and fuel costs.

Small cogeneration packages, starting at 37 KW, are already operating in New Jersey at YMCAs, hotels, and other businesses. Large food and pharmaceutical companies have opted to meet their loads with 8 MW to 23 MW units with only excess electrical sales to the local utility. No insoluble problems of providing backup electricity to the self-generators have occurred.

The utilities have reservations about self-generation when they see their baseload customers generate electricity for the majority of their needs while expecting the utility to be the provider of last resort or to furnish peaking service only. Utilities have also expressed concern over the impact of self-generation on remaining ratepayers. Indeed, the potential for some short-term impact on ratepayers similar to the effect produced by other more conventional methods of end-user conservation does exist. However, this must be balanced against load growth in other areas that may compensate for so-called lost revenues as well as the long-term benefits in the form of costs avoided due to lower system energy and capacity demand growth.

New developments in cogeneration equipment will allow cogenerators to be even more responsive to utility operating conditions and to be able to increase output during peak periods, thus obviating new utility peaking units. Self-generators can help meet peak by load shedding as well as by increasing their output. One cogenerator has even retrofitted an old turbine with steam injection to reduce pollution and provide peaking capacity.

Wheeling Options

For a competitive market to work, the seller of a commodity must have access to the potential buyers. For APPs, that access is available only through the utilities in the form of wheeling, which is the movement of electricity from one location to another across utility-owned transmission and distribution lines. Currently, all New Jersey utilities have agreed to limited wheeling within the context of the Stipulation. With this agreement, QF projects located in the state can bid to any New Jersey utility, as long as sufficient transmission capacity exists. This serves to broaden the market and contributes to a more competitive bid solicitation which, in turn, can benefit utilities and their ratepayers.

The larger issue of establishing a national transmission policy has yet to be resolved although the debate over PUHCA reform is bringing the transmission debate into focus. The opening of the interstate transmission grid to large-scale wheeling for supply projects could greatly intensify competition. However, the debate over important technical issues and legal barriers continues.

Other areas of contention are retail wheeling and self-wheeling. Retail wheeling is direct competition with the utility, wherein an APP sells electricity directly to an end-use customer, using the utility transmission system. Self-wheeling is similar but delivers electricity only to a distant facility owned by the APP.

The economic advantage of self-wheeling is that the APP is using its own excess electricity and offsetting retail rates rather than receiving the lower avoided-cost rate from the utility for the excess. Some APPs maintain that self-wheeling promotes efficiency by allowing the APP to size the equipment to include the load from sites that may not support stand-alone units.

The utilities oppose both self and retail wheeling concepts because they believe the APP would have unfair competitive advantage due to the fact that utility rates include societal costs in addition to the fact that APPs do not have a statutory obligation to serve.

With retail wheeling the utilities raise the technical problem of control of the current flow over the transmission system to assure reliable delivery of the power to the customer. Utilities also complain about the *cream skimming* effect of serving large customers with a wheeling contract that would result in the remaining customers paying more of the embedded costs of the utility rate base. No state or federal agency now has the legal authority to order a utility to wheel power where wheeling would result in higher costs for the remaining customers.

In wheeling arrangements, the APP compensates the utility for the use of the transmission and distribution facilities. (Of course, the electricity flow described in a wheeling contract does not necessarily correspond to the actual path followed by the APP's electricity.) Electricity will generally go to the nearest load center if needed. For example, the Cogen Tech 165 MW plant in Bayonne sells power to JCP&L, but the power is wheeled over PSE&G transmission facilities. In this case, because of the location, PSE&G also benefits, since the Bayonne facility allows PSE&G to avoid upgrades in the transmission facilities that would otherwise have been needed to serve new development along the Hudson River coastline area. Similarly, the ratepayers will see long-term savings from the reduction of need for interstate transmission lines that will not have to be expanded as well as local upgrades that may be avoided.

Ultimately, the question of open access to utility transmission systems raises complex issues of deregulation and unbundling of the generation segment of the electric industry. The concept requires further study into the impact on native load customers and the proper method for pricing that service.

Taxes

Gross Receipts and Franchise Taxes

Cogeneration facilities are exempt from the payment of gross receipts and franchise taxes (GR&FT) on their purchases of natural gas under *N.J.S.A.* 54:30A-50. In addition, they are exempt from GR&FT on electricity purchases up to the amount sold or purchased, whichever is smaller.

In 1989, discussion arose over whether GR&FT should be applied to sales of power from cogenerators to third parties or to out-of-state facilities or whether the tax should also apply to energy produced by QFs and consumed internally by the host facility.

These discussions ultimately led to the drafting of proposed legislative initiatives. Hearings on Senate bill S-1324, sponsored by Senator Van Wagner, were held on June 7, 1990. One of the principal arguments of the proponents of the proposed initiatives is that imposition of the GR&FT on *inside the fence* consumption of power from QFs is necessary in order to remove the competitive advantage that such arrangements have over utility-provided service that has the GR&FT assessed. However, issues of competitiveness can be addressed by allowing utilities greater freedom to compete for such projects. Consideration of the imposition of GR&FT on internally consumed QF output, however, must address the larger impact on state energy policy of such initiatives. An analysis of the total cost of all the various taxes paid by both utilities and non-utility cogenerators must be undertaken. For instance, while utilities are exempted from paying property taxes, APP facilities are provided no such relief. Moreover, it is not a foregone conclusion that societal goals require that no competitive advantage be afforded one type of technology over another.

A related issue is the inability of municipalities to receive additional GR&FT revenues when APP plants are constructed in their communities. It should be understood that the bulk of large cogeneration facilities now in operation or under development sell most of their power back to the electric utilities for resale. As a result, such power is ultimately resold on a retail basis and will therefore generate GR&FT revenues similar to a utility generating station. Therefore, the present inability of the host municipalities of these facilities to receive GR&FT compensation is largely a function of the allocation formula. In order to compensate municipalities that provide sites for non-utility generators supplying electric power to New Jersey, property related to APP facilities should be included in the GR&FT allocation formula. In order to avoid a potential windfall to host communities, however, resultant GR&FT compensation should be adjusted to reflect the collection of property taxes from these facilities.

Notable exceptions to the aforementioned scenario are projects that are located in New Jersey municipalities but sell their power to out-of-state clients. Because the output from these facilities is exported for resale, no GR&FT is generated in-state. As a result, no GR&FT compensation is available to the host community.

In formulating a policy that best serves the overall interests of the state, it is important to distinguish between initiatives taken to address budgetary considerations, *i.e.*, taxation policy, and actions taken to implement state energy policy. While in a narrow sense of state electric supply planning, some projects—such the one Cogen Technologies has proposed to site in Linden to generate electricity for sale to Consolidated Edison of New York—may not appear to provide any direct benefit to New Jersey, other benefits do accrue. The Linden project will create construction and some permanent jobs in New Jersey and will allow industrial steam customers situated near the project to cut energy costs. Efforts to tax electricity generated in-state for export purposes might negatively impact upon New Jersey's ability to freely import power from its neighbor states. New Jersey and its neighboring states derive substantial benefit from the free and unimpeded flow of energy and capacity throughout the region. Interstate and even inter-regional power markets enhance economic efficiencies. This broad market has permitted the state to realize substantial savings. Indeed, New Jersey is presently a net importer of almost one-third the electricity it consumes. The interstate flow of electricity should not be discouraged through inappropriate taxation policies or other artificial barriers.

Sales Tax

Cogenerators are exempt from sales tax under *N.J.S.A.* 54:32B-8.13.d on the purchase of equipment or supplies specifically dedicated to the cogeneration project. Regulations designated *N.J.A.C.* 12A:54-1.1 *et seq.* implement this exemption.

Siting

N.J.S.A. 40:55D-19 provides in part that if a public utility is aggrieved by the action of a municipal agency, an appeal may be taken to the Board. If, after hearing, the Board finds that the present or proposed use by the public utility is necessary for the service, convenience or welfare of the public, the utility may proceed in accordance with the decision of the Board.

Utilities are currently planning to purchase significant portions of their capacity needs from cogenerators, small power producers, and independent power producers. As a result, the State should consider whether *N.J.S.A.* 40:55D-19 should be amended to include this class of generators where the facility is being developed primarily to provide a New Jersey utility with needed capacity.

The Board has interpreted its authority in the siting area to include cogeneration and small power production, (In the Matter of the Appeal of Public Service Electric and Gas Company Pursuant to *R.S.* 40:55D-19 from the Decision of the Hamilton Township Planning Board Denying an Application for a Conditional Use Permit and Site Plan Approval for a Natural Gas Reduction and Electricity Production Facility, BPU Docket No. EE8605-481, October, 1986), but legislative clarification would assist in the development of needed alternative power production.

Jurisdiction

N.J.S.A. 48:2-13 provides that the operation of heat and power plant or equipment for public use shall be subject to the jurisdiction of the Board. It has to date been deemed unnecessary to regulate the sale of steam from a cogenerator to industrial and commercial customers.

As a result, consideration should be given to amending N.J.S.A. 48:2-13 to exempt the sale of steam from a qualifying PURPA facility (QF) to an industrial or commercial facility from being subject to the jurisdiction of the Board.

Conservation Incentives

Conservation is a source of energy that will allow utility customers to meet an end use at a lower cost and with greater environmental acceptability. One of the areas that has inhibited the full growth of conservation as a source of energy is the lack of financial incentives for utilities to promote conservation programs and to market them successfully. Historically, ratemaking procedures have stood in the way of effective implementation because no profit opportunity existed when conservation programs were successful. Under traditional ratemaking formulae, sales lost through conservation result in reduced utility earnings between rate cases. Conversely, construction of new plant represents an investment opportunity for a utility. Construction of new capacity, increased reliance on fossil fuels and increased dependence on purchased power—measures needed to support expanded sales that benefit utility shareholders—increase ratepayer costs.

In an effort to align utility shareholder and ratepayer interests, the Board initiated a rulemaking proceeding to explore various incentive mechanisms that would provide utilities with a clear, measurable and meaningful incentive (tied to results delivered) for promoting conservation.

The incentives rules encourage investments in end-use efficiency improvements and investments in upgrades to the power delivery system that can reduce line losses. Technologies that can cost-effectively reduce transmission and distribution system line losses are deemed eligible for incentives because they save energy and the savings can be relatively predictable and measurable.

Providing utilities with a profit opportunity on successful conservation programs will give utility management an incentive to apply its creativity, resources and marketing skills to causing conservation that will benefit the utilities and their customers. The resultant commitment of utility capital and other resources to energy efficiency measures will help remove existing barriers to greater penetration of conservation technologies. The unique access to energy users and consumption data that utilities enjoy by virtue of their role as energy purveyors can prove an invaluable resource in tapping efficiency opportunities. A partnership of utility resources and the existing private enterprise infrastructure involved in the business of equipment design, financing, marketing, sales and installation will result in an increase in energy efficiency in the state; enhanced business opportunities for private supply houses, installation contractors and energy service companies; and investment opportunities for the utilities. Investment of capital in the installation of equipment supplied and installed by in-state companies will provide a boost to economic growth in New Jersey.

Within the context of discussions regarding utility conservation incentive programs, an important issue is the exact role that utilities will play in this partnership. Specifically, given the existing infrastructure of private businesses involved in the distribution, installation and maintenance of appliances and other equipment, is it necessary for the electric and gas utilities to be directly involved in such endeavors, or should they be restricted to other roles such as marketing, design and financing? It seems clear that, in general, where an existing infrastructure is in place to supply high efficiency equipment and other conservation measures, the utility role should be limited to program design, marketing, assurance of quality control and savings measurement verification, provision of capital and, in some cases, selection of vendors. Actual sales and installation should not be ruled out, however, in those instances where an existing infrastructure does not exist for the direct provision of a particular service or measure.

On September 25, 1991, the Board adopted conservation incentive rules (*N.J.A.C.* 14:12, BPU Docket No. EX90040304). The rules require each public utility to submit Demand Side Management Resource Plans to the BRC every two years. Each plan must: specify the utility's overall capacity and energy savings goal; describe the impact of the savings goal on load growth and capacity forecasts; and describe proposed performance-based energy programs as well as core programs the BRC has determined must be included and continued in the DSM plans. Program descriptions must: explain the utility's anticipated marketing plan for conservation programs; specify how a utility will involve the private sector in implementing program measures; detail the utility's contractor procurement procedure; and provide an analysis of the program's impact on the existing private market infrastructure.

The rules give utilities an opportunity to recover program costs and lost revenues, and to earn returns on investments in energy efficiency measures based upon a sharing of program savings between utilities and ratepayers. The rules include a detailed formula to determine net benefits associated with utility-sponsored conservation activities. The formula expressly acknowledges the avoided societal cost of environmental impacts related to the construction and operation of electric and natural gas supply projects.

The rules allow utilities to pursue efficiency through one of two approaches—shared savings or standard offer. Under the first approach, a utility would earn incentives by a shared savings of a portion of a program's net benefits. Alternatively, a utility can develop a standard price offer that would apply equally to blocks of conserved energy delivered through a utility program, an independent energy service company or any other third party or end user who could meet certain minimum requirements. Under this option a price would be developed based on avoided cost and would also include adjustments for environmental externalities and lost contributions to fixed utility revenues.

The rules will have a positive effect on New Jersey's economy and environment. The accelerated deployment of efficient technologies will enable utility customers to reduce their energy costs thereby enhancing the state's competitive economic position. Independent businesses that provide energy services and those who supply and install efficient equipment will find expanded business opportunities under the rules. Increased investment in energy efficiency will divert business from out-of-state bulk fuel suppliers to in-state providers of energy-efficient equipment and services. Accelerated proliferation of conservation statewide will reduce the need to site and construct energy facilities and will curtail the need to burn more fossil fuel.

The conservation incentive rules will play a pivotal role in planning to meet New Jersey's future energy needs. The aggressive demand-side management approach the rules embody speaks directly to the state's least-cost utility planning goals. By effectively removing the incentive to build rather than conserve, the rules enable utilities to adopt a more integrated least-cost planning approach that achieves an economically and environmentally sound balance between supply-side and demand-side options.

Bill Redesign

The Board has initiated a bill redesign program to promote conservation by enhancing consumer understanding of energy consumption habits. Board and electric utility staff have been working together to develop billing formats that provide easy-to-understand usage information and graphics that increase consumer awareness. To date, the Board has approved new designs for implementation in early 1991 that include bar charts to reflect seasonal usage patterns and year-to-date consumption comparisons. JCP&L and Rockland Electric previously incorporated many billing features that encourage energy usage awareness and Board staff is working with these utilities to further refine designs where appropriate.

Future Conservation Directions

Any energy or capacity conserved as a result of a Demand Side Management (DSM) solicitation is of equal value to a utility whether it is the result of an improvement in electrical efficiency or is the result of a switch to a more energy-efficient process that uses an alternative fuel. Allowing for projects that improve energy efficiency would greatly expand the potential for cost-effective DSM projects.

As a result, utility DSM solicitations should allow for proposals from all projects that improve energy efficiency as opposed to accepting proposals only from projects that improve electrical efficiency.

One of the primary areas in energy growth in this state is in the construction of new commercial buildings. In many instances, the developer of the building focuses on constructing the building at the lowest front end cost without due consideration of the energy costs of the building after it is occupied. Once the building is constructed, it is more expensive if not impossible to reconfigure the building to an energy-efficient level. In order to assure that the proper decision is made at the front end of construction, the electric and gas utilities should be required to provide funding or necessary financial incentives so that the builder undertakes the full assessment of energy savings options before breaking ground. In addition, rebates or necessary financial incentives for the builder to invest in energy savings measures can be provided by the utility so that the building is energy efficient.

The utility, because of its role in providing extensions of service, knows when construction is commencing and can play a critical role in assuring that energy efficiency is fully considered. Energy and capacity savings will be provided to the other utility customers. Moreover, the state's economic development will be best serviced by energy-efficient buildings which make movement into New Jersey by business and industry all the more attractive.

Before commercial and industrial customers break ground for new or additional facilities, electric and gas utilities should require them to fully assess the implementation of conservation measures, and provide financial assistance to undertake the assessment and the recommended measures.

Least Cost Planning

While the electric utility industry has direct control in selecting its own production, transmission and distribution facilities, it does not control end uses. However, with a judicious selection of price signals and marketing techniques, a utility can influence customer behavior both in the purchase of and the use of energy consuming equipment. Instead of simply deliverers of electricity, utilities can be marketers of energy services: the heat, light, or power needed to operate the buildings and industries in their service area. The strategic objective should be to deliver energy services at the lowest possible cost to the consumer subject to the constraints identified in Chapter 21. This approach is commonly referred to as a least-cost strategy. With a least-cost strategy the utilities invest in conservation options or end-use technologies that conserve electricity on a equal basis with constructing new generation facilities in their resource planning.[22]

Energy conservation represents a principal policy mechanism in the overall objective of reducing the cost of providing electric service in the future. Avoiding the need for costly new baseload generating capacity can be achieved, in part, by controlling the growth of winter peak demands. Permitting the hook-up of inefficient primary electric resistance heating systems, when more efficient alternative systems are available throughout the State, undermines this objective; therefore, limitations on the hook-up of electric heat as a primary heating system should be considered.

Although the state has not cast formal least-cost legislation or regulations, the Board and its regulated utilities regularly employ least-cost planning strategies. For instance, in 1988 the Board adopted bidding procedures for utility procurement of non-utility supply and demand side projects that are designed to ensure that electric utilities pursue the least-cost means of meeting customer demands within the constraints of project viability and reliability, as well as environmental consideration, fuel efficiency, fuel diversity and other concerns. While the process does provide for utilities to build generating plant or procure inter-utility purchases outside of the bidding procedure, utilities are required to demonstrate that such arrangements provide terms more favorable than those available through the bidding process. See Chapter 21 for an expanded discussion of the role of least-cost strategies in New Jersey's energy planning.

Utility Forecast

By the year 2000 New Jersey utilities predict they will need both new generating facilities and expanded transmission facilities to meet the needs of their customers.[23] While the annual growth in both overall energy usage and peak demand had averaged almost 4 percent in recent years, the utilities believe that aggressive load management and conservation programs with anticipated economic trends will slow this growth to approximately 2 percent or even less through the year 2000. The Board expects that the incentives for expanded DSM investments by the utilities will cut further into that growth rate. Based on the utility- projected growth rate, as shown in Figure 8-18, the New Jersey utilities will require over 2,650 MW of additional generating capacity by the year 2000 and over 9,000 MW by the year 2010.

To illustrate, this aggregated 2,650 MW would be the equivalent of about two and one-half Hope Creeks or more electricity than the approximately 2.5 million residential electric nonheating customers used in all of 1987.

Of course, the utilities need not build large, centralized power plants as they have in the past. Smaller, more localized baseload and dispatchable units closer to the load centers and conservation may be more effective.[24]

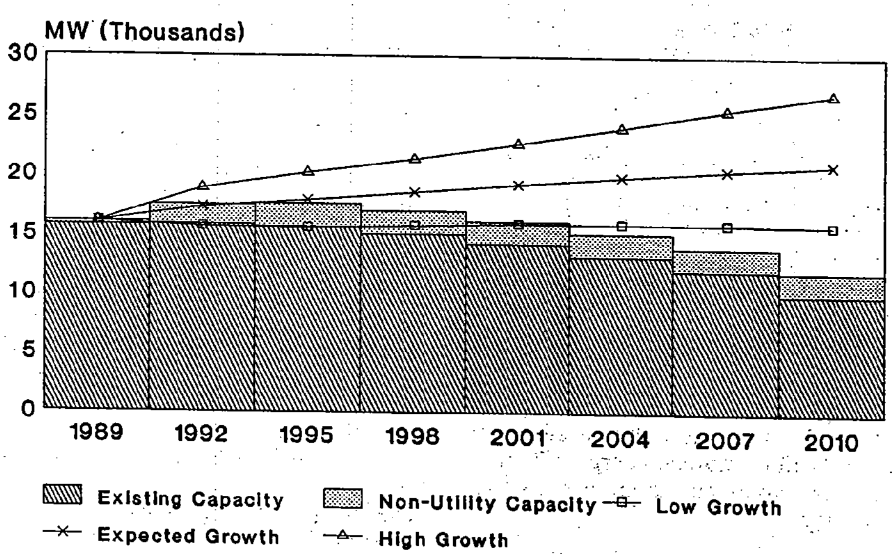
Regardless of economic assumptions, New Jersey utilities expect to need new generating capacity merely to replace existing equipment and purchase agreements. The utilities believe that some 5,800 MW of this capacity should be replaced by the year 2010.[25]

Predicting the need for power and/or energy and deciding who should provide the power makes projecting the need for new utility power plants difficult.

Widespread movements toward greater competition in generation are beginning to have effects as alternative power producers (APPs), [*e.g.*, independent power producers (IPPs) and small power producers or qualifying facilities (QFs)], challenge the utility monopoly with the potential to provide substantial power over the next decade. The major APPs employ cogeneration technology to derive both electricity and thermal energy from fuel combustion. (See Chapter 7) Cogeneration yields total efficien-

FIGURE 8-18

Projected Electric Requirements by NJ Electric Utilities for 1989-2010



Source: NJ's Electric Energy Future 9/88 cies higher than typical efficiencies of traditional central power plants that do not use waste heat.

Planning Process

In March 1989, then-Governor Kean called a conference to examine New Jersey's electric supply planning practices and suggest improvements. The resulting *Report of the Governor's Conference on Electricity Policy, Planning and Regulation* suggests a variety of changes to the electricity planning process and recommends a three-tiered approach to develop: (1) a state electricity plan that provides the overall goals and a vision of what is needed; (2) long range implementation plans prepared by each electric utility to detail all the options available to meet the state plan; and (3) short range action plans prepared by the utilities to indicate specific programs to implement these goals. The Electric Facility Need Assessment Act Certificate of Need process would be part of these plans. This approach is an interesting one worthy of further consideration. Ultimately though, the blueprint for electricity planning in the state shall be the adopted Energy Master Plan itself.

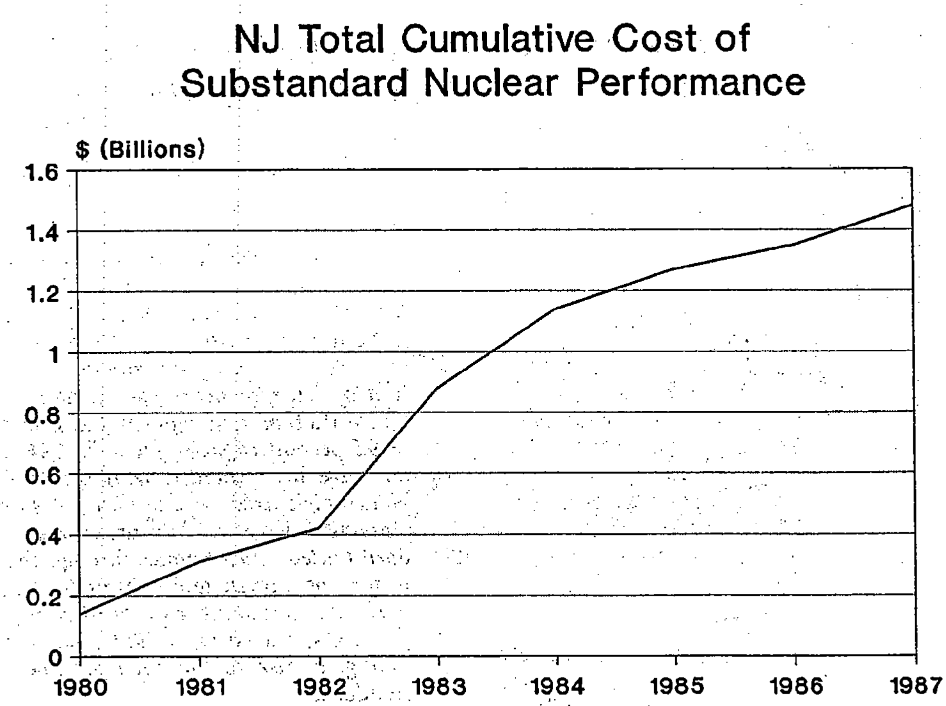
Need Determinations

In the late 1970s, a number of proposed and/or partially constructed generating plants had to be cancelled, owing at least in part to lower-than-expected growth rates in electricity consumption.[26] In response to public concerns about ratepayer liabilities for possible unnecessary construction, New Jersey adopted *certificate of need* legislation. The Electric Facility Need Assessment Act, *N.J.S.A.* 48:7-18d, requires that any electric utility proposing to build a new generating unit of 100 MW or greater and additions to existing units of 100 MW or 25 percent (whichever is smaller) apply to the Board for approval.

In August of 1989, Atlantic Electric Company filed a contingent Notice of Intent (NOI) to construct a 220 MW combined cycle generating facility. The NOI is the first step in the certificate of need process and this application is the first one submitted under the Electric Facility Need Assessment Act. AE labeled this filing as contingent because the proposed combined cycle unit was projected as being needed only if certain unexpected events occurred such as non-completion of one or more of the QF projects with which AE has purchase power agreements. Due to the perceived risk of the planned QF projects, AE has continued with contingency plans. In May of 1990, the Board issued its early assessment report on the proposed facility. In that report, the Board authorized AE to continue its contingency planning for the combined cycle facility and set forth a series of criteria that AE would have to meet before a Certificate of Need would be issued. AE's application for a contingent Certificate of Need was pending hearings at the OAL as of October 1991.

It should be emphasized that the Electric Facility Need Assessment Act does not apply to utility facilities smaller than 100 megawatts or to non-utility generation of any size. The overall impact of the Certificate of Need process on utility supply planning must be assessed.

FIGURE 8-19



Source: BPU testimony on A-1352, 8/11/88

No practical basis exists for requiring a utility to receive a Certificate of Need prior to constructing a generating plant while allowing a non-utility generator to build an identical facility without any similar review. Therefore, the state should consider subjecting all potential sources of capacity and energy to the same assessment criteria.

The Electric Facility Need Assessment Act should be modified to provide a review of capacity and energy needs and to provide a forum for reviewing the proposed method for procuring such capacity and energy. The review would include the appropriateness of identifying specific sources of capacity and energy and would include review of any proposed evaluation system such as a request for proposal (RFP).

Prior to procuring capacity and energy from any source, including its own construction, a utility would be required to demonstrate need. Once need is established, the utility would (through procedures established by the Board) evaluate all potential sources of capacity and energy based on price and non-price factors to determine which option provides the most benefits. Facility siting would be subject to standards established by DEPE and those standards would apply equally to utility and non-utility facilities. This proposal maintains the requirement that utility construction be reviewed to ensure it is needed, is appropriate technology and is appropriately sited. However, it expands the review to non-utility sources of capacity and energy and ensures that all potential sources are evaluated on an equal basis.

Nuclear Performance Standards

Some nuclear baseload plants have both performed poorly and required significant annual capital costs to keep them operating. (See Appendix: Largest Annual Net Capital Additions.) In New Jersey, therefore, review of the on-going capital additions required at the Oyster Creek, Salem, Hope Creek, TMI, and Peach Bottom units by state regulators would determine whether substantial capital investments in these plants are cost effective. However, the Board historically had reviewed these costs for reasonableness after-the-fact in conjunction with rate cases.

Nuclear performance standards represent a form of incentive regulation. With respect to the performance of nuclear plants, the 1985 Energy Master Plan stated:

> The [Board] shall consider that all base load power plants must achieve the operating efficiencies and reliability levels projected at the time of a regulatory review. Failure to achieve these levels shall subject the utility to restrictions in their authority to pass on excess fuel costs to ratepayers, while exceeding these projected levels shall entitle the utilities to bonuses. The [Board] shall promptly establish a regulatory system of penalties and bonuses to implement this policy.[27]

Performance standards are necessary to adequately balance investor and ratepayer interests, owing to the poor performance of nuclear power plants. Without risk allocation mechanisms, virtually all replacement power costs are recovered through the Levelized Energy Adjustment Charge (LEAC) and, therefore, passed on to the customers regardless of the cause of the poor performance.

TABLE 8-2

New Jersey Nuclear Performance Standard Allocation of Replacement Power Costs

Capacity Factor Performance (%)	Risk Allocation: Ratepayer (%)	Risk Allocation: Shareholder (%)
75 to 65	No impact	
below 65 to 55	70	30
below 55 to 45	60	40
below 45 to 40	50	50
below 40	Board Review	

Source: BPU Decision and Order Docket No. EX89080719, p. 43.

Initially, the high capital costs of nuclear power plants were to be offset by low operating costs, resulting in economical, year-round electricity. However, the nuclear plants actually operated at around 60 percent capacity factor even though they had been originally estimated to perform at 80 percent capacity factor. Ratepayers therefore bear both the high capital costs in rate base and replacement power costs through LEAC. As Figure 8-19 shows, the cumulative effect of the substandard nuclear performance has been over \$1.4 billion.[28] Conversely, performance standards should reward good performance. If the capacity factor exceeds the target, then some savings could accrue to the company and the remainder to the ratepayers.

The Board in its Decision and Order adopting nuclear performance standards for PSE&G stated:[29]

> *Nuclear plants are constructed with the expectation that their high capital costs will be offset by their low operating costs...At the time the decisions were made to construct each of [PSE&G's] five operating nuclear plants..they were projected to perform at approximately 80 percent capacity factors....[PSE&G] reported that the lifetime cumulative capacity factor for Salem I is 51.3 percent, Salem II - 47.7 percent, Peach Bottom 2 - 53.8 percent and Peach Bottom 3 - 60 percent. Further, plant operations have been characterized by wide swings in performance as evidenced by Salem II's 8 percent capacity factor in 1983 and Salem I's 95 percent capacity factor in 1985. Thus, ratepayers have been saddled with the cost burden of the plant's high fixed costs in base rates and expensive replacement power costs incurred as a result of substandard nuclear performance through the LEAC. It is this history of uneven and substandard nuclear performance, its attendant cost burden to ratepayers and [PSE&G's] increasing reliance on nuclear generation that gives rise to the need for nuclear performance standards.*

This standard adopted by the Board in 1987 was based on a target capacity factor of 70 percent. No reward or penalty was triggered for performance within 10 percent of this target. Performance outside this 10 percent plus or minus band triggered either a penalty or reward. Below 40 percent capacity factor, a Board review was required to determine appropriate action.

The 1987 performance standards raised questions about optimum design:

(1) What is the best *setpoint*—the divider between performance penalties and rewards?

(2) Should there be a *deadband*, a range in which performance changes are neither rewarded or penalized? The 1987 standard had a broad deadband, which tended to minimize the role performance standards could play.

(3) Should standards be based on thresholds or a constant slope? According to the 1987 standard, performance within the wide deadband carried no penalty or reward. At the edge of the deadband, a small incremental change in performance lead to a large instantaneous penalty or reward effect (*e.g.*, a 1 percent drop in performance from 60 to 59 percent automatically triggered a 20 percent disallowance of replacement power costs under the 1987 standard). Would the incentives work better with penalty and reward proportional to deviation from the setpoint selected?

The Board held a series of hearings in late 1989 to review the effects of the 1987 performance standard. As a result, the Board modified the standard. The target capacity factor remains at 70 percent but is now based upon maximum dependable capacity rather than design electrical rating. The zone of reasonableness (*i.e.*, acceptable deviation from the target) was modified to plus or minus 5 percent. The risk assessment allocations are now measured from the edge of the zone rather than from the target in order to mitigate the *hard shoulder* effect. In addition, the Board modified the replacement power cost sharing formulae as shown in Table 8-2.

Nuclear performance standards, a tool that provides an incentive for better performance and a sharing of nuclear performance risks, should be continued by the Board with an eye toward assuring that there is adequate ratepayer protection and appropriate utility incentives.

Load Factor

Load factor, the ratio of average to peak loads, is another measure of performance or efficiency. Meeting peak demands is expensive: peaking equipment is rarely and inefficiently used. In 1989, the average load factor of New Jersey electric utilities was 55.1. Table 8-3 shows that this number is below the national average, the PJM average and the New England Power Pool average.

Load factor can be affected by numerous variables, *e.g.*, demographics, end uses, etc. While a number of load management techniques can be employed to increase the load factor, those that reduce the peak load without increasing overall energy use are preferable. Therefore, load factor can indicate how well load management performs within a least cost planning strategy. While load management techniques provide important mitigation against peak load growth, in many cases, they do not reduce overall energy consumption or enhance efficiency. Indeed, load shifting may actually exacerbate environmental effects associated with baseload plants. Thus, while load shifting programs can impart substantial benefit to the system, they should be analyzed with consideration for these effects, as well as for the cost of baseload plant needed to serve these technologies.

TABLE 8-3

Comparison of State, Regional & National Load Factors

Year	New Jersey Load Factor	PJM Load Factor	New England Power Pool Load Factor	National Load Factor
1982	51.7	57.9	63.1	62.0
1987	52.9	58.2	61.8	60.8
1988	52.1	57.9	63.7	59.6
1989	55.1	61.4	60.1	61.3
1990	53.0	59.8	62.8	61.1

Sources: N.J. 1987-1990 - N.J. Energy Data System.
PJM 1987-1990 - PJM Interconnection System Highlights and Review.
National and New England Powerpool - North American Electric Reliability Council 1990 Electric Supply and Demand Report, NJ/PJM/NEPP/US 1982 - Edison Electric Institute analyst Carl Tobee.

If the load factor (which in 1988 was just under 55 percent compared to the national average of about 60 percent) increased by approximately 8 percent, the reduction in installed capacity at 15 percent reserve amounts to almost 1,800 MW. At $500/KW, this level of load factor improvement results in an avoided capital cost of $900 million.

Service Reliability

The concept of performance standards for individual power plants is appropriate for regulation in the current rate base environment. If the industry were restructured by divestiture of generation, this kind of standard would be a contract matter between the distribution company and its suppliers. In such a case, the regulator would be indifferent to how electric service was provided but would be concerned that the obligation to serve be met. In such a situation, the ideal measure would be the availability and quality of service to the customer at the meter. A proxy might be voltage and availability criteria at the substation.

Electro-Magnetic Fields

The issue of possible adverse health effects of magnetic fields created by the operation of utility transmission lines has generated considerable interest recently. Extensive research is currently being conducted in this area in an attempt to identify and quantify the possible adverse health effects.[30]

Since people live near electric transmission lines and electric transmission lines continue to be constructed in New Jersey, investigation of the effects on public health of the magnetic fields associated with these lines is necessary and the establishment of allowable limits for the fields may be required to protect the public health.

The DEPE Commission on Radiation Protection, established under *N.J.S.A.* 26:2D, has an advisory committee on non-ionizing radiation that will review and make recommendations to the commission on health effects of electromagnetic radiation. If it is determined that magnetic fields created by the operation of utility transmission lines adversely affect the public health, the state will establish limits for magnetic fields.

No adverse health impacts associated with electromagnetic fields have been shown conclusively to exist. However, in light of the uncertainty characterizing the current body of scientific knowledge, utilities should practice prudent avoidance when planning new transmission facilities.

Cost of Service and Rate Design

The goal of cost-based tariff design is to communicate an accurate price signal to utility ratepayers. As individual charges approximate their full cost basis, utility ratepayers are made more aware of the cost impacts of incremental consumption. As a result, conservation and load management objectives are enhanced, along with greater system efficiency.

Cost-based tariff design is a two-fold process, each component of which is essential. First, customer classes must be allocated that portion of the overall revenue requirement for which each is responsible, as determined by the cost of service study. Second, the customer demand and energy charges within each rate schedule must be set at a level reflective of the costs incurred in providing each type of service. Proposed tariff modifications should meet this cost of service test, while existing rates shall be moved toward their full cost basis over time.

Consistent with this approach, subsidization among and within rate schedules is not the preferred means of attracting new business and maintaining the existing ratepayer base in New Jersey. An overall reduction in each utility's cost of providing service, and a concomitant reduction in overall rates, should be this State's objective in enhancing New Jersey's attractiveness to new and existing customers. Alternatively, utilities may wish to consider whether shareholders should bear some of the short-term burden of providing incentive rates to customers. Other mechanisms or forms of regulatory structure may be appropriate to enable utilities to offer competitive pricing without creating cross-subsidies. This issue must be explored further.

Fuels

Natural Gas

Natural gas is attractive for electric generation projects since it is clean-burning and available on a long-term contract basis. The gas turbine equipment is less capital intensive and meets environmental criteria. The state is concerned about reliance on just one fuel for electrical generation purposes. Present and planned generation capacity additions rely primarily on natural gas as a fuel source. However, since deregulation, natural gas has been in good supply with only interstate pipeline capacity being a barrier to its greater use. The pipelines have applied to the FERC to increase capacity substantially to New Jersey so that cogenerators who wish to use gas should be able to do so for the foreseeable future. (See Chapter 4.)

The gas utilities in New Jersey have put in place special rates for non-utility cogeneration. Firm, interruptible, and transportation rates are available, depending upon the size and type of equipment and facility being served. The variety of tariffs allows the cogenerator to select the most economic choice. Some gas marketers will provide long-term contracts and move gas over interstate pipelines from the wellhead with utility transportation tariffs to deliver to the end user.

The other natural gas ratepayers can also benefit from an increase in gas use by electric generation facilities. Under traditional ratemaking procedures, the gas provided by the natural gas utilities to the generation facilities will spread fixed costs over larger volumes, thus reducing unit costs of gas. As long as the incremental contribution derived from sales to electric generators exceeds the incremental cost of service, all customers then see lower bills for their gas service.

A critical aspect of natural gas use is the reduction in air pollution that occurs when cogeneration replaces old boilers using oil or coal. Natural gas contains little sulfur dioxide, and nitrogen oxide control strategies are very effective on gas-burning equipment.

Oil

Since the oil crisis of the 1970s, oil serves as a back-up to industrial interruptible gas for electrical generation for price and environmental reasons. Today many environmental permits limit oil use to periods of gas interruption. In order to burn oil full time, the more severe environmental criteria that apply to gas must be met. In many cases #2 oil is the preferred choice as backup. The price of #2 oil has seldom, if ever, been low enough to warrant switching to it on an economic basis. Today, however, the ceiling price of interruptible natural gas is set on the basis of parity pricing with backup fuel so the main differences between natural gas and oil are the GR&FT exemption and any utility rate incentives.

Coal

The major impediments to the use of coal in New Jersey are environmental (air and water) concerns and transportation. Even with the development of clean coal technology, the water needs of a coal plant can be a severe siting constraint. (See Chapter 10.)

The utilities have had new coal capacity in their construction plans as recently as the early 1980s, but financing and siting problems as well as lower than expected load growth caused their removal from more recent plans. Even with higher than expected peak load growth, utilities generally favor capacity that is dispatchable, which is another area where coal plants appear to be at a disadvantage.

However, with proper environmental controls, coal does provide the potential for a long-term supply of energy at a relatively low commodity cost and, therefore, should remain an option available to New Jersey for future electric capacity needs. The DEPE recently issued permits for two coal-fired cogeneration facilities—the Chambers and Keystone projects—to be located along the Delaware River. Pollution control strategies incorporated into the approved designs include state-of-the-art nitrogen oxide controls and scrubbers for sulfur dioxide.

Pumped Storage

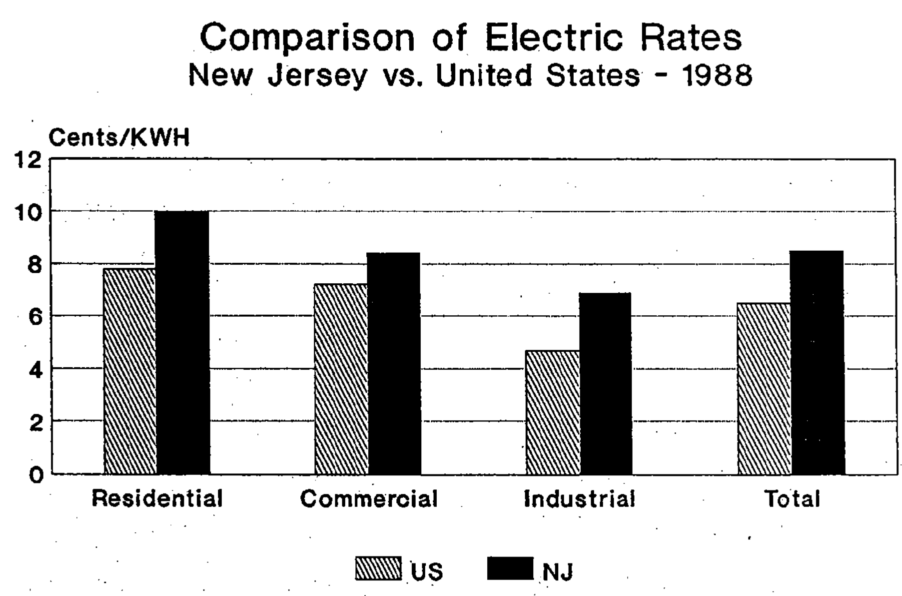
Pumped storage involves the conversion of electric energy into stored mechanical energy for later conversion back into electric energy at times of peak electricity demand. Water is pumped to a higher elevation using off-peak baseload generating facilities and is then released to power a hydro generator during on-peak periods. Pumped storage presently accounts for approximately 3 percent of PJM system capacity. This capacity (and potential additional pumped storage facilities) could be employed to offset the need to construct new peaking capacity and to burn related natural gas and fuel oil. In power systems where there are large power cost differentials between on- and off-peak periods, large energy cost savings can result. However, because the technology relies to a large degree on coal-fired baseload plants to supply pumping power, inclusion of environmental costs associated with baseload power generation could impact the cost/benefit analysis of such facilities. Nonetheless, pumped storage remains a potential source of peaking capacity.

The proposed 2,000 MW Mount Hope Water Power Project is now in the permitting process before the FERC. If approved, the project could benefit New Jersey; the Board would need to analyze the project in detail upon FERC approval to determine how it would fit into the overall least-cost planning processes of the state's utilities. Due to the projects's size and unique characteristics, this review process may have to take place outside of the established competitive bidding procedures.

Fuel Diversity

One of the goals of energy planners is to assure a continuous supply of electricity, no matter what fuel supply problems exist. In the past, oil, coal, and natural gas sup-

FIGURE 8-20



Sources: US Data - Financial Statistics of Selected Electric Utilities, EIA-0437(90). NJ Energy Data Stystem plies have been disrupted. Oil embargoes occurred in 1973 and 1979, and there was a gas supply problem in 1977. Labor strikes, both rail and mine, have posed coal supply problems, but since coal is mainly used for electricity generation, its problems have gone almost unnoticed by the general public. The supply of oil and coal can also be affected by barge and tugboat strikes and ice in the rivers. Most contracts signed by the utilities with non-utility co-generators are for output from gas-fired units. Currently the price of oil makes it a suitable substitute for gas so that no capacity would be lost in case of pipeline disruption or unanticipated demand.

Apart from concerns over supply disruptions, over-reliance on one type of fuel could severely impact the state's economy should large price spikes occur. An emerging issue is the heavy reliance of existing and planned (utility and non-utility) cogeneration facilities on natural gas as the primary fuel. The Board will monitor this situation and assess whether other sources of fuel supply should be further encouraged in order to maintain fuel diversity.

Within the structure of the Stipulation, the electric utilities have the flexibility to reflect concerns for fuel diversity.

Economic Development

Prices and Taxes

New Jersey electricity prices, while among the highest in the country, paradoxically do not appear to send a strong market signal regarding efficiency. As shown in Figure 8-20, New Jersey prices were significantly higher than the national average in 1986.[31]

The 1989 Grant Thornton Study of Manufacturing Climate ranked New Jersey 45th in energy costs to the manufacturing sector. The study ranked Pennsylvania 42nd, and New York 36th in the same costs. New Jersey's costs to the manufacturing sector are $6.09 per million BTU versus the United States average cost of $4.64 per million BTU.[32]. Between 1962 and 1985, every 10 percent increase in the real price of electricity resulted in a 1 percent decline in employment in the paper, primary metals, rubber and plastics, clay, and glass industries with a three-year lag.[33]

A DCEED report[34] identified the gross receipts and franchise taxes (GR&FT) imposed on electric utility revenues as one of the contributing factors in this price disparity. The GR&FT burden is assessed at the rate of approximately 12.5 percent of revenues—much higher than the national average tax rate of 7 percent. The concept of shifting the GR&FT from a tax on the value of energy to a proportional tax on a unit of energy for electric and natural gas sales has been discussed. This shift would prevent the tax from climbing rapidly during periods of high inflation or price shock as occurred during the 1970s. The proposal included imposing different unit taxes for each class of user based upon the proportional contribution made by each class to the total tax, so each class of user gains equally from the proposed change. The ultimate impact of the proposal would be to reduce the tax burden from 12.5 percent to 7 percent over a five- or six-year timeframe which would improve the economic competitiveness of New Jersey's commercial and industrial sectors. In June 1991 the Legislature passed and the Governor enacted a revision in the GR&FT structure applicable to electric and gas public utilities. The legislation establishes unit taxes for the sales of electricity and natural gas, as opposed to taxes heretofore levied against the utilities' revenues. The legislation also changes both the method and time of payment of those taxes.[35]

Findings

- A trend of increased competition in the electric generation market emerged in the late 1980s with the development of alternative power production.
- The BRC has instituted a competitive bidding system for electric utilities to procure alternative power capacity and large-scale conservation projects.
- The current regulatory structure treats alternative power producers differently than electric utilities in the areas of siting, technology, project approval, earnings surveillance and project risk.
- Current utility projections demonstrate the need for substantial increments of new generating capacity.
- The siting and operation of electric generating facilities have the potential to negatively impact environmental quality in New Jersey.
- The potential exists for conservation and and demand-side management energy efficiency measures to mitigate the need for new electric generating facilities.
- With appropriate price signals, financial incentives and marketing techniques, electric utilities can influence customer behavior in both the purchase and use of end-use equipment.
- The BRC adopted a rule in September 1991 to address barriers to conservation and create incentives for utility investment in demand-side management.
- Various taxation policies have been enacted or proposed that impact upon energy policy in the state.
- More electric generating capacity in New Jersey would reduce loading on the west-to-east electric transmission system and costs to consumers.
- Self-generation by many industrial and commercial electricity users can be installed without bidding under the Stipulation of Settlement and can be a powerful competitive force on utilities as well as a way to meet the state's capacity requirements.
- The performance of New Jersey's nuclear plants has been substandard relative to the national average and also relative to the performance anticipated during the planning and construction stages of the plants.
- The BRC has instituted nuclear performance standards to allocate the risks of poor performance and to encourage utilities to run nuclear units more effectively.

- Nuclear plants have required significant additional capital investments on an ongoing basis to meet operating license requirements.
- New Jersey utilities are relying significantly on power purchases from utilities outside New Jersey.
- New Jersey has a transmission capacity limitation. There is at the same time a public concern regarding the potential health effects of electromagnetic fields.
- Recent and planned additions to generating capacity rely primarily on natural gas as a fuel source.
- Electric prices in New Jersey are significantly higher than the national average.

Policy

- Utilities should deliver energy services at the lowest possible cost to consumers by appropriately considering conservation options or end-use technologies that conserve electricity on an equal basis with constructing new generation facilities.
- The BRC should consider implementing mechanisms to eliminate the distinction between utility and non-utility generation. Expanded competition could be achieved through some form of deregulation of utility generation or some form of increased regulatory oversight of APPs. Alternatively, to mitigate the current differential treatment of utility and non-utility generators, the BRC could consider applying a uniform set of rules to all electric generators.
- The State should consider modifying the Electric Facility Need Assessment Act to further integrate the regulatory treatment of of utility and non-utility generation.
- The siting, design and operation of electric generating facilities in the state must be consistent with the State's environmental quality standards.
- In the context of utility planning, consideration should be given to allowing non-utility cogenerators to demonstrate that they can displace existing utility capacity and save money for both the utilities and their ratepayers.
- The State should consider whether *N.J.S.A.* 40:55 (d) should be expanded to include alternative power producers in order to afford them the opportunity to appeal to the Board if they are aggrieved by a municipal agency's actions.
- In order to maintain and enhance regional power markets and resulting economic efficiencies, the free interstate flow of electricity should not by discouraged through inappropriate taxation policies or other artificial barriers.
- The State should support the efforts of the interstate pipelines to increase gas supplies to New Jersey to the extent necessary to provide natural gas to necessary electric generating facilities.
- The BRC should study the impact of unbundling electric utility services to determine if self-wheeling or retail wheeling can be implemented.
- Electric utilities should continue to diversify their supply options and not rely on one source of energy for the bulk of their requirements.
- To meet projected capacity needs of New Jersey consumers at the least possible cost, utilities should aggressively pursue cost-effective programs that improve generation and transmission efficiency and that optimize peak load management. Such efforts would offset the need to invest in capacity expansion and generating facility life extension.
- Performance standards for nuclear power plants should be continued.
- Least-cost planning principles dictate that modifications to existing generating plant should be considered within the context of alternative supply options. In light of substantial ongoing capital additions to existing nuclear facilities, other cost-effective supply alternatives must continue to be explored.
- Prior to adopting new legislation affecting energy supply facilities, the State should consider its impact on integrated energy supply planning.
- Electric utilities should aggressively employ cost-effective peak shaving load management techniques.
- Utilities should continue to cost-effectively reinforce existing and/or construct new transmission facilities where appropriate, subject to health and other siting concerns.
- The DEPE Commission on Radiation Protection is working to establish limits on electromagnetic fields that would apply to all electric transmission lines.
- Utilities should provide incentives for builders to construct energy-efficient structures that enable the control or channeling of ventilation to prevent air pollution.

Implementation

- Least-cost planning should be continued and refined by utilities and regulators as the fundamental strategy for meeting New Jersey's needs for the services provided by electricity. The BRC and the DEPE will develop guidelines for incorporating environmental costs within the least-cost planning framework.
- The Board will implement regulatory mechanisms set forth in rules adopted in September 1991 to provide long-range utility incentives for conservation via the ongoing rulemaking proceeding.
- The BRC should consider whether the current ratemaking structure provides the appropriate incentives for utilities to fully consider the least-cost means of meeting electric generating projects, whether from utility plant, purchases from non-utility generators or inter-utility purchases.

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Chapter 9

Renewable/Recoverable Energy Sources

As a result of the energy crises of the 1970s, interest grew in renewable energy technologies. Though often not economic at the time, projects for the home, as well as large scale commercial projects, went forward in the expectation of rising energy prices. As energy prices stabilized and then dropped in inflation-adjusted terms, interest waned.

In 1988, only a small fraction of the energy purchased in New Jersey was from renewable energy sources, about 0.1 percent or 2.3 TBtu—equivalent to 450,000 barrels of oil.[1] (See Table 9-3.) This chapter examines how much energy New Jersey gets from renewable sources (solar, hydro, wind, and waste), reviews past policies, and suggests directions for the future.

Technology and Economics

Combustion of Municipal Solid Waste

The primary benefit of garbage combustion under present technology is volume reduction, not energy production. A solid waste burning facility can provide sufficient steam to generate electricity for internal plant use and for sale to help reduce the cost of plant operation. A cheaper option is to sort and reuse material wherever economically feasible. Components of municipal garbage (paper, plastic, metals and organic matter) have greater value if they are kept separate for reuse than if they are mixed. Mixed garbage is useful only as fuel but its varied components hinder combustion and require special expensive processing to control toxic emissions.

On April 6, 1990, Governor Florio issued Executive Order No. 8 that directed state agencies to cease the permitting and financing of resource recovery facilities for 120 days so that a special Emergency Solid Waste Task Force could review the need for incinerators and their economic and health effects. The executive order stressed recycling, alternative technologies and source reduction as options of first resort because they can pose less of an environmental, siting and economic burden on the state's citizens. In addition, the energy saved through recycling should be considered in a comparative analysis of recycling and incineration. The Governor appointed a special committee to investigate waste options for New Jersey.[2]

On August 6, 1990, the Emergency Solid Waste Assessment Task Force issued its final report to Governor Florio. The task force recommended source reduction, waste reuse, recycling and composting as the primary means to reduce solid waste volume. It recommended removal of hazardous waste from the solid waste stream for separate management and reduction of toxic components in materials that do enter the waste stream. These measures taken together would lessen the need for incineration.

Methane from Waste

Gas produced from the decay of organic matter in landfills is about 60 percent methane and 40 percent carbon dioxide (a non-combustible gas). Natural gas, distributed by gas utilities, is almost pure methane with a heat value of approximately 1,020 Btu per cubic foot. Landfill gas, after some cleaning, has a heat value of about 500 Btu per cubic foot and can be used in boilers to produce steam or in combustion turbines to produce electricity.[3]

Several projects that generate electricity from landfill gas are going forward in New Jersey. The rates paid to qualifying independent electric power producers have been sufficient to attract funding from private investors. Kinsley's Landfill in Deptford Township produces about 26,000 cubic feet of medium Btu gas per hour. The gas generates 2.6 MW of electric power and yields a total of almost 11 gwh of electric energy a year, worth about $1.2 million at 1989 retail rates.[4] At the Hackensack Meadowlands District Landfill, a facility that began operation in April of 1990 will provide up to 7.8 million cubic fee a day to feed a PSE&G pipeline for sale to utility customers.

Methane is also produced through the breakdown or anaerobic digestion of sewage sludge.[5] The potential here is for the sewage plant operator to collect the gas and use it for fuel for sludge drying or in a boiler to produce steam and electricity. In the northeast, some sewage plants with anaerobic digesters produce and use sludge digester gas to supply heat to the digestion process. Where feasible, internal combustion engines could generate electricity and use waste heat for the digesters.[6] Only a few New Jersey sewage plants are designed for anaerobic digestion of sewage.[7] Technical considerations and the capital costs associated with gas production from sewage currently render the economics of this technology's application questionable.

Solar Energy

About 98,000,000 TBtu of solar energy reach New Jersey each year. If New Jersey could convert only 0.002 percent of this energy to usable form, all of the state's needs could be met by solar energy. The most direct and cheapest way to use solar energy is to take better advantage of natural light and solar warmth through passive, non-mechanical measures.

Passive measures avoid the use of pumps, fans or other mechanical devices. A building takes advantage of passive solar by its layout and orientation that optimize the collection of energy in the winter and the rejection of heat and avoidance of its collection in the summer. Mechanical devices may regulate shading and insulation as well as thermal mass to absorb and store heat. We estimate that about 20,000 homes have been designed to use passive solar energy, or only about 6 percent of the homes built in the last 10 years.[8]

Often street orientation hinders solar design. The state Department of Energy sought to convince municipalities to require street alignment that would accommodate the incorporation of passive solar energy in the design of residential buildings. As of the mid-1980s, fourteen municipalities had adopted or proposed appropriate regulations.[9]

Two sections of state code have been modified to encourage use of solar energy systems. As an incentive for the use of solar energy, the state exempts qualifying active and passive solar equipment from state sales and use taxes. The Energy Subcode of the New Jersey Uniform Construction Code (*N.J.A.C.* 5:23 et seq., allows a developer or builder to take credit for solar contribution in complying with the code. This allowance encourages a solar design that may require larger glass areas than the Energy Subcode would ordinarily permit.[10]

Many builders incorporate into new homes passive solar features such as large windows facing south with summer shading from landscape or overhangs, sunspaces, and thermal mass. Often these features also provide desirable aesthetic characteristics. However, few homes built in New Jersey are designed with passive solar as the primary focus. In such a home, passive solar energy can supply 30 to 50 percent of heating needs.[11]

Active solar energy is the use of a system in which pumps, heat exchangers, and other mechanical and/or electromechanical devices transfer the sun's energy from collectors to where it can be utilized. The only commercially available active solar energy systems are domestic water heaters. In the late 1970s when units that use antifreeze, pumps, and heat exchangers began to be purchased. By 1985, New Jersey had approximately 4,000 active and passive solar systems.[12] As of December 1988, we estimate that number has grown to 32,000.[13] The 1985 Energy Master Plan recommended 14 actions to promote the use of solar energy in New Jersey. It was an ambitious program, and implementation and results have not been easy to obtain. The energy division encouraged the installation of active solar domestic water heating by requiring that utilities make Home Energy Savings Program loans available for solar and solar-assisted water heaters, that all new residential construction be eligible for utility solar credit programs, and that utility programs be consistent throughout the state.[14] Approximately 12,000 utility-installed systems are now in place.[15] (See Table 9-1.)

TABLE 9-1

Economics of Active Solar Water Heaters

	Net present value if savings are	
Cost of System	$150	$250
$4,000	($2,761)	($1,637)
$3,000	(1,862)	(738)
$2,000	(520)	604
$1,000	600	1,724

Source: DEPE - see Appendix Table A-9-1 for assumptions.

Institutional barriers do not prevent the installation of solar energy systems in New Jersey residences. State law enables property owners to negotiate solar easements to assure continued access to solar energy.[16] The 1985 Master Plan sought to remove regulatory barriers that might be inhibiting the use of solar energy, such as deed restrictions that would prevent the installations of solar collectors.[17] Other proposals, such as training of plumbing inspectors and certification of solar water heater installers, were deemed unnecessary.[18] No significant legal barriers remain to the installation of active solar energy systems. Technical difficulties associated with a number of previous installations have lead some customers to express dissatisfaction with solar energy projects. In view of this experience, it may be appropriate to promulgate rules setting forth technical specifications for installations of solar water heating projects.

Apart from issues of technical installation standards, New Jersey consumers must carefully consider the cost-effectiveness of commercially available active solar domestic water heaters when making a decision to invest in such a renewable energy source. Low cost systems priced below $1,500 to $2,000 may be cost-effective at mid-1990 electricity prices. One must determine payback or cost-effectiveness on a project-by-project basis using specific cost and savings figures.

Large active water heaters are complex and expensive, even when sized to supply only 50 percent of domestic hot water needs. Rebates, grants, tax abatements, and a belief that energy prices would rise continually helped to create a market in New Jersey for these units. Because conventional energy prices have not risen as expected, the present utility-sponsored rebates and loans provide insufficient incentive to install active water heating equipment.

Photovoltaics

Direct conversion of sunlight to electricity—photovoltaics—is a solar technology that is developing rapidly. Photovoltaic systems consist of collector panels mounted on a roof or support that orients them towards the sun, mounting hardware, and wiring. If conventional AC appliances are to be powered, an inverter converts the DC output of the collectors. In some systems, storage, such as batteries, may be needed if power is required when light is insufficient. To interconnect with the electric utility, additional electrical control equipment may be needed.

Some photovoltaic systems track the sun as it moves in the sky; some use lenses to concentrate sunlight on the solar cell; and still others are simply flat plates mounted at the optimum angle for best total energy production. As the technology develops, the potential exists for individual homeowners and businesses to install a photovoltaic system that could meet all their electrical needs. While technically feasible, photovoltaic systems are currently too expensive for most traditional applications.

One particular advantage of the conversion of sunlight to electricity is that it produces power during summer afternoons when New Jersey utilities experience their peak demands. Currently, complete photovoltaic systems cost $5,000 to $10,000/KW, far too expensive for general uses.[19]

A 192 KW photovoltaic system installed in 1981 supplies electricity to a 24-home subdivision in Arizona. The full system cost about $9,500/KW. This system uses the utility for *storage*, selling excess electricity during the day and purchasing electricity at night.[20] The nominal cost for system electricity is relatively high—about $0.38 to $0.40/kwh when financed for 30 years at 6 percent.[21]

Arco Solar, the nation's largest manufacturer of solar equipment, recently improved the efficiency of its thin film copper indium diselenide photovoltaic materials. In commercial production, the price of panels would drop to about $900/KW.[22] Had the Arizona project been able to obtain panels at this mass manufacture price, the complete system cost would have been $5,000/KW or about $0.20/per kwh over the life of the project.[23]

The industry target is production of a $350/KW panel. As panel prices drop, the cost of the balance of the system becomes the controlling factor, *i.e.*, cost of equipment to convert the output of the panels to standard AC voltages, wiring, interconnection, and installation costs. Balance of system costs were about $4000/KW for the Arizona 192 KW system. Balance of system costs for a single residential installation have been estimated at around $2000/KW.[24]

TABLE 9-2

Comparison of Cost to Produce Electricity

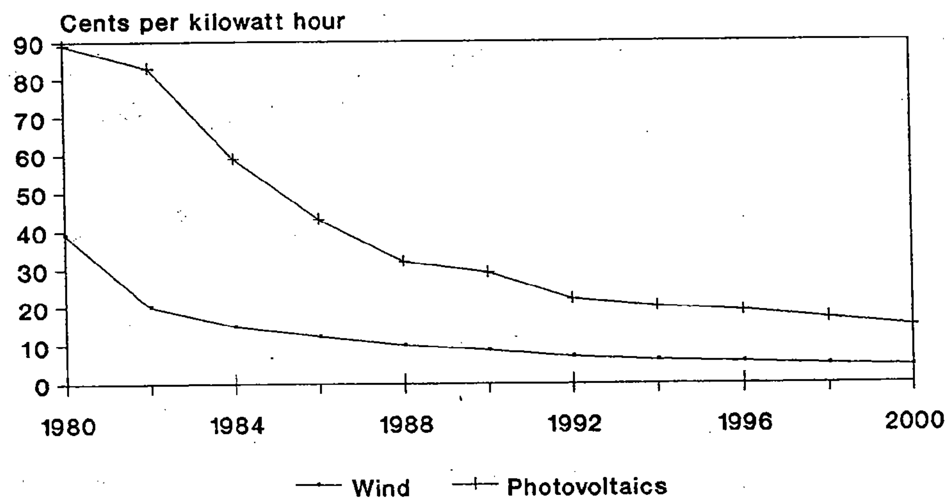
	Capital Cost $/kw	Operating Cost $/kwh	Aggregate $/kwh
Chronar Proposal 50 MW PV	2,500	0.05	0.13
Hope Creek 1100 MW Nuclear	3,600	0.11	0.13
JCP&L 100 MW Combustion Turbine	400	0.13	0.21
Stand Alone PV with Storage .006 MW	9,000	0.0	0.42

Note: PV - photovoltaic (solar electric).

Source: DEPE Analysis. All costs estimated. See Appendix Table A-9-1 for assumptions.

FIGURE 9-1

Actual and Projected Cost of Electricity from Wind and Photovoltaics



Note: Utility interconnected, no storage
Projections, 1992-2000
Source: US Department of Energy

Other system costs are not likely to experience the same cost reduction factors as the panels. However, some reductions may come from improved technology for the solid state inverter, the component that converts DC power to AC.

Photovoltaic systems have become the economic choice for certain applications, primarily in remote areas far from the utility grid. Applications include telecommunications repeater stations and remote monitoring devices. As additional applications for photovoltaics are found and as consumer products that rely on photovoltaics are used in increasing amounts, production costs for photovoltaics should continue to decrease.

Table 9-2 and Figure 9-1 show the impact that technological progress has had on the cost of photovoltaic panels. At $350/KW, photovoltaics will become cost competitive with conventional means of electricity production for many applications. That market would be huge, since every building has a roof and most are not shaded during most of the daylight hours. Already, at today's cost, consumer products that use photovoltaics, worth $1.5 billion, are being marketed each year. If the cost becomes competitive with conventional electricity, sales of consumer products would rise to about $5 billion a year, which photovoltaic industry experts say could happen by 1995.[25]

Hydroelectricity

Hydroelectricity, the production of electric power using moving water, is one of the oldest means of generation. The technology is mature and refinements will probably not provide breakthroughs in the capital cost to develop sites.

Due to its geography, New Jersey has only a small potential for hydroelectric power. In terms of physical or technical feasibility, the state could obtain a maximum of about 26 MW through the operation of hydro plants at 23 potential sites—enough to supply about 0.3 percent of its electric energy needs.[26] However, to date only five sites have proved to be economically viable enough to reach fruition. American Hydro Power operating at Dundee Damn in Clifton contracted with PSE&G to supply 2.1 MW of capacity; Great Falls Hydro Project operating at Paterson Falls in Paterson is under contract with PSE&G to supply 10.9 MW of capacity; and Great Bear Hydro at Columbia Lake in Warren County is under contract with JCP&L to supply 0.5 MW of capacity rendering a total of 13.5 MW of hydroelectric capacity supplied to New Jersey utilities. In addition, Riegel Products Division, a subsidiary of James River Corp. operates hydro plants at two northwestern New Jersey dams to obtain approximately 1 MW of capacity for use in the manufacture of paper and paper substrates.[27] Most of the remaining potential has little likelihood of development unless electricity prices double in real (noninflation) terms.

Another type of hydroelectricity is tidal power. With its relatively small difference between low and high tides, New Jersey is not expected to get any energy from this resource.

Wind Energy

Along a narrow strip of coastal New Jersey wind speeds average between 10 and 16 miles per hour (mph), a level that has potential for considerable generation of electricity using the newest wind turbine technology. The coastal strip, however, is densely populated and is an important tourist area. In 1987, fewer than 35 wind generating systems operated in New Jersey; today, none are under development. The potential for wind generation is great: it could supply electricity equal to almost a third of New Jersey electric utilities' annual output.[28] At least wind energy is a potential source that will remain available for consideration if future economic, environmental or supply constraints on other generation alternatives should begin to outweigh the aesthetic, noise and capital cost concerns associated with wind generation.

How Much Energy at What Cost?

Table 9-3 shows how much each of the major renewable energy sources supplies New Jersey at the present time. A detailed DEPE analysis shows that renewable energy now supplies about 2 TBtu or 0.1 percent of New Jersey purchases. Under an assumption of moderate growth, renewable sources could supply 5 TBtu by 2000 and under an accelerated program they could supply as much as 25 TBtu. Use of landfill gas has the most immediate potential.

Renewable energy use levels shown in Table 9-3, Potential 2000, could occur if non-renewable energy prices were to rise dramatically. The projections assume: (1) that all new housing will install active solar-assisted water heaters, which is unlikely unless required by law. Under current and likely energy prices, most of these units would not be economic unless costs are reduced by 50 to 75 percent. With electricity as the alternate fuel, the economic justification is, at best, marginal. With gas as the alternate fuel, no economic basis justifies such legislation; (2) that 60 percent of all new housing will have significant passive solar features; (3) that photovoltaic systems will be available at $2000/KW; and (4) that all of the hydroelectric sites and landfill and waste water treatment gas will be developed and put into operation. For wind energy, the potential in Table 9- 3 does not include any added coastal potential.

Solar energy has a large potential, particularly for passive use, that entails little cost. As Table 9-3 shows, a doubling of the contribution of renewable energy would have a far greater relative impact in an energy efficient economy. If it were possible to reduce purchased energy in the year 2000 to the level suggested in the best choice of services scenario, the amount of energy gleaned from renewable resources would become an increasingly important component of the total energy mix.

Because all sources of energy compete against one another in the marketplace, the development of renewable energy resources would not be encouraged if investment in other sources or conservation can produce a better return.

TABLE 9-3

New Jersey Renewable Energy Sources
(in TBtu)

	1989	Probable by 2000	Potential by 2000
Solar			
Active DWH	0.19	0.23	6.10
Passive Design	0.78	2.24	5.58
Photovoltaics	0.00	0.44	2.08
Wind	0.01	0.01	0.01
Hydro	0.65	1.00	1.15
Landfill Gas	0.12	0.75	9.34
Municipal Waste	0.54	0.54	0.54
Total Renewable	2.29	5.20	24.80
Purchased TBtu*	2,138	3,326	1,599
Contribution of Renewables	0.11%	0.15%	1.55%

Note: * 1989 EIA; Probable 2000 at 4.1% annual growth from 1989.
Potential 2000 at 2.3% annual decrease from 1989.
See Appendix Table A-24-1 for Potential 2000 assumptions.
Electricity credited at 10,000 Btu/kwh.

Source: DEPE Analysis, see Appendix Table A-9-1

Consistent with a commitment to least cost planning for all energy supplies, only the renewable energy projects that provide a better return than competing energy sources should be promoted. However, some special conditions may be relevant.

First, costs and benefits that may be external, *i.e.*, not reflected in prices, must be considered. These include environmental and other societal benefits. Second, some regulations and restrictions may distort or circumvent market incentives and discourage the use of cost-effective alternative energy sources.

Currently, for example, utilities are paying $0.21/kwh to $0.85/kwh for power from independent power producers.[29] Retail electric rates and the rates paid to alternative power producers determine whether an investment in a particular alternative or renewable energy project is justified and, therefore, whether the project will come to fruition. Electricity used on site by a non-utility or self-generator is never worth more than the retail rate.

New Jersey cannot expect renewable energy to be a major source of energy soon. Even under the most optimistic circumstances, we could expect no more than 3 percent of New Jersey's energy to come from renewables before year 2000 if energy prices remain low. However, as easily accessible fossil fuel supplies are exhausted and prices escalate commensurate with the increased cost of retrieving less accessible reserves, solar and other renewable technologies may become more cost-competitive, leading them to play a more dominant role in the overall energy supply picture.

Findings

- Building design is an ideal way to use the sun's energy when combined with other energy efficient building techniques.
- Nearly all regulatory barriers to the use of renewable energy sources have been eliminated.
- Photovoltaic production of electricity, if equipment and installation costs decline, or if electric rates rise, could become a cost-effective option to help reduce peak electric load in New Jersey.
- At mid-1990 prices, the cost-effectiveness of active solar water heating is marginal.
- Successful recycling and source reduction efforts can reduce the need to expend energy in the manufacture of new goods; New Jersey has adopted an aggressive recycling and source reduction policy that supports such energy savings.

Policies

- The State should encourage the use of cost-effective passive solar energy.
- The State should work aggressively to develop methane recovery systems because of their potential to produce energy and reduce methane releases.
- The State should encourage private sector development of photovoltaic projects.
- The DCA should consider the promulgation of technical specifications for the installation of solar domestic hot water systems.

Implementation

- The State should encourage broad use of building orientation and design elements that take advantage of natural heating, cooling and lighting to improve the efficiency of housing stock. Passive and active solar energy systems can reduce dependence on purchased energy in efficient buildings.
- State government should continue to help break down any nonmarket barriers to use of renewables and to render whatever assistance it can on a case-by-case basis to individuals, municipal agencies and institutions who wish to utilize solar, wind, or any other renewable resources.
- State government should encourage continued private sector development of renewable energy applications.

NOTES

1. Table 9-3.
2. Executive Order No. 8, 4/6/90.
3. 1985 New Jersey Energy Master Plan, pp. 188-189.
4. N.J. Department of Commerce, Energy and Economic Development (DCEED) *Qualifying Facilities Report...*, 5/88 Draft.

5. Conversations with DEP and New York/New Jersey Waste Water Treatment Operators.
6. *Ibid.*
7. Estimate based on all municipal sewage sludge being processed by anaerobic digestion.
8. DCEED staff estimate.
9. DCEED program manager's records.
10. Energy Subcode of the Uniform Construction Code.
11. "Passive Solar," brochure by Passive Solar Council, Alexandria, Virginia.
12. 1985 New Jersey Energy Master Plan, p. 85.
13. Estimate based on building permits; 22% south orientation, 5% optimum south glazing, 1% special glazing and summer shading.
14. *1985 New Jersey Energy Master Plan*, p. 86.
15. Total of those reported by each New Jersey electric utility.
16. N.J.S.A. 46:3-25.
17. *1985 New Jersey Energy Master Plan*, p. 88.
18. *1985 New Jersey Energy Master Plan*, pp. 88-89
19. Range from various publications including *Solar Age*, and *Research News*.
20. *Solar Age*, January, 1986, pp. 40-43.
21. Calculated using present value of costs divided by lifetime energy produced.
22. *Research News*, August 19, 1988, p. 910.
23. Calculated using present value of costs divided by lifetime energy produced.
24. Atlantic Electric, "Customer Photovoltaic Feasibility Study," October 13, 1986, p. 13.
25. *Wall Street Journal*, July 12, 1988.
26. DCEED, "Development Status of Dam Sites," January 22, 1988.
27. Calculated based on 50 percent capacity factor.
28. September 19, 1990 communication from Robert Williams, Center for Energy and Environmental Studies, Princeton, NJ.
29. Electric utility reports, 1988.

Chapter 10

Energy Facility Siting

This chapter summarizes, by energy source, New Jersey's laws, regulations, and policies for siting energy facilities. Energy facility siting is one of the principal implementing tools of New Jersey energy policy as embodied in the state's Energy Master Plan. Energy facility siting policies are intimately connected to and affected by policies on fuel supply and conservation. No fundamental reassessment of energy facility siting policy has been undertaken since the late 1970s. This chapter will establish broad policy guidelines for both the private and public sectors, update policies for energy facilities included in previous plans and suggest changes to the existing regulatory framework for energy facilities.

Aggressive conservation efforts, especially those enabled by the September 1991 Board of Regulatory Commissioners conservation incentive rulemaking (Docket No. EX90040304), will temper the need for additional energy facilities in the future. However, facilities will be needed if efficiency and load management gains do not outpace New Jersey's increasing appetite for electrical energy. The degree to which conservation can preempt the need for new capacity will depend on how rapidly efficient appliances and energy consuming systems replace older, inefficient ones and also on the rate of improvement to building shells. New and upgraded transmission lines will be needed to service both independent and utility owned electric generating facilities. The expansion of natural gas interstate and intrastate pipelines, and liquefied natural gas facilities are an inevitable consequence of increased use of natural gas for residential purposes and the generation of electricity by both utility and independent producers. A comprehensive siting process for linear facilities will facilitate the expansion of the natural gas network and cogeneration facilities.

Statutory and Administrative Authority

In a June, 1991 effort to consolidate state government and strengthen the state's ability to coordinate environmental and energy policy, Governor Florio issued Reorganization Plan #002- 1991 recasting the Board of Public Utilities (BPU) as the Board of Regulatory Commissioners *in but not of* the renamed Department of Environmental Protection and Energy (DEPE). The DEPE and the BRC support all energy planning and regulatory activity previously assigned to the energy division and the BPU.

The State derives its authority to regulate the construction and siting of energy facilities from several statutes. *N.J.S.A.* 48:2-23, as amended, grants the BRC the power to require public utilities to furnish safe, adequate and proper service and to furnish such service in a manner that tends to conserve and preserve the quality of the environment and prevent water, land and air pollution.

The Electric Facility Need Assessment Act (*N.J.S.A.* 48:7-16 et. seq.) requires that electric utilities obtain a certificate of need from the state prior to constructing new capacity. The Act applies to new electric generating units of 100 MW or more and to units that increase installed capacity by 25 percent or more than 100 MW, whichever is smaller. The certificate of need process was designed by the Legislature to balance the obligation of the State to assure a safe and adequate supply of electricity with the recognition that construction of excess electric generation capacity imposes unreasonable financial burdens on ratepayers. In granting or denying a certificate of need, the relationship of the proposed facility to overall state energy needs as determined by the state's Energy Master Plan must be considered.

With respect to energy facility siting, New Jersey statutes require that applicants obtain appropriate permits and approvals from the state prior to construction. More than one agency may be involved in the siting and permit process.

Among the criteria the state uses to evaluate an energy facility proposal are:

(1) Is the facility needed in the timeframe stated? Can conservation of energy resources defer, cancel or downsize the need for this type of facility?

(2) Is the facility as proposed utilizing the best available technology from both an environmental impact and energy efficiency standard?

(3) Do any cost effective and safe alternative locations exist for the proposed facility?

(4) Have all known human health impacts been considered in the choice of location and technology for the proposed facility?

The DEPE/BRC Reorganization Plan will foster the efficient implementation of a coherent public policy which advances a coordinated and integrated energy conservation and planning policy. This improved coordination will enhance the state's ability to respond to facility siting issues.

Facility Siting Policy

Natural Gas Facility Siting

Increased use of natural gas will usually require additional pipeline construction and will sometimes require other facilities. The type of facility to be constructed is dependent upon the state of the resource (liquid or gaseous), its source, and its end use.

LNG Peak-Shaving Facilities

Increased utilization of natural gas for winter heating would require increased natural gas storage facilities: increased underground storage in nearby states and LNG storage for peak-shaving to meet winter heating season needs. Such facilities would supplement natural gas supplies currently limited by long-haul pipeline capacity during high demand periods.

New LNG facilities that liquefy, store, and vaporize LNG to serve demand during peak periods should be located in generally remote, rural, and low population density areas where land use controls and/or buffer zones can be maintained.

LNG Import Facilities

Transporting natural gas economically from nations outside North America requires the gas to be liquefied. This option necessitates specialized liquefaction facilities, specially-equipped ships, and an onshore LNG receiving terminal usually located on coastlines or interstate waterways. In view of the controversy over the potential risk to the public's health, safety, and welfare posed by the tankering, transfer, and storage, an LNG import terminal in New Jersey is discouraged.

Pursuant to the 1979 amendments (P.L. 96-129) to the Natural Gas Pipeline Safety Act of 1968 (49 *U.S.C.* § 1671 *et. seq.*, the U.S. Department of Transportation established regulations for the siting, design, construction, initial inspection, and initial testing of any new LNG facility. The comprehensive standards developed by the USDOT's Materials Transportation Bureau appeared in the 45 *Fed. Reg.* 8933-9250 (1980), and were subsequently codified at 49 *C.F.R.* § 193.2001 *et seq.*. Other federal agencies (*e.g.*, the U.S. Coast Guard, the Economic Regulatory Administration, and the Federal Energy Regulatory Commission) have additional responsibilities in the siting and operation of LNG import facilities.

There are four completed LNG import terminals in the United States. Together, they could receive about 900 Bcf of LNG annually. However, the large terminals at Cove Point, Maryland; and Elba Island, Georgia no longer operate. Only terminals at Everett, Massachusetts, and Lake Charles, Louisiana still operate. As requests for authorization to import LNG increase, plans call for recommissiong the inactive terminals at Cove Point and Elba Island. The presence of these under-utilized facilities alleviates any need for import terminals within New Jersey.[2]

The state should discourage LNG marine terminals and associated facilities that receive, store, and vaporize natural gas in the state's coastal zone unless:

1. a clear and precise justification for such facilities exists in the national interest;
2. the proposed facility is located and constructed so it will not unduly endanger human life and property or otherwise impair the public health, safety, and welfare, as required by *N.J.S.A.* 13:19-10(f); and
3. such facilities comply with DEPE's Coastal Resource and Development Policies.

Any applications to construct LNG importation facilities must be evaluated on a case-by-case basis and be treated as a regional issue.

Natural Gas Pipelines

New Jersey currently has no indigenous natural gas supply and thus receives the major portion of its natural gas from the United States' gas producing regions (primarily the Gulf Coast states) via a vast network of pipelines. Additional Canadian gas should become available to New Jersey via the Iroquois pipeline.

In order to obtain adequate supplies of natural gas as well as to meet the increasing residential demand for gas service, new pipelines will be constructed as part of FERC's 1988 settlement agreement that provides additional supplies to the Northeast. Joint utilization of existing ROWs by new or looping pipelines can substantially decrease construction impacts and disturbance of ecological and cultural systems.

Expansion of the natural gas delivery system requires increased interstate pipeline system capacity. Using existing rights-of-way (ROWs) where possible would minimize the need to acquire new land and the environmental impact of pipeline construction. Utilization of ROWs by more than one pipeline should be encouraged to the maximum extent practicable.

Proposals for additions to Interstate Pipeline Capacity shall be reviewed concurrently by State Agencies upon a filing with the Federal Energy Regulatory Commission. The appropriate state agency shall participate fully in the Environmental Assessment prepared by FERC.

The company proposing such additions shall review with the BRC and other agencies the cost and environmental implications of its route and technology in an early assessment review. The Early Assessment Review is an informal consultative procedure designed to identify critical environmental, technology and human health concerns which may affect the approval of state permit applications for the proposed facility.

Compressor Stations

Compressors, an integral part of the natural gas system, are required at intervals along a pipeline to maintain the desired rate of flow within the system. For long distance pipelines the need to install compressors at various intervals is based on friction within the pipeline and the terrain over which the pipeline passes.

In order for interstate natural gas pipeline companies and distribution companies to increase their ability to deliver natural gas, they must enlarge their system capacity. Generally, they can increase output by constructing new looping pipeline segments that parallel existing pipelines, by increasing operating pressures, or by a combination of both of these strategies. New pipeline construction requires new compressor stations. When existing pipelines are to be operated at higher pressure to increase output, new compressors must be added to the system or existing compressors retrofitted to increase pressure.

In general, construction of new compressor facilities and/or the modification of existing facilities would be looked upon favorably because they would facilitate the increased utilization of natural gas in the state.

Specifically, the modification of existing compressor stations (*i.e.*, addition of new turbines, replacement of inefficient turbines, replacement of turbines with high pollutant discharge levels, or retrofitting existing turbines) is encouraged as long as all applicable air and water quality standards are met. Adequate visual and vegetative buffers and compliance with the noise standards established in *N.J.A.C.* 7:29-1.1 *et seq.* are also required.

The design and construction of new compressor stations must meet the standards specified by USDOT's Materials Transportation Bureau in 49 *C.F.R.* §§ 192.163 to 192.171. Additionally, companies wishing to construct new compressor stations must obtain the appropriate federal and state PSD or offset permits. If possible, compressor stations should be co-located with other facilities composing the gas transportation system.

Petroleum Facility Siting

Amendments to the Clean Air Act could affect oil refinery facilities in New Jersey. Refineries are major emitting sources of sulfur dioxide and nitrogen oxide. These two pollutants are the focus of reductions in the amendments. The emission allowance system contained in the legislation will potentially allow New Jersey's refineries to scale down operations and bank or sell the sulfur dioxide emissions associated with the facility. The sale, banking and scale-down of the refineries is currently beyond any state regulatory mechanism.

Reliable sources of refined petroleum products are critical to the New Jersey economy. Reliable sources of supply are a concern if New Jersey refineries drop below current levels of production. Motor gasolines and home heating oil are the most critical of these products.

New oil refineries are prohibited in New Jersey in that part of the state known as the Bay and Ocean Shore Segment (*N.J.A.C.* 7:7E-7.4(o)1.ii.

Modification and expansion of existing refineries would help meet the higher demand for the light products such as diesel and jet fuel and allow processing of a wider variety of crude oil being imported into the United States. The number of pollution incidents in 1990 mandates review of navigation practices and oil terminal operations.

Tanker Terminals

Many tank vessel terminals are on the waterways of the Delaware River and Bay and the New York Harbor. Recent refined products spills in the Arthur Kill and the Kill Van Kull of New York Harbor have prompted a comprehensive review by industry and government officials of tank vessel and oil terminal operations.

Transfer of products between terminal and tank vessels presents the potential for an environmental incident. Expansion of pipeline capacity to move petroleum products within the region would provide an alternative to tank vessel transportation.

New or expanded conventional tanker facilities are acceptable provided they meet the following conditions:

1. urban port locations are used for dockside transfer of fuels where required channel depths exist to accommodate coastal tankers;
2. joint utilization or multi-company use of dockside unloading facilities could minimize unnecessary urban waterfront development that would preempt alternative coastal dependent uses; and
3. a positive need determination has been made by the DEPE.

The DEPE should encourage the establishment of deep draft, in-harbor oil terminals where feasible, especially those developed in concert with coal transshipment facilities and/or container ship terminals that would require deep draft channels for access to dockside. Review of proposals for offshore tanker terminals and deepwater ports will be reviewed on a case-by-case basis. The siting of such terminals shall be in compliance with New Jersey's Coastal Zone Management Plan.

Deepwater ports have been developed in other parts of the world as an alternative to transitional transshipment by small tankers or lightering of medium size tankers in harbor areas. Deepwater ports that include offshore monobuoy systems are capital intensive and require high rates of utilization and output to justify their initial cost. The *Deepwater Port Alternatives for New Jersey* study determined that the economics of constructing a monobuoy system to serve New Jersey's refineries do not exist.[1]

The analysis supports deep draft, in-harbor oil terminals that reduce the number of small tankers that must enter Delaware Bay and New York Harbor and the number of transfers. For those vessels that require lightering before progressing to the tanker terminals, spills and hydrocarbon emissions can also be eliminated. In-harbor, deep draft terminals would be a more environmentally acceptable alternative method to reduce transportation costs that could be passed on to the consumer. The study concluded that an in-harbor deepwater oil terminal for New York Harbor appears feasible.

The state should encourage renovation and improvement of existing tank vessel terminals and review practices with industry to ensure the minimal opportunity for environmental incidents. Alternative practices and modes of transportation should be studied by the DEPE and the DOT.

Oil Pipelines

Transportation of oil by pipeline, rather than by tankers and barges can reduce the potential for spills. The State should encourage new land corridor pipeline capacity to displace, where possible, existing marine transfers of crude oil or refined petroleum products. New petroleum pipeline capacity must utilize existing Rights of Way and meet all Class 1 USDOT standards.

Storage Facilities for Crude Oil and Petroleum Products

Most storage facilities for crude and petroleum products have been in coastal areas near ports. The DEPE should review submissions for new facilities both from coastal dependent viewpoint and need criteria.

Storage of crude oil, liquefied gases, and other potentially hazardous liquid substances (as defined in *N.J.A.C.* 7:1E-1.3) is prohibited on barrier islands and discouraged elsewhere in the Delaware and Raritan Bay and Atlantic Ocean Shore region.

The siting of new storage facilities in the urban port regions is conditionally acceptable provided the following criteria are met:

1. There is a clearly demonstrated need for such facilities that would encompass strategic and demonstrated industrial factors;
2. Other siting alternatives outside the coastal zone are clearly unfeasible or counter-productive to energy efficiency;
3. The construction and operation of storage facilities utilizes the best and safest technologies to minimize spills and pollutants discharged into the atmosphere; and
4. The facilities meet all applicable air and water resource policies and regulations and are compatible with or adequately buffered from surrounding uses.
5. Proposals for storage facilities outside the coastal zone will be reviewed on a case-by-case basis and must meet need criteria as well as prudent siting standards that address adjacent land uses.

Coal Facility Siting

Coal facilities may be for transshipment or combined cycle electricity plants. In the early 1980's, a coal export/import facility was proposed for New York Harbor by the Port Authority of New York and New Jersey. Oil prices dropped and made coal relatively expensive and the proposal died. Small coal transshipment facilities may be needed to service independent power producers and clean coal combustion facilities. Small rail and water coal storage and transshipment facilities need to be evaluated on a case by case basis.

Facility storage and transshipment design must minimize fugitive dust emissions, ground and surface water pollution, noise and meet the needs of projects which will provide electric power to the state

Generation Facilities

Utility forecasts predict substantial need for new electricity generation and transmission. New Jersey's electric utilities will need to replace old facilities and/or increase transmission capability to import electricity if electric demand and use continue to rise at rates witnessed in recent years. Conservation gains available through the broad-based replacement of inefficient energy- consuming equipment and appliances with more efficient, commercially available models could stem this growth and alleviate the need to build new plant. Should growth in demand outpace utility efforts to capture efficiency gains, New Jersey must respond to complex facility siting challenges that affect the state's economy, environment and quality of life.

Public Utility Electric Generating Facilities

The siting of electric generation facilities may have to be expanded to account for the changed economic and environmental regulatory climate that evolved during the 1980's. Medium scale centralized fossil fuel plants built in modules are likely to be the form of a new grass roots generating capacity built by the public utilities. One current example is the 220 MW gas-fired combined cycle facility proposed by Atlantic Electric Company (AE). A Notice of Intent filed in accordance with the Electric Facility Need Assessment Act was received by the Board of Public Utilities in August, 1989, and a BPU early assessment report issued in May 1990 authorized AE to continue planning for the facility on a contingency basis. AE subsequently took the next step in its contingency planning process when it filed an application for a Certificate in November 1990. As of October 1991, the application was pending hearings at the Office of Administrative Law (OAL).

The Electric Facility Need Assessment Act (*N.J.S.A.* 48:7-16 *et seq.*) sets forth specific criteria that the State must apply in its evaluation of any application for a certificate of need which is required before construction of public utility electric generating facilities. New electric generating facilities of 100 MW or more, and existing electric facilities expanded by 25 percent or by more than 100 MW, whichever is smaller, must comply with the certificate of need requirements of the Electric Facility Need Assessment Act (*N.J.S.A.* 48:7-16 *et seq.*) and the regulations thereunder (*N.J.A.C.* 14A:14-1.1 *et seq.*).

Non-Utility Electric Generating Facilities

The growth in the number of alternative power producers, including non- utility cogenerators, has led to the formulation of separate siting criteria for these non-utility projects. In some cases, the cogeneration project may be larger than public utility projects, *e.g.*, Cogen Technologies has proposed a 600 megawatt natural gas fired cogeneration facility in Linden, New Jersey.

These projects are not subject to the siting requirements of the Electric Facility Need Assessment Act. However, they are subject to the individual permit requirements of the Department of Environmental Protection and Energy and are subject to coextensive jurisdiction pursuant to *N.J.S.A.* 52:27F-15(c).

Non-utility projects which may sell excess electricity to public utilities must meet the requirements of the BPU Stipulation of Settlement 8010-687B and are subject to coextensive jurisdiction pursuant to *N.J.S.A.* 52:27F-15(c).

The current differential siting treatment of utility and non-utility generation facilities should be reviewed. As stated previously, a public utility must petition the State for a Certificate of Need to build any plant that is 100 MW in size or greater. No such requirement exists for alternative power producers (APPs). As movement towards an increasingly competitive electric system continues, the State should assess whether it would be appropriate for all electric generation facilities to be governed by the same set of rules. In view of the expanding role that APPs are projected to play in meeting New Jersey's future energy needs, the concept of imposing a single set of rules on the siting and construction of utility and non-utility generation facilities deserves consideration.

Electric Generating Facilities: Self-Generation

Still another and potentially growing type of generation facility may be industrial or commercial facilities that choose to build generation capacity exclusively for their own use. Non-utility related projects may still substantially impact the surrounding community. Such facilities are subject to the coextensive siting process (*N.J.S.A.* 52:27F-15(c)).

Cogeneration Facilities

Although utility and non-utility cogeneration facilities will be encouraged (see Chapter 7, Cogeneration), they must meet criteria similar to all other facilities. The state encourages all commercial and industrial electricity consumers with suitable heat requirements to investigate the applicability of cogeneration.

In light of the State's recognition of the potential benefits of cogeneration technology, including reduced air emissions, economic development and business competitiveness, and decreased reliance on fossil fuels, the State should consider implementing a requirement that electric utilities evaluate the feasibility of cogeneration applications when assessing potential sites for new generating capacity.

Electrical Transmission Lines

A major environmental and health concern has risen with regard to electro-magnetic fields associated with transmission lines. There is disagreement within the scientific community regarding whether electric and magnetic fields produce adverse health effects in exposed populations; some published reviews of the scientific literature suggest that the government scrutinize the siting of new high voltage electric transmission lines.

The development of a comprehensive and coherent policy for transmission lines is essential to the State's ability to have adequate supplies of electric power. Without transmission lines access, no form of electric generation, including cogeneration facilities, can function. Therefore, if present and future scientific research establishes a link between electrical and/or magnetic fields associated with transmission lines and adverse health effects, an important goal to be achieved in the siting of new electrical generating facilities will be to minimize the need for new transmission rights-of-way (ROWs). This, in turn, will minimize new exposures to electro-magnetic fields. In addition, the upgrade of existing transmission lines may need to consider alternatives such as underground placement.

The DEPE Commission on Radiation Protection is drafting electro-magnetic field standards for all new transmission lines. Until those standards are promulgated pursuant to the Administrative Procedures Act, *N.J.S.A.* 52:14B-1 et. seq., the following criteria shall be followed in the siting of new transmission lines and the upgrading of existing lines.

Existing rights-of-way (ROWs) should be used to the maximum extent practicable to avoid human population concentrations. The DEPE, the BRC and the DOT should develop a comprehensive mechanism to solve competing interests in the use of existing ROWs.

NOTES

1. New Jersey Department of Energy and Port Authority of New York and New Jersey, *Deepwater Port Alternatives for New Jersey*, September, 1982.
2. EIA, *Natural Gas Annual 1989*, 9/28/90, p. 11.

Chapter 11

Residential Sector Energy Use

New Jersey residential energy consumption rose sharply in 1987 and 1988 and marginally in 1989 as new households and increased electric use per household outstripped a drop in per customer gas and oil use. In 1989, fuel (consumed at the generating plant) to produce electricity consumed by the end-user accounted for 43 percent of residential consumption. Natural gas, used directly to heat space and water and to cook, accounted for 38 percent and petroleum for the remainder. Figure 11-1 illustrates the proportions.

The analysis finds a large potential to reduce residential use over the next decade through weatherization and insulation of dwellings and through incremental replacement of existing appliances and equipment with the most efficient commercially available models. The potential savings offer New Jersey residents substantial benefits in lower energy bills and reduced environmental impacts. Residential buildings, equipment and appliance use offer the second largest savings potential after transportation.

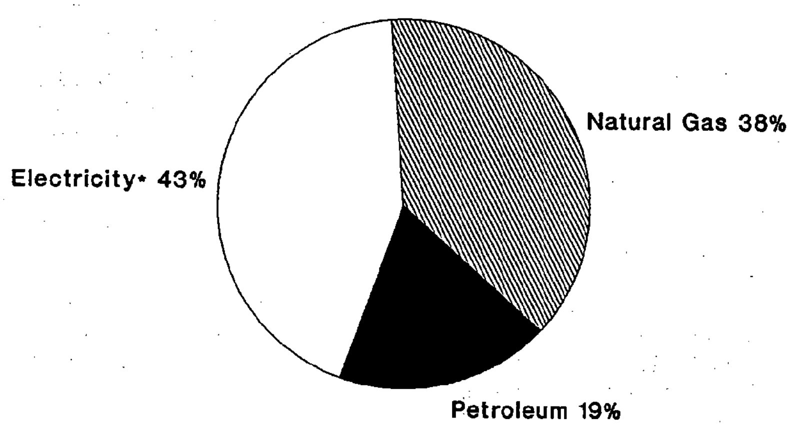
The potential for savings will vary in different parts of the state depending on the age and size of buildings, the area's weather profile and the portion of buildings constructed after 1977 under the state's energy subcode. Realization of the potential will hinge on energy prices, public concern, and the economics and availability of efficient technology. If energy prices remain low or drop, entrepreneurs, manufacturers and users will have less interest in the development, production and installation of new technology.

This chapter examines residential energy consumption by end use and the potential impact of energy efficiency on each use. Current consumption levels are compared to potential consumption levels that assume: (1) use of the most efficient appliances and equipment that are commercially available today and (2) a 25 percent improvement of building thermal performance.

Normal replacement of water and space heaters could account for a major fraction of the savings. Clock thermostats and other controls that closely match service delivery to time of use and routine maintenance can produce large savings at relatively low cost and could account for a large fraction of the retrofit savings. The savings calculation is based on changes that are relatively easy to quantify. Some consumers will not replace appliances but others will take further measures. The statewide average could reach the potential shown at some future date—though probably not before the year 2000 at present energy prices. Implementation of many of the policies outlined in this 1991 Plan will

FIGURE 11-1

NJ Residential Energy Consumption
1989 - 529 TBtu



Note: * Includes electrical system energy losses.
Source: EIA-0214(89)

TABLE 11-1

Residential End Use

Residential Appliance/Equipment	1988 Percent of Sales	1990 Sales	1989 EIA-Tbtu Input
Electric	PSE&G (%)	GWH	TBtu
Refrigerators	24%	4,923	55.7
Lighting	9%	1,871	21.2
Color TV	8%	1,687	19.1
Room A/C	8%	1,531	17.3
Central A/C	7%	1,470	16.6
Other/Freezer/Dryers	43%	8,769	99.2
Residential Electric	100%	20,252	229.0
Natural Gas	PSE&G (%)	MMTHM	TBtu
Space Heating	67%	1,218	135.2
Water Heating	22%	395	43.9
Kitchen Ranges	6%	111	12.4
Dryers	2%	42	4.7
Other	2%	38	4.3
Residential Natural Gas	100%	1,805	200.4
Petroleum	EIA (%)	MBBL	TBtu
Space Heat (# 2 Oil)	93%	15,926	92.8
Other Petroleum	7%	1,661	6.6
Residential Petroleum	100%	17,587	99.4
Coal	EIA (%)	MMST	TBtu
Heating/Misc.	100%	9	0.2
Residential EIA TBtu	100%		529.1

Notes: Totals may not add due to independent rounding. GWH=gigawatt hours; MMTHM= million therms=TBtu; MBBL=thousand barrels. MMST= million short tons. Appliance / Equipment amounts calculated by % of sales. EIA, EIA-0214(89). EIA annual estimates are the best data available for petroleum consumption.

Sources: PSE&G Energy Analysis and Forecast System for electric % of sales, based on 1988 survey. New Jersey Energy Profile, 1990, for GWH, MMTHM DOE/EIA-0214(90) - TBtu for energy input to electric generation, sales of natural gas, petroleum, coal and aggregate totals. Petroleum % calculated from EIA-0214(89) estimates.

accelerate the state's progress towards capturing a significant portion of these savings—wherever they are cost-effective—over the next decade.

Residential End Use

Electric Use

Fuel to generate electricity for residential use accounted for approximately half of 1989 residential consumption (529 TBtu) and over a tenth of New Jersey 1989 energy consumption (2138 TBtu). It is a large and growing component of energy consumption. Electricity non-heating sales per customer dropped in 1981, 1982, 1984, 1985, 1989 and 1990 after electricity price increases; but sales rose sharply—6 percent a year—in 1987 and 1988 when the average price per kilowatt-hour dropped slightly.[1]

Table 11-1 shows the portion of electric sales that PSE&G, the state's largest electric utility, attributes to each appliance.[2] The portion may vary somewhat in service territories that have newer housing or fewer multi-family dwellings. Based on PSE&G's analysis and the Energy Information Administration (EIA) estimate of fuel input to electric utilities, the table shows the amount of fuel use attributable to each appliance category. Refrigerators account for 24 percent of use, air conditioners for 15 percent, lighting for 9 percent, and resistance heating and other appliances for the remainder.

Over the past decade, residents have increased the number of appliances they own. Figure 11-2 shows results from a PSE&G survey. The number of refrigerators, the appliance that accounts for 24 percent of residential sales, has increased slightly over past decade. The number of air conditioners, both room and central, has increased and accounts for 15 percent of sales but the electric system impact is greater because use occurs over a short period of time on the hottest days of summer and contributes significantly to peak demand.

Gas Use

Residential gas sales have risen rapidly as homeowners have switched from oil to gas heat. However, heating sales per customer have decreased by more than 25 percent since 1978, in parallel with a decrease in the amount of cold weather and partly as a result of conservation. Average price per therm dropped through 1988 and has since risen slightly.[3]

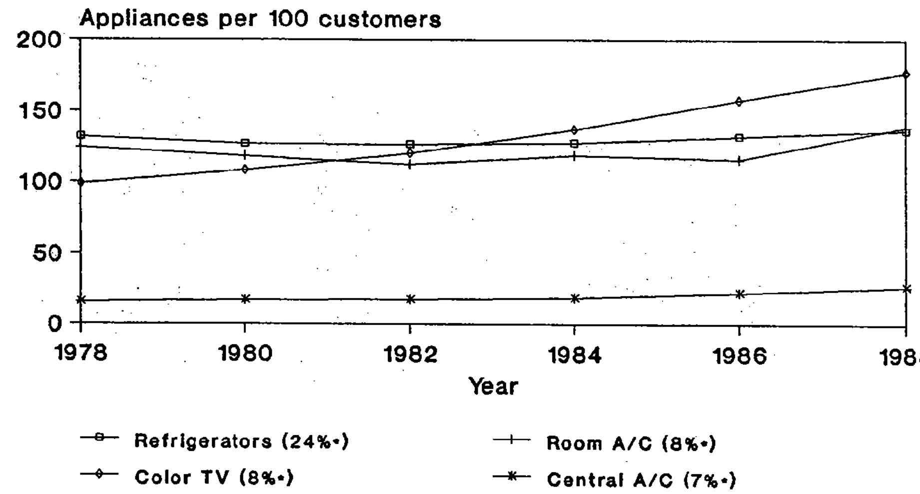
Table 11-1 shows the amount of natural gas sales for space and water heating according to a PSE&G survey in the state's largest gas service territory. The proportion may vary somewhat for service territories that have more new housing, different average size units or fewer multiple dwellings. Figure 11-3 shows the number of households that use gas, electric or fuel oil for space heat. Nearly half of households now use natural gas (49 percent) for space heat, the remainder use fuel oil, propane or kerosene (43 percent) or electric heat (8 percent).

Petroleum Use

Figure 11-3 shows the substantial number of New Jersey homes heated by fuel oil. The proportion, over two-thirds

FIGURE 11-2

Electric Appliance Ownership Trends
1978-1988



Note: * % of 1988 GWH sales attributable to appliances.
Source: PSE&G Appliance Survey, 1988.

before 1970, had dropped but still remained well above one-third or one million homes in 1990. Some households heat with propane—especially trailers and some homes that are equipped to use gas but that are located beyond the natural gas distribution lines.

Analysis

Electric Appliance Savings Potential

Stores now carry refrigerators with better insulation and more efficient refrigeration systems than the average model in homes today. Each appliance must have an energy rating tag or sticker that gives annual kilowatt-hour (kwh) use and operating cost under a specified set of conditions. A consumer can purchase an efficient model for little more than an inefficient one and, with electricity savings, can recover the cost differential within a few months or years.[4]

Table 11-2 shows the average amount of electricity appliances use now and the amount the most efficient model on the market uses. For some major appliances, the most efficient models can use 30 to 60 percent less electricity than the models they replace. Savings are possible with air conditioners, lighting, television sets, and most appliances.

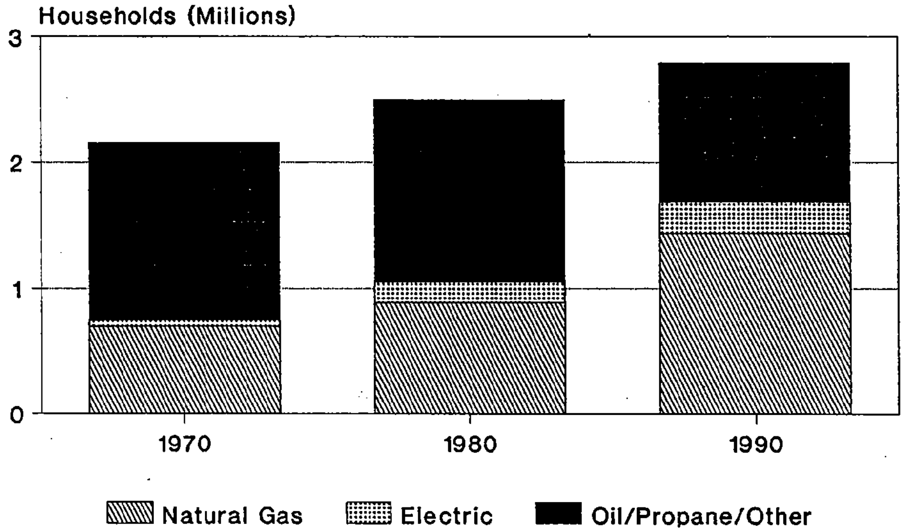
Refrigerators, which account for 24 percent of electric sales according to the PSE&G study, in 1988 used 1150 kwh per appliance per year. The most efficient model commercially available can cool equally well using only 744 kwh per year, a 35 percent savings. Statewide savings could total 1,738 gigawatt-hours (gwh) if all refrigerators were the most efficient model. Advertising for major electricity consuming appliances, refrigerators, air conditioners and color TVs, could be required to include energy efficiency ratings.

Lighting, now 9 percent of electric sales according to the study, has considerable potential for electric savings. Compact fluorescents for interior use and high-pressure sodium for exterior use can provide light of quality comparable to incandescents for many uses. These lights are considerably more expensive than incandescents but have a longer service life. Use of these high efficiency lights where they are on for long periods can produce savings. The lighting that used 1883 gwh in 1989 could use only 753 gwh, if it were the most efficient now available.

Table 11-2 expands on Table 11-1 and shows how replacement of existing major electric appliances with the most efficient commercially available models would change electric use. Table 11-2 and Figures 11-4 and 11-5 show present and potential electric appliance end use in New Jersey. These analyses assume no customer growth between 1990 and 2000. This assumption isolates the effects of the energy efficiency improvements considered. Table 11-2 presents 1990 residential electric sales by major appliance, then assumes all presently used appliances are replaced with the most efficient models commercially

FIGURE 11-3

NJ Residential Heating Trends
1970-1990



Source: Households from NJDOL
Heating Customers from DEPE, NJEDS

available today. For heating and cooling equipment, the scenario assumes an additional 25 percent savings for weatherization and superinsulation improvements. (See Table 11-2, notes A, B, and C).

The PSE&G appliance model output (from which this analysis arises) considered smaller gains in efficiency for appliances. It projected large increases in electricity for lighting, miscellaneous appliances, resistance heating and furnace auxiliary use and also projected a 9 percent increase in residential customers by the end of the decade. It reached substantially different conclusions about potential electric use over the next decade.

A factor that could raise electric use for refrigerators and air conditioners is an international agreement to reduce production of now commonly used refrigerants—chlorofluorocarbons (CFCs).[5] Substitute refrigerants now available may be less effective and their use could, at least in the short run, reduce the efficiency of cooling appliances and equipment.

Heating and Cooling Savings Potential

Energy requirements to heat and cool buildings depend on several factors: heating/cooling system technology, building structure, and individual habits or lifestyle. Analysts have no standard for measuring how much these factors together affect use. This analysis assumes that habits and lifestyle remain constant and that building retrofit can add an additional 25 percent to efficiency savings. For example, if an efficient air conditioner uses 200 kwh per year and the home's building shell efficiency is improved by 25 percent, the air conditioner then will require only 150 kwh per year to deliver the same comfort level.

Improvements to the building shell considered here are weatherization and superinsulation. Weatherization is exclusively applicable to existing structures and involves "seal-up" techniques that keep the structure from losing heat. Superinsulation is applicable to new construction. Superinsulated structures are (1) airtight with controlled ventilation; and (2) characterized by a high "R" or thermal resistivity value.[6]

Outside air introduced into buildings by natural infiltration or mechanical ventilation costs money for heating and cooling but dilutes indoor air pollutants. To balance economic and pollution control needs, ventilation standards or maximum allowable pollutant concentrations can be prescribed. National standards include those from the American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE). Its most recent update of ventilation codes, entitled 62-19-89 sets a minimum of 0.35 air changes per hour (0.35 ACH) or 15 cubic feet per minute per occupant (15 cfm/occupant), whichever is greater. The amended code limits for indoor radon are a maximum of four picocuries per liter. However, a maximum ambient air level standard could be more effective in protecting the public health. Codes set minimum but not maximum ventilation levels. The most effective means of maintaining and improving indoor air quality is reduction

TABLE 11-2

New Jersey Residential Conservation Technical Potential Through Appliance Efficiency and Insulation Improvements - Zero Customer Growth

Appliance	1988 Percent of Sales (1)	1990 Sales (gwh) (2)	Average Appliance Consumption (kwh/yr)(3)	Efficient Efficient Appliance Consumption (kwh/yr)(4)	Efficient Appliance Type or Conservation Measure (4)	Percent Savings with Efficient Appliance	Savings with Efficient Appliance (gwh)	Total Sales with Efficient Appliance (gwh)
Refrigerator	24.31	4,923	1,150	744	Whirlpool ET17HK1M	35.3	1,738	3,185
Lighting	9.30	1,871			Compact fluorescents for incan-descents (Phillips/Norelco SL-18), high-pressure sodium for porch and yard security lighting	60.0	1,123	749
T.V. (Color)	8.33	1,687	274	150	Best available models	45.3	764	923
Room A/C	7.56	1,531	371	(A) 171	Upgrade to EER of 12.0 plus retrofit factor	53.9	825	706
Central A/C	7.26	1,470	1,804	(B) 1,103	Upgrade to SEER of 12.0 plus retrofit factor	38.9	571	899
Freezer	4.64	940	1,115	530	Weighted avg.: Woods OC50 (chest) & Frigidaire UFE16DL (upright)	52.5	493	447
Clothes Dryer	4.39	889	938	799	Moisture sensor model, Sears 26F66811N	14.8	132	757
Cooking Range	3.88	786	980	814	Increased insulation, improved door seals, reduced contact resistance (surface), more reflective pans beneath elements	16.9	133	653
Water Heating	3.62	733	4,225	2,150	Tank wrap, bottom board & pipe insulation, anti-convection valves, low-flow fixtures as below	49.1	360	373
Dishwashers	2.46	498	310	(3) 209	Water-efficient mod. (Sears 22F15565N)	32.6	162	336
Dehumidifier	0.84	170	285	(3) 271		4.9	8	162
Heat Pumps	0.42	85	1,219	(C) 707	Efficiency plus retrofit factor	42.0	36	49
Other	22.99	4,656	--	--		0.0	0	4,656
Totals	100.00	20,252						

Notes:
A: 171 = (304)(9/12)(.75); where 304 is NEEPC best commercially available efficiency for 9 EER unit, upgraded to 12, and retrofit savings is 25 percent.
B: 1103 = (1930-460)(.75); where 1930 is PSE&G current average unit consumption, 460 is savings from upgrade to 12 SEER and retrofit savings is 25%.
C: 707 = (943)(.75); where 943 is PSE&G year 2000 efficiency, and retrofit savings is 25 percent.

Sources:
(1) PSE&G 1988 Customer Energy Use Survey.
(2) NJ Energy Data Base 1990 New Jersey electric utility residential sales of 20,252 gwh.
(3) PSE&G Electric Appliance Residential Forecast, 1987-2017 . Refrigerators average is weighted average of one and two door models.
(4) New England Energy Policy Council (NEEPC), Power to Spare, July 1987, unless otherwise indicated.

of pollutant sources, smoking, and aerosol or solvent use, among others.

Housing shell improvements primarily affect home heating and, to some extent, cooling. Historically, low-income homes have been disproportionately poorly weatherized.[7] Accordingly, they have been the target of a number of subsidy programs to help low-income residents pay for weatherization improvements. A discussion of housing shells in New Jersey means discussing New Jersey's weatherization programs—their objectives, problems, and accomplishments. (See Chapters 14 and 15.) Similarly, superinsulation of new construction is related to building codes. (See Chapter 16.)

New Jersey residential electric consumption could be reduced by more than 20 percent through use of more efficient, presently available electric appliances. See Appendix Table A-24-1.

Figures 11-4 and 11-5 compare major components of residential electric consumption now and under the efficiency scenario using data from Table 11-2. They show consumption levels for four major appliance groups: refrigerators, air conditioners, lighting and color TV and for the category *Other* that represents all remaining appliance categories shown in the Table 11-2. No conservation savings are projected for *other* consumption. Chapter 24, Choices for New Jersey 2000, presents a *best choice* scenario that summarizes the significant technical potential for energy efficiency gains in New Jersey. The calculations underlying the statement of New Jersey's technical potential to save energy come from Table 11-2; however, the calculations in Chapter 24 purposely exclude savings suggested here for air conditioning because replacement refrigerants for chlorofluorocarbons (CFCs) deemed harmful to the environment may yield appliance efficiency ratings below the levels assumed in the *best choice* scenario of most efficient model commercially available today.

Gas Appliance Savings Potential

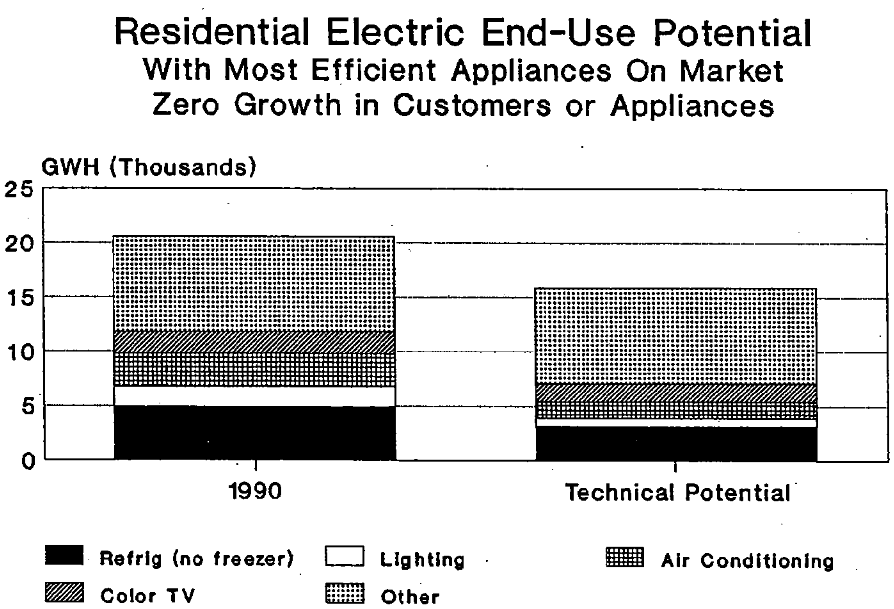
Table 11-3 and Figures 11-6 and 11-7 compare gas-fired heating equipment energy consumption now to potential natural gas consumption if all equipment was replaced with the most efficient commercially available models. Based on the calculations shown, consumption of gas residential customers could be reduced approximately 30 percent. See Appendix Table A-24-1.

Figures 11-6 and 11-7 compare savings for space heating, water heating, ranges and clothes dryers on a percentage and total therm basis respectively. The space heating calculation assumes an additional 25 percent reduction in energy use due to insulation and weatherization improvements to building stock. Improvements to space heating equipment offer the largest residential-sector gas savings opportunity to reduce consumption.

Policy, Regulation and Programs

The preceding analysis indicates that, from a technical standpoint, three techniques could effectively reduce residential sector energy consumption: (1) increased utiliza-

FIGURE 11-4

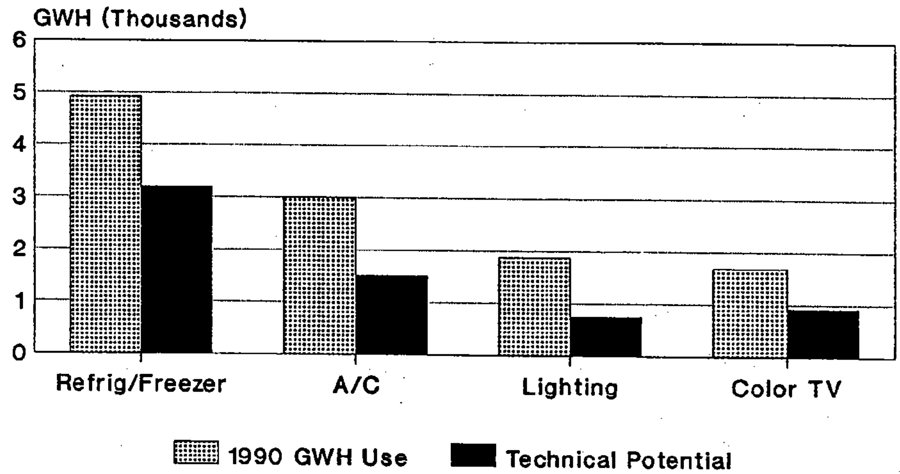


Source: Table 11-2. See table and text for assumptions underlying calculations
GWH - Gigawatthours

FIGURE 11-5

Residential Electric End-Use Potential

With Most Efficient Appliances on Market
Zero Growth in Customers or Appliances



Source: Table 11-2. See table and text for assumptions underlying calculations.
GWH - Gigawatthours

tion of more efficient appliances and heating/cooling equipment; (2) weatherization of existing housing structures; and (3) better thermal performance of new housing structures. These technical findings could be translated into policy and implemented.

In September of 1991, the Board of Regulatory Commissioners adopted a conservation incentive rulemaking that provides the state's electric and natural gas public utilities with an opportunity to earn a financial return on investments in conservation based on measured energy savings. (See Chapter 8.) This key regulatory initiative represents a major strategy in the state's effort to accelerate conservation gains statewide.

Appliance Efficiency Standards

Federal appliance efficiency standards presently exist in the National Appliance Energy Conservation Act of 1987 (NAECA).[7] These standards will be phased in over several years, and most will be effective by 1993.

Covered products (Section 6292 of the NAECA) include:

(1) Refrigerators, refrigerator-freezers, and freezers...

(2) Room air conditioners.

(3) Central air conditioners and central air conditioning heat pumps.

(4) Water heaters.

(5) Furnaces.

(6) Dishwashers.

(7) Clothes washers.

(8) Clothes dryers.

(9) Direct heating equipment.

(10) Kitchen ranges and stoves.

(11) Pool heaters.

(12) Television sets.

Section 6295, Energy Conservation Standards, states:

The purposes of this section are to:

(1) provide Federal energy conservation standards applicable to covered products; and

(2) authorize the Secretary to prescribe amended or new energy conservation standards for each type (or class) of covered product.

Specific standards are set out for each type of covered product, with dates by which the standards must be achieved. In general, the federal standards preempt state standards. The state may, however, apply for a waiver of federal preemption. The test in such cases is whether the state regulation is needed to meet *unusual and compelling state or local energy interests.*

For the most part, the federal government has taken over appliance efficiency standard improvements. The calculations presented previously indicate that energy savings can be achieved in New Jersey by utilizing more efficient

TABLE 11-3

New Jersey Residential Natural Gas Conservation Technical Potential Through Appliance Efficiency and Insulation Improvements - Zero Customer Growth

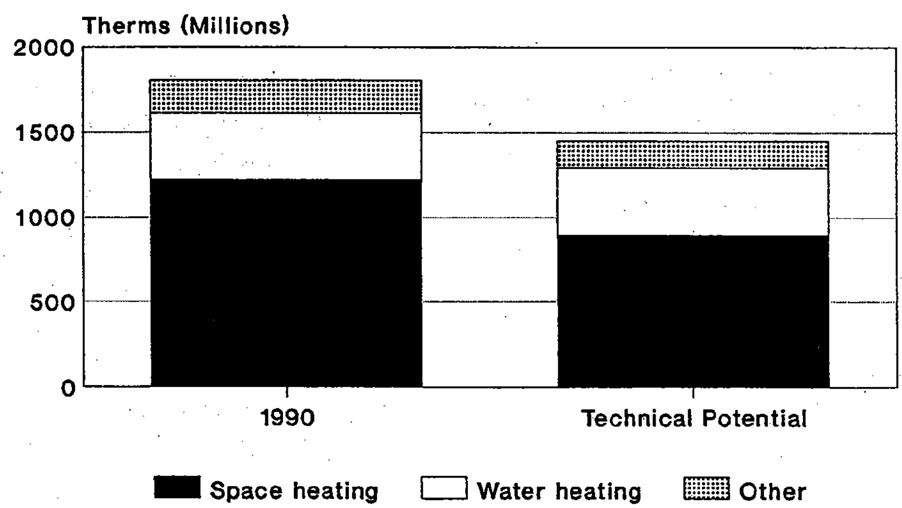
Appliance	1988 Percent of Sales (1)	1990 Sales (2) (MMThms)	Average Appliance Consumption (Therms/yr) (3)	Efficient Appliance Consumption (Therms/yr) (4)	Percent Savings W/ Efficient Appliance	Savings W/ Efficient Appliance (MMThms)	Total Sales W/ Efficient Appliance (MMThms)
Space Heating	66.77	1,218	976	(A) 589	39.65	321	896
Water Heaters	23.65	395	286	292	-2.10	-8	403
Ranges	6.86	111	76	54	28.95	34	79
Dryers	2.33	42	47	43	8.30	3	39
Other	0.39	38	–		0	0	38
Totals	100.00	1,805					

Note: A. 589 = (784.8)(.75), where 784.8 is PSE&G year 2000 efficiency, and retrofit savings is 25 percent.

Source: (1) PSE&G 1988 Customer Energy Use Survey.
(2) NJ Energy Data System, 1989 New Jersey gas utility residential sales of 1,805 MM Therms.
(3) PSE&G Residential Forecast 1987-2017.
(4) New England Energy Policy Council (NEEPC), Power to Spare, July 1987 unless otherwise indicated.

FIGURE 11-6

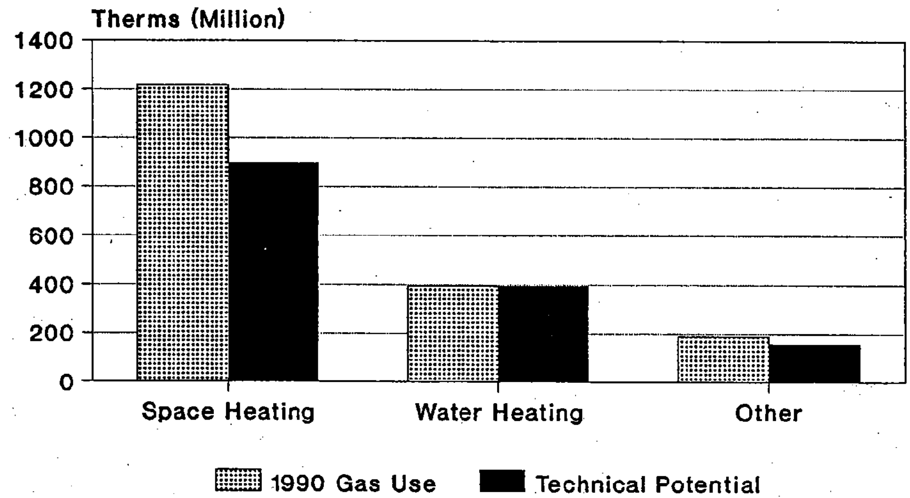
Residential Nat. Gas End-Use Potential
With Most Efficient Equipment On Market
Zero Growth in Customers or Level of Use



Source: Table 11-3. See table and text for assumptions underlying calculations.

FIGURE 11-7

Resd'l Natural Gas End-Use Potential
with most Efficient Equipment on Market
and Weatherization, Zero Customer Growth



Source: Table 11-3. See table and text for assumptions underlying calculations.

appliances. The extent to which savings will be realized through the federal standards is difficult to determine at this time, since the NAECA allows for further rulemaking, which could change the standards as presently set out. Analysis is needed to determine, from a legal standpoint, if it is feasible to override the federal standards with New Jersey's own state standards, or from a technical standpoint, if it is desirable to do so.

Once the impact of NAECA is known, if the state decides that additional appliance efficiency measures are needed, the state could continue to promote appliance efficiency standards or particular appliance efficiency measures through various approaches. These may include mandated utility rebates/incentives to customers and/or dealers for the purchase of more efficient appliances; modification of rate schedules and/or terms and conditions to ban inefficient technologies such as electric resistive heating except in superinsulated structures where the heating load is so low that the choice of heating source is immaterial; and modification of rate schedules to require higher efficiency levels as a condition for service.

Weatherization

Two low-income weatherization programs currently operate in New Jersey: the Department of Community Affairs' (DCA) Low-Income Energy Conservation Program, and the New Jersey electric utilities' weatherization programs, mandated by state conservation regulations. For an in-depth discussion of the status of these programs and their effectiveness, see Chapters 14 and 15.

Insulation of New Construction

Standards for insulation and for air infiltration must include consideration of indoor air quality in any cost/benefit analysis. New methods to control and channel air flow that maintain air quality by preferential removal of pollutants or of polluted air may help solve the dilemma of ventilation versus preservation of building heat or cool.

New Jersey requirements for insulation in new construction are governed by the National Energy Conservation Code of the Building Officials and Code Administrators (BOCA). Chapter 16 (Building Codes) presents an analysis of energy costs associated with a home built to 1990 BOCA National Energy Conservation Code standards and one built to a more stringent standard, the 1989 Model Energy Code of the Council of American Building Officials. This analysis demonstrates a cost savings of $140 per house per year on the average 2,400 square foot home that could be achieved through use of the Model Energy Code rather than the BOCA National Energy Conservation Code.

In addition, utility programs, such as JCP&L's Super Good Cents program, provide incentives to builders to build with insulation above the BOCA Code standard. For further discussion and analysis of these programs, see Chapter 17 (Home Energy Rating Systems).

Findings

- Fuel input for electricity accounted for 43 percent, natural gas for 38 percent and petroleum for 19 percent of residential fuel purchases in 1989.
- Natural gas for home heating has increased substantially as petroleum use has declined. Electricity for home heating has increased to approximately 8 percent of the total.
- The electric appliances that accounted for the greatest percentage of electric consumption were refrigerators plus freezers (approximately 30 percent) and air conditioners (approximately 15 percent).
- Replacement of refrigerators and freezers with the most efficient models commercially available today could substantially reduce electricity use for refrigeration if the old models were removed from service.
- Weatherization and insulation of homes has a large potential for saving energy at low cost.
- Replacement of inefficient water and space heating equipment with the most efficient types commercially available today has a large potential for saving energy both in natural gas and oil heated homes.
- State mandated utility home energy evaluation for existing homes and state building code requirements for new development can stimulate energy savings.
- Improvement in building shell performance and the use of higher efficiency appliances can be stimulated by utility incentive/penalty programs and modification of rate schedules and/or terms and conditions of service to ban inefficient technologies.
- The BRC adopted a rule in September 1991 that encourages utilities to invest in high efficiency appliances and equipment rather than in construction of additional generation capacity. The rule enables utilities to earn income on Board-approved investments in conservation that yield measurable savings.

Policy

- New Jersey should strive to achieve cost-effective residential appliance, equipment and building efficiency over the next decade equal to the highest efficiencies available today to heat, cool, light and power homes.
- New Jersey should continue to promote use of more efficient appliances in homes and apartments to avoid the economic impacts and environmental effects of increased energy consumption.
- New Jersey should promote weatherization of existing structures and superinsulation of new structures, accompanied by proper ventilation techniques to control potential dangers of increased indoor air pollution.

Implementation

- The State should promote cost-effective conservation in the residential sector by educating consumers on life-cycle costing for energy equipment and appliance purchases.
- Utility programs should be continually evaluated to ensure that the program design used is the one that most effectively achieves replacement of old, inefficient appliances with more efficient new ones.
- Regulations that enable utilities to earn income on investments in conservation can lead to significant energy efficiency gains statewide. The BRC should review Demand Side Management Resource Plans submitted by the utilities pursuant to the Board's September 1991 conservation incentives rulemaking in a timely manner to ensure prompt implementation of cost-effective conservation programs.
- The BRC should review federal regulations on appliance efficiency and determine if they encourage the development and sale of efficient equipment.
- The BRC and the utilities should increase consumer education. For example, life cycle cost labels for light bulbs (like unit prices for groceries) would allow consumers to compare total costs of screw-in fluorescents versus incandescent bulbs.
- The DCA and the DEPE should evaluate measures to achieve greater building shell efficiency in new construction. These measures can include future changes of building code and utility incentive programs or tariff design.

NOTES

1. New Jersey Energy Data Base (NJEDS), Department of Environmental Protection and Energy (DEPE).
2. Public Service Electric and Gas (PSE&G) Appliance Survey, 1988, pp. 2-4. The survey was conducted by randomly selecting approximately 1 percent of total customers in each group to receive appliance use questionnaires. The response rate was approximately 60 percent. The percentages shown represent total customer use, based on the survey results.
3. New Jersey Energy Data Base (NJEDS), Department of Environmental Protection and Energy (DEPE).
4. New England Energy Policy Council, *Power to Spare* (Boston: NEEPC, July 1987).
5. Montreal Protocol on Control of CFCs.
6. Walls range from R-25 to R-40, ceilings range from R-35 to R-65, and windows are at least R-2. See, J.D. Ned Nisson, Gautam Dutt, *The Superinsulated Home Book* (New York, NY: John Wiley and Sons, 1985). For New Jersey, the minimum values for the walls and ceilings of a superinsulated house are estimated at R-25 and R-40 to R-50 respectively. (Conversations with J.D. Ned Nisson, Editor, *Energy Design Update*, October, 1988).
7. U.S.C.A. 42, 6291-6309, Subchapter III - Improving Energy Efficiency, Part A - Energy Conservation Program for Consumer Products Other Than Automobiles.