

Chapter 1

Energy Goals for 2000

New Jersey can choose its energy future, or let others choose it. The objective of this Energy Master Plan is to provide information and a framework so that the people of New Jersey can decide on their energy future. The Plan seeks to give a consistent thrust to the policies and actions of state government that will offer New Jersey a coherent and definite direction to support its economic prosperity, protect its environment, and safeguard it from disruptions outside its control.

The 1991 New Jersey Energy Master Plan (Plan) focuses on the next decade and compares the energy, economic and environmental effects of several alternative futures. The Plan recommends a preferred energy future and identifies actions that the government and the private sector must take to achieve it.

The idea that New Jersey can help control its energy future surprises most citizens. After all, the apparent lesson of the 1970s was that foreign forces, led by the Organization of Petroleum Exporting Countries (OPEC), could raise energy prices or embargo supplies at will, driving the economy into a tailspin. But the real lesson comes from responses to OPEC's actions, responses that minimized the likelihood that history will repeat itself. America and other industrialized countries discovered the virtues of a "new" and very large source of energy: efficiency. Higher levels of insulation and more efficient cars, trucks, and industrial methods have allowed the United States and New Jersey to hold energy use to levels first reached in the early 1970s, while the economy expanded by 40 percent.¹

Efficiency gains were essential in undermining the leverage of OPEC and led to an era of declining energy prices.² This response shows that we can indeed choose our energy future. Today's challenge is to preserve and extend efficiency gains.

Petroleum supplies half the energy purchased in the state. Gas and electricity purchased through regulated utility companies supply most of the remainder. Electricity from non-utility and self-generators, rural cooperatives and municipal systems and propane together supply an additional fraction of a percent.

The state and its electric utilities are facing an unprecedented wave of economic and regulatory changes, that will require a radical revision in some of the industry's basic tenets: (1) production of electricity has gone from a decreasing cost to an increasing cost industry; (2) electric utilities are being pushed from their monopoly position as the sole source of power to one of several alternative suppliers; and (3) utilities and energy management companies are providing conservation services as a way to deliver the lowest cost energy services. The emergence of alternative power providers (e.g., non-utility cogenerators) and volatile growth in peak demand have complicated the planning process.³

The gas utilities are confronted by the urgency of finding adequate pipeline capacity to meet peak winter needs, by potential new opportunities, including providing fuel for alternative power production and possibly for air conditioning or in transportation, and by the need to promote energy efficiency.

Environmental concerns have come to the forefront. An integral part of energy planning involves grappling with such well-known but difficult problems as the direct relationship between automobile use and air pollution and heat emitted by generating facilities. More recently, questions of indoor air quality and global weather patterns have emerged as important energy-related environmental issues.

Beyond these concerns, New Jersey's tradition of home rule, combined with the spread of residences into rural areas, has brought on a clash between private interests and public needs for infrastructure. This clash is a critical issue in choosing New Jersey's energy future. Greater use of energy will require expansion of the highway system, more generating stations, transmission and distribution lines, pipelines, and gas storage depots.

This Plan cannot solve all of these problems. It does, however, call attention to needs, compare alternatives, and adopt a plan for action. The challenges of recent years have demonstrated how important it is for New Jersey to choose rather than drift.

Energy Supply

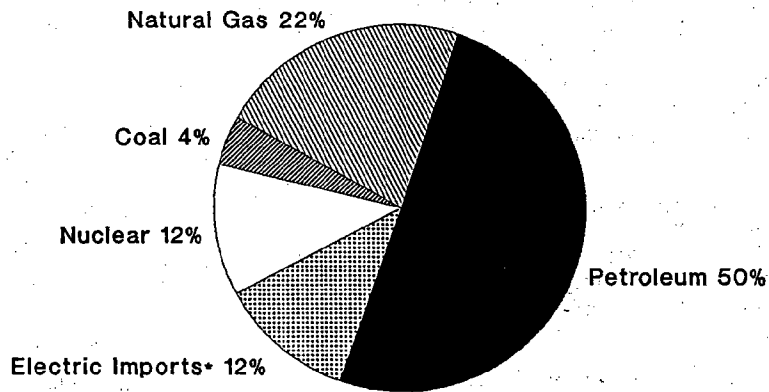
Estimates of oil, natural gas, coal and uranium reserves indicate that sufficient supplies exist to meet demand in this decade; however, the price at which they will be available is highly uncertain. Development and availability of reserves depends primarily on the price buyers are willing to pay for fuels and the return investors can expect to earn on their exploration and development investments.⁴ Environmental considerations can also affect the decision to develop known reserves. Finally, other countries control the bulk of worldwide proven oil reserves and can limit U.S. access.

Figure 1-1 highlights New Jersey's dependence on petroleum in the state's overall supply mix. Before 1970, petroleum supplied over three quarters of energy purchases. Today petroleum's share in the supply mix has dropped to one-half. Natural gas purchases, electricity from nuclear generation and imports of electricity generated out of state have increased. (See Figure 1-2.)

Like many northeastern states, New Jersey has no indigenous fossil fuel resources. The state imports all coal, gas, and petroleum it uses from other states or from abroad. According to the federal Energy Information Administration (EIA), New Jersey ranks 11th among all states

FIGURE 1-1

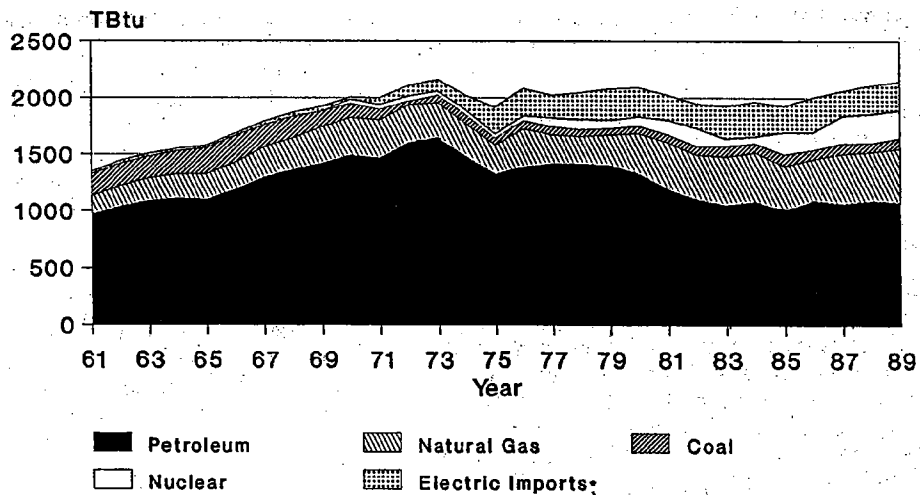
Energy Sources for New Jersey
1989 - 2138 TBtu



Note: *Primary fuel input TBtus for out-of-state generation of electricity.
Source: EIA-0214(89), adjusted by DEPE.

FIGURE 1-2

Energy Sources for New Jersey
1961-1989



Note: *Primary fuel input TBtus for electricity generated out-of-state.
Source: EIA-0214(89), adjusted by DEPE.

in energy purchases. Several northeastern refineries have closed or reduced their capacity in recent years, leaving fewer local sources for refined petroleum products. (See Chapter 3.) For the past several years, the state's electric utilities have purchased more than 30 percent of the kilowatt hours they distribute from power plants outside New Jersey. (See Chapter 8.)

Physical availability of petroleum, natural gas, and coal seems assured for the next decade. Although oil production is falling in the contiguous 48 states, reserves and production capacity in Alaska and outside the United States appear large enough to comfortably supply New Jersey and world requirements over the next decade. Possible natural gas sources include domestic and Canadian producing areas. Coal sources in the continental United States can satisfy present use and expected increases in domestic demand for many years to come.⁵

Petroleum

Petroleum supplied half of New Jersey's energy purchases in 1989. In recent years, more than three-quarters of refined petroleum products used in the state were made from imported crude oil.⁶ As domestic production continues to fall, we can expect to import increasing amounts of crude oil and refined petroleum products from abroad.⁷

The Middle East has 66 percent of worldwide crude oil estimated proven reserves. Proven worldwide crude oil reserves increased by more than half in the 1980s, however U.S. and U.S.S.R. reserves fell from 15 to 8 percent of the total. Increased production by Saudi Arabia and other countries offset declines in the U.S., Iraq and Kuwait.⁸

The EIA expects that oil prices will rise substantially over the next decade, that petroleum use will increase slightly and that, by 2000, net imports will supply 54 percent of U.S. oil use.⁹

Natural Gas

Natural gas supplied over a fifth of statewide energy purchases in 1989. Natural gas reserves are sufficient to meet growth projections in all market areas worldwide into the next decade.¹⁰ In Alaska, Canada, and Mexico, reserves are now available or plans exist for their development before 2000 depending on the market price.¹¹ Proposals before the Federal Energy Regulatory Commission (FERC) would add or expand natural gas interstate pipelines to New Jersey.¹²

Coal

Coal, used mainly to generate electricity both in-state and out of state for New Jersey consumption, supplied about one tenth of state-wide energy in 1989. Analysts expect coal to be readily available through the beginning—and probably the end—of the next century.¹³ Coal will compete with oil and natural gas for any increase in consumption in the next decade. The United States presently produces considerably more coal than it uses and exports a small proportion of total production. The U.S. Department of Energy forecasts that coal exports will at least remain

stable or may increase by as much as a third by the year 2000.¹⁴ Coal supplies for New Jersey should be sufficient throughout the next decade.

The major constraints on coal use are environmental. In addition to the environmental problems related to mining and transportation, coal use impairs air and water quality, leads to acid rain, and probably contributes to global warming.

Nuclear

Enriched uranium as fuel for electricity generation supplied about one-sixth of statewide energy in 1989. The nuclear industry has stagnated. Since 1978 utilities in the United States have ordered no nuclear power plants and have cancelled 78 orders.¹⁵ Safety issues, primarily waste disposal and emergency evacuation procedures, await resolution. Costs associated with these safety issues have risen dramatically along with insurance costs. The regulatory environment has changed considerably over the years in response to safety concerns and large cost overruns. Utilities have been unwilling to order new nuclear plants when they cannot accurately evaluate the costs of bringing a plant on line. The costs will not stabilize until most of the underlying health, safety, and waste disposal issues are settled.

Energy Price

Fuel prices in New Jersey are considerably higher than national averages but are close to prices in other northeastern industrial states. Both national and local prices are subject to fluctuations beyond state, and even federal, control. Table 1-1 compares New Jersey energy prices to those of neighboring states and the nation. New Jersey pays among the highest prices in the country for coal and electricity. The wholesale price of gasoline for New Jersey is comparable to other states in the region but is higher than the national average. Retail gasoline prices are moderated by the very low state tax on motor fuels. Coal prices are high throughout the Eastern U.S. but New Jersey's coal prices are somewhat greater because stringent air quality standards require use of more costly low-sulfur coal. Natural gas prices are in the top quarter nationally.

Because New Jersey imports nearly all purchased energy, it has no control over price changes determined by other countries or by national policy. Price rises will increase the outflow of income from New Jersey's economy to producing countries, while price decreases will reduce that outflow. If energy prices rise faster than the overall cost of living, as many analysts are predicting for the mid- and late 1990s, then New Jersey's economy would be adversely affected.

Energy Use

In 1989, New Jersey used 2,138 trillion Btu (TBTu), an average of 276 million Btu (MMBTu) per capita.¹⁶ The state ranked close to other northeastern industrial states in per capita use.¹⁷ (See Table 1-2.)

TABLE 1-1
New Jersey Fuel and Energy Prices Compared to Other States

	Retail Gasoline \$/MMBtu	Motor Fuel Tax Rates cents/gal ¹	Wholesale Gasoline cents/gal ²	City Gate Price Natural Gas \$/mcf ³	Coal \$/ton ⁴	Electric \$/kwh ⁵
U.S. highest	9.55	22.0	109.7	7.67	57.39	0.118
U.S. next highest	8.91	21.8	104.6	3.91	49.50	0.112
U.S. lowest	6.51	7.5	71.9	.34	9.17	0.047
New Jersey	7.58	10.5	87.3	3.23	49.50	0.112
New York	7.16	8.0	93.2	3.05	42.23	0.118
Pennsylvania	7.01	17.4	85.8	3.47	38.30	0.099
Maryland	8.18	18.5	94.2	3.16	42.66	0.088
U.S. Average	7.32	16.6	80.8	3.03	30.28	0.082
New Jersey rank - highest to lowest - among 50 states & D.C.	18	47	13	12	2	2

Notes: ¹ These general application rates, as of January 1, 1990, include but are not limited to excise taxes, environmental taxes, special taxes, and inspection fees. They do not include county and local taxes or any state taxes based on gross or net receipts.

New York levies a 4 percent state sales tax. Municipalities in NY State may apply an additional 3 percent sales tax. Special legislation permits NY City to apply an additional 4 percent. Georgia, the state with the lowest U.S. tax rate, levies a 1 percent state sales tax and a 3 percent second motor fuel tax. New Jersey and other states levy a gross receipts tax on petroleum products.

² Excluding taxes and resellers margins.

³ MCF - thousand cubic feet.

⁴ Coal prices not reports by all states.

⁵ Based on average cost of summer residential bills for 500 kwh.

Sources: Retail Gasoline: EIA/State Energy Price & Expenditure Report, 1988, Table 5, p. 9, published 9/90.
Motor Fuel Tax Rates: EIA/Petroleum Marketing Monthly, March 1991, p. 165.
Wholesale Gasoline: EIA/Petroleum Marketing Monthly, March 1991, Table 28, pp. 57-60.
Natural Gas: EIA/Natural Gas Monthly, May 1991, Table 27, p. 68.
Coal: EIA/Quarterly Coal Report, January-March 1991, Table 19, p. 39.
Electric: Residential Electric Bills, Summer 1990, p. 192-195, NARUC 3/22/91.

TABLE 1-2
Per Capita Energy Use in New Jersey
and Other Northeastern States - 1989
(MMBtu per capita)

State	All Use	Res.	Comm.	Ind.	Trans.
New Jersey	*276	68	61	67	*79
Pennsylvania	298	72	44	114	68
Maryland	269	69	35	89	76
New York	*209	57	54	39	*60
US average	328	67	52	119	90

Note: *Adjusted to allocate jet fuel consumption between NJ and NY.

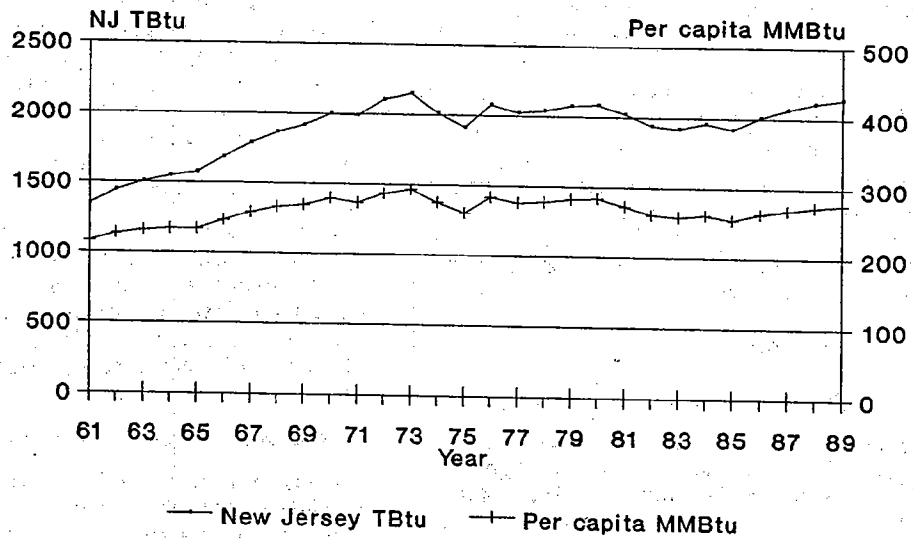
Source: EIA, State Energy Data Report, DOE/EIA-0214(89).

Figure 1-3 shows changes in annual and per capita energy use and in population in New Jersey over the past 26 years. From 1960 through 1973 total energy use and population both rose steadily: energy use grew on average more than 4 percent per year and population at an annual rate of 1.47 percent. But following the oil embargo of 1973, energy use dropped sharply, recovered, and then remained within a narrow range for a dozen years. Population continued to grow, but at a slower rate. As a result, per capita energy use fell by about 11 percent from its peak in 1973, reaching a low of 260.2 MMBtu per capita in 1983.¹⁸

The precipitous decline in world oil prices in late 1985/early 1986 led to a general fall in energy price levels, which in turn has led to an acceleration in energy use. Nationwide energy purchases have increased over the last four years at a rate approaching that prior to 1973. Energy purchases in New Jersey have increased less rapidly.¹⁹ Figure 1-4 shows energy used in each sector of the New Jersey economy.

FIGURE 1-3

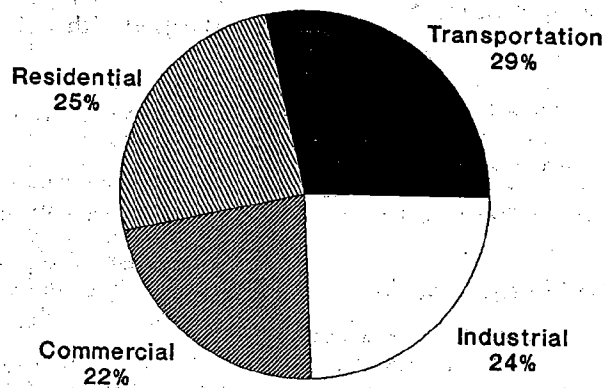
Energy Consumption in New Jersey
1961-1989



Note: MMBtu - Million Btu
Source: EIA-0214(89), adjusted by DEPE.

FIGURE 1-4

NJ Energy Consumption by Sector
1989 - 2138 TBtu



Source: EIA-0214(89), adjusted by DEPE.

Residential and commercial buildings used 47 percent of energy consumed in New Jersey in 1989.²⁰ The energy performance of buildings is much more expensive to change through retrofit than during construction.²¹ Since buildings last for scores of years, building codes and construction practices lock in energy use for a long time.

Transportation accounted for 29 percent of the state's energy use.²² Transportation needs depend on vehicle efficiency, mode of travel (e.g., car versus train), and land use. The location of buildings, jobs, shopping, and residences relative to each other help determine the transportation infrastructure and transportation energy requirements.²³

Industry used the remaining 24 percent of energy consumed in New Jersey in 1989.²⁴ Its portion has declined with the loss of manufacturing, and the remaining manufacturers have increased their efficiency using less energy for the amount of goods produced.

Needs

Need to Improve Our Competitive Edge

In spite of great progress, the United States uses more energy per dollar of output than its major foreign trade competitors. The U.S. saved \$150 billion in 1986, but we continue to spend \$440 billion each year on primary energy. Compared to such major foreign trade competitors as Japan, West Germany and France, the U.S. uses twice the amount of energy per dollar of gross national product (GNP). This nation's continued dependence on a high level of energy leaves it in a poor competitive position relative to more efficient economies. If the U.S. economy could produce at Japan's level of efficiency, it would reduce annual U.S. energy cost by an additional \$220 billion, 4.5 times the bill for energy imports and more than the U.S. budget or trade deficits. Increasing production efficiency would make U.S. goods and services competitive with other nations now and would give even greater benefits should the price of energy rise.²⁵ The severe tightening of energy supplies and the sharp price rises that resulted from the prolonged cold weather experienced in December 1989 demonstrated the vulnerability of the Northeast.²⁶

A competitive position for New Jersey, a consumer state, is more critical than for the nation as a whole. The state is entirely dependent on energy imports from foreign and domestic sources. In an energy emergency it lies distant from the Strategic Petroleum Reserve in the Southwest and at the end of the gas distribution network. It is more dependent than many other states on foreign petroleum imports.²⁷

Need to Bolster Our Energy Security

The United States is again increasing its dependence on imported petroleum. Domestic production is falling, and imports are rising and accounting for a greater portion of the balance of payments deficit.²⁸ This increasing dependence has major implications for economic development and energy security, which this Plan will address. The import cost is now about \$58 billion annually—over 63 percent of the nation's trade deficit in 1989 and up from 30

percent in 1988.²⁹ That outflow of dollars could expand to \$100 billion annually by the year 2000, if government projections for price and use are correct.³⁰

Need to Improve Environmental Quality

The increasing use of fossil fuels has major implications for environmental quality on local, state, national, and global levels. Investigators believe that if present use trends continue, the formation of ozone or the release of carbon dioxide (CO₂), a direct result of the intensive use of fossil fuels, will cause profound climatic changes with far-reaching implications for the earth's biosphere in the future. We cannot change impacts already in progress, only moderate further impacts.³¹

Hazardous conditions that affect the public health and the environment can arise from inadequately controlled or vented fossil fuel combustion or by internal engine combustion in closed or congested areas. Mitigation of some emissions, such as CO₂ or NO₂, inherent to fossil fuel combustion can be achieved by using less fuel to accomplish the desired ends.³²

Need to Balance Energy Needs and Impacts

Energy is fundamental to social and economic activity. It provides comfortable living and working space, light and power for commerce and industry, and mobility for people and goods. The way energy is supplied, distributed and used, however, can harm the environment through fuel spills, air pollution and disposal of waste. To gain the greatest benefit from the energy used while minimizing environmental impacts requires a clear understanding of social, economic and environmental benefits and impacts as well as integrated policies that balance these competing and interrelated considerations.

State Energy Policy Goals

The energy policy goals established in the 1977 initial legislative mandate and stated as the goals of previous New Jersey Plans—energy security, economic growth, and environmental quality—remain relevant to today's needs.³³ The goals of this 1991 Plan are as follows:

Goal #1:

To provide secure energy supplies and services to energy users.

This Plan recommends policies that improve energy efficiency for all uses to the maximum cost effective limit because increased energy efficiency is the most practical way to decrease reliance on imported energy. The policies also aim to reduce the state's dependence on imported energy by encouraging the development of alternative sources.

An economy less dependent on energy can remain strong in spite of fluctuating energy prices and supply disruptions resulting from the control of energy supplies by outsiders. Each barrel of oil, ton of coal, or kilowatt hour not needed because of efficiency improvements furthers our energy security goals by reducing our need to import fuel.

Goal #2:

To encourage economic growth by providing energy services at the least cost.

This Plan recommends policies for obtaining energy services from utilities at the least cost to users. It also supports the evolution of utilities into competitive providers of energy services other than power generation and distribution. The least-cost approach means that utilities strive to supply the lowest cost energy services, such as heat, light, cooling, and motor power, in contrast to providing low cost energy *per se*.³⁴ A kilowatt conserved as a result of a home retrofit is equivalent to one delivered by a power plant. Electric power generated from the waste heat of an industrial boiler is as useful as kilowatt hours produced from a utility's thermal power plant.

This Plan shows that energy prices in New Jersey are higher than in other parts of the country. The Plan also identifies policies available to New Jersey government to mitigate price increases and, where possible, to reduce or stabilize energy service costs.

The sharp rise in energy prices from 1974 to 1980 was a major factor in the economic problems of that period.³⁵ Stability in energy prices and in the total cost of energy services help promote economic development. Accelerated implementation of energy saving technologies in commercial and industrial processes and improvements in heating and cooling efficiency will bolster the economic competitiveness of New Jersey business and industry. At the same time, the use of energy efficient technologies will reduce the need for acquisition or construction of higher cost new energy supplies or facilities.

Goal #3:

To protect the public health and environment through wise and efficient energy use.

This Plan recommends policies that improve both indoor and outdoor air quality through measures that reduce energy use, while maintaining the services that energy provides. Chapter 19 describes auto and power plant emissions as the major causes of outdoor air quality degradation. It details measures that the state can take to reduce their harmful effects and the added enforcement effort necessary to gain maximum benefit from federal regulation of air pollution. The state depends mainly on enforcement of federal law to reduce environmental pollution. It can also promote the protection of the environment through education, incentives, and demonstration of less polluting fuels.

Fortunately, reduction and control of harmful emissions correlate directly with increasing energy efficiency and least-cost planning. The main tools for controlling energy costs are equally the main tools for improving environmental quality.

Goal #4

To balance energy needs and impacts through coordinated and integrated planning.

The state agencies responsible for energy, environmental, fiscal, health, housing and land-use planning, and

human services and transportation have worked together to produce this Plan. Decisions in one sector affect other sectors and impacts must be considered together. Recommendations set forth in this Plan attempt to serve the multiple and interrelated economic, social and environmental goals of the state.

Scenarios for 2000

Several independent organizations have developed national and global energy use scenarios for the year 2000 and beyond. These studies have all shown that increases in energy efficiency are possible and economically justified even at today's energy prices.

The analyses in this Plan consider the use efficiencies developed by the independent organizations and apply that potential to historical state use data. Based on these analyses, and on the different historical rates of growth in energy use before and after 1973, this Plan (in Table 1-3 and Chapter 24) describes three distinct scenarios of future energy use in New Jersey:

- **historical high growth:** increase at the 1960-1973 and 1986-1988 growth rate;
- **historical low growth:** rising slowly at the 1981-1986 rate; and
- **best choice:** decrease at a rate determined by incorporation of the most efficient appliances and equipment available today, efficient building techniques and additional initiatives undertaken to meet environmental, economic, and security considerations.

The three scenarios show a wide range of possible future energy use. The best choice scenario assumes that for environmental, economic and security reasons the state will implement policies to improve efficiency of energy use, including encouraging consumers to replace existing energy-using equipment with the most efficient equipment available today.

TABLE 1-3**Scenarios for Energy Use in New Jersey**

Scenario	% Change/Year	Scenario
		Year 2000 Tbtu
Best choice	-2.6	1,599
Historical low growth	+0.2	2,185
Historical high growth	+4.1	3,326

Note: 1989 purchases (EIA, without NY jet) = 2,138 Tbtu.
See Chapters 11, 12, 13, Figure 24-1.

Source: EIA 0214 (89) for Tbtu purchased (without NY jet).
High-growth series - 1960-1973.
Best choice scenario - Appendix A-24-1.
Low growth series - 1980-1988.

The scenarios are neither forecasts nor predictions. They are straight line projections of possible alternative levels of energy use, starting from the 1989 level and based either on an assumption of past rates of growth, or on the effectiveness of new policies to cause the incorporation of efficient technologies. They do not include the effects of other factors such as population growth, employment changes, or personal income.

Policymakers in government and in the private sector will choose New Jersey's energy future either by default or by conscious decision. The consequences of the choice are great. New Jersey now consumes about 2,000 TBtu of energy per year. Growth at historical rates could almost double this use by the year 2000 and require a large investment to construct generating plants, transmission systems and pipelines. In contrast, use of efficient appliances and equipment commercially available today would ensure a high efficiency future that would lower energy consumption and allow New Jersey to continue its economic development and protect its environment.

The Commissioners believe that New Jersey can be a leader and commend this Plan to the people and the Legislature for early consideration and implementation.

NOTES

1. W.U. Chandler, H.S. Geller, and M.R. Ledbetter, *Energy Efficiency: A New Agenda* (Washington, D.C.: American Council for an Energy-Efficient Economy, 1988), p. 16.
2. Chandler, *et al*, p. 12.
3. See discussion in Chapter 8, Electricity.
4. See discussion pp. 17-19, 26 and 35.
5. Energy Information Administration (EIA), *Annual Energy Outlook 1990*, DOE/EIA-0383(90), p. 13.
6. EIA, *Monthly Petroleum Supply*, November 1987, pp. xvii-xxix.
7. EIA, *Annual Outlook for Oil and Gas 1989*, DOE/EIA-0517(89), pp. 6-10 and Table ES1, p. x.
8. *Oil and Gas Journal Worldwide Report*, December 25, 1989, Vol. 87, No. 52, pp. 41.
9. EIA, *Annual Outlook for Oil and Gas 1989*, p. xi.
10. *Ibid.*, p. xii.
11. *Ibid.*, p. 11.
12. *Oil and Gas Journal*, January 30, 1989, Vol. 87, No. 5, p. 31.
13. Robert Stobaugh and Daniel Yergin, eds., *Energy Future, Report of the Energy Project at the Harvard Business School* (New York, NY: Random House, 1979), pp. 80-81.
14. EIA, *Quarterly Coal Report, January-March 1988* (Washington, D.C.: US Department of Energy, 1988), p. 9.
15. U.S. Council for Energy Awareness, *Historical Profile of U.S. Nuclear Power Development, 1988 ed.* (Washington, D.C.: U.S. Council Energy Awareness, 1988), p. 8.
16. Annual data from the EIA, *State Energy Data Report, 1960-89*, No. DOE/EIA-0214(89), (Washington, D.C.: U.S. Department of Energy, 1988). State data are available for 1970 through 1990 from the state energy data base maintained by the N.J. Department of Environmental Protection and Energy and from the EIA. The EIA, a statistical and analytical agency within the U.S. Department of Energy, compiles energy use data on a consistent basis for all states. Its data are available for 1960 through 1989. EIA data have been corrected by re-allocating jet fuel use between New York and New Jersey. (See Chapter 13.) The New Jersey Department of Labor (DOL) provides economic data.
17. EIA, Report DOE/EIA-0214(89).
18. Calculated from EIA, Report DOE/EIA-0214(88), p. 207, and U.S. Census Data 1980 Table 2, Land Area and Population.
19. EIA, Report DOE/EIA-0214(89).
20. EIA, Report DOE/EIA-0214(89), pp. 210-211.
21. Chandler, *et al*, p. 55.
22. EIA, Report DOE/EIA-0214(89), p. 213.
23. See Chapter 18, Land Development Patterns for Energy Efficiency.
24. EIA, Report DOE/EIA-0214(89), p. 212.
25. A.R. Rosenfeld, "Energy Conservation, Competition and National Security," in *Strategic Planning and Energy Management*, Vol. 8, No. 1 (Summer 1988).
26. Division of Energy Planning and Conservation, *An Analysis of December 1989 Heating Oil Price Increases*, Newark, 2/5/90.
27. EIA, *Monthly Petroleum Supply*, November 1987, pp. xvii-xxix.
28. See Chapter 24, Table 24-9.
29. *Ibid.*
30. Chandler *et al* p. 13.
31. Mintzer, Irving M., 1987, *A Matter of Degrees: The Potential for Controlling the Greenhouse Effect* (Washington, D.C.: World Resources Institute, April 1987), Research Report #5, p. 1.
32. *Ibid.*
33. New Jersey Department of Energy (DOE), *1978 Energy Master Plan*, p. i, and DOE, *1985 Energy Master Plan*, p. i. See also Chapter 2, History of Energy Policy in New Jersey.
34. R.W. Sant, D.W. Bakke, and R.F. Naill, *Creating Abundance: America's Least-Cost Energy Strategy*, James Bishop, Jr., ed., (New York: McGraw-Hill, 1984).
35. Real gross domestic product in the United States grew at an annual average rate of 2.1 percent during the years of steeply rising energy prices from the beginning of 1974 through 1980, compared to an annual average rate of 3.2 percent from 1960 to 1985. During this period of rising energy prices, inflation, as measured by the implicit index of consumer prices, rose at an annual average rate of 8.3 percent compared to an annual average rate of 5.0 percent from 1960 to 1985. *Historical Statistics, 1960-85*, Organization of Economic Cooperation and Development, Paris, 1987. See also *Time*, July 9, 1979.

Chapter 2

History of Energy Policy in New Jersey

The history of energy planning in New Jersey begins with the 1974 Task Force on Energy Report to the Governor.¹ The report, produced in 30 days in the crisis atmosphere of an oil embargo, set forth several objectives that remain the major themes of energy planning:²

- Describe the state's energy supply and consumption flows, and how they fit into national and international patterns.
- Develop an approach to conserving energy that will provide both immediate and long-term economically justified benefits.
- Define adverse environmental effects associated with increasing supplies of energy and a strategy to combat them.

In 1977 the state established its own Department of Energy (DOE). The enabling legislation³ incorporated many recommendations from the Task Force 1974 report. In part, the legislation required that a Division of Energy Planning and Conservation within the DOE: gather and analyze energy data relating to present and future energy demand and resources; establish an energy information system; design, implement and enforce a program for energy conservation in the commercial, industrial and residential sectors; and prepare an energy master plan (to be updated every three years) with a 10-year window on the distribution, consumption and conservation of energy in the state. Using the process of preparation and adoption provided in the statute, the DOE adopted Energy Master Plans for the state in 1978 and 1985; however, a 1981 draft Plan prepared during the transition between administrations went through proposal and public hearings stages but was never adopted.

In 1986, the Reorganization Plan for the Department of Energy (No. 001-1986) transferred statutory responsibilities related to energy planning, recycling and the state's energy subcode from the DOE to the commerce, environmental protection and community affairs departments respectively. Further, statutes revised pursuant to P.L. 1987, c. 365 modified the energy master plan process. Previous energy master plans were adopted unilaterally by the DOE after a public hearing and comment process. The revised statutes established an Energy Master Plan Committee composed of the heads of the Departments of Commerce, Energy and Economic Development; Community Affairs; Environmental Protection; Health; Human Services; Transportation; and Treasury.

Although statute charged the state's energy division with primary responsibility for formulating an energy master plan, efforts of the Board of Public Utilities (BPU) helped shape and direct the evolution of energy policy in New Jersey since 1974. A BPU inquiry into electric public utility construction practices and a study of electric utility

plans to convert certain facilities to burn coal yielded proceedings rich in written testimony concerning utility practices.⁴ In 1988, the BPU concluded a stipulation settlement on cogeneration and small power production.⁵ The stipulation implemented many of the 1985 Energy Master Plan recommendations on contracting mechanisms between electric utilities and non-utility generators. It also obviated the former process of conducting *ad hoc*, prolonged contract negotiations by establishing an auction and bid system for supplying new power capacity for electric utilities.

In a March 1989 Governor's Conference on Electricity Policy, Planning and Regulation, public and industry officials convened to discuss how New Jersey could best meet growing demand for electricity needed to support the state's economy in an environmentally acceptable way and to identify means to strengthen the State's electricity planning and regulatory policies and institutions. This conference helped clarify the most critical issues facing government and industry in the 1990s and underscored the importance of integrated energy planning and regulation. The conference report called for increased utility and customer conservation incentives and a more centralized and coordinated government structure for resource planning and utility regulation.

In a June 1989 effort to *coordinate the energy supply policies of this State with the regulation of energy companies as public utilities [and] ensure that all sectors of the State's economy are supplied with the most reasonably priced sources of energy consistent with maintaining environmental standards*, the Governor issued Reorganization Plan No. 002-1989 transferred the Division of Energy Planning and Conservation from the commerce department to the Board of Public Utilities. With this reorganization, the responsibility of the commerce department commissioner to serve on and to chair the Energy Master Plan Committee was reassigned to the president of the Board of Public Utilities.

The series of executive efforts to enhance the state's energy planning, environmental protection and utility regulation abilities culminated with Governor Florio's June 1991 Reorganization Plan #002-1991. The reorganization provides for the *increased coordination and integration of the State's utility, environmental and energy policies* through its transfer of the Board of Public Utilities recast as the Board of Regulatory Commissioners (BRC) in but not of the Department of Environmental Protection and Energy (DEPE). The reorganization transferred the chairmanship of the Energy Master Plan Committee to the DEPE commissioner but retained a seat on the committee for the chairman of the BRC. All energy planning and policy functions previously assigned by statute to the energy division are continued and supported by the DEPE in close coordination with other environmental and utility regulatory activities. The reorganization positions New Jersey to deal most

effectively with the multiple energy, environmental and economic challenges of the the next decade.

Past Energy Master Plans

The two adopted Plans and the 1981 draft Plan show the evolution of energy policy since 1974 that sets the stage for this 1991 Plan.

The 1978 Plan

The 1978 Plan set forth the statutory goals that each version since has incorporated.⁶

- To assure uninterrupted energy supplies to all residential, commercial, utility, and industrial users in New Jersey;
- To promote economic growth while safeguarding environmental quality; and
- To encourage the lowest possible energy costs consistent with the conservation and efficient use of energy.

The 1978 Plan identified three strategies to meet those goals:⁷

- (1) Establish an independent capability to determine the state's energy needs, including the need for new energy facilities. The Plan identified an energy data base and forecasting capability as tools for this task.
- (2) Promote conservation as a *new source of energy* to meet future demand. The Plan proposed implementing this strategy through integrating energy and environmental planning.
- (3) Use indigenous supplies of energy, solid waste, biomass, solar, wind, and low-head hydro.

The 1978 Plan, developed under the pressures of establishing a new cabinet level agency and the lack of adequate data, did not present a sophisticated economic analysis of the state's energy problems. Subsequently, DOE, with Rutgers and Princeton Universities, developed the New Jersey Energy Data System as a tool to monitor energy use in the state. This initial Plan dealt with issues rather than planning. The 1978 Plan reflected the federal philosophy of the 1970s, that regulatory mechanisms could order energy markets and ensure reliable supplies of energy to the state.

Its major contribution was establishing a process for evaluating energy facility siting proposals. Earlier, state government had reacted to each proposal separately and without formal evaluation procedures. The 1978 Plan contained a Memorandum of Understanding (MOU) between the Commissioners of Environmental Protection and Energy establishing a process for joint evaluation of facility siting proposed for the coastal zone.⁸

The MOU reflected the range of energy facility siting proposals being considered, including floating nuclear power plants, off-shore bases to support Baltimore Canyon exploration, off-shore pipelines to bring oil and gas from Baltimore Canyon wells to interstate pipeline junctions, deepwater oil terminals, and liquefied natural gas storage facilities on Staten Island.

At the same time, cost overruns in the construction of nuclear facilities and the abandonment of partially completed facilities led to a prolonged legislative debate regarding the role state government should play in determining the need for electric generating facilities. The debate ultimately resulted in the enactment of the Electric Facility Need Assessment Act.⁹

The Draft 1981 Plan

DOE prepared, proposed and held hearings on a 1981 draft Plan but did not adopt it. The document included results from the data base, forecasts of primary fuels, and electricity use. It proposed coal as a major primary fuel option for the industrial sector and for electricity generation.¹⁰

The USDOE had initiated a mandatory electric utility coal conversion program for power plants. The Port Authority of New York and New Jersey had proposed building a coal import/export terminal in Jersey City that would have created a new rail/barge/ocean collier inter-connection, and encouraged utilities and industries in New Jersey to use coal.¹¹

1981 was a year of economic redirection. Refineries in the state were closing or reducing output. Unemployment was increasing. The service sector was beginning a rapid expansion while the manufacturing sector was shrinking. This was the year of highest retail oil prices but the first fall in world crude oil prices.¹²

Falling oil prices upset the economics of coal use and brought about a review of state and federal policies.¹³ At the same time, industries and utilities began conversion to gas/oil dual fuel capability, enabling them to respond quickly to competitive price changes. All these events caused a fundamental review of the primary fuels policy in the Plan and delayed its adoption. The 1981 revisions contained a policy statement that became a cornerstone of the 1985 Plan:

*Indeed, New Jersey's future economic development is largely dependent on finding a clean, relatively inexpensive alternative to the fuel mix we now employ. Conservation is therefore clearly the fuel of first dependence—the least expensive, quickest, and least polluting of all our fuel options.*¹⁴

The 1985 Plan

The 1985 Plan set forth policies to promote energy efficiency in the production and use of energy and reoriented energy regulation to incorporate market forces. The 1985 Plan recognized that reducing energy use can moderate environmental impacts of using fossil fuels and nuclear power.¹⁵

Saved energy converts all New Jersey consumers into energy producers, as plugging leaky attics and managing over-lit and over-heated buildings yield owners the equivalent of high financial returns on their investments in saved energy.

DOE outlined its implementation strategy in a series of regulations mandating energy conservation programs.¹⁶

The regulations required utilities to measure the amount of energy saved and relate the gains to plans for adding new capacity.

A goal of the 1985 Plan was to bring competition to the utility industry through the increased participation of alternative power producers in meeting the state's energy needs and through least-cost planning.¹⁷ Least-cost planning theory continues to be a cornerstone of the state's energy planning and utility regulation activities.

The 1985 document was the last Plan issued by the DOE. The legislation required that to the extent practical and feasible the actions of all state agencies must conform to the Plan.¹⁸ Affected state agencies commented on the draft Plan prior to its adoption but had no direct responsibility in preparing and adopting it.

The 1991 Plan

This 1991 Plan is the first to be adopted by a committee of cabinet-level department heads. Chaired by Commissioner Scott A. Weiner of the Department of Environmental Protection and Energy, the 1991 Energy Master Plan Committee members who adopted this Plan are Board of Regulatory Commissioners (BRC) Chairman Dr. Edward H. Salmon, Department of Community Affairs (DCA) Commissioner Melvin R. Primas, Department of Health (DOH) Commissioner Frances J. Dunston, M.D., Department of Human Services (DHS) Commissioner Alan J. Gibbs, Department of Transportation (DOT) Commissioner Thomas M. Downs and State Treasurer Douglas C. Berman.

The process of developing this 1991 Plan caused state planners and regulators, utilities, alternative power producers, energy equipment vendors and service providers, public interest groups, energy users and others to review a broad range of energy-related issues that affect New Jersey's environment, quality of life and economic competitiveness. A draft 1989 Plan prepared by the Division of Energy Planning and Conservation with the assistance of staff from the other Energy Master Plan Committee departments provided a starting point for this 1991 Plan. Public hearings were held on the 1989 draft document, but the Committee deferred adoption of the Plan in July of 1989 pending the transfer of the energy division to the BPU. In October of 1990, the Energy Master Plan Committee issued a draft of the current Plan for public comment. The October draft was the product of months of effort within seven departments of state government to set forth key information and proposals that would steer a more public debate. Public interest and private business groups responded to staff requests for specific data and information during the development of the draft and participated in a series of informal roundtable discussions on policies promoted in the Plan. The Committee chaired public hearings on the Plan attended by more than 500 people in December 1990 and reviewed written comments submitted by more than 80 groups and individuals.

To ensure that all state energy planning activities are informed and consider the impact of policies on energy users, energy providers and on the state's environmental and economic well-being, the DEPE will revive the Ad-

visory Council on Energy Planning and Conservation. Original DOE statute (N.J.S.A. 52:27F-12) called for the creation of an Advisory Council to strengthen the state's ongoing energy planning activities. The council's 15 members are to serve without compensation at the Governor's appointment, with the advice and consent of the Senate, and are to represent: *the natural gas industry, the bottle gas industry, the home heating oil and coal industry, terminal operators, oil refiners, gasoline retailers, electrical utilities, nuclear fuel suppliers, environmental organizations, the solar energy industry, manufacturing industrial consumers, the transportation industry and the academic community.* Although each reorganization plan retained the Advisory Council language, the council has been inactive for several years.

The Energy Master Plan Committee will continue to enlist the kind of broad-based public participation that is crucial to the successful implementation of public policy goals. As each member-department begins to implement Plan policies that have direct bearing that department's statutory functions and responsibilities, the public will again be invited to participate in the rulemaking process.

NOTES

1. Report to the Governor of New Jersey From The Task Force on Energy, (Trenton, May 1974).
2. *Ibid.*
3. P.L. 1977, c. 146 and N.J.S.A. 52:27F-1 et seq.
4. Board of Public Utilities, Docket No. 762-194.
5. Board of Public Utilities, In the Matter of Consideration of Cogeneration and Small Power Production Standards, Docket No. 8010-687B, Stipulation of Settlement.
6. New Jersey Department of Energy, 1978 Energy Master Plan, p. i, and NJDOE, 1985 Energy Master Plan, p. i.
7. *Ibid.*
8. DOE-DEP Memorandum of Understanding, 1978 New Jersey Energy Master Plan, Attachment II, pp. IA-40.
9. Electric Facility Need Assessment Act, P.L. 1983, c. 115.
10. DOE, Draft Revisions to the New Jersey Energy Master Plan, Sept. 1981, p. D-13.
11. Newark Star Ledger, January 6, 1982, p. 26 and January 22, 1982, p. 25.
12. New Jersey Department of Commerce, Energy and Economic Development (DCEED), New Jersey Energy Profile: 1987 Edition (Newark: DCEED, 1988), and Shell Briefing Service, Energy in Profile, No. 3, 1988.
13. DOE, 1985 Energy Master Plan, p. 39.
14. DOE, Draft Revisions to the New Jersey Energy Master Plan, Sept. 1981, p. C-3. See also NJDOE, 1985 Energy Master Plan, p. ii.
15. DOE, 1985 Energy Master Plan, p. ii.
16. N.J.A.C. 14A:20-1, et seq.
17. DOE, 1985 Energy Master Plan, p. iv.
18. N.J.S.A. 52:27F-15.

Chapter 3

Petroleum

New Jersey produces no crude oil but, in 1989, consumed more petroleum than 43 other states,¹ more than half of it in transportation.² The Northeast (11 states from Maryland to Maine) is more petroleum dependent than other regions of the country. It has limited refinery capacity, negligible crude production and high product demand, particularly in winter for home heating. It relies heavily upon foreign petroleum sources and thus is particularly vulnerable to supply disruptions.

U.S. crude oil is the source of less than one quarter of the refined petroleum products consumed in the Northeast.³ Foreign crude oil refined overseas or imported to the Gulf Coast, the Northeast or the Midwest for refining supplies three quarters of products consumed in our region. Since 1986, the proportion of imported to domestic crude oil and refined product has increased as U.S. sources have produced less.

This chapter reviews the sources and uses of petroleum purchased in New Jersey. It examines the environmental, economic, and security implications of our present pattern of high dependence on imported crude and petroleum products and looks to the year 2000.

Petroleum Use

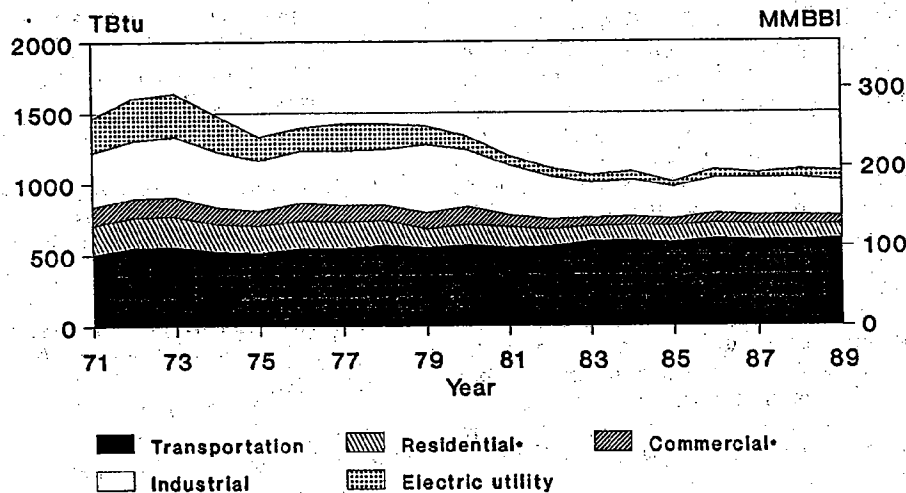
New Jersey has reduced its dependence on petroleum significantly from more than 70 percent of the state's annual consumption before 1970 to approximately 50 percent in 1989. (See Chapter 1, Figure 1-1).⁴ The Arab Oil Embargo of 1973-74, price increases, and a realization of the potential for future supply disruptions moderated demand. Only transportation demand has increased. Figure 3-1 shows state petroleum use in million barrels (MMbbl) for transportation, industrial, residential, commercial and utility sectors. (See Appendix Table A-3-2 for data).⁵

Transportation use, 103 MMbbl in 1973, rose through the 1980's to 112 MMbbl in 1989.⁶ In the last three years, use of motor gasoline and jet fuel has surpassed earlier highs. Lower prices for gasoline, a general increase in vehicle miles traveled, population shifts from urban to suburban locations, strong sales of larger cars, and increased air traffic have caused the rise in use.

Industrial use, in contrast, fell by more than one third from 74 MMbbl in 1973 to 45 MMbbl in 1989. Over this period energy-intensive "smokestack" industry declined

FIGURE 3-1

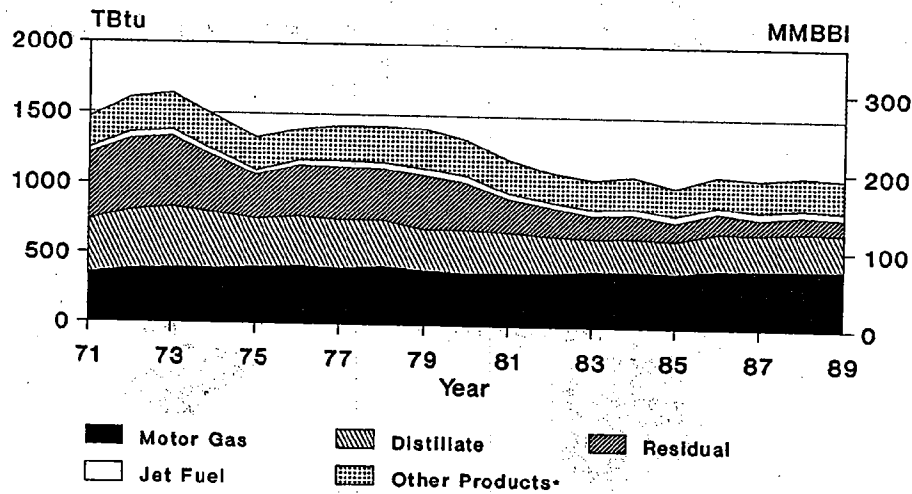
NJ Petroleum Consumption by Sector 1971-1989



Note: •Building space conditioning, lighting, appliances, and equipment use
Source: EIA-0214(89), adjusted by DEPE.

FIGURE 3-2

NJ Petroleum Consumption by Product
1971-1989



Note: *Asphalt, road oil, aviation gas, LPG, lubricants, feedstocks and other.
Source: EIA-0214(89), adjusted by DEPE.

and other industry developed the capability to switch to natural gas when it was less expensive than petroleum.

Building use (primarily oil-fired heating for the residential and commercial sectors) also fell by more than half

from 60 MMbbl in 1973 to 28 MMbbl in 1989. Customer investment in fuel-efficient heating equipment, conversions to natural gas-fired heating systems, automatic set-back thermostats, weatherization, and upgraded insulation caused the decrease.

New Jersey electric utilities' in-state petroleum use dropped from 49 MMbbl in 1973 to only 10 MMbbl in 1989.⁷ Utilities instead increased their reliance on nuclear and natural gas-fired generation.

TABLE 3-1

Imported Crude Oil Input to Petroleum Product
Northeast United States

Source	Imported Crude Oil Input, %	Total Product Volume (MMBBL/D)	Portion of Total Product Volume (MMBBL/D)
Imported	100%	1.20	1.20
Other U.S. regions	38%	1.06	0.40
Northeast refineries	91%	1.15	1.05
Total	78%	3.41	2.65

Note: MMBBL/D - million barrels per day - based on 1986 imports.

Sources: EIA, Petroleum Supply Monthly, November 1987, p. xix, Table FE1 & p. xxii; and Petroleum Supply Annual 1986, p. 27, Table 5, and p. 28, Table 6.

Petroleum Supply

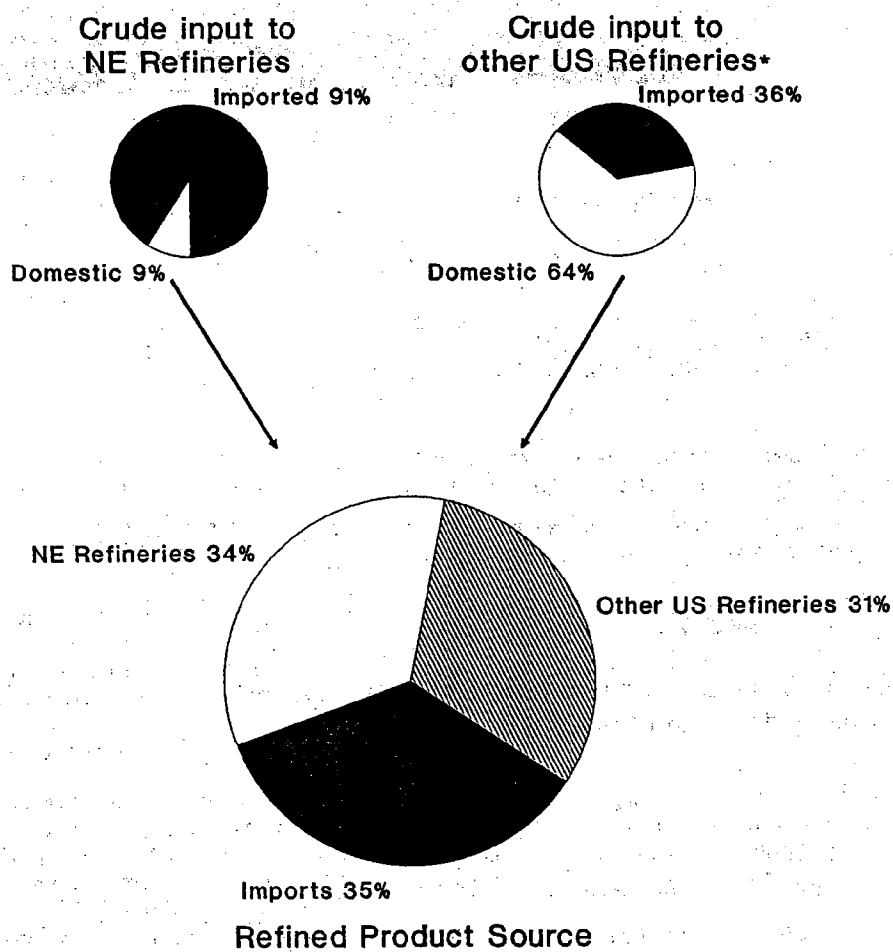
Imported crude oil is the source for more than 75 percent of petroleum product consumed in the Northeast. Figure 3-2 shows the amount of petroleum product by type supplied to New Jersey over the period 1970 to 1989.⁸ Figure 3-3 and Table 3-1, (based on a detailed Energy Information Administration analysis of 1987 regional petroleum supply containing statistics that generally apply to New Jersey.⁹), illustrate the Northeast's dependence on imported crude oil and petroleum product.

Figure 3-3 shows the relative importance of three sources of petroleum product used in the Northeast:

- tanker shipment from other countries
- local refinery output
- pipeline, barge and tanker shipment from the Gulf Coast and other U.S. regions.

FIGURE 3-3

Imported Crude Oil as Source for Product Delivered to Northeastern States
1986



Source: DOE/EIA-0109(11/87)
*Refineries Supplying Product to NE

TABLE 3-2
Major Sources of Crude Oil Imports,
Comparison of U.S. with PADD I - 1990

Source	United States			PADD I		
	Rank	Amount MBBL/D	%	Rank	Amount MBBL/D	%
Saudi Arabia	1	1,195	20	2	193	15
Nigeria	2	784	13	1	405	32
Mexico	3	689	12	5	77	6
Venezuela	4	666	11	3	120	10
Canada	5	643	11	6	57	5
Iraq	6	514	9	7	43	3
United Kingdom	7	236	4	4	93	7
Angola	8	155	3	9	12	1
Columbia	9	140	2	8	14	1
Other		873	15		234	19
Total crude imports		5,895	100		1,248	100

Notes: PADD - Petroleum Administration for Defense District. PADD I includes all Atlantic coast states plus Vermont and parts of Pennsylvania and West Virginia.
MBBL/D - thousand barrels per day.

Source: EIA, Petroleum Supply Annual 1988, p. 37-40, Table 15.
See also Appendix Table A-3-3.

Approximately 35 percent of refined petroleum product consumed in the Northeast comes from other countries; 34 percent is refined here in the Northeast; 31 percent comes from refineries in other U.S. regions. While Northeast refineries obtain more than 90 percent of their crude oil input from other countries, refineries in other U.S. regions rely on imported crude for only one third of their input. The Colonial Pipeline, the only pipeline that brings product into New Jersey, carries most Gulf Coast product.

TABLE 3-3

Proved Reserves of Liquid Hydrocarbons
(Million Barrels)

Year	Natural Gas		Total
	Crude Oil	Liquids	
1979	29,810	6,615	36,425
1981	29,426	7,068	36,494
1984	28,446	7,643	36,089
1987	27,256	8,147	35,403
1989	26,501	7,769	34,270

Source: EIA, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1989 Annual Report, p.8, Table 1.

Tankers and barges carry only a small portion, but provide critical extra supplies to meet peak period demand.¹⁰ Table 3-2 ranks by volume the major sources of crude oil refined in 1988 in the United States and in the Petroleum Administration for Defense District (PADD) I (i.e., all Atlantic coastal states, Vermont and parts of Pennsylvania and West Virginia).¹¹ Over the past decade, crude oil imports from Mexico, Canada, the North Sea and Venezuela have risen and displaced imports from the Middle East. The Energy Information Administration (EIA) expects that trend to change as domestic crude oil production continues to decline and as non-OPEC production peaks in the mid-1990s. As the EIA observes, *About two-thirds of the world's proved oil reserves are in the Middle East (virtually all in the Persian Gulf).*¹² Table 3-3 shows the drop in U.S. proved reserves.

Most crude imports for Northeast refineries arrive by tanker at eastern ports. Domestic crude for the Northeast comes mainly from Alaska and California. Tankers carry it to the Panamanian Pacific Port of Puerto Armuelles and unload it to Panapipe, the 82 mile, 800 thousand barrels per day Trans-Panama Pipeline System, for transport to Chiriqui Grande, the Atlantic Port.¹³

While Gulf Coast refineries have the capacity to meet surges in demand, limitations of pipeline, tanker, and barge transportation may restrict the availability of distillates from this source. Shortages of home heating oil and propane in the Northeast during December 1989 demonstrated those limitations.¹⁴

TABLE 3-4
Refinery Operating Capacity
(Million Barrels Per Day)

	<u>N.J.</u>	<u>PADD 1</u>	<u>U.S.</u>
1977	0.7	1.9	16.4
1980	0.6	2.0	17.9
1985	0.4	1.5	15.0
1987	0.4	n/a	15.3
1990	0.5	1.4	15.6

Note: PADD - Petroleum Administration for Defense District.
PADD 1 includes all Atlantic Coast states plus Vermont and parts of Pennsylvania and West Virginia.

Sources: N.J. and U.S. data (as of January 1); Oil and Gas Journal, Annual Refining Issues, March 1977-1990;
PADD 1 data - EIA, Petroleum Supply Annual
DOE/EIA - 0340(90).

Refinery Capacity

U.S. refinery capacity dropped sharply from 1980 to 1985 but has increased slightly since then. Table 3-4 shows the changes. Expansion of refinery capacity in the 1970s occurred in Texas, Louisiana and California.¹⁵ Decreased demand for #4 and #6 heavy heating oils then caused smaller, older and less efficient refineries, many in the Northeast, to close. The older refineries had been able to process the sweet (low sulfur-content) and light OPEC crudes¹⁶ but could not process the heavier crudes from Canada, Venezuela, and Mexico.

Demand has increased for the lighter distillates, gasoline and jet fuel, that refineries with modern processing capacity are able to produce. Industry mergers/buy-outs have permitted companies to consolidate operations in large, new efficient refineries and to retire older units. Some companies have withdrawn totally from some market areas.

Crude oil producing nations have constructed large modern refineries that are cost-competitive with western refineries because of lower labor costs and different environmental regulations. In 1988, the Saudi Arabian Government purchased a half-interest in Texaco's southeastern refining and marketing system to form a joint venture called Star Enterprises. In 1986, the Venezuelan National Oil Company bought a half-interest in Southland Corporation's refining and distribution network.

Northeastern Refineries

Eleven major crude processing refineries are located in the Northeast: five in Pennsylvania, five in New Jersey and one in Delaware. (See Table 3-5) These refineries have a capacity to process 1270.5 thousand barrels per day but some of that capacity produces only asphalt or lubricating oils rather than the products with highest seasonal demand—heating oil or motor gasoline.

Three refineries are in northern New Jersey near the New York harbor. The largest, Exxon Bayway in Linden with 10 percent of Northeast crude refining capacity, was temporarily closed for evaluation in March of 1990 and halted all its waterborne transport operations at the Bayway refinery and Bayonne tank farm.¹⁷ It reopened all its operations early in the summer of 1990 and now operates at full capacity. The Chevron refinery in Perth Amboy stopped distillate production in 1983 after making a considerable investment during a "turnaround" outage. It now produces only asphalt but did produce some distillate

TABLE 3-5

New Jersey Crude Oil Refining Capacity (Thousand Barrels Per Day)

<u>Year</u>	<u>Exxon</u>	<u>Chevron</u>	<u>Mobil</u>	<u>Texaco/ Coastal¹</u>	<u>Amerada Hess²</u>	<u>Seaview</u>	<u>N.J. Total</u>
1979	290	168	98	88	68	N.A.	712
1984	100	80	100	90	0	44	414
1988	130	80	100	90	0	0	400
1991	130	0	100	105	0	0	335

Note: ¹ Texaco sold refinery to Coastal in December 1984.

² This refinery, mothballed in 1974, reopened in 1985 to process low sulfur vacuum gas oil from its Virgin Islands refinery into unleaded gasoline. Crude oil distillation capacity at the refinery remains shut down.

Sources: EIA, 1984 Petroleum Supply Annual, Table 32, p. 93. 1988 Petroleum Supply Annual, Table 31, p. 86. DOE/EIA-0340(90)/1, Petroleum Supply Annual, Table 38, p. 106.

during the December 1989 shortages.¹⁸ The Amerada Hess refinery in Port Reading closed in 1974 until 1985 and now produces unleaded gasoline from products received from its Virgin Islands refinery.¹⁹

Three New Jersey refineries are along the Delaware River near Camden. The largest is the Coastal Refinery in Westville (Eagle Point), formerly owned by Texaco, with a crude capacity of a 109,250 barrels per calendar day (b/cd). The second, Mobil in Paulsboro, has a 100,000 b/cd capacity. Both of these have downstream capacity to refine heavy intermediate products into gasoline and lighter products. The Seaview facility in Thorofare, built in the late 1970s, produces lubricating oils and asphalt.²⁰

Reducing Vulnerability To Supply Disruptions

Because New Jersey has limited ability to increase the reliability of its oil supply, it must direct policies and programs towards reducing oil use through efficiency and by shifting to less polluting alternative fuels, such as natural gas, wherever practicable. Conservation is the most rapid and cheapest way to reduce vulnerability. It is reliable, economic, and flexible.

New Jersey can reduce its petroleum dependence most rapidly and at the least cost through expansion of alternatives to single passenger vehicle travel. Carpools, vanpools and measures that encourage use of mass transit offer multiple benefits. They reduce petroleum dependence, commuting costs, road congestion and air pollution.

Federal Clean Air Act amendments signed into law in November 1990 could impact petroleum use. They require that all private motor vehicles in areas cited for "severe" nonattainment of federal ozone standards use reformulated gasoline beginning in 1995. In addition, motor vehicle fleets of 10 or more vehicles capable of central fueling will be required to phase in the use of alternative fuels such as methanol or natural gas. Beginning with model year 1998, 30 percent of new fleet acquisitions must run on alternative fuels; the requirement escalates to 50 percent for model year 1999 fleet purchases and 70 percent for model year 2000. Eighteen of the state's 21 counties (i.e., all but Warren, Atlantic and Cape May counties) earned the "severe" nonattainment designation for ozone air pollution by virtue of the state's proximity to Philadelphia and New York City—two of nine cities nationwide ranked as severe. Reformulated gasoline requirements will be enforced statewide and it is anticipated that alternative-fuel fleet requirements will be enforced statewide. These provisions could reduce the state's dependence on petroleum by as much as 60,000 barrels per day or approximately 25 percent of 1988 motor gasoline use.²¹

Broad application of several available fuel-saving technologies (e.g., multi-point fuel injection, four valves per cylinder, improved tires) could double auto fuel economy. However, cars twice as efficient as current models will cost \$200 to \$800 more. Since this cost increase will produce some resistance from both manufacturers and consumers, bold policy initiatives such as a higher fuel tax, an oil import fee or a gas-guzzler tax could be required to accomplish the fuel economy goal.²² It is important to note that

gasoline tax in the United States is about \$.30 per gallon, compared to \$1.80 in West Germany and \$1.41 in Japan. (See Chapter 13: Energy Use in Transportation, Table 13-7.) Should supplies in the global marketplace tighten and threaten to trigger price increases of unknown duration, consumer and manufacturer resistance to greater investments in automobile efficiency could soften.

Storage of Reserves

In response to the petroleum shortfall caused by the five-month long 1973-74 Arab oil embargo, Congress authorized the creation of the Strategic Petroleum Reserve (SPR) through the Energy Policy and Conservation Act (EPCA) of 1975. The EPCA called for a reserve of up to one billion barrels of petroleum products to reduce the impact of disruptions in petroleum supplies and to carry out obligations of the United States under the International Energy Program. The SPR program under President Bush is directed towards providing 750 million barrels of crude oil in underground salt caverns at six sites located in the Gulf Coast area. As of January 1991, the SPR contained 585 million barrels of crude oil. That storage level, targeted to equal 90 days worth of crude oil imports, now contains about a 77-day supply at a rate of 7.6 million barrels per day imports. The fill rate dropped off from a high of 234 thousand barrels per day in 1981 to a rate of 30 thousand barrels per day in 1989. The federal fiscal year 1992 budget request marks the first year in which 750 million barrels of capacity is available; it also proposes continuation of a responsible level of operations and a maintenance program to assure cost-effective capability to a drawdown. The budget proposes to increase the fill rate to 50 thousand barrels per day commencing in the last half of 1992.²³

For Northeast crude and product supplies, the SPR could assist only indirectly. It does not address replacement of direct product import to the Northeast—now over a third of product supply. The price rises and supply problems in the Northeast in December 1989 pointed out the need for additional local storage of product. A 1990 Board of Public Utilities energy division report, *An Analysis of December 1989 Heating Oil Price Increases*, recommended measures necessary for New Jersey to avoid vulnerability to supply shortages and resulting effects on consumers: extraordinary price hikes, lack of appropriate information on deliveries, and limits on ability to switch suppliers. Recommendations for storage included:

- evaluation of the economic feasibility of establishing minimum inventory levels for refined petroleum products for the state and the Northeast, both at the wholesale and retail levels.
- development of federal incentives to encourage suppliers to maintain stocks of refined product adequate for seasonal demand at the wholesale level. The federal government should encourage suppliers to institute summer fill programs at the wholesale level. The state should encourage retailers to institute summer fill programs at the retail level.²⁴

Petroleum Price

The price of oil rose several fold from 1972 to 1980 in response to supply disruptions caused by the OPEC countries and speculation in the world commodity market. From a peak in 1980, the real price (in 1980 dollars) dropped in 1989 to near the lowest level in a decade. The August 1990 invasion and occupation of Kuwait by Iraq and the subsequent trade embargo imposed on Iraq by the United Nations then drove the price of crude oil higher on the world market for a short period. The West Texas intermediate spot price at Cushing, Oklahoma reached a high of \$41.07 per barrel on October 11, 1990, an increase of \$19.48 per barrel from the August 2, 1990 price of \$21.59 per barrel. However, after January 16, 1991, optimism regarding the ability of U.S.- and Saudi Arabian-lead coalition military forces to quickly resolve the conflict with Iraq caused crude prices to drop dramatically and settle close to the pre-invasion level of \$21 per barrel.

Outlook

Short Term Outlook

A global market controls New Jersey's future price and supply outlook. Severe weather conditions, transportation disruptions, and economic and political events exert pressure on price and supply. Table 3-6 shows the EIA's summary outlook. While many factors controlling the petroleum price and supply matrix lie beyond the scope of

TABLE 3-6

U.S. Petroleum Supply, Demand, and Imports EIA Projection- Reference Case

<u>Supply, Demand & Imports</u>	<u>1989</u>	<u>1995</u>	<u>2000</u>
World Oil Price ¹ (1989 \$/barrel)	18.81	24.00	25.70
Production (Quads) ²			
Crude Oil	16.24	14.59	11.72
Other Liquids ³	<u>2.15</u>	<u>2.60</u>	<u>2.32</u>
Total	18.39	17.19	14.04
Consumption (Quads)	34.21	34.22	36.70
Net Imports (Quads)	15.25	17.15	22.37
Net Imports percent of Consumption	45	50	61

Note: ¹ Cost of imported crude oil to U.S. refiners.
² Quad = Quadrillion BTU per year.
³ Includes natural gas liquids, processing gain and other domestic production.

Source: EIA, Annual Energy Outlook 1991, January, 1991, p. 43, Table A-1.

state government, one factor New Jersey government could influence is refined product inventory. The Department of Environmental Protection and Energy (DEPE) is investigating ways to improve storage and inventory practices to help mitigate any future temporary supply disruptions and price spikes.

The EIA anticipates that world crude oil prices may remain relatively low for a few more years. It points out that in the near-term, sufficient excess crude production capacity exists to meet demand and that different interests among OPEC countries now limit its ability to control the output of member countries. Saudi Arabia has extensive oil reserves that will last well into the next century and *desires to maintain production and pricing in a manner that will guarantee a market for its oil over the long run*. In contrast, *other countries, such as Algeria, Libya, and Indonesia, have reserves that will not last nearly as long as those of Saudi Arabia and therefore are interested in receiving higher prices in the near term.*²⁵

OPEC supplies are again dominant in the world market. Its oil production capacity, recently over 28 million barrels per day, is well over half of market economy energy consumption (i.e., excluding consumption of centrally planned economies of Eastern Europe, the Soviet Union and China). Its share of market economy demand that decreased sharply from a high of 67 percent around 1973 to below 40 percent in 1985 climbed back to 45 percent in 1989. The EIA projects a continuing increase in its share.²⁶

The United States' domestic oil production in 1989, including lower 48, Alaska, natural gas liquids, and other components, amounted to 9.2 million barrels per day. Expanded demand coupled with falling domestic production caused an increase in crude oil imports to 7.2 million barrels per day. The EIA projects that domestic production will continue to decline. Production could drop at a rate between 1.8 (for a high price scenario) and 3.8 percent per year (for a low price scenario). Alaskan production, now nearly a quarter of total domestic crude oil production, has or will soon peak for its primary fields.²⁷

The EIA's *Annual Energy Outlook 1990*, released in January 1990, distinguished between the world market economies that account for about four fifths of world oil consumption for which demand is expected to grow, and centrally planned economies for which demand is expected to decline.²⁸ Recent changes in centrally planned economies, with emphasis on economic development, may cause their demand to grow also.

Year 2000

The EIA's *Annual Energy Outlook 1991* gives projections for domestic crude oil output and the amount of imports necessary to meet increased demand through 2010. It expects that demand will catch up with the current excess in world oil capacity in the 1990s. Then OPEC, with its large resource base, will play a greater role.²⁹

For market economies in the year 2000 the EIA projects the economic growth rate to drop from a recent rate of 4.0 to a range between 2.2 and 3.0 percent average annual rate of growth (see Table 3-6). It projects that OPEC oil

production capacity will expand from a recent capacity of 28.2 million barrels per day to a range between 34 and 36 million barrels per day. It finds that the U.S. refiner acquisition cost of imported oil would rise from a 1989 base of \$18.81 to a range between \$23 and \$45 per barrel (1990 dollars). It expects U.S. oil consumption to rise from a 1989 level of 17.5 million barrels per day to a range between 18.8 and 21.8 million barrels per day.³⁰

The EIA projects that after a few more years of relatively flat real oil prices rising demand, limits on supply from non-OPEC sources, and the concentration of world resources in the OPEC nations will lead to more rapid price increases after the mid-1990s. It expects U.S. oil production to fall, from about 10 million barrels per day in 1989 to about 8.5 million barrels per day in 2000. It finds that even with more supplies from natural gas liquids and non-petroleum sources, net petroleum imports will grow from 7.2 MMbbl/d to 10.8 MMbbl/d (with high oil prices) and 15.7 MMbbl/d (with low oil prices). It projects that foreign sources will supply nearly two thirds of U.S. domestic petroleum requirements by 2010.³¹

Findings

- Crude oil delivered to New Jersey and East Coast refineries comes almost exclusively (90 percent) from other countries. Both crude oil and product refined in other regions or other countries must come long distances via pipeline, tanker, barge or truck. Crude stored for national emergencies is in Louisiana and Texas, far from local refineries.
- New Jersey ranks seventh highest nationally in petroleum consumed. In 1989, petroleum supplied more than half of all energy purchased. Transportation consumed 57 percent, industry 23 percent, buildings 14 percent, and in-state electricity generation by electric utilities 6 percent.
- The state can mitigate its vulnerability to supply disruptions and cost escalation by reducing its high dependence on petroleum products. Effective measures include: improvement of auto and light truck motor fuel efficiency; expansion of alternatives to single-passenger auto travel to work—mass transit and carpools and vanpools; improvement of space-heating equipment efficiency; and increased insulation and weatherization of buildings.
- Petroleum space-heating consumers have experienced sharp price increases for heating fuels during periods of exceptionally severe cold weather conditions. Consumers can eliminate their vulnerability to seasonal increases by taking steps to reduce use of and dependence on petroleum: improve heating equipment efficiency; insulate and weatherize buildings; install alternative heating capability; and maintain sufficient fuel storage capacity to carry a building through the coldest winter month.

Policy

- The State should promote significantly increasing the fuel economy of cars and light trucks.
- The State should promote expanded use of ridesharing, vanpooling, and mass transit to reduce single passenger auto use for frequent trips such as travel to work.
- The State should encourage Congress to increase the fill rate of the Strategic Petroleum Reserve to provide increased protection against the possibility of an interruption in imported supplies.
- The State should support and develop means to encourage increased storage of refined petroleum products in New Jersey and the Northeast, both at the wholesale and retail levels. The State should do so in a manner that would mitigate potential air quality impacts and the increased risk of oil spills from the movement of additional products in harbors and waterways.

Implementation

- New Jersey, through its congressional delegation, should adopt a leadership role in urging the U.S. National Highway Traffic Safety Administration to raise Corporate Auto Fleet Efficiency (CAFE) standards.
- The DOT should facilitate greater use of vanpooling and carpooling.
- New Jersey should reduce petroleum dependence for motor vehicle use through programs outlined in Chapter 13, Transportation.
- The DEPE should seek the support of the New Jersey Congressional delegation to fill the Strategic Petroleum Reserve to a level of 750 million barrels at an increased rate.
- The DEPE is evaluating the economic feasibility of establishing minimum inventory levels for refined petroleum products both at wholesale and retail levels. This evaluation should consider: limitations imposed by the present transportation infrastructure that moves the product from the prime suppliers to the end users, and the feasibility of establishing a Northeast regional product reserve.
- New Jersey's congressional delegation should promote the development of federal incentives to encourage suppliers at the wholesale level to maintain stocks of refined product adequate for seasonal demand. The federal government should encourage suppliers to institute summer fill programs at the wholesale level. The DEPE should encourage retailers to institute summer fill programs at the retail level.
- New Jersey should enact legislation to require heating oil and propane dealers to provide consumers with appropriate price and quantity information at the time of delivery.

 NOTES

1. Energy Information Administration (EIA), *State Energy Data Report, 1960-1989*, DOE/EIA-0214(89), p. 11.
2. *Ibid.*, pp. 213.
3. EIA, *Petroleum Supply Annual, May 1991*, p. xv.
4. EIA, *State Energy Data Report 1960-1989*, p. 209.
5. EIA, *State Energy Data Report, 1960-1989*, pp. 210-211.
6. EIA, *State Energy Data Report, 1960-1989*, pp. 213. Figures adjusted by the N.J. Department of Environmental Protection and Energy.
7. EIA, *State Energy Data Report, 1960-1989*, p. 214.
8. EIA, *State Energy Data Report 1960-1989*, pp. 209.
9. EIA, *Petroleum Supply Annual, May 1989*, pp. 34-43.
10. Board of Public Utilities, *An Analysis of December 1989 Heating Oil Price Increases*, November 1990.
11. PADD stands for Petroleum Administration for Defense District (PADD). PADD I is the East Coast from Florida to Maine plus West Virginia and all of New England. PADD II is northcentral U.S. from North Dakota to Tennessee. PADD III is the Gulf Coast from Texas to Alabama plus New Mexico and Arkansas.
12. EIA, *Annual Energy Outlook 1990*, p. 8.
13. National Petroleum Council, *Petroleum Liquids Transportation*, Vol. V, p. 42, Washington, D.C., 1989.
14. BPU, *An Analysis of December 1989 Heating Oil Price Increases*, 2/5/90.
15. *Oil and Gas Journal*, Annual Refining Issues, 1977-1990, March 1990.
16. Light crude oil: Density value greater than 30 degrees on American Petroleum Institute (API) scale.
Heavy crude oil: Density value less than 20 degrees on API scale.
17. *Newark Star Ledger*, March 3, 1990, p. 1.
18. Phone conversation with Jack Galloway, Chevron, January 31, 1990.
19. Phone conversation with Lucy Domenick, Amerada Hess, April 27, 1990.
20. *Oil and Gas Journal*, Annual Refining Issue, 1990.
21. Communication from John Elston, NJ Department of Environmental Protection, September 18, 1990.
22. W.W. Chandler, H.S. Geller and M.R. Ledbetter, *Energy Efficiency: A New Agenda*, (Washington, D.C.: American Council for an Efficient Economy, 1988), pp. 28-30.
23. USDOE *Posture Statement and Fiscal Year 1992 Budget Overview*, 1991.
24. BPU, *An Analysis of December 1989 Heating Oil Price Increases*, 2/5/90.
25. EIA, *Annual Energy Outlook 1991*, p. 7.
26. *Ibid.*, p. 19.
27. *Ibid.*, pp. 4, 18 and 21.
28. *Ibid.*, p. 8-9.
29. *Ibid.*, p. 6.
30. *Ibid.*, p. 21.
31. *Ibid.*, p. 21.

Chapter 4

Natural Gas

Natural gas is a clean fuel that consists primarily of methane, a compound of hydrogen and carbon. When burned, the predominant products of combustion are water and carbon dioxide. Natural gas occurs in underground reservoirs of ancient sedimentary rock. Sometimes the gas is found with crude oil and sometimes in separate gas fields. Gas produced at the well is gathered by local pipelines, cleaned, and then transported to most parts of the United States via interstate pipelines and local distribution networks. At year-end 1989, proved reserves of dry natural gas in the United States were estimated at 167 trillion cubic feet (Tcf)—about 0.5 percent less than in 1988.

A by-product of oil extraction operations, natural gas was initially either flared off at the wellhead or used as a fuel near its source. By the 1920s, improvements in pipeline technology allowed producers to ship natural gas farther from the wellhead. Subsequently, wells were drilled specifically to find natural gas. During the 1920s and 1930s, expansion of the interstate pipeline system led to increased use of natural gas. In 1938, Congress passed the Natural Gas Act, in response to complaints of discriminatory pricing and uncertainty of supply. This law regulated the transportation and sale of natural gas in interstate commerce.

In 1954, a Supreme Court ruling (*Phillips Petroleum v. Wisconsin*, 347 U.S. 672) helped to stimulate the demand for natural gas by setting price ceilings on the previously unregulated wellhead price of natural gas in interstate commerce. That decision created two markets: an unregulated intrastate market and a regulated interstate one. Production and reserves dedicated to the interstate market began to decline in the late 1960s and early 1970s as producers found they could obtain higher prices in the intrastate market.

The Arab oil embargo of 1973 further increased the demand for natural gas, as petroleum consumers sought to switch to a fuel that was cheaper and more reliable in supply. This increased demand was not met by an equivalent increase in supplies, resulting in curtailments and shortages in the interstate market during the mid-1970s. To resolve these problems, the Natural Gas Policy Act (NGPA), 15 U.S.C. § 717, was passed in 1978 as a compromise designed to increase supplies and to allow for the gradual decontrol of certain categories of old gas by January 1, 1985. (Old gas is gas committed to interstate commerce prior to passage of the NGPA.) The NGPA also increased the supply of gas by allowing intrastate pipelines to sell to interstate pipelines and local distribution companies (LDCs) without regulation by the Federal Energy Regulatory Commission (FERC).¹

The supply outlook has also been impacted by recent policy changes of both the U.S. and Canadian govern-

ments. The policy changes have made Canadian gas prices more competitive with domestically produced gas and thus larger quantities are available for export.

In New Jersey, natural gas became available after World War II to supplement gas produced by burning coal. By the 1960s, natural gas completely replaced manufactured gas due to its lower price and higher heating value. At the same time that demand was growing in the late 1960s and early 1970s, natural gas production and the reserves committed to interstate sales were declining. By mid-1972, New Jersey's utilities found it increasingly difficult to obtain the natural gas required to meet demand. In 1975, the Public Utilities Commission (now the Board of Regulatory Commissioners or the BRC) issued an executive order requiring gas utilities to obtain PUC approval before making commitments to new customers or increasing service to existing customers. The Governor issued an executive order mandating that, among other requirements, thermostat settings be lowered and all nonessential uses of natural gas be discontinued. (Today, BRC approval for new gas supply is no longer required.) Beginning in 1978, the supply situation changed. As a result of conservation, the slow economy, and the Natural Gas Policy Act, adequate gas supplies became available again, but at higher prices.

New Jersey purchases of natural gas have increased considerably since 1970. They accounted for one-sixth of energy purchases in 1970 and grew to over one-fifth of purchases in 1989. Nationally natural gas accounted for one-third of purchases. Most use is for space heating in residential (46 percent) and commercial (28 percent) buildings and varies with seasonal heating requirements. The industrial sector consumed 13 percent and electric utilities used 12 percent of natural gas consumed statewide in 1989. (See Figure 4-1 and Appendix: Natural Gas Consumption in New Jersey.)

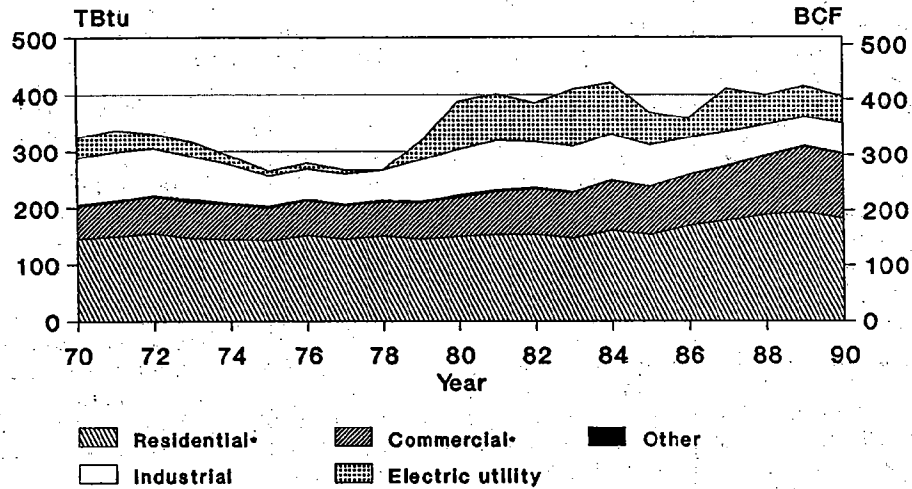
For quantifying volumes of natural gas, the industry uses several units interchangeably. This discussion uses British thermal units (Btu) rather than cubic feet (cf) or therms when needed to make direct comparisons with the energy value of other fuels. The following are units of measure of natural gas and their approximate equivalent in Btu: 1 cf = 1,000 Btu; 1,000 cf (1 Mcf) = 1 million Btu (MMBtu); 1 million cf (1MMcf) = 1 billion Btu; 1 billion cf = 1 trillion Btu (TBTu). In 1989, an average residential gas heating customer used about 10 Mcf or 10 million Btu.

Industry Structure

The natural gas industry has been undergoing rapid and profound changes. New regulatory approaches are significantly restructuring the traditional functions of and relationships among producers, pipelines, distributors, and end-users. The roles of federal and state regulators are also being redefined. A more complex gas industry is emerging,

FIGURE 4-1

NJ Natural Gas Consumption by Sector 1970-1990



Note: *Building space conditioning, lighting, appliance and equipment use.
Source: NJ Energy Data System.

TABLE 4-1

Profiles of Natural Gas Companies in New Jersey - 1990

<u>LDC</u>	<u>Area Served</u>	<u>Square Miles Served</u>	<u>Municipalities</u>	<u>Number of Customers</u>	<u>Number of Res. Heating Customers</u>
E'town	Northwest plus Union County	1,300	74	226,005	141,609
NJN	Southeast plus Morris County	1,436	104	307,700	256,189
PSE&G	Central through Northeast	1,150	267	1,489,174	885,352
SJ	Southern	2,500	112	217,636	175,305

Source: Utility companies annual reports, 1990, NJEDS.

with decreased regulation and increased competition. These new relationships are now in place and are functioning in parallel with the traditional roles.

The traditional gas industry has separate providers of three essential service components: producers own gas wells and sell under long-term contracts to interstate pipeline companies, who in turn sell to LDCs. Sometimes the pipeline company selling to the LDC is not directly connected to it. In those cases, a pipeline that is directly connected transports the gas for a fee. The end-user, *i.e.*, residential, commercial, industrial, or electric utility, purchases only from the LDC. Federal regulations controlled wellhead prices until January 1, 1985, when most wells were deregulated. The few remaining controls on wellhead prices will be abolished by January of 1993. Pipeline rates are federally regulated while the states set LDC rates. However, alternative arrangements have emerged as a result of various deregulating events of the last 10 years.

LDC Transportation Gas: LDCs now purchase significant portions of their natural gas directly from producers or energy brokers. Some of this gas is bought in the spot market, is interruptible, and usually costs less than the firm gas supplies purchased from interstate pipeline companies under long-term contracts. LDCs are renegotiating their contracts with pipelines to convert some of their pipeline gas purchases to firm transportation capacity. They can then use that capacity to transport gas purchased from other suppliers. For example, in 1989, Public Service Electric and Gas Company (PSE&G) purchased 56 percent of its total 1989 gas supply from producers. (See Appendix, Gas Purchases by each LDC).

End-user Transportation Gas: The larger end-users now purchase some of their natural gas directly from producers, usually via a new entity in the business—the marketer or broker. This energy marketer can be either an independent or a wholly-owned subsidiary of a pipeline company or of an LDC. The marketer matches end-user requirements with available gas at the wellhead and with pipelines having excess capacity. Under this new arrangement, neither the LDC nor the pipeline owns the gas it carries, and each charges a fee to recover transportation costs. Most end-users who purchase transportation gas are in the industrial sector. A few others are in the commercial sector. Although LDCs currently sell substantial volumes of transportation gas, the percentage of transportation gas to total sales varies from LDC to LDC, depending upon the number of industrial customers served and market conditions. NJN, a company that sold no transportation gas through 1989, commenced sales in April of 1990.² (See Table 4-2).

Interstate Pipelines Serving New Jersey LDCs

Five interstate pipeline companies connect directly to one or more of New Jersey's LDCs to deliver natural gas. They are: Algonquin Gas Transmission Corp. (AGT), Columbia Gas Transmission Corp. (Columbia), Tennessee Gas Pipeline Co. (Tennessee), Texas Eastern Transmission Corp. (Texas Eastern) and Transcontinental Gas Pipe Line Corp. (Transco).

Local Distribution Companies

New Jersey's natural gas consumers are supplied by four LDCs—Elizabethtown Gas Company (E'town), New Jersey Natural Gas Company (NJN), Public Service Electric and Gas Company (PSE&G), and South Jersey Gas Company (SJ). Figure 4-2 defines each company's franchise territory. Tables 4-1 and 4-2 compare selected statistics for each LDC.

PSE&G, although it serves the smallest territory as measured in square miles, is by far the largest LDC in terms of the total volume of gas sold. In 1989, PSE&G sold approximately 70 percent more gas than the other three LDCs combined.

The four LDCs currently receive part of their natural gas supplies by direct purchase from Transco, Texas Eastern, AGT, Columbia, and Tennessee. Gas purchased from other suppliers is transported for a fee via one of these five companies in order to be delivered. Supplies of natural gas that are in excess of the quantity required by those customers who use gas as their sole source of energy (*i.e.*, firm customers) make possible sales of gas to commercial and industrial customers whose equipment is capable of using either natural gas or other fuels such as heating oil or propane (*i.e.*, interruptible customers).

Elizabethtown Gas Company³

E'town serves a franchised territory consisting of 74 municipalities in central and northwestern New Jersey, with about 226,000 customers. These two service areas, separated by about 30 miles of PSE&G territory, include a concentration of diversified industry, such as chemicals and allied products, fabricated metal products, assembly plants, and primary metal industries. (See Appendix: Elizabethtown Gas Company Natural Gas Consumption.)

To ensure sufficient quantities of gas during the winter months, E'town supplements its supply of pipeline gas purchased pursuant to long-term contracts with storage gas transported during nonpeak periods for use during peak periods. E'town also uses liquified natural gas (LNG) and propane to meet peak demand. (See Appendix: Elizabethtown Gas Company Gas Purchases.)

New Jersey Natural Gas Company⁴

NJN serves about 308,000 customers in Monmouth and Ocean counties and parts of Morris and Middlesex counties. Its Morris County section is physically separated from its main service area by approximately 35 miles of PSE&G territory. NJN's service territory has an estimated population of 1.2 million and is growing rapidly. This growth has resulted in record customer additions in 1985, 1986 and 1987. NJN projects 35,000 new customers over the next five years. (See Appendix: New Jersey Natural Gas Company Natural Gas Consumption.)

NJN's four suppliers of natural gas are Texas Eastern, AGT, Consolidated, and Boundary. The gas is delivered via the interstate pipelines of Texas Eastern, AGT, Tennessee, and Transco. (See Appendix: New Jersey Natural Gas Company Gas Purchases.)

FIGURE 4-2

Service Territories of Natural Gas Companies Operating in NJ

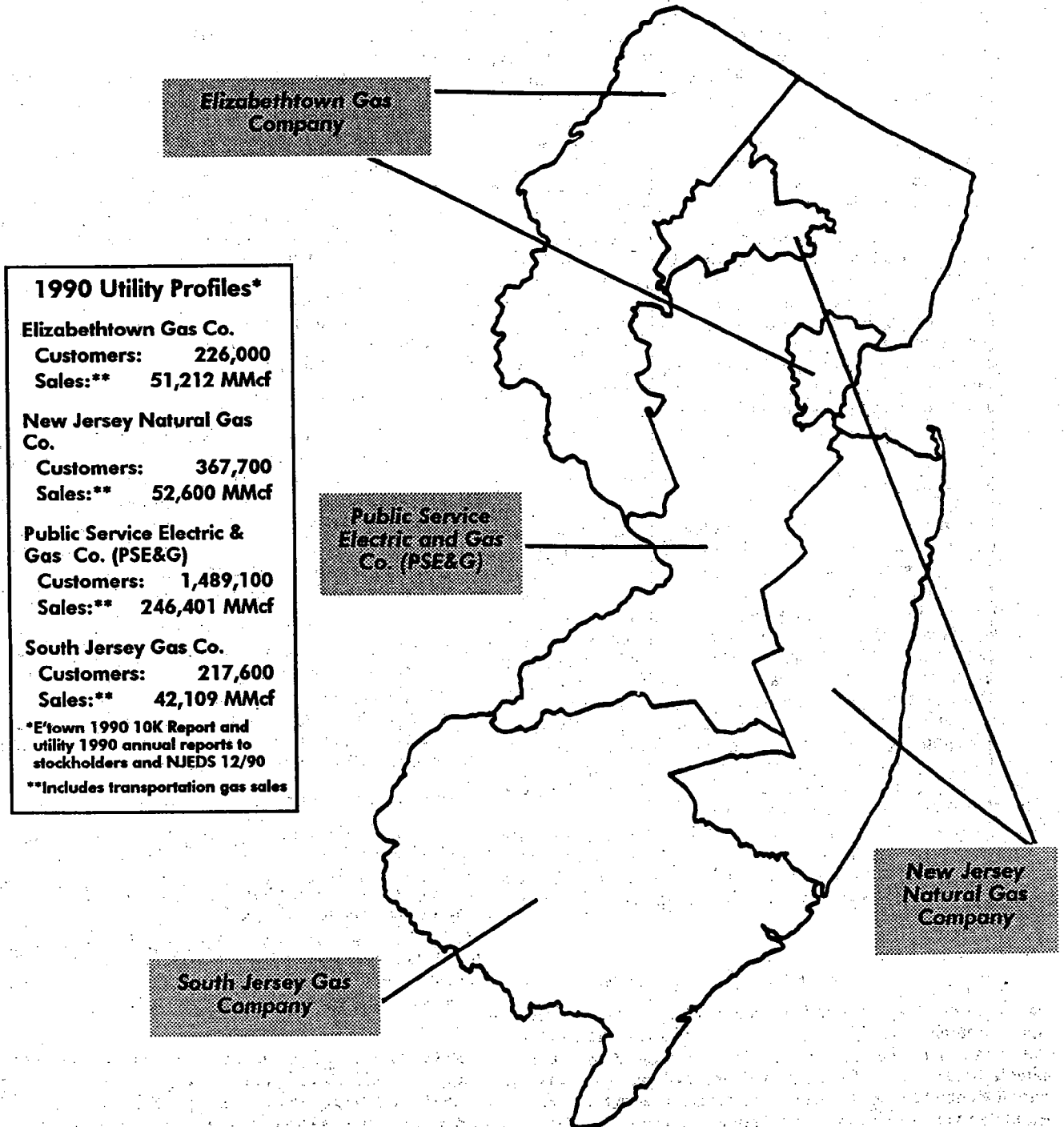


TABLE 4-2
Natural Gas Local N.J. Distribution Companies
System Sales and End-User Transportation Service

<u>LDC</u>	<u>Year</u>	<u>System Sales (MMCF)</u>	<u>End-User Transport MMCF</u>	<u>Total Deliveries (MMCF)</u>	<u>Transport as Percent of Deliveries</u>
E'town	1986	32,909	13,198	46,107	29
	1987	35,552	11,796	47,348	25
	1988	41,858	8,419	50,277	17
	1989	39,557	8,718	48,275	18
	1990	41,116	10,096	51,212	20
NJN	1986	46,120	0	46,120	0
	1987	53,759	0	53,759	0
	1988	56,097	0	56,097	0
	1989	54,967	0	54,967	0
	1990	51,924	676	52,600	1
PSE&G	1986	212,933	1,493	214,426	1
	1987	218,046	9,812	227,858	4
	1988	227,808	13,867	241,675	6
	1989	247,877	14,959	262,836	6
	1990	228,195	18,206	246,401	7
SJG	1986	36,775	0	36,775	0
	1987	40,690	131	40,821	1
	1988	37,611	3,123	40,734	8
	1989	35,099	8,578	43,677	20
	1990	31,715	10,394	42,109	25

Sources: E'town: NUI 10K Report to SEC, year ending 9/30/89, p. 3, 9/30/90, p.3.
 NJN: NJRC Annual Report to Stockholders, year ending 9/30/89, p. 31, 9/30/90 p.31.
 PSE&G: PSEG Annual Report to Stockholders, year ending 12/31/90, p.47.
 SJG: SJI Annual Report to Stockholders, year ending 12/31/90, p. 23.

To meet the demand on the coldest days of the year, NJN purchases storage service from its pipeline suppliers and maintains liquefied natural gas (LNG) and liquefied propane gas (LPG) storage facilities. NJN began receiving deliveries from Keystone, a storage facility, on November 1, 1986. Under this service, NJN injects its own gas supplies into storage during the summer months and receives deliveries of these supplies during the winter heating season. NJN also added storage capacity in southern New York State and expects withdrawals commencing in the 1991-92 winter season.

Public Service Electric & Gas Company⁵

PSE&G serves a gas territory from central to north-eastern New Jersey consisting of 267 municipalities with approximately 1.5 million customers. (The gas territory is not identical to the electric territory.) The company supplies its customers principally with natural gas, which is supplemented with purchased refinery gas. (See Appendix: Public Service Electric and Gas Company Natural Gas Consumption.) On the coldest days approximately 9 percent of

the gas available to PSE&G's firm customers comes from its supplemental sources.

In 1989, PSE&G obtained natural gas principally from three pipeline suppliers (Transco, Texas Eastern, and Tennessee Gas Pipeline Company) and from one producer (Energy Development Corporation, a wholly-owned subsidiary of Enterprise, which is PSE&G's parent company). In addition, PSE&G delivered spot purchase gas to customers under transportation agreements accounting for 7 percent of its annual gas sendout. (See Appendix: Public Service Electric and Gas Company Gas Purchases.) In warm months, PSE&G stores natural gas under storage contracts with its principal suppliers, to be withdrawn on selected winter days. Underground storage capacity approximates a 30-day supply.

PSE&G met all of the demands of its firm customers during the 1989-90 and 1990-91 winter seasons. During the 1990-91 heating season through February 28, 1991, PSE&G interrupted service to interruptible customers for 5 days. During the 1989-90 heating season, service to such

customers was interrupted for 44 days. These interruptions were due to lack of capacity on interstate pipelines, not by constraints within PSE&G's distribution network.

On January 1, 1985, the price of a significant portion of wellhead gas under contract to pipeline suppliers was decontrolled. Two of PSE&G's pipeline suppliers, Transco and Tennessee, have incurred significant costs to resolve past take-or-pay claims in contracts with producers. Both of these pipelines charge a portion of these costs to their customers, including PSE&G, in accordance with FERC Order 500. PSE&G passes the bulk of these costs onto its customers as part of the Levelized Gas Adjustment Charge.

The regulatory framework established by FERC Orders 436 and 500 has increased competition in the gas market by encouraging pipelines to act as nondiscriminatory transporters of gas. These regulations enabled PSE&G to transport substantial quantities of low-cost spot gas by converting a portion of its pipeline contract volumes to firm transportation, while obtaining gas from producers and marketers.

PSE&G purchased low-cost spot gas in 1990, amounting to 63 percent of total gas purchased, to displace more costly gas supplies available under long-term pipeline contracts.

South Jersey Gas Company⁶

SJ, a subsidiary of South Jersey Industries, serves a territory that comprises 112 municipalities in southern New Jersey with approximately 218,000 customers. The franchise area to the east is centered on Atlantic City and the neighboring resort communities in Atlantic and Cape May counties, which experience large population increases in the summer months. (See Appendix: South Jersey Gas Company Natural Gas Consumption.)

South Jersey Energy Company, a wholly-owned subsidiary of South Jersey Industries, provides services for the acquisition and transportation of natural gas for large volume users.

SJ's service territory includes the Pinelands region, a largely undeveloped area in the heart of southern New Jersey. Future construction is expected to be limited by statute and by a master plan adopted by the New Jersey Pinelands Commission. However, in terms of potential growth, these limitations do not affect significant portions of SJ's service area.

SJ obtains natural gas from two interstate pipeline companies, Transco and Columbia. The utility has a natural gas purchase agreement with Columbia. A Transco gas purchase agreement expired in 1990 but SJ continues to obtain gas from Transco under an interim firm service rate schedule. SJ began taking deliveries of Columbia-supplied gas in January 1988 under a purchase agreement that expires in 2009. SJ utilizes underground gas storage services to supplement its winter season gas supplies. SJ also relies upon the use of liquefied natural gas and liquefied petroleum gas to meet peak season demand. (See Appendix: South Jersey Gas Company Gas Purchases.)

In 1990, SJ purchased approximately 16,300 Mcf of gas from its affiliate, South Jersey Exploration Company. This gas was produced in Texas and transported to New Jersey by Transco. However, effective April 1, 1990, SJ ceased purchasing gas from SJ Exploration, which is now an inactive company. In 1989, SJ purchased 26,282,654 Mcf of natural gas directly from producers and gas marketers for transportation to its service territory. This gas represented 59 percent of its total gas supply.

Price and Market Share

In 1990, New Jersey's residential gas market share was 46 percent of total consumption, whereas the U.S. residential market was only 23 percent. (See Appendix: Natural Gas Consumption in New Jersey and Natural Gas Consumption in the United States.) In contrast, the industrial sector represented the largest market for gas in the United States with a 45 percent share, while it accounted for a much smaller share—14 percent—in New Jersey. These differences result primarily from differences in price. In 1990, the delivered price of natural gas in New Jersey ranged from 10 percent to 38 percent higher than the national average in all consuming sectors except electric utilities. (See Appendix: Comparison of Natural Gas Prices).

Because New Jersey obtains its gas by way of interstate pipelines and 93 percent of the supply comes from the Gulf Coast, New Jersey is literally at the end of the pipeline and pays higher transportation costs than most states. Another factor in the higher cost of natural gas in New Jersey is the state's Gross Receipts and Franchise Tax (GR&FT) assessed at approximately 12.5 percent of utility revenues—a rate about 5 percent higher than the national average. Legislation adopted in June 1991 (P.L. 1991 c. 184) revised the tax structure as it applies to electric and gas public utilities. The new law establishes unit taxes for electricity and natural gas sales.

The average domestic wellhead price of natural gas rose dramatically until 1984. It dropped significantly in 1986 and 1987 and held at that level through 1989. Retail prices in New Jersey followed a similar pattern. (See Appendix: Domestic Wellhead Price vs. New Jersey All Sector Average Price.)

New Jersey's industrial sector accounted for about 14 percent of gas consumption in 1990. About half of this amount was consumed by interruptible industrial customers—those with dual fuel capability who can switch from gas to fuel oil. The extent to which fuel switching will occur depends upon the price of natural gas compared to oil. Since interruptible gas has averaged about 10 percent less in price than fuel oil in recent years, these customers have used gas except on the coldest days when their supply was interrupted by the LDC or the interstate pipeline.

New Jersey LDCs file monthly parity tariffs with the BRC for natural gas sold to industrial and commercial customers with alternative fuel capabilities. These tariffs are based on the competitive price of fuel oil or propane and establish a parity price for natural gas. In general, an LDC

can vary the price of gas to this class of customers within a range of 90 to 110 percent of the parity price. However, an LDC may never charge less than its *floor price* which is effectively the LDC's cost of acquiring the gas plus applicable taxes and a margin of one cent per hundred cubic feet or 10 cents per Mcf. Parity pricing and flexible tariffs enable an LDC to price competitively and thereby retain customers which, in turn, helps to spread the cost of the system resulting in lower rates to all customer classes.

Regulatory Overview

Federal Energy Regulatory Commission (FERC)

The 1938 Natural Gas Act (NGA), regulates wholesale transactions and transportation of natural gas in interstate commerce. This law is the basis for FERC to regulate interstate pipelines by authorizing construction and operation of their facilities and by setting rates for transportation and sale of gas. Therefore, any interstate pipeline desiring to build facilities, transport natural gas, or sell gas for resale must first seek and obtain prior approval from FERC.⁷

Various regulatory actions have spurred the development of a more market-oriented natural gas industry. The most significant of these have been FERC Order 380, Order 436 (later replaced by Order 500) and Order 451. The collective thrust of these Orders is to treat natural gas as a commodity so that competition will increase among natural gas suppliers and between natural gas and alternative fuels. A wider range of natural gas supply and transportation services has become available to meet customer needs.

The phased decontrol of the wellhead price of *new* natural gas prices has been implemented in accordance with the Natural Gas Policy Act of 1978 (NGPA). Under the NGPA most new gas supplies (generally those produced from wells drilled after April 20, 1977) were decontrolled on January 1, 1985. In spite of the fears of some analysts, gas prices did not increase following decontrol, but, in fact, declined.⁸

FERC Order 380

In May of 1984, FERC issued Order 380 that prohibited the recovery of non-incurred variable costs. This meant that LDCs were no longer liable for the variable costs on gas volumes not taken.

FERC Order 436

On October 9, 1985 FERC issued Order 436 covering take-or-pay buyouts, transportation policy, and expedited certification of new facilities.

Take-Or-Pay Policy: The take-or-pay provision of long-term contracts between pipelines and producers requires that pipelines pay for contracted volumes of gas, even if they have no need for that gas. Recovery of lump sum payments made to producers to modify existing take-or-pay obligations will be considered by FERC in pipeline company rate cases.

Transportation Policy: A pipeline company can provide self-implementing (that is, without prior FERC ap-

proval) transportation service only if it does so on a non-discriminatory basis for all shippers, and agrees to allow all of its existing firm sales customers either to reduce their purchase obligations on a five-year schedule of 15 percent in years one and two, an additional 20 percent in year three, and an additional 25 percent in each of years four and five, or to convert that amount to transportation service.

Transportation rate guidelines require volumetric rates (a flat charge per unit transported) that reflect variations in cost due to distance and season of use.

FERC's policy is to allocate variable pipeline transportation capacity on a first-come, first-served basis. However, priority for firm transportation is effectively given to existing customers via conversion rights and remains unavailable for new customers. New customers may also find it difficult to access interruptible transportation. FERC must decide what restrictions on open access capacity are acceptable.

Optional Expedited Certificates: FERC will give expedited treatment to proposals for pipeline facilities to provide new services if the sponsor is willing to accept the full risk of the project (i.e., the cost of the project cannot be shifted to nonparticipating customers at any time). If the proposal is for providing transportation service, the applicant must agree to the open transportation policy. Where a bypass situation is involved, parties adversely affected have a right to challenge the application but carry the burden of proof.

The pipeline companies saw Order 436 as pressuring them to relinquish their merchant function and become only transporters, effectively reducing their ability to plan and control how their systems are used.

On June 23, 1987, the District of Columbia Circuit Court of Appeals issued its decision on an appeal of Order 436. The court vacated the order, indicating that the various parts of Order 436 are interdependent and that FERC did not adequately consider the effect of contract reduction/conversions on the ability of pipelines to recover take-or-pay obligations. The court upheld specific aspects of the order, including the open access conditions for transportation, the rate requirements, and the optional expedited certificates. The court found that FERC justified contract conversions to transportation but not contract reductions. The court instructed FERC to reconsider the option of conditioning producer access to nondiscriminatory transportation for a producer providing take-or-pay relief.

FERC Order 500

On August 7, 1987 FERC issued Order 500 as an interim rule, to correct the problems identified by the Court of Appeals when it vacated Order 436. Order 500 readopts the regulations originally formulated by Order 436 and adds the following:

- (1) Producers must offer to credit gas transported by a pipeline against that pipeline's take-or-pay liability.
- (2) A pass-through mechanism provides for equitable sharing between pipelines and their customers of the

cost of settling already accrued take-or-pay obligations.

(3) Principles are adopted on which pipelines may base future gas supply charges.

(4) Contract Demand (CD) Adjustments: The objectives of the CD reduction right granted in Order 436 remain valid, but now FERC cannot justify this option on a generic basis. FERC believes that in the short-term the goals it hoped to accomplish with this option may largely be achieved through other means.

On October 16, 1989, a federal appeals court held that Order 500 does not comply with the court mandate issued in the FERC Order 436 case. As a result, the court retained jurisdiction over the matter and ordered FERC to issue a final rule by mid-December that remedies the problems the court found.

A major aspect of the court's ruling in the Order 500 case, *A.G.A. v. FERC*, was its decision to vacate the "sunset" provision. This provision set March 31, 1989, as the deadline by which pipelines could file to recover take-or-pay settlement expenses under the cost-sharing mechanism established in an Order 500 policy statement. The policy allowed a pipeline to recover between 25 percent and 50 percent of its settlement expenses through a fixed charge to its customers if it agreed to absorb a like amount.

In December of 1989, FERC issued Order 500-H that contains a new sunset date of December 31, 1990 for cross-crediting of transportation gas and for equitable sharing of take-or-pay costs.

FERC Order 451

The NGPA had established 16 categories of old gas with price ceilings ranging from about \$0.23/Mcf to \$2.57/Mcf. According to the federal Department of Energy (DOE), that pricing system, which was based on contract vintage, distorted price signals in natural gas markets, raised consumer prices above market clearing levels, and inhibited efficient production of least-cost supplies.⁹

On June 6, 1986 FERC issued Order 451, which eliminated old gas price vintaging and replaced it with a single new ceiling price of \$2.57 per Mcf for all vintages of old gas. The \$2.57 price was effective June 1986 and was subject to an inflation factor adjustment for each month thereafter. Order 451 also provides for a "good faith negotiation process" by which a higher price, up to the new maximum lawful price, may be collected by producers from purchasers under certain eligible contracts for old gas. Order 451 was ruled invalid in a split decision by the 5th U.S. Circuit Court of Appeals in September 1989. FERC appealed this decision to the Supreme Court and, in January of 1991, the U.S. Supreme Court upheld Order 451 by reversing the 5th Circuit Court.

Marketing Affiliates

In November, 1986 FERC initiated an inquiry into whether pipeline marketing affiliates have an unfair competitive advantage in acquiring and using the pipeline's transportation services. FERC also established an internal task force and procedure for dealing with complaints of

discriminatory and anticompetitive practices by pipelines and their affiliates.

Full implementation of the spirit of the new federal policies, including participation by all major pipeline companies in the open transportation program, will create many new choices and opportunities for LDCs and their customers. Such fundamental changes will offer more choices for LDC purchasing and marketing strategies and state regulatory policies. Planning to meet the needs of a market that can exercise its own supply options will become more difficult.

In New Jersey, the Board of Regulatory Commissioners has authority over transactions between LDCs and their affiliates to assure that all transactions occur at arm's length. As the natural gas utilities set up marketing affiliates, the BRC has to assure that the utility is not giving its affiliate an unfair advantage or taking actions to the detriment of its core customers.

Board of Regulatory Commissioners (BRC)

In New Jersey the state BRC evaluates the LDCs' operating and capital requirements and sets a level of revenue that will enable an LDC to provide safe and reliable service. The BRC is responsible for setting rates and determining how the additional required revenues should be allocated to each class of customer. The BRC also reviews and analyzes future gas costs through the Levelized Gas Adjustment Charge process, reviews and approves utility demand-side management and conservation program plans and participates in and develops positions on gas matters before the FERC.

Environmental Considerations

In January 1989 the U. S. Environmental Protection Agency (USEPA) set a deadline of October 1991 for New Jersey to devise a new strategy for bringing the state into compliance with national air quality standards for ozone.¹⁰ The Clean Air Act Amendments of 1990 identify new deadlines and a series of measures New Jersey must take to attain national air quality standards for ozone and carbon monoxide.

The combustion of natural gas generally produces far lower emissions of pollution that cause ozone than the combustion of other fossil fuels. In fact, natural gas offers the opportunity to reduce simultaneously emissions of all of the major contributors to ozone formation—nitrogen oxides, reactive hydrocarbons, and carbon monoxide. The two largest sources of hydrocarbon emissions are transportation and industrial processes, which contribute about equal quantities of pollution. Carbon monoxide is the second most pervasive urban air pollutant. Vehicles are the source of over two-thirds of carbon emissions and a substantial amount of nitrogen oxide emissions.¹¹

Therefore, reducing the use of gasoline-powered vehicles by switching to alternative fuels, such as methanol or natural gas, can significantly improve air quality. (See Chapter 13, Energy Use in Transportation and Chapter 19, Energy Efficiency and the Environment.)

Sources of Supply and Reserves

The contiguous 48 states supply about 93 percent of the natural gas consumed in the United States. Canada supplies the remainder. In 1989, Canada exported about 1.3 Tcf to the United States. The most prolific United States production area is the Gulf Coast—onshore and offshore Texas and Louisiana. In 1989 these two states produced about 11.3 trillion cubic feet (Tcf) or 62 percent of total United States marketed production of 18 Tcf.¹²

Proved reserves of dry natural gas in the contiguous 48 states have declined from 169 Tcf in 1979 to 158 Tcf at year-end 1989. Total U.S. proved reserves (which include Alaska) stand at 167 Tcf. The EIA defines *proved reserves* as those volumes of gas that geological and engineering data demonstrate to be recoverable from known reservoirs under existing economic and operating conditions. Initial estimates are based upon exploratory wells and are preliminary judgments. As more wells are drilled and production data become available, proved reserve estimates are revised upward or downward. Petroleum engineering and geological judgment are required in estimating reserves. Therefore, the results are approximations affected by subjective judgment rather than precise measurements.¹³

At current consumption levels the U.S. has about nine years of reserve gas. However, the introduction of unconventional gas recovery techniques is expected to increase U.S. production.¹⁴

On November 1, 1986, the Canadian National Energy Board (NEB) deregulated gas and replaced its system of prior approval of specific prices with quarterly monitoring of domestic and export prices. However, the price for exported gas cannot be less than the price charged to Canadians for similar service in the area adjacent to the export point.¹⁵

Canadian natural gas reserves are estimated at 97 Tcf for 1989. Of this amount, 67 Tcf is in conventional areas, while the remainder is located in frontier areas. This reserve base is large relative to Canada's domestic consumption of approximately 2.1 Tcf/yr—a 32 year reserve, without the frontier gas.¹⁶

Canadian imports offer New Jersey an opportunity both to increase and to diversify its supply of natural gas with several advantages over Gulf Coast supplies. Canada, with little demand in its eastern provinces for the gas, has expressed an interest in exporting large volumes to the Northeast on a long-term basis. The price of the gas will reflect market conditions and will be competitive with alternative fuel sources.

Pipeline Projects to Increase Supplies to the Northeast

Many gas utilities in the Northeast are experiencing increases in demand. In response to this need, 72 proposals for expanding pipeline capacity were filed with FERC, mostly in FERC's *open season* from July 1987 to January 15, 1988. These proceedings were concluded by settlement in November of 1989.

Niagara Import Point (NIP) project, a Northeast Settlement project, will make almost 16 Bcf available to New Jersey upon its completion. Compared to New Jersey's 1989 annual consumption of 414 Bcf, this project represents a supply increase of 4 percent. The project started flowing gas in November of 1990.

In April 1989 FERC approved an order declaring that the ANR, Champlain, and Iroquois pipeline projects are discrete, noncompetitive filings so that each project could obtain financing and permits and begin construction. The Champlain pipeline is not likely to be built in the near future because of a lack of potential customers.

Iroquois pipeline received FERC approval in November of 1990 and anticipates being able to complete construction and start flowing gas by November 1991. Full operation of the system is expected by early 1992. Once completed, Iroquois will supply gas by pipeline displacement to two New Jersey LDCs: NJN and PSE&G. The total amount of additional natural gas available for these LDCs will be about 20 Bcf annually, which represents a supply increase of about 5 percent for New Jersey.

Least-Cost Planning Strategies for LDCs

Least-cost planning is the integration of supply-side and demand-side options into a resource plan that provides adequate and reliable service at the lowest possible price to a utility's customers. A successful plan would conserve energy, create opportunities for customers to reduce their gas bills, maximize the utilities' planning flexibility, and curtail their need for capital expenditures.

Least-cost gas service balances supply-side planning with demand-side management options. Gas purchasing plans will seek to achieve the lowest cost mix of short-term and long-term supplies. This includes alternatives such as gas storage, seasonal purchases, and utilizing local peaking supplies (e.g., liquefied natural gas). These supply-side efforts can then be compared to the savings achievable from demand-side management efforts. Such measures include conservation and load balancing.

Traditionally, gas utility supply planning has consisted primarily of matching load requirements with the right kind of gas purchase strategies. An integrated least-cost strategy, on the other hand, evaluates alternative ways for meeting these load requirements. The costs of building and financing new gas supply pipelines and distribution and transmission systems are ultimately borne by the utilities' customers. These costs can be lowered by reducing demand through conservation measures. Demand-side management and supply-side planning must therefore aim to reduce the LDCs' revenue requirements by selecting the least expensive gas purchase plans consistent with reliable supplies for firm customers and reducing the need for capital expenditures.

To determine if the policy implemented by an LDC is least-cost, planning models as well as managerial judgment can be developed that evaluate demand-side and

supply-side options simultaneously and indicate which approach minimizes the present value of revenue requirements.

Issues Affecting Supply Planning

Many industrial customers who use gas to generate electricity and operate manufacturing processes have dual fuel capability that enables them to either switch to alternative fuels or take advantage of the spot gas market to meet their energy needs. Residential and commercial customers generally do not have this option.

The LDC must secure supplies that are sufficient to serve its firm customers while providing a price structure that is attractive to large industrial users who frequently are interruptible customers. Interruptible customers contribute to the cost of operating the LDC network and help to reduce costs to firm customers.

The starting point for the effective use of energy is the price of the commodity. Natural gas utility pricing and any flexible pricing provisions should recognize the fixed and variable pipeline and local system cost of providing service. No utility should have an approach that attempts to sell gas to any user without regard to its actual cost. Economic development in the State is best enhanced with cost based pricing to all sectors of the economy, be they residential, commercial, electric generating and cogeneration or industrial customers.

The tariffs of the natural gas utilities include consideration of cost of service principles to promote conservation and cost-effective use of energy. The use of declining block tariffs is under constant review.

Long Term Supplies and Spot Purchases

To moderate the uncertainty of spot gas supply, LDCs have long-term pipeline supply contracts. Some LDCs also purchase significant quantities of gas in the spot market where gas is sold for delivery "on the spot" or soon after purchase. In the short run spot gas may serve as a cheap source of supply, but it cannot provide supply security. Specifically, spot gas often is not available on the coldest days because most interstate pipeline capacity is required to satisfy firm service demands. Spot gas supply and cost fluctuate depending on market conditions—especially the price of oil.

These contracts had been the predominant source of gas for LDCs because of the efficiency and reliability they provided. Most long-term contracts now contain provisions for periodic price adjustments based on market conditions. These contracts may contain gas inventory charges that protect pipelines when certain minimum levels of gas are not purchased by their customers. In the current partially deregulated market, supply security may increasingly be dependent on the willingness of the LDC to pay the market price for gas rather than on the use of long-term supply contracts. Though there is a lag between exploration for gas reserves and delivery to the marketplace, in the short run higher market prices may induce higher rates of production from existing wells and therefore increase sup-

plies. With market-priced gas, the need to depend on long-term contracting to ensure security of supplies may be reduced.

Capacity Brokering

LDCs have excess capacity, *i.e.*, capacity not needed in the off-peak season, reserved for them on interstate pipelines. FERC is considering giving LDCs and other holders of firm pipeline capacity the right to broker that capacity to other end users. LDCs should aggressively pursue capacity brokering to bring in additional income to reduce their overall cost of operation. In the restructure of the gas market where producers now sell directly to end-users and no longer need to sell to pipelines, the long-term contracts between LDCs and producers have market-based pricing terms.

The Levelized Gas Adjustment Charge

The Levelized Gas Adjustment Charge (LGAC) allows an LDC to fully pass on the commodity cost of gas to the ratepayer. This raises some questions: (1) Are LDCs slow to switch supply sources and capacity to avoid the costs of acquiring new interconnection? (2) Could an LDC overspend on input costs covered by an LGAC to minimize those costs not covered? Any such cost not covered by the LGAC can be recovered only after a rate proceeding, while LGAC costs are recovered on a yearly basis.

In traditional test-year ratemaking, the gas utility would bear the full risk of actual gas service costs being different from costs based on forecasted demand. This condition may have induced the utility in the past to minimize risk by contracting for long-term, fixed-price gas supply. If all gas costs are passed on to customers through the LGAC mechanism, the utility may lack the incentive to seek the cheapest gas. The BRC is aware of these concerns and reviews the LDCs' gas costs in the LGAC process.

Demand Side Measures

The demand-side component of natural gas least-cost planning includes increasing end-use efficiencies to reduce gas demand through conservation and marketing additional off-peak gas services to improve LDC load factors. Greater end-use efficiency would enable an LDC to satisfy more end usage with a fixed level of capacity, thereby avoiding capital expenditures. Increased off-peak sales would enable LDCs to better utilize existing capacity and spread fixed costs over greater volume sales thus reducing the average unit cost of gas to customers.

Conservation

Conservation is a source of energy that will allow utility customers to meet end use at a lower cost and greater environmental acceptability. In a 1982 decision and order, the BPU directed each gas and electric utility under its authority to develop comprehensive conservation, cogeneration and load management plans. Resultant utility conservation efforts have aimed to increase customer awareness of energy-efficient options and provide incentives for the installation of energy-efficient equipment through a variety of home energy audit, appliance rebate,

subsidized loan and direct investment programs. (See Chapters 11, 12 and 14.) If they are effectively designed, administered and promoted, such programs can motivate consumers to take specific actions that will cause measurable reductions in energy use. In June and December of 1990, the Board conducted public hearings to discuss a proposed rulemaking that would allow utilities to profit on cost-effective conservation efforts. Independent contractors and equipment suppliers will be given an opportunity to compete for demand-side management (DSM) business. On September 25, 1991, the Board adopted new regulations that promote cost-effective investment by utilities in DSM initiatives. This is accomplished by allowing utilities to earn financial returns on conservation investments comparable to returns on utility-owned supply-side projects. Utilities must submit formal DSM plans to the Board for review within 90 days of the rules' publication in the *New Jersey Register* in November, 1991.

Some LDCs offer service contracts for repair of residential furnaces and hot water heaters. Each LDC must present data to the Board in the context of a rate case to demonstrate that the price for such service contracts is cost-based and is not subsidized by the regulated portion of its business. Additionally, the companies provide update information on a regular basis. The Board is now in the process of re-examining this issue as a result of questions raised at energy master plan public hearings. A related issue is that some LDCs sell and install gas furnaces, hot water heaters and other gas appliances. This business must not be subsidized by the utility or regulated side of their business. LDCs must demonstrate that their appliance sales and service business is not subsidized by ratepayers. The Board initiated a policy review in December of 1990 in support of the then-Board President's view that utilities should be prohibited from selling and installing appliances. The Attorney General advised the Board that, under existing law, it does not have the jurisdiction to prohibit such activity.

A key area where the LDC can improve its ability to meet the demands of its customers at the lowest cost and improve the state's economic attractiveness is to play an active role in promoting efficiency before buildings are constructed. Conservation programs can provide incentives for builders to install energy-efficient appliances and other energy-efficient measures in new construction.

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 served by energy-efficient buildings which make movement into New Jersey by business and industry all the more attractive.

Expanding Gas Markets: Cogeneration, Gas Air Conditioning, Unbundled Services

Cogeneration provides an avenue for LDCs to lower unit costs of providing gas service. Increased use of natural gas for cogeneration benefits an LDC's other gas customers directly by spreading the fixed costs of the gas system over greater sales volumes. In addition, affordable supplies of

natural gas for cogeneration benefit the state by reducing overall energy costs for industry in general, thereby creating a better economic climate. Cogeneration, both for self-consumption and for resale to electric utilities, helps New Jersey electric ratepayers by providing a more competitive environment for the production of electricity. Cogeneration may also lead to the elimination or reduction of new, expensive capacity that regulated electric companies build to serve their customers.

A potential market also exists in the commercial sector for gas air conditioning. Substantial markets for gas air conditioning may exist in the casino industry, the hotel industry and other commercial enterprises. The growth of office automation and use of computers has created an increased cooling load to which gas air conditioning can be applied. Gas cooling also may be marketable to super-markets for use in refrigeration. The growth of gas air conditioning can reduce the peak load of electric utilities in New Jersey, delay or reduce the need for capital addition to the state's electric systems, and fill the valley in LDCs' load profiles. (See Chapters 10 and 11.)

Unbundling is the provision of distinct types of utility service, e.g., transportation, storage, interruptible service and peaking service, either individually or in combination. Unbundling of services provided by LDCs could forestall a decrease in demand for their services as oil competes with natural gas as an alternative fuel, as pipeline companies compete with gas utilities to supply gas, and as producers, marketers, and brokers compete with the utilities to sell natural gas.

In addition, the unbundling of services enhances the ability of industrial customers, and specifically non-utility cogenerators, to secure their own fuel sources and to receive services that supplement transportation, such as peaking, storage, and standby service. Peaking service provides gas to sales customers who know with certainty that they will need supplemental gas service in the winter; storage service meets the needs of customers who want to store their transport gas on the utility's system. Standby service makes gas available to customers with unanticipated needs. New Jersey's LDCs are currently in the process of providing unbundled services to their larger customers. In the next few years, this will become more important.

LDC Transportation Tariffs

The price a customer pays for gas purchased from New Jersey LDCs is based on the LDCs' gas purchase and distribution plant costs. Transportation tariffs arose as a result of FERC provisions for direct sales of gas from producers to end users. Pipelines and LDCs contract to move the gas for the final consumer. How much should this consumer, usually an industrial user, pay for the use of the LDC's distribution network? The higher the contribution, the higher the price of gas becomes for New Jersey's industrial consumers. The lower the contribution, the larger the proportional cost the local distribution system becomes for firm customers.

Outlook

The EIA expects gas supplies to be relatively abundant at prices that compare favorably with competing fuels, leading to increased consumption. According to the EIA, 1990 consumption in the U.S. was 18.5 Tcf. The EIA estimates consumption will rise to about 21.6 Tcf in the year 2000. Wellhead prices averaged \$1.77 per Mcf in 1990 and are expected to rise to about \$2.61 by 2000 as an increasing segment of supply is produced from higher cost sources.¹⁷

Most of this rise in consumption is expected to come from increased use by electric utilities, when low capital cost combined-cycle units burning natural gas are introduced. Consumption in the industrial sector is forecasted to reach 7.5 Tcf by the end of the century, due mainly to higher industrial output and an increase in cogeneration. In the residential and commercial sectors, consumption through the year 2000 should also increase with demand somewhat dampened by the greater efficiency of new gas heaters and ongoing upgrades of older gas furnaces.¹⁸

The outlook for natural gas markets reflects heightened competition among gas suppliers, and also between them and the suppliers of alternative fuels. By January of 1993, all wellhead gas will be free of price controls, and FERC policy is facilitating open access to interstate pipelines. Today's market is also characterized increasingly by spot sales and supply agreements in which prices are flexible. As gas becomes more competitive, its price should track the energy-equivalent prices for alternative fuels.

The level of natural gas proved reserves for the entire United States including Alaska increases from about 167 Tcf at year-end 1989 to about 175 Tcf by 2000. This is due mostly to strong increases in wellhead prices, which are estimated to rise about 15 percent annually.¹⁹

By the year 2000, the EIA estimates that U.S. annual consumption of natural gas will exceed domestic production by an estimated 2 Tcf. This difference will probably be made up from an increase in net imports, mainly from Canada, facilitated by the U.S. - Canada Free Trade Agreement. Liquefied natural gas will also serve as a major source of imports.

Canadian gas exported to the U.S. is produced mainly in Alberta. Total Canadian reserves are about 97 Tcf. This, however, includes the Sable Island field in Nova Scotia, which is estimated to contain 3 Tcf of natural gas. However, this off-shore source, which would require an undersea pipeline, is too expensive to bring to market at current price levels.²⁰

Findings

- Natural gas supplies, which are from domestic or Canadian sources, are secure compared to crude oil and petroleum product supplies of which more than 50 percent are imported.
- The combustion of natural gas produces significantly smaller quantities of polluting gases compared to petroleum products, thereby helping to improve New

Jersey's air quality, which currently is in violation of federal standards.

- New Jersey and the other northeastern states need increasing supplies of natural gas.
- Existing pipelines flowing gas to the region operate at capacity during portions of the winter peak season, presenting issues of deliverability.
- Profound regulatory changes by FERC have restructured traditional functions and created uncertainties in natural gas planning among producers, pipelines, LDCs, and end-users.
- Current New Jersey LDC strategies need to more fully incorporate conservation into the planning process.
- Prior regulations offered utilities no profit incentive to reduce demand through conservation programs. To encourage cost-effective utility-sponsored programs, the BRC adopted new regulations that will allow utilities to benefit from cost-effective conservation measures that result in measurable energy savings.
- Opportunities exist for vehicle fleets fueled with natural gas. (See Chapter 13.)

Policy

- New Jersey should encourage competition among natural gas suppliers and between natural gas and other fuels.
- The BRC supports the completion of new pipeline projects to the northeast approved by FERC.
- The BRC will require each gas LDC to demonstrate that it provides least-cost gas service without jeopardizing a secure supply for firm customers.
- LDCs must employ a planning model that integrates supply-side and demand-side options.
- The BRC shall implement the new regulations that reward utilities for promoting cost-effective conservation measures.
- The BRC should set transportation tariffs that have the flexibility to meet the rapid changes in the gas market. They must be low enough to allow natural gas to compete with oil for industrial consumers, while enabling captive residential consumers to reap some of the benefits of increased competition. These tariffs should provide appropriate incentives to the LDCs. The advantages of price cuts, the spot market, and conservation alternatives shall be made available to as many consumers as possible.

Implementation

- New Jersey will continue to promote conservation, including energy subcode improvements for new construction and weatherization programs in existing homes. Specifically, since almost three-quarters of all natural gas consumed in New Jersey is used for residential and commercial buildings heating applications, replacement of older gas furnaces with new energy-

efficient units where cost-effective offers a significant savings opportunity. (See Chapters 11 and 12.)

- The BRC will provide utilities with adequate profit incentives to aggressively pursue conservation. Further, the Board will work to develop partnerships with independent contractors, in recognition of the fact that New Jersey will achieve its energy conservation goals only with the active involvement of the private sector.
- The BRC will continue to work with utilities to enhance the least-cost planning process and encourage a mix of supply and demand side options that best serves the utility and its ratepayers.

NOTES

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Chapter 5

Coal

Coal, America's most abundant fossil fuel and once the nation's leading energy source (in the late 19th and early 20th centuries) supplied less than one fifth of total U.S. energy consumption by 1971.¹ (See Figure 5-1 and Appendix: Coal Consumption in the United States.)

The availability of cheap and convenient oil and natural gas shortly after World War II brought a dramatic decline in coal use in key industries. The relaxation of import controls on oil in the 1950s allowed heavy fuel oil to be used in boilers. These controls were eventually abandoned altogether in early 1973. Stricter clean air standards, passed in the 1960s, tended to favor oil and natural gas over coal. Periodic labor strikes disrupted the flow of coal to the market, further undermining its position. Finally, by the end of the 1960s, large nuclear reactors came on line. All these factors combined to significantly reduce coal's importance in the nation's energy picture.

Federal legislation, regulations, and administrative orders attempted to enhance coal's position through the late 1970s. A concerted effort was made to encourage oil-burning electric generating plants to switch to coal, in order to relieve the nation's dependence on oil imports. A reversal of federal policy caused problems for the coal in-

dustry, as Washington encouraged the short-term use of natural gas, instead of coal, for electric power generation.

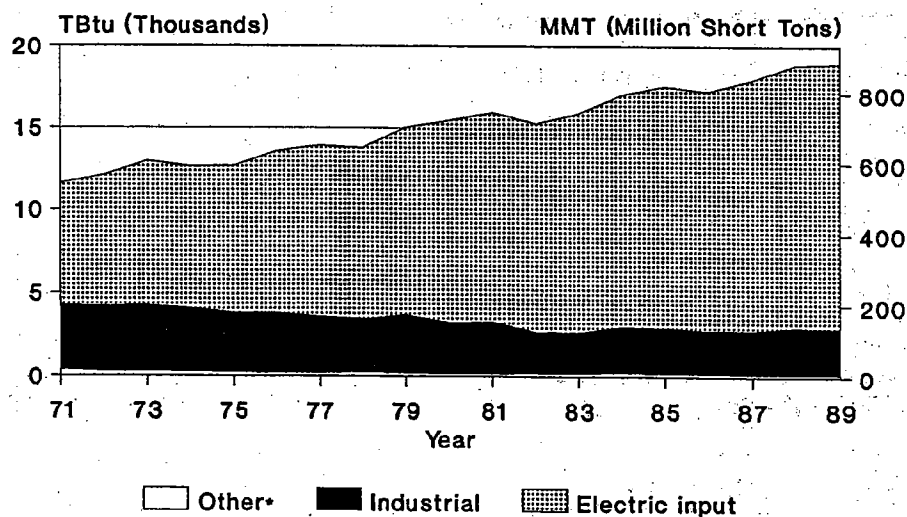
Supply

The United States produced nearly one billion short tons of coal in 1990, slightly less than China, the world's largest producer, and slightly more than the U.S.S.R., the third largest producer. The combined production of the three countries accounted for over half of total world production. The U.S. exports about one-tenth of the coal produced here.²

In terms of heat value, annual U.S. production equals about 21 quads (1 quad = 1,000 Tbtu). A recent estimate of reserves finds about 150,000 quads of economically recoverable coal worldwide. The U.S.S.R. leads the world in quantity of reserves—approximately 70,000 quads—an amount double that of the 35,000 quads in the U.S. and three times the amount present in China. These economically recoverable coal reserves are almost 200 times as great as those of natural gas or petroleum.³

FIGURE 5-1

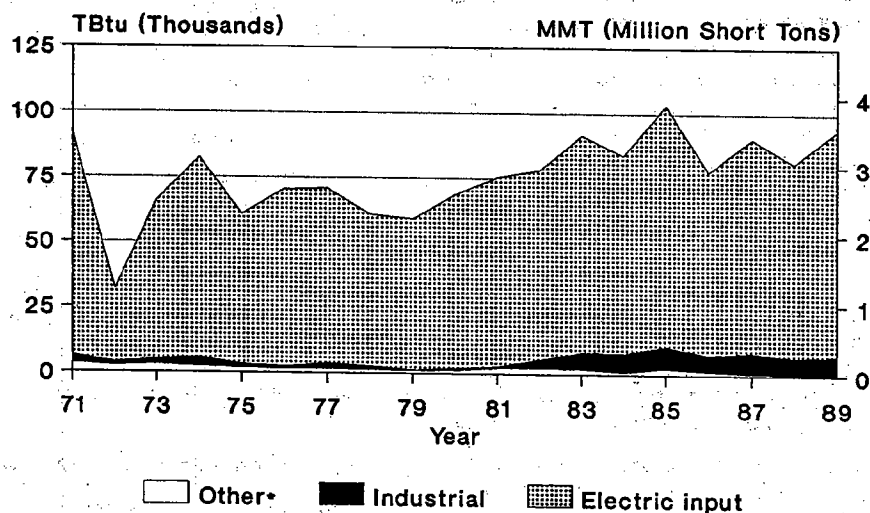
US Coal Consumption by Sector 1971-1989



Note: *Residential, commercial, and transportation consumption is minimal.
Source: EIA-0214(89), adjusted by DEPE.

FIGURE 5-2

NJ Coal Consumption by Sector 1971-1989



Note: *Residential, commercial, and transportation consumption is minimal.
Source: EIA-0214(89), adjusted by DEPE.

Price

The price of coal to electric utilities more than doubled between 1972 and 1982 when it reached a high of almost \$60/ton for in-state plants. By 1990, the price dropped back to below \$50/ton. Coal costs for New Jersey utility-owned minemouth plants—Keystone and Conemaugh—located in Pennsylvania were 50 percent lower than coal costs to in-state plants in the 1970s. Today, in-state plants pay approximately 29 percent more for coal. The price differential results, in part, from the expense of transporting coal from out-of-state mines to New Jersey plants and, in part, from the premium paid for low-sulfur content coal required under New Jersey's air quality regulations.

Coal's cost in 1982 was less than half the cost of natural gas or #6 residual fuel (based on equivalent energy value in dollars/MBtu) used to generate electricity in New Jersey plants. In 1990, coal's cost was approximately two-thirds that of natural gas or residual fuel.⁴

Consumption

New Jersey coal use, about 3 million short tons (MMT) in 1989, accounts for only 4 percent of in-state New Jersey energy consumption. However, when one includes coal used to generate electricity in other states for import to New Jersey, coal supplies about 10 percent of the state's energy.⁵ Electric utility use has risen from a low of 1.1 MMT in 1972 to nearly 3 MMT in recent years and ac-

counts for 90 percent of in-state coal use. Most of this is bituminous coal. Today, five in-state generating stations burn coal: Atlantic Electric's (AE) B.L. England plants in Beesley's Point and its Deepwater plant near the Delaware River; the City of Vineland's (Vinel) H.M. Down plant; Public Service Electric & Gas Company's (PSE&G) Hudson facility in Jersey City and its Mercer facility in Hamilton Township.⁶ PSE&G is the major coal user accounting for three-quarters of coal-fired generation.⁷

Industrial use has risen from a low of less than 20 thousand short tons (or 0.02 MMT) in 1980 to almost 300 short tons (0.3 MMT) since 1983—about 10 percent of in-state coal use.

Residential and commercial uses, each below 100 thousand short tons since 1970, dropped to about 10 thousand short tons each in 1988.⁸ (See Figure 5-2 and Appendix: Coal Consumption in New Jersey.) Coal was displaced for several reasons: fuel oil was cheap; storage and transportation options allowed fuel oil to be utilized easily; boilers were more easily maintained with fuel oil; and air pollutants were reduced. Virtually all of the coal consumed in these sectors is anthracite from eastern Pennsylvania.

Environmental Impacts of Coal Use

Coal combustion produces pollutants sulfur oxides (chiefly SO₂) and nitrogen oxides (generally referred to as NO_x). Utility boilers are significant NO_x and SO₂ sources

in New Jersey and elsewhere.⁹ Sulfur oxide emissions can be controlled through the use of low-sulfur coal, precombustion separation, and exhaust scrubbing. Low temperature of combustion controls nitrogen oxide emissions.

The state's air pollution regulations limit the sulfur content of coal used in New Jersey. PSE&G, the major consumer of coal in New Jersey, burns 1 percent sulfur coal; Atlantic Electric burns 3 percent sulfur coal; Vineland burns 1.5 percent sulfur coal. The anthracite coal, which makes up the remaining consumption, is generally less than 1 percent sulfur. Sulfur dioxide (SO₂) emissions from in-state electricity generation totaled almost 76,000 tons in 1985 and accounted for nearly half of New Jersey's total and double the next largest source, industrial fuel combustion. (See Chapter 19, Table 19-2.)

The long debate over the exact causes of and cures for acid rain and dry acid precipitation continues. The harmful ecological effects have become an international issue and have prompted programs to reduce emissions of sulfur and nitrous oxides that come from burning coal and other fossil fuels. (See Chapter 1, Energy and the Environment.)

Acid deposition is a major international concern and has continually been an issue between the United States and Canada. In January 1986, Special Envoys Drew Lewis (United States) and William Davis (Canada) issued a joint report on their efforts to assess the acid rain problem affecting the United States and Canada. Their report recognized acid rain as a serious environmental problem for both nations and acknowledged that only a limited number of potential avenues exist for achieving major reduction in acidic air emissions, all carrying high socioeconomic costs.

The White House announced on March 18, 1987, a three-point program to carry out the envoys' recommendations. The three steps included: (1) a request for \$2.5 billion, to be matched by industry, for Clean Coal Technology and Innovative Control Technology programs over the next five years; (2) an advisory panel to help the Secretary of Energy select innovative control technology projects for funding; and (3) a Presidential Task Force on Regulatory Relief to review federal and state economic regulatory programs.

In November of 1990, the President signed into law the Clear Air Act (CAA) Amendments of 1990. The CAA amendments require substantial reductions of acid deposition precursor emissions at fossil-fired power plants in the U.S. See Chapter 19, Energy and the Environment, for details.

In the long term (5-20 years) increased concern about greenhouse gases may limit utilization of coal; carbon dioxide, a major product of combustion, is increasing steadily in the atmosphere. Because CO₂ absorbs infrared radiation from the earth, its accumulation may cause global warming. The ratio of carbon to hydrogen is very high in coal (relative to petroleum and natural gas) and much more CO₂ per Btu of energy is produced from coal than from alternative fuels. (See Chapter 19, Table 19-1.)

Improved Combustion Technologies

The acid rain debate has encouraged research into technology engineered to reduce the environmental impacts of coal use. Public Law 98-473 established the Clean Coal Technology program within the USDOE in 1984. To date, USDOE has conducted three rounds of solicitations involving a total of \$1.5 billion. In Public Law 101-121, enacted on October 23, 1989, Congress provided \$1.2 billion for the final two rounds of the CCT program, \$600 million each for program cycles IV and V. The deadline for applications cycle IV funds was May, 1991.¹⁰

Currently proposed/funded improved combustion technologies—often referred to as *clean coal technologies*—and strategies utilize fluidized-bed combustion, in-duct and in-furnace sorbent injection, low-NO_x burners, coal conversion, selective catalytic reduction, flue-gas desulfurization, fuel reburning, and slagging combustion. Of these approaches, fluidized-bed boilers have proven successful in large-scale industrial use and are currently used in four utility demonstration projects ranging in size from 80 to 160 MW.¹¹

Fluidized-bed Combustion Technology

Fluidized-bed combustion is an alternative boiler technology. In the firebox of a conventional boiler, fuel burns on a grate or in midair. In a fluidized-bed combustor, the firebox is loaded with inert granular particles of sand, limestone, or ash. Air blown up through orifices in the floor of the firebox makes the particles into a fluidized bed, which glows like bubbling molten lava. The fuel charge may be less than 1 percent of the material in the bed. Even very low-quality fuel can be burned, such as low-grade coal, urban refuse, or even wet sludge, which could not be burned in conventional fireboxes.¹²

Because of their ability to capture SO₂ and their economic advantage in low-grade fuel usage, fluidized-bed combustors (FBCs) are making significant contributions to the U.S. industrial energy picture. During combustion, FBCs capture sulfur by forming calcium sulfate, a dry material that is easier to dispose of than wet scrubber sludge. In addition, because of lower combustion temperatures and *in situ* chemical reactions, nitrogen oxide formation is minimized.

The FBC method can produce usable energy from coal with reduced atmospheric pollution and acceptable costs. Sulfur oxides formed during conventional coal combustion contribute to an increasing environmental problem. Historically, these noxious compounds, (sulfur dioxide and sulfur trioxide), were discharged through the boiler stack to the atmosphere. In recent years, however, federal and state regulations require the control of these emissions to acceptable levels.

FBCs achieve this level of control by chemically capturing these compounds before they exit the boiler. Crushed limestone or dolomite is injected into the combustor along with the coal to be burned. As the coal is burned, the sulfur oxides combine with the calcium from the limestone or dolomite to form gypsum (calcium sulfate). As much as 90

percent of the sulfur present in the coal can be captured in this way. Thus, a bituminous coal containing 3 percent sulfur can be burned in an FBC with atmospheric emission of 0.6 pounds of SO₂ per million Btu, which is within the requirements of the EPA New Source Performance Standards (NSPS) for utility applications. This cleanup can be achieved without exhaust gas scrubbers. Similarly, FBCs have been demonstrated to operate with NO_x emissions below 0.6 pounds per million Btu, also within the NSPS for utility applications.

Fluidized bed combustors can be divided into atmospheric and pressurized types.

Atmospheric Fluidized-bed Combustion: There are two major types of atmospheric fluidized-bed combustion (AFBC) systems, bubbling-bed and circulating-bed systems. The bubbling bed consists of a boiler coupled to a combustion chamber that is modified to accommodate the fluidized bed.

The circulating-system fluidized-bed design goes a step further. This design actually induces solids to escape the combustion area and recycles them into the combustion chamber.

Pressurized Fluidized-bed Combustion: The pressurized fluidized-bed combustion (PFBC) system also contains in-bed boiler tubes to generate steam, which turns a turbine. In contrast to the AFBC, the combustion gases are at higher temperature and pressure (in excess of 10 atmospheres). The PFBC system uses those pressurized, high-temperature combustion gases not only to generate steam but to drive a gas turbine to generate additional power. The merger of a gas turbine with the steam turbine results in a combined cycle arrangement.

Combustion gases, cleaned by a series of high temperature dust separators (usually cyclones), drive the gas turbine. The turbine in turn drives both an air compressor (to pressurize combustion air for the fluidized bed) and a generator (to produce electric power). Gases exhausted from the gas turbine contain considerable heat, and this heat preheats feedwater for the steam-turbine cycle. The preheated feedwater is then sent to tubes within the fluidized bed where it evaporates to steam.

Typically, one-quarter of the electric generation in PFBC comes from the gas turbine, with the balance coming from the steam turbine. The combined-cycle feature of PFBC yields more efficient generation of electricity than with either an AFBC system or a conventional coal-fired unit.

PFBCs are inherently modular, so new capacity can be built in increments as demand grows; thus, they can reduce capital costs without the economic risks of building larger conventional coal-fired plants. Some manufacturers, architects, and engineers claim that the modular feature and the smaller size of the PFBC plants allow a 25 percent shorter construction period than for conventional coal-fired units.

Atmospheric fluidized-bed combustion systems are widely used. Of the two types of AFBCs, bubbling-bed systems are widely used in smaller plants; circulating systems

prevail in larger industrial applications, where they are more economical than bubbling-bed systems. The pressurized fluidized-bed system is complex to build and too costly for all but the largest companies.

In the past, utilities showed little interest in fluidized-bed systems, because the technology had not been demonstrated on a large (i.e., utility) scale. FBCs must compete with traditional combustors in the utilities' boiler market. However, this trend could change in the next five to ten years, as experience is gained from projects recently begun.

Of all the coal, oil, gas, and nuclear utility boilers in the United States, 18.5 percent are more than 30 years old and 10.6 percent are more than 40 years old. In view of this situation, FBC boilers could soon come into widespread use. The future for FBCs in the United States looks promising in the large industrial boiler sector, where FBCs currently account for 25 percent of its coal burning capacity, or about 20 million short tons of coal per year. In the small industrial boiler sector, however, FBCs are usually not as economically attractive.

Coal Gasification

Coal gasification, a technology used in three projects approved by USDOE and funded through the federal Clean Coal Technology program, is an option available for both retrofit and new power generation projects. The coal gasification process produces a fuel gas from coal using either an air-blown or oxygen-blown gasifier. The fuel gas is then used to power a turbine or produce steam in a boiler for production of electricity. By-products of the gasification process include salable sulfur and vitrified ash or slag which can be sold. The fuel can include sewage sludge and other organic wastes. The primary advantage of coal gasification versus conventional pulverized coal boilers with scrubbers stack emissions that exceed all new source performance standards. Gasification can provide 99 percent sulfur removal with pure sulfur as a marketable by-product as compared to 85-95 percent removal efficiency for a scrubber-equipped coal boiler.

High capital costs and operational uncertainties have been obstacles to coal gas commercialization; however, as the Clean Air Act increases the cost of new coal plants and the gasification technology matures, coal gasification may well become economically competitive for large power generation projects. PSE&G signed a power purchase agreement to buy power from a large coal gasification project—the Towner Project—and filed for Board approval of the agreement in April of 1991 (Docket No. EM91040844). The matter was under review by the Board of Regulatory Commissioners (BRC) at press time. Should natural gas increase in cost, gasified coal could replace it as the primary fuel in existing combined cycle facilities.

Outlook

The U.S. Energy Information Administration (EIA), in a January 1990 assessment, expected coal production to grow through the year 2000 when coal's share of U.S. energy production may exceed 33 percent—up from 31

percent in 1988. A sustained sharp rise in oil prices could force greater reliance on coal; however, environmental considerations and the strong Clean Air Act could slow a change to coal.¹³

The CAA amendment requirements to control acid rain will raise the cost of generating electricity from coal—particularly in the industrial Midwest, which is most dependent upon coal. However, clean coal technology that substantially mitigates the emissions problem could emerge as an economically attractive alternative to current generating technologies and could permit this country to rely more heavily on coal.

No new orders for nuclear plants are expected within the forecast horizon. Nevertheless, the additions to nuclear capacity that are now scheduled to come on line over the next five years are expected to reduce the share of coal in supplying baseload electricity during that time. Coal will continue to be a major supplier of baseload electricity demand. Atlantic Electric is under contract to purchase capacity and energy from two coal-fired cogeneration facilities in South Jersey—the Chambers and the Keystone projects. Atlantic Electric expects that these facilities will satisfy the utility's incremental power needs through the late 1990s. Jersey Central Power and Light is under contract to purchase 200 megawatts of power from the proposed Logan Energy/Mission Energy coal-fired independent power production facility. In addition, JCP&L has contracted to purchase an interest in the Phillips coal-fired generating station located near Pittsburg, Pennsylvania from Duquesne Power. JCP&L filed the agreement with the Board in February of 1991 (Docket No. EM91010067) and it was the subject of hearings before the BRC at press time.

As the planned additions to nuclear capacity end after 1995, coal's chief competition will begin to come from natural gas in combined-cycle units. Even though gas units are expected to provide the majority of new capacity in the post-1995 period, existing coal plants are expected to be utilized even more fully as demand for electricity increases to the year 2000.

Lack of growth in U.S. heavy industry (such as steel and automobile manufacturing) is expected to depress the growth rate for coal. Industrial demand for energy in general is likely to fall as energy-intensive industries move abroad and the domestic economy continues its transformation from one based on heavy manufacturing to one that is oriented more toward service and light industry. There seems to be no reason why residential and commercial demand for coal will not continue its slow decline.

The minemouth price of coal is expected to increase modestly at an annual rate of 1.4 percent until 2000. This increase contrasts with the sharp declines between 1980 and 1986, when excess production capacity caused real prices to drop at an annual rate of more than 5 percent. The prices of coal to end-users (especially electric utilities) are expected to climb somewhat more rapidly than minemouth price. End-use prices will increase primarily because of higher transportation costs, which are fueled in turn by higher world oil prices. Nevertheless, coal prices should rise less than those of any other major fuel through

2000, widening the cost advantage of coal over petroleum and natural gas, especially for electric utilities.

Findings

- Coal is in abundant supply in this country and offers a long-term means to maintain the state's fuel diversity.
- The cost of coal is competitive with other fuels and its use could increase at relatively low incremental cost if other fuels were unavailable.
- Coal use in New Jersey is primarily—90 percent—for electric generation, the remainder is used in industrial plants.
- New Jersey's coal-fired utility plants emit significant amounts of sulfur and nitrogen oxides that react in air to become components of acid deposition. New plants would have equipment to control emissions.
- Coal combustion produces greater quantities of CO₂ and ash per unit of energy than petroleum or natural gas combustion.
- Continued development of technology that reduces pollutant emissions from coal and will increase the state's ability to meet or exceed air quality standards.

Policy

- Coal use in New Jersey should continue but in an environmentally acceptable manner.
- New Jersey should support *clean coal technology* research and development.
- Coal should compete unhandicapped with other fuels, including natural gas. Once the public health and environmental costs of each fuel are fully internalized, the market should decide the relative values of the attributes of coal and natural gas. Evaluation of external costs is complicated and difficult to accomplish but necessary to enable market prices to reflect the true cost of any given fuel's use.
- The DEPE and the BRC should explore means to internalize, and thereby allocate to users, the environmental cost of producing electricity from coal. They should consider treating out-of-state generation on the same environmental terms as New Jersey generation.

Implementation

- The DEPE should develop an effective coal waste disposal program to enable continued coal use by the electric utilities.

NOTES

1. Energy Information Administration (EIA), *State Energy Data Report 1960-1989*, p. 23.
2. EIA, *Quarterly Coal Report*, DOE/EIA-0121 (91Q1), pp. 22 and 79.
3. Fulkerson, et. al. *Energy from Fossil Fuels*, *Scientific American*, September 1990, Table p. 130.

4. Annual Energy Outlook, DOE/EIA-0383, March 1991, p. 64.
5. EIA, *State Energy Data Report 1960-1989*, 1990, p. 214.
6. Mid-Atlantic Area Council (MAAC), *Bulk Power Supply Program*, 4/1/88, Section II-A.
7. DEPE, *New Jersey Monthly Energy Profile*, 12/90.
8. EIA, *State Energy Data Report*, EIA-0214 (89).
9. EIA, *Quarterly Coal Report*, October-December 1987, p. 5.
10. EIA, *Annual Outlook for U.S. Coal 1988*, September 1988, p. 22.
11. Jason Makansi, "Subsidies to Ensure Coal Option Under Future Control Scenarios," *Power*, (Dec. 1988), p. 23.
12. *Ibid.*, pp. 25-31.
13. EIA, *Annual Energy Outlook 1990*, January, 1990.

Chapter 6

Nuclear Power

Nuclear power supplies more than one-third of New Jersey's electricity. Four nuclear facilities generate electricity within state borders: Jersey Central Power and Light Company's (JCP&L) Oyster Creek facility; the two Salem Units No. 1 and No. 2 owned in part by Public Service Electric and Gas Company (PSE&G) and Atlantic Electric Company (AE); and the Hope Creek facility also owned in part by PSE&G and AE. In addition, New Jersey electric utilities have ownership interest in four other nuclear generating stations located in Pennsylvania. PSE&G and AE own shares of the two Peach Bottom Units No. 1 and No. 2. JCP&L owns one-quarter of the Three Mile Island (TMI) Unit No. 1 as well as a quarter of the Three Mile Island Unit No. 2 that no longer operates as a result of a March 1979 accident.¹

The seven nuclear generating units run on enriched uranium and provide approximately 4003 MW of maximum dependable capacity for New Jersey. Their electrical output satisfied 40 percent of statewide demand in 1990. Table 6-1 profiles the location, ownership and capacity and age of each unit.

The average age of baseload nuclear plants serving New Jersey is approximately 14 years, making these facilities relatively new compared to many baseload fossil fuel plants now in use. (Table 6-2 summarizes nuclear generating capacity as a percent of total capacity for the state's three electric facilities.) During the past two decades, utilities chose nuclear technology for virtually all baseload capacity plant additions; however, current societal concerns regarding nuclear power make the prospect of

TABLE 6-1
New Jersey Utility
Nuclear Facility Ownership

<u>Nuclear Facility</u>	<u>Location</u>	<u>Start-Up Date</u>	<u>Summer* Capacity (MW)</u>	<u>Percent NJ Utility Ownership</u>	<u>NJ Utility-Owned Capacity (MW)</u>
Oyster Creek	Lacey Township, NJ	1969	620	JCP&L - 100	620
Peach Bottom No. 2	York County, PA	1974	1,051	PSE&G - 42.49 AE - 7.51	447 79
Peach Bottom No. 3	York County, PA	1974	1,035	PSE&G - 42.49 AE - 7.51	440 78
Three Mile Island No. 1	Dauphin County, PA	1974	808	JCP&L - 25	202
Salem No. 1	Lower Alloways Township, NJ	1977	1,106	PSE&G - 42.59 AE - 7.41	471 82
Salem No. 2	Lower Alloways Township, NJ	1981	1,106	PSE&G - 42.59 AE - 7.41	471 82
Hope Creek	Lower Alloways Township, NJ	1986	1,031	PSE&G - 95 AE - 5	979 52
Total					4,003

Note: * Maximum dependable capacity as listed in "Licensed Operating Reactors," U.S. Nuclear Regulatory Commission, (NUREG-0020, Vol. 14, No. 1, January 1990).

Source: NUREG-0020 Vol. 14, No. 1, January 1990, and utility annual reports to DEPE. 1989 FERC Forms No. 1.

TABLE 6-2

New Jersey Utility Nuclear Capacity
Megawatt Capacity - 1990

<u>Utility</u>	<u>Total Capacity (MW)</u>	<u>Nuclear Capacity (MW)</u>	<u>Nuclear as a Percent of Total Capacity</u>
Atlantic Electric	2,089	373	18
Jersey Central Power & Light	4,285	822	19
Public Service Electric & Gas	10,118	2,808	28
PJM System	50,984	12,695	25

Source: MAAC Regional Reliability Council, 4/1/90, Tables IIA and IIB, and NUREG-0020 Vol. 14, No.1, January 1990.

adding additional nuclear generating capacity in the foreseeable future almost nonexistent. Safeguarding the public health and welfare against the possibility of an accidental release of radiation or more serious mishap is the most critical concern. Appropriate sites that can accommodate the large plants and that have adequate buffers from populated areas are difficult to find in New Jersey and the cost of installing required equipment and other safeguards necessary to protect the public health is extremely high.

Significant economic barriers stand in the way of any future nuclear generating additions in New Jersey. Presently, the cost of constructing a nuclear plant is prohibitive. Even taking into account its low fuel costs, it is unlikely that nuclear technology could compete with conventional fossil fuel or renewable energy technologies on an overall cost basis. More study is necessary to ascertain whether standardizing nuclear plant design could help control the cost of these facilities. Siting this type of facility is also extremely difficult.

Lack of an acceptable method to permanently dispose of spent nuclear fuel and other radioactive wastes in an environmentally acceptable manner further hampers use of this technology. Spent fuel is now stored on site; the siting and construction of any long-term permanent disposal facility is still uncertain. A New Jersey Low-Level Radioactive Waste Disposal Facility Siting Board has been established to site a facility to accommodate low-level nuclear waste.

As power plants approach the end of their useful lives, the monumental task of decommissioning the units has to be addressed. Plant decommissioning presents significant technical and financial challenges that must be met to maintain the safety of the state's residents and to control the cost of these activities to New Jersey's electric ratepayers. Present utility base rates do reflect funding of mandated decommissioning accounts to ensure that monies will be available to complete these activities; however, many uncertainties still exist. In light of these uncertain-

ties, the Board of Regulatory Commissioners (BRC) has approved for publication in the November 4, 1991 *New Jersey Register* a proposed rule that would require the filing of periodic decommissioning cost updates by the state's electric utilities to ensure that the level of funding in rates remains consistent with timely cost estimates.

These barriers and public concerns need to be addressed before nuclear generation can again be considered a viable option for meeting new demands for power in New Jersey. However, if costs associated with this technology can be reduced and if health, safety and environmental concerns can be satisfied, use of nuclear power could provide an alternative to fossil fuel combustion and its negative environmental effects.

Findings

- Uranium-fueled nuclear reactors supply more than one-third of New Jersey's electricity. Four nuclear facilities generate electricity within state borders and New Jersey electric utilities have ownership interest in four other nuclear generating stations located in Pennsylvania.
- Significant barriers stand in the way of any future nuclear generating additions in New Jersey. It is unlikely that nuclear technology could compete with conventional fossil fuel or renewable energy technologies on an overall cost basis. Siting this type of facility is also extremely difficult.
- Cost, siting, and waste disposal technology barriers—as well as public concerns—need to be addressed before nuclear generation can again be considered a viable option for meeting new demands for power in New Jersey. However, if costs associated with this technology can be reduced and if health, safety and environmental concerns can be satisfied, use of nuclear power could provide an alternative to fossil fuel combustion and its negative environmental effects.

- Many variables will affect State policy on nuclear power. For example, the impact that such legislation as the federal Clean Air Act or adoption of a carbon tax will have on the future selection of energy options remains unresolved.
- Industry is investigating new reactor designs that may improve the viability of nuclear technology in the future.

Policy

- The State should closely monitor the implications of federal Clean Air Act and other legislation on future state energy planning.
- The State should support efforts to site low and high level radioactive waste disposal facilities in a manner that provides long-term disposal in an environmentally acceptable manner.

Implementation

- Although no new nuclear facilities will be built in New Jersey in the near future, the State should continue to monitor the viability of nuclear power as a source of future electrical generation and examine new reactor designs as they become available.
- The BRC should monitor new reactor design efforts to gauge their impact on the economic and developmental viability of future projects.

NOTES

1. U.S. Nuclear Regulatory Commission, *Licensed Operating Reactors*, (NUREG-0020, Vol. 14, No. 1, January 1990), Mid-Atlantic Area Council Regional Reliability Council Coordinated Bulk Power Supply Program (April 1, 1990) and utility annual reports to the BRC.

Chapter 7

Cogeneration

Cogeneration is the simultaneous production of electricity and useful thermal energy. Cogeneration systems are more efficient than conventional electric power plants. Conventional power plants produce as much electricity as possible from the fuel they burn and then dump waste heat to cooling waters or the atmosphere. Their overall efficiency rarely exceeds 35 percent. Cogeneration systems, in contrast, achieve overall efficiencies of up to 80 percent by producing electricity and using the thermal energy that would otherwise be wasted. This thermal energy can take the form of steam, hot air, or hot water and can be used in plant operations or sold to others nearby. (See Figure 7-1.)

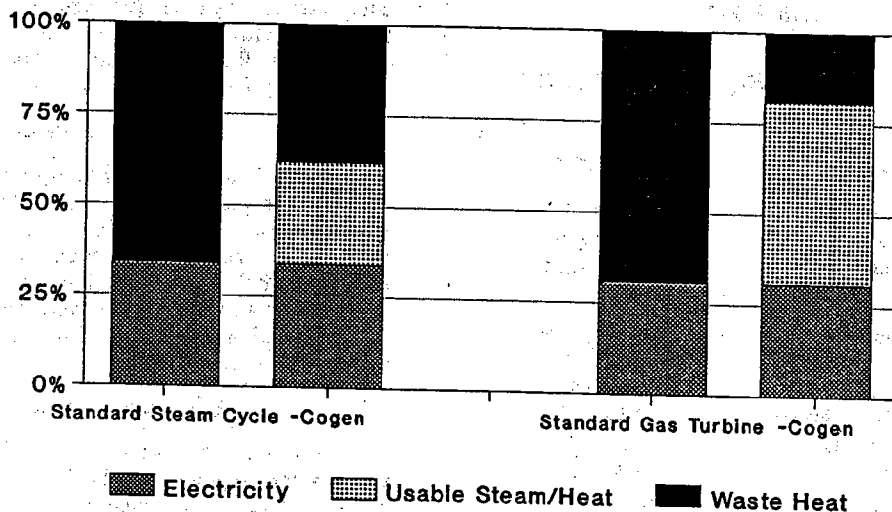
Cogeneration was popular at the beginning of the electricity era because of its higher efficiency. Later, and until the late 1960s, economies of scale made large central utility plants less expensive to build and operate. In the 1970s as fuel costs rose relative to capital costs, economics favored cogeneration, but regulatory barriers and utility opposition made it impractical until Congress passed the 1978 Public Utility Regulatory Policies Act (PURPA). Part of an omnibus energy bill, PURPA promoted non-utility cogeneration, primarily by requiring that utilities purchase the electrical output.

Growth in peak demand and energy use that has outstripped all forecasts will spur the need for additional electric generation if efficiency gains cannot fully offset growth. (See Chapter 8.) Cogeneration, more energy efficient and less polluting than central utility generation on a per kilowatt-hour basis, warrants promotion and investment. Nuclear generation has higher capital costs.¹ Coal-fired plants in New Jersey face several obstacles: stringent air quality standards, need to locate near adequate water supplies, and access to transportation for coal and coal wastes. The state's last new coal-fired facility was brought on line in 1981.² Oil, now mainly from other countries is undesirable for security reasons.³ Natural gas has been used for intermediate and peaking units with relatively low efficiencies.

Clean-burning cogeneration units can replace older, more polluting sources of power and limit the need for construction of new central power plants. Cogeneration applications can also help New Jersey businesses lower their operating costs and enhance the state's economic competitiveness and ability to retain and attract jobs.

FIGURE 7-1

Comparison of Fuel Conversion Efficiency Generation and Cogeneration Technologies Under Optimum Operating Conditions



Source: Table 7-2. See text and table for explanatory notes and discussion.

Technology and Economics

Cogeneration Efficiency

Neither electric utilities nor industrial process steam users are optimally efficient. Utilities do not recover the waste heat from the exhaust of their boilers or combustion turbines and as a result plant operating efficiencies currently average approximately 30 percent. Industrial users often need only low-temperature steam, but combustion processes dictate much higher output temperatures to raise steam from boilers. Cogeneration partially captures the respective utility and industrial efficiency losses and results in lower costs for both steam and electricity by using a combined system. (See Figure 7-1).

Technology and Size

Each cogeneration system has advantages based on the need for electricity or steam. The characteristics of various systems are shown in Table 7-1. The user's specific electricity and steam or hot water requirements determine the choice of equipment. A critical step in the decision to install cogeneration is an evaluation of the economics of a particular project to ensure the selection of the right technology and size for the application.

Temperature, quality of steam, maintenance schedule, construction time, and environmental impacts (noise, air, water) determine equipment for a particular application and dictate whether a topping or bottoming cycle is indicated. The amount of steam required will determine whether supplemental firing of the waste heat recovery boilers is needed. The process steam requirements for a particular facility may even necessitate the installation of backup boilers to keep a plant on line while the cogeneration unit is undergoing maintenance.

Basic types of prime movers are steam turbines, gas turbines, and reciprocating engines. (See Table 7-2.) The steam turbine provides a large amount of steam and a rela-

tively small amount of electricity. The combustion turbine provides a higher electrical output with proportionately less steam. The highest relative electrical output comes from the reciprocating engine. These generalizations reflect the ratio of electricity to heat also known as the net heat rate. Many different combinations of equipment can change these relationships when heat recovery, supplemental firing, or combined cycle systems are included.

Steam turbines are primarily suited to large installations from 100 MW to utility-sized units of up to 1,000 MW each. Oil, gas, coal or even garbage can fuel these units. Gas turbines are available in sizes from 75 KW to large units of 200 MW that could be used in refineries. Reciprocating engines, which include spark ignition, rotary, and diesel configurations, are available ranging from household-sized 10 KW units to units of up to 25 MW suitable for large business installations.

Packaged Units

To make cogeneration less expensive, manufacturers often assemble the components at the factory. The prime mover and generator are mounted on a skid and delivered to the site, leaving only the fuel and electric hookups to be done at the customer's facility. As manufacturers have become more familiar with the market for cogeneration, the size of skid-mounted units has steadily increased. Today large gas turbines in the 50 MW range will arrive on site with only a few months installation time required. Many small packaged units are available that can meet the electricity, heating, and air conditioning needs of commercial buildings.

PURPA Machines

Cogeneration units built to the lowest efficiency standard allowed by law—so-called "PURPA machines", have been criticized by the utility industry as utility units without the protection of regulation. Built by cogenerators primarily to profit from high avoided cost rates, PURPA machines, the cogeneration industry argues, still produce electricity at a lower cost than nuclear plants. For a complete analysis of the problems that have occurred nationally with the implementation of PURPA, see the Federal Energy Regulatory Commission Notice of Proposed Rulemaking Docket No. RM88-6-000.

Use Efficiency

High efficiency electrical equipment can be more cost effective than cogeneration in certain applications. Even after the energy-efficient devices are installed, there is still a place for cogeneration. Cogeneration has encouraged the utilities to help customers identify and make energy efficiency improvements that lower their electric bills. Providing technical assistance and offering incentive rates help utilities to keep customers.

Economics of Cogeneration

From the perspective of potential users, the only reason to consider cogeneration is if energy cost savings can be shown. Some of the factors that must be evaluated are electricity and thermal requirements, costs for electricity and fuel before and after cogeneration, cost of capital, tax

TABLE 7-1

Cogeneration Technology and Applications

<u>Technology</u>	<u>Capacity - MW</u>
Reciprocating Engines	0.01 to 25
Gas Turbines	0.07 to 200
Steam Turbines	8.00 to 1000
<u>Applications</u>	<u>Required - MW</u>
Small Commercial	0.01 to 8
Hospitals, Institutions	0.35 to 75
Large Commercial	8.00 to 75
Industrial	8.00 to 200

Source: Connecticut Cogeneration Handbook updated by BPU.

TABLE 7-2

Cogeneration Topping Cycle Performance Parameters

Cogeneration Systems	Electrical Capacity of a Single Unit (kw)	Heat Rate ² (Btu/kwh)	Electricity Efficiency (%)	Thermal Efficiency (%)	Total Efficiency (%)	Exhaust Temp °F	Steam \$/hr. Generation @125 psig
Small Reciprocating Gas Engines	1-500	25,000 to 10,000	14-34	52	66-86	600-1200	0-200 ¹
Large Reciprocating Gas Engines	500-17,000	13,000 to 9,500	26-36	52	78-88	600-1200	200-10,000 ¹
Diesel Engines	100-1,000	15,000 to 11,000	23-31	44	67-75	700-1500	100-400 ¹
Industrial Gas Turbines	800-10,000	14,000 to 11,000	24-31	50	74-81	800-1000	3,000-30,000
Utility Size Gas Turbines	10,000-75,000	13,000 to 11,000	26-31	50	76-81	700	30,000-300,000
Steam Cycles	5,000-100,000	50,000 to 10,000	7-34	28	35-62	350-1000	10,000-100,000

¹ Hot water @ 250°F is available at 10 times the flow of the steam.

² Heat rate is the heating value input to the cycle per kwh of electrical output. To determine electrical generation percent efficiency of a prime mover from its heat rate: Electric Efficiency = $\frac{3413}{\text{Heat Rate}} \times .10$

Source: Connecticut Cogeneration Handbook updated by DEPE.

considerations, maintenance, staffing and payback or present worth analysis. Many industrial and commercial electricity consumers who are installing cogeneration equipment have made such analyses and have seen quick paybacks.

Environment

Cogeneration would result in lower net air emissions at many industrial and commercial sites statewide where old fuel-burning equipment remains in use at facilities that pre-date the Department of Environmental Protection and Energy's existence. Under DEPE policy, air permits for such facilities are renewed every five years and regulations allow these facilities to operate without the addition of "state of the art" (SOTA) pollution controls. If the facilities were to upgrade to more efficient equipment, the replacement equipment would then become subject to often costly SOTA requirements. Therefore, businesses thus have an incentive to repair rather than replace unregulated equipment to avoid the expense of SOTA controls.

Cogeneration could also reduce sulfur dioxide emissions produced at out-of-state plants that generate electricity for New Jersey consumption. Many of these plants burn high sulfur coal and have no pollution controls. However, some cogeneration systems, such as the reciprocating engines shown in Table 7-2, cannot meet New Jersey emission standards with control technology now available.

The state of California allows new equipment that replaces higher pollution sources to avoid prevention of significant deterioration (PSD) and nonattainment regulations with a *netting* analysis.⁴ This analysis allows the new cogeneration installation to receive credit for the reduction in emissions from the boiler on site. When cogeneration was first becoming popular, the DEP, based on California precedent, proposed the use of selective catalytic reduction (SCR), an expensive technology for the control of nitrogen oxides (NO_x). In order to allow cogeneration to develop economically, the Division of Energy Planning and Conservation (DEPC) proposed use of a netting analysis but instead the DEPE and the DEPC together developed a NO_x control strategy for gas turbine cogenerators that would meet appropriate environmental standards without jeopardizing cogeneration. Thus, the DEPE's proposal for SCR was changed into an emission limit guideline that was not technology-specific. (See Appendix: Gas Turbine Nitrogen Oxides Control Strategy.)

Since 1987, the DEPE has approved more than 2,000 MW of cogeneration. Projects that provide most of this capacity use SCR, but a substantial portion of the capacity comes from projects that use other air pollution control technology that is almost as low as SCR in air contaminant emission rates. Consequently, New Jersey is achieving significant air quality and economic benefits from cogeneration.

Markets

The present market for cogeneration begins with small scale units starting at 24 KW which can be installed in fast food restaurants, hotels, YMCAs and office buildings where electricity, space heating, and air conditioning loads can all be met by a properly sized unit.

Since most commercial and industrial sites have substantial electricity and winter heating requirements, a summer use for the heat may be the determining factor in whether a project can be sold. Air conditioning is one of the most important value-added components to fit a cogeneration system to the customer's load profile, but it raises the installed cost when absorption chilling is used for air conditioning purposes.⁵ Depending upon the level of complexity, the cost for packaged units can vary for three typical 100 KW set-ups from \$400/KW to \$1500/KW.⁶ Where the heat load is high enough year around, the cogeneration unit could be sized to meet the electrical needs of the existing air conditioning system with excess electrical sales in the winter. A cogeneration unit could also be sized in conjunction with storage ice-making equipment to level the building's electrical load, thus allowing the unit to operate on a 24-hour basis in the typical office building. Proper evaluation of loads and operating conditions determines the number of hours that a cogeneration unit operates and, therefore, the savings over utility-supplied power.

Though the economics and maintenance requirements for household-sized cogeneration are not currently favorable in New Jersey, the equipment is available. Conceivably an electric generation unit with space heating and air conditioning as a package may one day be as common as a refrigerator, if utility electricity prices rise above cogeneration package costs providing an incentive for homeowners and if maintenance intervals improve.⁷

Cogeneration technology has the potential to provide significant benefits to the state. This technology does not have to be the exclusive domain of the non-utility generation sector. No technological reasons exist to preclude utilities from constructing cogeneration facilities if appropriate sites and thermal applications can be identified. The State should, therefore, consider implementing a requirement that electric utilities evaluate the feasibility of cogeneration applications when planning new generating capacity, subject to fuel diversity, dispatchability and other operational and planning constraints. (See Chapter 10.)

Findings

- Cogeneration can be a cost-effective and energy-efficient means of meeting New Jersey electricity capacity and thermal energy needs; the technology is available to both utility and non-utility generators.
- Cogeneration improves generation and overall energy efficiency and reduces the state's reliance on imported fossil fuels.
- To gain the maximum environmental advantages of cogeneration requires policies that allow full development of its potential. New cogeneration technology

can meet reasonable air quality standards. New Jersey can benefit most from a strong environmental program that allows clean, economic cogeneration to come on line.

- Cogeneration can provide a means for New Jersey businesses to reduce their operating costs, thereby enhancing the state's economic competitiveness and companion ability to retain and attract jobs.
- Cogeneration can also help reduce the acid deposition that results from electricity generation in states that allow higher emission levels.
- New gas pipeline capacity would facilitate the growth of gas turbine and reciprocating cogeneration facilities in New Jersey.

Policy

- The State should continue to promote cost-effective cogeneration to meet New Jersey's power needs economically and to reduce environmental impacts.
- The State should work to minimize regulatory impediments to rapid deployment of this technology that has so much potential to reduce environmental problems and enhance the economic competitiveness of New Jersey businesses.
- The State should evaluate the elimination of grandfathered air emission permits that allow continuing pollution from sources that obtained permits before more stringent standards took effect. Under a revised policy, only companies able to prove that cogeneration would not be economic would be allowed to keep a grandfathered status.

Implementation

- The BRC and the DEPE should cooperate to assure the installation of environmentally sound cogeneration that reduces air emissions and acid rain problems.
- The BRC should continue to support fuel diversity in applications for new electric generation to guard against supply disruptions and price risk exposure.

NOTES

1. U.S. Council for Energy Awareness *Historical Profile of U.S. Nuclear Power Development*, 1988 edition (Washington, D.C.: U.S.C.E.A., 1988).
2. Telephone conversation with William O'Sullivan, P.E., Assistant Director, Environmental Quality, DEP, 1988.
3. G. Alan Petzet, "Higher U.S. demand, prices likely; production expected to keep falling," *Oil & Gas Journal*, November 14, 1988 p. 76.
4. California Health and Safety Code, Section 41605.
5. J.A. Mullory, Jr. et al., "Packaged Cogeneration Installation Cost Experience," *Retrofit Opportunities for Energy Management and Cogeneration*, Chapter 64, Association of Energy Engineers Atlanta Conference, 1988.
6. *Ibid.*
7. Gas Research Institute 1987 Annual Report, p. 14.