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NORTH ATLANTIC REGIONAL WATER RESOURCES STUDY. APPENDIX P. POWE--ETC(U)
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1 OF 2
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North Atlantic Regional Water Resources Study

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Appendix P
Power

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NORTH ATLANTIC REGIONAL WATER RESOURCES STUDY COORDINATING COMMITTEE

MAY 1972

The North Atlantic Regional Water Resources (NAR) Study examined a wide variety of water and related land resources, needs and devices in formulating a broad, coordinated program to guide future resource development and management in the North Atlantic Region. The Study was authorized by the 1965 Water Resources Planning Act (PL 89-80) and the 1965 Flood Control Act (PL 89-298), and carried out under guidelines set by the Water Resources Council.

The recommended program and alternatives developed for the North Atlantic Region were prepared under the direction of the NAR Study Coordinating Committee, a partnership of resource planners representing some 25 Federal, regional and State agencies. The NAR Study Report presents this program and the alternatives as a framework for future action based on a planning period running through 2020, with bench mark planning years of 1980 and 2000.

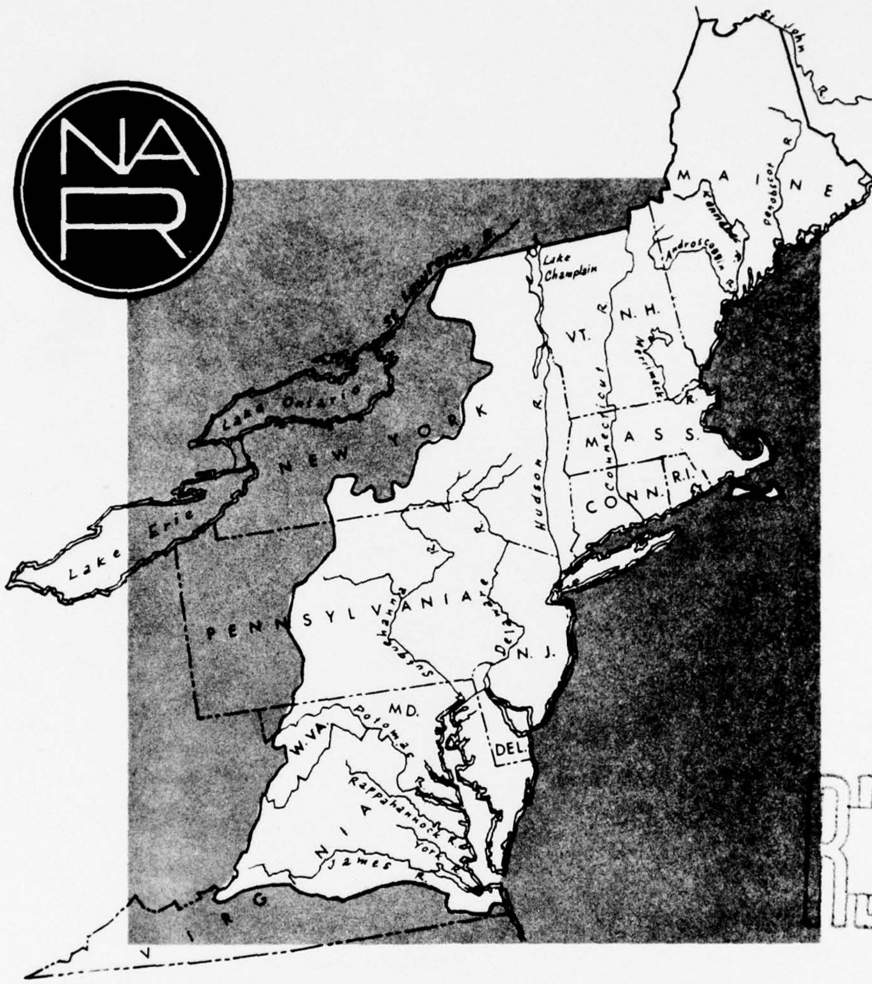
The planning partners focused on three major objectives -- National Income, Regional Development and Environmental Quality -- in developing and documenting the information which decision-makers will need for managing water and related land resources in the interest of the people of the North Atlantic Region.

In addition to the NAR Study Main Report and Annexes, there are the following 22 Appendices:

A. History of Study
B. Economic Base
C. Climate, Meteorology and Hydrology
D. Geology and Ground Water
E. Flood Damage Reduction and Water Management for Major Rivers and Coastal Areas
F. Upstream Flood Prevention and Water Management
G. Land Use and Management
H. Minerals
I. Irrigation
J. Land Drainage
K. Navigation
L. Water Quality and Pollution
M. Outdoor Recreation
N. Visual and Cultural Environment
O. Fish and Wildlife
P. Power
Q. Erosion and Sedimentation
R. Water Supply
S. Legal and Institutional Environment
T. Plan Formulation
U. Coastal and Estuarine Areas
V. Health Aspects

WATER RESOURCES NEEDS AND POTENTIALS FOR AN EXPANDING SOCIETY

Appendix P
Power



Prepared by

New York Regional Office
of the
Federal Power Commission, New York

410 081

for the

NORTH ATLANTIC REGIONAL WATER RESOURCES STUDY
COORDINATING COMMITTEE

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CHAPTER 1

INTRODUCTION

A comprehensive survey of the water and related land resources of the North Atlantic Region (NAR) involves among other things a thorough examination of the area's electric power and supply requirements. The economic well being and industrial progress of the region depend in no small measure on an adequate and economic supply of power for its population and industries.

PURPOSE AND SCOPE

The technological advance in electric power generation during recent years has been very rapid and future progress promises even greater strides. Since the inception of the electric utility industry (about 1880) production and consumption has roughly doubled in each succeeding decade. This history of growth can be put into perspective and dimension by noting that our population has quadrupled (from 50 to 200 million) in the past 90 years, whereas total electric energy production by utility companies has increased nearly 4.5 times since 1950. The net increase in production between 1968 and 1969, exceeds by almost 25 percent the total production of electrical energy in 1930.

This Appendix was prepared to provide information on past and future requirements of a market for power in the NAR, which is served in a coordinated manner by a group of interconnected electric utilities. Historic and estimated future (to the year 2020) electric power requirements are presented. The power market area varies geographically from the study region because it was selected to follow Federal Power Commission "Power Supply Area" boundaries. Data are presented by sub-areas which correspond to PSAs or groupings thereof within the power market. Estimates are made of the types of electric generating stations which will supply the future power requirements. The production of electric power from steam and hydroelectric plants involve the consumptive and non-consumptive use of large quantities of water, and is therefore among the principal purposes which the Region's water resources are called upon to serve.

Data presented in this Appendix represent attempts to identify orders of magnitude rather than to specify types or pinpoint the locations of needed facilities. The factors that effect power facility location and design are so numerous and change so rapidly that even relatively short range proposals may need to be materially altered. Capacity locations are therefore designated by sub-areas only and no further refinement is attempted or implied. The Appendix includes a complete accounting of all existing and anticipated future electric generating facilities, undeveloped hydroelectric power resources, and water requirements for thermal generation in the North Atlantic Region.

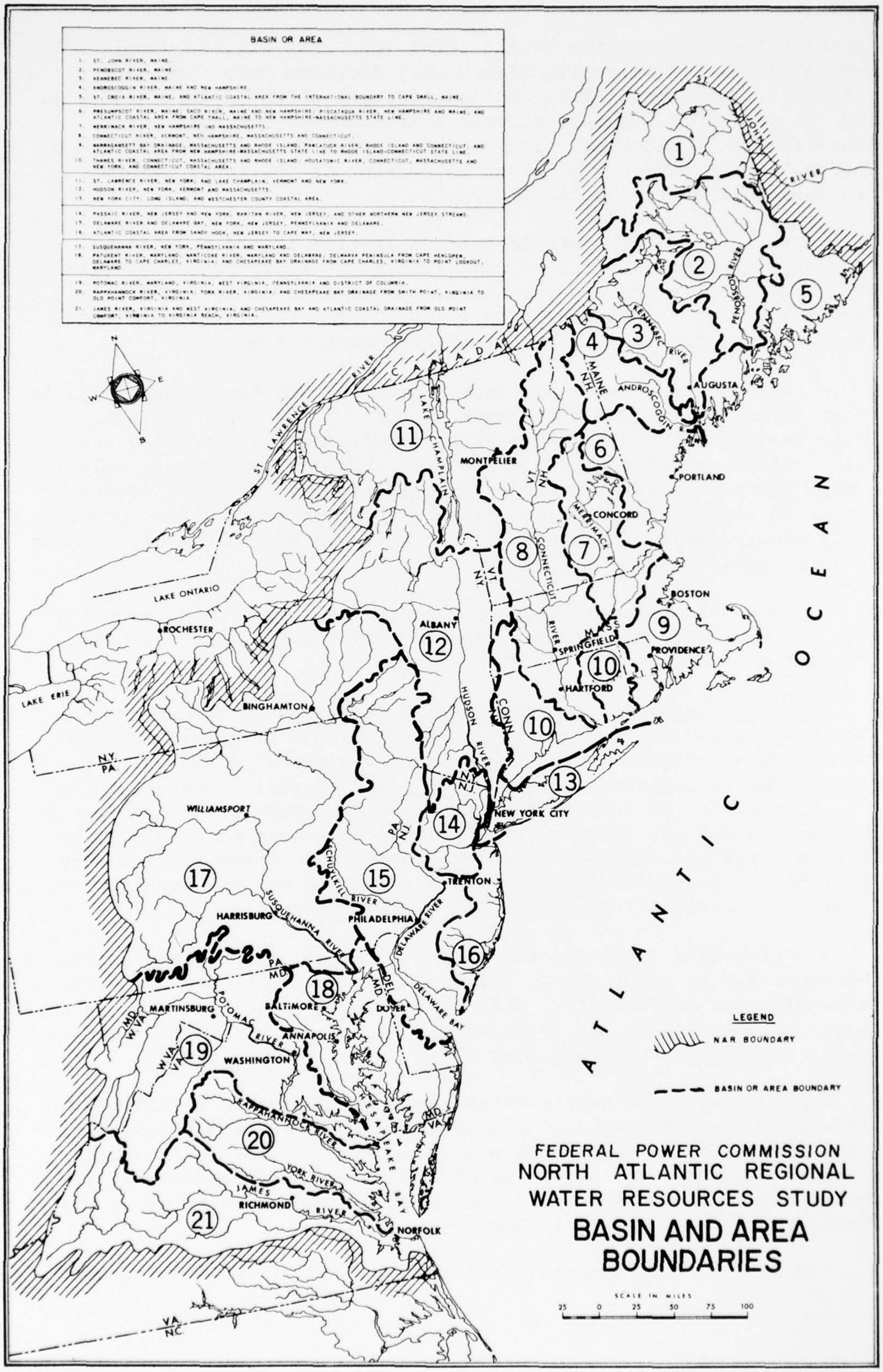
METHODOLOGY AND ASSUMPTIONS

Requirements. The material herein is presented in terms of estimated requirements for the power market, subdivided to show the estimated mix and magnitude of the supply within the 21 areas (Figure P-1) delineated by the Coordinating Committee. The basic data and general background information used in the analysis have been taken from reports and other documents provided by the electric power industry, from economic projections prepared for use in connection with North Atlantic Regional Studies, and from other available sources.

The projections assume that during the next five decades there will be no sudden shift in the economy, no disastrous wars, no widespread epidemic, and no economic or other catastrophe. The projections assume that the Nation will experience annual increases in population and proportional increases in the number of electricity customers. The projections reflect a general optimum arising from the widely held belief that there will be greater residential consumption, increased commercial applications, and expanded industrial usage. Not only will there be more homes with more electric appliances, but also more families who choose the advantages of electric space heating and cooling.

Supply. Planning for future power developments is based on present technology with some presumed improvements in efficiency. While it is likely that some revolutionary technological changes will be made between 1980 and 2020 in the power generation and transmission fields, no attempt has been made in this study to predict what those changes may be under the national efficiency and regional development objectives. It is presumed that if new techniques are developed they will have an economic advantage over current technologies, and would thus permit some savings over the pattern of development reflected in this Appendix. If such advantages are possible, they would apply to areas outside of as well as within the North Atlantic Region. Hence the relative position of the NAR with respect to other areas would probably not be materially affected. Under the environmental quality objective, it is assumed that there will be technical advances made in the use of "exotic" fuel generation which will be non-dependent on water for cooling and perhaps make less demands for esthetic treatments. A limited amount of such generation is projected for benchmark years 2000 and 2020.

Hydroelectric Power. No distinction is made between conventional and pumped storage hydroelectric power insofar as general plans and anticipated results are concerned. It is


BASIN OR AREA
1. ST. JOHN RIVER, MAINE.
2. PENOBSCOT RIVER, MAINE.
3. KENNEBEC RIVER, MAINE.
4. ANDROSCOGGIN RIVER, MAINE AND NEW HAMPSHIRE.
5. ST. CROIX RIVER, MAINE, AND ATLANTIC COASTAL AREA FROM THE INTERNATIONAL BOUNDARY TO CAPE SMALL, MAINE.
6. PRESUMPSCOT RIVER, MAINE; SACO RIVER, MAINE AND NEW HAMPSHIRE; PISCATAQUA RIVER, NEW HAMPSHIRE AND MAINE; AND ATLANTIC COASTAL AREA FROM CAPE SMALL, MAINE TO NEW HAMPSHIRE-MASSACHUSETTS STATE LINE.
7. MERRIMACK RIVER, NEW HAMPSHIRE AND MASSACHUSETTS.
8. CONNECTICUT RIVER, VERMONT, NEW HAMPSHIRE, MASSACHUSETTS AND CONNECTICUT.
9. NARRAGANSETT BAY DRAINAGE, MASSACHUSETTS AND RHODE ISLAND; PAWCATUCK RIVER, RHODE ISLAND AND CONNECTICUT; AND ATLANTIC COASTAL AREA FROM NEW HAMPSHIRE-MASSACHUSETTS STATE LINE TO RHODE ISLAND-CONNECTICUT STATE LINE.
10. THAMES RIVER, CONNECTICUT, MASSACHUSETTS AND RHODE ISLAND; HOUSATONIC RIVER, CONNECTICUT, MASSACHUSETTS AND NEW YORK, AND CONNECTICUT COASTAL AREA.
11. ST. LAWRENCE RIVER, NEW YORK; AND LAKE CHAMPLAIN, VERMONT AND NEW YORK.
12. HUDSON RIVER, NEW YORK, VERMONT AND MASSACHUSETTS.
13. NEW YORK CITY; LONG ISLAND; AND WESTCHESTER COUNTY COASTAL AREA.
14. PASSAIC RIVER, NEW JERSEY AND NEW YORK; RARITAN RIVER, NEW JERSEY; AND OTHER NORTHERN NEW JERSEY STREAMS.
15. DELAWARE RIVER AND DELAWARE BAY, NEW YORK, NEW JERSEY, PENNSYLVANIA AND DELAWARE.
16. ATLANTIC COASTAL AREA FROM SANDY HOOK, NEW JERSEY TO CAPE MAY, NEW JERSEY.
17. SUSQUEHANNA RIVER, NEW YORK, PENNSYLVANIA AND MARYLAND.
18. PATUXENT RIVER, MARYLAND; NANTICOKE RIVER, MARYLAND AND DELAWARE; DELMARVA PENINSULA FROM CAPE HENLOPEN, DELAWARE TO CAPE CHARLES, VIRGINIA; AND CHESAPEAKE BAY DRAINAGE FROM CAPE CHARLES, VIRGINIA TO POINT LOOKOUT, MARYLAND.
19. POTOMAC RIVER, MARYLAND, VIRGINIA, WEST VIRGINIA, PENNSYLVANIA AND DISTRICT OF COLUMBIA.
20. RAPPAHANNOCK RIVER, VIRGINIA; YORK RIVER, VIRGINIA; AND CHESAPEAKE BAY DRAINAGE FROM SMITH POINT, VIRGINIA TO OLD POINT COMFORT, VIRGINIA.
21. JAMES RIVER, VIRGINIA AND WEST VIRGINIA; AND CHESAPEAKE BAY AND ATLANTIC COASTAL DRAINAGE FROM OLD POINT COMFORT, VIRGINIA TO VIRGINIA BEACH, VIRGINIA.
N
E
W
S
CANADA
ST. LAWRENCE RIVER
LAKE CHAMPLAIN
LAKE ONTARIO
LAKE ERIE
ROCHESTER
BINGHAMTON
WILLIAMSPORT
HARRISBURG
ALBANY
MONTPELIER
AUGUSTA
PORTLAND
CONCORD
BOSTON
SPRINGFIELD
PROVIDENCE
HARTFORD
NEW YORK CITY
TRENTON
PHILADELPHIA
BALTIMORE
DOVER
ANNAPOLIS
WASHINGTON
MARTINSBURG
RICHMOND
NORFOLK
KENNEBEC RIVER
PENOBSCOT RIVER
ANDROSCOGGIN
MERRIMACK R.
CONNECTICUT RIVER
HUDSON RIVER
SCHUYLKILL RIVER
SUSQUEHANNA RIVER
DELAWARE RIVER
DELAWARE BAY
POTOMAC RIVER
RAPPAHANNOCK RIVER
YORK RIVER
JAMES RIVER
CHESAPEAKE BAY
MAINE
N.H.
VT.
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21
ATLANTIC OCEAN
LEGEND
NAR BOUNDARY
BASIN OR AREA BOUNDARY
FEDERAL POWER COMMISSION
NORTH ATLANTIC REGIONAL
WATER RESOURCES STUDY
BASIN AND AREA
BOUNDARIES
SCALE IN MILES
25 0 25 50 75 100

FIGURE P-1

assumed that the portion of the total load that will be supplied by conventional hydroelectric plants will decrease over the years to the point where it will be an insignificant amount, proportionally, by the year 2020. Pumped storage installations, however, are anticipated to materially increase at a pace that would maintain a hydroelectric capacity of about 10 percent of the total demand throughout the study period.

The location of hydroelectric generation is, of necessity, based on the availability of useable sites. Known potential sites would be used in the order of their economic advantage within the constraint imposed by providing a reasonable distribution of peaking capacity throughout the established market area.

Hydroelectric power projects, basically pumped storage, will be used primarily to supply the peak portion of the power demands. Site availability rather than water requirement is the prime consideration. After completing the pump storage impoundment, only small amounts of water are necessary to replace operating losses. Under this mode of operation, hydroelectric projects would derive only minor and limited benefits from incremental investment in water supply facilities.

Under these general criteria, there are no apparent reasons why the hydroelectric capacity should vary significantly between the three objectives.

Cooling Water for Thermal Power Generation. Power demands for the North Atlantic Regional area were developed originally by conventional coordinated study areas and power market areas which correspond to regions of coordinated power operations (see Chapter 2). The amount of total demand that would be supplied by generation within the NAR was based on studies that have been made jointly by the industry and the Federal Power Commission. These studies also provided estimates of the power generation mix and the breakdown of thermal generation into fossil and nuclear categories.

Anticipated locations and sizes of thermal plants were initially based on Market study needs and on the basis of optimum power system economics and reliability. This area-wide apportionment is considered to be the most efficient proposal and thus is in effect the plan that would satisfy the national efficiency objective.

The total power supply within each study area is relatively fixed. To satisfy the regional development objective a redistribution (from the most efficient placement) can be made which would enhance the economic well-being of those areas which have been projected, by economic studies, to be most likely benefited by the location of large generating stations.

Under the environmental quality objective it has been assumed that some form of "exotic" generation will replace varying amounts of conventional thermal generation. Even though new forms of generation may be more costly, they may have a beneficial impact on air and water quality. Another criteria for the environmental quality objective is the potential reassignment of thermal capacities from inland to coastal areas so as to protect the rapidly dwindling supplies of high quality fresh water.

With the adoption of a general power supply program by sub-areas for each objective of plant sizes (see Chapter 7) for the thermal generation supply, it follows that water requirements (consumptive and non-consumptive) can be delineated. The non-consumptive use (cooling water flow through the generating facility's condenser) is a fixed quantity and varies with plant design. Expected increases in design and operating efficiencies for the period of this study will modify full load condenser requirements from an estimated flow of 1.7 $ft^3/s/MW$ in 1980 to 1.1 $ft^3/s/MW$ in the year 2020 for nuclear generation based on a temperature rise of 15°F. Consumptive losses, however, depend upon the method used in handling the cooling water. In the recent past the most universal, and most efficient, system was the "once-thru" design where water taken directly from a stream is passed through the condenser and then discharged, at a higher temperature, to the original watercourse. When flow or temperature constraints exist, cooling towers can be used. In the "open system", water leaving the condenser is cooled before discharge to the waterbody, while in the "closed system" the cooled water is circulated between tower and condenser. Where appropriate topographic conditions exist a cooling pond can be used to provide a condenser water supply relatively unaffected by flow and temperature restrictions. For nuclear plant efficiencies anticipated in the year 2000 and at full load operation; consumptive losses are estimated at 10.4 $ft^3/s/1000$ MW for once-thru, 12.2 $ft^3/s/1000$ MW for ponds, and 17.4 $ft^3/s/1000$ MW for cooling towers.

The criteria for power cooling devices will vary for each objective. Under the national efficiency objective, once-thru cooling will predominate in all areas where adequate river flows will permit its technical development. It is recognized that for the large installations envisioned for the future, once-thru design will be not only generally impractical but often impossible except in coastal regions. The large (2000 MW+) plants' requirements for cooling water are such that few inland areas provide sufficient flows for dependable once-thru operation. Under the regional development objective the desire to increase total output of a designated region may necessitate the use of cooling systems. Therefore, for this objective a greater stress is put on cooling ponds and cooling towers. The use of once-thru condenser cooling is considered only in those areas where large flows are available and average sized installations envisioned. In planning for the environmental quality objective, almost complete dependence was placed on the use of open and closed type cooling towers in inland areas and a mix of towers and other devices for estuarine and coastal areas.

CHAPTER 2

DESCRIPTION OF POWER MARKET AREA

DETERMINATION OF MARKET

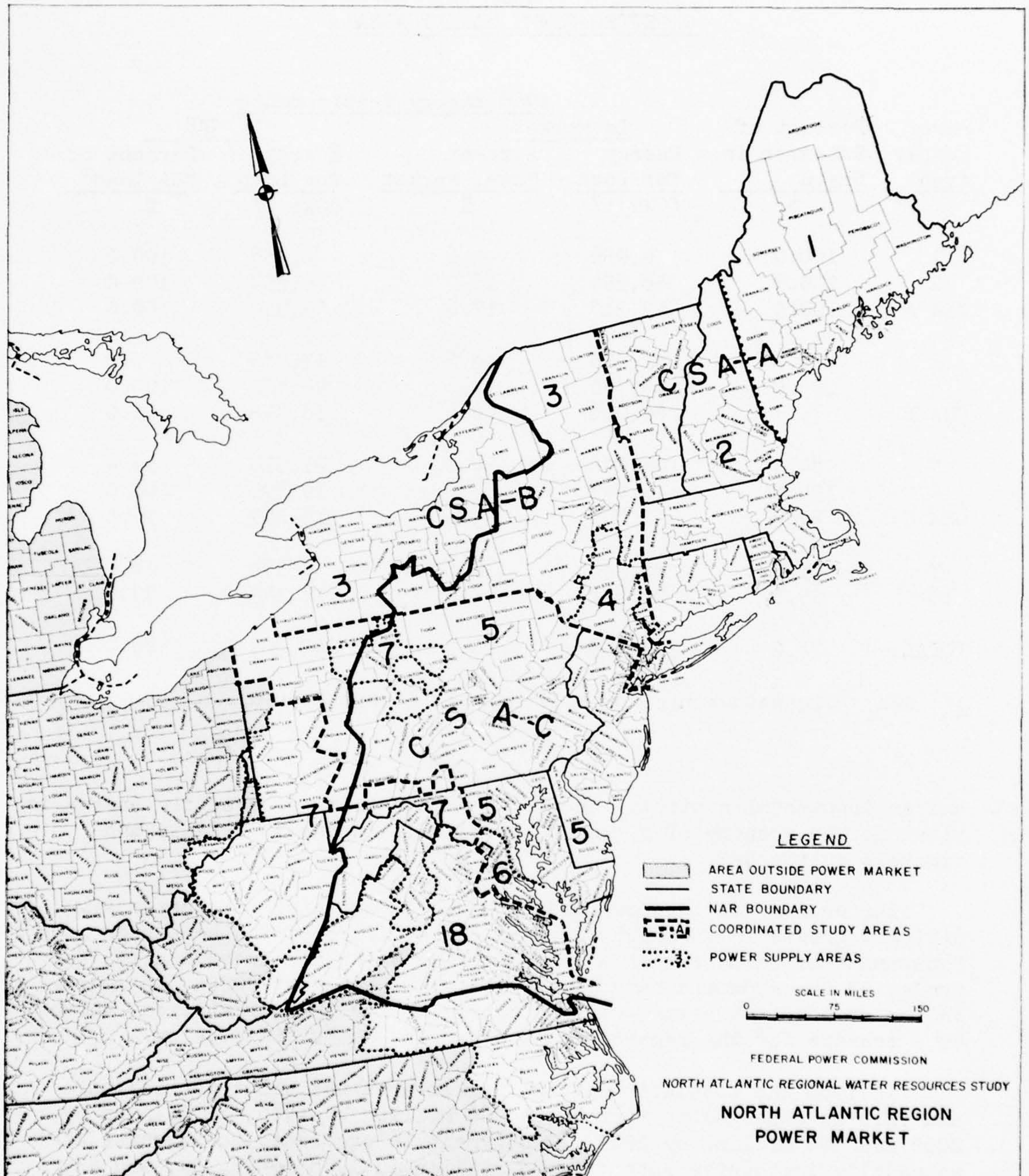
The Federal Power Commission in its regulatory work relating to the assemblage and analysis of statistics on power requirements and supply for the electrical utility industry has divided the contiguous United States into 48 Power Supply Areas (PSA). These PSAs are generally determined on the basis of service areas and operating relationships of utility systems comprising them. In turn, power supply areas may be grouped into Coordinated Study Areas (CSA), again determined mainly by the degree of coordination among component power supply areas.

The market selected for this study approximates the area in the NAR. Complete PSAs were used so that data could be presented on the basis of existing utility service areas. The market area consists of PSAs 1 through 7, and 18, extending east to west from the Maine-New Brunswick boundary to the Ohio-Pennsylvania border in northwestern Pennsylvania and north to south from the Canadian border to the Roanoke River in North Carolina. CSA A (PSAs 1 and 2) is comprised of the six New England states, CSA B consists of PSAs 3 and 4 (New York State), CSA C embraces PSAs 5 and 6 within the states of Delaware and New Jersey, parts of Maryland, Pennsylvania and Virginia, and Washington, D.C. PSA 7 consists of parts of Maryland, Virginia, West Virginia and Pennsylvania. PSA 18 includes parts of Virginia, West Virginia and North Carolina. Only PSAs 1, 2, 4 and 6 lie wholely within the NAR boundary. Figure P-2 shows the geographical extent of the market area by PSAs . Table P-1 shows comparative data for the region and the selected market area.

RELATIONSHIP OF POWER TO THE ECONOMY OF THE AREA

In the overall assessment of any regional water and related land use the relationship of electricity to the various factors that determine a region's economy is an interdependent one. The proper appraisal of electric power must be made in the context of the total environment and its economic, physical, cultural and social effects.

Electricity has filled and will continue to fill an important role in channeling the nation's productive resources into efficient use. Since it is an auxiliary, and indeed a breeder of economic growth, electric power has furnished a rising proportion of the country's energy requirements. The expanding use of energy-consuming capital equipment has been a principal source of improvement of national productivity and a stimulus to economic progress. Electric power consumption increases in direct proportion with rising standards of living, higher income and technological progress. The pace of technological advances can be expected to continue creating new markets, increased leisure time and accompanying trends toward a shorter work week. This in turn will increase the desire and need for new forms of basic and luxury appliance items, recreation, newer cleaner methods of heating and transportation,



CSA-A
CSA-B
CSA-C
1
2
3
4
5
6
7
18
LEGEND
AREA OUTSIDE POWER MARKET
STATE BOUNDARY
NAR BOUNDARY
COORDINATED STUDY AREAS
POWER SUPPLY AREAS
SCALE IN MILES
0 75 150
FEDERAL POWER COMMISSION
NORTH ATLANTIC REGIONAL WATER RESOURCES STUDY
NORTH ATLANTIC REGION
POWER MARKET
FEBRUARY 1971
FIGURE P-2

TABLE P-1

COMPARATIVE DATA FOR THE REGION
AND
SELECTED POWER MARKET AREA

Power Supply Area	Percent of Sub-Area in Basin	1968 Energy Requirements In Market: Energy for Load (GWh)1/	In Market: Percent Total Market	In NAR: Energy for Load (GWh)1/	In NAR: Percent of PSA Load
	%		%		%
1	100.0	4,956	1.6	4,956	100.0
2	100.0	48,354	16.0	48,354	100.0
CSA A	100.0	53,310	17.6	53,310	100.0
3	58.1	41,298	13.6	13,753	33.3
4	100.0	44,720	14.8	44,720	100.0
CSA B	71.1	86,018	28.4	58,473	68.0
5	84.5	102,998	34.0	99,310	96.4
6	100.0	10,897	3.6	10,897	100.0
CSA C	87.8	113,895	37.6	110,207	96.8
7	41.0	28,560	9.5	5,174	18.1
18	55.0	20,812	6.9	16,143	77.6
TOTAL	74.2	302,595	100.0	243,307	80.4

1/ GWh = Gigawatt-hours, or millions of Kilowatt-hours

and environmental control. Thus, the availability of electric energy is vital in the economy of a region, especially in one as dynamic and vigorous as the NAR.

The economy of the power market area is expected to undergo significant growth in the next 50 years. The Office of Business Economics, Department of Commerce, in a report to the Water Resource Council, has projected the economic base of the nation to the year 2020. An aggregation of selected areas, closely approximating the market area, serves as a measure for the region's future growth, as outlined below.

In 1968 the population of the market area was about 58 million and this is expected to increase to 66 million by 1980, 83 million by 2000 and 104 million by 2020. Employment is predicted to increase at an equally impressive rate from 23 million in 1968 to 27, 34, and 43 million by 1980, 2000, and 2020, respectively. Estimated future employment shows increases in trade and service sectors, moderate increases in manufacturing, and declines in agriculture and mining.

Projected per capita income in the market area varies from $3380 in 1970 to $13,209 in 2020, as compared to a national average of $3910 (preliminary) in 1970 and projected $12,411 in 2020.

Agricultural production is presently diversified in the area, consisting of both large and small scale farming operations providing primarily grain, potatoes, cranberries, tobacco, and truck crops, and dairy operations. Its future appears to be tied to the local area's population growth and the ability of market-oriented local producers to compete successfully.

The largest portion of the labor force is devoted to manufacturing, with a significantly large percentage in primary metal and chemicals. Apparel, food products, paper and paper products, chemicals, and primary metals are among the region's chief manufactured products.

The market area, which includes the megalopolis from Washington, D.C. to Boston, Mass. is expected to continue to provide extensive opportunities for expansion. While the area's future growth rate may not be as great as some other specific parts of the country, it is expected to be above average. Its electric load is estimated to comprise over 20 percent of the national total throughout the study period.

CHAPTER 3

POWER MARKET REQUIREMENTS

UTILITY SERVICE IN MARKET

Electric service in the NAR market area in 1968 was provided by 381 systems, 102 private investor owned and 279 publicly (government) owned. The latter supplied 5 percent of the total energy used. In 1968, 82 utilities had energy requirements greater than 100 million kilowatt-hours, or 100 gigawatt-hours (GWh). These principal utilities constituting only 21.5 percent of the total number accounted for 97.8 percent of the market load. Table P-2 summarizes data on installed capacity and energy requirements in 1968. Table P-3 lists the major systems in the market area with energy requirements of 500 gigawatt-hours and their corresponding 1968 installed capacity, and net generation.

Total power production by the private ownership sector of the industry was 288,000 gigawatt-hours in 1968, or 95 percent of the total. Practically all of this energy was accounted for by the 50 major private systems except for 923 GWh, supplied by 52 minor systems. Thirty-three private systems and one public system with energy requirements in excess of 500 gigawatt-hours had an aggregate load of 286,700 gigawatt-hours, about 95 percent of the market requirements. The 34 major utilities also accounted for 95.3 of the total installed capacity. Seven utilities had requirements of over 15,000 gigawatt-hours in 1968.

TABLE P-2

ELECTRIC UTILITIES SERVING THE MARKET AREA-1968

	Systems (No.)	Systems (%)	Installed Capacity (MW)	Energy Requirements (GWh)	Energy Requirements (%)
TOTAL MARKET					
Privately Owned					
Major Systems 1/	50	13.1	60,154	286,628	94.7
Minor Systems	52	13.7	304	923	0.3
Total-Private	102	26.8	60,458	287,551	95.0
Publicly Owned					
Major Systems 1/	32	8.4	3,706	9,231	3.1
Minor Systems	247	64.8	333	5,813	1.9
Total-Public	279	73.2	4,039	15,044	5.0
Total Major Systems 1/	82	21.5	63,860	295,859	97.8
Total Minor Systems	299	78.5	637	6,736	2.2
Grand Total	381	100.0	64,497	302,595	100.0
CSA - A					
Privately Owned					
Major Systems 1/	26	17.5	11,118	48,467	90.9
Minor Systems	28	19.0	30	445	0.9
Total-Private	54	36.5	11,148	48,912	91.8
Publicly Owned					
Major Systems 1/	14	9.5	345	2,515	4.7
Minor Systems	80	54.0	143	1,883	3.5
Total-Public	94	63.5	488	4,398	8.2
Total Major Systems 1/	40	27.0	11,463	50,982	95.6
Total Minor Systems	108	73.0	173	2,328	4.4
Grand Total	148	100.0	11,636	53,310	100.0

1/ Energy requirements greater than 100 gigawatt-hours.

TABLE P-2 (cont'd)

ELECTRIC UTILITIES SERVING THE MARKET AREA-1968

	Systems (No.)	Systems (%)	Installed Capacity (MW)	Energy Requirements (GWh)	Energy Requirements (%)
CSA - B					
Privately Owned					
Major Systems 1/	8	10.7	15,351	80,704	93.8
Minor Systems	11	14.6	17	140	0.2
Total-Private	19	25.3	15,368	80,844	94.0
Publicly Owned					
Major Systems 1/	4	5.3	3,200	4,313	5.0
Minor Systems	52	69.4	55	861	1.0
Total-Public	56	74.7	3,255	5,174	6.0
Total Major Systems 1/	12	16.0	18,551	85,017	98.8
Total Minor Systems	63	84.0	72	1,001	1.2
Grand Total	75	100.0	18,623	86,018	100.0
CSA - C					
Privately Owned					
Major Systems 1/	13	14.0	24,357	110,688	97.2
Minor Systems	11	11.8	256	302	0.3
Total-Private	24	25.8	24,613	110,990	97.5
Publicly Owned					
Major Systems 1/	5	5.4	90	1,158	1.0
Minor Systems	64	68.8	112	1,747	1.5
Total-Public	69	74.2	202	2,905	2.5
Total Major Systems 1/	18	19.4	24,447	111,846	98.2
Total Minor Systems	75	80.6	368	2,049	1.8
Grand Total	93	100.0	24,815	113,895	100.0

1/ Energy requirements greater than 100 gigawatt-hours.

TABLE P-2 (cont'd)

ELECTRIC UTILITIES SERVING THE MARKET AREA-1968

	Systems (No.)	Systems (%)	Installed Capacity (MW)	Energy Requirements (GWh)	Energy Requirements (%)
PSA 7					
Privately Owned					
Major Systems 1/	2	12.5	4,972	28,006	98.0
Minor Systems	1	6.2	0	25	0.1
Total-Private	3	18.7	4,972	28,031	98.1
Publicly Owned					
Major Systems 1/	2	12.5	58	228	0.8
Minor Systems	11	68.8	10	301	1.1
Total-Public	13	81.3	68	529	1.9
Total Major Systems 1/	4	25.0	5,030	28,234	98.8
Total Minor Systems	12	75.0	10	326	1.2
Grand Total	16	100.0	5,040	28,560	100.0
PSA 18					
Privately Owned					
Major Systems 1/	1	2.0	4,356	18,763	90.1
Minor Systems	1	2.0	1	11	0.1
Total-Private	2	4.0	4,357	18,774	90.2
Publicly Owned					
Major Systems 1/	7	14.3	13	1,017	4.9
Minor Systems	40	81.7	13	1,021	4.9
Total-Public	47	96.0	26	2,038	9.8
Total Major Systems 1/	8	16.3	4,369	19,780	95.0
Total Minor Systems	41	83.7	14	1,032	5.0
Grand Total	49	100.0	4,383	20,812	100.0

1/ Energy requirements greater than 100 gigawatt-hours.

TABLE P-3

ELECTRIC UTILITIES IN MARKET AREA - 1968
(Requirements greater than 500 gigawatt-hours)

Utility	Installed Capacity (MW)	Net Generation (GWh)	Energy Requirements
PSA 1			
Central Maine Power Co.	655	3,480	3,452
Bangor Hydro Electric Co.	131	569	757
PSA 2			
New England Electric System	1,748	8,236	10,610
Boston Edison Co.	1,982	9,082	6,657
Connecticut Light & Power Co.	1,148	6,190	6,506
Hartford Electric Light Co.	766	3,759	4,091
United Illuminating Co.	1,002	3,480	3,757
Public Service Company of N.H.	799	3,473	2,639
Western Massachusetts Electric Co.	394	1,574	2,548
Eastern Utilities Associates	393	1,815	2,138
Central Vermont Public Service Corp.	90	205	1,073
New Bedford Gas & Edison Light Co.	131	593	839
Cambridge Electric Light Co.	92	383	702
Green Mountain Power Corp.	83	174	611
Total CSA-A	9,414	43,013	46,380
PSA 3			
Niagara Mohawk Power Corp.	2,895	15,041	25,322
New York State Electric & Gas Corp.	759	4,414	7,115
Power Authority of State of N.Y.	3,102	21,007	3,758
Rochester Gas & Electric Corp.	519	2,194	3,626

TABLE P-3 (cont'd)

ELECTRIC UTILITIES IN MARKET AREA - 1968
(Requirements greater than 500 gigawatt-hours)

Utility	Installed Capacity (MW)	Net Generation (GWh)	Energy Requirements (GWh)
PSA 4			
Consolidated Edison Co. of N.Y.	7,942	29,706	31,038
Long Island Lighting Co.	2,307	9,904	9,085
Central Hudson Gas & Electric Co.	590	2,928	2,508
Orange & Rockland Utilities, Inc.	338	1,783	1,848
Total CSA-B	18,452	86,977	84,300
PSA 5			
Public Service Electric & Gas Co.	6,345	24,297	23,543
Philadelphia Electric Co.	5,103	19,192	22,077
General Public Utilities	3,204	17,276	19,919
Pennsylvania Power & Light Co.	2,464	12,502	13,317
Baltimore Gas & Electric Co.	2,293	12,038	11,044
Delmarva Power & Light Co.	989	5,461	4,298
Atlantic City Electric Co.	734	4,386	3,296
Bethlehem Steel Co.	159	1,095	1,292
PSA 6			
Potomac Electric Power Co.	2,973	12,912	10,464
Total CSA-C	24,264	109,159	109,250
PSA 7			
Allegheny Power System	3,215	16,561	17,978
Duquesne Light Co.	1,757	9,602	10,028
Total PSA 7	4,972	26,163	28,006
PSA 18			
Virginia Electric & Power Co.	4,356	21,056	18,763
Grand Total	61,458	286,368	286,699

Requirements of publicly owned systems were over 15,000 gigawatt-hours in 1968 or 5 percent of the total market requirements. Of this amount 32 of the larger systems accounted for over 9,200, while 247 minor systems had a total of 5,800 gigawatt-hours. Table P-4 summarizes sources of supply of publicly-owned systems in the market area.

TABLE P-4

ENERGY SOURCES, PUBLICLY OWNED UTILITIES - 1968

	Market Sub-Areas					
	CSA-A	CSA-B	CSA-C	PSA-7	PSA-18	Total
Purchase All Requirements						
No. of Systems	57	45	54	9	42	207
Energy (GWh)	2,471	892	1,971	207	1,931	7,472
Generate All Requirements						
No. of Systems	8	8	2	1	0	19
Energy (GWh)	465	3,886	64	7	0	4,422
Purchase & Generate						
No. of Systems	29	3	13	3	5	53
Energy (GWh)	1,462	396	870	315	107	3,150
Total						
No. of Systems	94	56	69	13	47	279
Energy (GWh)	4,398	5,174	2,905	529	2,038	15,044

The majority of publicly owned utilities purchase all of their requirements from privately owned utilities. However, in New York State, (CSA-B), the Power Authority of the State of New York supplies over 76 percent of the almost 5 billion kilowatt-hours required by the publicly owned utilities in the state.

PAST AND ESTIMATED FUTURE POWER REQUIREMENTS

Forecasts of power consumption to 1980 may be made with a reasonable degree of accuracy and to 2020 with less precise but still acceptable results for planning purposes. In general, one of the principal tools used in the estimating modus operandi is the historical record of experience. Total requirements are normally arrived at through a ratiocination of necessity predicated on existing types and classes of service in constituent areas making up the market. Patterns of expanding energy requirements are well established, giving consideration to those known and potential factors that would affect them in any given area. For example, the number, location and relative requirements of future load concentrations are unlikely to change drastically from those presently existing. The megalopolis area from Washington, D. C. to Boston is expected to continue as the most concentrated load area of the region. The availability of coastal waters as a source of cooling for industry, as well as large electric generating stations, is one of the reasons that vaticinate a continuing growth. Various areas within the market as well as the NAR are noted for their position and value in the regional economy. Based on past statistics and knowledge of current population trends, housing patterns and employment, reasonable estimates of the future energy demands and its distribution in the basin can be established.

In 1968, power requirements of the market area amounted to 302,600 gigawatt-hours with an associated peak demand of 57.1 gigawatts, as compared with 175,100 gigawatt-hours and 33.1 gigawatts in 1960. Power requirements of the NAR in 1968 are estimated to be about 243,300 gigawatt-hours or 80 percent of total market requirements. As shown on Figure P-3 and in Table P-5, it is estimated that the market load will increase to 625,000 gigawatt-hours and 116 gigawatts by 1980, and 4,683,000 gigawatt-hours and 856 gigawatts by the year 2020.

DISTRIBUTION OF UTILITY LOAD

Generally, the distribution of electric power requirements in an area conforms to population arrayal. This is especially true of the NAR market area where the bulk of the utility load is apportioned along the high density coastal reached. This geographical dispersion of load, varying in degree of concentration suggests the useful concept of load centers, whose very location and power needs are important building-blocks in system planning schemes for generating and transmission facilities. Load centers generally relate to Standard Metropolitan Statistical Areas and are usually key points on backbone transmission networks for the reception of large blocks of power. Load centers conform to large concentrations of population or heavy power-consuming industrial complexes. Massena, New York is an example of the latter, where low cost hydroelectric power has fostered the location of an extensive aluminum producing

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POWER REQUIREMENTS
OF
UTILITY MARKET AREA

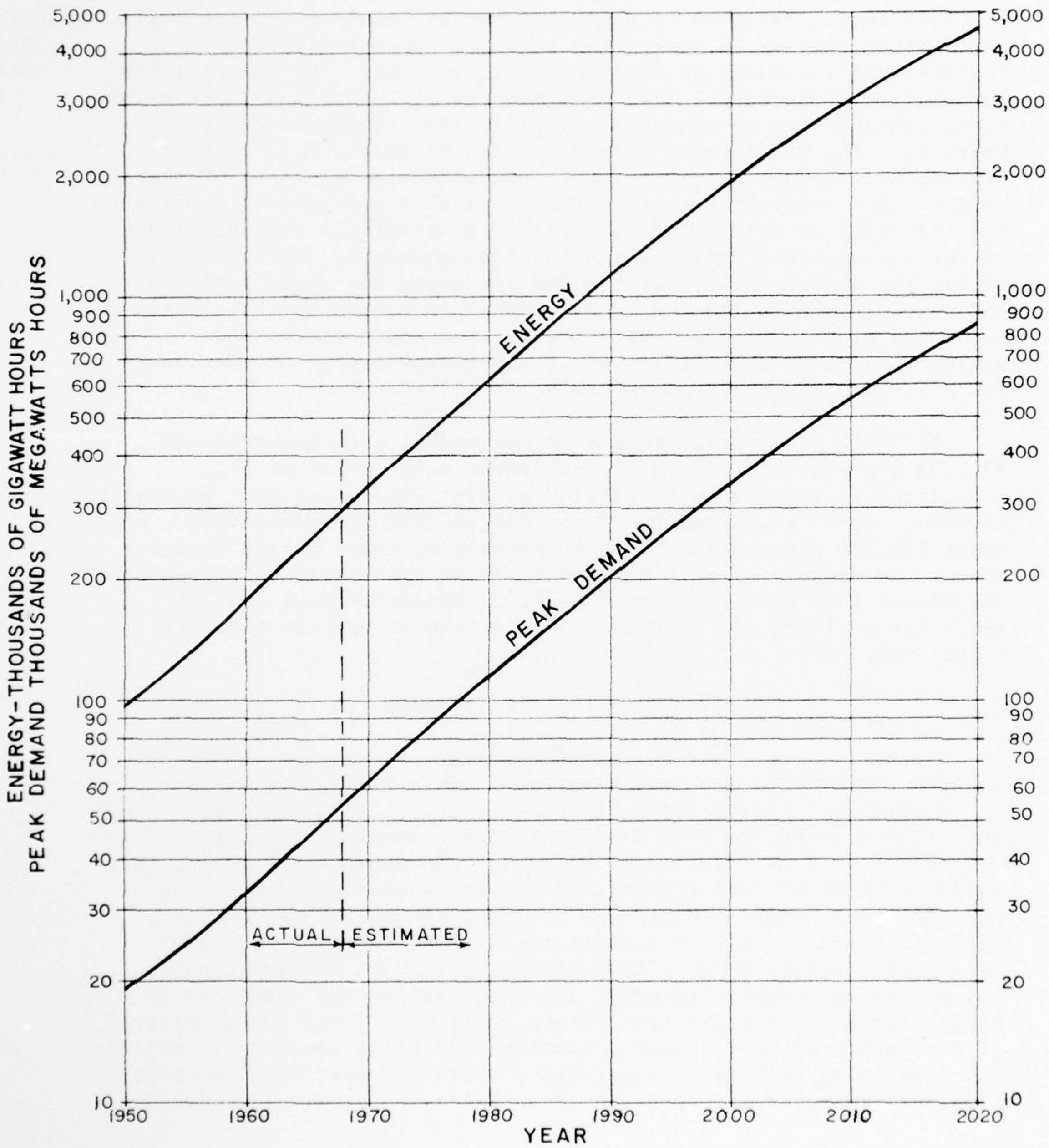

Figure P-3

TABLE P-5

POWER REQUIREMENTS IN MARKET AREA
(Actual)

	Energy/Load (GWh)	Peak Demand 1/ (MW)	Load Factor (%)
1950			
CSA-A	16,669	3,608	52.7
CSA-B	32,782	6,324	59.2
CSA-C	34,108	6,646	58.6
PSA-7	10,678	1,938	62.9
PSA-18	3,639	751	55.3
Total	97,906	19,267 2/	58.0
1960			
CSA-A	30,468	6,181	56.1
CSA-B	54,715	10,121	61.5
CSA-C	63,016	12,004	59.8
PSA-7	17,544	2,994	66.7
PSA-18	9,380	1,815	59.0
Total	175,123	33,114 2/	60.2
1968			
CSA-A	53,310	11,236	54.0
CSA-B	86,018	15,442	63.4
CSA-C	113,895	21,460	60.4
PSA-7	28,560	4,662	69.7
PSA-18	20,812	4,275	55.4
Total	302,595	57,075 2/	60.4

1/ Coincidental peak
2/ Totals non-coincidental

TABLE P-5 (Cont'd)

POWER REQUIREMENTS IN MARKET AREA
(Estimated)

	Energy/Load (GWh)	Peak Demand 1/ (MW)		Load Factor (%)
1980				
CSA-A	111,000	22,100		57.2
CSA-B	160,000	29,300		62.2
CSA-C	244,260	45,270		61.4
PSA-7	52,600	8,640		69.3
PSA-18	57,420	11,170		58.7
Total	625,280	116,480	2/	61.1
2000				
CSA-A	382,500	74,600		58.4
CSA-B	444,500	81,100		62.4
CSA-C	742,700	135,900		62.2
PSA-7	146,000	23,900		69.5
PSA-18	193,800	36,900		60.0
Total	1,909,500	352,400	2/	61.7
2020				
CSA-A	978,000	187,100		59.5
CSA-B	1,064,200	194,000		62.4
CSA-C	1,803,800	325,400		63.1
PSA-7	349,600	57,000		69.8
PSA-18	488,000	92,800		60.0
Total	4,683,600	856,300	2/	62.3

1/ Coincidental peak
2/ Totals non-coincidental

complex. Although the delineation of load centers involves individual judgement and power requirements may not be known with exactitude, still they contribute significantly in determining the general direction and dimension of system expansions in the future.

There are 71 load centers in the NAR market area estimated to have present peak demands in excess of 100 megawatts. By 2000, 14 of these 71 load centers are expected to have demands over 5,000 megawatts. Alone, they account for roughly 65 percent of the total distributed load in the area. Table P-6 lists the major load centers, with estimated 1980-2000-2020 peaks. Allocation of peak demand to a specific load center on a power sub-area supply basis ranges from 65 percent for CSA-A to 100 percent for PSA 18. Some sections of the area, such as Vermont, the northern sections of New Hampshire, and a large portion of Maine are devoid of load centers that meet the size criteria adopted.

CLASSIFIED SALES

Total utility load is the summation of the demands of various sectors having differing characteristics and requirements, and therefore subject to apportionment into distinct categories. Such classification is essential to the orderly and efficient management of utility operations and facilitates the analysis and utilization of power requirements and supply data. Further, consideration of power needs on a class of service basis, taking into account all the factors peculiar to a particular category, helps to identify the area's industrial and commercial development, the state of the economy, and the probable direction of future growth.

Classes of power use may be broadly defined as rural and residential, commercial, industrial, and all other. Relatively small in magnitude, the latter would include street and highway lighting, water pumping, electrified transportation, schools, and other municipal services. Rural consumption includes electric energy used in agriculture and can vary greatly depending upon the type of farm served and the extent that labor saving devices are utilized. Residential use is a function of population, the amount of disposable income, and use per customer, which will determine, to a large degree, the saturation of high energy use appliances, such as water heaters, ranges, air conditioners and electric heat. For the most part the commercial category encompasses those utility customers serving directly the functional and recreational needs of the population. These include such establishments as retail stores, filling stations, theatres, shopping centers and the like. The industrial customer usually includes the large bulk power consumers in many industries such as processing of primary and non-ferrous metals, chemical production, general manufacturing and various types of mining.

TABLE P-6

ESTIMATED PEAK DEMAND OF PRINCIPAL LOAD CENTERS 1/
(Megawatts)

Load Center	1968	1980	2000	2020
CSA-A				
Boston, Mass.	2,520	5,380	17,800	44,300
Providence, R. I.	680	1,430	4,600	11,600
Hartford, Conn.	590	1,330	4,100	10,200
Fall River-New Bedford, Mass.	390	800	2,600	6,500
Springfield-Holyoke, Mass.	380	820	2,700	6,600
Stamford, Conn.	370	720	2,400	6,000
Lawrence-Lowell, Mass.	370	740	2,500	6,100
New Haven, Conn.	350	760	2,500	6,100
Bridgeport, Conn.	340	710	2,300	5,800
Waterbury, Conn.	250	510	1,700	4,300
Worcester, Mass.	220	490	1,600	3,900
Meridan-Middletown, Conn.	200	410	1,400	3,400
Portland, Maine	180	390	1,400	3,700
Augusta, Maine	180	390	1,300	3,500
Manchester-Nashua, N.H.	180	380	1,200	3,100
Brockton, Mass.	180	390	1,200	3,100
Fitchburg-Leominster, Mass.	180	390	1,200	3,100
Willimantic, Conn.	140	260	900	2,200
Bangor, Maine	130	240	900	2,400
New London, Conn.	120	270	900	2,200
CSA-B				
New York, N. Y.	6,960	12,120	34,600	83,300
Long Island, N. Y.	1,905	3,320	9,500	22,800
*Buffalo-Niagara, N. Y.	1,800	3,200	8,500	20,100
Massena, N. Y.	670	1,070	3,100	7,200
*Rochester, N. Y.	660	1,270	3,300	7,600
Albany, N. Y.	415	730	1,900	4,600
*Syracuse, N. Y.	405	720	1,900	4,500
Binghamton, N. Y.	210	380	1,000	2,400
Elmira-Corning, N. Y.	180	320	800	2,000
*Geneva-Auburn, N. Y.	160	290	800	1,800
Utica-Rome, N. Y.	155	280	700	1,700
*Jamestown, N. Y.	110	200	500	1,300
*Ithaca, N. Y.	110	200	500	1,300
Newburgh-Poughkeepsie, N. Y.	100	170	500	1,100
CSA-C				
Philadelphia, Pa.	3,865	7,850	23,300	54,800
Northeast, N. J.	2,775	5,850	17,300	40,800
Washington, D. C.	2,625	6,000	17,800	41,900
Baltimore, Md.	2,330	4,950	14,700	34,600

TABLE P-6 (Cont'd)

ESTIMATED PEAK DEMAND OF PRINCIPAL LOAD CENTERS 1/
(Megawatts)

Load Center	1968	1980	2000	2020
CSA-C (Cont'd)				
New Brunswick-Perth Amboy, N.J.	1,040	2,120	6,300	14,800
Camden, N. J.	870	1,570	4,600	10,900
Allentown-Bethlehem-Easton, Pa.	815	1,850	5,500	12,900
Lancaster-York, Pa.	635	1,370	4,000	9,600
Wilmington, Del.	550	1,060	3,100	7,400
Scranton-Wilkes-Barre, Pa.	420	820	2,400	5,700
Trenton, N. J.	385	670	2,000	4,700
Harrisburg, Pa.	360	710	2,100	4,900
Reading, Pa.	325	710	2,100	4,900
Altoona-Johnstown, Pa.	320	670	2,000	4,700
*Erie, Pa.	295	630	1,900	4,400
Vineland, N. J.	220	430	1,300	3,000
Atlantic City, N. J.	210	390	1,200	2,700
Lebanon, Pa.	190	390	1,200	2,700
PSA-7				
*Pittsburgh, Pa.	1,690	3,100	8,500	20,400
*Butler-Kittanning, Pa.	510	1,015	2,700	6,500
*Washington-Monessen, Pa.	480	930	2,500	5,900
*Uniontown-Connellsville, Pa.	350	660	1,800	4,300
Hagerstown, Md.-Chambersburg, Pa.	290	500	1,500	3,400
Bellefont, Pa.	200	335	1,000	2,400
*Morgantown, W. Va.	190	370	1,000	2,400
*Parkersburg, W.Va.-Marietta, Ohio	190	370	1,000	2,400
*Clarksburg, W. Va.	180	380	1,000	2,400
*Weirton, W. Va.	180	290	900	2,100
*Cumberland, Md.	145	260	800	2,000
Frederick, Md.	130	215	600	1,400
Winchester, Va.	125	250	600	1,400
PSA-18				
Norfolk-Hampton, Va.	1,232	3,070	10,400	26,100
Alexandria, Va.	1,029	2,545	8,600	21,600
Richmond-Petersburg, Va.	973	2,845	8,900	22,400
Charlottesville, Va.	479	1,175	4,000	10,000
*Albemarle, N. C.	394	1,085	3,400	8,700
*Chase City, N. C.	201	450	1,600	4,000
Total Load Centers	49,033	98,965	296,400	715,000
Total Market	57,075	116,480	352,400	856,300

1/ Non-coincidental peak
* Outside NAR Boundary

Table P-7 indicates actual distribution of sales by class of service for 1968 and estimates of future distribution for 1980, 2000 and 2020. Only minor changes have been anticipated in existing patterns of future energy utilization.

TABLE P-7

ENERGY DISTRIBUTION BY CLASS OF SERVICE

CLASS		MARKET SUB-AREAS CSA-A	CSA-B	CSA-C	PSA-7	PSA-18	TOTAL
1968 Actual							
Rural & Residential	GWh	17,021	21,404	30,487	6,654	7,097	82,663
	%	31.9	24.9	26.8	23.3	34.1	27.3
Commercial	GWh	12,291	23,615	22,819	5,012	4,917	68,654
	%	23.0	27.5	20.0	17.5	23.6	22.7
Industrial	GWh	17,215	25,673	48,385	14,251	4,324	109,848
	%	32.3	29.8	42.5	49.9	20.8	36.3
All Other	GWh	1,894	7,736	3,041	479	2,528	15,678
	%	3.6	9.0	2.7	1.7	12.1	5.2
Total Sales	GWh	48,421	78,428	104,732	26,396	18,866	276,843
	%	90.8	91.2	92.0	92.4	90.6	91.5
Losses	GWh	4,889	7,590	9,163	2,164	1,946	25,752
	%	9.2	8.8	8.0	7.6	9.4	8.5
Total Energy	GWh	53,310	86,018	113,895	28,560	20,812	302,595
	%	100.0	100.0	100.0	100.0	100.0	100.0
1980							
Rural & Residential	GWh	35,110	43,300	65,080	12,120	17,350	172,960
	%	31.6	27.1	26.6	23.0	30.2	27.7
Commercial	GWh	24,660	45,100	50,200	9,460	17,300	146,720
	%	22.2	28.2	20.6	18.0	30.1	23.5
Industrial	GWh	36,870	44,930	104,650	25,910	13,080	225,440
	%	33.2	28.1	42.8	49.3	22.8	36.0
All Other	GWh	3,940	12,690	4,790	900	4,520	26,840
	%	3.6	7.9	2.0	1.7	7.9	4.3
Total Sales	GWh	100,580	146,020	224,720	48,390	52,250	571,960
	%	90.6	91.3	92.0	92.0	91.0	91.5
Losses	GWh	10,420	13,980	19,540	4,210	5,170	53,320
	%	9.4	8.7	8.0	8.0	9.0	8.5
Total Energy	GWh	111,000	160,000	244,260	52,600	57,420	625,280
	%	100.0	100.0	100.0	100.0	100.0	100.0

TABLE P-7 (Cont'd)

ENERGY DISTRIBUTION BY CLASS OF SERVICE

CLASS		MARKET SUB-AREAS CSA-A	CSA-B	CSA-C	PSA-7	PSA-18	TOTAL
2000							
Rural & Residential	GWh	120,600	125,800	197,000	33,300	54,700	531,400
	%	31.5	28.3	26.5	22.8	28.2	27.8
Commercial	GWh	83,200	127,700	151,900	26,600	64,500	453,900
	%	21.8	28.8	20.5	18.2	33.3	23.8
Industrial	GWh	130,000	118,800	322,600	71,500	46,100	689,000
	%	34.0	26.7	43.4	49.0	23.8	36.1
All Other	GWh	12,300	33,400	12,300	2,500	11,300	71,800
	%	3.2	7.5	1.7	1.7	5.8	3.7
Total Sales	GWh	346,100	405,700	683,800	133,900	176,600	1,746,100
	%	90.5	91.3	92.1	91.7	91.1	91.4
Losses	GWh	36,400	38,800	58,900	12,100	17,200	163,400
	%	9.5	8.7	7.9	8.3	8.9	8.6
Total Energy	GWh	382,500	444,500	742,700	146,000	193,800	1,909,500
	%	100.0	100.0	100.0	100.0	100.0	100.0
2020							
Rural & Residential	GWh	307,100	307,400	478,000	79,400	132,300	1,304,200
	%	31.4	28.9	26.5	22.7	27.1	27.8
Commercial	GWh	201,500	307,900	379,400	64,000	170,300	1,123,100
	%	20.6	28.9	21.0	18.3	34.9	24.0
Industrial	GWh	345,200	278,900	776,800	170,900	118,600	1,690,400
	%	35.3	26.2	43.1	48.9	24.3	36.1
All Other	GWh	30,300	77,300	27,900	6,000	23,400	164,900
	%	3.1	7.3	1.5	1.7	4.8	3.5
Total Sales	GWh	884,100	971,500	1,662,100	320,300	444,600	4,282,600
	%	90.4	91.3	92.1	91.6	91.1	91.4
Losses	GWh	93,900	92,700	141,700	29,300	43,400	401,000
	%	9.6	8.7	7.9	8.4	8.9	8.6
Total Energy	GWh	978,000	1,064,200	1,803,800	349,600	488,000	4,683,600
	%	100.0	100.0	100.0	100.0	100.0	100.0

CHAPTER 4

UTILITY POWER SUPPLY FOR MARKET

GENERATING FACILITIES

The NAR market area was supplied at the end of 1968 by an aggregate generating capacity of 64,497 megawatts. Of this total 51,879 megawatts were located in the NAR. Steam-electric capacity amounts to 84 percent of the total power supply in the market area. Hydroelectric and pumped storage capacity accounted for 12 percent of the total market capacity, with 64 percent of the market's total hydro capacity located within the NAR confines. Table P-8 lists the 1968 utility installed capacity and generation in the NAR and the market area by type of prime mover. Table P-9 includes the latest data available for all generating facilities in the NAR, both utility and industrial, by NAR Basins or Areas. Table P-10 lists the principal stations with capacities over 10 MW for hydro and internal combustion and gas turbine (IC/GT), and 100 MW for fossil and nuclear steam. Almost 32 percent of the total market area supply is located in two NAR Basins-the New York City-Long Island area, and the Delaware River area. Less than 5 percent of the total generating facilities are located in NAR Areas 1 through 7.

UTILITY FOSSIL STEAM CAPACITY

At the end of 1968 utility fossil steam capacity in the market area consisted of 719 units in 192 plants totaling 53,045 megawatts. Of this amount, 608 units in 162 stations aggregating 43,355 megawatts were located within the NAR. Thirty-two plants in the market area were over 500 megawatts in size, with a total capacity of 26,046 megawatts or almost 50 percent of the market.

Table P-11 shows the distribution of plant and unit sizes by market and NAR Basin areas for 1968. Ravenswood, in New York City, with an installed capacity of 1827 megawatts is the largest steam plant in the NAR. It also contains the largest unit, 1,027 megawatts. The 1872 MW Keystone mine mouth plant in western Pennsylvania is the largest steam plant in the market area. Unit sizes vary widely, ranging from one unit of 1,027 megawatts to several rated under 1,000 kilowatts. Sixty-one units installed in the market area since 1961 and totaling 18,564 megawatts, accounted for almost 35 percent of the total utility steam capacity in the market area. Over 45 percent of the fossil units were placed in service prior to 1941 but they represent less than 16 percent of the total market's capacity or 8,131 megawatts. Scheduled for service in the NAR are an additional 21,217 MW of fossil steam capacity, 88 percent of which is to be installed prior to 1975. The Susquehanna Basin will receive the largest portion 3,769 MW or about 18 percent of the total to be added. Table P-12 details scheduled or planned capacity by NAR areas and Table P-13 their scheduled installation date.

TABLE P-8

UTILITY INSTALLED GENERATING CAPACITY AND ENERGY PRODUCTION IN 1968

SUMMARY

Type of Capacity	NAR Market		NAR Basin		
	Installed Capacity				
	(MW)	(% Tot.)	(MW)	(% Tot.)	(% Market)
Fossil Steam	53045	82.2	43355	83.6	81.7
Nuclear Steam	1206	1.9	1106	2.1	92.7
IC/GT	2612	4.0	2574	5.0	98.5
Conv. Hydro	6224	9.7	3674	7.1	59.0
Pumped Storage	1410	2.2	1170	2.2	83.0
Total	64497	100.0	51879	100.0	80.4
	Net Generation				
	(GWh)	(% Tot.)	(GWh)	(% Tot.)	(% Market)
Fossil Steam	257108	86.3	209302	89.6	81.4
Nuclear Steam	6177	2.1	5842	2.5	94.6
IC/GT	2190	0.7	2159	0.9	98.6
Conv. Hydro	33513	11.2	17256	7.4	51.5
Pumped Storage	(1113)	(0.3)	(897)	(0.4)	80.6
Total	297875	100.0	233662	100.0	78.4

TABLE P-8 (cont'd)

UTILITY INSTALLED GENERATING CAPACITY AND ENERGY PRODUCTION IN 1968

CSA-A

Type of Capacity	NAR Market		NAR Basin		
	Installed Capacity				
	(MW)	(% Tot.)	(MW)	(% Tot.)	(% Market)
Fossil Steam	9027	77.6	9027	77.6	100.0
Nuclear Steam	785	6.7	785	6.7	100.0
IC/GT	582	5.0	582	5.0	100.0
Conv. Hydro	1211	10.4	1211	10.4	100.0
Pumped Storage	31	0.3	31	0.3	100.0
Total	11636	100.0	11636	100.0	100.0
	Net Generation				
	(GWh)	(% Tot.)	(GWh)	(% Tot.)	(% Market)
Fossil Steam	42516	82.2	42516	82.2	100.0
Nuclear Steam	4206	8.1	4206	8.1	100.0
IC/GT	445	0.9	445	0.9	100.0
Conv. Hydro	4549	8.8	4549	8.8	100.0
Pumped Storage	5	0.0	5	0.0	100.0
Total	51721	100.0	51721	100.0	100.0

TABLE P-8 (cont'd)

UTILITY INSTALLED GENERATING CAPACITY AND ENERGY PRODUCTION IN 1968

CSA-B

Type of Capacity	NAR Market		NAR Basin		
	Installed Capacity				
	(MW)	(% Tot.)	(MW)	(% Tot.)	(% Market)
Fossil Steam	14017	75.3	11201	84.0	79.9
Nuclear Steam	275	1.5	275	2.1	100.0
IC/GT	362	1.9	348	2.6	96.1
Conv. Hydro	3729	20.0	1510	11.3	40.5
Pumped Storage	240	1.3	0	---	---
Total	18623	100.0	13334	100.0	71.6
	Net Generation				
	(GWh)	(% Tot.)	(GWh)	(% Tot.)	(% Market)
Fossil Steam	61073	69.7	46113	80.7	75.5
Nuclear Steam	1511	1.7	1511	2.6	100.0
IC/GT	231	0.3	230	0.4	99.6
Conv. Hydro	24958	28.5	9318	16.3	37.3
Pumped Storage	(216)	(0.2)	0	---	---
Total	87557	100.0	57172	100.0	65.3

TABLE P-8 (cont'd)

UTILITY INSTALLED GENERATING CAPACITY AND ENERGY PRODUCTION IN 1968

CSA-C

Type of Capacity	NAR Market		NAR Basin		
	Installed Capacity				
	(MW)	(% Tot.)	(MW)	(% Tot.)	(% Market)
Fossil Steam	21184	85.4	18852	84.0	89.0
Nuclear Steam	46	0.2	46	0.2	100.0
IC/GT	1516	6.1	1501	6.7	99.0
Conv. Hydro	930	3.7	911	4.0	98.0
Pumped Storage	1139	4.6	1139	5.1	100.0
Total	24815	100.0	22449	100.0	90.5
	Net Generation				
	(GWh)	(% Tot.)	(GWh)	(% Tot.)	(% Market)
Fossil Steam	107126	96.4	98628	96.2	92.1
Nuclear Steam	125	0.1	125	0.1	100.0
IC/GT	1444	1.3	1432	1.4	99.2
Conv. Hydro	3330	3.0	3243	3.2	97.4
Pumped Storage	(902)	(0.8)	(902)	(0.9)	100.0
Total	111123	100.0	102526	100.0	92.3

TABLE P-8 (cont'd)

UTILITY INSTALLED GENERATING CAPACITY AND ENERGY PRODUCTION IN 1968

PSA-7

Type of Capacity	NAR Market		NAR Basin		
	Installed Capacity				
	(MW)	(% Tot.)	(MW)	(% Tot.)	(% Market)
Fossil Steam	4870	96.6	1482	97.6	30.4 /1
Nuclear Steam	100	2.0	0	---	---
IC/GT	8	0.2	23	1.5	287.5 /1
Conv. Hydro	62	1.2	14	0.9	22.6
Pumped Storage	0	---	0	---	---
Total	5040	100.0	1519	100.0	30.1
	Net Generation				
	(GWh)	(% Tot.)	(GWh)	(% Tot.)	(% Market)
Fossil Steam	25865	98.0	7882	99.2	30.5 /1
Nuclear Steam	335	1.3	0	---	---
IC/GT	18	0.1	7	0.1	38.9 /1
Conv. Hydro	166	0.6	55	0.7	33.1
Pumped Storage	0	---	0	---	---
Total	26384	100.0	7944	100.0	30.1

/1 Mt. Storm Steam Station & GT included in NAR Basin but not in Market.

TABLE P-8 (cont'd)

UTILITY INSTALLED GENERATING CAPACITY AND ENERGY PRODUCTION IN 1968

PSA-18

Type of Capacity	NAR Market		NAR Basin		
	Installed Capacity				
	(MW)	(% Tot.)	(MW)	(% Tot.)	(% Market)
Fossil Steam	3947	90.1 /1	2793	95.0	70.8
Nuclear Steam	---	---	---	---	---
IC/GT	144	3.3 /1	120	4.1	83.3
Conv. Hydro	292	6.6	28	0.9 /2	9.6
Pumped Storage	---	---	---	---	---
Total	4383	100.0	2941	100.0	67.1
	Net Generation				
	(GWh)	(% Tot.)	(GWh)	(% Tot.)	(% Market)
Fossil Steam	20528	97.3 /1	14163	99.1	69.0
Nuclear Steam	---	---	---	---	---
IC/GT	52	0.3 /1	45	0.3	86.5
Conv. Hydro	510	2.4	91	0.6 /2	17.8
Pumped Storage	---	---	---	---	---
Total	21090	100.0	14299	100.0	67.8

/1 Mt. Storm Steam Station & GT included in Market, but not in NAR Basin.

/2 Includes 14 MW of capacity and 37 GWh located in NAR Basin but outside the Market Area.

TABLE P-9

TOTAL GENERATING CAPACITIES - UTILITY AND OTHER KNOWN FACILITIES

NAR Areas - 1969

Area	Steam Electric		Hydroelectric			
	Nuclear (MW)	Fossil (MW)	Pump. (MW)	Conv. (MW)	IC/GT (MW)	Total (MW)
1	-	50	-	2	30	82
2	-	189	-	131	22	342
3	-	13	-	209	4	226
4	-	104	-	158	4	266
5	-	193	-	28	22	243
			-			
6	-	485	-	58	23	566
7	-	620	-	74	62	756
8	785	1,126	-	642	139	2,692
9	-	5,385	-	3	230	5,618
10	-	2,220	31	101	345	2,697
11	-	50	-	1,218	74	1,342
12	275	1,520	-	392	157	2,344
13	-	10,201	-	-	407	10,608
14	-	4,776	-	6	479	5,261
15	-	6,779	339	68	746	7,932
16	550	349	-	-	56	955
17	46	3,643	800	839	240	5,568
18	-	3,049	-	1	416	3,466
19	-	3,970	-	13	423	4,406
20	-	430	-	-	5	435
21	-	2,858	-	31	148	3,037
Total	1,656	48,010	1,170	3,974	4,032	58,842

TABLE P-10

PRINCIPAL GENERATING FACILITIES - 1968 1/

Area and Plant Name	Location	Type 2/	Capacity (MW)
1. St. John			
Base Power Plant	Limestone, Me.	O	15.4
2. Penobscot			
Penobscot	Millinocket, Me.	H	87.0
Graham	Veazie, Me.	O	12.0
3. Kennebec			
Harris	Indian Stream Twp., Me.	H	75.0
Wyman	Moscow, Me.	H	72.0
Williams	Embden, Me.	H	13.0
Weston	Skowhegan, Me.	H	12.0
4. Androscoggin			
Berlin	Berlin, N.H.	H	32.5
Upper	Rumford, Me.	H	22.0
Gulf Island	Lewiston, Me.	H	19.2
Smith	Berlin, N.H.	H	15.0
Lower	Rumford, Me.	H	12.8
5. St. Croix			
Mason	Wiscasset, Me.	FS	146.5
6. Presumpscot			
W. F. Wyman	Yarmouth, Me.	FS	213.6
Schiller	Portsmouth, N.H.	FS	178.8
Skelton	Buxton-Dayton, Me.	H	16.8
White Lake	Tamworth, N.H.	O	18.6
7. Merrimack			
Merrimack	Bow, N.H.	FS	459.2
Amoskeag	Manchester, N.H.	H	16.0
Lowell	Lowell, Mass.	H	10.7
Merrimack	Bow, N.H.	O	37.2*
Cherry St.	Hudson, Mass.	O	19.8
8. Connecticut			
Connecticut Yankee	Haddam Neck, Conn.	NS	600.3
Rowe	Rowe, Mass.	NS	185.0
Middletown	Middletown, Conn.	FS	422.0
South Meadow	Hartford, Conn.	FS	216.8
West Springfield	W. Springfield, Mass.	FS	209.6
Mt. Tom	Holyoke, Mass.	FS	136.0
Moore	Littleton, N.H.	H	140.4

TABLE P-10 (cont'd)

PRINCIPAL GENERATING FACILITIES - 1968 1/

Area and Plant Name	Location	Type 2/	Capacity(MW)
8. Connecticut - (cont'd)			
Comerford	Monroe, N.H.	H	140.4
Cabot	Montague, Mass.	H	51.0
Bellows Falls	Bellows Falls, Vt.	H	40.8
Harriman	Whitingham, Vt.	H	33.6
Cobble Mountain	Granville, Mass.	H	33.0
Wilder	Lebanon, N.H.	H	16.2
Vernon	Hinsdale, N.H.	H	16.0
Hadley Falls	Holyoke, Mass.	H	15.0
Deerfield #5	Florida, Mass.	H	15.0
McIndoes	Monroe, N.H.	H	10.6
Lost Nation	Groveton, N.H.	O	21.4*
Enfield	Enfield, Conn.	O	18.6*
Middletown	Middletown, Conn.	O	18.6
West Springfield	W. Springfield, Mass.	O	18.6
East Springfield	Springfield, Mass.	O	16.0
Ascutney	Ascutney, Vt.	O	13.2
Thompsonville	Thompsonville, Conn.	O	12.0
South Meadow	Hartford, Conn.	O	10.0
No. 10 Holyoke	Holyoke, Mass.	O	10.0
9. Massachusetts Coastal			
Brayton Point	Somerset, Mass.	FS	1124.7*
New Boston	South Boston, Mass.	FS	717.7
Canal Plant	Sandwich, Mass.	FS	542.5
Mystic New	Everett, Mass.	FS	468.8
Somerset	Somerset, Mass.	FS	325.0
Salem Harbor	Salem, Mass.	FS	319.9
Edgar New	N. Weymouth, Mass.	FS	300.0
South Street	Providence, R.I.	FS	188.6
Edgar Original	N. Weymouth, Mass.	FS	157.9
L Street	S. Boston, Mass.	FS	153.8
Mystic Original	Everett, Mass.	FS	150.0
Manchester St.	Providence, R.I.	FS	132.0
Cannon St.	New Bedford, Mass.	FS	115.5
Framingham	Framingham, Mass.	O	33.5
Edgar	N. Weymouth, Mass.	O	33.5*
Lynnway Diesel	Lynn, Mass.	O	22.0
Gloucester	Gloucester, Mass.	O	21.0
L Street	South Boston, Mass.	O	18.6
Mystic	Everett, Mass.	O	16.8*
Peabody	Peabody, Mass.	O	11.2
Brayton Point	Somerset, Mass.	O	11.0

TABLE P-10 (cont'd)

PRINCIPAL GENERATING FACILITIES - 1968 1/

Area and Plant Name	Location	Type 2/	Capacity(MW)
10. Thames			
Bridgeport Harbor	Bridgeport, Conn.	FS	660.5
Devon	Devon, Conn.	FS	454.0
Norwalk Harbor	Norwalk, Conn.	FS	326.4
Montville	Montville, Conn.	FS	176.0
Steel Point	Bridgeport, Conn.	FS	155.5
English	New Haven, Conn.	FS	146.2
Shepaug	Southbury, Conn.	H	37.2
Rocky River	New Milford, Conn.	H(PS)	31.0
Stevenson	Stevenson, Conn.	H	30.5
Silver Lake	Pittsfield, Mass.	O	72.0*
Cos Cob	Greenwich, Conn.	O	63.8*
Branford	Branford, Conn.	O	18.6*
Tunnel	Norwich, Conn.	O	18.6*
Franklin Drive	Torrington, Conn.	O	18.6
Torrington Term.	Torrington, Conn.	O	18.6
Bridgeport Harbor	Bridgeport, Conn.	O	18.6
Doreen	Pittsfield, Mass.	O	18.6*
Woodland Road	Lee, Mass.	O	18.6*
Norwalk Harbor	Norwalk, Conn.	O	16.3
Devon	Devon, Conn.	O	16.3
Tracy	Putnam, Conn.	O	16.0
Danielson	Danielson, Conn.	O	12.0
South Norwalk	S. Norwalk, Conn.	O	10.3
11. Lake Champlain			
[Robert Moses St. Lawrence	Massena, N.Y.	H	912.0
Colton	Colton, N.Y.	H	30.0
Five Falls	South Colton, N.Y.	H	22.5
Rainbow	South Colton, N.Y.	H	22.5
Stark	South Colton, N.Y.	H	22.5
South Colton	South Colton, N.Y.	H	19.4
Blake	South Colton, N.Y.	H	14.4
High Falls	Moffitsville, N.Y.	H	14.1
Rutland	Rutland, Vt.	O	31.2
Gorge #16	Colchester, Vt.	O	17.0
12. Hudson			
Indian Point	Buchanan, N.Y.	NS	275.0
Danskammer	Roseton, N.Y.	FS	531.9
Lovett	Tompkins Cove, N.Y.	FS	490.1*
Albany	Albany, N.Y.	FS	400.0

TABLE P-10 (cont'd)

PRINCIPAL GENERATING FACILITIES - 1968 1/

Area and Plant Name	Location		Capacity(MW)
12. Hudson (cont'd)			
Spier Falls	Corinth, N.Y.	H	44.4
School St.	Cohoes, N.Y.	H	38.8
Stewarts Bridge	Hadely, N.Y.	H	30.0
Sherman Island	Glen Falls, N.Y.	H	28.8
Neversink	Grahamsville, N.Y.	H	25.0
Trenton	Trenton Falls, N.Y.	H	23.6
Beardslee	Manheim, N.Y.	H	20.0
E. G. West	Hadely, N.Y.	H	20.0
Grahamsville	Grahamsville, N.Y.	H	18.0
Prospect	Trenton Falls, N.Y.	H	17.3
Sturgeon Pool	Rifton, N.Y.	H	14.4
Schaghticoke	Schaghticoke, N.Y.	H	13.1
Albany Gas Turbine	Albany, N.Y.	O	116.7*
Coxsackie	Coxsackie, N.Y.	O	21.3*
Indian Point	Buchanan, N.Y.	O	16.6*
13. Nassau & Suffolk Counties and New York City			
Ravenswood	Long Island City, N.Y.	FS	1,827.7
Astoria	Astoria (Queens) N.Y.	FS	1,550.6
Arthur Kill	Travis (Staten Island) N.Y.	FS	911.7*
Hudson Avenue	Brooklyn, N.Y.	FS	845.0
East River	Manhattan, N.Y.	FS	833.6
Northport	Northport, N.Y.	FS	774.2
Waterside	Manhattan, N.Y.	FS	712.2
Hell Gate	Bronx, N.Y.	FS	611.2
Port Jefferson	Port Jefferson, N.Y.	FS	467.0
Glenwood	Glenwood Landing, N.Y.	FS	377.3
E. F. Barrett	Island Park, N.Y.	FS	375.0
74th St.	Manhattan, N.Y.	FS	269.0
Sherman Creek	Manhattan, N.Y.	FS	216.5
59th St.	Manhattan, N.Y.	FS	184.5
Far Rockaway	Far Rockaway, N.Y.	FS	113.6
Kent Avenue	Brooklyn, N.Y.	FS	107.5
West Babylon	W. Babylon, N.Y.	O	55.8
74th St.	Manhattan, N.Y.	O	37.2
Hudson Ave.	Brooklyn, N.Y.	O	35.7
59th St.	Manhattan, N.Y.	O	34.2*
Kent Avenue	Brooklyn, N.Y.	O	28.0*
Mun. Elec. Gen. Sta.	Rockville Center, N.Y.	O	26.6
Power Plant #2	Freeport, N.Y.	O	19.0*

TABLE P-10 (cont'd)

PRINCIPAL GENERATING FACILITIES - 1968 1/

Area and Plant Name	Location	Type 2/	Capacity(MW)
13. Nassau & Suffolk Counties and New York City (cont'd)			
E. F. Barrett	Island Park, N.Y.	O	18.6
Ravenswood	L.I. City, N.Y	O	16.0
Astoria	Astoria (Queens) N.Y.	O	16.0
Port Jefferson	Port Jefferson, N.Y.	O	16.0
Northport	Northport, N.Y.	O	16.0
Glenwood	Glenwood Landing, N.Y.	O	16.0
Waterside	Manhattan, N.Y.	O	14.0
Southold	Southold, N.Y.	O	14.0
Power Plant #1	Freeport, N.Y.	O	13.1
Southhampton	Southampton, N.Y.	O	11.5
14. Passaic River			
Hudson	Jersey City, N.J.	FS	1,114.5
Sewaren	Sewaren, N.J.	FS	820.0
Bergen	Ridgefield, N.J.	FS	650.4
Linden	Linden, N.J.	FS	519.4
Sayreville	Sayreville, N.J.	FS	343.8
Essex	Newark, N.J.	FS	329.3
Kearny A	Kearny, N.J.	FS	304.5
Kearny B	Kearny, N.J.	FS	294.1
Marion	Jersey City, N.J.	FS	125.0
Werner	South Amboy, N.J.	FS	116.2
Kearny B	Kearny, N.J.	O	164.8*
Sewaren	Sewaren, N.J.	O	115.2
Hudson	Jersey City, N.J.	O	115.2
Essex	Newark, N.J.	O	30.0
Bergen	Ridgefield, N.J.	O	18.6
Linden	Linden, N.J.	O	18.6
15. Delaware			
Eddystone	Eddystone, Pa.	FS	707.2
Mercer	Hamilton Twp., N.J.	FS	652.8
Burlington	Burlington, N.J.	FS	490.5
Richmond	Philadelphia, Pa.	FS	474.8
Delaware	Philadelphia, Pa.	FS	439.2
Portland	Portland, Pa.	FS	426.7
Cromby	Cromby, Pa.	FS	417.5
Edge Moor	Edge Moor, Del.	FS	389.8
Southwark	Southwark, Pa.	FS	345.0
Schuylkill	Philadelphia, Pa.	FS	325.4
Martins Creek	Martins Creek, Pa.	FS	312.5

TABLE P-10 (cont'd)

PRINCIPAL GENERATING FACILITIES - 1968 1/

Area and Plant Name	Location	Type 2/	Capacity(MW)
15. Delaware (cont'd)			
Deepwater	Penns Grove, N.J.	FS	308.3
Chester	Chester, Pa.	FS	256.0
Titus	Reading, Pa.	FS	225.0
Barbadoes	Norristown, Pa.	FS	155.0
Delaware City	Delaware City, Del.	FS	130.0
Gilbert	Holland, N.J.	FS	126.1
Yards Creek	Blairstown, N.J.	H(PS)	338.7
Wallenpaupack	Hawley, Pa.	H	40.0
Rio	Lumberland, N.Y.	H	10.0
Mercer	Hamilton Twp., N.J.	O	115.2
Southwark	Philadelphia, Pa.	O	74.4
Allentown	Allentown, Pa.	O	64.0
Delaware	Philadelphia, Pa.	O	55.8*
Chester	Chester, Pa.	O	55.8*
Barbadoes	Norristown, Pa.	O	45.0
Fishbach	Pottsville, Pa.	O	37.2*
Eddystone	Eddystone, Pa.	O	37.2
Deepwater	Penns Grove, N.J.	O	18.6
Delaware City	Delaware City, Del.	O	18.6
Schuylkill	Philadelphia, Pa.	O	18.6*
National Park	National Park, N.J.	O	18.6*
Burlington	Burlington, N.J.	O	18.6
Portland	Portland, Pa.	O	18.0
Titus	Reading, Pa.	O	18.0
West	Marshallton, Del.	O	17.6
Bethlehem	Bethlehem, Pa.	O	17.5
Edge Moor	Edge Moor, Del.	O	15.0
Kent	Dover, Del.	O	14.0
South Madison St.	Wilmington, Del.	O	11.7
Lansdale	Lansdale, Pa.	O	11.2
16. Monmouth County Streams			
Oyster Creek	Lacey Township, N.J.	NS	550.0*
B. L. England	Beesley's Point, N.J.	FS	299.2
Missouri Ave.	Atlantic City, N.J.	O	55.8*
17. Susquehanna			
Brunner Island	York Haven, Pa.	FS	1,558.7*
Shawville	Shawville, Pa.	FS	625.0
Sunbury	Shamokin Dam, Pa.	FS	409.8
Goudey	Binghamton, N.Y.	FS	145.8
Stanton	Harding, Pa.	FS	140.5

TABLE P-10 (cont'd)

PRINCIPAL GENERATING FACILITIES - 1968 1/

Area and Plant Name	Location	Type 2/	Capacity (MW)
17. Susquehanna (cont'd)			
Crawford	Middletown, Pa.	FS	116.7
Holtwood	Holtwood, Pa.	FS	105.0
Muddy Run	Drumore, Pa.	H(PS)	800.0
Conowingo	Conowingo, Md.	H	474.5
Safe Harbor	Safe Harbor, Pa.	H	230.6
Holtwood	Holtwood, Pa.	H	107.2
York Haven	York Haven, Pa.	H	19.6
Harrisburg	Harrisburg, Pa.	O	64.0
West Shore	Harrisburg, Pa.	O	37.2*
Harwood	Hazeltown, Pa.	O	32.0
Williamsport	Williamsport, Pa.	O	32.0
Jenkins	Laflin, Pa.	O	32.0
Lock Haven	Lock Haven, Pa.	O	18.6*
18. Patuxent			
Chalk Point	Brandywine, Md.	FS	727.6
H. A. Wagner	Ann Arundel Co., Md.	FS	627.8
C. P. Crane	Baltimore Co., Md.	FS	399.8
Riverside	Baltimore Co., Md.	FS	333.5
Westport	Baltimore, Md.	FS	311.5
Gould St.	Baltimore, Md.	FS	173.5
Indian River	Millsboro, Del.	FS	163.2
Sparrows Point	Sparrows Point, Md.	FS	158.5
Notch Cliff	Baltimore Co., Md.	O	144.0*
Westport	Baltimore, Md.	O	121.5*
Easton	Easton, Md.	O	19.4
Vienna	Vienna, Md.	O	18.6
Indian River	Millsboro, Del.	O	18.6
Chalk Point	Brandywine, Md.	O	16.2
C. P. Crane	Baltimore Co., Md.	O	16.0
H. A. Wagner	Ann Arundel Co., Md.	O	16.0
Crisfield	Crisfield, Md.	O	11.4
Bayview	Cape Charles, Va.	O	10.0
19. Potomac			
Mt. Storm	Mt. Storm, W. Va.	FS	1,140.5
Dickerson	Dickerson, Md.	FS	586.5
Benning	Benning, D. C.	FS	553.6
Potomac River	Alexandria, Va.	FS	514.8
Possum Point	Dumfries, Va.	FS	491.0
Buzzard Point	Washington, D. C.	FS	270.0

TABLE P-10 (cont'd)

PRINCIPAL GENERATING FACILITIES - 1968 1/

	Area and Plant Name	Location	Type 2/	Capacity (MW)
	Potomac (cont'd)			
19.	R. Paul Smith	Williamsport, Md.	FS	159.5
	Buzzard Point	Washington, D. C.	O	288.0
	Possum Point	Dumfries, Va.	O	96.0
	Mt. Storm	Mt. Storm, W. Va.	O	18.6
	Dickerson	Dickerson, Md.	O	16.2
20.	Rappahannock & York			
	Yorktown	Yorktown, Va.	FS	375.0
21.	James			
	Chesterfield	Chester, Va.	FS	1,484.4*
	Portsmouth	Chesapeake, Va.	FS	649.6
	Bremo	Bremo Bluff, Va.	FS	284.3
	12th St.	Richmond, Va.	FS	102.5
	Reeves Avenue	Norfolk, Va.	FS	100.0
	Reusens	Lynchburg, Va.	H	12.5
	Portsmouth	Chesapeake, Va.	O	147.8*

1/ Nuclear and Fossil Steam - 100 MW or greater, Hydro and Other - 10 MW or greater

2/ NS-Nuclear Steam, FS-Fossil Steam, H-Conventional Hydro, H(PS)-Pumped Storage Hydro, O-Internal Combustion, Gas Turbine and Diesel.

* Includes capacity installed in 1969.

TABLE P-11

FOSSIL STEAM-PLANT AND UNIT SIZES - 1968

Market

Market Area	Total Capacity (MW)	No. of Plants	No. of Units	Average Plant Size (MW)	Average Unit Size (MW)
CSA-A	9,027	63	226	143	40
CSA-B	14,017	36	150	389	94
CSA-C	21,184	63	244	336	87
PSA-7	4,870	21	69	232	71
PSA-18	3,947	9	30	439	132
Total	53,045	192	719	276	74

NAR Basin Areas

Market Area	Total Capacity (MW)	No. of Plants	No. of Units	Average Plant Size (MW)	Average Unit Size (MW)
CSA-A	9,027	63	226	143	40
CSA-B	11,201	25	106	448	106
CSA-C	18,852	59	231	320	82
PSA-7	1,482	8	20	185	74
PSA-18	2,793	7	25	399	112
Total	43,355	162	608	268	71

TABLE P-12

SCHEDULED OR PLANNED CAPACITY ADDITIONS BY NAR AREAS

	Steam Electric				Hydro		IC/GT	
	Nuclear		Fossil					
Area	No. of Units	Total MW	No. of Units	Total MW	No. of Units	Total MW	No. of Units	Total MW
1	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-
5	1	830	-	-	-	-	-	-
6	-	-	1	400	-	-	2	44
7	-	-	-	-	-	-	6	30
8	1	537	1	375	7	1,610	5	166
9	1	650	6	2,532	-	-	20	454
10	2	1,482	1	375	5	1,000	11	210
11	-	-	-	-	-	-	1	25
12	3	3,287	5	2,585	12	2,800	17	416
13	1	850	4	2,523	-	-	44	1,967
14	-	-	2	472	3	122	22	1,740
15	6	6,736	4	2,928	NA	1,300	54	1,449
16	2	1,740	2	560	-	-	4	143
17	5	4,484	4	3,769	NA	1,500	10	219
18	2	1,804	3	732	-	-	19	711
19	-	-	5	2,427	-	-	4	79
20	2	1,750	1	845	-	-	-	-
21	2	1,600	1	694	NA	-	9	217
Total	28	25,750	40	21,217	27 +	8,332	228	7,870

TABLE P-13

SCHEDULED OR PLANNED CAPACITY ADDITIONS
IN NAR AREAS BY PERIOD OF INSTALLATION

Year	Steam Electric Nuclear MW	Steam Electric Fossil MW	Hydro MW	Ic/Gt MW	Total MW
1969	550	2,858	--	1,422	4,830
1970	652	740	--	2,768	4,160
1971-1975	19,511	15,046	2,732	3,670	40,959
After 1975	5,037	2,573	5,600	10	13.220
Total	25,750	21,217	8,332	7,870	63.169

The rapid growth of power demands, siting problems, and high load densities brought about by the large urban areas in the regions, will dictate the selection of large unit sizes. The average unit size of the 40 units scheduled to be installed is 530 MW compared to the present NAR Basin average size of 268 MW. Plant sizes also will increase. The Martins Creek plant on the Delaware is scheduled at over 2700 MW when completed. Thus by the year 2000, it is anticipated that units of up to 2000 MW and plants of 5,000 MW will be in use. Of the new capacity scheduled, fossil steam represents 33 percent as compared to 84 percent, which is its present share of the market. As long as fossil-fuel capacity remains competitive with nuclear and "other" fuels, continued use of fossil fuels for generation in the NAR and other coal-producing areas of the market may be expected.

UTILITY NUCLEAR STEAM CAPACITY

At the present time five nuclear plants are operating in the NAR and eight in the market area. The unit at Millstone, Conn. (652 MW) is the most recent unit to go into operation. Between 1971 and 1975, 19,511 megawatts in 21 units are due to be installed in the NAR region and 21,243 megawatts in 23 units are scheduled for the market. The largest known nuclear complex will be on the Hudson River about 40 miles north of New York City at Buchanan, N.Y. where over 2400 megawatts will be installed by the year 1973.

Nuclear capacity will form an increasingly larger share of the market area's future power supply growing from less than 2 percent in 1968 to 30 percent by 1980. While a further increase in nuclear share of the total supply may be expected after 1980, fossil steam is not likely to be entirely supplanted, particularly as generation developed for peaking and intermediate load factor duty.

Since nuclear-fueled plants in sizes greater than two million kilowatts are already under construction in the region, it is reasonable to predict nuclear plants of 3 to 4 million kilowatts in the future. One constraint on size of power plants may be the size of investment committed to one location. For a plant of four million kilowatts this may approach a billion dollars. Another constraint is that plant sizes must be in balance with the other elements of the bulk power system that affect the stability and reliability of power supply.

INTERNAL COMBUSTION AND GAS TURBINE CAPACITY (IC/GT)

Internal combustion generating capacity in the past was most commonly associated with the power supply of small utilities, generally municipally owned. Such units were of relatively minor significance on large systems and their use was somewhat limited until fairly recently. With developments in the application of gas turbines to electric power generation, particularly the adaptation of aircraft jet engines, unit sizes have been extended. Accumulated operating experience in various industries, including electric power, has demonstrated their adaptability for reserve and peaking duty on utility loads. As a result, IC/GT has become increasingly important in system planning. The experience of utilities during major power failures in recent years has indicated the need on predominantly thermal systems for "quick start" power sources such as IC/GT to supply station auxiliaries in reenergizing systems. Among the advantages offered by these two prime mover types that have proven attractive to system planners, are their relatively low capital cost, flexibility in the size of installations, comparative freedom of choice in location, and relatively short lead times between the decision to buy and the in-service dates. The short lead time is particularly significant at this time when many utilities are hard pressed to maintain adequate margins of supply.

At the end of 1968 there were 435 IC/GT units in the market area totaling 2,612 megawatts of which 2,574 megawatts are installed in the NAR region. By 1970, 4,190 additional megawatts are scheduled for installation in the NAR. This represents an increase of 163 percent over all the IC/GT capacity existing in 1968. Since construction lead times are short in relation to other forms of generating capacity, scheduled additions after 1971 represent only a small portion of that capacity which will be in service by 1980.

The largest addition at a single location is at Edison, N.J., consisting of three GT units totaling 502 megawatts. The largest single gas turbine unit is the Astoria #4 unit (176 MW) in Astoria, N.Y., on the Consolidated Edison system.

HYDROELECTRIC CAPACITY

Conventional hydro, distinguished from pumped storage, currently represents less than 10 percent of the total installed capacity in the market area, and produces about 11 percent of total generated energy. These proportions are expected to decline as remaining available sites become developed and other types of generation are expanded. Most conventional hydro may be used either for peaking or base load operation, depending on plant design, system requirements, and prevailing conditions of water and economy. The advantages of hydroelectric power for power system operation are well known; high availability, quick starting and flexible operation, absence of pollution, and low costs for operation and maintenance. Also, a preliminary permit has been granted for Enfield, a 90 megawatt conventional hydroelectric plant on the Connecticut River.

Table P-10 contains an inventory of existing conventional hydroplants 10 MW and over in the NAR Region. Of the total of 3,229 MW of conventional hydro capacity 33 percent is located in the Lake Champlain Basin, 26 percent in the Susquehanna Basin and 16 percent in the Connecticut Basin.

There are in addition to conventional hydroelectric projects, three pumped storage plants; Yards Creek (339 megawatts), Muddy Run (800 megawatts), and Rocky River (31 megawatts) presently in operation. A fourth pumped storage project, Lewiston (240 megawatts) serves the market area. Muddy Run on the lower Susquehanna is the largest operating pumped-storage plant in the United States. Three pumped storage projects are currently under construction, Northfield Mountain (1000 megawatts) and Bear Swamp (600 megawatts) in the Connecticut Basin, and Blenheim-Gilboa (1000 megawatts) in the Hudson Basin. Cornwall (1800 MW) also in the Hudson Basin, has been granted a license, but the order has been appealed to the courts. One project, Longwood Valley (121 MW) has a license pending. Preliminary permits have been granted for two sites in the Housatonic Basin, although the permittee has indicated the intent to develop only one site. These projects, Schenob Brook and Canaan Mt. (1000 to 2000 MW) have been offered in open forum for public approval. This is a new approach by the utilities to forestall extensive delays. Two other sites, Stoney Creek and Tocks Island are under intensive study.

The NAR region is fortunate in having a large number of sites suitable for pumped storage plants. As the requirement for peaking capacity grows it is apparent that pumped storage capacity will take an increasingly larger role.

PROJECTS OPERATING UNDER FPC LICENSE

The Federal Power Act authorizes and empowers the Federal Power Commission to issue licenses to non-federal interests for the construction, operation, and maintenance of dams, powerhouses and appurtenances, for hydroelectric power development. The Act reserves to the United States the right to recapture a non-publicly owned project upon expiration of license after paying the licensee's net investment in the project, plus any severance damages. Projects to be licensed or relicensed shall, in the judgment of the Commission, be best adapted to a comprehensive plan for improving waterways for the benefit of interstate commerce, for water power development, and for other beneficial public uses, including recreation.

There are in the NAR region 115 projects with a total installed capacity of 9,504 megawatts presently under FPC license. These include utility, municipally, and industrial owned or operated projects. Licenses for 1,844 megawatts in 34 projects are still pending. Table P-14 lists licensed project data by basins.

TRANSMISSION FACILITIES

The pattern of bulk power transmission in the market area of the NAR is one of coordination of operating procedures and planning for reliability of power supply. This is being implemented by reliability coordination agreements between neighboring systems and pools, as well as by joint study programs conducted by systems and by the sharing of generating capacity and reserves.

The NAR region, especially the northeast, has a long history of operating coordination and planning that has led, over the years, to the formation of four pooling arrangements and four coordinating agencies: New England Power Pool (NEPOOL); New York Power Pool (NYPP); Pennsylvania-New Jersey-Maryland Interconnections (PJM); Virginia-Carolinas Reliability Group (VACARS); and East Central Area Reliability Coordinating Committee (ECAR); Middle Atlantic Area Reliability Coordination Committee (MAAC); the Northeast Power Coordinating Council (NPCC); and the Southeastern Electric Reliability Council (SERC).

In a continuing effort to capitalize on the economies of bulk power supply and to achieve increasing standards of reliability, coordinated planning and development has been extended over broader geographic and electrical load areas. Inter-area reliability coordination will continue to expand due to technological advance-

TABLE P -14

HYDROELECTRIC LICENSED PROJECTS 1/ DATA BY BASIN

Basin No.	Projects Under FPC License		Projects With License Pending		Total	
	Number	Capacity (MW)	Number	Capacity (MW)	Number	Capacity (MW)
1	2	2	-	-	2	2
2	7	120	2	6	9	126
3	15	207	-	-	15	207
4	12	142	-	-	12	142
5	-	-	-	-	-	-
6	7	46	-	-	7	46
7	5	36	-	-	5	36
8	21	2,771	6	13	27	2,784
9	-	-	-	-	-	-
10	2	2	7	91	9	93
11	11	1,110	6	18	17	1,128
12	13	3,022	6	64	19	3,086
13	-	-	-	-	-	-
14	-	-	1	121	1	121
15	2	379	3	26	5	405
16	-	-	-	-	-	-
17	8	1,636	1	2	9	1,638
18	-	-	-	-	-	-
19	7	10	-	-	7	10
20	-	-	-	-	-	-
21	3	21	2	1,503	5	1,524

1/ Projects may contain more than one development. Also includes those projects where construction has not begun or are under construction.

ments in generator unit sizes, extra high voltage (EHV) transmission, computer technology, and other aspects of power supply technique and methodology. Reliability of a bulk electric power supply system is measured by the availability of a continuous and uninterrupted supply of electricity. Outages of individual components such as a generating unit, transmission line, transformer or circuit breaker should not result in a widespread interruption of service if the system is properly planned, designed, and operated. The inherent reliability of a system is also increased by properly planned and coordinated pooling among neighboring areas with adequate interconnected transmission, capable of withstanding severe system disturbances.

An extensive network of EHV lines grid the NAR region and the NAR market area. They provide the means for delivering bulk power from concentrations of generation to points of use, interconnect utility systems with neighbors, obtain and provide assistance in emergencies, and permit economical interchange of power.

The major utility systems in the six New England States (power market sub-region CSA-A) are presently embarked on a large-scale coordinated power supply development program, comprising economical large size generating units interconnected by an extensive 345-kilovolt backbone transmission network. The 345-kv transmission network will form a loop serving major substations accessible to points of heavy load concentration. The transmission system will link all major new generation including the 1,000-MW Northfield Project and will tie with the New York systems in southeastern New York.

As generating unit sizes increase and opportunities develop for interchange of larger blocks of power with other power producing areas, a 765-kv transmission interconnection between the 345-kv system of New England and the systems of other areas will be developed. The 765-kv transmission will extend from Maine through Massachusetts into central New York, eventually forming loops in southern New England.

In New York State power market sub-region CSA-B backbone transmission is presently 345 kilovolts with a substantial underlying network of 230 and 110 kilovolts. In the late 1970's as the overall load grows it will be necessary to increase the transmission capability in the state. A 765-kv network is contemplated, with a tie to New England, then extending across the state to Niagara where it would enter Ontario and link with 765 kv in Michigan. It would also be strongly linked to the 500-kv PJM system in the central and western parts of the state.

In the PJM area (power market sub-region CSA-C) the 345 and 500-kv transmission grids associated with three mine plants are being completed. This EHV network will facilitate the delivery of the mine-mouth generation to the east and about double the interchange capacity between PJM and the adjoining pools (NYPP, ECAR, and VACARS). Underlying the 500 and 345 EHV network in the PJM area is an extensive transmission network of 230 kv, 138 kv and 115 kv. This large capacity grid is a significant factor in the movement of power through the region and achievement of desired level of reliability. PJM, in June 1968, had completed over 2,900 circuit miles of 230-kv transmission and has more than 1,300 circuit miles under construction.

In PSA-7, the eastern portion of ECAR, transmission patterns are similar to that of the rest of the area with backbone transmission at 345-kv, 230-kv and 138-kv with substantial ties to the neighboring system areas in ECAR. There is one notable installation of a 500-kv loop from Mt. Storm Generating Station in W. Virginia to Richmond, Va. in PSA-18, and to Washington, D.C. in PSA-6. This loop is the start of an extensive 500-kilovolt overlay of the present transmission systems by companies in PSA-18. Much of the existing transmission in PSA-7 and PSA-18 is at 138-kv and 110-kv. No expansion above 500 kilovolts is foreseen in the near future in these areas.

Principal electric facilities in the Northeastern area are shown on Figure P-4.

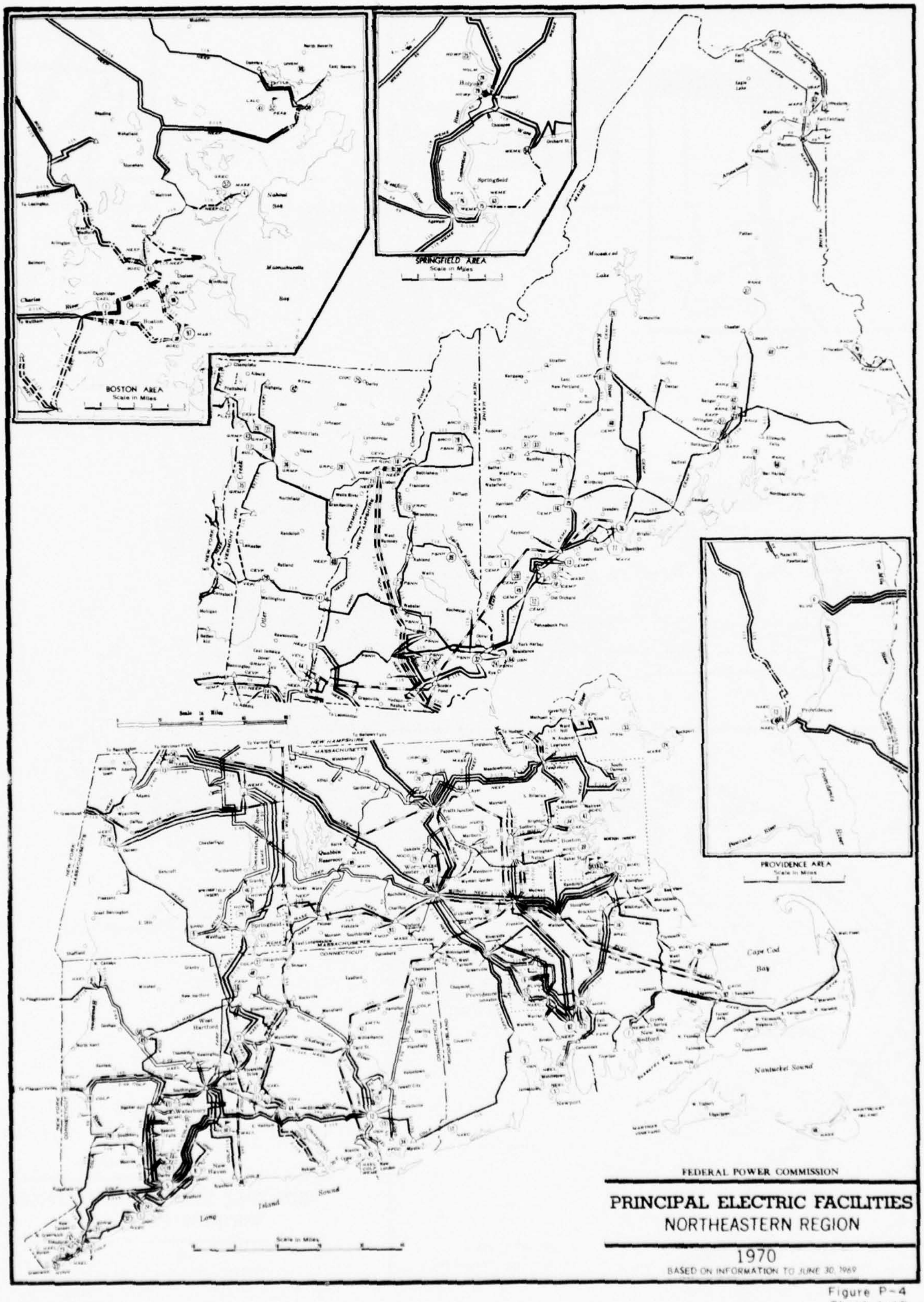

Figure P-4
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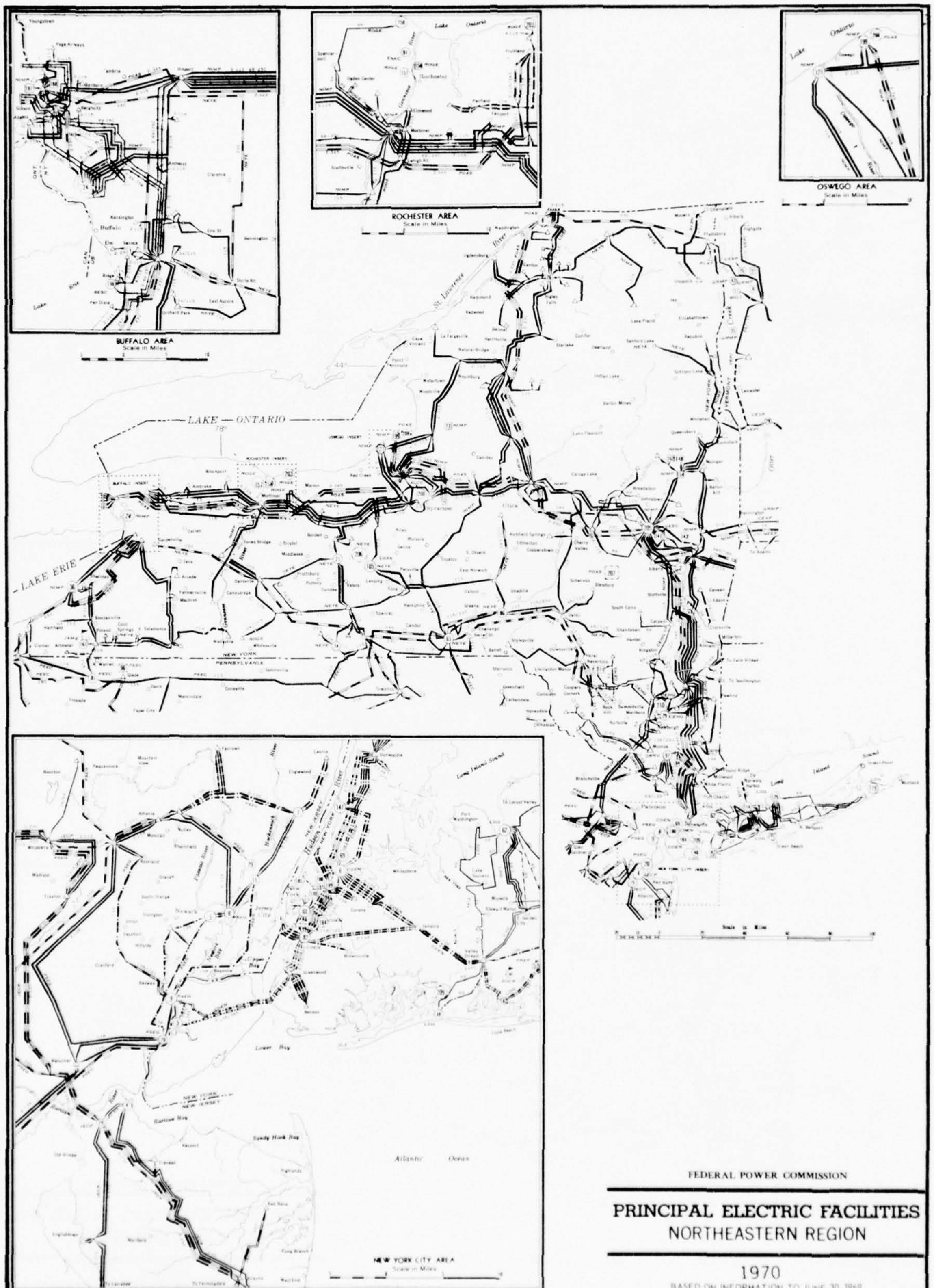

Figure P-4
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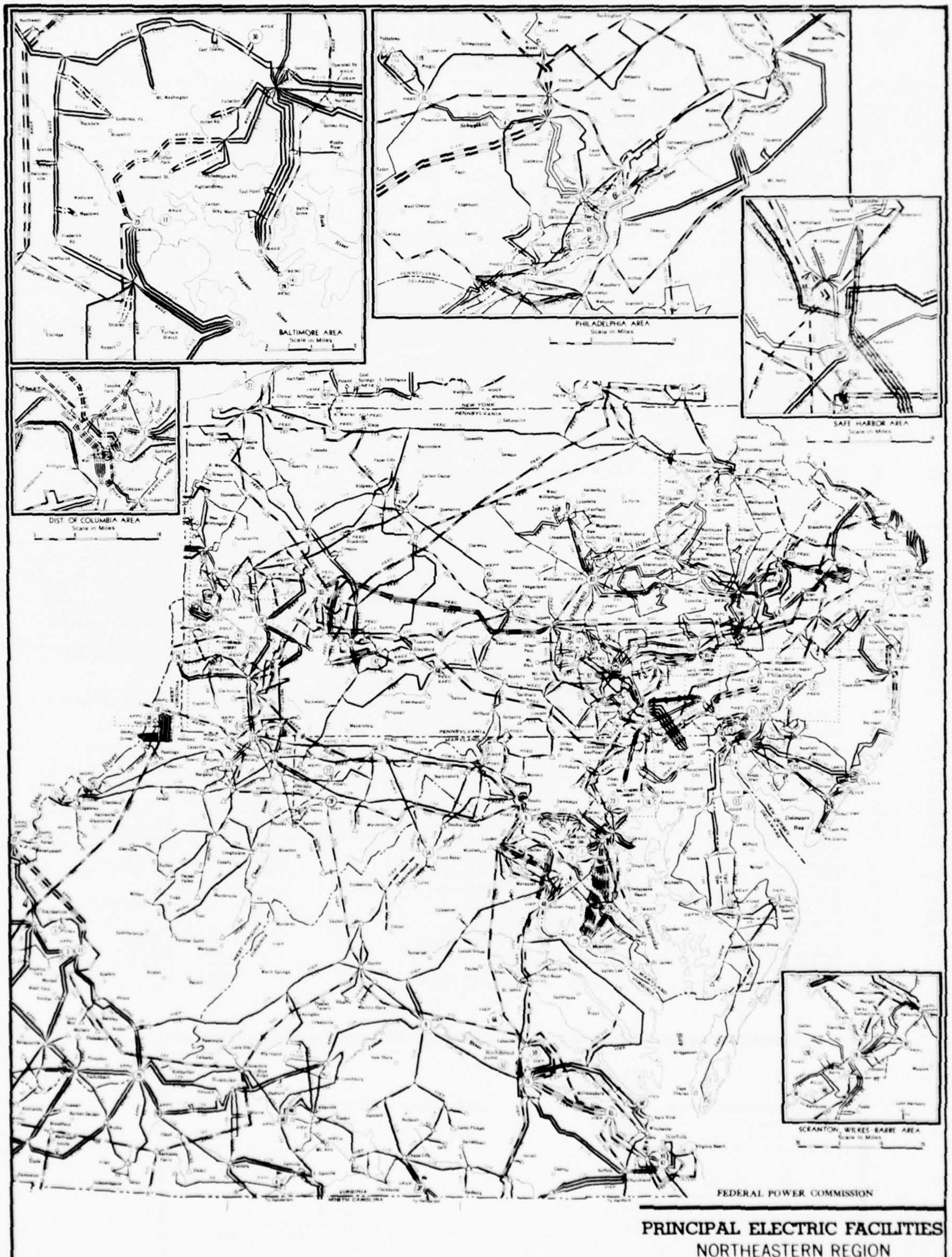

Figure P-4
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OWNERSHIP LIST

Utility Abbreviations	Type of Owner	Utilities
		CONNECTICUT
AMTH	IND	American Thread Co
PFCC	IND	Chas. Pfizer and Co., Inc
COLP	PRI	Connecticut Light & Power Co., The
COYA	PRI	Connecticut Yankee Atomic Electric Co
CHBC	IND	Chase Brass and Copper Co
FARP	PRI	Farmington River Power Co., The
GEEC	IND	General Electric Co
GROT	MUN	Groton
HAEL	PRI	Hartford Electric Light Co., The
NYNH	IND	N.Y., N.H. & Hartford Railroad
NOWI	MUN	Norwich
SCMC	IND	Scovill Mfg. Co
SONW	MUN	South Norwalk
UNIC	PRI	United Illuminating Company, The
USN	FED	U.S. Navy
WALL	MUN	Wallingford
		DELAWARE
DEPL	PRI	Delmarva Power & Light Co. of Delaware
DODE	MUN	Dover
DUNE	IND	Du Pont de Nemours, E. I. & Co
SEAF	MUN	Seaford
		DISTRICT OF COLUMBIA
PERC	IND	Penn Central
POEP	PRI	Potomac Electric Power Co
		MAINE
BAHE	PRI	Bangor Hydroelectric Co
CEMP	PRI	Central Maine Power Co
EAFP	IND	Eastern Fine Papers, Inc
EAME	COOP	Eastern Maine Electric Coop
FRPL	IND	Fraser Paper, Ltd
LIPP	IND	Lincoln Pulp & Paper Co
MAPS	PRI	Maine Public Service Co
MAYA	PRI	Maine Yankee Atomic Power Co
OXPC	IND	Oxford Paper Co
PECF	IND	Penobscot Chemical Fiber Co
RUFP	PRI	Rumford Falls Power Co
SACR	IND	Saint Croix Paper Co
SARP	IND	Saint Regis Paper Co
USAF	FED	U.S. Air Force
USN	FED	U.S. Navy
WASD	IND	Warren, S. D., Co
		MARYLAND
BAGE	PRI	Baltimore Gas & Electric Company
BESC	IND	Bethlehem Steel Co
DEPM	PRI	Delmarva Power and Light Co. of Md
HAGE	MUN	Hagerstown
PEEC	PRI	Pennsylvania Electric Co
PERC	IND	Penn Central
POEC	PRI	Potomac Edison Co., The
POEP	PRI	Potomac Electric Power Co
POTC	PRI	Potomac Transmission Co
SOME	COOP	Southern Maryland Electric Coop., Inc
SUEC	PRI	Susquehanna Electric Co
USAR	FED	U.S. Army
WEPC	IND	West Virginia Pulp & Paper Co
AMOP	IND	American Optical Co
BOMI	IND	Boott Mills
BOEC	PRI	Boston Edison Co
BRAI	MUN	Braintree
BREC	PRI	Brockton Edison Co
CACO	PRI	Canal Electric Company
CAEL	PRI	Cambridge Electric Light Co
CAVE	PRI	Cape & Vineyard Electric Co
CRBC	IND	Crocker Burbank and Co
FARE	PRI	Fall River Electric Light Co
FIGE	PRI	Fitchburg Gas & Electric Light Co

Utility Abbreviations	Type of Owner	Utilities
		MASSACHUSETTS
GEEC	IND	General Electric Company
HOLM	MUN	Holyoke
HOWP	PRI	Holyoke Water Power Co
HUDS	MUN	Hudson
IPSW	MUN	Ipswich
LALC	IND	Lawrence, A. C., Leather Co
MABT	MUN	Massachusetts Bay Transportation Authority
MASE	PRI	Massachusetts Electric Co
MUEL	PRI	Montaup Electric Co
NAGE	PRI	Nantucket Gas & Electric Co
NEBG	PRI	New Bedford Gas & Edison Light Co
NEEP	PRI	New England Power Co
NOCO	IND	Norton Co
OXPC	IND	Oxford Paper Co
PEAB	MUN	Peabody
SPRD	MUN	Springfield
STPA	IND	Strathmore Paper Co
TAUN	MUN	Taunton
UNSM	IND	United Shoe Machinery Co
USN	FED	U.S. Navy
WAIN	IND	Ware Industries Inc
WEME	PRI	Western Massachusetts Electric Co
WHMW	IND	Whitin Machine Works
YAEC	PRI	Yankee Atomic Electric Co
		NEW HAMPSHIRE
BRCO	IND	Brown-New Hampshire Inc
FRPC	IND	Franconia Paper Corporation
NEEP	PRI	New England Power Company
PSNH	PRI	Public Service Co. of New Hampshire
		NEW JERSEY
ATCE	PRI	Atlantic City Electric Company
JECP	PRI	Jersey Central Power & Light Co
NEJP	PRI	New Jersey Power & Light Co
PSEG	PRI	Public Service Electric & Gas Co
VINE	MUN	Vineland
		NEW YORK
ALCC	IND	Allied Chemical Corp
BESC	IND	Bethlehem Steel Co
CEHG	PRI	Central Hudson Gas & Electric Corp
COEN	PRI	Consolidated Edison Company of New York
EAKC	IND	Eastman Kodak Co
FREP	MUN	Freeport
GEEC	IND	General Electric Co
JAME	MUN	Jamestown
LOIL	PRI	Long Island Lighting Co
LOSI	PRI	Long Sault Inc
NEYE	PRI	New York State Electric & Gas Corp
NIMP	PRI	Niagara Mohawk Power Corporation
ORRU	PRI	Orange & Rockland Utilities, Inc
POAS	STATE	Power Authority of the State of New York
ROCK	MUN	Rockville Center
ROGE	PRI	Rochester Gas & Electric Corp
		PENNSYLVANIA
BESC	IND	Bethlehem Steel Co
BLCC	IND	Blue Coal Co
DULC	PRI	Duquesne Light Co
HECC	IND	Hershey Chocolate Corp
JOLS	IND	Jones & Laughlin Steel Co
LADA	MUN	Lansdale
MEEC	PRI	Metropolitan Edison Co
PEEC	PRI	Pennsylvania Electric Co

Utility Abbreviations	Type of Owner	Utilities
		PENNSYLVANIA—Continued
PEPC	PRI	Pennsylvania Power Co
PEPL	PRI	Pennsylvania Power & Light Co
PERC	IND	Pennsylvania Railroad Co., The
PHEC	PRI	Philadelphia Electric Co
SAHW	PRI	Safe Harbor Water Power Corp
SAJC	IND	St. Joseph Lead Co
SAEC	PRI	Saxton Experimental Corp
UNGI	PRI	United Gas Improvement Co
WEPP	PRI	West Penn Power Co
WECO	IND	Westinghouse Elec. Corp
		RHODE ISLAND
BLVG	PRI	Blackstone Valley Electric Co
MOEL	PRI	Montaup Electric Company
NAEC	PRI	Narragansett Electric Co., The
NEEL	PRI	Newport Electric Corp
USN	FED	U.S. Navy
		VERMONT
BULI	MUN	Burlington
CEVP	PRI	Central Vermont Public Service Corp
CIUC	PRI	Citizens Utilities Co
GIPC	IND	Gilman Paper Co
GRMP	PRI	Green Mountain Power Corp
NEEP	PRI	New England Power Co
STPK	IND	Standard Packaging Co
VEPI	PRI	Vermont Electric Power, Inc
VEYA	PRI	Vermont Yankee Nuclear Corp
		VIRGINIA
APPC	PRI	Appalachian Power Co
CEVC	COOP	Central Virginia Electric Cooperative
DAVI	MUN	Danville
DEPV	PRI	Delmarva Power and Light Co. of Va
DUNE	IND	Du Pont de Nemours, E. I. & Co
MECH	COOP	Mecklenburg Electric Coop., Inc
OLDP	PRI	Old Dominion Power Company
POEV	PRI	Potomac Edison Co. of Virginia
POEP	PRI	Potomac Electric Power Company
SHVE	COOP	Shenandoah Valley Electric Cooperative
TVA	FED	Tennessee Valley Authority
USAR	FED	U.S. Army
USN	FED	U.S. Navy
VIEC	COOP	Virginia Electric Coop
VIEP	PRI	Virginia Electric & Power Co
		WEST VIRGINIA
APPC	PRI	Appalachian Power Company
DULC	PRI	Duquesne Light Co
FOMA	IND	Food Machinery & Chemical Corp
MOPC	PRI	Monongahela Power Co
OHPC	PRI	Ohio Power Co., The
POEC	PRI	Potomac Edison Co., The
POTC	PRI	Potomac Transmission Co
POWV	PRI	Potomac Edison Co. of West Virginia
VIEP	PRI	Virginia Electric & Power Co
WEPP	PRI	West Penn Power Co
WHEC	PRI	Wheeling Electric Company

TYPE OF OWNERSHIP

PRI	Private
COOP	Cooperatives
MUN	Municipalities
STATE	State or Territory
FED	Federal
IND	Industrial and Privately Owned Schools

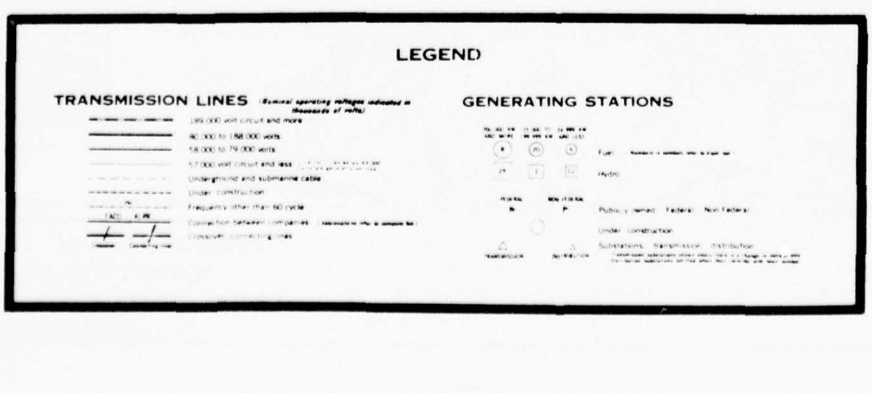

Figure P-4
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PLANT LIST

CONNECTICUT

Plant No.	Name of Plant	Utility Abbreviations
1	Bridgeport Harbor	UNIC
		UNIC
2	Bulls Bridge	COLP
4	Danielson	COLP
5	Devon	COLP
		COLP
8	English	UNIC
9	Falls Village	HAEL
10	Derby (Housatonic)	UNIC
		UNIC
11	Middletown	HAEL
		HAEL
12	Montville	COLP
		COLP
13	New London Submarine Base	USN
14	Norwalk Harbor	COLP
		COLP
15	Norwich	NOWI
		NOWI
16	Rainbow	FARP
18	Rocky River	COLP
20	Shepaug	COLP
21	South Norwalk	SONW
22	South Meadow	HAEL
		HAEL
23	Stamford	HAEL
24	Steel Point	UNIC
26	Stevenson	COLP
27	Thompsonville	COLP
29	Tunnel	COLP
		COLP
30	Pierce	WALL
32	Bridgeport	GEEC
33	Cos Cob	NYNH
34	Groton	PFCC
35	Mais	SCMC
41	Waterville	CHBC
42	Willimantic	AMTH
		AMTH
44	Haddam Neck	COYA
45	Millstone	HAEL[1]
46	Branford	COLP
47	Tracy	COLP
48	Enfield	COLP
49	Torrington	HAEL
50	Franklin Dr. (Torrington)	HAEL

[1] Jointly owned by HAEL, COLP & WEME

DELAWARE

Plant No.	Name of Plant	Utility Abbreviations
2	Delaware City	DEPL
		DEPL
3	St. Jones River	DODE
4	Edgemoor	DEPL
		DEPL
5	Indian River	DEPL
		DEPL
		DEPL
		DEPL
8	Seaford	SEAF
9	South Madison St.	DEPL
10	West	DEPL
11	McKee Run	DODE
12	Kent	DEPL
13	Seaford	DUNE

DISTRICT OF COLUMBIA

Plant No.	Name of Plant	Utility Abbreviations
1	Benning	POEP
		POEP
2	Buzzard Point	POEP
		POEP

MAINE

Plant No.	Name of Plant	Utility Abbreviations
4	Bonny Eagle	CEMP
6	Bucksport No. 1	SARP
7	Bucksport No. 2	SARP
10	Cape	CEMP
11	Caribou	MAPS
		MAPS
		MAPS
		CEMP
12	Cataract	CEMP
13	Wyman, W. F.	CEMP
14	Cumberland Mills (5 plts)	WASD
15	Cumberland Mills	WASD
16	Deer Rips	CEMP
19	Ellsworth	BAHE
22	Fraser Paper Ltd	FRPL
23	Graham Station	BAHE
		BAHE
25	Gulf Island	CEMP
26	Harris	CEMP
33	Lower Station	RUFP
36	Mason	CEMP
37	Medway	BAHE
		BAHE
38	Milford	BAHE
		BAHE
42	Oldtown	PECF
		PECF
47	Rumford	OXPC
		OXPC
		CEMP
49	Skelton	EAFP
51	South Brewer	RUFP
57	Upper Station	RUFP
		BAHE
58	Veazie	CEMP
59	West Buxton No. 1 & No. 2	CEMP
60	Weston	CEMP
61	Williams	CEMP
62	Wyman	CEMP
63	Loring Air Force Base	USAF
64	Kittery	USN
		USN
		MAPS
66	Flo's Inn	BAHE
68	Bar Harbor	LIPP
69	Lincoln	SACR
70	Woodland	SACR
77	Bailey Point No. 1	MAYA

MARYLAND

Plant No.	Name of Plant	Utility Abbreviations
5	Conowingo	SUEC
6	Cumberland	POEC
8	Dickerson	POEP
		POEP
11	Gould Street	BAGE
12	Hagerstown	HAGE
		HAGE
13	Wagner, Herbert A.	BAGE
		BAGE
		BESC
14	Pennwood	BAGE
16	Riverside	BAGE
17	Smith, R. Paul	POEC
20	Sparrows Point	BESC
22	Vienna	EASP
		EASP
23	Westport	BAGE
		BAGE
25	Crane, Charles P.	BAGE
		BAGE
26	Chalk Point	POEP
		POEP
27	Luke	WEPC
29	Morgantown	POEP
30	Notch Cliff	BAGE
31	Calvert Cliffs	BAGE

[1] Jointly owned by BAGE & POEP

MASSACHUSETTS

Plant No.	Name of Plant	Utility Abbreviations
1	Blackstone Street	CAEL
2	Boston Navy Yard	USN
4	Lynnway	MASE
		MASE
5	Cabot	WEME
7	Cannon Street	NEBG
8	Cherry St.	HUDS
9	Cobble Mountain	SPRD[1]
13	Deerfield No. 5	NEEP
15	East Braintree (Allen St.)	BRAI
16	East Bridgewater	BREC
17	Edgar	BOEC
20	Fitchburg	FIGE
24	Gloucester	MASE
		MASE
		HOWP
25	Hadley Falls	FARE
27	Hathaway Street	HOLM
28	Holyoke	HOLM
		HOLM
		HOWP
29	Holyoke No. 1—Riverside	HOWP
33	Ipswich	IPSW
34	Kendall Square	CAEL
36	Lawrence	OXPC
		OXPC
39	L Street—New Boston	BOEC
		BOEC
41	Peabody	LALC
46	Mt. Tom	HOWP
47	Mystic	BOEC
49	Nantucket	NAGE
52	Peabody	PEAB
57	River Works	GEEC
58	Rowe	YAEC
59	Salem Harbor	NEEP
60	Sherman	NEEP
62	Somerset	MOLL
63	State St.	WEME
65	Taunton (2 Plants)	TAUN
		TAUN
69	United Shoe	UNSM
74	Webster Street	MASE
75	West Springfield	WEME
		WEME
76	West Springfield	STPA
		STPA
		STPA
78	Morningside	GEEC
79	Worcester	NOCO
82	Brayton Point	NEEP
		NEEP
		NEEP
83	Potter, N. P.	BRAI
86	Fitchburg	CRBC
		CRBC
87	Lowell	BOMI
		BOMI
88	Plain St. No. 4 Sta.	BRAI
		BRAI
89	Ware	WAIN
		WAIN
90	Whitinsville	WHMW
		WHMW
92	Canal	CACO
93	Southbridge	AMOP
94	East Springfield	WEME
97	South Boston	MABT
98	Lincoln	MABT
99	Pilgrim	BOEC

[1] Leased to Western Massachusetts Electric Co.

NEW HAMPSHIRE

Plant No.	Name of Plant	Utility Abbreviations
1	Amoskeag	PSNH
2	Ayers Island	PSNH
3	Merrimack	PSNH
4	Cascade	BRCO
		BRCO
5	Comerford	NEEP
6	Garvins Falls	PSNH
		PSNH
18	Kelley's	PSNH
		FRPC
19	Lincoln	FRPC
20	Manchester	PSNH
21	[illegible]	NEEP
26	Daniel Street	PSNH
27	Riverside	BRCO
		BRCO

NEW HAMPSHIRE—Continued

Plant No.	Name of Plant	Utility Abbreviations
28	Riverside	BRCO
30	Moore, Samuel C.	NEEP
32	Schiller	PSNH
35	Smith	PSNH
36	Vernon	NEEP[1]
39	White Lake	PSNH

[1] Includes 2,400 kw on Vermont side of Connecticut River.

NEW JERSEY

Plant No.	Name of Plant	Utility Abbreviations
1	Bergen	PSEG
		PSEG
2	Burlington	PSEG
		PSEG
3	Deepwater	ATCE
		ATCE
4	Werner, E. H.	JECP
5	Essex	PSEG
		PSEG
6	Gilbert	JECP
8	Kearney	PSEG
		PSEG
		PSEG
9	Linden	PSEG
		PSEG
11	Marion	PSEG
12	Mercer	PSEG
		PSEG
15	Missouri Avenue	ATCE
		ATCE
19	Sayreville	JECP
20	Sewaren	PSEG
		PSEG
22	Vineland	VINE
		VINE
25	England, B. L.	ATCE
26	Oyster Creek	JECP
27	Yards Creek	JECP[1]
29	Hudson	PSEG
		PSEG

[1] Pumped storage—jointly owned by JECP and PSEG

NEW YORK

Plant No.	Name of Plant	Utility Abbreviations
2	Albany	NIMP
		NIMP
		NIMP
5	Arthur Kill	COEN
		COEN
		COEN
6	Astoria	COEN
		COEN
		COEN
8	Moses, Robert—St. Lawrence	POAS
13	Bennetts Bridge	NIMP
21	Greenidge, C. A.	NEYE
24	Huntley, Charles R.	NIMP
		NIMP
26	Colton	NIMP
29	Danskammer	CEHG
36	Dunkirk	NIMP
		NIMP
40	East River	COEN
		COEN
42	Barrett, E. F.	LOIL
		LOIL
		LOIL
48	Far Rockaway No. 1 & 2	LOIL
57	Freeport (2 plants)	FREP
		FREP
62	Glenwood Landing 2 & 3	LOIL
		LOIL
63	Goudey	NEYE
		NEYE
69	Hell Gate	COEN
		COEN
74	Hickling	NEYE
82	Hudson Avenue	COEN
		COEN
		COEN
84	Indian Point	COEN
		COEN
		COEN
86	Jennison	NEYE
91	Kodak Park	EAKC
		EAKC
		EAKC
97	Lovett	ORRU
		ORRU
105	Milliken	NEYE
		NEYE
111	Neversink	CEHG
114	Northport	LOIL
		LOIL
		LOIL
121	Oswego	NIMP
		NIMP
129	Port Jefferson	LOIL
		LOIL
139	Rockville Centre	ROCK
		ROCK
141	Schenectady	GEEC
143	School Street	NIMP
147	Sherman Creek	COEN
148	Sherman Island	NIMP
154	Spier Falls	NIMP
157	Station No. 3	ROGE
		ROGE
158	Station No. 5	ROGE
159	Station No. 7 (Russell)	ROGE
161	Carlson, S. A.	JAME
162	Stewarts Bridge	NIMP
180	Waterside No. 1 & 2	COEN
		COEN
		COEN
		COEN
184	Kent Avenue	COEN
		COEN

NEW YORK—Continued

Plant No.	Name of Plant	Utility Abbreviations
185	59th Street	COEN
		COEN
186	74th Street	COEN
		COEN
		COEN
187	Moses, Robt.—Niagara	POAS
188	Lewiston Pump	POAS
189	Ravenswood	COEN
		COEN
		COEN
191	East Hampton	LOIL
		LOIL
198	Lackawanna (2 Plants)	BESC
199	Nine Mile Point	NIMP
		NIMP
200	Syracuse	ALCC
202	West Babylon	LOIL
203	Ginna, R. E.	ROGE
		ROGE
205	Rotterdam	NIMP
206	Bell	NEYE
207	Blenheim-Gilboa	POAS
208	J. A. Fitzpatrick	POAS
209	Inwood	LOIL
210	Roseton	CEHG

PENNSYLVANIA

Plant No.	Name of Plant	Utility Abbreviations
1	Armstrong	WEPP
4	Barbadoes	PHEC
		PHEC
		PHEC
5	Bethlehem	BESC
		BESC
		BESC
11	Chester	PHEC
		PHEC
		PHEC
12	Colfax	DULC
14	Crawford	MEEC
15	Cromby	PHEC
		PHEC
17	Delaware	PHEC
		PHEC
		PHEC
19	Eddystone	PHEC
		PHEC
		PHEC
21	Elrama	DULC
24	Eyler	MEEC
26	Phillips, Frank R.	DULC
27	Front Street	PEEC
34	Hershey	HECC
35	Holtwood	PEPL
36	Holtwood	PEPL
38	Hunlock Creek	UNGI
41	Reed, James H.	DULC
42	Johnstown (3 Plants)	BESC
43	Lansdale	LADA
		LADA
		LADA
44	Martins Creek	PEPL
		PEPL
45	Milesburg	WEPP
46	Mitchell	WEPP
48	Nanticoke	BLCC
51	New Castle	PEPC
58	Piney	PEEC
60	Pittsburgh Works	JOLS
62	Portland	MEEC
		MEEC
65	Richmond	PHEC
		PHEC
67	Safe Harbor	SAHW
		SAHW
68	Saxton	PEEC
		SAEC
69	Schuylkill	PHEC
		PHEC
		PHEC
		PHEC
70	Seward	PEEC
72	Shawville	PEEC
		PEEC
73	Shippingport	DULC
75	Southwark	PHEC
		PHEC
		PHEC
76	Springdale	WEPP
78	Stanton	PEPL
82	Suburban	PEPL
83	Sunbury	PEPL
		PEPL
85	Titus	MEEC
		MEEC
86	Wallenpaupack	PEPL
87	Warren	PEEC
90	Williamsburg	PEEC
91	York Haven	MEEC
92	Brunner Island	PEPL
		PEPL
		PEPL
		PEPL
94	Peach Bottom	PHEC
		PHEC
96	Seneca	PEEC
98	E. Pittsburgh	WECO
100	Weaton, G. T.	SAEC
103	Keystone	PEPL
		PEPL
104	Muddy Run	PHEC
		PHEC
105	Harwood	PEPL
106	Allentown	PEPL
107	Harrisburg	PEPL
108	Williamsport	PEPL
110	Fishbach	PEPL
111	West Shore	PEPL
113	Homer City	PEEC
		PEEC
114	Conemaugh	PEEC
		PEEC

PENNSYLVANIA—Continued

Plant No.	Name of Plant	Utility Abbreviations
115	Cheswick	DULC
116	Hatfields Ferry	WEPP
117	Jenkins	PELP
118	Montour	PELP
119	Moser	PHEC
120	Falls	PHEC
121	Three Mile Island	MEEC

[1] One-third owned by Penna. Power & Light Company
[2] Financed by GPU Subsidiaries under the name of Saxton Experimental Corporation
[3] Jointly owned by PEPL, PHEC, BAGE, JECP, PSEG, ATCE & DEPL
[4] Pumped storage
[5] Jointly owned by PEEC and NEYE
[6] Jointly owned by PEEC and CLEI
[7] Jointly owned by WEPP and Allegheny Member Co.
[8] Jointly owned by ATCE, DEPL, PSEG & PHEC

RHODE ISLAND

Plant No.	Name of Plant	Utility Abbreviations
4	Manchester Street	NAEC
5	Newport	NEEL
6	Pawtucket No. 1	BLVG
9	Quonset Point	USN
12	South County	NAEC
13	South Street	NAEC
		NAEC
16	Jepson	NEEL

VERMONT

Plant No.	Name of Plant	Utility Abbreviations
2	Bellows Falls	NEEP
8	Essex No. 19	GRMP
		GRMP
10	Gilman	GIPC
		GIPC
14	Harriman	NEEP
17	J. Edward Moran	BULI
20	Marshfield	GRMP
22	Milton	CEVP
		CEVP
25	Newport (2 Plants)	CIUC
		CIUC
26	Peterson	CEVP
29	Rutland	CEVP
35	Vergennes No. 9	GRMP
		GRMP
36	Waterbury Dam	GRMP
40	Wilder	NEEP
41	Ascutney	CEVP
42	Sheldon Spring	STPK
		STPK
		STPK
43	Gorge No. 16	GRMP
44	Vernon	VEYA

[1] Includes 16.2 Mw on New Hampshire end of dam

VIRGINIA

Plant No.	Name of Plant	Utility Abbreviations
8	Brantly	DAVI
9	Bremo Bluff	VIEP
15	Chesterfield	VIEP
16	Claytor	APPC
17	Clinch River	APPC
25	Glen Lyn	APPC
32	Kerr, John H.	USAR[1]
46	Portsmouth	USN
47	Portsmouth	VIEP
		VIEP
		VIEP
48	Possum Point	VIEP
		VIEP
51	Reeves Avenue	VIEP
54	Riverton	POEV
55	Potomac River	POEP
56	Smith Mountain	APPC
57	Spruance	DUNE
		DUNE
58	Yorktown	VIEP
59	12th Street	VIEP
60	Leesville	APPC
65	Surry	VIEP
66	North Anna	VIEP

[1] Power marketing under Southeastern Power Administration

WEST VIRGINIA

Plant No.	Name of Plant	Utility Abbreviations
1	Albright	MOPC & POEC[1]
3	Cabin Creek	APPC
5	Charleston	FOMA
10	Kammer	OHPC
11	Kanawha River	APPC
13	Lake Lynn	WEPP
21	Parkersburg	FOMA
		FOMA
22	Sporn, Philip	APPC & OHPC[2]
23	Rivesville	MOPC
25	Willow Island	MOPC
26	Windsor	OHPC & WEPP[3]
28	Mount Storm	VIEP
		VIEP
		VIEP
29	Fort Martin	MOPC[4]
30	Mitchell	OHPC

[1] 69.0 Mw operated by Monongahela Power Co.
[2] Plant operated by Central Operating Co.
[3] Operated by Beech Bottom Power Co.
[4] Jointly owned by MOPC, POEC, WEPP & DULC

Figure P-4
Sheet 5 of 5

CHAPTER 5

POTENTIAL HYDROELECTRIC POWER IN THE STUDY REGION

GENERAL

The Federal Power Commission compiles and publishes basic data on undeveloped hydroelectric power resources throughout the United States. The estimates are based principally on river basin surveys and project investigations that have been made over the years by Federal and State agencies, various Federal-State entities operating under the aegis of the Water Resources Council, and others, including water resources appraisal studies undertaken by the Commission staff.

The compilation of undeveloped water power includes projects for which studies have indicated both engineering and economic feasibility, as well as projects at sites where physical conditions indicate engineering feasibility but for which detailed studies of economic feasibility have not been made. The estimates are subject to revision either by increase or decrease as additional information becomes available concerning streamflow, reservoir sites, costs, and other pertinent factors.

The undeveloped hydro power picture is constantly changing as new projects are constructed and as continuing studies uncover new potential projects or investigations demonstrate the desirability to modify earlier plans. As additional information is obtained and new studies made, the inventory of potential projects is revised. However, the estimate taken in the aggregate serves to indicate, from a long range view, the overall water power potential and resources available for possible future development.

INVENTORY OF POTENTIAL CONVENTIONAL HYDRO POWER

In 1970 conventional hydroelectric capacity accounted for about seven percent of all the electrical generating capacity in the NAR. For many years this proportion has been on the decline with the development of the few remaining available sites and the rapid installation of other types of generation.

Economic and other factors will preclude the development of most of the potential hydroelectric sites in the NAR. Detailed analyses of projects at sites having relatively small power potentials (less than 15 MW) frequently result in adverse findings of economic justification. Also, in many cases highways, industrial plants, and other facilities have been constructed in areas that would be required for reservoirs of potential projects. The costs of relocation are often so great as to render a potential project uneconomical for development.

Additionally, legislation may prohibit the development of potential hydroelectric sites. The Wild and Scenic Rivers Act, Public Law 90-542 is one such example. This Act declares it to be the policy of the United States that selected rivers of the nation, which possess outstanding and remarkable scenic, recreational, geologic, fish and wildlife, historic, cultural, or other similar values, shall be preserved in free-flowing condition and, together with their immediate environments, shall be protected for the benefit of present and future generations. The Congress declared in the Act, that the established national policy of dam and other construction at appropriate sections of the nation's rivers needs to be complemented by a policy that would preserve other selected rivers in their free-flowing state to protect the water quality of such rivers and to fulfill other vital national conservation purposes. Accordingly, the Act instituted a National Wild and Scenic Rivers System.

The Act provides for two streams named in Section 2(a) for inclusion in the national Wild and Scenic Rivers System upon application of the Governor of the State concerned. Section 3(a) names eight streams as components of the system. Under Section 5(a) a total of 27 rivers are named for study as potential additions to the national system. Within the NAR, the Allagash, from its source to its confluence with the Saint John, is listed under Section 2(a). Section 5(a) lists three streams: The Delaware River from Hancock, New York to Matamoras, Pennsylvania; the East and West Branches of the Penobscot; and Pine Creek (Susquehanna River Basin) from Ansonia to Waterville, Pennsylvania.

Public Law 90-542 also provides procedures to be followed in the study of potential additions to the wild and scenic river system. Every study and plan is to be coordinated with other planning in the river basin. Each wild and scenic river proposal is to be accompanied by a report showing among other things, the reasonably foreseeable potential uses of the land and water which would be enhanced, foreclosed or curtailed if the area were included in the national system.

There are no major Federal hydroelectric plants in the region but Congress has authorized power developments at the Dickey-Lincoln School, Tocks Island, and Salem Church projects. The proposed conventional power installation at the Tocks Island reservoir project on the Delaware River would have a capacity of about 70 MW. However, a non-Federal pumped storage development has been proposed which would pump water from Tocks Island reservoir to an upper pool on Kittatinny Mountain and discharge either above or below Tocks Island dam. If this scheme of development is adopted the plan for a conventional power installation may be abandoned.

The Dickey-Lincoln School project would be on the St. John River in Maine. The Corps of Engineers, in fiscal years 1966 and 1967, spent nearly two million dollars on plans for this project but the Congress did not appropriate additional planning funds for use in fiscal years 1968, 1969, or 1970. The development would have an installed capacity of 830 megawatts.

The Salem Church project is planned for the Rappahannock River in Virginia. The project would utilize a static power head of 175 feet and a usable power storage of 517,000 acre-feet to develop an installed capacity of 89 megawatts. Other purposes include flood control, water supply, recreation, and water quality control.

Table P-15 lists, by areas, the undeveloped conventional hydroelectric potential in the North Atlantic Region. Based on the foregoing considerations relatively few projects have been considered for development during the time frame of this study. Low load factor peaking will be supplied primarily by pumped storage developments.

POTENTIAL PUMPED STORAGE DEVELOPMENT

With the almost total lack of economical conventional hydro sites in the NAR it is fortunate that most areas have the capability of pumped storage development. An appraisal of potential pumped storage sites in the NAR was abstracted from an inventory periodically issued by the Federal Power Commission titled Hydroelectric Power Resources of the United States. These data provided a guide in developing an inventory of economical projects. Unit costs at 1968 prices, ranged from $80 to $130 per kilowatt and capacities from 500 to more than 5,000 megawatts. The priority, timing, and amount of pumped storage development depend upon the requirements and characteristics of the electrical load and relative project economies. Elements of the public have objected to the siting of certain pumped storage works and, particularly, to the appearance of associated transmission lines. Meeting esthetic requirements will increase the cost of pumped storage, although it is unlikely that these considerations will control the economic feasibility of well-conceived projects. Esthetic considerations are major factors that must be taken into account in planning all types of generation or transmission.

Table P-16 is a summary by area , of the pumped storage potential in the NAR. Constrained by topographic and other natural features, the pumped storage potential varies throughout the region. The inventory does provide an indication of where and, by means of unit costs, an approximate time frame when various components of low load factor generation will be available to supply systems operation in the most economical manner.

Potential sites included in the projected power supply have

TABLE P-15

INVENTORY OF POTENTIAL CONVENTIONAL HYDRO DEVELOPMENT SITES

Area	Number of Projects and Total Gross Installation							
	Under 10 MW		10-50 MW		50-100 MW		Over 100 MW	
	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.
1	2	8	1	18	1	70	1	760
2	2	11	10	200	-	-	-	-
3	-	-	4	106	1	90	1	180
4	2	14	13	272	-	-	1	263
5	1	5	-	-	-	-	-	-
6	2	13	3	65	-	-	-	-
7	3	20	10	188	-	-	1	230
8	10	69	22	364	2	156	1	145
9	-	-	-	-	-	-	-	-
10	4	25	4	73	-	-	-	-
11	11	79	20	351	1	87	-	-
12	9	58	6	124	3	231	-	-
13	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-
15	3	26	17	409	2	170	1	150
16	-	-	-	-	-	-	-	-
17	-	-	6	129	3	225	7	1,499
18	-	-	-	-	-	-	-	-
19	-	-	13	338	4	220	1	120
20	1	6	3	38	1	89	-	-
21	-	-	11	227	1	69	1	232

not been subject to detailed engineering studies. These studies would more carefully examine project construction costs and associated transmission costs, evaluate the energy losses in pumping and transmission, and compare the results with the costs of alternative types of facilities. A further determinative factor in the development of pumped storage capacity, would be a canvass of all forms of peaking capacity available at the time decisions for such capacity additions must be made. Environmental and esthetic considerations would also be taken into account and might be governing factors in the selection of particular projects for construction.

TABLE P-16

INVENTORY OF POTENTIAL PUMPED STORAGE SITES - 1968 DOLLARS

Area	Under $90/KW		Between $90-100/KW		Over $100/KW	
	Number	Total Capacity (MW)	Number	Total Capacity (MW)	Number	Total Capacity (MW)
1	1	1,104	5	4,282	11	12,926
2	-	-	3	2,675	6	10,384
3	6	11,786	-	-	3	1,742
4	1	1,800	4	4,227	10	6,268
5	-	-	-	-	-	-
6	-	-	-	-	-	-
7	2	2,663	-	-	3	1,908
8	1	1,450	12	19,121	18	8,030
9	-	-	-	-	-	-
10	6	24,170	3	2,615	7	3,018
11	9	13,071	10	11,867	6	3,106
12	21	45,717	20	20,141	28	21,906
13	-	-	-	-	-	-
14	-	-	1	120	-	-
15	11	16,452	13	19,681	19	12,395
16	-	-	-	-	-	-
17	75	106,529	53	58,804	121	69,777
18	-	-	-	-	-	-
19	25	39,261	12	11,718	19	12,393
20	-	-	-	-	-	-
21	2	6,000	-	-	6	9,330

CHAPTER 6

THERMAL POWER

CONSIDERATIONS OF POWER PLANT SITE SELECTIONS

General. With increasing population, expanding economy, and the more active interest of the general public and governmental (Federal, State, and Local) agencies in community matters (i.e., preservation of natural environment), the problems associated with plant siting decisions are becoming more and more complex. Along with the factors traditionally included in plant site investigations such as economics, area capacity requirements, possible transmission requirements, availability and condition of land, and availability of cooling water, the utilities must give increasing consideration to water and air pollution as well as to the physical appearance of the plant itself. Area considerations for power plant siting vary widely and reflect the specific needs for fuel storage, cooling devices, type of prime mover, and many other factors. As these additional requirements tend to eliminate a number of otherwise potential sites, it is evident that only a few sites will meet all of the economic, esthetic and ecologic considerations that are desired. Controls on costs for power generation have frequently influenced the degree of environmental protection achieved in the past. With the increasing emphasis on environmental and ecological protection, however, the Federal Government, some state governments, investor owned utilities, and some research institutes, have ongoing and future programs to minimize the conflicting problems of various interests and still maintain a reason ble cost for electric power.

Load Center Proximity. A major consideration in the siting of a power plant is its proximity to load centers. Location of coal or oil-fired plants near concentrations of population is being met with greater opposition as people are becoming more concerned about air pollution. The future use of these types of thermal plants will require greater research and investment in methods of controlling particulates, sulfur dioxide, and other gaseous discharges.

The foregoing problem is not relevant to a nuclear power plant, although the potential for increased radioactive emissions is of concern to some scientists. Thus far most nuclear plants have been located some distance from population centers, but it is expected that as more experience is gained in the design, construction, and operation of nuclear plants the use of locations nearer population centers will probably be permitted.

A problem in relation to load center proximity common to both the nuclear and the coal-fired steam plant is the large amounts of water used for dissipation of the waste heat. Large fossil plants normally require condenser flows of about 0.8 to 1.2 ft^3/s per MW of capacity while light water nuclear plants of the same output require half again as much. Lakes and streams near large cities are used for transportation, industrial processes, recreation, municipal water supplies, and sewage disposal, so the control of rejected heat to these lakes and streams is apt to be particularly critical, and has become a problem of increasing magnitude as power plants have grown in size and other uses of these water bodies have increased.

Access. Another important siting consideration is the plant's access to a good modern highway to provide access for plant construction and operation. In the absence of rail or water access, the highway must also serve for delivery of all or part of the operation materials, equipment, and fuel. The standards for the highway will depend on weight, type, and volume of traffic to be handled.

Rail or water access is highly desirable for delivery of heavy equipment and for fuel (to facilities not serviced by pipeline), and where feasible, use of both alternatives is usually economical. Delivery of large shop-fabricated and assembled reactor vessels is readily accomplished by water route. If coal is to be delivered by rail or water, major consideration must be given to waterfront and rail facilities. Daily coal requirements of large modern stations demand careful coordination of the design of coal receiving facilities, both for efficiency of operation and effect on freight charges resulting in delay in return of cars or barges. The area required for coal storage will often depend upon the reliability and frequency of coal deliveries.

Fuel Supply. An essential item to be considered in selecting a site for a generating plant is the availability of an adequate supply of competitively priced fuel for the life of the plant. The location of a nuclear plant presents no problems in this respect because of the minimal transportation cost of nuclear fuel. Oil- and gas-fired plants are usually located where ample supplies are available on a competitive basis for the life of the plant. A new plant relying on gas will need long-term contracts to assure competitive fuel costs.

Coal-fired plants are usually located so that more than one field can be considered as a source of fuel for the plant site. The successful operation of unit trains on fast schedules and in some cases movements of coal by barge to power plants over long distances enables coal deposits at some distance from the site to be considered as alternative sources for the plant. The present and projected future availability of coal and its cost delivered to the plant will, of course, be a major factor in the final measure of the attractiveness of a site.

Additional Considerations. Geological conditions are among the considerations in choosing a site. A satisfactory foundation for the structure must be assured. The selection of a site should consider the presence of faulting which could present foundation problems, such as instability of rock foundation during an earthquake or the necessity for extensive excavation due to crushed and broken rock.

Siting of steam power plants entails questions of meteorology and hydrology. The relationship of meteorology to the physical requirements of siting an electric generating plant is an important consideration, especially in designing the air pollution control features of the plant. Meteorological parameters should be identified on a seasonal and annual basis from measurements made at the site or from representative data recorded at nearby points. Plant grades should be selected above the elevation of the greatest flood that may reasonably be expected based on actual storm and flood records.

The steam power plant must be afforded a dependable source of cooling water for all conditions in which the plant is expected to continue operation. A nuclear plant requires a reliable source of water even when it is not in operation, to remove decay heat from the reactor. In addition, a source of cooling water for emergency reactor shutdown must be assured. All plants must be sited with a view towards satisfying applicable state and federal standards relating to acceptable thermal criteria of the condenser effluent.

In site selection it is essential that proper consideration be given to the impact of the plant on the appearance of the surrounding area as well as the impact of the transmission lines that must radiate from the plant, as technology of underground transmission has not yet been developed to the point where it is practical for transmitting large blocks of power over long distances. Latest data available indicates that a double circuit 345 KV transmission line requires about 21 acres per mile of right-of-way.

Certain employee amenities such as housing, modern conveniences, and educational institutions are important considerations. When selecting a plant site the facilities available for employees within commuting distance of the site should be considered. Additionally, the taxing policies of the state and local government have considerable influence on the economics of building and operating a generating plant.

Thermal Effects. Control of the effects of the discharge of heated waste waters poses a major problem of increasing importance in connection with siting of new steam power plants. This is one of the most difficult problems facing the Environmental Protection Agency in carrying out the Federal responsibilities for water pollution control today. The hazards involved in the discharge of waste heat are obvious, but in most cases their effects are quite subtle. The complexity of the problem is intensified by the substantial changes in temperature in the aquatic environment that occur normally from natural causes. What is often not recognized is that in many of our waterways the waste heat is imposed upon an environment which is already near a critical point for certain segments of the aquatic life we seek to protect, for the processes we hope to limit, and for the water resources we propose to use.

With respect to our knowledge of the impact of waste heat on water quality, the unknowns still far exceed the knowns in water quality requirements -- even to the experts. Based on the data now available and experience with other wastes, it is only prudent that great care be exercised so as to avoid damage to the aquatic environment rather than to plan to correct gross problems after plants have been completed.

The most pronounced effects of thermal pollution are upon aquatic life. In general, bio-chemical processes, including the rate of oxygen utilization by aquatic life, double for each 10°C. rise in temperature up to 30°C - 35°C, but as water temperatures rise, the water can hold less dissolved oxygen. Thus, as temperatures rise a double phenomenon occurs, i.e., potential supplies of dissolved oxygen decrease, while the need for same increases.

The thermal effect of plant effluents can have good or bad repercussions. On the plus side of the ledger, an increase in temperature can result in more rapid development of eggs, faster growth of spat, fingerlings, or juvenile and larger fish of a given class. The temperatures at which maximum development takes place at each stage of the life cycle varies with species. Over a period of several generations the species composition of affected areas of streams, reservoirs, lakes, or estuaries can be expected to change if the temperature is changed, even by a small amount.

Another potential advantage to thermal discharge in the northern climates is its tendency to reduce ice coverage, and thus improve water quality by permitting the addition of oxygen if it has been depleted as a result of upstream organic waste discharges. However, the additional heat may also increase local fogging conditions.

An increase in temperature may also be responsible for making the waters more desirable for swimming and associated body contact sports if the waters are normally so cold as to preclude such use. If the water is already warm, however, further increases can reduce the esthetic and recreational value.

On the minus side of the ledger, where the temperature of the effluent goes beyond a certain point, aquatic life can be adversely affected. Fish hatch will be reduced and greater mortalities in the development stages will occur. A change in temperature also has a number of indirect effects. There is a potential for fish kills when a plant has to suddenly shut down, during periods of cold weather, when fishes have moved into the "mixing zone" attracted by and acclimated to a higher water temperature. Fish kills of this nature have been reported. Even where a temperature change is not directly damaging to the development of desirable species, an increase is usually found to facilitate the more rapid development of less desirable or undesirable species. While fish are generally available in discharge areas, it is often found that an increase in temperature results in a loss of the more desirable cold water sport species since their upper tolerance level is often exceeded. A warmer temperature is also considered to increase the occurrence of disease in fish populations.

A particular problem exists with migratory species, since changes in temperature are apparently important in a number of species as the stimulator of migratory activity. Too early migration, avoidance reactions to changes that occur near a water discharge, viability of eggs or sperm, or the availability of appropriate food when the eggs hatch, are probably more important in the preservation of migratory species than the direct lethal effects of the discharge.

Any increase in temperature from cooling water discharges will result in increased evaporation and consequent reduction in the available supply and an increase in the concentration of the minerals present. While not ordinarily of sufficient magnitude to constitute a problem, if the water is subject to a number of cooling cycles and evaporative cooling devices, a measurable loss in supply and an increase in solids may result. Additionally, the possibility exists that accidental releases of chemical additives used in the generating cycle might find its way to a water body, causing possible deleterious effects to aqua-culture.

Increased temperature will also increase the rate of solution of minerals in deposits with which the water comes in contact.

Though not normally a problem, acceleration of corrosion of highway, navigation, or intake structures will reduce the service life of the structure and may have economic consequences. In addition, the value of the water for further cooling for various industrial uses will be reduced in areas where the temperature is increased substantially.

Waste Heat Studies. The Johns Hopkins University has ongoing field research activities relative to the discharge of heated effluents into surface waters for the Edison Electric Institute. Initial phases of this program were directed towards physical aspects of heat dissipation from surface waters. Physical and meteorological data have been collected from eleven existing steam electric generating stations located at various latitudes in the United States. Results of physical aspects of this research program are currently under analysis and publication. Intermediate results have proved surprising, and contradictory of some previous investigations. It has been found from this study that the capacity of a cooling lake to dissipate heat to the atmosphere during periods of low wind velocity is quite appreciable. This work has considerable significance for the design and performance analysis of power plant cooling lakes.

Biological data collection was initiated by the study in 1968. Field data have been collected over the past two years on a year-round basis with hydrological and meteorological data being recorded on a continuous basis. The investigations have had two principal objectives: (1) study of populations of aquatic organisms (fish, plankton, and benthic invertebrates) residing in the mixing areas resulting from thermal discharges; and (2) study the effects of entrainment of microscopic organisms in waters used for cooling at these same stations.

Results of the biological aspects of the study have been rather surprising. The populations located in thermally influenced zones of the three sites (an estuary, a tidal river, and a stratified reservoir) have very little variance with those of comparable habitats lacking influence of thermal discharges. In fact, at one site, the population, size and condition of fishes in the zone of thermal influence appear to be equal to or better than those of control areas during even the warmer periods of the year (July - September). Comparisons of planktonic populations do not reveal significant reductions in species composition or diversity in thermal areas. Entrainment studies have yet to be completed for a full summer period. The project will run for another two years, during which time additional data will be collected and analyzed.

Studies are under way to find practical ways of utilizing waste heat, before it enters the cooling water, before the heated cooling water is discharged to the receiving water, or in the receiving water. Possible uses include space heating, air conditioning and refrigeration, desalination of water, industrial processes, extended periods of navigation, improvements in irrigation agriculture, and advances in aquaculture.

Waste heat is now being used in several instances to heat buildings. In some cases relatively low pressure or exhaust steam from thermal generating plants is used in industrial processes. However, on a national scale such uses of waste heat would account for only a very small proportion of the total available supply. Very few industrial processes can efficiently use energy of such low quality. In some cases it might be beneficial from an overall community standpoint to reduce the efficiency of a power plant in order to supply economical heat to nearby users. This would represent a trade-off between electric power and steam use which could be optimized at the local level.

Agriculture is a potential user of waste heat. Irrigation with heated water could promote faster seed germination and growth and extend the growing season. Hot houses could be used to grow tropical or subtropical crops in the more temperate regions of the country. Specialized, high income crops could be produced on a year round basis. However, such problems as soil adaptability, crop resistance to heat, and parasites, would have to be solved before large-scale use of heated water for crop production could become common practice.

Another potential use of condenser discharge water is aquaculture. Marine and freshwater organisms may be cultured and grown in channels or ponds fed with heated water. For example, it may be possible to grow commercially valuable oysters in areas where they cannot normally reproduce or survive due to low water temperatures. Studies are being made of the possibility of increasing lobster production in Maine with the use of waste heat. Waste heat from a steam-electric plant on Long Island, New York, is being used in an attempt to increase oyster production. Consideration is being given to a similar technique in the Puget Sound region of Washington State to promote the spawning and growth of oysters, crabs, and mussels. Proposals have been made in Wisconsin to use waste heat to warm sport fish hatchery waters and increase growth rates. The University of Miami's Institute of Marine Science is conducting an experiment in shrimp farming at Florida Power and Light Company's Turkey Point plant.

Some other uses of low grade energy derived from heated discharge water await further studies and developments. These would include airport defogging, waste water and sewage treatment processes, navigational investigations, and algae-plankton farming for food production.

Air Pollution. The present and potential air pollution situation in many parts of the United States is now recognized as a major concern of government. To mount a program for the effective control of air pollution on a nationwide basis Congress enacted an Air Quality Act and placed heavy responsibility on the Environmental Protection Agency (EPA) to make its provisions effective. Toward that end, EPA is currently undertaking a broad spectrum of research and development in areas of control technology, meteorology, and other relevant factors toward the significant reduction of contaminants from stationary sources.

Air pollution control is a vital element in the siting of generating plants because a substantial portion of emissions from stationary sources is attributed to the electric power industry--primarily in the form of particulate matter and sulfur and nitrous oxides--in and near major population centers. The projected power needs of the Nation, the long economic life of power plants, and the trend toward larger unit size all underscore the importance of including air pollution control as a major siting criteria in planning future plants. As new plants are built and older plants are gradually replaced, cognizance of air pollution control requirements in the location and design phase represents a major step toward meeting national air pollution control objectives while also meeting the Nation's future power requirements at reasonable costs.

Air pollution is a byproduct of many of the most important trends of our times: growing population; burgeoning technology; increasing urbanization; and rising demands for products, service, and energy. Combustion of fossil fuels and the resulting byproducts make up the bulk of the total annual emissions in this country of some 142 million tons of air pollutants, as shown below.

(In millions of tons annually (1966))

	Carbon monoxide	Sulfur oxides	Nitrogen oxides	Hydro-carbons	Partic-ulates	Totals
Motor vehicles	66	1	6	12	1	86
Industry	2	9	2	4	6	23
Power plants	1	12	3	1	3	20
Space heating	2	3	1	1	1	8
Refuse disposal	1	1	1	1	1	5
Total	72	26	13	19	12	142

Transportation accounts for nearly 60 percent of the total emission; however, this source is not a significant contributor of sulfur oxides, because the fuels used are low in sulfur content. Fossil-fueled power plants (which produced over 85 percent of the electricity generated in the United States in 1966) discharge almost 50 percent of the sulfur oxides, 25 percent of the particulate, and about 25 percent of the nitrogen oxide emissions.

When fossil fuels are burned, chemical oxidation occurs as combustible elements of the fuel are converted to gaseous products and the non-combustible elements to ash. Usually more than 95 percent of the gaseous combustion products are not known to be harmful at the present time (oxygen, nitrogen, carbon dioxide, and water vapor) and are not a factor in air pollution. The noxious gases (oxides of sulfur and nitrogen, and organic compounds including polynuclear hydrocarbons) are harmful to plants, humans, animals, and material. Controls are available for particulates, but there are presently no fully tested commercially available control systems for the oxides of nitrogen and sulfur. Combustion of natural gas yields comparable quantities of the oxides of nitrogen, but is usually very low in the production of particulates and sulfur oxides.

Oxides of sulfur are one of the major factors contributing to air pollution. Sulfur dioxide may, upon discharge, convert to sulfur trioxide, and the latter to sulfuric acid mist, which may cause extensive damage to human and vegetable life, as well as to property. Sulfur oxides in combination with other pollutants, e.g., particulates, have been shown to exhibit synergistic effects several times more severe than comparable exposure to either pollutant alone. Extensive research efforts are under way to develop economical control processes for industrial units.

Nitric oxide, though not a very toxic gas when isolated, oxidizes in the atmosphere to nitrogen dioxide, a lung irritant. Under the action of sunlight, nitrogen dioxide dissociates into nitric oxide and atomic oxygen. Some of the latter then combines with molecular oxygen to form ozone, a highly irritating gas and a health hazard. The nitrogen dioxide combines with various hydrocarbons, forming various organic nitrogen compounds. Gaseous emissions from coal combustion include oxygenated organic compounds (such as aldehydes, carbon monoxide, hydrocarbons), as well as the oxides of sulfur and nitrogen.

Particulate emissions from coal-fired units consist primarily of carbon, silica, alumina, and iron oxide in the flyash. All but the smallest of the submicron particles of fly ash can be removed by control equipment before flue gases are discharged.

Health and nuisance aspects of a fossil-fired plant normally increase in direct proportion to the population. Population centers in the immediate vicinity of a plant may present air quality problems related to dust from handling coal or fly ash as well as from stack emissions. Sites having population centers (within one mile of the site) in relatively deep valleys which may channel atmospheric emissions are not desirable. Air quality considerations related to population should take into account both existing and expected future developments and populations in the area of concern.

Agriculture and forestry is primarily affected by emissions of sulfur dioxide. Plant tolerance levels are reasonably well known, and proper planning and design can assure that they will not be exceeded.

There are three general approaches to the control of sulfur oxides and/or particulate emissions arising from fuel combustion: fuel changes, stack gas cleaning, and improvements in combustion efficiency.

Fuel changes include both fuel substitution and fuel switching. The former is defined as the replacement of one fuel with another of the same type, an example being the substitution of low-sulfur coal for high-sulfur coal. Fuel switching is defined as the replacement of one fuel with another of a different type (e.g., switching from coal to oil or natural gas).

Stack gas cleaning is applicable to the control of both sulfur oxides and particulate emissions, but currently it is widely applied only in control of particulates.

Radiological Effects. A rem is a unit used to measure radioactivity effect on man. A millirem is one thousandth of a rem. The Federal Radiation Council has recommended that the general public never be exposed to more than 500 whole-body millirems of radiation per year. One can safely receive much higher doses of radiation for short periods of time, or in local parts of the body. Some average dosage levels are enumerated below:

T.V. set - less than 1 millirem per year;

Cross-country jet flight from cosmic rays - 1 millirem;

Two week vacation in the mountains - 3 millirems;

Living in a wooden house - 11 millirems per year;

Chest X-ray - 100 millirems;

Natural background, San Francisco - 120 millirems per year;

Natural background, N.Y.C. - 135 millirems per year;

Natural background, Denver - 150 millirems per year;

Complete dental X-ray - 5,000 millirems;

Cancer therapy - 500,000 millirems or more.

Nuclear power reactors add waste heat and low levels of radioactivity to the environment. The development of nuclear reactor technology in the United States has been characterized by an overriding concern for the health and safety of the public and for the protection of the environment. Its safety record in comparison with other industrial activities is excellent. No member of the general public has received a radiation exposure in excess of prescribed standards from the operation of civilian nuclear power plants in the United States, according to Atomic Energy Commission statistics. No accidents of any type affecting the general public have occurred in any civilian nuclear power plant in the United States.

During their operation nuclear power plants are permitted to release, under well controlled and carefully monitored conditions, low levels of radioactivitity. Experience with licensed operating power reactors shows that such levels of radioactivity are only a small percentage of release levels permitted under A.E.C. regulations. These limit the dose for the general public at 500 millirems per year from licensed sources. Typical nuclear power plant off-site dose design objective is one percent of A.E.C. regulations and operating reports from plants in the field show an order of magnitude of about 1 millirem per year. In evaluating the acceptable risk from radiation exposures, the Council employs the best technical experts in the field, and takes into account the recommendation of the National Committee on Radiation Protection and Measurement and the International Commission on Radiological Protection.

Nuclear reactor technology has been developing in the United States for more than 25 years. During this time the knowledge necessary to protect public health and safety has advanced with the technology. Protection of public health and safety in the design, construction, and operation of reactors is a statutory responsibility of the A.E.C. under the Atomic Energy Act of 1954, and the Commission regards this as an overriding consideration in all its activities including the licensing and regulation of nuclear reactors. In carrying out this responsibility, the A.E.C. devotes special attention to assuring that radioactive wastes produced at nuclear power reactors and other facilities are carefully managed and that releases of radioactivity into the environment are within government regulations.

The management of radioactive waste material in the growing nuclear energy industry can be classified into two general categories: The treatment and disposal of materials with low levels of radioactivity, i.e., the low activity gaseous, liquid, and solid wastes produced by reactors and other nuclear facilities such as fuel fabrication plants; and the treatment and permanent storage of much smaller volumes of wastes with high levels of radioactivity.

The high level wastes of the latter category are by-products from the reprocessing of used fuel elements for nuclear reactors. These high-level fuel reprocessing wastes have a higher hazard potential than the former category. The two types are unfortunately misunderstood by much of the public.

Neither the reprocessing of used fuel nor the disposal of high-level wastes is conducted at the sites of nuclear power stations. After the used fuel is removed from the reactor, it is securely packaged and shipped to the reprocessing plant. After reprocessing, the high-level wastes are concentrated and safely stored in tanks under controlled conditions at the site of the reprocessing plant. Only a few reprocessing plants will be required within the next decade to handle the used fuel from civilian nuclear power plants. As with the power reactors themselves, the A.E.C. carefully regulates the operation of such plants.

More than 20 years of experience has shown that underground tank storage is a safe and practical means of interim handling of high-level wastes. Tank storage, however, does not provide a long-term solution to the problem. Accordingly, using technology developed by the A.E.C., these liquid wastes are to be further concentrated, changed into solid form, and transferred to a Federal site, such as an abandoned salt mine, for final storage. These mines have a long history of geological stability, are impervious to water, and are not associated with usable groundwater resources. This procedure will provide assurance that these high-level wastes are permanently isolated from man's environment.

Technology developed for the treatment and storage of radioactive wastes produced at presently operating power reactors is considered more than adequate for the expanding industry during the next decade. These treatment systems include short-term storage of liquid wastes, evaporation, demineralization, and filtration of liquids and gases, and compression of solid wastes. They also include chemical treatments to concentrate radioactive materials, and immobilization of radioactive solids and liquids in concrete or other materials.

Operating experience in licensed power reactors shows that levels of radioactivity in effluents have generally been less than a few percent of authorized release limits. Environmental monitoring programs to measure radioactivity are carried out by licensees, some of the states, the Bureau of Radiological Health of the U. S. Public Health Service, and the Atomic Energy Commission. The quantities of radioactivity released are so small that it has been difficult to measure any increase in radioactivity which can be attributed to effluents from nearby nuclear power reactors, above natural background levels in rivers and streams.

Environmental and Esthetic Effects of Plant Sites and Transmission Facilities. The electric power industry has not been established without great impact on man's environment. Problems of air pollution and thermal pollution have been discussed in the preceding sections. Many other problems exist, especially in regard to generation and transmission systems.

There are many esthetic considerations associated with the siting, construction, and operation of generating stations. For example, coal piles, coal handling equipment, and stacks add to the normal problems of a large industrial structure at fossil-fueled generating stations. Not only do coal piles contribute to an unsightly overall appearance, but they are frequently involved in water pollution. With the passage of time and the occurrence of storm water runoff, the smaller particles find their way into the nation's waterways. Nuclear plants pose the problem of large containment vessel structures and hydro plants often intrude on scenic areas, or entail competitive use of water that may preclude other esthetic developments. Gas turbine and internal combustion plants are beset with noise and fume problems.

The location of a hydroelectric development is controlled by topographic and hydraulic criteria, and in most cases the type and form of the structure is also pre-ordained by geological and topographic considerations. Even working within the framework of this seemingly confined atmosphere, there are many and varied options available to the architect and engineer to enhance the esthetic and environmental features of the project. One such innovation involves the concept of "integrated design", where the powerhouse is integrated with the downstream face of the dam, rather than simply placing it adjacent to the slope. This permits visitors access to the spillway and massive gates, an admirable way of bringing the public into direct confrontation with a large part of the operation and function of the dam.

Beyond the structure itself the contractor has it within his power to preserve the region's natural features. It is well within his power to confine his operations in a manner that would safeguard timber stands and rock formations, and thus eliminate, to a great extent, the unsightly construction scars that debase so many hydroelectric sites. Sand and gravel pits, spoil areas, and access roads can all be planned with a view to preserving the area's pristine quality.

There are many considerations involved in site selection of steam electric generating stations, some of which are directly related to minimizing the project's assault on the environment. Esthetics and environmental effects, until recently, were often reviewed as an afterthought rather than as a prime consideration. Recent concern with environmental factors has led to a vast change in site selection and design concepts. Some major projects have taken advantage of the opportunity to blend their plants with the surrounding area by the employment of various species of trees and shrubbery in conjunction with blending the plant into the natural terrain.

Other problems that tend to limit the number of sites esthetically suitable for fossil-fuel electric plants are the fuel storage and ash disposal areas with their attendant structures and associated transportation facilities. The space requirements for these facilities aggravates the problem of concealment. A 3,000-MW coal-fired plant needs 900 to 1,200 acres of land, for optimum convenience and economy.

In many cases cooling towers must be employed for thermal power plants located on inland water. These towers present difficult esthetic problems. If mechanical draft towers are used, the structures may be several hundred feet long and 60 feet high. Forced draft towers emit vapor into the air that may create fog banks, snow, rain, sleet, or ground ice, under certain atmospheric conditions. If natural draft towers are employed in the alternative, the structures are hyperbolic in shape with a circular base and a height of about 400 feet each. The plumes from these giant hyperbolic towers present less of an esthetic or environmental problem than those from the forced draft systems, but this may prove an under-compensation for their enormous size. In both cases local noise conditions can constitute a major nuisance.

Power and other utility transmission systems currently create a landscape that is a tapestry of wires caught up from time to time by giant gaunt steel towers or obstrusive pole structures. Transmission systems probably generate more complaints from the public than all other facilities combined. Concealment of transmission towers and lines is virtually impossible, but much can be done to render them less intrusive and more attractive. Regardless of the general scheme employed in the layout of a transmission line, the appearance of the individual towers will usually be of a major concern. They cannot always be placed out of view, or effectively blended into the surroundings by landscaping or painting. Some companies have responded to this challenge by proposing a completely new design for transmission towers. They have attempted to unclutter the traditional tower and make it more graceful. They have sought to eliminate the appearance of stark utility and emphasize, instead, a streamlined beauty.

The Federal Power Commission, under Order No. 414, adopted new regulations, effective January 1, 1971, implementing procedures for the protection and enhancement of esthetic and related values in the design, location, construction, and operation of licensed hydroelectric power project works.

Transmission towers of this size and type cannot be easily hidden or camouflaged.

Figure P-5

The regulations require all applications for new projects to include an exhibit showing the applicant's efforts to protect and enhance natural, historic, scenic, and recreational values in locating rights-of-way and transmission facilities. The exhibit (map, photographs or drawings) to be submitted with applications for licenses must show measures which will be taken during construction and operation of the project to prevent or minimize damage to the environment and preserve the project's scenic values.

The Commission at the same time issued a set of guidelines designed to provide an indication of the basic principles to be applied in the planning and design of electric power transmission facilities. The guidelines seek to provide the most acceptable answers from an environmental standpoint, taking into account safety, service reliability, land use planning, economics and technical feasibility.

Many companies, after vast amounts of experimentation, have decided that the pole is preferable to any other possible configuration. The simple streamline pole has met with great public acceptance in many instances, as being the least obstrusive on the environment.

It is the opinion of a great many of the industry's critics that it is not so much the structures themselves that offend esthetic sensibilities, and thus assault the human environment, as the rights-of-way slashes in which they are placed. In creating new rights-of-way, many forward-looking utilities have taken great care to insure proper placement. Attempts have been made to locate lines as far away from highways or other public gathering places as possible. In any event, structures are generally located away from skyline ridges, where the sky cannot be utilized as a backdrop. If ridge-top structures cannot be avoided, limited height trees planted along the ridge under the transmission line help to make the right-of-way gap less obvious.

Underground transmission systems would be ideal from the esthetic standpoint. A report to the Federal Power Commission by an Advisory Committee on Underground Transmissions was published in April 1966. This study showed that the cost of underground transmission was too high for general application at present, but it recommended intensive research to improve underground transmission technology.

OTHER FORMS OF GENERATION (EXOTICS)

General. In addition to the utility industry's constant effort to improve operating efficiency, the search for new forms of generation is prompted by military and space requirements, a need to find new sources of energy, and a desire to protect our environment.

Researchers throughout the world have been engaged in this search and have been investigating many sources of energy in their efforts to develop new generating methods. The researchers have demonstrated the technical feasibility of producing electricity from fuels in the earth and from the energy of the sun, wind, waves and tides. They are considering the possibility of harnessing earth's magnetic and gravitational fields, earth's rotational energy, and energy stored on the moon's surface by years of electron bombardment from the sun. Generating methods related to these energy sources have been investigated with varying degrees of intensity and depth and are presently being pursued in relation to the degree of promise they hold.

Of the many research efforts, several that hold particular interest for the utility industry are thermionic, thermoelectric, solar, and geothermal generation; fluid-dynamic converters, and the nuclear fusion reactor; and the development of fuel cells. Nuclear researchers are also actively involved in the development of breeder reactors to optimize the use and increase the availability of nuclear fission fuels. A brief discussion of each major area of research follows.

Thermionic Generation. When heat is constantly applied to metals a point is reached where electrons acquire enough energy to overcome retarding forces at the surface of the metal and escape into the atmosphere. This simple phenomenon, which is the pertinent feature of thermionic generation, was discovered in 1878 by Thomas Edison.

The simple thermionic generator consists of two plates, the emitter and the collector, separated by a small space. By the addition of heat energy, electrons are freed from the emitter and pass through the intervening space to the collector. This passage of electrons and the electrical properties of the collector enable the development of a voltage difference across the plates. Electric current can then be made to flow through an external load connected between the emitter and collector. The constant application of heat energy provides a constant output of low-voltage direct current electricity.

Thermionic generation is possible with a number of heat sources, and units have been developed utilizing solar, nuclear, and fossil fuels. This exotic generation, however, has been more extensively investigated with reference to space activities than central power station development. The general consensus is that future efforts will be concentrated in space oriented activities beyond 1980. The likelihood of an appreciable thermionic impact in the area of central station power generation prior to 1990 appears remote.

Thermoelectric Generation. The thermoelectric generator is a device which converts heat energy directly into low-voltage direct current electricity. It utilizes the "Seebeck principle", that a voltage difference is produced at one end of two joined dissimilar conductors when heat is applied to the opposite end. With the development of the transistor and advancements in the technology of semiconductor material, it became possible to produce usable generating units. Usable amounts of electric power are produced by connecting several generating units into thermopiles for use as a single generator. It is also possible to operate the generators in different segments of a wide range of operating temperatures, by varying the conductor materials.

Experimentation in the field of thermoelectric generation is reaching the point of diminishing returns. Though thermoelectric generation appears suitable for installations requiring modest power levels and maintenance free operation, it is unlikely that the method can compete with existing large central station power plants in the foreseeable future.

Solar Generation. As early in 1901 energy from the sun was used to provide power for a steam engine. Since then solar energy has been used to power many devices. Its use for the most part was restricted to latitudes between 40 degrees north and 40 degrees south and to applications which were not sensitive to its discontinuous nature. Such things as solar water heating plants and solar distillation plants have been functioning satisfactorily for years. By 1966, Israeli scientists had developed a solar powered electric generating plant which incorporated a mirror collector and a heat storage system enabling night operation at reduced load. The most successful application of solar energy to date has taken place in the space programs. The use of solar heat sources to power thermoelectric and thermionic conversion devices was a factor in the successful completion of several space programs. Based on the technology available today the economics of solar generation are questionable except for space usage and other equally unique applications.

Solar energy has been considered in two connections: one such concept involves the development of floating power plants that will utilize the solar-produced temperature differential which exists between the upper and lower levels of Caribbean waters and the Gulf Stream. The higher temperature upper levels and colder lower levels have been suggested for use as a heat source and heat sink to produce up to 100 megawatts of electric power. A second concept involves the orbiting of space vehicles for the purpose of creating central station power generation.

At present, solar conversion is in an unfavorable economic position. Recent research and development of organic compounds possessing semiconductor and photovoltaic properties has made inroads on the efficiency and cost-weight problems which have made existing systems uneconomical. Successful development of such devices would make the possibility of orbital power stations more nearly feasible. Solar stations orbiting the earth would thereby collect solar energy from the sun and convert this energy to electric energy for micro-wave transmission to earth. Large design problems are needful of solution, largely in the areas of orbital characteristics, conversion devices, transmission facilities, and reception of power on earth.

Fusion Reactor. A fusion reactor will utilize a sustained combining, or fusion, of the nuclei of light elements to release nuclear energy and make it available for the production of electric energy. The development of a fusion reactor involves the establishment of conditions to produce a fusion reaction and the creation of technologies for harnessing the released energy and converting it into electric power.

There are several known reactions which can be the basis for a controlled fusion reaction. These include deuterium-tritium, deuterium-helium, and two deuterium-deuterium reactions. The major reason for interest in the fusion reactor stems from the fact that deuterium, a stable isotope of hydrogen found in all water, is so plentiful and the fusion process can function as a tritium breeder.

To accomplish the reaction it is necessary to raise a fuel to temperatures in the range of 100 million to 1 billion degrees Kelvin; to hold the resultant gaseous dispersion of ions and electrons (plasma) in a configuration which would provide an ion density in the order of 10^{15} ions per cubic centimeter; and to confine this hot plasma at these densities for periods of time in the order of tenths of a second. For fusion to take place, a suitable ion density must be maintained for a sufficiently long time at adequately high temperatures. These criteria necessitate the formation and containment of a super-hot plasma, at temperatures which no known container material can withstand, and at densities equivalent to a nearly perfect vacuum. Simultaneously, fuel must be fed to the system and electrical energy extracted from the developed heat energy. Near term development is highly unlikely.

Fuel Cells. Fuel cells are electrochemical devices in which the chemical energy of a fuel, such as hydrogen, is converted continuously and directly to low-voltage direct current electricity. Fuel cells have the same basic elements as the battery: two electrodes, the anode and cathode, separated by an electrolyte. In contrast to the battery the fuel cell is an open system which requires a continuous supply of reactants for the production of electricity. The quiet, relatively low temperature operation of fuel cells and their promise of a highly efficient energy conversion process has focused considerable interest on the device.

One of the greatest potentials of the fuel cell is its capability of ultimately replacing many present day peak power devices. Fuel cells also offer an opportunity to reduce the rate of air pollution by using systems which employ sulfur and particulate-free fuel with emissions consisting almost entirely of carbon dioxide and water, with low quantities of nitrogen oxides and unburned hydrocarbons.

It is felt that the fuel cell will have limited applications and will not replace central station power generation in the foreseeable future. Although fuel cell efficiencies of 60 to 90 percent have been reported, overall fuel cell systems involving conversion to ac power have efficiencies under 50 percent. It has been predicted by some that fuel cells up to 100 kW will be available in the mid 1980's at costs up to 300 dollars per kilowatt.

Geothermal Generation. Geothermal generation is a process by which natural steam entrapped below the surface of the earth's crust is used to produce electrical power. The steam is released from the earth's depths by means of holes bored through the surface. The steam made available by "tapping" the pocket is transmitted by pipe to a generating facility nearby. The process takes advantage of the many hot spots, such as geysers, hot springs, and fumaroles, which exist within the earth's surface.

Many scientists foresee future installations involving deep drilling through the earth's mantle (20-30 miles) making it possible to tap energy sources almost anywhere on earth. They also envision producing high-pressure steam by the injection and recirculation of water through huge subterranean hot cavities created by underground nuclear explosions. Recent legislation, PL 91-581 approved late in 1970 authorized the Department of Interior to license geothermal development.

IMPROVED FUELS

Low-Sulfur Coal. The use of low-sulfur fuel is one method for reducing sulfur dioxide pollution from stationary combustion sources. There is much disagreement as to what constitutes "low-sulfur" coal. There is also a scarcity of information necessary to determine the size of commercial reserves, even if an arbitrary definition of the term were universally accepted. These uncertainties appear to have a profound effect on decision making processes within the electric power industry and the coal mining and transportation industries.

On the basis of air pollution regulations, coal considered to be "low-sulfur" in St. Louis (2 percent) would not be considered low in sulfur in New York City, where one percent sulfur is proposed as the maximum. Neither would be adequately low in sulfur to meet the recommended limits of sulfur oxide emissions from Federal facilities in New York or Chicago.

Low-sulfur bituminous coal, particularly of high-grade metallurgical coking qualities, is essentially a different commodity from bituminous steam coal. Because of significant savings deriving from the use of low-sulfur coke (produced from low-sulfur bituminous coal) in metallurgical processes, steel companies demand and are prepared to pay a premium for low-sulfur coking coal. For that reason, mining companies will frequently produce from slightly thinner seams, work at somewhat greater depths, engage in some degree of selective mining, and perhaps even clean the coal a bit more thoroughly. A demand for similar quality power-plant coal would be likely, therefore, to increase the mine price by $2 to $3 per ton.

When low-sulfur coal replaces higher sulfur coal in an existing power plant, several characteristics of the substitute coal must be carefully scrutinized. Some of the more important constraints imposed by plant design limitations which must be watched within allowable limits are:

ash fusion temperature - which determines the design of the boiler furnace;

grindability - which determines, where applicable, the adequacy of available grinding equipment;

total ash content - which determines the capacity of fly-ash precipitators or other ash handling equipment. An increase in ash content of the coal from 8 percent to 10 percent means about a 25 percent increase in the total volume of ash; and

volatility - which determines the design of the boiler furnace.

Statistical analysis indicates a strong inverse relationship between the sulfur content of a coal and its ash-softening, or fusion, temperature. As the sulfur content declines, fusion temperature increases. Consequently, switching to coal with a lower sulfur content, but with a higher ash fusion temperature, may cause serious heat exchange and slag tapping problems in "wet-bottom" boilers, which are usually designed to operate at a relatively low ash-fusion temperature range. Conversion of "wet-bottom" to "dry-bottom" design is costly and is likely to result in a loss of capacity.

Low-Sulfur Oil. The combustion of residual fuel oil constitutes an air pollution problem because of the substantial emissions of sulfur dioxide. Lighter fuel oils are not considered at present to contribute significantly to air pollution.

Three methods are presently available for obtaining low-sulfur residual fuel oil:

production of residual oil by refining low-sulfur crude oil;

desulfurization of crude, distillate, and/or residual oils;

reducing sulfur level of high sulfur residual oil by blending it with low-sulfur oil from either of the above.

Natural low-sulfur crude oil both in the United States and worldwide is limited in availability and will not present a significant factor in nationwide alleviation of sulfur dioxide pollution. Its availability may be sufficient, however, to contribute meaningfully to air pollution abatement in a few selected localities. Availability of foreign crude oil and petroleum products is affected by import policies and foreign relations as well as economic factors. A long-range solution to the sulfur in oil problem may be found in oil from shale, particularly in the central and western regions of the country which are near the oil shale deposits.

The oil industry has developed the technology for desulfurizing residual oil for an estimated increase in cost of from about 25 cents to a dollar a barrel, depending on the type of feedstock, extent of desulfurization, and processing methods.

A desulfurization plant for residual oil began operations in Japan in September 1967. A few others are under construction or in the planning stage as are a number of plants for desulfurizing heavy distillate gas oil which can be used as a blending stock for reducing sulfur in residual oil.

(Breeder Reactors) Nuclear Fuel. Several reactors have a potential for breeding--that is, for producing more nuclear fuel than they consume--because of the materials, or combinations of materials, that are used to build them.

How does a breeder work? Uranium-235 atom can fission when its nucleus absorbs a neutron. The fission reaction releases free neutrons that may, in turn, initiate other fissions. All the neutrons released, however, are not necessarily absorbed by fissionable material; some are wasted by being absorbed in the structural material of the reactor, the control elements, or the coolant. The breeder concept puts the wasted neutrons to work and exploits the characteristics of certain fertile materials. When the nucleus of an atom of fertile material absorbs a neutron, the fertile atom can be transformed into an atom of a fissionable material -- a different, but very desirable substance. By careful selection and arrangement of materials in the reactor -- including, of course, fissionable and fertile isotopes -- the neutrons not needed to sustain the fission chain reaction can fairly effectively convert fertile material into fissionable material. If, for each atom that fissions, more than one atom of fertile material becomes fissionable material, the reactor is said to be breeding. One fertile material is uranium-238, which is always found naturally with fissionable uranium-235. When 238 U nuclei absorb neutrons they are converted to nuclei of fissionable plutonium-239.

Reactor engineers have, for many years, known that in principle it is possible to build a nuclear power reactor that will regenerate much more nuclear fuel than it consumes. The development of such a reactor faces formidable technical obstacles. The Atomic Energy Commission, in cooperation with industry, has launched a program which should bring practical breeder reactors to the market by the year 1990.

CHAPTER 7

FUTURE GENERATING CAPACITY

GENERAL

The preceding chapters established estimates of the expected future power load of the NAR market area and the additional capacity requirements needed to serve it. The next logical step is to estimate in a broad manner the make-up of this augmented power supply.

The availability of coal in Pennsylvania has been recognized in the pattern of future generation shown in this Appendix....a pattern believed to be feasible in terms of delivered fuel costs and air pollution considerations. A number of relatively large fossil-fueled plants are anticipated in central and western Pennsylvania. Several large oil fired units are expected along the Atlantic Coastal areas. These sites offer economic installations for generating stations that can be supplied with fuel by seagoing tankers. The environmentally more desirable use of natural gas in liquid form and delivered by tanker would foster the development of coastal sites.

Within the NAR, the megalopolis area from Washington, D. C. to Boston is expected to continue as the most concentrated load area of the Region, and for this reason the largest number of generating plants will be found in and around that area. The availability of coastal waters as a source of cooling for the large stations anticipated in the future also makes the megalopolis area a naturally desirable region for plant sites.

A trend towards the installation of nuclear units became evident during the past decade. This trend will accelerate as urban siting of nuclear generation becomes practical during the 1980 to 2000 period due to economics and the solution which these plants offer to the problems of air pollution and site restrictions. With the development of large concentrations of nuclear and fossil base load plants in the NAR power market an adequate supply of peaking power becomes mandatory.

Under normal system operation, generating facilities can be generally classified by their operating characteristics. These are base load and peak load operation. There are no hard and fast rules as to the amounts of each form of generation required for system use. Under existing patterns of electric energy utilization, however, certain generalities can be stated. In the NAR, for the year 1980, it is estimated that about 75 percent of the installed capacity will be base load capacity that will operate for long continuous periods of time at load factors between 80 to 90 percent. The remainder will operate for varying periods of time, usually at load factors of less than 25 percent.

Capacity must be available to serve all portions of the system load from base to peak. In the past, before loads had reached their present levels of magnitude, utilities usually depended on their older, less efficient, thermal units and hydroelectric capacity to serve the peak portions of the load. As new capacity was placed in service on the base of the load, existing units moved progressively towards the peaking portion. With utility loads approximately doubling every ten years and with the rapid growth in power pooling, requirements are reaching an order of magnitude where older units available for peaking and reserve duty may not be sufficient for this purpose and capacity will have to be provided specifically for such functions.

Optimum utilization of large thermal units requires their operation at high load factors over their lifetime, perhaps in the order of 65 to 70 percent. This would correspond to an average annual use of about 5,700 to 6,100 hours per year. Power market planners must resort to other prime mover types for peaking and reserve functions that would operate only a few hundred to 2,000 hours per year. Economic justification of the high production expenses usually associated with such restricted operation is met by low investment costs, relative to base load investments, for peaking and reserve capacity. Capacity is available today for such specialized duty as evidenced by the installation of various large scale peaking units: conventional and aircraft jet engine gas turbines, peaking steam, and pumped storage hydroelectric power. It is believed that systems serving the market will take advantage of all these, particularly pumped storage opportunities. The availability of pumping energy and the topographic conditions in the region enhances the attractiveness of pumped storage hydro as a source of economical peaking power.

TYPES OF GENERATION

Fossil-Fueled Steam for Base Load Generation. The trend towards larger and larger fossil-fueled generating units to capture the economies of scale is to a large degree shaping the plans for expansion of electric power systems throughout the Nation. This trend is even more pronounced in the high load areas of the northeastern region. In the late 1950's a 300 MW generating unit was considered maximum, but one short decade later units as large as 1,300 MW, are scheduled for operation in the United States.

Plant sizes may increase to 5,000 MW by the year 1990 with unit sizes ranging in the neighborhood of 1,500 MW. Reliability is becoming increasingly important, and the previous rapid advances of high pressure steam technology are tempered by the need to more thoroughly prove the expected gains in efficiency. Heat rates may be further improved by advances in boiler efficiency, better exhaust and condenser design, and possibly by use of combined cycles. It is unlikely, however, that the large improvements in efficiency will continue at the pace set in the past decade.

Automation and precise controls will be necessary to properly and adequately control the tremendously concentrated energies of the super-sized generating units. Controlled heating and expansion of boiler and turbine parts on startup and shut-down will be required to eliminate damage by thermal stresses and to avoid unnecessary maintenance of the large units, thereby assuring high availability. Response of machines to spinning reserve contingencies will have to improve as sizes increase and fewer total units are on the line at any given time. Boiler response to sudden system changes in generation or load will also have to be improved.

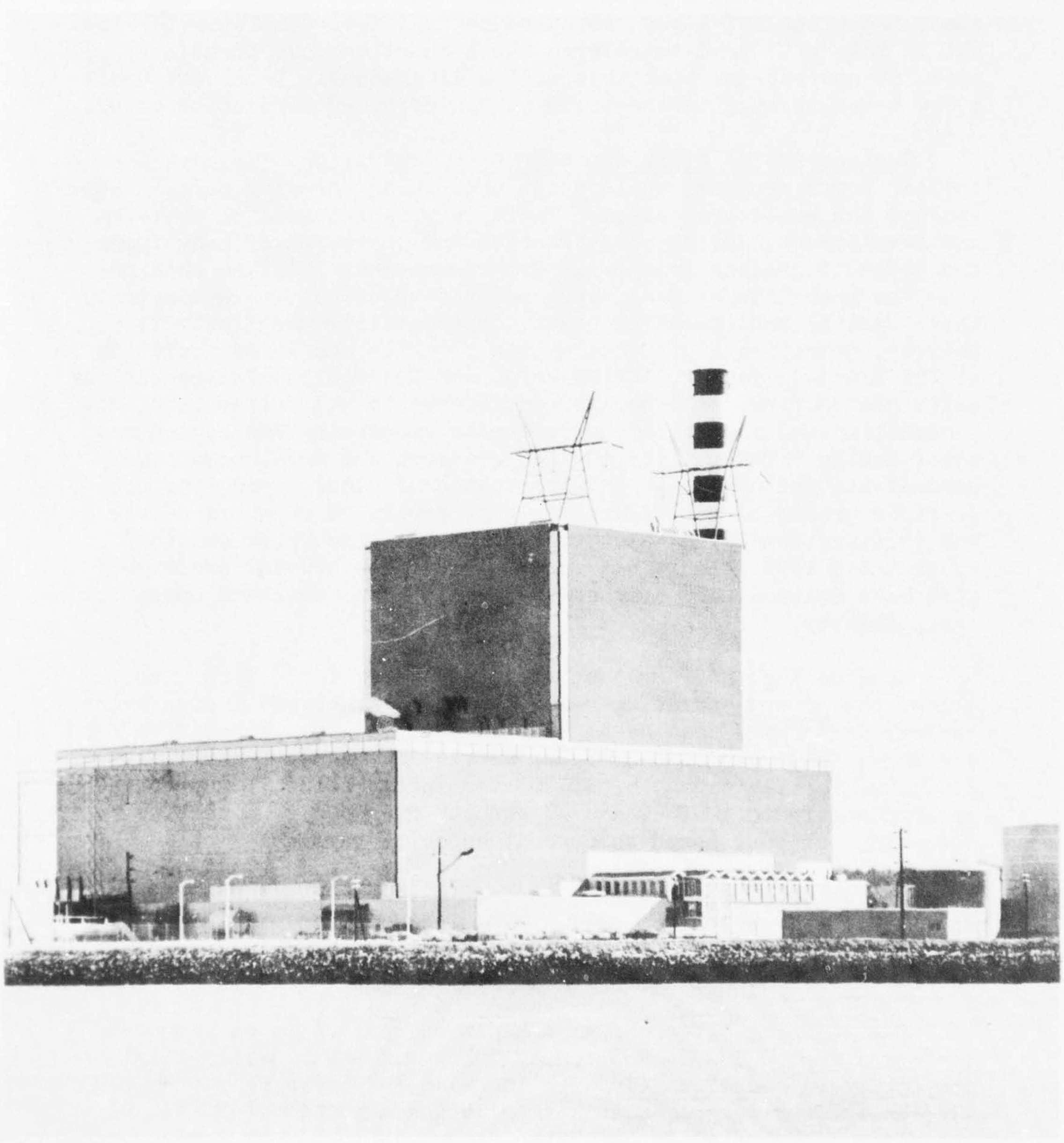
Fuel supply in storage as protection against production or transportation stoppages or other problems will represent a major inventory investment for large concentrations of generating capacity at a given site. Sixty-day supplies are presently commonplace, and may have to be increased to seventy-five or even ninety, to adequately protect against shortages.

Automated transmission safeguards against generation upsets caused by loss of a large unit, loss of major sectors of load or disturbances of frequency and/or voltage will be more important as systems continue to expand and protection of components from damage becomes more vital to reliability and availability.

There has been a leveling off of the past decade's increases in size of boilers and turbines and increases in steam conditions, which signals the realization that operating experience must catch up to predictions and justification for future advances in unit sizes.

Investment costs per kilowatt are normally expected to decrease with increasing unit size, but, in addition to inflation, the demands of the early 1970's for cleaner air, reduced thermal discharges to streams and lakes, and esthetics, are absorbing the dollars saved by building larger facilities. High stacks, better precipitators, sulfur dioxide collection processes, cooling towers, and better architecture and landscaping where necessary, all add to the cost of any size unit. However, size helps to hold the line on total cost per kilowatt.

Fuel costs for coal and oil with reduced sulfur content are increasing now, as are some freight rates along the east coast. Disposal of ashes will continue to be a problem as coal quality deteriorates when less desirable reserves are tapped and ash content increases.



Canal Electric, is a 560,000 kilowatt generating station located at Sandwich, Mass. by the Cape Cod Canal. The higher section houses the 18-story high fossil- steam generator.

Figure P-6

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NORTH ATLANTIC REGIONAL WATER RESOURCES STUDY. APPENDIX P. POWE--ETC(U)
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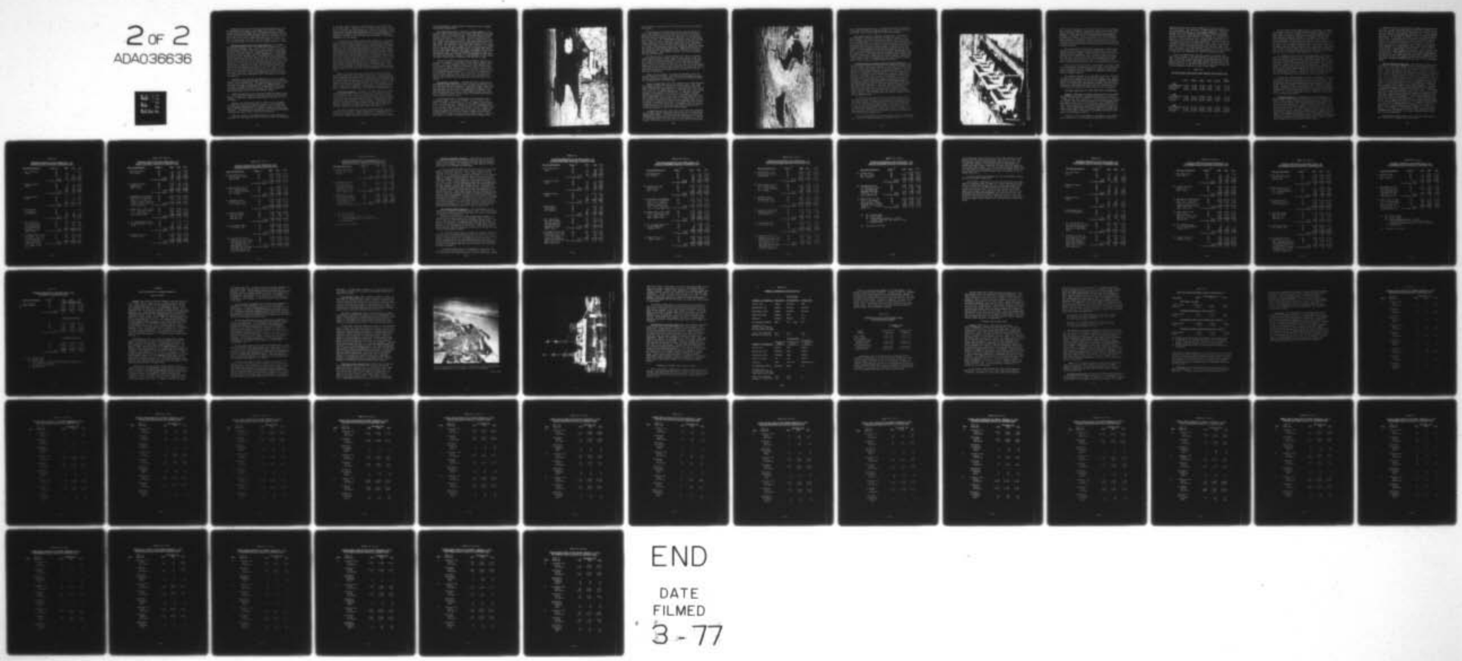

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Power production costs have historically decreased with time as improvements were made to the thermal efficiencies of plants, and as unit sizes increased; these efficiencies have now reached a point where possible gains are much smaller for present day units. Also, the prices of labor, maintenance, and fuel continues to rise. All of this will tend to reverse the production cost trend. At best, it now appears that this cost will gradually level off until a new break-through in the basic method of power production occurs.

Nuclear-Fueled Steam for Base Load Generation. The domestic nuclear power program, while still undergoing "growing pains", has reached the adolescent stage. There is much required in research and development, design, construction and operation of many types and sizes of nuclear reactors. Experience must still be obtained from the operation of many types under development, to demonstrate their capital and operating costs, dependability and flexibility. However, operating experience gained from the continued operation of the Dresden, Yankee, Indian Point and Connecticut Yankee nuclear units has confirmed the earlier confidence in the reliability, dependability and flexibility of the water-moderated and cooled reactor design. Thus, while nuclear research and developments may demonstrate the advantage and importance of other types, the projections presented herein are based primarily on reactors of the PWR (Pressurized Water Reactor) and BWR (Boiling Water Reactor) types until 1990 when it has been assumed fast breeder prototypes will have successfully demonstrated their advantages and operating acceptability.

Considering the fact that the plants are of the first generation, the power generating records at the Yankee and Indian Point nuclear units have been good. The cumulative gross generation from the first full year of commercial service in megawatt-hours, is 6,750,000 for Yankee and 5,605,000 for Indian Point, for average gross plant factors of 69 and 47 percent over their respective operating periods, based on current capacity ratings.

Operating experience from Connecticut Yankee and Peach Bottom No. 1, the only units recently coming into service, has been satisfactory. Connecticut Yankee has successfully completed its first refueling.

Capital cost differential against nuclear units as compared to fossil-fuel units has continued. However, this differential has decreased significantly with increase in unit size and should also be further decreased as air pollution abatement receives more attention. Increased capital expenditures dictated by environmental considerations would further reduce the differential.

With the concept of field fabrication of reactor vessels an accepted fact, the transport limit on size will have been eliminated.

As a result, reactor units of 2,500 MW capability are conceivable by the late 1980's. However, for the purpose of this study, a size limit of 2,000 MW has been assumed as a practical objective. It has been assumed that engineered safeguards will be so thoroughly demonstrated by the 1980's, that urban siting will become acceptable. However, no assumption has been made that containment or engineered safeguards will be relaxed.

The presently installed nuclear power capability in the market area is approximately 2 percent of the total electrical capability. However, there is under construction or scheduled over 25,000 megawatts of nuclear capacity with in-service dates through the 1970's. Presently, there are four major suppliers of nuclear steam systems competing for the electrical generating business, and these augmented by competent field fabrication of large pressure vessels contribute materially to nuclear power growth. This growth rate is such that by the early 1970's nuclear power will account for about sixty or seventy percent of the new capacity being installed. It is probable fossil capacity additions will be continued, to a limited degree in the coal producing areas and the remainder of the non-nuclear capacity installed will consist of developable hydro, quick start thermal peaking, and large blocks of pumped storage. These plants will complement the nuclear generation by improving capacity factor operation, thus improving overall performance of the nuclear plants.

There is a possibility that other types of nuclear reactors may prove competitive in the period under study. One such is the high temperature gas-cooled reactor of the type in experimental use in the 40 MW Peach Bottom No. 1 unit and the 330 MW Fort Saint Vrain (Colorado) plant now under design. Favorable results from this advanced converter concept could stimulate sufficient interest to result in some capacity additions of this type. No attempt has been made to evaluate the potential of thermonuclear power generation and no estimates of useful power from fusion are contained herein.

Peak Load Generation. Generation for peak loads differs from other generation only in that it is required to operate for relatively short periods. This requirement can be met by most types of generating facilities, with the exception that serious operating difficulties are encountered when the load on high-pressure, high-temperature steam turbines is varied rapidly. Consequently, the choice of facilities to carry the peak of the load is wide, and should be governed by overall system economics rather than by the specific suitability of particular forms of generation.

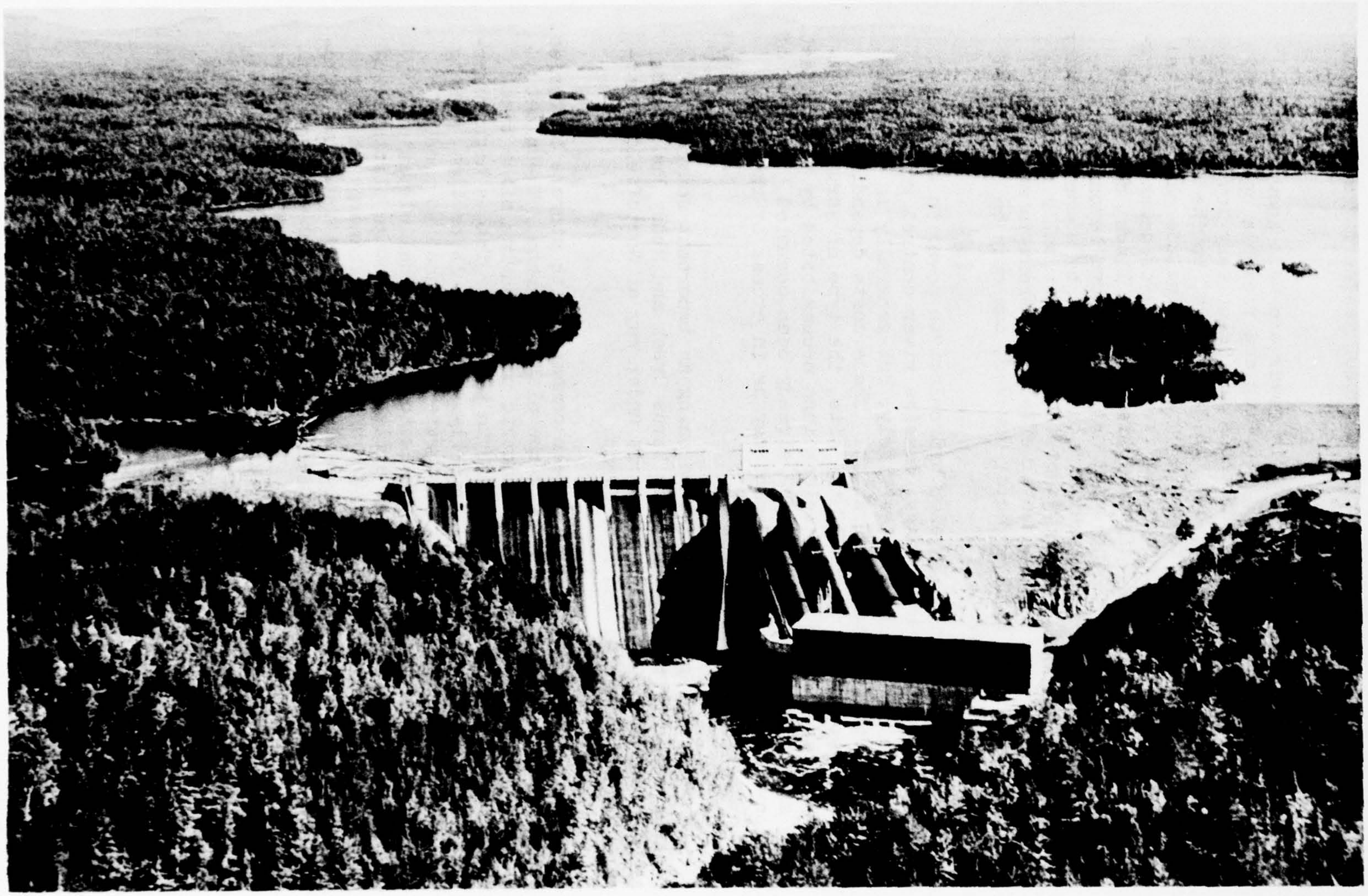
The need to operate for only short periods provides an opportunity for cost savings. These savings may be accomplished by sacrificing fuel economy to effect a reduction in investment or by providing an energy supply source which is adequate only to operate the plant during its limited hours of required use (as in pumped storage and peaking hydro).

The balancing process is sensitive to small changes in construction costs, site features, fuel costs, and load size and variability, and to the characteristics of the transmission and other generating facilities in the system. Therefore, generalizations concerning proportions of the various types of peaking generation are, at best, only educated guesses. The total peaking requirement can, however, be reasonably well determined from the shape of the load curve. The available conventional hydro capacity is generally fitted into the load curve to make the best use of the water supply that is available at any particular time, so a hydro plant may be used for base load generation when water is abundant, and for peaking at other times. Peaking requirements that cannot be met by conventional hydro are provided for by using pumped storage, peaking steam, gas turbines, diesels, or other equipment in the ascending order of their costs of production at the time of peak.

The rate at which the various types of peaking capacity will be added to systems in the Northeast defies precise advance determination. It can be presumed, however, that where physical sites for economical pumped storage are available, and so long as relatively low-cost energy for pumping can be provided by essentially base-load equipment, pumped-storage will constitute a major portion of the peaking equipment addition. It can also be presumed that some additional diesel and gas turbine units will be acquired because of their advantages for peaking and for providing at-site run-down and start-up power for the large base-load plants of the future.

<u>Hydroelectric Generation</u>. Conventional hydro, distinguished from pumped storage currently accounts for about one-tenth of all the electrical generating capacity in the North Atlantic Region and this proportion is declining as the remaining available sites become developed and other types of generation are expanded. Conventional hydro may be used for either peaking or base load generation, depending on plant design, system requirements and prevailing conditions of water supply.

Existing hydroelectric developments in the Northeast are of two general types. One is the "cascade" type, in which a long reach of a river is developed by a series of dams with essentially level pools between them. Examples of cascade developments exist on the Kennebec, Racquette, Connecticut and lower Susquehanna Rivers. The rivers may or may not have controllable storage to regulate the stream flow during the greater part of the year. The second type includes separate projects with integral storage that generally operate partly as base load and partly as peaking plants. They can, and usually do, produce substantial quantities of energy beyond



Harris Station, 75,000 kilowatts on the upper reaches of the Kennebec River is a typical conventional hydroelectric plant.

Figure P-7

those required to support their firm capacities during some seasons of the year.

The advantages of hydroelectric power are well known and include: high availability; quick starting and flexible operation; absence of pollution; and predictable and relatively low maintenance and operating expenses, due, in large part, to the absence of any cost for fuel. The disadvantages usually include: high capital costs; remote locations, often far from centers of demand, with consequent expenses for long distance transmission lines; dependence on variable stream flows and other natural factors beyond the control of man; and operating restrictions imposed by competitive water uses which may override power generation. Additionally there are the possible adverse environmental effects inherent in most man-made developments. These effects, however, can only be determined on a site by site basis.

The capital cost to develop hydroelectric power in a conventional plant with gated intakes, massive river control works, and other expensive features varies widely, but generally is the highest of any form of power generation. These costs depend, among other things, on the nature of the site, the type of structure contemplated, and the extent of relocations necessitated by the project. Since most of the good sites have already been occupied, the cost of new conventional hydro development may be in excess of that for available alternatives.

Pumped storage capacity is becoming an important source of peaking capacity in the NAR. The Yards Creek and Muddy Run plants are in operation and construction is under way at Northfield Mountain, Blenheim-Gilboa, and Bear Swamp.

Pumped storage plants have been compared with storage batteries. The comparison stems from the way the plants operate. The plant uses energy generated in steam electric plants during night time hours, or other low demand periods, to pump water into a high reservoir, where it is retained temporarily. At some later time, during periods of high demand, the stored water is released to produce hydroelectric power as it falls back to its original elevation. Due to unavoidable losses in the cycle, pumped storage plants actually consume about three kilowatt-hours of thermal energy to lift the quantity of water which eventually will generate about two kilowatt-hours of hydroelectric energy. The disadvantage with respect to energy is more than offset by low investment cost and other desirable characteristics which have made pumped storage attractive to systems operation in the North Atlantic Region.

A pumped storage plant, even with a very high head, generally has the same favorable operating characteristics as a conventional hydroelectric plant -- rapid start-up and loading, long life, low operating and maintenance costs, and low outage rates. By pumping in the offpeak hours, the plant factor of the thermal units is improved, thus reducing severe cycling of these units and improving

BLENHEIM-GILBOA PUMPED STORAGE POWER PROJECT
Power Authority of the State of New York
(under construction)

Figure P-8

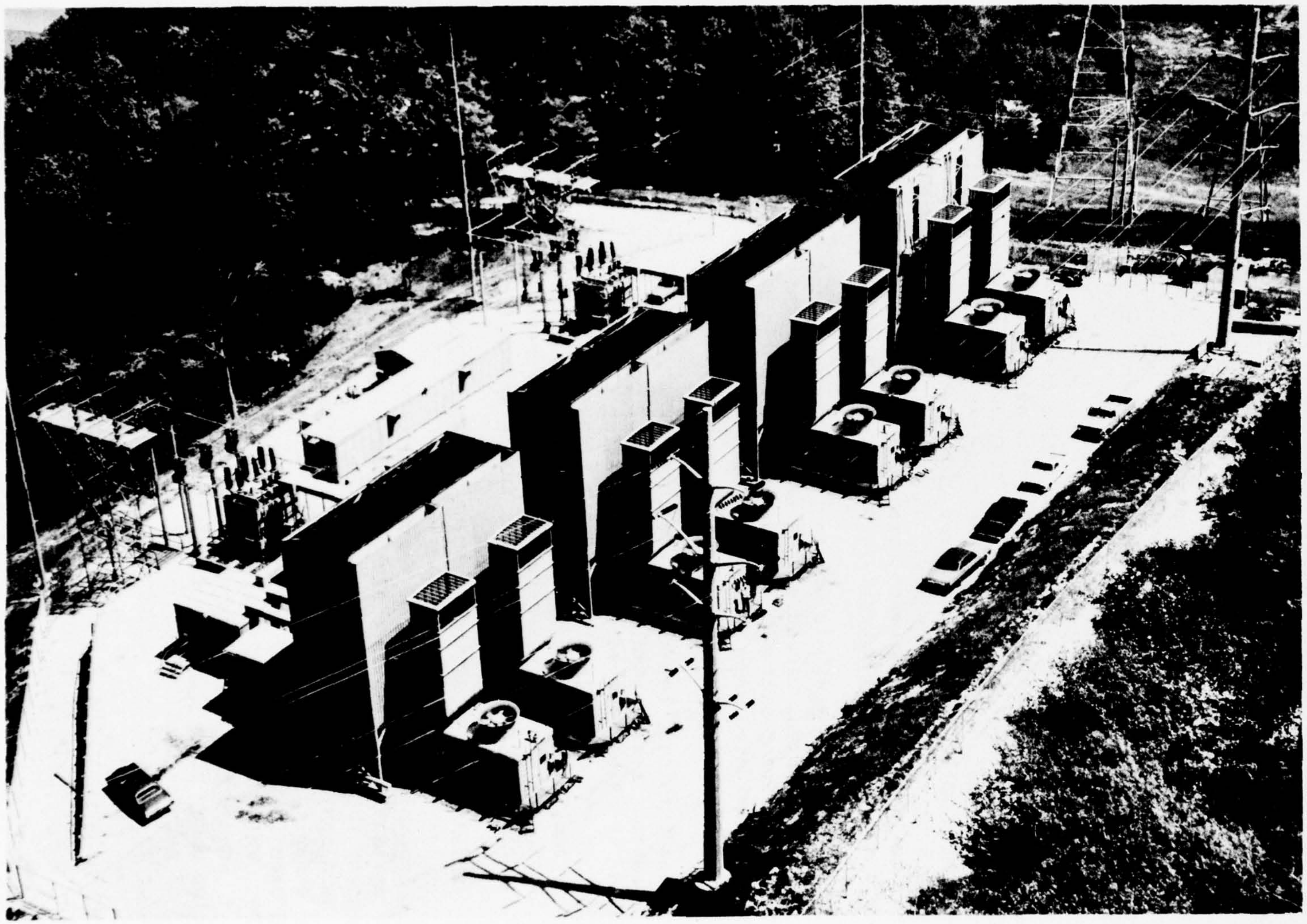
their efficiency and durability. No additional capital investment is required to produce the pumping energy, so, in effect, the only significant cost of such energy is for the fuel consumed.

Water power projects contribute substantially to recreation and conservation, but the limitation of power in respect to the other features of a project must be recognized. Water power generation causes water level fluctuations, even in large reservoirs, and unduly restrictive limitations on plant operation may jeopardize the feasibility of a power project. Users of the many-purpose developments must tolerate a certain amount of esthetic discord between the natural landscape and power generating and transmission works. If the transmission lines must be buried underground, then the capital cost of the works must be increased, and the power from the plant becomes less competitive with other sources of generation. Indeed, under present technology and costs the general feasibility of any project could be jeopardized by insistence that the project area be entirely free of visible transmission lines.

Internal Combustion, Diesel, and Gas Turbine Generation. Internal combustion units have been used for peaking on power systems for many years. The renewed interest in this type of peaking capacity has resulted primarily from the recent development of low cost, packaged, automatically operated, unattended diesel units. Diesel units, while available in capacities up to 6 MW, are usually manufactured in ratings of about 2 MW and are frequently combined in multiples to provide plants of up to approximately 10 MW capacity. Straight diesel, super-charged diesel, or dual-fuel engines are available. A single engine and generator are usually mounted on a structural steel base and enclosed in a sound suppressing and weatherproof housing, together with lubricating and cooling equipment, and other accessories. Automatic control equipment can be included in this enclosure, or in a separate control cubicle. Plants with multiple units often have all controls mounted in a single cubicle. These packaged units can be shipped on freight cars or trucks to the site and installed outdoors, requiring very little foundation work.

On major power systems diesels are not widely used, since available sizes are too small. They are sometimes installed for the primary purpose of deferring investment in transmission facilities, or to provide load protection and to assure satisfactory voltage at times of maximum peak demand. Since these units can be readily and cheaply moved, they could serve this purpose in many different locations on a system over a period of years. Such applications would ordinarily be expected in areas of relatively low load density and growth rate.

The gas turbine-generator unit has demonstrated its suitability as a source of economical peaking and emergency power. It is low in



Notch Cliff gas turbine units, an installation of 8-18,000 kilowatt units recently put in service in the Baltimore Md. area.

Figure P-9

first cost, quick starting, offers wide choice of site locations, and is readily automated. Plants with single prime movers of the simple open-cycle type are available in ratings up to about 50 megawatts. These plants are pre-engineered and pre-packaged to minimize field labor. Units in the order of 10 MW are shipped assembled, but larger ones are erected in the field on concrete slab foundations. Typically, plants are furnished with a self-contained cooling system and weatherproofed housings, and include provision for self-contained starting and remotely controlled unattended operation.

Gas turbine units with multiple prime movers driving single generators are now being offered by manufacturers. One design employs several jet engines equally divided on either end of the centrally located generator. More than ten of this type unit, some rated up to 175 MW, have been ordered by several utilities. One such unit, rated at 140 MW, has been operating since 1965. Other designs using different arrangements of multiple prime movers driving single generators are also available and in service.

Units can be remotely started, synchronized, and fully loaded in 2 to 20 minutes, depending on size and type. This feature provides significant start-up, stand-by and manpower savings that must be considered when these units are compared to alternative forms of peaking capacity.

Gas turbines, because of low investment cost and flexibility in location, are adaptable to a variety of peaking uses. These include stand-by reserve capacity, peaking capacity, and capacity supply in extended areas of a system. An additional application has arisen following the 1965 Northeast blackout, namely the installation of gas turbine-generator units as cranking units for the start-up of steam power plants during system disturbances.

ESTIMATED COMPOSITION OF FUTURE POWER SUPPLY ALTERNATIVES

General. Retirement of thermal units was taken at 40 years for estimating convenience although amortization of capital investment in such units is usually at a 35-year period. There is no hard and fast rule, however, as to actual removal from service. For example, over 1,000 MW in existence in the New England area had been installed prior to 1930 with many units dating back to 1920. While retired units are sometimes considered replaced in kind, such a simplifying assumption is inappropriate where the region under study is part of a larger market and capacity taken out of service may be replaced by a different prime mover type and/or in a different location.

Included in the future capacity requirements of the market area, Table P-17, is an allowance for reserves to provide for capacity on scheduled or forced outage and for possible errors in load forecasting. The importance of reserve capacity determination in system planning can not be too strongly emphasized. Too much reserve results in unnecessary and premature capital expenditures, whereas, too little could contribute to partial loss of load and possible complete system collapse. The problem is a difficult one, made more so by the growing size of system loads, complexities of power pool operations, more rigid reliability criteria and advances in generating unit sizes and EHV transmission. There is no one universally accepted method of evaluation. The current trend appears generally to favor a probabalistic approach utilizing today's computer techniques. For study purposes, a value of 25 percent reserves has been carried through for each benchmark year, and is believed to be reasonable and conservative in light of existing knowledge.

Long term load forecasts are more prone to inaccuracy than near future estimates. Since the factors of construction lead time make it possible to delay completion of scheduled capacity should such a step be advisable, load predictions on the high side can be readily adjusted. On the other hand, should a load prediction turn out to be too low, it may not be possible to plan and construct the required additional capacity in time to meet demands.

TABLE P-17

ESTIMATED TOTAL POWER SUPPLY NORTH ATLANTIC REGION MARKET AREA

	CSA-A	CSA-B	CSA-C	PSA-7	PSA-18	Total Market
1980						
Peak Demand-MW	22,100	29,300	45,270	8,640	11,170	116,480
Reserves-MW	5,900	5,300	9,030	1,660	2,430	24,320
Total-MW	28,000	34,600	54,300	10,300	13,600	140,800
2000						
Peak Demand-MW	74,600	81,100	135,900	23,900	36,900	352,400
Reserves-MW	18,200	18,600	30,100	5,500	9,300	81,700
Total-MW	92,800	99,700	166,000	29,400	46,200	434,100
2020						
Peak Demand-MW	187,100	194,000	325,400	57,000	92,800	856,300
Reserves-MW	45,700	49,000	81,600	14,000	23,200	213,500
Total-MW	232,800	243,000	407,000	71,000	116,000	1,069,800

In projecting a future capacity mix for the market, an endeavor was made to develop a realistic and meaningful balance of prime mover types that would be compatible with system operation, available forms of generation, and specific regional resources that would influence capacity selection. For example, the market's varied topographic features and water resources would restrict hydro development in some areas and foster its use in other sections. In regions where economical pumped storage sites abound, full use was made of the topographic advantage and a reasonable distribution of peaking capacity effected between power supply areas. The rising cost of fossil fuels in many sectors of the region is one significant factor in acceleration of the projected transition from dependence on base load fossil steam generation to nuclear.

The thermal-electric plant cooling requirements differ somewhat with different types of fuel. Measurable differences are found between fossil and nuclear fueled stations, and these differences will vary through time. For this reason Tables P-18 to P-21 includes as a part of its capacity mix the projected use of nuclear and fossil fueled generation at each benchmark year. Ongoing research in power production is concerned chiefly with developments of so called "exotic" generating devices such as the fuel cell and MHD (magnetohydrodynamics). Included in the "non-condensing" category are internal combustion plants, gas turbines, diesels, and, for the environmental quality objective, "exotic" generation.

The electric power industry is active in many phases of utility research and development that may result in substantial changes from system techniques and characteristics prevailing today. In distribution there is mounting pressure to place facilities underground from the standpoint of reliability and esthetic considerations. Research in bulk power transmission is aimed at extending present EHV voltage levels, achieving a breakthrough in underground transmission, and overcoming the conversion problems in DC transmission. All of these developments will no doubt have some effect on the estimates made herein.

Planning Objectives. In keeping with the requirements of the North Atlantic Region Water Resource Study, there are presented herein three possible patterns of future power supply composition. Each of the tabulations that follow represents an attempt to estimate what might happen under a particular development objective if all other objectives were disregarded. They are not plans, in the normal sense, because it is obvious that in the real world none of the objectives can be completely isolated from the others, and that any practical "plan" would involve some trade-offs among all objectives. In a framework study such as this, the intent has been to develop broad limits within which realistic plans might be developed, and within which actual developments seem likely to occur, rather than to make specific proposals for future actions.

The main report for this study will summarize a mixed-objective plan for power (and other functions) that will attempt to reflect the interface of all functional needs such as water quality, fish and wildlife, flood control, recreation, etc., on the location and type of power facilities that will be built to meet projected power needs. In the light of current events, the future pattern of area power development will more likely be determined by the impact of new capacity additions on the ecology and environment than on the availability of water for cooling use. Economic efficiency will be a continuing but not a controlling constraint. Since supplemental cooling methods often operate essentially as closed systems, they produce the least impact on the ecology of the area, and it appears that there will be a shift, over the span of the study, toward a pattern of development from flow-through to cooling devices. The basic concepts of the various objectives as they relate to power facilities, are very broadly summarized in the following sections, and possible patterns of generation for each objective, considered independently, are shown in the accompanying tables.

National Efficiency Objective. The national efficiency objective suggests what might happen if future power developments were made solely on the basis of efficiency and reliability of power service, presuming that the only constraints on location of facilities, types of generation, and types of fuel are those required to meet the water use, land use, and minimum environmental restrictions. This objective involves the most effective use of resources for economic power development and thus it provides a base against which the costs and benefits of meeting other desirable goals can be measured. The location and types of facilities suggested for this national efficiency objection are based on region-wide studies prepared in considerable detail for the 1970-1980 period. The additions suggested for the period after 1980 are geared to estimates of future power demands as set forth in Chapter 3, with patterns of generation developed primarily from current trends. The devices for cooling under this objective would be the least costly and most efficient. Once-through cooling will therefore predominate in all areas where adequate river flows and coastal and estuarine conditions will permit its development. It is virtually certain that both control standards and technology will change during the study period. No attempt has been made to reflect these possible changes in the national efficiency objective. If changes in standards occur, they will be administratively imposed and will apply to all objectives, so the relations between objectives will remain constant. Additionally, if technological changes occur they will be adopted only if they are more efficient than currently available equipment and/or procedures. Any adopted changes will be available to other objectives.

The anticipated power supply for the national efficiency (or base) objective, is summarized in Table P-18.

TABLE P-18

ESTIMATED COMPOSITION OF NAR POWER SUPPLY - MW
NATIONAL EFFICIENCY OBJECTIVE BY BENCHMARK YEARS

Area and Description	Supply 1/	1980	2000	2020
1. St. John River,	NS	--	--	4,000
Maine	FS	20	--	--
	NC	100	250	600
	H	--	800	1,300
	Total	120	1,050	5,900
	% of Total Market	2/	0.24	0.55
2. Penobscot River,	NS	--	--	2,000
Maine	FS	60	530	1,500
	NC	70	180	430
	H	140	140	2,000
	Total	270	850	5,930
	% of Total Market	0.19	0.20	0.55
3. Kennebec River,	NS	--	--	3,000
Maine	FS	--	500	1,500
	NC	20	30	80
	H	220	1,720	2,800
	Total	240	2,250	7,380
	% of Total Market	0.17	0.52	0.69
4. Androscoggin	NS	--	--	2,000
River, Me. &	FS	--	--	--
New Hampshire	NC	10	30	70
	H	160	160	1,100
	Total	170	190	3,170
	% of Total Market	0.12	2/	0.30
5. St. Croix River,	NS	855	7,855	23,000
Me., and Atlantic	FS	145	600	1,600
Coastal Area from	NC	70	180	420
the International	H	25	--	--
Boundary to Cape	Total	1,095	8,635	25,020
Small, Maine	% of Total Market	0.78	1.99	2.34
6. Presumpscot River, Me.,	NS	860	7,860	22,000
Saco River, Me. & N.H.,	FS	407	614	1,500
Piscataqua River, N.H.	NC	80	200	500
& Me.; and Atlantic	H	60	55	45
Coastal Area from	Total	1,407	8,729	24,045
Cape Small, Me. to	% of Total Market	1.00	2.01	2.25
N.H. - Mass. State				
Line				

TABLE P-18 (cont'd)

ESTIMATED COMPOSITION OF NAR POWER SUPPLY - MW
NATIONAL EFFICIENCY OBJECTIVE BY BENCHMARK YEARS

Area and Description	Supply 1/	1980	2000	2020
7. Merrimack River,	NS	--	--	8,000
N.H. & Mass.	FS	499	1,368	3,000
	NC	200	520	1,200
	H	80	485	1,835
	Total	779	2,373	14,035
	% of Total Market	0.55	0.55	1.31
8. Connecticut River	NS	2,498	7,313	15,000
Vermont, N.H.,	FS	912	750	1,500
Mass., Conn.	NC	470	1,170	2,700
	H	2,240	3,880	6,960
	Total	6,120	13,113	26,160
	% of Total Market	4.35	3.02	2.45
9. Naragansett Bay Drainage,	NS	4,250	24,250	56,000
Mass. & R.I., Pawtucket	FS	6,033	6,394	6,200
River, R.I. & Conn., &	NC	770	1,920	4,500
Atlantic Coastal from N.H.	H	5	--	--
- Mass. State Line to R.I.-	Total	11,058	32,564	66,700
Conn. State Line.	% of Total Market	7.84	7.50	6.23
10. Thames River, Conn., Mass.,	NS	2,680	9,680	21,000
& R.I.; Housatonic River,	FS	2,152	3,148	6,000
Conn., Mass. & N.Y.; &	NC	1,160	2,900	6,700
Conn. Coastal Area.	H	780	3,010	9,010
	Total	6,772	18,738	42,710
	% of Total Market	4.81	4.32	3.99
11. St. Lawrence River, N.Y.;	NS	--	4,000	10,000
& Lake Champlain, Vermont	FS	34	--	--
& N.Y.	NC	270	670	1,500
	H	1,220	4,200	8,450
	Total	1,524	8,870	19,950
	% of Total Market	1.08	2.04	1.86
12. Hudson River, N.Y.,	NS	6,502	21,512	45,000
Vermont & Mass.	FS	3,305	6,437	14,000
	NC	830	2,251	5,000
	H	3,400	7,900	20,500
	Total	14,037	38,100	84,500
	% of Total Market	9.97	8.78	7.90

TABLE P-18 (cont'd)

ESTIMATED COMPOSITION OF NAR POWER SUPPLY - MW
NATIONAL EFFICIENCY OBJECTIVE BY BENCHMARK YEARS

Area and Description	Supply 1/	1980	2000	2020
13. New York City; L.I.;	NS	1,949	11,949	32,000
& Westchester County	FS	8,307	7,185	13,000
Coastal Area	NC	2,150	5,700	12,900
	H	--	--	--
	Total	12,406	24,834	57,900
	% of Total Market	8.80	5.72	5.41
14. Passaic River, N.J. &	NS	--	5,000	16,000
N.Y.; Raritan River,	FS	4,871	3,039	4,000
N.J.; & other Northern	NC	600	1,700	4,600
N.J. Streams.	H	130	130	300
	Total	5,601	9,869	24,900
	% of Total Market	3.97	2.27	2.33
15. Delaware River &	NS	6,280	37,280	85,000
Delaware Bay, N.Y.,	FS	5,411	1,874	13,000
N.J., Penn., & Del.	NC	900	2,700	7,100
	H	1,775	4,210	7,500
	Total	14,366	46,064	112,600
	% of Total Market	10.20	10.61	10.53
16. Atlantic Coastal	NS	1,415	17,415	49,000
Area from Sandy	FS	1,149	1,899	10,500
Hook, N.J. to	NC	50	200	500
Cape May, N.J.	H	--	--	--
	Total	2,614	19,514	60,000
	% of Total Market	1.86	4.50	5.61
17. Susquehanna River,	NS	4,418	19,018	54,600
N.Y., Penn., Md.	FS	7,661	10,077	12,500
	NC	300	850	2,300
	H	2,765	11,840	33,400
	Total	15,144	41,785	102,800
	% of Total Market	10.76	9.63	9.61
18. Patuxent River, Md.;	NS	3,804	21,804	54,000
Nanticoke R., Md., & Del.;	FS	3,413	3,201	7,000
Delmarva Peninsula from	NC	500	1,550	4,000
Cape Henlopen, Del. to	H	--	--	--
Cape Charles, Va.; &	Total	7,717	26,555	65,000
Chesapeake Bay Drainage	% of Total Market	5.50	6.12	6.08
from Cape Charles, Va.				
to Point Lookout, Md.				

TABLE P-18 (cont'd)

ESTIMATED COMPOSITION OF NAR POWER SUPPLY - MW
NATIONAL EFFICIENCY OBJECTIVE BY BENCHMARK YEARS

Area and Description	Supply 1/	1980	2000	2020
19. Potomac River, Md.,	NS	--	9,000	28,000
Va., W. Va., Penn.,	FS	5,133	4,829	2,500
and D. C.	NC	407	701	2,300
	H	10	1,000	4,000
	Total	5,550	15,530	36,800
	% of Total Market	3.94	3.58	3.44
20. Rappahannock River,	NS	1,750	6,500	11,500
Va.; York R., Va.;	FS	1,220	1,220	1,220
and Chesapeake Bay	NC	5	180	480
Drainage from Smith	H	0	100	100
Point, Va., to Old	Total	2,975	8,000	13,300
Point Comfort, Va.	% of Total Market	2.11	1.84	1.24
21. James River, Va. &	NS	1,600	13,500	46,000
W. Va.; & Chesapeake	FS	2,622	4,000	4,000
Bay & Atlantic Coast-	NC	208	1,100	2,000
al Drainage from Old	H	1,500	2,000	3,000
Point Comfort, Va.	Total	5,930	20,600	55,000
to Virginia Beach, Va.	% of Total Market	4.21	4.75	5.14

1/ NS - Nuclear Steam
FS - Fossil Steam
NC - Non-Condensing Capacity - includes
Internal Combustion, Gas Turbine, Diesel
H - Hydroelectric

2/ Less than 0.1 percent

Regional Development Objective. This objective is designed to identify that pattern of future development that would concentrate new facilities in those areas where they are most needed to bolster their economy, or, conversely, to keep them out of areas that appear to be already over-developed.

It has been assumed under this objective that the total power supply for the NAR would be the same as that required for the national efficiency objective. If the regional goals for all sections of the nation were analyzed and balanced to meet national needs, it is quite likely that NAR's share of the national total would be somewhat different than its share as developed under an efficiency concept. In the absence of a nationwide analysis, however, and in view of NAR's relatively large size, both geographically and load-wise, it has been assumed that the differences would be small enough to warrant their being rejected. Consequently, the regional development totals for NAR are the same as the national efficiency totals, and the mixes by types are identical on a region-wide basis. Within NAR, however, the mix for each sub-area varies between the national efficiency and regional development objectives, reflecting changes in location of some plants (from the most efficient placement) to reassign them into depressed sub-areas. Furthermore the intent is to locate them where they would enhance the economic well-being of those areas which have been projected, by economic studies, to be most likely benefited by the location of large generating stations. A possible pattern of generation for the regional development objective is shown in Table P-19.

Environmental Quality Objective. The environmental quality objective is designed to show what could be done to provide maximum environmental protection within reasonable cost limits, but without any specific cost constraints.

Under this objective it has been assumed that decreases in thermal-electric power supply, and a greater stress on pollution control devices, would best meet environmental quality needs. This was done by replacing, in benchmark years 2000 and 2020, varying amounts of conventional thermal generation by some form of "exotic" generation, the reassignment of generation to areas where environmental problems would be minimized, and the use of wet and dry type cooling towers wherever needed.

The so-called "exotic" types of generation involve technologies that have not yet been perfected, but that are believed to offer enough promise to warrant the supposition that one or more improved methods of generation will be available before the year 2020. It is further assumed that for the environmental quality objective such new techniques would be put into use if they provided environmental protection, even though they may be more expensive than currently available equipment.

It has been assumed that the evironmental quality objective will not involve any curtailment of total power consumption. This is predicated on the further assumption that the added power demands

TABLE P-19

ESTIMATED COMPOSITION OF NAR POWER SUPPLY - MW
REGIONAL DEVELOPMENT OBJECTIVE BY BENCHMARK YEARS

Area and Description	Supply 1/	1980	2000	2020
1. St. John River, Maine	NS	--	--	4,000
	FS	20	500	1,000
	NC	100	350	800
	H	--	800	1,300
	Total	120	1,650	7,100
	% of Total Market	2/	0.38	0.66
2. Penobscot River, Maine	NS	--	--	2,000
	FS	60	530	1,000
	NC	70	180	350
	H	140	140	2,000
	Total	270	850	5,350
	% of Total Market	0.19	0.20	0.50
3. Kennebec River, Maine	NS	--	1,000	4,000
	FS	--	--	500
	NC	20	50	100
	H	220	1,720	2,800
	Total	240	2,770	7,400
	% of Total Market	0.17	0.64	0.69
4. Androscoggin River, Me. & New Hampshire	NS	--	1,000	3,000
	FS	--	500	500
	NC	10	140	200
	H	160	160	1,100
	Total	170	1,800	4,800
	% of Total Market	0.12	0.41	0.45
5. St. Croix River, Me., and Atlantic Coastal Area from the International Boundary to Cape Small, Maine	NS	855	8,855	24,000
	FS	145	600	2,100
	NC	70	245	450
	H	25	--	--
	Total	1,095	9,700	26,550
	% of Total Market	0.78	2.23	2.48
6. Presumpscot River, Me., Saco River, Me. & N.H., Piscataqua River, N.H. & Me.; and Atlantic Coastal Area from Cape Small, Me. to N.H. - Mass. State Line	NS	860	9,860	25,000
	FS	407	614	1,500
	NC	80	250	575
	H	60	55	45
	Total	1,407	10,779	27,120
	% of Total Market	1.00	2.48	2.54

TABLE P-19 (cont'd)

ESTIMATED COMPOSITION OF NAR POWER SUPPLY - MW
REGIONAL DEVELOPMENT OBJECTIVE BY BENCHMARK YEARS

Area and Description	Supply 1/	1980	2000	2020
7. Merrimack River, N.H. & Mass.	NS	--	--	8,000
	FS	499	1,368	3,000
	NC	200	500	1,135
	H	80	485	1,835
	Total	779	2,353	13,970
	% of Total Market	0.55	0.54	1.31
8. Connecticut River, Vermont, N.H., Mass., Conn.	NS	2,498	5,313	12,000
	FS	912	250	1,000
	NC	470	810	2,140
	H	2,240	3,880	6,960
	Total	6,120	10,253	22,100
	% of Total Market	4.35	2.36	2.07
9. Naragansett Bay Drainage, Mass. & R.I.; Pawtucket River, R.I. & Conn.; & Atlantic Coastal from N.H. - Mass. State Line to R.I. - Conn State Line	NS	4,250	21,250	53,000
	FS	6,033	6,394	6,200
	NC	770	1,850	4,400
	H	5	--	--
	Total	11,058	29,494	63,600
	% of Total Market	7.84	6.79	5.95
10. Thames River, Conn., Mass. & R.I.; Housatonic River, Conn., Mass. & N.Y.; & Conn. Coastal Area.	NS	2,680	9,680	21,000
	FS	2,152	3,148	6,000
	NC	1,160	2,850	6,550
	H	780	3,010	9,010
	Total	6,772	18,688	42,560
	% of Total Market	4.81	4.30	3.98
11. St. Lawrence River, N.Y.; & Lake Champlain, Vermont & N.Y.	NS	--	5,000	10,000
	FS	34	500	500
	NC	270	820	2,000
	H	1,220	4,200	8,450
	Total	1,524	10,520	20,950
	% of Total Market	1.08	2.42	1.96
12. Hudson River, N.Y., Vermont & Mass.	NS	6,502	20,512	42,000
	FS	3,305	5,937	13,000
	NC	830	2,151	4,500
	H	3,400	7,900	20,500
	Total	14,037	36,500	80,000
	% of Total Market	9.97	8.41	7.48

TABLE P-19 (cont'd)

ESTIMATED COMPOSITION OF NAR POWER SUPPLY - MW
REGIONAL DEVELOPMENT OBJECTIVE BY BENCHMARK YEARS

Area and Description	Supply 1/	1980	2000	2020
13. New York City; L.I.; & Westchester County Coastal Area	NS	1,949	11,949	35,000
	FS	8,307	7,185	13,500
	NC	2,150	5,800	13,400
	H	--	--	--
	Total	12,406	24,934	61,900
	% of Total Market	8.80	5.74	5.79
14. Passaic River, N.J. & N.Y.; Raritan River, N.J.; & other Northern N.J. Streams.	NS	--	4,000	14,000
	FS	4,871	3,039	3,500
	NC	600	1,500	4,100
	H	130	130	300
	Total	5,601	8,669	21,900
	% of Total Market	3.97	2.00	2.05
15. Delaware River & Delaware Bay, N.Y, N.J., Penn., & Del.	NS	6,280	35,280	78,000
	FS	5,411	1,374	10,000
	NC	900	2,500	6,400
	H	1,775	4,210	7,500
	Total	14,366	43,364	101,900
	% of Total Market	10.20	9.99	9.53
16. Atlantic Coastal Area from Sandy Hook, N.J. to Cape May, N.J.	NS	1,415	19,415	55,000
	FS	1,149	2,399	13,000
	NC	50	400	900
	H	--	--	--
	Total	2,614	22,214	68,900
	% of Total Market	1.86	5.12	6.44
17. Susquehanna River, N.Y., Penn., Md.	NS	4,418	18,418	53,000
	FS	7,661	9,577	11,000
	NC	300	805	2,100
	H	2,765	11,840	33,400
	Total	15,144	40,640	99,500
	% of Total Market	10.76	9.36	9.30
18. Patuxent River, Md.; Nanticoke R., Md., & Del.; Delmarva Peninsula from Cape Henlopen, Del. to Cape Charles, Va.; & Chesapeake Bay Drainage from Cape Charles, Va. to Point Lookout, Md.	NS	3,804	23,404	58,600
	FS	3,413	3,701	9,500
	NC	500	1,800	5,000
	H	--	--	--
	Total	7,717	28,905	73,100
	% of Total Market	5.50	6.66	6.83

TABLE P-19 (cont'd)

ESTIMATED COMPOSITION OF NAR POWER SUPPLY - MW
REGIONAL DEVELOPMENT OBJECTIVE BY BENCHMARK YEARS

Area and Description	Supply 1/	1980	2000	2020
19. Potomac River,	NS	--	10,500	31,000
Md., Va., W.Va.,	FS	5,133	4,829	2,500
Penn., and D.C.	NC	407	821	2,500
	H	10	1,000	4,000
	Total	5,550	17,150	40,000
	% of Total Market	3.91	3.95	3.74
20. Rappahannock River,	NS	1,750	5,400	9,400
Va.; York River, Va.;	FS	1,220	1,220	1,220
and Chesapeake Bay	NC	5	160	380
Drainage from Smith	H	0	100	100
Point, Va., to Old	Total	2,975	6,880	11,100
Point Comfort, Va.	% of Total Market	2.11	1.58	1.04
21. James River, Va. and	NS	1,600	13,100	45,100
W.Va.; & Chesapeake	FS	2,622	4,000	4,000
Bay & Atlantic Coastal	NC	208	1,000	1,900
Drainage from Old Point	H	1,500	2,000	3,000
Comfort, Va. to Virginia	Total	5,930	20,100	54,000
Beach, Va.	% of Total Market	4.21	4.63	5.05

1/ NS - Nuclear Steam
FS - Fossil Steam
NC - Non-Condensing Capacity - includes Internal Combustion, Gas Turbine, Diesel
H - Hydroelectric

2/ Less than 0.1 percent

of environmental control devices will offset any decreases in residential and other uses that may result from efforts to avoid the environmental effects of non-essential uses of electricity. The economic base studies for this report have not anticipated any planned slow-down of the economy and the power needs are geared to the economic base studies. If such a planned slow-down should occur, it would change the time-frame in which the developments would occur, but probably would not significantly affect the location or mix of needed facilities.

A possible pattern of generation for the environmental quality objective is shown in Table P-20

The patterns of generation for the three objectives are summarized on a regional basis in Table P-21. These hypothetical possibilities provide some insight into the patterns that might develop if one or another of the stated objectives provided an absolute control over resource uses. As a practical matter, when actual plans are developed, the influences of the various objectives will be weighed and proposed developments will reflect some mix of the alternative possibilities that is responsive to public needs and desires as they develop over time. The alternatives outlined herein merely suggest limits within which realistic plans could be prepared.

TABLE P-20

ESTIMATED COMPOSITION OF NAR POWER SUPPLY - MW
ENVIRONMENTAL QUALITY OBJECTIVE BY BENCHMARK YEARS

Area and Description	Supply 1/	1980	2000	2020
1. St. John River, Maine	NS	--	--	--
	FS	20	--	--
	NC	100	250	4,600
	H	--	800	1,300
	Total	120	1,050	5,900
	% of Total Market	2/	0.24	0.55
2. Penobscot River, Maine	NS	--	--	--
	FS	60	--	--
	NC	70	710	3,930
	H	140	140	2,000
	Total	270	850	5,930
	% of Total Market	0.19	0.20	0.55
3. Kennebec River, Maine	NS	--	--	--
	FS	--	--	--
	NC	20	530	4,580
	H	220	1,720	2,800
	Total	240	2,250	7,380
	% of Total Market	0.17	0.52	0.69
4. Androscoggin River, Me. & New Hampshire	NS	--	--	1,000
	FS	--	--	--
	NC	10	30	1,070
	H	160	160	1,100
	Total	170	190	3,170
	% of Total Market	0.12	2/	0.30
5. St. Croix River, Me., and Atlantic Coastal Area from the International Boundary to Cape Small, Maine	NS	855	7,855	21,000
	FS	145	600	600
	NC	70	180	3,420
	H	25	--	--
	Total	1,095	8,635	25,020
	% of Total Market	0.78	1.99	2.34
6. Presumpscot River, Me., Saco River, Me. & N.H., Piscataqua River, N.H. & Me.; and Atlantic Coastal Area from Cape Small, Me. to N.H. - Mass. State Line	NS	860	7,860	19,000
	FS	407	614	1,000
	NC	80	200	4,000
	H	60	55	45
	Total	1,407	8,729	24,045
	% of Total Market	1.00	2.01	2.25

TABLE P-20 (cont'd)

ESTIMATED COMPOSITION OF NAR POWER SUPPLY - MW
ENVIRONMENTAL QUALITY OBJECTIVE BY BENCHMARK YEARS

Area and Description	Supply 1/	1980	2000	2020
7. Merrimack River,	NS	--	--	7,000
N.H. & Mass.	FS	499	368	--
	NC	200	1,520	5,200
	H	80	485	1,835
	Total	779	2,373	14,035
	% of Total Market	0.55	0.55	1.31
8. Connecticut River	NS	2,498	4,313	6,000
Vermont, N.H.,	FS	912	250	1,000
Mass., Conn.	NC	470	4,670	12,200
	H	2,240	3,880	6,960
	Total	6,120	13,113	26,160
	% of Total Market	4.35	3.02	2.45
9. Narragansett Bay Drainage,	NS	4,250	22,250	50,000
Mass. & R.I.; Pawtucket	FS	6,033	6,194	5,000
River, R.I. & Conn., &	NC	770	4,120	11,700
Atlantic Coastal from N.H.	H	5	--	--
-Mass. State Line to R.I.-	Total	11,058	32,564	66,700
Conn. State Line.	% of Total Market	7.84	7.50	6.23
10. Thames River, Conn.,	NS	2,680	8,680	16,000
Mass., & R.I.;	FS	2,152	2,148	3,500
Housatonic River, Conn.,	NC	1,160	4,900	14,200
Mass. & N.Y.; & Conn.	H	780	3,010	9,010
Coastal Area	Total	6,772	18,738	42,710
	% of Total Market	4.81	4.32	3.99
11. St. Lawrence River,	NS	--	--	--
N.Y.; & Lake Champlain,	FS	34	--	--
Vermont & N.Y.	NC	270	4,670	11,500
	H	1,220	4,200	8,450
	Total	1,524	8,870	19,950
	% of Total Market	1.08	2.04	1.86
12. Hudson River, N.Y.,	NS	6,502	15,512	26,000
Vermont, & Mass.	FS	3,305	3,937	8,500
	NC	830	10,751	29,500
	H	3,400	7,900	20,500
	Total	14,037	38,100	84,500
	% of Total Market	9.97	8.78	7.90

TABLE P-20 (cont'd)

ESTIMATED COMPOSITION OF NAR POWER SUPPLY - MW
ENVIRONMENTAL QUALITY OBJECTIVE BY BENCHMARK YEARS

Area and Description	Supply 1/	1980	2000	2020
13. New York City: L.I.;	NS	1,949	11,949	34,000
& Westchester County	FS	8,307	7,185	11,000
Coastal Area.	NC	2,150	5,700	12,900
	H	--	--	--
	Total	12,406	24,834	57,900
	% of Total Market	8.80	5.72	5.41
14. Passaic River, N.J. &	NS	--	4,000	12,000
N.Y.; Raritan River,	FS	4,871	3,039	3,000
N.J.; & other Northern	NC	600	2,700	9,600
N.J. Streams.	H	130	130	300
	Total	5,601	9,869	24,900
	% of Total Market	3.97	2.27	2.33
15. Delaware River &	NS	6,280	31,280	68,000
Delaware Bay, N.Y.,	FS	5,411	874	5,000
N.J., Penn, & Del.	NC	900	9,700	32,100
	H	1,775	4,210	7,500
	Total	14,366	46,064	112,600
	% of Total Market	10.20	10.61	10.53
16. Atlantic Coastal	NS	1,415	17,415	45,000
Area from Sandy	FS	1,149	1,899	9,800
Hook, N.J. to	NC	50	200	5,200
Cape May, N.J.	H	--	--	--
	Total	2,614	19,514	60,000
	% of Total Market	1.86	4.50	5.61
17. Susquehanna River,	NS	4,418	12,418	28,000
N.Y., Penn., Md.	FS	7,661	6,077	--
	NC	300	11,450	41,400
	H	2,765	11,840	33,400
	Total	15,144	41,785	102,800
	% of Total Market	10.76	9.63	9.61
18. Patuxent River, Md.;	NS	3,804	21,804	49,000
Nanticoke R., Md., &	FS	3,413	2,701	5,500
Del.; Delmarva Peninsula	NC	500	2,050	10,500
from Cape Henlopen, Del.	H	--	--	--
to Cape Charles, Va.; &	Total	7,717	26,555	65,000
Chesapeake Bay Drainage	% of Total Market	5.50	6.12	6.08
from Cape Charles, Va.				
to Point Lookout, Md.				

TABLE P-20 (cont'd)

ESTIMATED COMPOSITION OF NAR POWER SUPPLY - MW
ENVIRONMENTAL QUALITY OBJECTIVE BY BENCHMARK YEARS

Area and Description	Supply 1/	1980	2000	2020
19. Potomac River,	NS	--	6,000	17,500
Md., Va., W.Va.,	FS	5,133	4,329	1,500
Penn., and D.C.	NC	407	4,201	13,800
	H	10	1,000	4,000
	Total	5,550	15,530	36,800
	% of Total Market	3.94	3.58	3.44
20. Rappahannock River,	NS	1,750	5,500	9,500
Va.; York River, Va.;	FS	1,220	1,220	1,220
and Chesapeake Bay	NC	5	1,180	2,480
Drainage from Smith	H	--	100	100
Point, Va., to Old	Total	2,975	8,000	13,300
Point Comfort, Va.	% of Total Market	2.11	1.84	1.24
21. James River, Va. and	NS	1,600	12,500	37,000
W. Va.; & Chesapeake	FS	2,622	3,500	3,000
Bay & Atlantic Coastal	NC	208	2,600	12,000
Drainage from Old	H	1,500	2,000	3,000
Point Comfort, Va. to	Total	5,930	20,600	55,000
Virginia Beach, Va.	% of Total Market	4.21	4.75	5.14

1/ NS - Nuclear Steam
FS - Fossil Steam
NC - Non-Condensing Capacity - includes Internal Combustion, Gas Turbine, Diesel, and includes an anticipated use of "exotic" generation.
H - Hydroelectric

2/ Less than 0.1 percent

TABLE P-21

ESTIMATED COMPOSITION OF NAR POWER SUPPLY - MW
BY OBJECTIVES AND BENCHMARK YEARS

	Area and Description	Supply 1/	1980	2000	2020
			National Efficiency		
1.	North Atlantic	NS	38,861	223,936	587,100
to	Region Summary	FS	53,354	57,665	104,520
21.		NC	9,170	24,982	59,880
		H	14,510	41,630	102,300
		Total	115,895	348,213	853,800
		% of Total Market	82.3	80.2	79.8
			Regional Development		
		NS	38,861	223,936	587,100
		FS	53,354	57,665	104,520
		NC	9,170	24,982	59,880
		H	14,510	41,630	102,300
		Total	115,895	348,213	853,800
		% of Total Market	82.3	80.2	79.8
			Environmental Quality		
		NS	38,861	189,336	446,000
		FS	53,354	44,935	59,620
		NC	9,170	72,312	245,880
		H	14,510	41,630	102,300
		Total	115,895	348,213	853,800
		% of Total Market	82.3	80.2	79.8

1/ NS - Nuclear Steam
FS - Fossil Steam
NC - Non-condensing - Internal Combustion, Gas Turbine, Diesel and includes an anticipated use of "exotic" generation for Environmental Quality.
H - Hydroelectric

CHAPTER 8

WATER REQUIREMENTS FOR THERMAL GENERATION

COOLING SYSTEMS

General. The largest industrial demand on the water resources of the North Atlantic Region is that of thermal electric generation. Steam electric power plants withdraw more water than any other industry and nearly all of the withdrawals are for cooling and condensing the steam used to produce electric energy. Water introduced into the boiler is converted to steam to drive the turbo-generator unit. Steam leaving the turbine at less than atmospheric pressure is passed through the condenser where it is cooled and condensed back into water. The condensate is pumped back into the boiler in a closed circuit system. Thus, the only consumptive use in the boiler-generator circuit is the feedwater make-up required to replace water losses. Losses in this circuit are quite small; the requirement for a 1,000-megawatt plant operating at full load is estimated to be only 0.5 ft^3/s. The major use at a steam-electric plant is the large separate flow through the condensers required to carry away the waste heat of condensation. Essentially, no water is used consumptively in the condensers, but losses do occur when condenser flows are returned to the source bodies of water at higher temperatures, or are passed through cooling towers or ponds.

Withdrawals of water for cooling at steam-electric plants currently constitute the largest non-agricultural diversion of water. Either fresh, brackish, or saline water can be used for this purpose and, in some cases, sewage effluents as well. The amount of water required through the condenser depends upon the type of plant, its efficiency, and the temperature rise within the condenser. The temperature rise of cooling water in the condenser is usually in the range of 10° F. to 20° F. Currently, a large nuclear steam-electric plant at full load requires about 50 percent more condenser water for a given temperature rise than a fossil-fueled plant of equal size. By 1980, this added requirement is expected to decrease substantially. Such high requirements result from the lower throttle steam temperatures and the resultant lower operating efficiencies of nuclear plants.

Steam-electric plants, whether nuclear fueled or fossil-fueled, operate on the thermodynamic process known as the "Rankine cycle" which limits the maximum theoretical thermal efficiency to about 60 percent. The best actual overall plant efficiency today is about 40 percent, including all thermal, mechanical and electrical losses. This means that for each kilowatt-hour being produced by a plant with this efficiency it is necessary to burn a fuel equivalent of 8,530 Btu, or slightly less than one pound of average grade coal. Of this, 3,413 Btu, the heat equivalent of one kilowatt-hour, is converted to electrical output and the remainder is lost. Plants having lower efficiencies require greater gross Btu inputs to produce the same 3,413 Btu per kilowatt-hour of generation. Consequently, more waste heat is discharged to the condensers of these plants. It is apparent then that waste heat discharges to the condenser is directly related to the efficiency of the plant.

All waste heat from steam-electric plants must eventially be discharged into the atmosphere. This can be accomplished in several ways. It may be transferred directly to the air or it may be transferred to water as an intermediate step and then to the air. Because of costs and engineering difficulties that have been associated with the direct transfer process, nearly all the existing generation in the United States at the present time use cooling water as an intermediate transfer agent.

The process of moving the waste heat from the steam-generation cycle to the water is accomplished by heat transfer through a steam condensing unit. In this process the expanded steam leaving the turbine is passed around the condenser tubing. Cooling water is passed through the tubing and the waste heat remaining in the steam is transferred through the tubing to the cooling water which in turn carries it away. For a given rate of heat removal, the temperature rise in the cooling water is inversely proportional to the amount of water circulated through the condenser. The size of the condenser and the amount of water circulated can be varied substantially. The usual design is for a temperature rise through the condenser with an average of approximately 15° F.

Nuclear plants (using current design standards) have a lower thermal efficiency than fossil plants, this being about 32 percent, or a heat rate of 10,750 Btu/kilowatt-hour. Since there is no significant heat loss directly to the atmosphere in nuclear plants, the unit cooling water requirement per million kilowatt-hours of electric generation becomes even greater. With continuing progress in design efficiencies it is expected that this requirement will decrease substantially in the future.

The principal types of cooling systems for steam-electric plants are (1) flow-through, where cooling water is taken from a suitable source, such as rivers or cooling ponds, passed through the condensers, and returned to the source body of water; (2) wet towers, where water is recirculated through the condenser after it has been cooled in an evaporative cooling tower or other cooling system in which the heated water is exposed to circulating air; and (3) dry towers, where cooling water is contained in a closed system and its heat dissipated to the air through heat exchangers. In some cases a combination of systems may be used. The water withdrawal and consumption requirement varies widely among these systems.

Flow-through Cooling. Where adequate supplies of water are available and applicable water quality standards can be met, the once-through cooling system is usually adopted. Although that system is normally more economical than other systems, the number of sites available for its use for large plants is limited because of the resulting impact on the water bodies. Sources of cooling water for once-through systems include flowing streams, ponds, lakes, reservoirs, estuaries and the ocean.

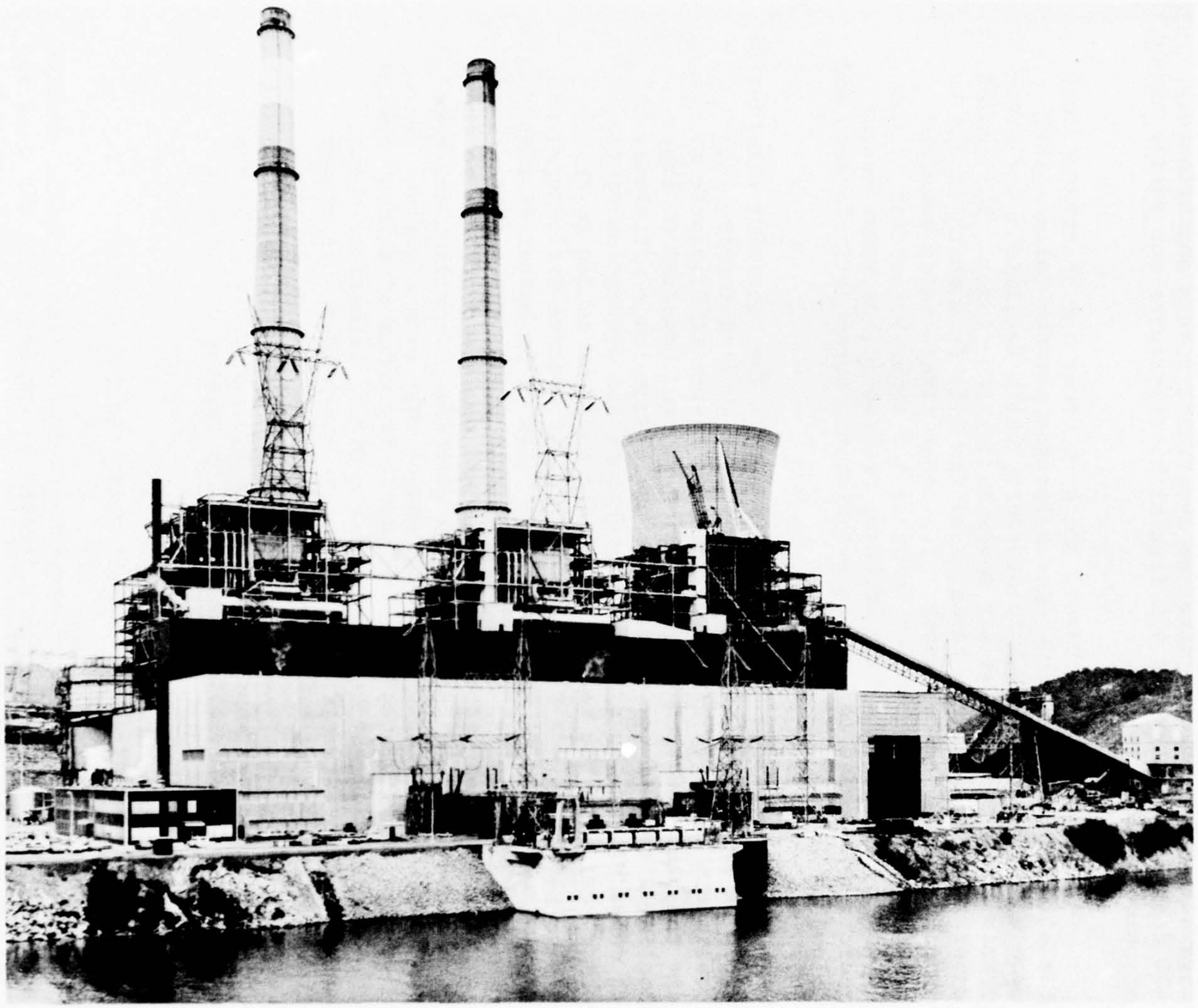
The primary consumptive use of cooling water is the amount of evaporation caused by the increase in water temperature as it passes through the plant's condensing unit. For purposes of this study it is estimated that under average conditions about 55 percent of the cooling in a flow-through system using a river intake and discharge is the result of this forced evaporation.

In some cases, the most economical source of cooling waters will be natural or artificial reservoirs or ponds. The cooling water is taken from these impoundments and returned to them after having circulated through the condenser. The heat added to the reservoir increases surface evaporation and causes added water loss which must be replaced by sufficient inflow. About 65 percent of the cooling in a flow-through system using cooling ponds is through increased evaporation. For proper heat dissipation, the surface area of a pond used for cooling purposes only, should be no less than 1 to 2 acres per megawatt. The area should be increased to from 4 to 6 acres per megawatt where the reservoir is of a multi-purpose nature. The ideal configuration for a cooling lake is an exaggerated crescent with the two tips contacting the intake and discharge of the plant. A pre-cooling lake of perhaps five percent of the total may be used between the plant and the main lake. This would provide a specific mixing zone and provide a production area for a warm water fishery. Non-competitive uses of the reservoir would include recreation, enhanced wildlife and water-fowl habitat, and a potential for municipal and agricultural water supplies.

Evaporative Cooling Towers (Wet). When neither streams nor water impoundments are available, or the water temperature regulations are so restrictive as to curtail their use, steam-electric stations can employ evaporative cooling towers. In the commonly used "wet" cooling towers, the heated water is cooled by the circulation of air through a falling spray of water in the tower. Until recently, most towers in this country have been mechanical draft. A mechanical draft tower for a 1,000-megawatt plant may be 600 feet long, 70 feet wide,

Vermont Yankee Nuclear Station under construction, showing the partially completed mechanical draft evaporative cooling towers (wet).

Figure P-10



Recently constructed fossil-steam station with a natural draft hyperbolic evaporative cooling tower (wet) in center of photograph.

Figure P-11

and 60 feet high. These towers will eject large quantities of warm moist air, possibly causing fog, rain, ice, and snow at various times of the year. Natural draft (hyperbolic in design) towers have a higher initial cost, but cost relatively little for operation and maintenance. Because of their greater height, heat, fog, and vapor usually do not reach the ground in bothersome quantities. A 1,000-megawatt plant would require two hyperbolic towers approximately 400 feet in diameter and 400 feet high, structures not easily hidden or camouflaged.

In the wet cooling tower, the warm water may be sprayed into the air or allowed to flow onto a lattice network called "fill" upon which it is broken into droplets, which facilitate the evaporative heat transfer as air moves through the tower. The cooled water is collected in a basin under the fill from which it can be pumped back to the condenser. For power plants using wet-type cooling towers, evaporation accounts for about 90 percent of the cooling. Withdrawals from streams, reservoirs, or ground-water sources are needed to replace evaporation, spray drift losses, and "blowdown".

Non-evaporative Cooling Towers (Dry). The remaining alternative would be the use of non-evaporative, dry cooling towers. Such towers use a closed piping or radiator system to dissipate to the air the heat absorbed by the cooling water. Compared to other cooling alternatives, this device has a much lower efficiency as it depends upon the dry bulb temperature and convection of the waste heat from the water through the radiator tubing to the atmosphere. Whether of the mechanical or natural draft type, the towers would need to be increased in size or in number as compared with the evaporative cooling type. This would create further environmental and esthetic problems and would add greatly to the unit cost of the installation. An additional detriment would be the increased operating and maintenance cost plus a decided decrease in total operating efficiency. The value of a "dry" system of cooling which may outweigh the factors of esthetics, costs, and efficiency is its almost complete independence of stream flows. The cooling process would have no effect on stream temperatures, flow regulation criteria, or meteorology of the area other than thermal increases in the surrounding air. The small water losses could easily be made up by tapping ground water sources.

COMPARISON OF THERMAL PLANT COOLING SYSTEMS

Table P-22 shows a comparison of various thermal plant cooling systems. The table views each system in general terms and uses as its base the fresh water flow-through system. By this means values and comparisons can be made beyond those solely associated with capital costs.

TABLE P-22

SUMMARY OF COMPARATIVE COOLING DEVICES

Parameter of Comparison	Flow Through: Fresh Water	Flow Through: Estuary-Marine	Flow Through: Cooling Lake
Initial Cost	Lowest	Moderate	High
Operational Cost	Lowest	Moderate	Moderate
Maintenance Costs	Lowest	Moderate	Moderate
Plant Efficiency	Highest	High	Low
Esthetics	Neutral	Neutral	Good
Environmental Effects	Many	Few - Many	Few
Consumptive use at full load - 36% Eff. (Heat Rate 9500 Btu/kWh)			
Fossil $ft^3/S/1000$ MW	12.2	12.2	14.4
Nuclear $ft^3/S/1000$ MW	14.3	14.3	16.8

Parameter of Comparison	Cooling Towers: Wet-Natural Draft	Cooling Towers: Wet-Mechanical Draft	Cooling Towers: Dry-Natural or Mechanical Draft
Initial Cost	Higher	High	Highest
Operational Cost	Moderate	High	Highest
Maintenance Costs	Moderate	High	Highest
Plant Efficiency	Low	Low	Lowest
Esthetics	Poor	Very Poor	Extremely Poor
Environmental Effects	Moderate	Many	Few
Consumptive use at full load - 36% Eff. (Heat Rate 9500 Btu/kWh)			
Fossil $ft^3/s/1000$ MW	20.6	20.6	0
Nuclear $ft^3/s/1000$ MW	24.2	24.2	0

Costs of cooling systems depends, in a large degree, on the design criteria and site conditions. A range of costs is presented in Table P-23 for the major types of cooling devices. Because of the relatively limited number of nuclear plants for which data are available, and the lack of recent dry tower construction, the range of costs for such plants is largely estimated. For each type of system, the cost of the condenser has been excluded since it is common to all. Investment costs cover such items as land, pumps, piping, canals, ducts, intake and discharge structures, dikes, cooling towers, and appurtenant equipment.

TABLE P-23

COMPARATIVE COSTS OF COOLING WATER SYSTEMS FOR STEAM-ELECTRIC PLANTS

Type of System	Investment Cost ($/kW) Fossil-Fueled Plant	Investment Cost ($/kW) Nuclear-Fueled Plant
Once through	2.00- 3.00	3.00- 5.00
Cooling ponds	4.00- 6.00	6.00- 9.00
Wet cooling towers:		
Mechanical draft	5.00- 8.00	8.00-11.00
Natural draft	6.00- 9.00	9.00-13.00
Dry cooling towers:		
Mechanical draft	18.00-20.00	26.00-28.00
Natural draft	20.00-24.00	28.00-32.00

Construction costs for steam-electric generating plants currently run between 140 to 160 dollars per kilowatt for fossil-fueled plants and between 190 and 210 dollars per kilowatt for nuclear plants. The cost of the cooling system, including the condenser, can represent from five to fifteen percent of the total costs, depending on the type of plant and degree of cooling being considered. In addition to differences in capital costs there are operating expenses associated with each type of cooling.

Cooling towers have pumping heads in the range of 35 to 55 feet greater than those required in flow-through systems. This added pumping power for towers is equivalent to about one-half percent or more of the plant output. Power to drive the fans in mechanical draft cooling towers is equivalent to upwards of an additional one percent of the plant output. Annual operating and maintenance expenses, other than the cost of power for pumping and to drive fans, is equivalent to one percent or more of the investment costs of cooling towers. Thus, the use of evaporative wet cooling towers rather than flow-through systems may increase the cost of power by as much as five percent. Also, the higher water temperature at the condenser inlet that would normally result from the use of cooling towers would produce a lower turbine efficiency. Most estimates indicate a one percent capacity penalty chargeable against plants using wet cooling towers.

ESTIMATED COOLING WATER NEEDS

General. Many rivers in the NAR have sufficient annual discharges to sustain the operation of a large steam-electric generating plant on a flow-through basis. Where such streams exist, they have already been subject to thermal plant development. While there is no problem of water availability, there is a question of steam-electric plant compliance with water quality standards if flow-through cooling is used. As a result of the Federal Water Quality Act of 1965, the states have been called upon to prepare water quality standards for interstate waters within their boundaries. As a part of these standards, the several states within the Power Region have adopted water discharge standards with regard to maximum permissible temperatures. At the present time, the effect of existing and possible future legislation regulating heat input is uncertain. Depending on the outcome of a number of ecological studies dealing with the effects of heat inputs from steam-electric generation and the direction of future regulating legislation, supplemental cooling may become necessary. If properly accounted for in the planning stage, such a future requirement should not constitute a major barrier to power development in the Region. It will, however, result in a higher consumptive use of cooling water, a higher operating cost to the utilities and in all probability, a higher cost of electricity for the consumer).

At the present time, planning for near future generating capacity has a construction lead time of about seven years. Accordingly, estimates of cooling water use in the years 2000 and 2020 can only be a rough guide to be reviewed periodically as new situations develop. In order to determine future cooling water requirements and consumptive water use in the NAR, projections of future steam-electric capacity were made (Chapter 7). These data are given by areas for each objective and benchmark year. Water use will vary with the type of cooling device used and the composition of the capacity mix. The efficiency of the generating plant will also affect the amount of water required and lost. For purposes of this report, Table P-24 shows the heat rates and water use values which are assumed to be typical for the capacity that will be installed during the study period's benchmark years. Existing water use varies widely due to extremes in operating efficiencies. For comparison purposes, however, the following values are assumed representative:

Fossil-fuel-1.0ft^3/s/MW condenser requirements; 0.0095 ft^3/s/MW flow through consumptive losses; and 0.0145 ft^3/s/MW tower consumptive losses.

Nuclear - 1.7 ft^3/s/MW condenser requirements; 0.016 ft^3/s/MW flow through consumptive losses; and 0.025 ft^3/s/MW tower consumptive losses.

The estimates of capacity additions in each area, by itself, will not allow for a realistic accounting of water use on an average yearly basis. All thermal stations have varying periods when they are subject to outages. These can be scheduled times for normal maintenance or unscheduled times when equipment breakdown occurs. Some units which operate under conditions of high temperature and pressure are not normally subject to stop and start operation. Other units, designated as "peaking-steam", can be more easily manipulated to serve varying swings in utility system loads. As a general rule, nuclear plants will operate at high load factors (about 80 percent) during their early years and fossil units at lower load factor rates (about 65 percent). In each succeeding benchmark year, as the impact of increased nuclear generation takes effect, the average of new and older units will drop the average load factor rate to about 65 percent in 2020 while fossil units are estimated to average about 45 percent load factor at that time.

Tables P-25 - 27 give the water use data for the individual areas of the North Atlantic Region, by national efficiency, regional development, and environmental quality objectives. In examining these water use data the following general comments should be understood.

Cooling Water Required. The amount of cooling water required to be circulated through a plant's condenser is not dependent on the cooling method that is used. Furthermore, the total water quantities required are not a dependable measure of the adequacy of an area's

TABLE P-24

WATER USE VALUES FOR THERMAL ELECTRIC POWER PLANTS 1/

Plant Type	Benchmark Year 1980	2000	2020
Heat Rates - Btu/kWh			
Fossil-fueled	9,000/9,500	8,500	8,000
Nuclear	9,500	8,000	7,500
Condenser Requirements - ft^3/s per MW 2/			
Fossil-fueled	0.90	0.55	0.50
Nuclear	1.40	1.00	0.75
Consumptive Losses (Flow Through)-ft^3/s per MW 2/ 3/			
Fossil-fueled	0.0075	0.0050	0.0046
Nuclear	0.0130	0.0082	0.0067
Consumptive Losses (Cooling Towers)-ft^3/s per MW 2/			
Fossil-fueled	0.0113	0.0077	0.0068
Nuclear	0.0194	0.0132	0.0100

1/ Average annual flows based on estimated load factor values.
2/ Parameters of 15°F average temperature rise in condenser water; 10 percent heat loss for fossil and 2-3 percent for nuclear; and gross generator output of 3,600 Btu/kWh.
3/ Average values for a mix of river intake and cooling pond withdrawals.

water supply to meet steam-electric cooling needs since it includes the cumulative total of water recirculated in cycling type systems as well as re-use by downstream plants and water taken from still-water bodies. Cooling water required is entered herein primarily as a measure of the total volume of water that passes through condenser units, and is separated under the designations "saline" and "non-saline".

Diversion. This is the maximum amount of water that would have to be withdrawn in order to meet the needs of steam-electric generation. In general, the amount of water required to be diverted when compared to the amount of water available determines the type of cooling to be used. Water diverted at one location can be re-used at downstream plants. Flow-through cooling represents the most economical type of cooling although it requires the greatest diversion. In wet cooling, closed circuit towers require the least diversion of water. It is the estimated mix of cooling devices, flow-through, cooling ponds, and a variety of cooling towers, that will determine the total flow to be diverted. Diversions are also separated into two categories, saline and non-saline.

Consumption. The consumptive use of cooling water is that portion of the diverted flow which is lost through evaporation. Consumptive use of cooling water is a further restrictive requirement on the location of steam-electric generation. Historically, all large steam-electric generating plants in this country have relied on the use of both saline and non-saline water as a cooling medium. The vast quantities of saline water available for power cooling, eliminates the value of noting saline water consumption. Therefore, the non-saline water consumption has been further refined under the designations, brackish and fresh and entered on the water use tables. In areas where water flows are insufficient to sustain a flow through cooling methods without adversely affecting the temperature criteria of water quality standards, varying forms of cooling devices can be used. In all areas of the North Atlantic Region adequate flows are available to sustain the estimated consumptive use of fresh water to the year 2020.

TABLE P-25

AVERAGE ANNUAL WATER USE FOR THERMAL GENERATION - FT^3/S
NATIONAL EFFICIENCY OBJECTIVE BY BENCHMARK YEARS

Area	Class of Water Use	Benchmark Year 1980	2000	2020
1	Condenser Flow			
	Saline	--	--	--
	Non-Saline	19	--	3,000
	Withdrawal			
	Saline	--	--	--
	Non-Saline	19	--	3,000
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	1	--	28
2	Condenser Flow			
	Saline	--	--	--
	Non-Saline	57	300	2,100
	Withdrawal			
	Saline	--	--	--
	Non-Saline	57	300	2,100
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	1	4	22
3	Condenser Flow			
	Saline	--	--	--
	Non-Saline	--	275	2,900
	Withdrawal			
	Saline	--	--	--
	Non-Saline	--	275	2,900
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	--	3	29

TABLE P-25 (cont'd)

AVERAGE ANNUAL WATER USE FOR THERMAL GENERATION - FT^3/S
NATIONAL EFFICIENCY OBJECTIVE BY BENCHMARK YEARS

Area	Class of Water Use	Benchmark Year 1980	2000	2020
4	Condenser Flow			
	Saline	--	--	--
	Non-Saline	--	--	1,500
	Withdrawal			
	Saline	--	--	--
	Non-Saline	--	--	800
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	--	--	14
5	Condenser Flow			
	Saline	1,344	6,197	12,100
	Non-Saline	--	2,330	7,580
	Withdrawal			
	Saline	1,344	6,197	12,100
	Non-Saline	--	2,330	7,580
	Non-Saline Consumption			
	Brackish	--	19	49
	Fresh	--	--	7
6	Condenser Flow			
	Saline	1,611	6,307	12,100
	Non-Saline	--	2,275	6,775
	Withdrawal			
	Saline	1,611	6,307	12,100
	Non-Saline	--	2,275	6,075
	Non-Saline Consumption			
	Brackish	--	19	47
	Fresh	--	--	14

TABLE P-25 (cont'd)

AVERAGE ANNUAL WATER USE FOR THERMAL GENERATION - FT^3/S
NATIONAL EFFICIENCY OBJECTIVE BY BENCHMARK YEARS

Area	Class of Water Use	Benchmark Year 1980	2000	2020
7	Condenser Flow			
	Saline	--	--	750
	Non-Saline	550	950	6,500
	Withdrawal			
	Saline	--	--	750
	Non-Saline	550	950	3,575
	Non-Saline Consumption			
	Brackish	--	--	17
	Fresh	6	10	52
8	Condenser Flow			
	Saline	--	1,000	1,350
	Non-Saline	4,646	7,919	11,775
	Withdrawal			
	Saline	--	1,000	1,350
	Non-Saline	2,372	5,645	8,850
	Non-Saline Consumption			
	Brackish	15	17	22
	Fresh	41	63	91
9	Condenser Flow			
	Saline	11,700	30,900	49,700
	Non-Saline	--	--	--
	Withdrawal			
	Saline	11,700	30,900	49,700
	Non-Saline	--	--	--
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	--	--	--

TABLE P-25 (cont'd)

AVERAGE ANNUAL WATER USE FOR THERMAL GENERATION - FT^3/S
NATIONAL EFFICIENCY OBJECTIVE BY BENCHMARK YEARS

Area	Class of Water Use	Benchmark Year 1980	2000	2020
10	Condenser Flow			
	Saline	5,900	9,600	8,100
	Non-Saline	--	3,300	12,000
	Withdrawal			
	Saline	5,900	9.600	8,100
	Non-Saline	--	3,300	9,800
	Non-Saline Consumption			
	Brackish	--	8	46
	Fresh	--	20	38
11	Condenser Flow			
	Saline	--	--	--
	Non-Saline	40	4,000	8,500
	Withdrawal			
	Saline	--	--	--
	Non-Saline	40	4,000	8,500
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	1	34	75
12	Condenser Flow			
	Saline	--	--	--
	Non-Saline	12,300	28,500	43,200
	Withdrawal			
	Saline	--	--	--
	Non-Saline	12,300	19,150	14,050
	Non-Saline Consumption			
	Brackish	98	126	61
	Fresh	15	140	417

TABLE P-25 (cont'd)

AVERAGE ANNUAL WATER USE FOR THERMAL GENERATION - FT^3/S
NATIONAL EFFICIENCY OBJECTIVE BY BENCHMARK YEARS

Area	Class of Water Use	1980	Benchmark Year 2000	2020
13	Condenser Flow			
	Saline	10,900	18,490	31,450
	Non-Saline	--	--	--
	Withdrawal			
	Saline	10,900	18,490	31,450
	Non-Saline	--	--	--
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	--	--	--
14	Condenser Flow			
	Saline	4,900	4,370	7,350
	Non-Saline	--	3,000	7,500
	Withdrawal			
	Saline	4,900	4,370	7,350
	Non-Saline	--	3,000	6,000
	Non-Saline Consumption			
	Brackish	--	16	43
	Fresh	--	8	28
15	Condenser Flow			
	Saline	2,900	11,200	20,000
	Non-Saline	11,240	29,970	55,950
	Withdrawal			
	Saline	2,900	11,200	20,000
	Non-Saline	5,500	13,690	23,360
	Non-Saline Consumption			
	Brackish	30	58	126
	Fresh	107	256	505

TABLE P-25 (cont'd)

AVERAGE ANNUAL WATER USE FOR THERMAL GENERATION - FT^3/S
NATIONAL EFFICIENCY OBJECTIVE BY BENCHMARK YEARS

Area	Class of Water Use	Benchmark Year 1980	2000	2020
16	Condenser Flow			
	Saline	2,700	10,700	19,120
	Non-Saline	330	8,750	25,480
	Withdrawal			
	Saline	2,700	10,700	19,120
	Non-Saline	330	6,810	20,670
	Non-Saline Consumption			
	Brackish	3	70	223
	Fresh	--	14	24
17	Condenser Flow			
	Saline	--	--	--
	Non-Saline	13,344	28,496	49,825
	Withdrawal			
	Saline	--	--	--
	Non-Saline	3,550	15,900	25,450
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	146	269	498
18	Condenser Flow			
	Saline	200	9,000	23,200
	Non-Saline	8,500	16,850	24,500
	Withdrawal			
	Saline	200	9,000	23,200
	Non-Saline	8,500	12,680	17,150
	Non-Saline Consumption			
	Brackish	81	113	120
	Fresh	--	57	106

TABLE P-25 (cont'd)

AVERAGE ANNUAL WATER USE FOR THERMAL GENERATION - FT^3/S
NATIONAL EFFICIENCY OBJECTIVE BY BENCHMARK YEARS

Area	Class of Water Use	Benchmark Year 1980	2000	2020
19	Condenser Flow			
	Saline	--	1,250	5,800
	Non-Saline	4,975	11,690	18,800
	Withdrawal			
	Saline	--	1,250	5,800
	Non-Saline	3,415	10,000	16,600
	Non-Saline Consumption			
	Brackish	22	45	74
	Fresh	33	63	101
20	Condenser Flow			
	Saline	375	3,820	7,900
	Non-Saline	3,625	5,000	4,600
	Withdrawal			
	Saline	375	3,820	7,900
	Non-Saline	130	154	120
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	82	90	58
21	Condenser Flow			
	Saline	700	3,800	14,000
	Non-Saline	5,100	14,600	25,800
	Withdrawal			
	Saline	700	3,800	14,000
	Non-Saline	5,100	9,980	14,300
	Non-Saline Consumption			
	Brackish	35	49	30
	Fresh	17	90	232

TABLE P-26

AVERAGE ANNUAL WATER USE FOR THERMAL GENERATION - FT3/S
REGIONAL DEVELOPMENT OBJECTIVE BY BENCHMARK YEARS

Area	Class of Water Use	1980	Benchmark Year 2000	2020
1	Condenser Flow			
	Saline	--	--	--
	Non-Saline	19	275	3,450
	Withdrawal			
	Saline	--	--	--
	Non-Saline	19	275	1,845
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	1	3	41
2	Condemser Flow			
	Saline	--	--	--
	Non-Saline	57	300	1,950
	Withdrawal			
	Saline	--	--	--
	Non-Saline	57	300	1,200
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	1	4	23
3	Condenser Flow			
	Saline	--	--	--
	Non-Saline	--	1,000	3,425
	Withdrawal			
	Saline	--	--	--
	Non-Saline	--	1,000	2,000
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	--	9	39

TABLE P-26 (cont'd)

AVERAGE ANNUAL WATER USE FOR THERMAL GENERATION - FT^3/S
REGIONAL DEVELOPMENT OBJECTIVE BY BENCHMARK YEARS

Area	Class of Water Use	Benchmark Year 1980	2000	2020
4	Condenser Flow			
	Saline	--	--	--
	Non-Saline	--	1,300	2,775
	Withdrawal			
	Saline	--	--	--
	Non-Saline	--	820	900
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	--	14	31
5	Condenser Flow			
	Saline	1,344	6,527	11,205
	Non-Saline	--	3,000	9,750
	Withdrawal			
	Saline	1,344	6,527	11,205
	Non-Saline	--	3,000	9,750
	Non-Saline Consumption			
	Brackish	--	25	69
	Fresh	--	--	7
6	Condenser Flow			
	Saline	1,611	6,307	12,100
	Non-Saline	--	4,275	9,525
	Withdrawal			
	Saline	1,611	6,307	12,100
	Non-Saline	--	2,335	4,685
	Non-Saline Consumption			
	Brackish	--	19	40
	Fresh	--	26	53

TABLE P-26 (cont'd)

AVERAGE ANNUAL WATER USE FOR THERMAL GENERATION - FT^3/S
REGIONAL DEVELOPMENT OBJECTIVE BY BENCHMARK YEARS

Area	Class of Water Use	Benchmark Year 1980	2000	2020
7	Condenser Flow			
	Saline	--	--	750
	Non-Saline	550	250	6,500
	Withdrawal			
	Saline	--	--	750
	Non-Saline	550	950	4,275
	Non-Saline Consumption			
	Brackish	--	--	17
	Fresh	6	10	55
8	Condenser Flow			
	Saline	--	--	350
	Non-Saline	4,646	6,644	9,750
	Withdrawal			
	Saline	--	--	350
	Non-Saline	2,400	4,345	4,720
	Non-Saline Consumption			
	Brackish	15	18	22
	Fresh	41	52	88
9	Condenser Flow			
	Saline	11,700	28,000	46,600
	Non-Saline	--	--	--
	Withdrawal			
	Saline	11,700	28,000	46,600
	Non-Saline	--	--	--
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	--	--	--

TABLE P-26 (cont'd)

AVERAGE ANNUAL WATER USE FOR THERMAL GENERATION - FT^3/S
REGIONAL DEVELOPMENT OBJECTIVE BY BENCHMARK YEARS

Area	Class of Water Use	1980	2000	2020
			Benchmark Year	
10	Condenser Flow			
	Saline	5,900	8,900	7,800
	Non-Saline	--	4,000	12,300
	Withdrawal			
	Saline	5,900	8,900	7,800
	Non-Saline	--	3,030	6,870
	Non-Saline Consumption			
	Brackish	--	25	49
	Fresh	--	13	73
11	Condenser Flow			
	Saline	--	--	--
	Non-Saline	40	5,300	9,000
	Withdrawal			
	Saline	--	--	--
	Non-Saline	40	1,450	2,600
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	1	65	112
12	Condenser Flow			
	Saline	--	--	--
	Non-Saline	12,300	27,300	40,300
	Withdrawal			
	Saline	--	--	--
	Non-Saline	12,300	17,050	11,680
	Non-Saline Consumption			
	Brackish	98	129	114
	Fresh	15	137	353

TABLE P-26 (cont'd)

AVERAGE ANNUAL WATER USE FOR THERMAL GENERATION - FT^3/S
REGIONAL DEVELOPMENT OBJECTIVE BY BENCHMARK YEARS

Area	Class of Water Use	Benchmark Year 1980	2000	2020
13	Condenser Flow			
	Saline	10,900	18,490	28,850
	Non-Saline	--	--	5,020
	Withdrawal			
	Saline	10,900	18,490	28,850
	Non-Saline	--	--	5,000
	Non-Saline Consumption			
	Brackish	--	--	70
	Fresh	--	--	--
14	Condenser Flow			
	Saline	4,900	3,370	2,830
	Non-Saline	--	3,000	10,100
	Withdrawal			
	Saline	4,900	3,370	2,830
	Non-Saline	--	2,028	4,299
	Non-Saline Consumption			
	Brackish	--	16	93
	Fresh	--	13	23
15	Condenser Flow			
	Saline	5,900	5,200	7,250
	Non-Saline	8,239	33,700	62,160
	Withdrawal			
	Saline	5,900	5,200	7,250
	Non-Saline	2,550	14,500	26,875
	Non-Saline Consumption			
	Brackish	--	74	207
	Fresh	107	312	512

TABLE P-26 (cont'd)

AVERAGE ANNUAL WATER USE FOR THERMAL GENERATION - FT^3/S
REGIONAL DEVELOPMENT OBJECTIVE BY BENCHMARK YEARS

Area	Class of Water Use	Benchmark Year 1980	2000	2020
16	Condenser Flow			
	Saline	2,700	9,700	11,830
	Non-Saline	330	12,000	38,550
	Withdrawal			
	Saline	2,700	9,700	11,830
	Non-Saline	330	4,225	19,090
	Non-Saline Consumption			
	Brackish	3	102	362
	Fresh	--	39	89
17	Condenser Flow			
	Saline	--	--	--
	Non-Saline	13,344	27,570	47,850
	Withdrawal			
	Saline	--	--	--
	Non-Saline	3,550	7,800	13,800
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	146	298	550
18	Condenser Flow			
	Saline	200	3,600	14,000
	Non-Saline	8,500	24,120	38,600
	Withdrawal			
	Saline	200	3,600	14,000
	Non-Saline	8,500	15,120	18,450
	Non-Saline Consumption			
	Brackish	81	132	167
	Fresh	--	117	264

TABLE P-26 (cont'd)

AVERAGE ANNUAL WATER USE FOR THERMAL GENERATION - FT^3/S
REGIONAL DEVELOPMENT OBJECTIVE BY BENCHMARK YEARS

Area	Class of Water Use	Benchmark Year 1980	2000	2020
19	Condenser Flow			
	Saline	--	2,200	6,800
	Non-Saline	4,975	12,240	20,400
	Withdrawal			
	Saline	--	2,200	6,800
	Non-Saline	3,415	6,800	10,350
	Non-Saline Consumption			
	Brackish	22	50	120
	Fresh	33	83	110
20	Condenser Flow			
	Saline	375	3,220	6,470
	Non-Saline	3,625	4,500	4,350
	Withdrawal			
	Saline	375	3,220	6,470
	Non-Saline	130	144	80
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	82	89	53
21	Condenser Flow			
	Saline	700	1,800	12,800
	Non-Saline	5,100	16,200	26,200
	Withdrawal			
	Saline	700	1,800	12,800
	Non-Saline	5,100	9,235	4,980
	Non-Saline Consumption			
	Brackish	35	70	48
	Fresh	17	100	278

TABLE P-27

AVERAGE ANNUAL WATER USE FOR THERMAL GENERATION FT^3/S
ENVIRONMENTAL QUALITY OBJECTIVE BY BENCHMARK YEARS

Area	Class of Water Use	Benchmark Year 1980	2000	2020
1	Condenser Flow			
	Saline	--	--	--
	Non-Saline	19	--	--
	Withdrawal			
	Saline	--	--	--
	Non-Saline	19	--	--
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	--	--	--
2	Condenser Flow			
	Saline	--	--	--
	Non-Saline	57	--	--
	Withdrawal			
	Saline	--	--	--
	Non-Saline	57	--	--
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	1	--	--
3	Condenser Flow			
	Saline	--	--	--
	Non-Saline	--	--	--
	Withdrawal			
	Saline	--	--	--
	Non-Saline	--	--	--
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	--	--	--

TABLE P-27 (cont'd)

AVERAGE ANNUAL WATER USE FOR THERMAL GENERATION - FT3/S
ENVIRONMENTAL QUALITY OBJECTIVE BY BENCHMARK YEARS

Area	Class of Water Use	Benchmark Year 1980	2000	2020
4	Condenser Flow			
	Saline	--	--	--
	Non-Saline	--	--	750
	Withdrawal			
	Saline	--	--	--
	Non-Saline	--	--	25
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	--	--	10
5	Condenser Flow			
	Saline	1,344	8,527	17,830
	Non-Saline	--	--	--
	Withdrawal			
	Saline	1,344	8,527	17,830
	Non-Saline	--	--	--
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	--	--	--
6	Condenser Flow			
	Saline	1,590	4,582	7,030
	Non-Saline	--	4,000	9,420
	Withdrawal			
	Saline	1,590	4,582	7,030
	Non-Saline	--	1,090	1,980
	Non-Saline Consumption			
	Brackish	--	48	99
	Fresh	--	--	20

TABLE P-27 (cont'd)

AVERAGE ANNUAL WATER USE FOR THERMAL GENERATION - FT^3/S
ENVIRONMENTAL QUALITY OBJECTIVE BY BENCHMARK YEARS

Area	Class of Water Use	Benchmark Year 1980	2000	2020
7	Condenser Flow			
	Saline	--	--	2,250
	Non-Saline	550	350	3,000
	Withdrawal			
	Saline	--	--	2,250
	Non-Saline	550	350	100
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	6	4	40
8	Condenser Flow			
	Saline	--	2,000	3,100
	Non-Saline	4,646	3,464	2,250
	Withdrawal			
	Saline	--	2,000	3,100
	Non-Saline	2,372	1,317	61
	Non-Saline Consumption			
	Brackish	15	10	--
	Fresh	41	34	30
9	Condenser Flow			
	Saline	11,700	28,800	44,200
	Non-Saline	--	--	--
	Withdrawal			
	Saline	11,700	28,800	44,200
	Non-Saline	--	--	--
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	--	--	--

TABLE P-27 (cont'd)

AVERAGE ANNUAL WATER USE FOR THERMAL GENERATION - FT^3/S
ENVIRONMENTAL QUALITY OBJECTIVE BY BENCHMARK YEARS

Area	Class of Water Use	Benchmark Year 1980	2000	2020
10	Condenser Flow			
	Saline	5,900	9,400	9,300
	Non-Saline	--	2,000	5,700
	Withdrawal			
	Saline	5,900	9,400	9,300
	Non-Saline	--	2,000	5,020
	Non-Saline Consumption			
	Brackish	--	16	43
	Fresh	--	--	10
11	Condenser Flow			
	Saline	--	--	--
	Non-Saline	40	--	--
	Withdrawal			
	Saline	--	--	--
	Non-Saline	40	--	--
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	1	--	--
12	Condenser Flow			
	Saline	--	--	--
	Non-Saline	12,300	21,100	25,100
	Withdrawal			
	Saline	--	--	--
	Non-Saline	12,300	17,212	8,412
	Non-Saline Consumption			
	Brackish	98	143	122
	Fresh	15	64	188

TABLE P-27 (cont'd)

AVERAGE ANNUAL WATER USE FOR THERMAL GENERATION - FT^3/S
ENVIRONMENTAL QUALITY OBJECTIVE BY BENCHMARK YEARS

Area	Class of Water Use	Benchmark Year 1980	2000	2020
13	Condenser Flow			
	Saline	10,900	18,490	31,450
	Non-Saline	--	--	--
	Withdrawal			
	Saline	10,900	18,490	31,450
	Non-Saline	--	--	--
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	--	--	--
14	Condenser Flow			
	Saline	4,900	5,370	8,000
	Non-Saline	--	1,000	3,250
	Withdrawal			
	Saline	4,900	5,370	8,000
	Non-Saline	--	1,000	2,521
	Non-Saline Consumption			
	Brackish	--	8	22
	Fresh	--	--	10
15	Condenser Flow			
	Saline	5,900	6,200	6,700
	Non-Saline	8,239	28,420	50,800
	Withdrawal			
	Saline	5,900	6,200	6,700
	Non-Saline	2,550	12,060	19,525
	Non-Saline Consumption			
	Brackish	--	135	253
	Fresh	107	190	334

TABLE P-27 (cont'd)

AVERAGE ANNUAL WATER USE FOR THERMAL GENERATION - FT^3/S
ENVIRONMENTAL QUALITY OBJECTIVE BY BENCHMARK YEARS

Area	Class of Water Use	Benchmark Year 1980	2000	2020
16	Condenser Flow			
	Saline	2,700	8,150	15,950
	Non-Saline	330	11,300	24,750
	Withdrawal			
	Saline	2,700	8,150	15,950
	Non-Saline	330	2,555	5,530
	Non-Saline Consumption			
	Brackish	3	113	254
	Fresh	--	26	33
17	Condenser Flow			
	Saline	--	--	--
	Non-Saline	13,344	19,696	23,050
	Withdrawal			
	Saline	--	--	--
	Non-Saline	3,550	2,300	821
	Non-Saline Consumption			
	Brackish	--	--	--
	Fresh	146	225	284
18	Condenser Flow			
	Saline	200	13,280	26,050
	Non-Saline	8,500	12,270	17,150
	Withdrawal			
	Saline	200	13,280	26,050
	Non-Saline	8,500	10,270	9,670
	Non-Saline Consumption			
	Brackish	81	120	167
	Fresh	--	--	27

TABLE P-27 (cont'd)

AVERAGE ANNUAL WATER USE FOR THERMAL GENERATION - FT^3/S
ENVIRONMENTAL QUALITY OBJECTIVE BY BENCHMARK YEARS

Area	Class of Water Use	1980	Benchmark Year 2000	2020
19	Condenser Flow			
	Saline	--	1,250	3,750
	Non-Saline	4,975	8,440	11,750
	Withdrawal			
	Saline	--	1,250	3,750
	Non-Saline	3,415	2,610	3,570
	Non-Saline Consumption			
	Brackish	22	60	110
	Fresh	33	42	32
20	Condenser Flow			
	Saline	375	3,220	6,470
	Non-Saline	3,625	4,600	4,400
	Withdrawal			
	Saline	375	3,220	6,470
	Non-Saline	130	150	85
	Non-Saline Consumption			
	Brackish	--	8	18
	Fresh	82	82	36
21	Condenser Flow			
	Saline	700	550	7,800
	Non-Saline	5,100	16,450	24,200
	Withdrawal			
	Saline	700	550	7,800
	Non-Saline	5,100	6,718	700
	Non-Saline Consumption			
	Brackish	35	89	70
	Fresh	17	101	226