National
Hydroelectric Power
Resources Study

Marketing and Transmission of Federal Hydroelectric Power

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Resources Study

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Marketing and Transmission of Federal Hydroelectric Power

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There are five power marketing agencies in the United States. This volume discusses the history of these agencies and their role in marketing Federal hydroelectric power. A separate appendix has been prepared by each of the PMA's and is included in the report.

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NATIONAL HYDROELECTRIC POWER RESOURCES STUDY

Marketing and Transmission of Hydroelectric Power

Part 1

Introduction and Summary

INTRODUCTION AND SUMMARY

FEDERAL POWER MARKETING PROGRAM

The Federal Power Marketing Program began in the early 1900's when the Bureau of Reclamation constructed several irrigation projects that included facilities to generate hydroelectric power. Although much of the electricity generated was needed to pump water for irrigation, a substantial amount was surplus and sold to help repay the Federal Government's investment in the projects. The Bureau of Reclamation marketed the surplus power, giving preference to cities and other municipal entities.

The Federal power program expanded greatly in the 1930's and 1940's when the Great Depression served as the spur for Federal Public Works Programs, including construction of multiple-purpose dams. The Corps of Engineers' 308 Reports on the Tennessee and Columbia Rivers and the Pick-Sloan plan for the Missouri River served as important blueprints for expanding the power program.

Four acts laid the foundation for the power marketing functions: The Tennessee Valley Authority Act of 1933, the Bonneville Project Act of 1937, the Reclamation Project Act of 1939, and the Flood Control Act of 1944.

The Bonneville Project Act of 1937, which established the Bonneville Power Administration (Bonneville) set a power marketing pattern that was essentially adopted nationwide in Section 5 of the Flood Control Act of 1944. As multiple-purpose water projects were completed in most areas of the Nation, additional power marketing administrations (PMAs) were established:

- The Southwestern Power Administration (Southwestern) in 1945
- The Southeastern Power Administration (Southeastern) in 1950
- The Alaska Power Administration (Alaska) in 1967
- The Western Area Power Administration, (Western) in 1977. (Prior to the formation of Western by the Department of Energy Reorganization Act of 1977, the Bureau of Reclamation marketed the power from the Corps of Engineers dams as well as Bureau of Reclamation dams located in the Western States outside the Columbia River Basin.)

The five PMAs, which became a part of the U.S. Department of Energy when it was established in 1977, market power in 33 States (Figure 1).

Three concepts are embedded in power marketing law:

- Preference in the sale of power is given to public bodies and cooperatives.
- Power must be priced at the lowest possible rate consistent with sound business principles, to recover the cost of producing the power.
- Power must be marketed to encourage its use on a widespread basis, generally adopting uniform system-wide or large-area rates.

The five PMAs market surplus power produced by 122 Federally-owned multiple-purpose projects. The output of these projects--130.5 billion KWh in 1980--constitutes about 45 percent of the Nation's hydropower production. The capacity of the plants (31,409 MW) constitutes about one-half of the Nation's hydropower capacity. To carry out the marketing function, the PMAs operate and maintain approximately 30,000 miles of high voltage transmission lines and other related facilities.

The PMAs sell power at wholesale to 886 customers (Figure 2). The customers--municipal utilities, cooperatively owned utilities, investor-owned utilities, industries, and State, county and Federal entities--in turn provide retail electric service to millions of consumers. Bonneville markets the most power and plays a major role in influencing power development in the Pacific Northwest. Western markets the second largest volume of power. Western has the greatest number of customers.

Revenues obtained from the PMAs from the sale of power and from transmission services pay for project operations and maintenance costs, project capital investment allocated to power, and interest on the power investments. Power revenues also help pay for investments in irrigation projects that are beyond the ability of the irrigators to repay.

Appropriations to operate the PMAs, except those for Bonneville, are made annually by the Congress. Revenues collected are deposited in the United States Treasury. In 1974, Congress enacted the Federal Columbia River Transmission System Act, which authorized Bonneville to place its revenues in a revolving fund and to expend them for any purpose necessary to carry out the duties prescribed for it by law, including construction, operation, and maintenance of the transmission system, marketing of electric power, and the purchase of power on an emergency basis. The Act also authorized the Administrator of Bonneville to borrow up to $1.25 billion by issuing revenue bonds.

OFFICE OF POWER MARKETING COORDINATION

Organizationally, the PMAs report to the Secretary of Energy through the Assistant Secretary for Conservation and Renewable Energy.

The Office of Power Marketing Coordination (OPMC) has been established within the Office of Conservation and Renewable Energy to help coordinate the activities of the PMAs. Its primary activities include:

- Serves as Washington staff representative, both within and outside the Department of Energy, for matters of general concern to PMAs.
- Coordinates budget submittals of PMAs.
- Coordinates PMAs program planning and implementation.

- Provides staff services to the Assistant Secretary in power marketing matters.
- Provides Washington office services for the Alaska, Southeastern, and Southwestern Power Administrations (Bonneville and Western maintain offices in Washington to provide their own support services.)
- Coordinates power rate actions of PMAs.
- Provides staff representation for the Department on the Water Resources Council.
- Represents DOE on the Interagency Committee on Cost Allocations, the Power Rate Council, and the Columbia River Treaty Permanent Enginering Board.
- Acts on behalf of the Assistant Secretary, at his request, testifies at hearings, and represents the Department on matters affecting power marketing.

OPMC responsibilities are carried out by three divisions: Power and Water Resources Division, Financial Management and Operations Division, and the Rates, Contracts, and Power Allocation Division.

POWER MARKETING ADMINISTRATIONS

The PMAs vary considerably in the amount of electricity marketed, the revenues produced, the number of customers, the size of service areas, and organizational structures (Figures 1-7). Southeastern, for example, does not have field offices or an engineering design section, since it does not construct and operate transmission and related facilities.

Bonneville Power Administration

Major Federal development of hydroelectric power in the Pacific Northwest began in 1933 with the construction of the Bonneville and Grand Coulee Dams on the Columbia River. The Bonneville Power Administration was created in 1937 to market power from the Bonneville Dam and build necessary transmission lines. Marketing power from the Grand Coulee Dam was assigned to Bonneville in 1941, and the provisions of the Bonneville Project Act of 1937 now apply to the sale of power from all but one of the 31 Federal projects in the Pacific Northwest.

During World War II, Bonneville rapidly expanded its transmission grid to serve a growing population and wartime industry. It markets power at wholesale to electric utilities, certain Federal facilities, and large electro-process industries--primarily the aluminum reduction industry which consumes about 30 percent of Bonneville's power.

During the 1960's, Bonneville was involved in major undertakings that have had a profound effect upon the regional power network. The first was the Columbia River Treaty between the United States and Canada, which provided for the construction of four large dams in Canada to store water for flood control and increased power production at plants downstream in the United States. Subsequently, the construction of the Pacific Northwest-Pacific Southwest Intertie provided for the bulk exchange of power between the two regions which enjoy a substantial diversity in loads. Also, in 1966, after complex negotiations spearheaded by Bonneville, the first nuclear powerplant in the Pacific Northwest began operation using waste steam from the Hanford New Production Reactor.

During the 1970's, Bonneville was heavily involved in implementing the region's unique Hydrothermal Power Program involving more than 100 utilities, major industries, and the Federal Government. The program integrates large new base-load thermal projects with peaking capacity installed at Federal dams. Bonneville transmits and markets the "blended" power at wholesale rates.

Bonneville markets power from 30 hydroelectric projects, the output of the Hanford nuclear project, and part of the output of the Trojan nuclear project. During fiscal year 1980, Bonneville marketed 18.6 million KW of capacity and 81.0 billion KWh of energy. Its sale of this electricity produced $505 million in revenues. Bonneville markets about 50 percent of the region's electric energy, and operates 80 percent of the region's high-voltage transmission grid, consisting of about 12,700 circuit miles of high-voltage transmission lines and 340 substations.

Bonneville, with Headquarters in Portland, Oregon, serves 161 customers in the Pacific Northwest through its eight area and district offices. Its service area includes Oregon, Washington, Idaho, that part of Montana west of the Continential Divide, and small parts of Nevada and Wyoming (Figure 1). Customers include publicly owned, cooperatively owned, and investor-owned utilities, large industrial installations, and Federal agencies. Bonneville, in cooperation with its customers, the States, and the general public, plans for the orderly development of the region's potential electric energy resources--both hydro and thermal.

Southwestern Power Administration

The Federal Works Agency in 1941, authorized the Federal Government to take control of the State-owned Grand River Dam Project in Oklahoma. National security dictated such action because the project supplied electric power for an important munitions factory. In 1943, an Executive Order authorized the Federal Works Agency also to market surplus power and energy from the Norfolk Project in Arkansas. The same year, the Secretary of the Interior became responsible for marketing the output from Denison Dam in Texas, and the duties vested in the Federal Works Administration were transferred to the Secretary.

In November 1945, the Secretary of the Interior by Secretarial Order created the Southwestern Power Administration (Southwestern) to market electricity generated at the hydroelectric projects constructed by the Army Corps of Engineers in Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas.

The Federal transmission system operated by Southwestern consists of about 1,636 miles of 69-, 138-, and 161-kilovolt transmission lines, 31 bulk power substations, 19 radio/microwave stations, and related facilities. Forty-five 138- and 161-kilovolt interconnections with neighboring utility systems are controlled from the system control center at Springfield, Missouri. The field offices for maintenance and operation of these lines are located at Springfield Missouri, Jonesboro, Arkansas, and Ada and Muskogee, Oklahoma. Southwestern's headquarters is in Tulsa, Oklahoma.

Electricity is marketed from 21 projects with a total installed capacity of 1.9 million KW. Two additional projects now under construction are expected to be completed by 1983. Sales during fiscal year 1980 were $62.7 million bringing the revenue earned in all years to $806 million.

Southeastern Power Administration

The Southeastern Power Administration (Southeastern) was created by Secretarial Order in March 1950 to transmit and dispose of the electric power and energy generated at reservoir projects controlled by the Army Corps of Engineers in 10 Southeastern States: West Virginia, Virginia, North Carolina, South Carolina, Georgia, Florida, Alabama, Mississippi, Tennessee and Kentucky. Southeastern's headquarters is in Elberton, Georgia. It has no field offices.

When Southeastern was established, there were only two hydroelectric projects with an aggregated installed capacity of 110,000 kilowatts. Two contracts covered the sale of this power to two customers. There were an additional five projects scattered throughout the area scheduled to begin operation in one to three years and an additional 15 projects authorized for construction. Today, Southeastern has 21 hydroelectric projects with an aggregate installed capacity of 2.7 million KW. An additional 300,000 KW facility is under construction.

As the number of Federal projects increased, it became increasingly important to integrate the power outputs of individual projects into systems. This approach enables Southeastern to take advantage of stream flow diversities among the different rivers to increase the dependable capacity of the hydroelectric systems to levels substantially above those that could be obtained by simply adding together the outputs of the various projects. Southeastern has integrated its 21 projects into the following five systems: Kerr-Philpott, Georgia-Alabama, Jim Woodruff, Laurel, and Cumberland Basin.

Southeastern does not own any transmission facilities. However, agreements were reached with various utilities in the area to wheel power from the

Federal projects to Southeastern's customers. Southeastern's basic marketing pattern provides for three-way arrangements among Southeastern, the investor-owned utilities, and preferred customers located in the utilities' power service area.

During fiscal year 1980, Southeastern marketed 2.7 million KW of capacity and 8.2 billion KWh of energy, selling power and energy to 80 municipalities, 108 rural electric cooperatives, one Federal agency, and eight privately owned utilities. Sales during the year earned $63 million, bringing the revenue earned in all years to $840 million.

Alaska Power Administration

The Alaska Power Administration (Alaska) established by Secretarial Order on June 16, 1967, promotes the development and use of Alaska's water, power and related resources. Alaska operates, maintains and markets the power of the two Federal hydroelectric projects in Alaska: The Eklutna Project, serving the Anchorage-Palmer area, and the Snettisham Project, serving the Juneau area.

The Eklutna Project, which the Bureau of Reclamation built in 1955, has a capacity of 30,000 KW and is 34 miles northwest of Anchorage and 8 miles south of Palmer. The project has 47 miles of 115-kilovolt transmission lines, which run from the powerplant to Anchorage and Palmer. Power is marketed to three local utilities, and all costs associated with the project are reimbursable from power sales revenues. Eklutna Lake is the project's storage reservoir with a capacity of 174,800 acre-feet. A low earth-fill dam (replaced after the 1964 earthquake) retains the water.

The Snettisham Hydroelectric Project is 28 miles southeast of Juneau. To develop the power potential of Long Lake (138,000 acre-feet of storage), an underground powerplant was built at the head of Speel Arm. Water flows through an 8,000-foot tunnel from the Lake to the 47,160-kilowatt powerplant. The Juneau substation is the local area control center. Operators at the substation supervise the Snettisham Project and other utility powerplants in the Juneau system.

Alaska also studies transmission systems and power markets in coordination with other Federal, State, and local agencies. The existing non-Federal power systems depend primarily on oil and natural gas for power supplies.

Western Area Power Administration

Western Area Power Administration (Western) was created on December 21, 1977, by Section 302 of the Department of Energy Organization Act of 1977. Western was formerly a part of the Department of the Interior's Bureau of Reclamation. Headquartered in Golden, Colorado, it provides service to customers in all or parts of 15 Western States: Arizona, California, Colorado, eastern Montana, Nebraska, Nevada, New Mexico, North Dakota, South Dakota, Utah, eastern Iowa, western Kansas, western Minnesota, western Texas, and Wyoming; a marketing area of 1,269,958 square miles.

The electric power marketed is generated by the Bureau of Reclamation, the Army Corps of Engineers, and the International Boundary and Water Commission. The major projects are the Colorado River Storage Project, the Central Valley Project, the Pick-Sloan Missouri Basin Program, the Boulder Canyon Project, and the Parker-Davis Project.

The power is produced at 48 powerplants. In 1980, Western marketed 36.6 billion KWh, with annual revenue from power sales totaling $365 million. It has 464 preference customers. The system has an installed generating capacity of 8,065 MW and maintains 15,897 circuit miles of transmission lines and 218 substations.

CONSERVATION PROGRAM

The PMAs promote conservation and the development of renewable energy resources through a variety of activities.

- Purchase energy from generating facilities using renewable resources.
- Provide standby energy storage and other load-shaping services to developers of renewable resource generating facilities.
- Provide transmission and interconnection services to integrate the output from renewable energy generating facilities into regional grid systems.
- Undertake and/or encourage PMA customers to pursue pilot programs to demonstrate the cost-effectiveness of energy conservation measures.
- Cooperate with suppliers and users of Federally transmitted power to develop solar and other renewable energy and to promote energy conservation.
- Whenever appropriate, act as the laboratory for experimenting with conservation, and renewable energy initiatives.

One of the most significant conservation programs has been to conserve oil through flexible operation of Federal hydropower plants and special power marketing arrangements. In 1979 this program conserved 7-million barrels of oil.

Another important conservation related activity is the development of interregional interties to take advantage of seasonal diversity in loads. To further this program, OPMC and Bonneville participated in the National Power Grid Study. This study identified opportunities to make more effective use of our electric power resources and offered a series of recommendations to take advantage of the opportunities.

MARKETING FEDERAL HYDROPOWER PRODUCED IN AREAS NOT SERVED BY POWER MARKETING AGENCIES

No provisions have been made for the marketing of Federally produced hydroelectric power in 17 States, Puerto Rico, and the territories, because the production of hydroelectric power has not been an authorized purpose of Federal water projects in those areas. The dramatic increase in cost of energy, however, has altered the benefit-cost ratios for many potential hydropower projects and has made the installation of hydroelectric facilities very attractive at many existing Federal dams. There are 156 Corps dams in areas where no power marketing arrangements have been made. Of these, the Corps believes 129 merit study for hydropower development. There has already been a broad interest shown in these projects--non-Federal interests have made filings on 100 of the projects as of March 1, 1981.

Administration policy is to encourage non-Federal development of hydroelectric resources at Federal multiple-purpose water projects, except where Federal interests cannot be adequately protected through contractual arrangements with non-Federal developers. Federal development is appropriate where there is a need to meet Federal energy contractual commitments; where non-Federal development could clearly interfere with other existing uses of a Federal facility; or where there are unresolvable safety, environmental, or operational problems.

Policy governing the marketing of power produced at Corps of Engineers' projects is controlled primarily by the Flood Control Act of 1944. Further policy is provided by a large number of other Acts, including the Bonneville Project Act of 1937, as amended, the Reclamation Project Act of 1939, and the Department of Energy Organization Act of 1977.

The Flood Control Act of 1944 directs that power is to be marketed by the Secretary of Energy, acting by and through the Administrator of a regional power marketing administration. Preference in the sale of Federal power is to be given to public bodies and cooperatives. This has meant that the bulk of Federal power is sold at wholesale to municipal electric utilities and rural electric cooperatives. Rates charged the utility customers are set at the lowest possible level consistent with sound business principles to recover the cost of producing and transmitting the power, including repayment of the capital investment allocated to power with interest. In a few special circumstances in the West, rates for power from Corps of Engineers' projects also provide assistance to irrigation. Rates are generally uniform throughout each system, or over large areas, to make the benefits of Federal hydropower widely available.

While the Administration may recommend and the Congress approve Federal development of hydroelectric power at existing or potential Federal water resources projects in areas not now served by a Federal power marketing agency, no policy decision has been made about marketing under such circumstances. Three options, however, appear to be the most viable:

1. The Office of Power Marketing Coordination in Washington, DC., could contract to market the power, using the same criteria that the five power marketing administrations use in their respective areas. This probably would be useful as a temporary measure for an individual isolated project in an unserved area if it appeared likely that other projects might be developed in the same region at a later time. Existing utilities would have to be willing to provide wheeling services to deliver the power.

2. Marketing could be assigned to the nearest or most logical power administration. Thus, for example, the development of power at an existing Corps of Engineers water project on the Upper Mississippi River could be assigned to the Western Area Power Administration. Similarly, the development of power at a Corps of Engineers project on the Allegheny River in Western Pennsylvania could be assigned to the Southeastern Power Administration. Such assignment would be workable for relatively isolated projects, but would have to be re-examined if Federal development of hydroelectric power were authorized at several projects in the same river basin or in the same region.

3. A new power administration could be established to serve the region in which the new power is developed. A new administration could be justified if several projects were to be developed within an unserved area. Formation of such organizations would be desirable to integrate the outputs of the projects, to optimize marketability, and to assure adequate transmission services. Under this approach, low-cost projects could serve to assist higher-cost projects, thus permitting full development of the potential hydropower which would otherwise be foregone if projects were developed on an isolated basis.

If Federal hydropower is developed in areas not now served by a power marketing administration, the Administration will examine the workable alternatives available at the time and will select the most appropriate arrangement.

ELECTRIC POWER MARKETING AREAS OF DEPARTMENT OF ENERGY AND TENNESSEE VALLEY AUTHORITY

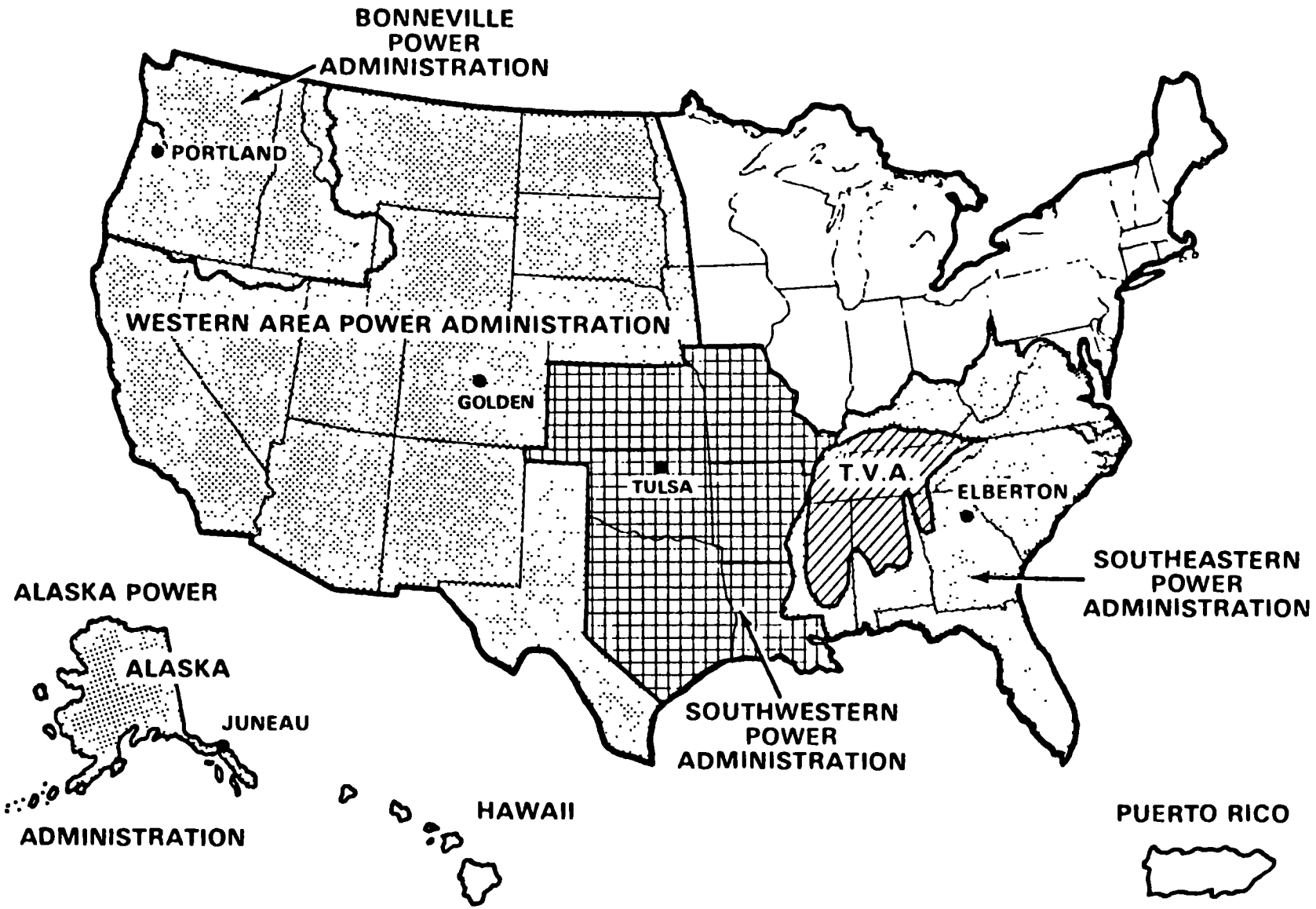

Figure 1

POWER MARKETING ADMINISTRATIONS
PRIMARY STATISTICS
(FY 1980)

POWER ADMINIS-TRATION	SALES (MILLIONS OF MEGAWATT HOURS)	REVENUES ($ MILLIONS)	NAMEPLATE CAPACITY (MEGAWATTS)	POWERPLANTS (ALL TYPES)	SUBSTATIONS (ALL VOLTAGES) 1/	TRANSMISSION LINES (000 MILES)	CUSTOMERS: MUNICIPALS	CUSTOMERS: COOPERATIVES	CUSTOMERS: INVESTOR-OWNED	CUSTOMERS: STATE/COUNTY/FEDERAL	CUSTOMERS: INDUSTRIAL/OTHER	CUSTOMERS: ALL CUSTOMERS (TOTAL)	
ALASKA	.3	3	77	2	4	2/	3	1	1	–	–	5	
BONNEVILLE	81	505	18,626	30	57	12.7	36	54	8	32	31 3/	161	
SOUTHEASTERN	8.2	63	2,712	21	–	–	80	108	8	3	–	199	
SOUTHWESTERN	4.4	61	1,929	21	32	1.6	37	7	7	5	1	57	
WESTERN AREA	36.6	365	8,065	48	218	15.9	206	41	20	85	112	464	
TOTALS	130.5	997	31,409	122	611	30.2	362	211	44	125	144	886	

1/ Owned by the Federal Government, operated by the Corps of Engineers and the Bureau of Reclamation; (except Alaska Power Administration operates projects in Alaska); output marketed by the power marketing agencies.

2/ 90 miles

3/ Out of Region and Canadian Customers include: 3 California investor-owned, 5 California municipals, 1 State agency, 3 Western Area Power Administration Regions, British Columbia Hydropower Authority, and Bountiful, Utah

Figure 2

DEPARTMENT OF ENERGY

ALASKA POWER ADMINISTRATION

ORGANIZATION CHART

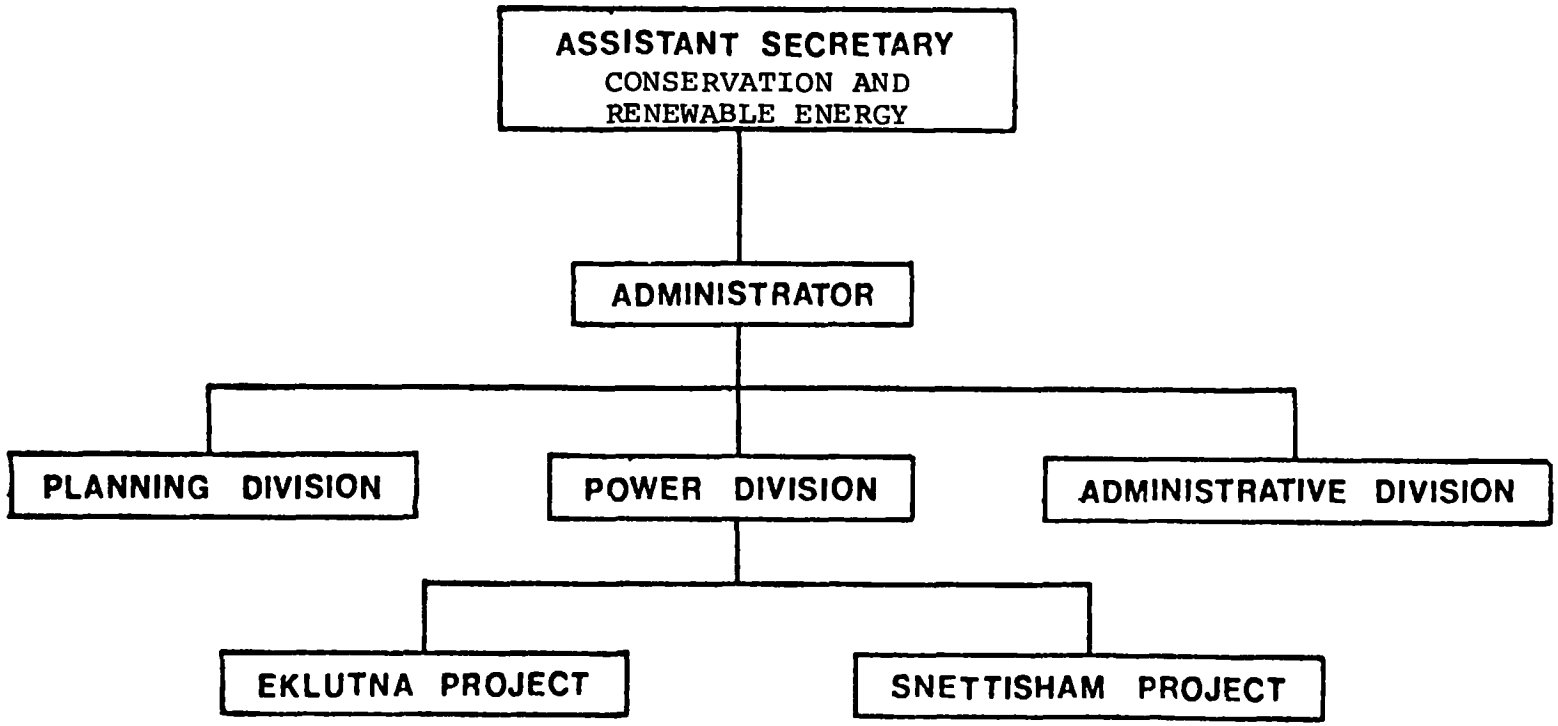

Figure 3

Official Organization Chart
U S DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION

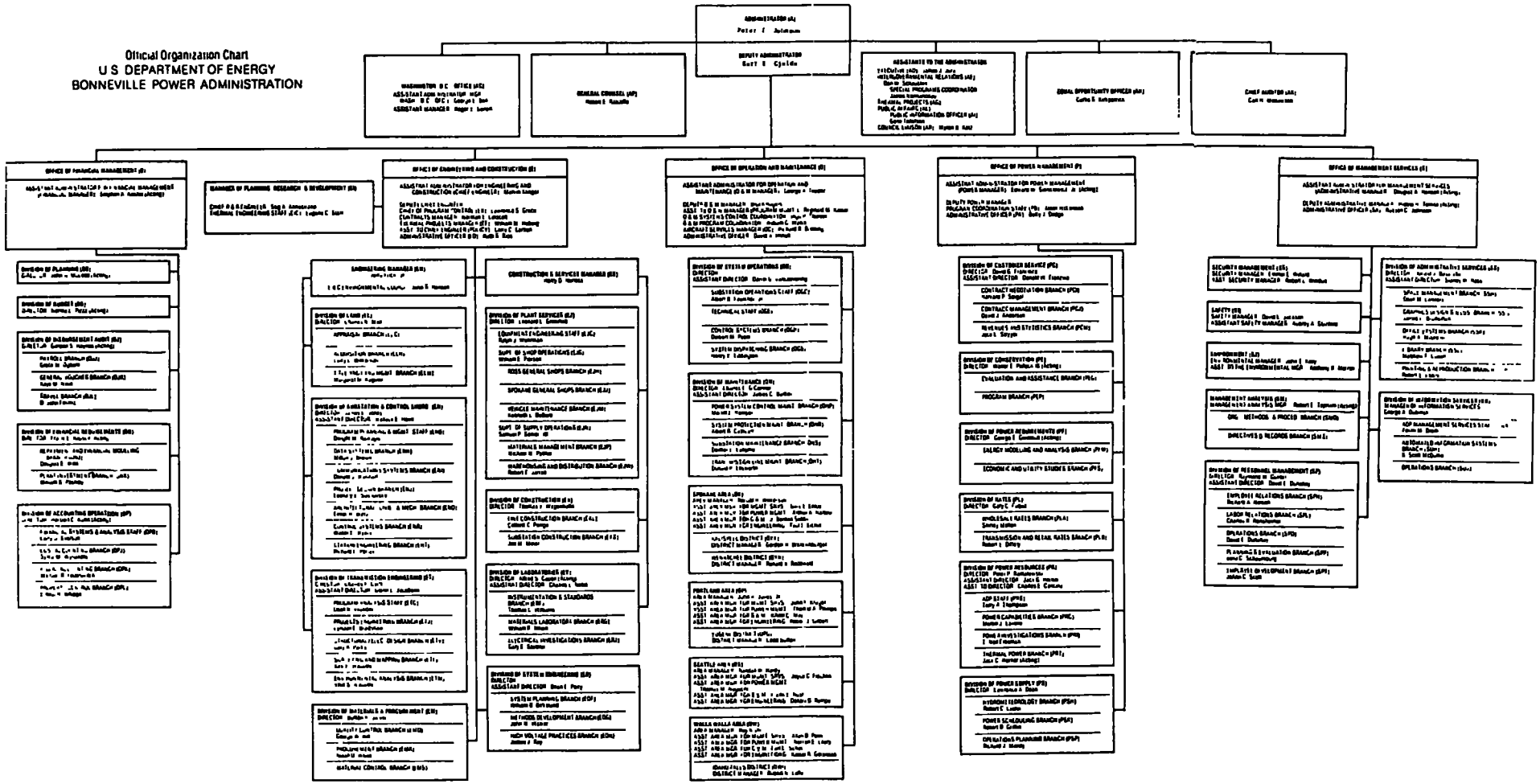

Figure 4

SOUTHEASTERN POWER ADMINISTRATION

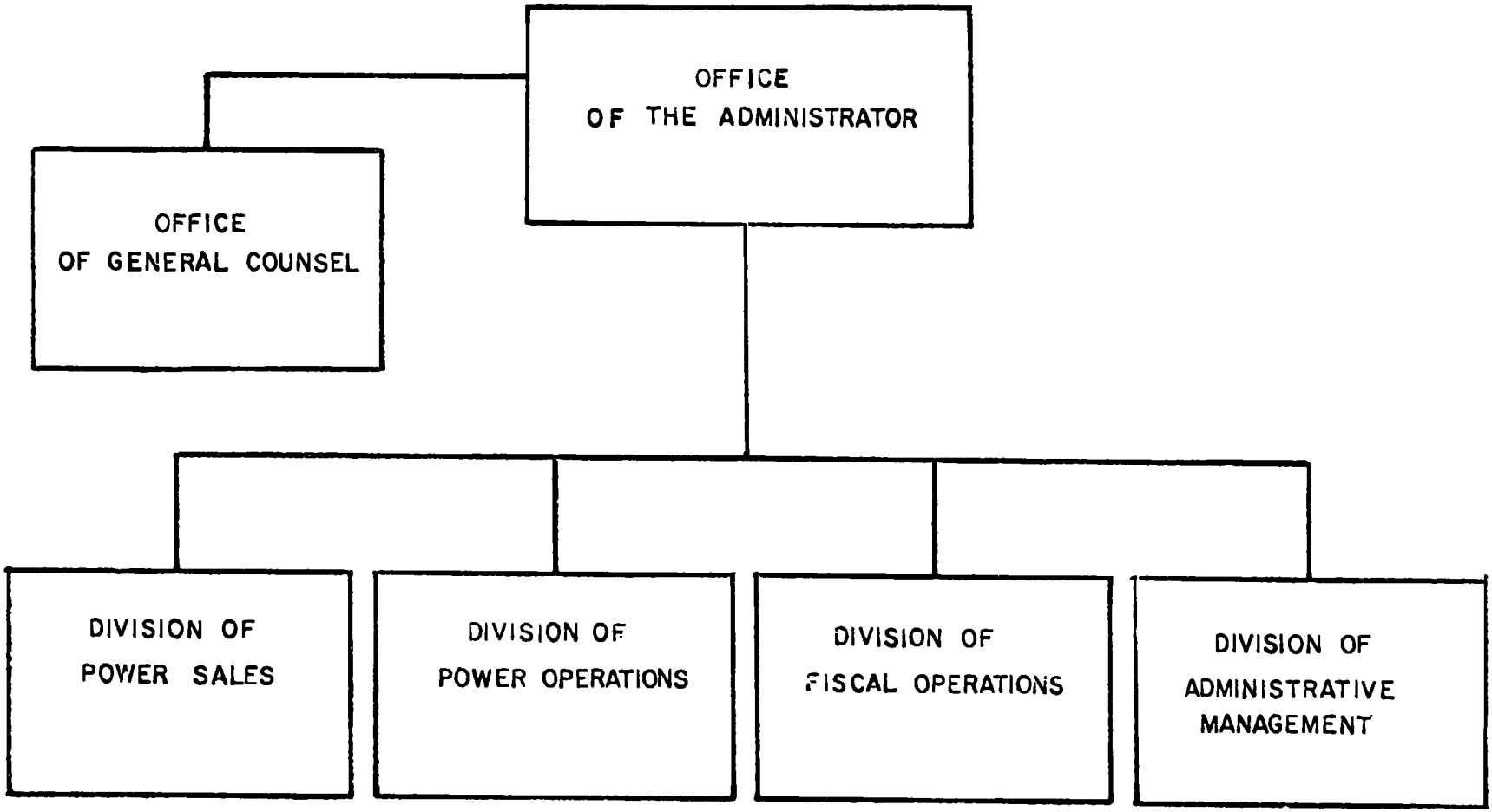

Figure 5

SOUTHWESTERN POWER ADMINISTRATION

OFFICE OF THE ADMINISTRATOR

J. Hammett	Administrator
W. Jamison	Deputy Administrator
L. Pruitt	Confidential Assistant
D. Donaldson	Executive Assistant

LEGAL

J. Swidensky	Chief Counsel
C. Borchardt	Attorney-Advisor
R. Zieren	Attorney-Advisor

PERSONNEL

D. Duran	Personnel Officer
V. Bradshaw	Personnel Management Specialist

EEO

Vacant	EEO Officer

DIVISION OF POWER FACILITIES

J. McClanahan	Chief, Division
E. Riggin	Br. Engineering
N. Dean	Br. Maintenance

DIVISION OF POWER MARKETING

W. Bowers	Chief, Division
F. Reeves	Br. Rates & Repay.
G. Horton	Br. Customer Service
G. Johnson	Br. Power Operations
K. Kerr	Br. Power Res. Prod.

DIVISION OF ADMINISTRATIVE MANAGEMENT

F. Gajan	Chief, Division
W. Spear	Budget Analyst
K. Mulnix	Br. Computer Services
L. Bevins	Br. Finance & Accounts
G. Kelly	Br. General Services

AREA OFFICES

R. Krahn	Muskogee
K. Blevins	Jonesboro
J. Walker	Springfield

DISPATCHING UNIT

W. Roberts	Springfield

Figure 6

Western Area Power Administration Organization

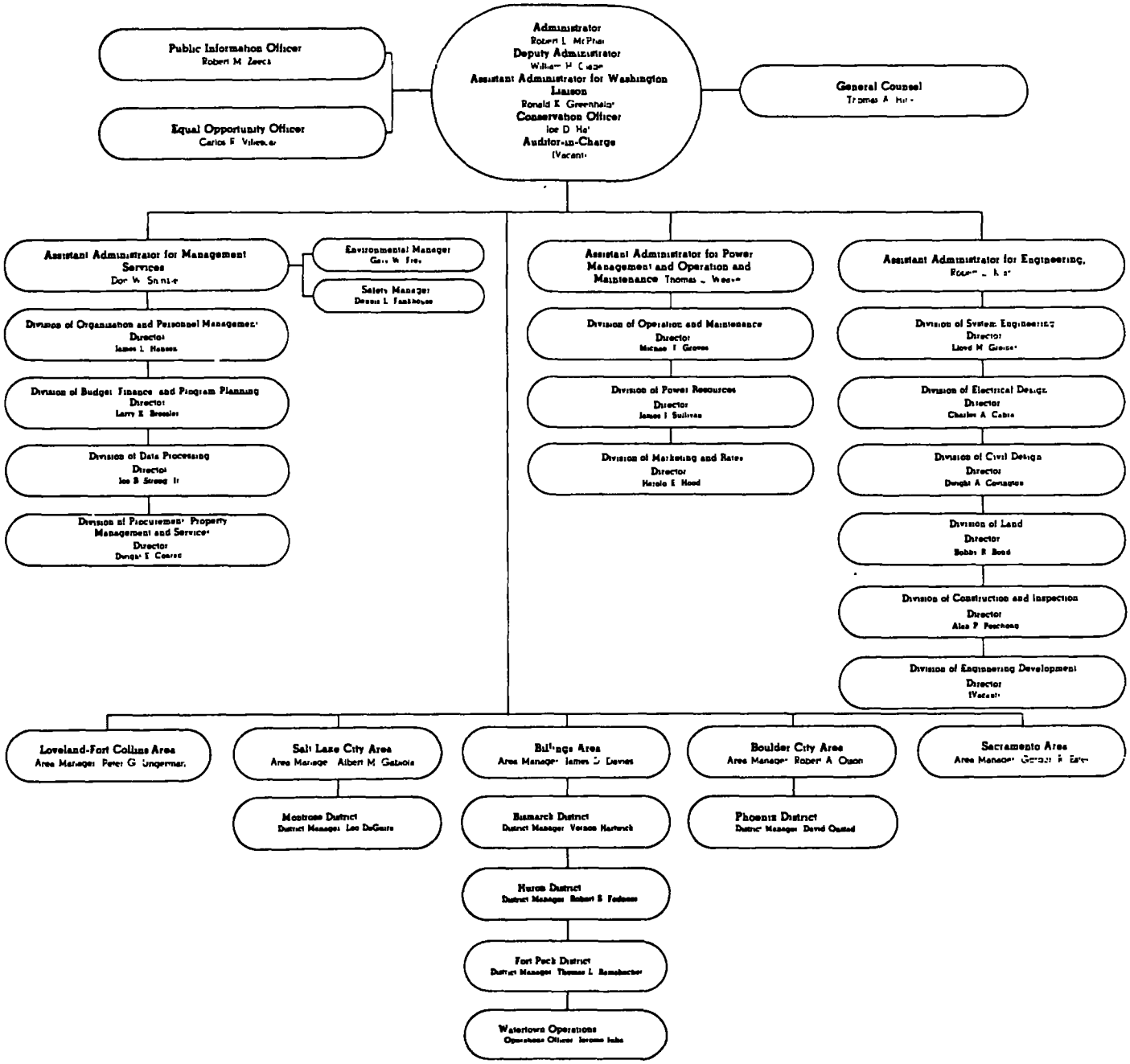

Figure 7

NATIONAL HYDROELECTRIC POWER RESOURCES STUDY

Marketing and Transmission of Hydroelectric Power

Part 2

History of Power Marketing in the United States

I. Non-Federal Development of Water Power

The development of the power potential of the Nation's rivers from the very beginning attracted the attention of private interests which lobbied Congress for permission to construct powerplants on navigable waters. Congress itself controlled the development of these installations until 1920 by the enactment of special laws permitting these plants to be constructed. In 1920 the Federal Power Commission was created and was empowered to license all non-Federal hydroelectric projects. By 1911, at least seventeen laws had been enacted granted power privileges to private parties at Federal Government dams. The earliest was the Act of August 11, 1888, and empowered the Secretary of War to grant leases or licenses for the use of the waterpower of the Muskingham River, Ohio, on such terms as were "just, equitable, and expedient." 1/

Between 1903 and 1909, President Theodore Roosevelt vetoed bills allowing private power dams at: Muscle Shoals, Alabama, on the Tennessee River 2/; the Rainy River on the Canadian border 3/; and on the James River in Missouri. 4/ His messages recognized that proceeds from the sale of power could be used to defray the cost of river improvements.

Accordingly, it did not seem right to give away valuable water power rights to private individuals. 5/ In 1912 President Taft, for like reasons, vetoed a bill which would have authorized the Alabama Power Company to construct a powerplant on the Coosa River in Alabama. 6/

Despite these vetoes private development continued. According to a 1916 report from the Department of Agriculture to Congress, as of that time, 87 hydroelectric power projects had been constructed throughout the country. 7/ These were characterized as having been

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1/ Sen. Doc. No. 57, 62nd Cong., 1st Sess. (1911); City of Bountiful, Utah et al, Docket No. EL78-43, FERC Opinion No. 88, at 14 (June 27, 1980).

2/ 36 Cong. Rec. 3071 (March 6, 1903).

3/ 42 Cong. Rec. 4698 (April 13, 1908).

4/ 43 Cong. Rec. 978 (January 15, 1909).

5/ 36 Cong. Rec. 3071; 42 Cong. Rec. 4698; and 43 Cong. Rec. 978.

6/ Sen. Doc. No. 949, 62nd Cong., 2d Sess. (1912).

7/ Sen. Doc. No. 316, 64th Cong., 1st Sess. at 79-80 (1916).

"constructed under [F]ederal and [S]tate authority, but in a helter skelter fashion," 8/ involving undertakings which often failed to fully utilize the power possibilities or to even recognize the possibility of navigation or flood control. 9/ Often they were "worse than nothing" in that they occupied sites and precluded later development according to an intelligent plan . 10/

Congress in 1920 in order to control development of water resource projects enacted the Federal Water Power Act. 11/ This law established the Federal Power Commission. The 1920 Act, which regularized and facilitated permission for development, provided that all non-Federal projects on navigable waters and public lands must be licensed by the Commission. Section 7(a) of this Act, 12/ accorded States and municipalities a preference in the award of hydroelectric licenses, provided that the projects of these public bodies were equally as well adapted to the conservation of water resources as were those proposed by private applicants. When Congress passed the Federal Power Act in 1935 to extend FPC control to private wholesale power sales in interstate commerce, the 1920 Act was incorporated into Part I of the new law.

The non-Federal projects which Congress approved in these early years were not totally private undertakings. Congress enacted laws in 1906 and 1913 granting the cities of Los Angeles and San Francisco the right to utilize the public lands for the development of water and power for the use of their citizens.

Congress by the Act of June 20, 1906, 13/ granted to the city of Los Angeles all of the necessary rights of way over public lands in the counties of Inyo, Kern, and Los Angeles for the purpose of constructing a municipal water and power system. Pursuant to this authority the city built an aqueduct system to the Owens River to secure a water supply. This included the installation of approximately 200 megawatts of power at six plants located at sites adjacent to the Owens River and the Los Angeles Aqueduct.

8/ Fly, The Role of the Federal Government in the Conservation and Utilization of Water Resources, 86 U. of Penn. L. Rev. 274, 289 (1938).

9/ Ibid., at f.n. 8.

10/ Ibid., at f.n. 8.

11/ Act of June 10, 1920 (41 Stat. 1063; 16 U.S.C. 792), I Federal Reclamation and Related Laws Annotated 262, cited hereafter as F.Recl.R.L.A.

12/ 16 U.S.C. 800; I F.Recl.R.L.A. 270.

13/ 34 Stat. 801.

The 1913 Raker Act, 14/ while according San Francisco the right to develop the water and power of the Tuolumne River, forbade the lease or sale of these power rights to private corporations. These restrictions were subsequently upheld by the Supreme Court. 15/

II. Federal Water Programs for Marketing Power From Federal Projects

At this time power is marketed from 121 Federally owned multiple-purpose projects, having a combined nameplate of capacity of 30,680 megawatts. This is exclusive of the power marketed by the independent Tennessee Valley Authority. The Federal Government through the five Power Marketing Administrations (PMAs) within the Department of Energy operates and maintains 30,100 miles of high voltage transmission lines. In 1978 the PMAs sold 198 billion kilowatthours of energy, making the Department of Energy one of the world's largest marketers of electric energy. The PMAs market about 40% of the Nation's hydro power.

This vast undertaking had a rather modest beginning.

A. Power Developments on Early Reclamation Projects

The Reclamation Project Act of 1902, 16/ which authorized the Department of the Interior to undertake irrigation and reclamation projects on an extensive scale in the 17 western States, did not provide for the production of electric power. Nevertheless, as an incident to construction of project features, it was frequently necessary to construct small powerplants to provide power for construction purposes. It was soon recognized that many dams and canal drops located at Federal Reclamation projects presented opportunities for the installation of hydroelectric powerplants.

The 1902 Reclamation Act was supplemented by Section 5 of the Act of April 16, 1906. 17/ The 1906 Act authorized the Secretary of the Interior to develop this power potential on Reclamation projects through installation of power facilities or through the lease of the power privileges to others who would install the facilities. The 1906 Act also established two basic policies which have persisted to this day: (1) net power revenues derived from such leases are credited against the cost of the project, thus reducing the repayment obligation which users of water provided from the Reclamation projects must repay to the Government, and (2) that preference in the sale or lease of power was to be given to municipal purposes (later broadened to include all public agencies and cooperatives).

14/ 38 Stat. 242, 245.

15/ United States v. City and County of San Francisco, 310 U.S. 16 (1940).

16/ Act of June 17, 1902 (32 Stat. 388; 43 U.S.C. 391), I F.Recl.R.L.A. 31.

17/ 34 Stat. 117; 43 U.S.C. 522; I F.Recl.R.L.A. 111.

The first Federally generated power sold was from the Roosevelt Dam built in 1909, as a feature of the Salt River Federal Reclamation Project. 18/

By 1932 there were 20 hydroelectric powerplants on 11 of the 29 Federal reclamation projects. These projects had a total installed capacity of 102,500 kilowatts and they generated 331,739,500 kilowatthours of energy. Of this amount, approximately two thirds was used for commercial or industrial uses. 19/

B. Wilson Dam

Congress, by enactment of the National Defense Act of 1916, authorized Federal construction of the Wilson Dam on the Tennessee River at the Muscle Shoals site in order to provide a source of power for nitrate plants. The project was completed in 1925. 20/ Wilson Dam power not needed for operation of the nitrate works was sold exclusively to the Alabama Power Company and affiliated companies which owned the only transmission lines extending to the Wilson Dam. 21/

C. Hoover Dam

In 1928 Congress authorized the construction of Boulder Dam (later redesignated as Hoover Dam). This 1,249,800 kilowatt facility was by far the largest Federally constructed water resource project authorized up to that time. It was the first multipurpose large scale undertaking. The 1928 Act directed that the Boulder Dam be used for controlling floods, improving navigation, regulating the flow of the Colorado River, reclamation of public lands, as well as for the generation of electrical energy as a means of making the project self supporting and a financially solvent undertaking. 22/

18/ Report on Water Resources and Power, Prepared for the Commission on Organization of the Executive Branch of the Government by the Task Force on Water Resources and Power, dated June, 1955, p. 279 (hereinafter referred to as 1955 Hoover Commission Report).

19/ 1955 Hoover Commission Report, 1148, citing Report of the Commissioner of Reclamation for Fiscal year 1932.

20/ Act of June 3, 1916 (39 Stat. 166, 215); and Swidler & Marquis, TVA in Court; Study of TVA's Constitutional Litigation, 32 Iowa Law Review 296, 298 (1947).

21/ Ibid., at f.n. 20.

22/ Act of December 21, 1928 (45 Stat. 1057; 43 U.S.C. 617 et seq.), I F.Recl.R.L.A. 414.

D. New Deal Expansion of Federal Water Resources

The Federal water resources program, including development of hydroelectric power, was rapidly expanded during the New Deal days of the 1930s with the enactment of the Tennessee Valley Authority Act of 1933, 23/ the authorization for the construction of the Grand Coulee Dam on the Columbia River and the Parker Dam on the Colorado River in 1935, 24/ the Bonneville Project Act of 1937, 25/ the 1937 authorization of the Central Valley Project, including the Shasta Dam on the Sacramento River in California, 26/ and the Reclamation Project Act of 1939. 27/

E. Colorado River Storage Project and Central Arizona Project

In 1956 Congress authorized additional Federal power on the Colorado River with the enactment of the Colorado Storage Project Act. 28/ In 1968 Congress permitted Federal participation by the Bureau of Reclamation along with non-Federal power suppliers in the construction and operation of a thermal generating powerplant located near Page, Arizona, in order to assure the Government pumping power required for the Federal Central Arizona Reclamation Project. 29/

F. Projects of the Corps of Engineers

By the 1935 Flood Control Act and subsequent Flood Control and River and Harbor Acts, the Congress authorized numerous river-development projects to be constructed by the Corps of Engineers for flood control, navigation and other purposes including power.

The Corps is the Nation's largest single producer of hydroelectricity. It operates 67 projects housing 317 turbine-generator units with a total installed electrical capacity of 18,300 megawatts as of April 1979. About two-thirds of this capacity is in the Pacific Northwest, where waterpower is abundant. 30/

23/ 48 Stat. 58, as amended, 16 U.S.C. 831 et seq.

24/ Act of August 30, 1935 (49 Stat. 1039; 33 U.S.C. 540), I F.Recl.R.L.A. 538.

25/ Act of August 20, 1937 (50 Stat. 731; 16 U.S.C. 832), I F.Recl.R.L.A. 568.

26/ Act of August 26, 1937 (50 Stat. 844), I F.Recl.R.L.A. 583.

27/ Act of August 4, 1939 (53 Stat. 1187; 43 U.S.C. 485), I F.Recl.R.L.A. 634.

28/ Act of April 11, 1956 (70 Stat. 105; 43 U.S.C. 620), II F.Recl.R.L.A. 1248.

29/ Section 303(b) of the Act of September 30, 1968 (82 Stat. 889; 43 U.S.C. 1524(b)).

30/ Hydropower, the Role of the U.S. Army Corps of Engineers, at 2 (1979).

Over 40 years ago the Corps started a comprehensive hydroelectric program in the Pacific Northwest with the design and construction of a 518,000 kw plant at the Bonneville Lock and Dam project on the Columbia River in Oregon. Congress pursuant to the 1935 River and Harbor Act 31/ authorized the Bonneville Dam on the Columbia River Oregon. This facility, which went into service in 1938, was the first of twenty-three Pacific Northwest hydro projects, constructed by the Corps of Engineers pursuant to various River and Harbor Acts enacted between 1945 and 1962. These Acts are the River and Harbor Acts of 1945, 32/ 1946, 33/ 1950, 34/ and 1962. 35/

31/ Act of August 30, 1935 (49 Stat. 1028, 1038); 1955 Hoover Commission Report, at 451.

32/ Act of March 2, 1945 (59 Stat. 10, 22), authorizing the construction of Ice Harbor, Little Goose, Lower Granite, Lower Monumental, and McNary Dams, in accordance with H. Doc. No. 704, 75th Cong., 2d Sess. (1938). The Ice Harbor Dam has an installed capacity of 603 MW; Little Goose 810 MW; Lower Granite 810 MW; Lower Monumental 810 MW; and McNary 980 MW. See 1979 Annual Report of the Bonneville Power Administration, Table 3 at 37. See also U.S. Army Corps of Engineers Annual Report on Civil Works Activities for F.Y. 1979, Vol. II Report of the Walla Walla, Washington District, Table 39-B, cited as 1979 Army Civil Works Annual Report.

33/ Act of July 24, 1946 (60 Stat. 634, 637), authorizing the construction of a dam at Foster Creek, in accordance with H. Doc. No. 693, 79th Cong., 2d Sess. (1946). This facility was renamed Chief Joseph Dam by the Act of June 30, 1948 (62 Stat. 1171, 1174). The Chief Joseph Dam has an installed capacity of 2069 MW. See 1979 Army Civil Works Annual Report, Seattle, Washington District, Table 38-B. See also 1979 Annual Report of the Bonneville Power Administration, Table 3 at 37.

34/ Act of May 17, 1950 (64 Stat. 163, 179), authorizing the construction of Libby, John Day, and The Dalles Dams in accordance with H. Doc. No. 531, 81st Cong., 2d Sess. (1950). Libby Dam has an installed capacity of 420 MW; The Dalles 1807 MW; and John Day 2160 MW. See 1979 Army Civil Works Annual Report, Seattle, Washington District, Table 38-B, and Portland, Oregon District, Table 37-B. See also 1979 Annual Report of the Bonneville Power Administration, Table 3 at 37.

35/ Act of October 23, 1962 (76 Stat. 1173, 1193), authorizing the Bruces Eddy Dam in accordance with H. Doc. No. 403, 87th Cong., 2d Sess. (1962). This facility was renamed Dworshak Dam by the Act of August 15, 1963 (77 Stat. 173). It has an installed capacity of 400 MW. See 1979 Annual Report of the Bonneville Power Administration, Table 3 at 37. See also 1979 Army Civil Works Annual Report, Walla Walla, Washington District, Table 39-B.

In all, the Department of the Army has constructed approximately 11,888 megawatts of hydroelectric power in the Pacific Northwest. These projects include ten powerplants having a nameplate, capacity of 400 megawatts or more. The three largest of the Pacific Northwest hydro projects of the Corps of Engineers are John Day, with 2160 MW nameplate, Chief Joseph, with 2069 MW, and The Dalles, with 1807 MW.

Another sizable complex of Army power dams, whose aggregate nameplate capacity is approximately 2098 megawatts, is located on the main stem of the Missouri River. These include Ft. Peck, Montana, authorized in 1938, 36/ and five downstream dams: Garrison in North Dakota; and four in South Dakota, Big Bend, Fort Randall, Gavins Point, and Oahe. The North Dakota and South Dakota dams were authorized by Section 9(a) of the Flood Control Act of 1944. 37/

In addition to these plants on the Missouri River the Corps has constructed numerous smaller projects within the southeast and southwestern portion of the United States, pursuant to the authority of Flood Control and River and Harbor laws enacted between 1938 to 1962. 38/

It also has an additional 21 dams with an aggregate nameplate capacity of approximately 1916 megawatts in the States of Arkansas, Missouri, Oklahoma, and Texas. 39/ It has two

36/ Act of May 18, 1938 (52 Stat. 604), I F.Recl.R.L.A. 604.

37/ Act of December 22, 1944 (58 Stat. 887, 891), II F.Recl. R.L.A. 806. All six of the Army's Missouri River Dams are shown at page 6, Table 1 of the 1979 Annual Report of the Western Area Power Administration.

38/ See Hydropower, The Role of the United States Army Corps of Engineers at 22-24 (1979) and 1979 Army Civil Works Annual Report, Forth Worth, Texas District, Table 16-B; Little Rock, Arkansas District, Table 18-B; Kansas City, Missouri District, at 20-12; St Louis, Missouri District, Table 14-B; Tulsa, Oklahoma District, 19-20 - 19-24; Mobile, Alabama District, Table 10-B; Nashville, Tennessee District, Table 23-B; and Savannah, Georgia District, Table 8-B; Wilmington, North Carolina District, 6-15 - 6-16.

39/ These include: nine in Arkansas having a combined nameplate capacity of approximately 1011 MW (Beaver Lake, Blakely Mountain, Bull Shoals, Dardanelle, DeGray, Greers Ferry, Narrows, Norfork, and Ozark); seven in Oklahoma having a combined nameplate capacity of approximately 509 MW (Broken Bow, Eufula, Ft. Gibson, Robert S. Kerr, Keystone, Tenkiller Ferry, and Webbers Falls); two in Missouri having a combined capacity of 242 MW (Stockton and Table Rock); two in Texas having a combined capacity of 82 MW (Sam Rayburn on the Angelina River and at Whitney on the Brazos River) and the 70 MW Denison Dam on the Red River, forming the boundary between Oklahoma and Texas. See 1978 Annual Report of the Southwestern Power Administration at 28, and 1979 Army Civil Works Annual Report of the Forth Worth, Little Rock, Kansas City, St. Louis, and Tulsa Districts.

projects under construction in Missouri, the Clarence Cannon and Harry S. Truman Projects, which will add an additional 218 megawatts to its projects located within these States. 40/

The Corps has 21 dams having an aggregate nameplate capacity of approximately 2712 megawatts located in Alabama, Georgia, Florida, Kentucky, North Carolina, South Carolina, Tennessee, and Virginia. 41/

No Army power dams have been constructed in the Northeast. Congress in 1965 authorized a power dam in Maine. The Dickey Lincoln School Project on the Upper St. John River, a multipurpose project for flood control, recreation, and power, was authorized by the Flood Control act of 1965. 42/ This legislation permits the installation of 760 megawatts at the project. Basic provisions would be included in the initial project to accommodate the installation of an additional 380 megawatts. The project at this time is in the advance engineering and design stage.

III. Power Marketing Arrangements Within DOE

While the Corps builds and operates its dams, it doesn't sell the power. Under Federal law, power generated at Corps projects is marketed by the Department of Energy to public bodies, power cooperatives, and private utilities. Similarly, power generated at projects constructed by the Water and Power Resources Service, the former Bureau of Reclamation, and the International Boundary and Water Commission, is marketed by the Department of Energy to such customers.

40/ 1978 Annual Report of the Southwestern Power Administration at 29.

41/ These projects include: nine in the Cumberland River Basin in Tennessee and Kentucky, having a combined nameplate capacity of 914 MW; four in the Alabama River Basin in Alabama and Georgia, having a combined nameplate capacity of 717 MW; two in the Savannah River Basin, having a combined nameplate capacity of 544 MW; four in the Apalachicola River Basin in Georgia, Alabama, and Florida, having a combined nameplate capacity of 320 MW; and two in the Roanoke River Basin in Virginia and North Carolina, having a combined nameplate capacity of 218 MW. See Southeastern Power Administration 1975-1979 Progress Report, at 8.

42/ 1979 Army Civil Works Annual Report, for New England Division at 1-26, 1-27, and 1-44.

The Secretary of the Interior was given the responsibility for disposing of all power generated at Army projects throughout the country. This is reflected in the Bonneville Project Act of 1937, 43/ the Fort Peck Project Act of 1938, 44/ and Section 5 of the Flood Control Act of 1944. 45/ This function passed to the Secretary of Energy upon the creation of the Department of Energy. The responsibility for the marketing of this power has been assigned to: the Bonneville Power Administration, in the case of Corps projects located within the Pacific Northwest; the Western Area Power Administration with respect to Army projects located in the Missouri River Basin, and California; the Southwestern Power Administration, with respect to Army dams located in the States of Oklahoma, Texas, Missouri, and Arkansas; and the Southeastern Power Administration with respect to Corps dams located in the States of Alabama, Georgia, Florida, North Carolina, Kentucky, South Carolina, Tennessee, and Virginia.

The Secretary of Energy acts by and through the Administrators of five power marketing administrations (PMAs): the Alaska Power Administration (APA or Alaska) with headquarters in Juneau, Alaska, established by the Secretary of the Interior in 1967; the Bonneville Power Administration (BPA or Bonneville), headquartered in Portland, Oregon, established by the Bonneville Project Act of 1937; 46/ the Southeastern Power Administration (SEPA or Southeastern), headquartered in Elberton, Georgia, established by the Secretary of the Interior in 1950; the Southwestern Power Administration (SWPA or Southwestern) with headquarters in Tulsa, Oklahoma, established by the Secretary of the Interior in 1943; and the Western Area Power Administration (WAPA or Western), with headquarters in Golden, Colorado, established by the Secretary of Energy pursuant to Section 302(a)(3) of the Department of Energy Organization Act. 47/ WAPA markets the power from all of the Reclamation projects, a function formerly carried out by the Bureau of Reclamation of the Department of the Interior, now known as the Water and Power Resources Service. The Service continues to construct and operate the hydroelectric power facilities.

43/ Act of August 20, 1937 (50 Stat. 731; 16 U.S.C. 832); I F.Recl.R.L.A. 568.

44/ Act of May 18, 1938 (52 Stat. 403; 16 U.S.C. 833); I F.Recl.R.L.A. 604.

45/ Act of December 22, 1944 (58 Stat. 887, 890; 16 U.S.C. 825s); II F.Recl.R.L.A. 800.

46/ 50 Stat. 731; 16 U.S.C. 832a; I F.Recl.R.L.A. 568.

47/ Act of August 4, 1977 (91 Stat. 567; 578; 42 U.S.C. 7152(a)(3)).

The five power marketing administrations of the Department of Energy taken together constitute one of the largest electric utility systems in the United States. They operate in 33 States; they market power from Federal hydroelectric power projects having an installed capacity of more than 30,000 megawatts; their Fiscal Year 1981 sales are expected to amount to more than 216,000 gigawatthours and yield revenues of more than $1 billion. 48/

A. Comparison of DOE Power Projects with TVA Power Program

A comparison with the independent TVA is in order. TVA has somewhat less capacity than the power marketing administration, having approximately 27,018 megawatts of its own generation, 49/ as opposed to the approximately 30,680 megawatts of the PMAs. 50/ The TVA system is essentially thermal. Approximately 84% of the TVA capacity is fuel fired. 51/ The PMAs are almost totally hydro. 52/

48/ See Testimony of Assistant Secretary Davis, "Energy and Water Development Appropriations for 1981--Hearings Before a Subcommittee of the Committee on Appropriations, House of Representatives," 96th Cong., 2d Sess., Subcommittee on Energy and Water Development, Part 7, at 2562, 2576 (1980).

49/ Compare Tennessee Valley Annual Report 1978 Volume II Appendixes Schedule C., page 29, with the Fiscal Year 1981 Appropriation Hearings cited in f.n. 48, at page 2562. The total installed capacity which TVA claims is somewhat higher being 28,308,710 kw, inclusive however of the twelve hydro plants of the Aluminum Company of America, whose operations are carried out at TVA's direction, and eight Army Dams in the Cumberland River Basin located within the TVA Service Area, power from which is marketed by the Southeastern Power Administration.

50/ See 1979 Annual Report of the Bonneville Power Administration, Table 3, p. 37; 1979 Annual Report of the Western Area Power Administration, Table 1, p. 7; 1975-1979 Progress Report of the Southeastern Power Administration, p. 8; and 1978 Annual Report of the Southwestern Power administration, page 28; and 1977-1978 Report of the Alaska Power Administration, pages 4 and 6.

51/ As shown on pages 29, 34 and 36 of the TVA Annual Report cited in f.n. 49, TVA had a total fuel fired capacity of 23,762 MW in 1978. Its total capacity, including its modest hydroelectric capacity, was 27,018 MW. The ratio of fuel fired capacity to total capacity is 84%.

52/ See Hearings cited at f.n., 48, at page 2562 and Reports cited at f.n. 50.

In Fiscal Year 1978 TVA realized $2.3 billion on sales of 117,946 gigawatthours of energy. 53/ The PMAs realized a little less than $702 million on sales of 198,058 gigawatthours of energy. 54/ During this comparison year the power marketing administrations sold roughly 80,000 gigawatthours more energy than did TVA, but derived less than a third as much revenue as TVA realized from its sales of energy. The fact that the PMAs sold more but earned only a fraction of the amount that the largely thermal TVA earned during this time, is a reflection, first, of the relative abundance of hydroelectric power, and, second that this type of power is not subject to ever increasing fuel costs.

B. Bonneville Power Administration

The Bonneville Power Administration, which was created by the Bonneville Project Act of 1937, disposes of the electric energy generated at Federal multipurpose projects comprising the Columbia River Federal Power System. The latter is composed of thirty one such Federal projects, of which ten, including the 5463 megawatt Grand Coulee Dam, were constructed by the Bureau of Reclamation. The balance was constructed by the Army's Corps of Engineers. The total installed capacity of this power system is approximately 17,927 megawatts, exclusive of the 1954 additional megawatts under construction. 55/

The Bonneville Power Administration is by far the largest of the Federal power marketing agencies, based upon the factor of installed capacity. 56/

BPA has long been the major power supplier in the Pacific Northwest. As early as 1953, 55% of all electric power produced in Washington, Oregon, Idaho, and Montana was Federally produced power. 57/ While there has been a considerable increase in the total Federal capacity in the intervening years, the Federal Government remains the dominant power supplier in this region.

53/ See TVA Annual Report, cited at f.n. 49, Exhibit II, page 7.

54/ See Hearings cited at f.n. 48 at page 2576.

55/ 1979 Annual Report of the Bonneville Power Administration, Table 3, p. 37.

56/ BPA has more than twice as much capacity as the Western Area Power Administration (WAPA), the next largest. WAPA has 8050 megawatts, as compared to BPA's 17,927 megawatts. The much smaller Southwestern Power Administration (SWPA) has 1916 megawatts, and the slightly larger Southeastern Power Administration (SEPA) has 2712 megawatts of installed capacity. See Reports cited at f.n. 50.

57/ 1955 Hoover Commission Report, at 453.

In Fiscal Year 1979 it had revenues of approximately $296.5 million based upon service to 161 customers, including 36 municipalities, 26 public utility districts, 6 Federal agencies, 17 industrial customers, and private utilities, as well as 14 customers located outside the Pacific Northwest. 58/

By agreement within the Pacific Northwest region, Bonneville has been given the responsibility to build the regional high voltage transmission grid. This function was legislatively recognized in the Federal Columbia River Transmission System Act of 1974. 59/ This statute gives BPA the authority to spend its revenues without further appropriation 60/ and to use proceeds from the sale of revenue bonds, which the Act authorizes it to issue, to finance further construction of the Federal transmission system in the Pacific Northwest. 61/

C. Western Area Power Administration

The Western Area Power Administration, which was created pursuant to the authority of the DOE Organization Act of 1977, succeeded to the power marketing function of the Bureau of Reclamation. It is the marketing agent for power generated by the Water and Power Resources Service, the Corps of Engineers, and the International Boundary and Water Commission. The power it markets includes that produced at various Reclamation projects located throughout the west and at large Army dams located on the Missouri River. In Fiscal Year 1979 it had an installed capacity of approximately 8050 megawatts, and 15,766 miles of transmission lines. It served 464 customers over a fifteen State area. The area it serves is generally west of the Mississippi River to the coast of California, north to the Canadian border, and south to the Mexican border. It does not however serve customers within the Pacific Northwest States of Oregon, Washington, Idaho and western Montana, which area is served by the Bonneville Power Administration. In 1979 WAPA derived a revenue of $306.3 million. WAPA's customers included 206 municipalities, 41 cooperatives, 81 State and Federal agencies, 34 irrigation districts, and 20 private utilities in addition to the Water and Power Service at various points. 62/

58/ 1979 Annual Report of the Bonneville Power Administration at 44 (Statement of Revenues and Expenses) and Table 4 at pages 38-39.

59/ Act of October 18, 1974 (88 Stat. 1376; 16 U.S.C. 838).

60/ 16 U.S.C. 838i(b).

61/ 16 U.S.C. 838k(a).

62/ 1979 Annual Report of the Western Area Power Administration, Table 1, at 7, Table 8, at 17, and Tables 10 and 11, at 21.

D. Southeastern Power Administration

The Southeastern Power Administration (SEPA) was created by the Secretary of the Interior in 1950 to carry out his responsibilities under Section 5 of the Flood Control Act of 1944 with respect to disposal of power in the ten southeastern States of Virginia, West Virginia, Tennessee, Kentucky, North Carolina, South Carolina, Georgia, Florida, Alabama, and Mississippi. 63/

Unlike the other power marketing administrations it has no transmission lines. It is totally dependent upon private utilities to deliver power which it markets. 64/ In 1979, it had an installed capacity of approximately 2712 megawatts. It served 199 customers, including 108 cooperatives, 80 municipalities, the Tennessee Valley Authority, the Crisp County Power Commission, the South Carolina Public Service Commission, and 8 private utilities. In 1979 it had a total revenue of approximately $58.7 million from its sales. 65/ Arrangements are in effect whereby it may bank energy for use when it has deficiency in the energy available to it at its plants. 66/

E. Southwestern Power Administration

The Southwestern Power Administration (SWPA) was created in 1943 by the Secretary of the Interior to carry out the responsibility under a Presidential Executive Order to market power from the Norfork Dam on the White River in Arkansas and at the Denison Dam on the Red River between Oklahoma and Texas. Its authority was enlarged by the Secretary of the Interior to carry out the Secretary's power marketing responsibility under Section 5 of the Flood Control Act of 1944. It is authorized to market power over a six State area comprising Arkansas, Oklahoma, Missouri, Kansas, Louisiana, and Texas. 67/ In Fiscal Year 1978 it had an installed capacity of approximately 1916 megawatts, and 218 megawatts under construction. It had a 1636 miles of high voltage transmission lines. It served 62 customers, including 37 municipalities, 14 cooperatives, 5 Federal agencies, 5 private utilities, and 1 industrial load from which it derived a revenue of approximately $50.1 million. 68/

63/ 1955 Hoover Commission Report, at 541 and 1975-1979 Progress Report of the Southeastern Power Administration, at p. 2.

64/ 1955 Hoover Commission Report at 546.

65/ 1975-1979 Progress Report of the Southeastern Power Administration, at 8 and 14.

66/ Ibid., at f.n. 65, at 10 and 12.

67/ 1955 Hoover Commission Report, at 525; and 1978 Annual Report of the Southwestern Power Administration, at 2.

68/ 1978 Annual Report of the Southwestern Power Administration, at 28-29, 24-27, 6, and, Exhibit 1 at 15.

F. Alaska Power Administration

The Alaska Power Administration, the smallest of the PMAs, operates the Eklutna and the Snettisham Projects whose combined capacity is 77 megawatts. In Fiscal Year 1978 it derived $3,157,862 from the sale of power from these projects. 69/

IV. Preference Clause and 1955 Attorney General's Opinion

The preference clause has been an essential part of the Federal power marketing law from the beginning. Section 5 of the Act of April 16, 1906 authorized the Secretary of the Interior to develop power at any Reclamation project or to lease the power privilege "giving preference to municipal purposes." 70/

The preference clause was broadened by a series of enactments between 1933 and 1944, which even though varying somewhat in their wording, declare generally that public bodies and non-profit cooperatives are entitled to preference in the sale of Federally generated power. These acts are: the 1933 law creating the Tennessee Valley Authority 71/ (according preference to States, counties, municipalities and cooperative organizations supplying electricity to their own members and not organized or doing business for profit); Section 4(a) of the Bonneville Project Act of 1937 72/ (according preference to public bodies and cooperatives in sale of power generated at Bonneville Dam); Section 9(c) of the Reclamation Project Act of 1939 73/ (according preference in sale of power generated on Reclamation projects to municipalities and other public corporations and agencies, and also to cooperatives and other non-profit organizations financed in whole or in part by loans made pursuant to the Rural Electrification Act of 1936) and; Section 5 of the Flood Control Act of 1944 74/ (according preference to public bodies and cooperatives in sale of power generated at Flood Control dams).

69/ 1977-1978 Annual Report of the Alaska Power Administration, at 4, 6, and 11.

70/ 34 Stat. 117; 43 U.S.C. 522; I F.Recl.R.L.A. 111.

71/ Act of May 18, 1933 (48 Stat. 58, 64; 16 U.S.C. 831i).

72/ Act of August 20, 1937 (50 Stat. 733; 16 U.S.C. 832c(a)), I F.Recl.R.L.A. 571.

73/ Act of August 4, 1939 (53 Stat. 1194; 43 U.S.C. 485h(c)), I F.Recl.R.L.A. 647.

74/ Act of December 22, 1944 (58 Stat. 890; 16 U.S.C. 825s), II F.Recl.R.L.A. 800.

Congress intended by the enactment of these laws to prevent monopolization of public power resources, to promote the widespread distribution of the benefits of these resources among the public, and to prevent anyone from making a profit on the sale of the power made possible by the Federal investment. The history of the preference clause in the Interior power marketing statutes and in related statutes, such as the Federal Water Power Act of 1920 and the TVA Act of 1933, is reviewed in the article by John B. O'Brien, Jr., in the Volume 3 of the 1955 Hoover Commission Report. 75/ This history was likewise reviewed in the July, 1955 decision of Attorney General Brownell. 76/

The 1933 TVA Act and the 1937 Bonneville Act, in addition to identifying customers entitled to preference, enumerate procedural requirements, protective to their interests, which must be observed in the sale of Federal power. For example, Section 5 of the Bonneville Project Act 77/ requires that contracts of the Bonneville Power Administration made for the sale of power to a non-preference purchaser, engaged in the sale of power to the general public, must specify cancellation of a contract upon five years' notice if the power is likely to be needed to satisfy the requirements of public bodies or cooperatives.

Section 4(d) of the 1937 Bonneville Act 78/ requires "reasonable" opportunity and time be granted for those within "economic transmission distance of the Bonneville Project" to create public bodies and cooperatives to purchase preference power. Section 4(c) of that Act 79/ specifies that preference customers must be given reasonable time to take steps for financing of facilities to enable them to enter the power business.

In contrast thereto, the 1939 Reclamation Project Act, applicable to power from Reclamation projects, and the 1944 Flood Control Act, applicable to Army dams, do no more than enumerate the classes entitled to a preference in the purchase of this power. This does not mean that preference customers from these projects have lesser rights than customers served by BPA.

75/ 1955 Hoover Commission Report, at 1107.

76/ 41 Op. A.G. 236 (1955), a copy of which is attached.

77/ Act of August 20, 1937 (50 Stat. 734; 16 U.S.C. 832d(a)), I F.Recl.R.L.A. 572-73.

78/ 50 Stat. 733; 16 U.S.C. 832c(d), I F.Recl.R.L.A. 572.

79/ 50 Stat. 733; 16 U.S.C. 832c(c), I F.Recl.R.L.A. 571.

In 1955 Attorney General Brownell ruled that the statutes under which the Interior Department markets power from Federal dams are in pari materia, that is, that they generally are taken from the same body of law and are to be construed together. Thus, laws which Congress enacted in connection with the Bonneville Project must be considered in construing the less specific Section 5 of the Flood Control Act of 1944 and other power marketing statutes.

The Attorney General considered the proposed disposition of Federal power from the Corps of Engineers' Clark Hill Dam on the Savannah River to an investor owned utility under circumstances which were intended to be beneficial to preference customers. The Attorney General rejected the proposed sale by ruling that the Secretary of the Interior does not "discharge his statutory duty of giving a preference in 'the sale' of power to public bodies and cooperatives by disposition to a private company under an arrangement whereby the latter obligates itself to sell an equivalent amount of power to preference customers to be designated by the Secretary." The Attorney General held that if a preference customer is not able to take delivery of the power at the time it is available for sale, the Secretary of the Interior is free to contract with a non-preference customer, but such contract would have to contain an "adequate provision enabling the Secretary to deal with the preference claimant should it subsequently obtain the means to take and deliver the power." 80/

Court decisions applying the preference clause include City of Santa Clara v. Andrus, 81/ which held that the sale of Federal power to private utilities for later return ("banking") is illegal when preference customers are foreclosed from receiving that power, and Arizona Power Pooling Association v. Morton, 82/ which held that the preference clause applies to thermally generated power as well as hydroelectric power. In Arizona Power Pooling the electricity involved was thermal power from a project in which the Bureau of Reclamation had a part interest.

V. Cost Recovery, Cost Allocation and Rate Setting

The Federal power marketing program is entirely reimbursable. Nevertheless, the goal is to provide power to consumers at the lowest possible rates. Rates for electric power are set to recover all costs of producing that power. Capital investment allocated to power is repaid with interest over a period which may not exceed fifty years. The cost recovery directives of

80/ 41 Op. A.G. 236, 244 (1955).

81/ 572 F.2d 660, 669-72 (9th Cir. 1978), cert. denied, 439 U.S. 859 (1978).

82/ 527 F.2d 721 (9th Cir. 1975), cert. denied, 425 U.S. 911 (1976).

the power marketing statutes with general application are found in Section 5 of the Flood Control Act of 1944 and Section 9(c) of the Reclamation Project Act of 1939. Under the 1944 Flood Control Act rate schedules must recover the cost producing and transmitting electric energy including amortization of capital investment allocated to power over a reasonable period of years. This has been determined to be fifty years.

Section 9(c) of the Reclamation Project Act of 1939 requires power rates for Reclamation power which cover the "annual operation and maintenance cost," a minimum 3% annual interest on an "appropriate share of construction investment" and such other fixed charges as the Secretary deems proper. The appropriate share of construction investment, as used in the 1939 Act, refers to the portion of Reclamation project investment allocated to power. The words "such other fixed charges" as used in Section 9(c) of the 1939 Act reflects return of capital investment allocated to power. This is not a predetermined annual sum but will vary year by year with changes in availability of water and market conditions. 83/ The interpretation that has been given these laws requires the repayment of investment allocated to power with interest within fifty years and to recovery of annual operating costs on a pay as you go basis.

The process of allocation of costs in multipurpose water projects should be briefly noted. These are projects which serve two or more purposes such as: navigation, flood control, irrigation, power, municipal and industrial water supply, recreation, and fish and wildlife. Cost allocation becomes important since Congress has made some of these functions non-reimbursable, as in the case of navigation and flood control. 84/

An agreement was reached on March 12, 1954 between the Department of the Army, the Department of the Interior, and the former Federal Power Commission. 85/ Under this agreement, the separable costs-remaining benefits method was considered in the preferable method for general application. Except where explicit statutory provision is made to the contrary the ultimate responsibility for cost allocations rests with the construction agency. 86/

83/ See Memorandum of February 15, 1974 from the Assistant Solicitor, Power of the Department of the Interior to the Assistant Secretary of the Interior-Land and Water Resources, M-36874, attached hereto.

84/ See Memorandum of December 12, 1978 from Richard K. Pelz, Office of General Counsel, DOE (Power Marketing) to Robert M. Hallman, Associate General Counsel for Programs, attached hereto.

85/ 1955 Hoover Commission Report, at 286.

86/ See Memorandum cited at f.n. 84.

Under existing law, rates for power are set not only to recover investment allocated to power but also investment in irrigation works beyond water user ability to repay. Congress was concerned in 1977, when the DOE Organization bill was before it, that power users might be required to assume disproportionate costs, if reallocations of costs were to occur. To prevent this, Congress accepted the McGovern Amendment to the DOE Organization Act. 87/ Under this amendment there may be no reallocation of joint costs of multipurpose projects heretofore allocated "unless and to the extent that such change is hereafter approved by Congress." 88/

The policy of the Department of Energy respecting the recovery of reimbursable power costs is set forth in DOE Order No. RA-6120.2, dated September 20, 1979. This replaced a similar provision of the Department of Interior (730 DM 4) without substantive change. This order specifies the total revenues of any project administered by a power marketing administration must be sufficient to meet the annual operation and maintenance costs, to repay Federal investment in generation and transmission facilities within a fifty year period, and to repay irrigation system construction costs at designated Reclamation projects which are beyond the repayment ability of the irrigators. Each increment of investment must be amortized within its prescribed period.

The adequacy of power revenues is tested, as specified in this order, by a power system repayment study. This projects existing revenue and costs for the entire power system over the remainder of repayment periods for major investments to determine if there will be enough revenue to recover all reimbursable costs. If the estimated future unamortized power investment exceeds the allowable unamortized investment, an increase in rates will be necessary to assure complete recovery of costs.

By Delegation Order 0204-33, effective January 1, 1979 (43 F.R. 60636) the Secretary of Energy delegated to the Assistant Secretary Resource Applications, the authority to develop power and transmission rates, acting by and through the various power marketing administrations. The Assistant Secretary is empowered by this delegation to confirm and approve these rates and to place them in effect on an interim basis. This order also delegates to the Federal Energy Regulatory Commission the authority to finally confirm or disapprove the rates adopted by the Assistant Secretary on an interim basis.

87/ Section 302(a) of P.L. 95-91; (9t Stat. 567, 568; 42 U.S.C. 7152(a)(3)); 123 Cong. Rec. 15,300 (May 19, 1977); Remarks of Senator McGovern); and Memorandum cited at f.n. 84.

88/ Ibid., at 87.

NATIONAL HYDROELECTRIC POWER RESOURCES STUDY

Marketing and Transmission of Hydroelectric Power

Part 3

Bonneville Power Administration Appendix

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MARKETING AND TRANSMISSION APPENDIX
FOR THE
BONNEVILLE POWER ADMINISTRATION

National Hydroelectric Power Resources Study
(Section 167, P.L. 94-587)

SECTION 1 INTRODUCTION AND SUMMARY

The Bonneville Power Administration (BPA), a separate and distinct organizational entity within the Department of Energy, is the power marketing agency responsible for the sale and disposition of the hydroelectric power generated at 30 of the largest power dams in the Columbia River Basin. The capacity of these dams, constructed and operated on the main stem of the Columbia River by the U.S. Army Corps of Engineers and the Water and Power Resources Service, was significantly enhanced by the Columbia River Treaty with Canada signed in 1961. The Bonneville service area is limited by law to include Washington, Oregon, Idaho, Montana west of the continental divide, and portions of Wyoming, Utah, Nevada, and California.

Bonneville also markets a limited amount of thermal power and has executed contracts by which it expects to acquire additional thermal generation. Overall, BPA markets approximately 50 percent of the electric energy in the Pacific Northwest. The agency has also built and maintains nearly 80 percent of the high voltage transmission system.

Federal power generation for the Pacific Northwest began in 1938 at Bonneville Dam, a project constructed and operated by the Corps of Engineers and is one of the oldest multiple-purpose water resource projects incorporating electric generating facilities. Due to the immense power potential of the Columbia River and its tributaries, the largest powerplants in the nation are located in this river basin.

The Pacific Northwest has 40 percent of the nation's hydroelectric potential, of which almost half has been developed. However, the region is deficient in other energy resources. No crude oil is produced commercially, and recent drilling for natural gas has yielded only small amounts. Petroleum products must be imported. Until recently, there was only a modest amount of coal mining in the region. Therefore, the region has developed and is heavily dependent on hydropower for generating electricity.

BPA and the Pacific Northwest face a firm electric energy insufficiency in the 1980's. While the region's utilities have reduced their forecasted future energy needs, deficits are projected to continue to increase in all years through 1990. Regional demand for electric energy in the Pacific

Northwest is expected to grow from 17,500 average megawatts in 1980-81 to about 24,600 average megawatts in 1990-91. The projected deficits are greater, despite the fact that the projected needs have been reduced from an average annual growth rate of 7.4 percent in the 1960's to a 3.5 percent growth rate in the 1980's. Deficits result from unanticipated delays in the scheduled completion of thermal plants on which the region is relying to meet its load growth. Ongoing and planned conservation efforts will help reduce but will not eliminate the deficit. Even with development of all the conservation and renewable resources that might be achievable, the region may still fall short of meeting its firm energy requirements under adverse streamflow conditions.

Until September 1973, BPA generally had sufficient power available to satisfy the requirements of all customers, including investor-owned utilities, who--unlike public bodies and cooperatives--are not accorded preference and priority to Federal power by law. For some years, BPA had known that it could not continue to meet the firm energy requirements of its customers without acquiring additional resources. Therefore, in 1973, BPA could not offer new contracts for firm power to its investor-owned utility customers. In June 1976, BPA took the additional step of notifying its existing preference customers that it will not have sufficient firm energy available after June 30, 1983, to continue to meet their load requirements and satisfy other firm energy commitments.

The recently enacted Pacific Northwest Electric Power Planning and Conservation Act (PL 96-501) significantly expands Bonneville's mission and gives the Bonneville Administrator, in cooperation with a Regional Planning Council, the authority to coordinate planning, conservation, and resource development in the Northwest. (See 4.1) The legislation gives BPA authority to acquire additional hydro and non-hydro resources to meet its contractual obligations. It could also facilitate the development of hydropower by providing funds for studies and engineering investigations to qualify projects for licensing.

Significant additional hydroelectric potential has been identified in the Pacific Northwest, although the constraints associated with developing this resource must also be recognized. The existing hydro system includes most of the more economical generation sites. Most undeveloped sites are located on the headwater tributaries. Headwater sites are most valuable when they can be developed for upstream storage, but many of these sites will provide only seasonal energy and most will not have sufficient storage potential to make efficient use of their more intermittent steamflow patterns. Such sites involve environmental considerations as well as concern by upstream residents that their lands not be flooded for the benefit of a downstream users. Many sites, if developed, may pose problems particularly related to the degradation of fish spawning areas, wildlife habitat, and wilderness.

Further hydroelectric development will be possible in the region through the installation of additional units at existing dams and the construction of new water resource projects. However, thermal generating plants will continue to provide an increasing percentage of the region's energy requirements, and

resources such as wind, biomass, and geothermal energy will also become increasingly important. At the same time, conservation programs and development of small renewable resource facilities can continue to reduce regional energy demand. No single resource can provide all the region's energy needs. Hydropower, however, promises to be as important a part of the region's energy future as it has been in the past.

2.1 Bonneville Authority and Mission

2.1.1 Authorities

The Bonneville Project Act of 1937, as amended, is the legislation which established the Bonneville Power Administration and provides for the marketing of electric energy surplus to Project needs. 16 U.S.C. 832a(a). By separate legislation the Administrator is also designated the marketing agent for all other electric power generated by Federal generating plants in the Pacific Northwest, with the exception of the Green Springs project which is operated by the Water and Power Resources Service. 16 U.S.C. 838f. A limited amount of thermal power is acquired by net-billing contracts.

The Bonneville Power Administrator is authorized to dispose of power resources by contract for terms not exceeding 20 years. The statute provides directory language that sales should benefit the "general public, and particularly . . . domestic and rural consumers" and grants preference and priority "at all times" to public bodies and cooperatives. 16 U.S.C. 832c(a).

The Bonneville Project Act speaks not only to power sales, but also to power transmission. The Administrator is ". . . directed to provide, construct, operate, maintain, and improve such electric transmission lines and substations and facilities . . . as he finds necessary . . . for the purpose of transmitting electric energy . . . from the Bonneville Project to existing and potential markets." 16 U.S.C. 832a(b). The Bonneville transmission responsibilities in the Pacific Northwest were expanded by the Federal Columbia River Transmission System Act of 1974 (Public Law 93-454). Pursuant to the Transmission Act, the Administrator is given additional responsibility, subject to appropriate congressional approval, to ". . . operate and maintain the Federal transmission system within the Pacific Northwest and . . . construct improvements, betterments, and additions . . . which he determines are appropriate to: (a) integrate and transmit . . . power from existing or additional Federal or non-Federal generating units; (b) provide service to [BPA] . . . customers; (c) provide interregional transmission; or (d) [otherwise] maintain the electrical stability and electrical reliability of the Federal system." 16 U.S.C. 838b. The Transmission System Act also established the Bonneville Power Administration Fund and placed BPA on a self-financing basis. Bonneville may make expenditures from the fund, if included in the Administrator's annual budget submitted to Congress, "without further appropriation and without fiscal year limitations . . . ." 16 U.S.C. 838i. These expenditures are for a number of purposes including construction, acquisition, and replacement of the transmission system, research and development, and short-term power purchases to meet contractual commitments.

Both the power marketing and power transmission responsibilities of the Bonneville Power Administration are subject to certain legislative requirements. Key among these are those to ". . . encourage the widest possible use of all electric energy . . . provide reasonable outlets therefore, and to prevent monopolization . . . ." 16 U.S.C. 832a(b). The Administrator is also directed by the Transmission Act to design rates which implement the policies of assuring the "widest possible diversified use of electric power at the lowest possible rates . . . consistent with sound business principles . . . ." 16 U.S.C. 838g.

Public Law 88-552, the Pacific Northwest Preference Act, is another law governing Bonneville operations. This Act provides that the Pacific Northwest shall have first priority to electric energy and peaking capacity of the Federal hydroelectric plants in the PNW. Sales of hydroelectric generation and capacity outside the PNW are directed to ". . . be limited to surplus energy and surplus peaking capacity." 16 U.S.C. 837a.

The Department of Energy Organization Act of 1977 transferred the Bonneville Power Administration from the Department of Interior to the Department of Energy. 42 U.S.C. 7152. By the terms of the Act the Bonneville Power Administration is to ". . . be preserved as [a] separate and distinct organizational entity within the Department."

On December 5, 1980, the President signed into law the Pacific Northwest Electric Power Planning and Conservation Act (PL 96-501 - the Regional Power Act). The new law fundamentally alters institutional arrangements in the Pacific Northwest for the development, financing, and marketing of electric power. The Regional Act is discussed in Section 4.

For a discussion of BPA's statutory authorities prior to enactment of the Regional Power Act, see the revised draft environmental impact statement of "The Role of the Bonneville Power Administration in the Pacific Power Supply System" published in April 1980.

2.2 The Federal Columbia River Power System

The Federal Columbia River Power System (FCRPS) is comprised of three principal elements: (1) the hydroelectric generating projects constructed and operated by the U.S. Army Corps of Engineers and the Water and Power Resources Service within the Pacific Northwest region, (2) the electric transmission system constructed and operated by the Bonneville Power Administration, and (3) power acquired by BPA through exchanges and net-billing and to be acquired under the Regional Power Act.

The present regional electric power system serves an area of approximately 300,000 square miles consisting of the States of Idaho, Oregon, Washington, that portion of Montana west of the Continental Divide, and very small portions of northern California, western Wyoming, northern Nevada, and northern Utah. (See Fig. 2-1.) Nearly 7.7 million people inhabit this region which has a moderately higher than average population growth rate.

Electric energy development in the Pacific Northwest has been predominately influenced by the availability of hydroelectric power from the Columbia River and its tributaries. For many years, nearly all of the firm electric energy in the region came from hydroelectric generation. By 1980 firm energy supplied from hydroelectric sources has been reduced to 75 percent of the region's total with the remainder being supplied by the Hanford Generation Project, the Trojan nuclear plant, the Centralia coal-fired plant, Boardman coal plant, other smaller thermal projects, and imports of energy from thermal projects located outside the region.

The total nameplate rating of all existing hydroelectric generation facilities in the Pacific Northwest as of March 1980 exceeded 26,680 MW. An additional 1,280 MW of hydroelectric resources under construction will bring the total nameplate rating to nearly 28,000 MW. Thermal resources in the region for the same period totaled approximately 6,448 MW of existing generation and 7,948 MW of additional thermal generation under construction.

BPA's transmission system consists of about 12,600 circuit miles of high-voltage transmission lines and 347 substations. The BPA transmission system constitutes America's largest high-voltage transmission network and is the "backbone" grid to which all interconnected utilities in the region are tied for reliability and efficiency. BPA also markets and exchanges electric power interregionally over the Pacific Northwest-Pacific Southwest Intertie, and with Canada over interconnections with utilities in British Columbia.

Nearly all FCRPS dams serve other Congressionally authorized purposes in addition to power generation. Some dams, such as the ones constructed in Canada under the Canadian Treaty and in Montana, exist primarily to store water for release through downstream generating plants. These reservoirs regulate streamflows and provide flood control as well. The owners of these storage impoundments are compensated for the downstream power benefits which their reservoirs create.

Corps of Engineers' projects serve flood control, navigation, recreation, and other purposes; and Water and Power Resources Service dams, in addition to the purposes above (except navigation), provide storage for irrigation. Formal agreements between BPA, the Corps of Engineers, and the WPRS assure that the FCRPS is operated to meet these different requirements.

The Pacific Northwest Coordination Agreement, adopted in 1964, formalized operational procedures which originally had been in effect through the Northwest Power Pool. The Agreement enabled the operation of non-Federal projects in coordination with FCRPS projects and clarified the rights and responsibilities of project owners in response to effects of projects constructed according to the Columbia River Treaty.

Bonneville and several private and public utilities have constructed the largest power interconnection in the United States as a joint venture. (See Figure 2-2.) The participants include Portland General Electric Company, Pacific Power and Light Company, Pacific Gas and Electric Company, Southern California Edison Company, Los Angeles Department of Water and Power, and the Water and Power Resources Service.

FIGURE 2-1

Pacific Northwest Power System
Major Facilities Existing and Under Construction

Major BPA Transmission Facilities
Major Non BPA Transmission Facilities
Federal Hydroelectric Dam
Columbia River Treaty Dams

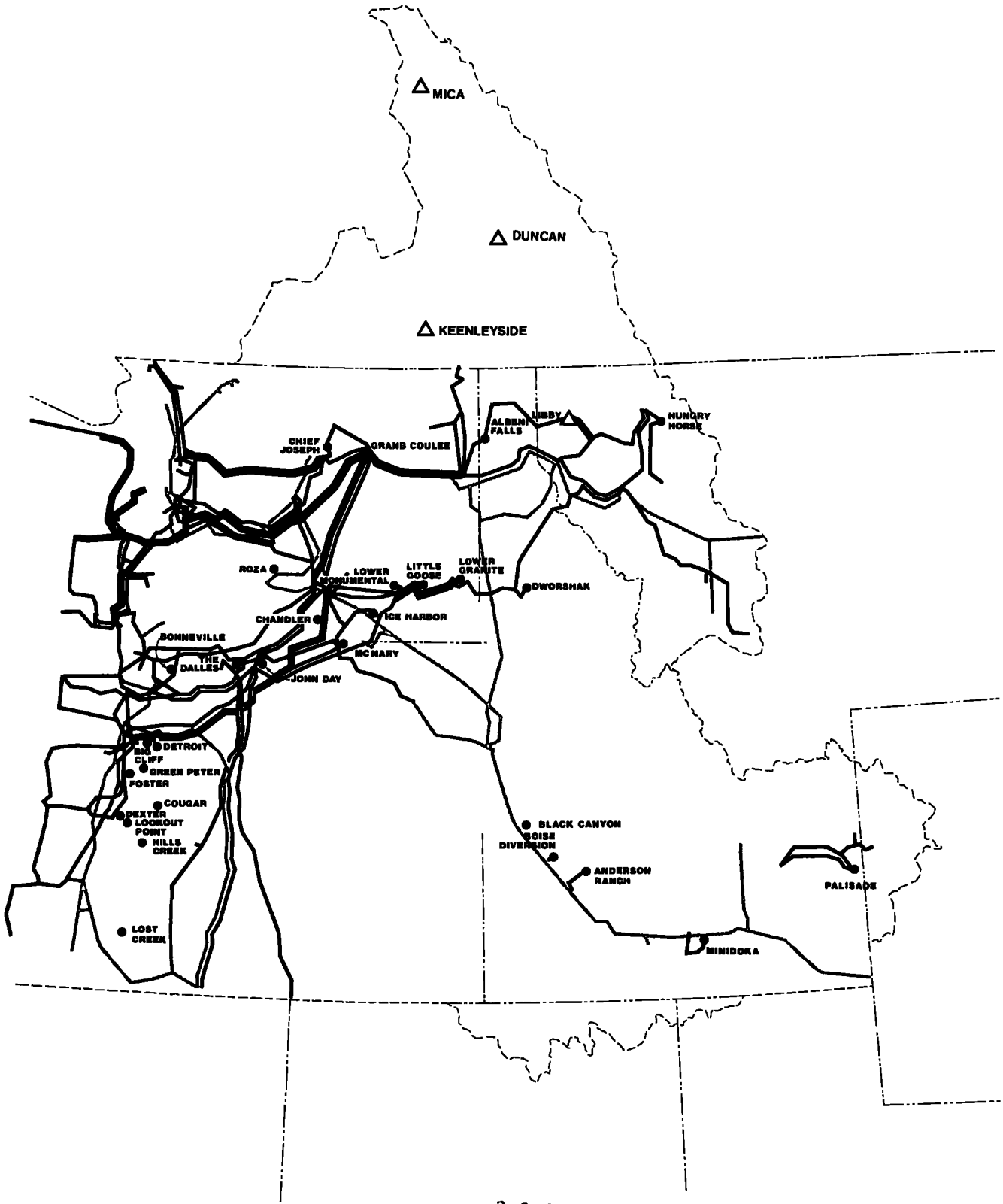
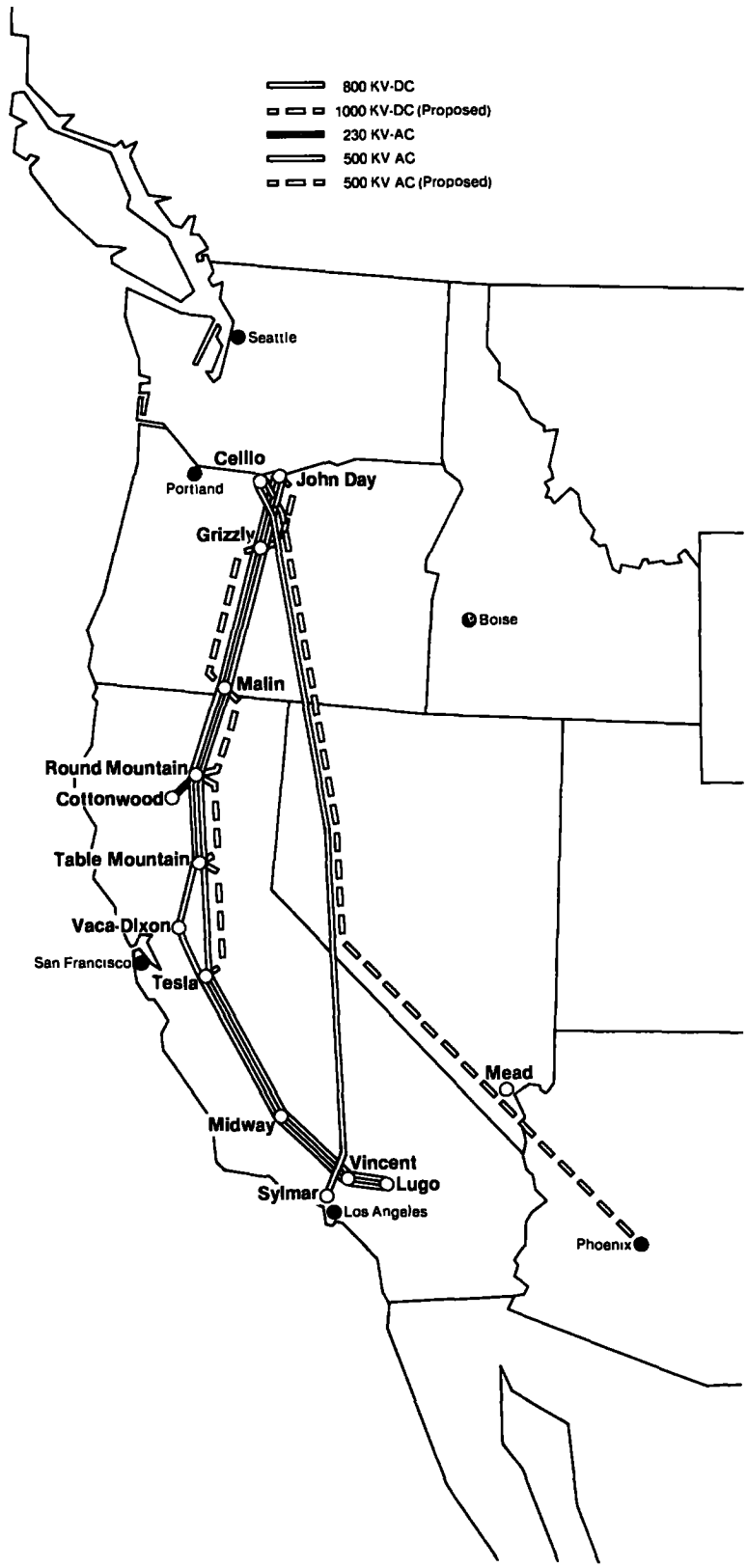


FIGURE 2-2
PACIFIC NORTHWEST-PACIFIC SOUTHWEST INTERTIE



Under the peak/energy exchange contracts now in effect, at peak load times in the Southwest, hydropower is transmitted north to south. When load levels drop in the Southwest, power is transferred south to north assisting the Northwest with meeting its obligations. In addition, these interconnections have provided markets for the sale of power which is secondary to Pacific Northwest needs.

The essential economy of the big interties between power systems is that peakloads can be met with less plant investment than if each region were to install all the generating capacity necessary to meet its own peak requirements.

2.2.1 The One-Utility Concept

To meet the region's electricity needs at the lowest practical cost and to maximize efficiency, the region's utilities and the Federal government joined together in 1958 to plan, build, and operate the region's entire electric system as though it were under a single ownership--the "one-utility" concept.

Under this concept, the operation of thermal plants is integrated with hydro operations. Bulk transmission, peaking capacity, forced outage reserves, reserves for unanticipated load growth, and, when available, surplus hydro energy for thermal fuel displacement become primarily Federal responsibilities. Building the most economical powerplants timed, sized, and located to meet regional needs (instead of only the needs of the owners), and providing essential low-voltage transmission and distribution are then the key responsibilities borne by non-Federal utilities.

The high degree of coordination among utilities in the Pacific Northwest, as fostered by a number of organizations, serves to spread the risk of load and generation uncertainties. Risks diminish because unexpectedly rapid load growth in one utility may be offset by unanticipated slow load growth in another. Similarly, the pooling of resources allows one utility's resources to act as partial reserves for other utilities. The combined effect is a reduction in the risk of over- or underbuilding the generation system, as well as a reduction in problems of meeting loads.

The pooling of load forecasts and resources on a regionwide basis (reflecting utility coordination) enables the region to be viewed as a single entity for planning and reserve purposes. This approach is made possible by the region's interconnected transmission system. If each utility must individually guard against the risks of being unable to meet its load, it will attempt to hold reserves sufficient to offset that risk. The total reserves held in this effort by <u>all</u> utilities would be greater than the reserves necessary under the one-utility concept. The amount of planning reserves required is reduced because one utility's rapid growth may be offset by reduced load on another utility. Forced outage reserves are reduced because one utility can draw on other utilities' resources to act as reserves if a forced outage occurs. In addition to the aspects of risk sharing already mentioned, regional cooperation helps to optimize the efficiency of the

system. The diversity of peaks throughout the region allows some of the peakload to be treated as a "baseload" regionwide. Therefore, fewer peaking units are required and more efficient generation by base units is allowed. Pooling of resources also permits use of larger, more economical generating facilities, allows for more efficient operation of the coordinated system, and facilitates higher load factors.

The one-utility concept has assisted BPA to develop a regional transmission system with fewer overlapping facilities, increased reliability, and, therefore, a lower overall cost.

2.2.2 The Hydro-Thermal Power Program

Until the mid-1960's, virtually all of the electricity generated in the Pacific Northwest was hydropower. Regional planners and engineers had long recognized, however, that there was a limited amount of economically feasible and environmentally acceptable hydro energy potential. As that potential was progressively developed and as the region's population, economy, and demand for electric energy continued to grow, planners and engineers concluded that thermal powerplants would have to be built to supplement dams in supplying electricity to meet growing loads.

The concept of blending hydro and thermal resources together was not new. In 1958, the Corps published a revision of the U.S. Senate Public Works Committee's "308 Report," which spelled out the concepts of joint operation of hydro projects with thermal projects. These concepts were developed into an action program by the Joint Power Planning Council in 1968 called the Hydro-Thermal Power Program (HTPP). Under this program seven powerplants were planned for construction.

While some of the details of the Hydro-Thermal Power Program are complicated, the essential features are quite simple. Basically, it was designed to fulfill two key objectives. First, it should permit development of an adequate and reliable supply of power to meet future Northwest electricity demand at the lowest practicable cost. Second, the long-range plan should achieve optimum combination of the region's generating and transmission resources--hydro and thermal, Federal and non-Federal, public and private, existing and planned. Even before the program was approved, it was also assumed that an optimal future power system, which would be able to meet electric energy demand with: (1) substantial flexibility as far as plant siting was concerned, and (2) the most efficient use of generation and transmission resources, could be structured to pay maximum effective attention to protection of the environment.

Perhaps the most significant feature of the HTPP was that BPA acquired some of the capability of some of the proposed thermal powerplants through "net-billing." Under this arrangement, preference utilities (public bodies and cooperatives) would build portions or all of certain thermal powerplants to meet their future power requirements and then furnish the capability to BPA. BPA in turn would bear the preference customers' shares of the costs of those powerplants, acquire the power output, and blend it with Federal

hydropower. BPA then would sell the blended product to its various customers, including the participating preference utilities. It would "pay" those utilities for their shares of the powerplants' costs by reducing their bills for power purchases and other services from BPA; and the participating utilities would pay the amount of the credit to the operating entity. Three goals would be accomplished: (1) financing costs for preference utilities to build powerplants would be reduced (through lower interest rates) because of commitments by BPA to acquire capability and pay costs, (2) BPA's power supply would be augmented, and (3) costs would be distributed to all consumers of BPA power.

However, this financial arrangement has experienced problems. The use of net-billing has been limited by a number of factors. First, costs for thermal plant construction increased more rapidly than BPA could adjust its wholesale power rates, which are based on blended hydro-thermal costs. If additional thermal powerplants were net-billed in addition to the four which are already covered under net-billing, the sums that BPA would be obligated to credit against preference customers' billings (reflecting thermal projects' costs) would exceed the sums they owe BPA (reflecting BPA's rates for blended hydro-thermal power). These rising costs of net-billing accounted for a large percent of the 1979 rate increase of 88 percent. Expansion of net-billing has also been affected by a 1972 Treasury ruling which disallowed the use of tax-exempt bonds for construction of powerplants from which BPA would acquire more than 25 percent of the output.

2.2.3 The Columbia River Treaty

In 1964, the Columbia River Treaty between the Canadian and United States governments inaugurated a construction program in Canada and the United States to harness the upper reaches of the Columbia and its tributaries and develop their potential to the mutual advantage of both countries.

The United States derives two major benefits from the Treaty. One is flood control--reducing the danger of serious flooding on both the Columbia and Kootenay Rivers (Kootenai in the United States). The other is the acquisition of a large block of lower cost firm power. For its part, Canada also receives flood control on the Columbia and Kootenay and an equal share of lower cost power from the Columbia River, which it has sold to Northwest utilities under the Columbia Storage Power Exchange Agreements.

In accordance with the Treaty, Canada built three dams in British Columbia which were completed between 1967 and 1973. The Treaty also allowed the United States to construct a fourth dam, Libby, in northwestern Montana, which backs water 42 miles into Canada. These dams have added about 20.5 million acre-feet of storage, more than doubling the amount of water that can be stored to regulate flows on the mainstem of the Columbia River. (See 3.4.1.) This means that some amounts of water formerly flowing unchecked to the sea can be held back to control floods and released as needed to produce power at dams in Canada and downstream in the United States.

The regulation of streamflows made possible by the three Canadian reservoirs enables the dams in the United States to produce up to 2.8 million kilowatts of dependable capacity, which Canada and the United States share equally. Canada has sold its share to utilities in the United States on a long-term contract. One-half of the downstream power benefits attributable to each Canadian project go to the United States purchasers for 30 years after the completion date of each project. Thereafter, they revert to Canada.

Generation at Libby Dam would add to this supply about 750,000 kilowatts of firm power at site and downstream in the United States. Thus, total Treaty power benefits in the United States, including Canada's share, could amount to as much as 3.5 million kilowatts. Canada, too, can reap downstream benefits from Libby Dam, estimated by the British Columbia Hydro and Power Authority to be about 200,000 kilowatts. This includes the Kootenay Canal project on that river in Canada.

2.2.4 Interregional Interties

The Pacific Northwest and the Pacific Southwest have constructed interties between utilities in the regions. Two 500 kV alternating current lines and two high voltage (800 kV) direct current lines were originally planned.

The two alternating current lines from BPA's John Day Substation on the Columbia River in Oregon to Vincent Substation of the Southern California Edison Company, near Los Angeles, California, have been in service since 1968.

The first direct current (Celilo-Sylmar) 800 kV (± 400 kV) line, which runs from the BPA Celilo Converter Station near The Dalles, Oregon, to the Los Angeles Department of Water and Power (LADW&P) Sylmar Converter Station near Los Angeles, California, was energized for commercial operation on May 21, 1970. The principal participants in the Celilo-Sylmar intertie include BPA, LADW&P, Southern California Edison Company, and a number of municipalities in the Los Angeles area. Bonneville Power Administration constructed and maintains the Celilo Converter Station and the transmission line to the Oregon-California border. The LADW&P constructed and maintains the line from the border to and including the Sylmar Converter Station.

The region's utilities are also exploring the use of interconnections with adjacent regions to provide for summer-winter power exchanges. For example, the peak demand for electricity in the Pacific Northwest occurs during the winter. The peak in the Southwest usually occurs during the summer. With summer-winter power exchanges, the resources of each region could be pooled to minimize the need for generating the relatively expensive power for peak periods. Interconnections are also used to market surplus energy, to import electricity to help alleviate forecasted deficits, and to provide system reliability.

BPA has budgeted funds for upgrading the existing DC interconnection with the LADW&P. Completion of this project, scheduled for 1985, will permit further exchange contracts and sale of energy surplus to Pacific Northwest needs, to offset oil-fired generation in the Pacific Southwest.

Thus far, in 12 years of operation, the PNW-PSW interregional connection, in addition to other benefits, enabled the Northwest entities to market about 98 million megawatthours of energy that was surplus to the needs of the Pacific Northwest. This is equivalent to about 166 million barrels of fuel oil that California utilities did not have to burn.

BPA, in conjunction with representatives of British Columbia Hydro and Power Authority and the Alberta Interconnected systems, is studying the use of surplus nonfirm energy for exchanges among utilities in the United States and Canada.

On a longer term basis, United States and Canadian entities are exploring the use of coal mined in Alberta to generate power expressly for export to the U.S.

Other long-term considerations are the construction of a second DC line which would have a southern terminal near Phoenix and/or a third AC line to Northern California. Preliminary feasibility analyses of these additional interties are underway. Completion of these lines would permit more efficient operation of generation located in the Pacific Northwest and Pacific Southwest regions of Western United States, reduce the need for oil-fired resources, and increase reliability.

BPA also has some intertie capacity that runs between the Northwest and eastern Montana. Studies of connections with the Missouri and the Colorado River Basins (WAPA) are underway to examine the costs and benefits of exchanges.

2.2.5 Pacific Northwest Utility Organizations

Since the early 1940's, regional utilities have combined to form organizations designed to coordinate and develop more efficiently the power resources of the Pacific Northwest. Cooperative groups have been formed for three basic purposes: (1) construction of generation facilities, (2) coordination and management of operations, and (3) planning for power facilities to meet future needs of the region.

Washington Public Power Supply System (Supply System). The Washington Public Power Supply System is a municipal corporation and joint operating agency in the State of Washington, currently composed of 19 public utility districts and four municipal electrical systems. The corporation, established in January 1957, is authorized by Washington statute to acquire, construct, and operate plants and facilities for the generation and/or transmission of electric power. The more than 100 utilities which participate in the construction and financing of its projects serve over 2,500,000 people in the Pacific Northwest.

Public Power Council. In 1966, the Pacific Northwest publicly-owned power systems joined together to form the Public Power Council. The organization, established to assure an adequate long-range power supply to its members, was set up as a foundation program of the Northwest Public Power Association. The Council worked to help develop the Hydro-Thermal Power Program.

The Columbia River Water Management Group is a committee formed to consider special problems relating to operation and management of water control facilities. The Group includes representatives of State and Federal agencies involved in water management or streamflow forecasting, and coordinates a variety of management and forecasting functions of the various agencies. This committee is a forum for the exchange of information on issues of river use and provides input to aid the coordinated operation of Pacific Northwest resources.

Intercompany Pool (ICP). The Intercompany Pool was created in 1947 to coordinate the power operations of the investor-owned utilities of the Pacific Northwest. ICP's original members were Portland General Electric Company, Pacific Power & Light Company, The Washington Water Power Company, and Puget Sound Power & Light Company. In September 1973, the ICP Agreement was revised to include three new member investor-owned utilities: Idaho Power Company, Utah Power & Light Company, and The Montana Power Company. The Pool office is located in Spokane, Washington.

Pacific Northwest Utilities Conference Committee (PNUCC). Individual utility load and resource forecasts are assembled into a regional forecast under the auspices of the Pacific Northwest Utilities Conference Committee (PNUCC), an organization of all of the public and private utilities in the West Group Area of the Northwest Power Pool. The regional forecast is used as a basis for planning resources and preparing for potential deficits.

The utilities in the Pacific Northwest individually prepare load forecasts for their service areas. In addition, BPA takes the responsibility for forecasting the loads of those public agency systems without generation and other loads served by the Federal System. These are combined by the Subcommittee on Loads and Resources of PNUCC for inclusion in its annual forecasts of power loads and resources, and compiled in the West Group Forecast.

Pacific Northwest Regional Commission (PNWRC). The Governors of Oregon, Washington, and Idaho, together with a Federal member appointed by the President, comprise the Pacific Northwest Regional Commission. The Commission completed in 1977 a regional energy study (The Northwest Energy Policy Project) which: (1) identified and evaluated alternative energy policies that the Northwest States, individually and collectively, could use as policy levers to influence the evolution of the region's future energy production and consumption patterns, and (2) assessed future regional demand, the environmental impacts of meeting those demands, alternatives, and other related matters that could assist the Northwest States, utilities, local governments, and Federal agencies in energy planning on a coordinated regional basis.

Northwest Power Pool. In 1964, at the same time the Columbia River Treaty was ratified, some of the region's utilities in the Northwest Power Pool signed the Pacific Northwest Coordination Agreement, which provided for the expanded coordination of the Columbia River System and other coastal river systems to assure optimum utilization of their power resources.

Pacific Northwest utilities continue to cooperate in the planning and operation of the regional power supply system. Existing facilities are coordinated through the Northwest Power Pool and the parties to the Pacific Northwest Coordination Agreement. The Northwest Power Pool provides informal coordination of the FCRPS with the operations of the major public and private utilities in the region; the Coordination Agreement formalizes coordination to maximize the efficiency of the operation of the region's hydro resources.

2.3 Resource Capabilities of System

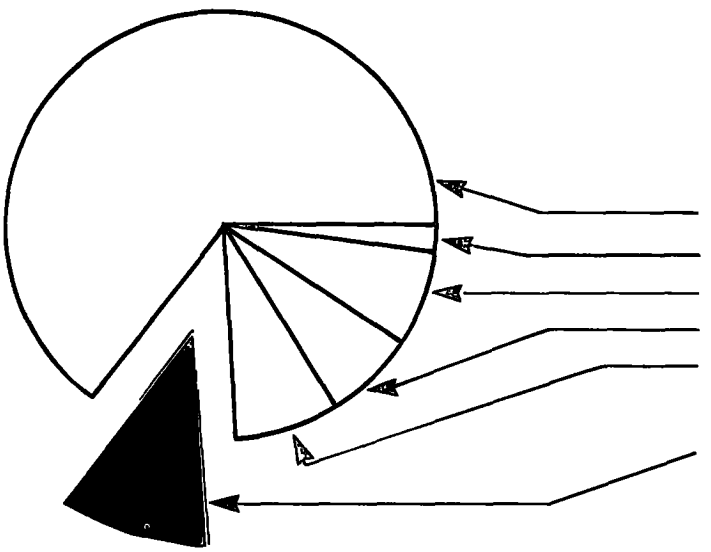
In operating year 1980-81, the region will rely on hydroelectric power to meet 75 percent of its electrical requirements. Figures 2-3 and 2-4 from the May 1980 Power Outlook show how the BPA area relies heavily on hydro for meeting energy and peak demands. Figures 2-5 and 2-6 graphically present the forecasted resource mix--the percentage of hydro significantly decreases from 64.9 percent to 47.3 percent for energy, and from 80.4 percent to 62.7 percent for peak by 1990.

Figure 2-7 shows the major hydro and thermal projects in the Pacific Northwest. Table 2-1 gives the generation capabilities of the existing hydro units, Table 2-2 lists projects by ownership, and Table 2-3 by State.

FIGURE 2-3

1980-81 Resource Mix—Energy

Total Load—18,451 MW (Includes Reserves)[1]



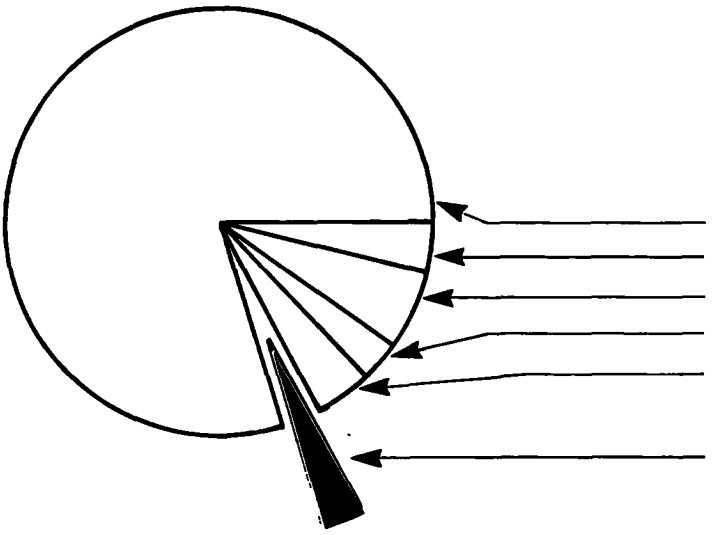
		Percent	MW
Hydro	—	64.9%	11,982
Oil	—	2.0	370
Coal	—	7.2	1,321
Nuclear	—	6.9	1,280
Misc.	—	7.9	1,458
			16,411
Deficit	—	11.1	2,040
		100.0%	18,451

[1] From Table 2

Total Energy Load (Line 3)	18157
Reserves (Line 34)	294
Total Load	18451

FIGURE 2-4

1980-81 Resource Mix—Peak
Total Load—36,838 MW (Includes Reserves)[1]



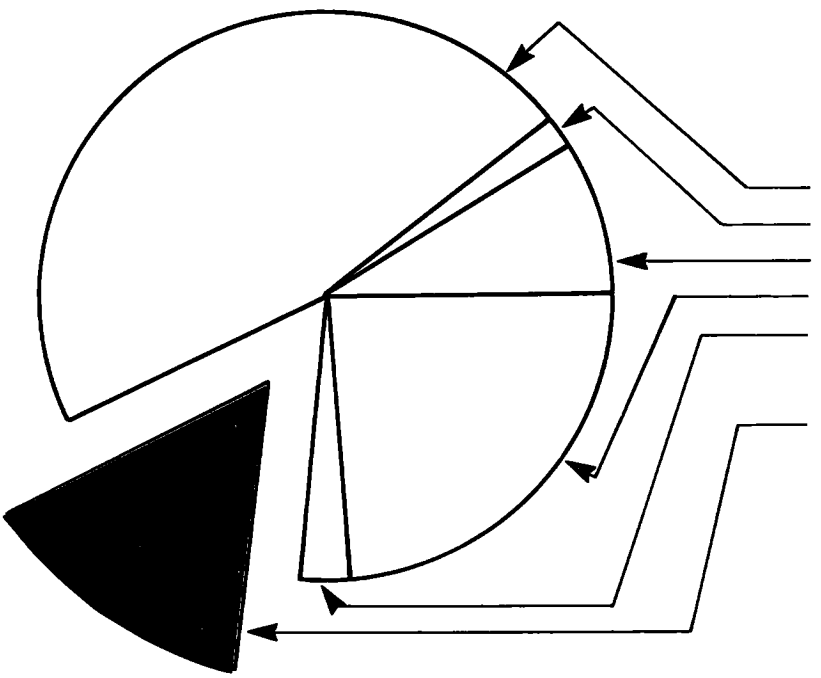
		Percent	MW
Hydro	—	80 4%	29,606
Oil	—	3 9	1,430
Coal	—	5 7	2,120
Nuclear	—	2 9	1,080
Misc.	—	4.0	1,459
			35,695
Deficit	—	3.1	1,143
		100.0%	36,838

[1] From Table 4

Total Peak Load (Line 3)	29494
Reserves (Lines 34 & 35)	7344
Total Load	36838

FIGURE 2-5

1990-91 Resource Mix—Energy
Total Load—25,380 MW (Includes Reserves)[2]



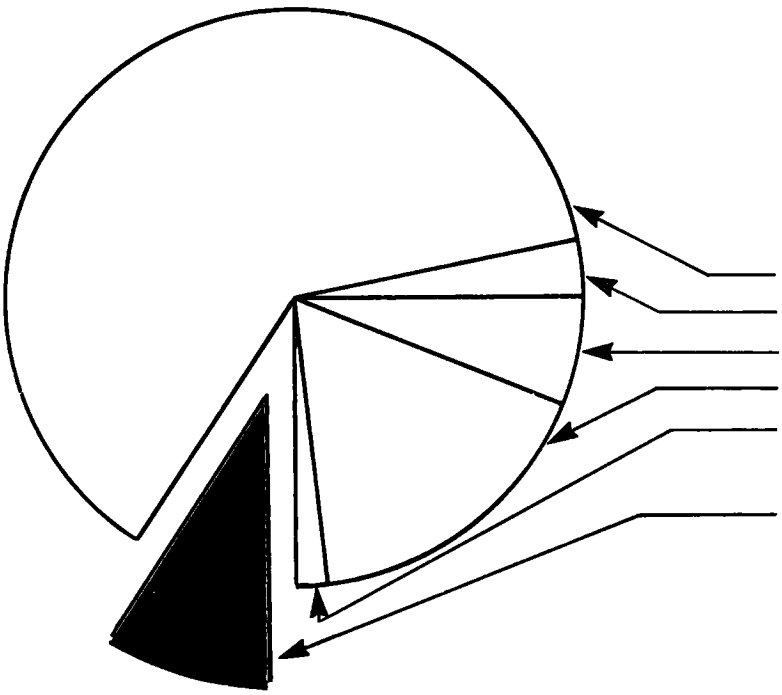
		Percent	MW
Hydro	—	47 3%	12,001
Oil	—	1 5	384
Coal	—	8.8	2,237
Nuclear	—	24 0	6,099
Misc.	—	2.4	598
			21,319
Deficit	—	16.0	4,061
		100.0%	25,380

[2] From Table 2

Total Energy Load (Line 3)	24740
Reserves (Line 34)	640
Total Load	25380

FIGURE 2-6

1990-91 Resource Mix—Peak
Total Load—49,676 MW (Includes Reserves)[2]

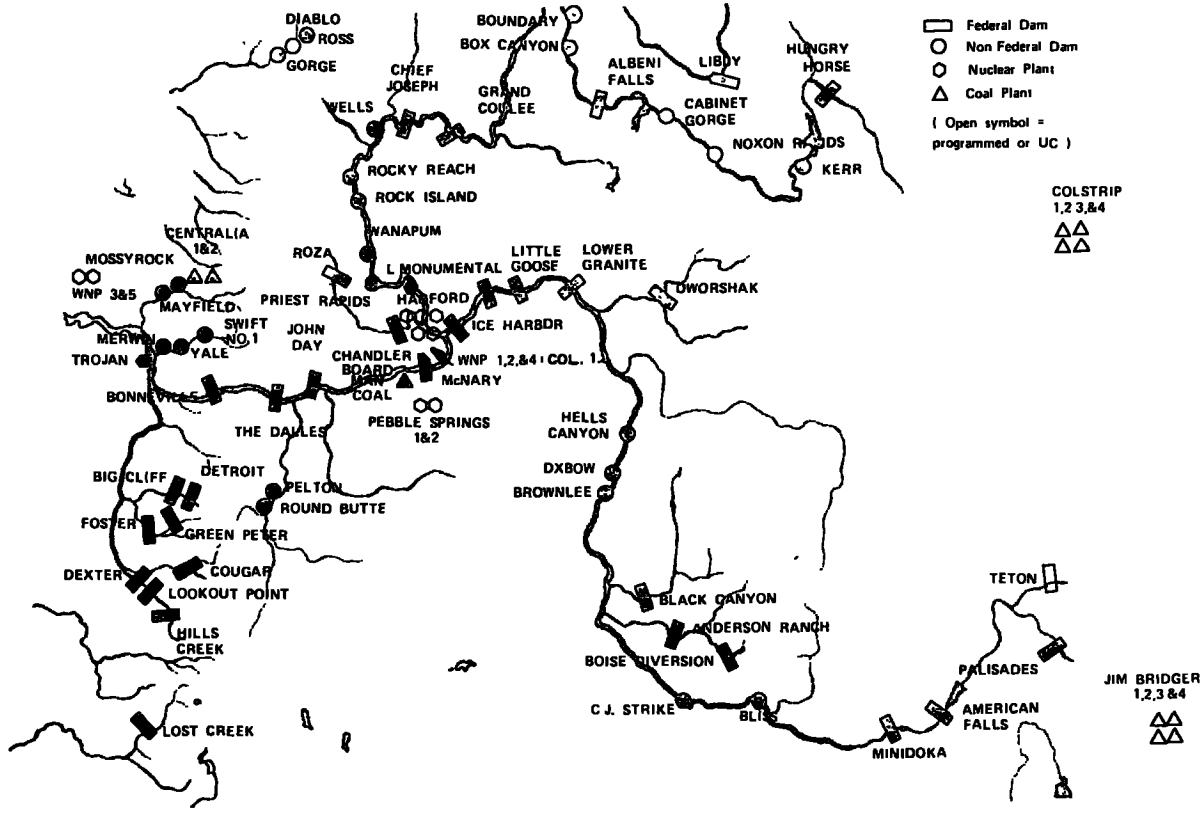


		Percent	MW
Hydro	—	62 7%	31,125
Oil	—	3 2	1,609
Coal	—	6 3	3,100
Nuclear	—	17 0	8,448
Misc.	—	1.6	806
			45,088
Deficit	—	9.2	4,588
		100.0%	49,676

[2] From Table 4

Total Peak Load (Line 3)	39263
Reserves (Lines 34 & 35)	10413
Total Load	49676

Figure 2–7 MAJOR HYDRO AND THERMAL PROJECTS IN THE PACIFIC NORTHWEST



FEDERAL COLUMBIA RIVER POWER SYSTEM
General Specifications of Projects Existing, Under Construction, Authorized or Licensed, and Potential Peaking Capability of Installations

December 31, 1979

Project	Type	Utility, State	Stream	Initial Date in Service	Existing No of Units	Existing Peaking Capability—kW	Under Construction No. of Units	Under Construction Peaking Capability—kW	Authorized—Licensed No of Units	Authorized—Licensed Peaking Capability—kW	Potential No of Units	Potential Peaking Capability—kW	Project Totals No of Units	Project Totals Peaking Capability kW
Albeni Falls	H	C of Eng Idaho	Pend Oreille	Mar 25, 1955	3	49,000	–	–	–	–	–	–	3	49,000
Anderson Ranch	H	WPRS[1] Idaho	S Fk Boise	Dec 15, 1950	2	34,500	–	–	–	–	1	17,250	3	51,750
Big Cliff	H	C of Eng Oregon	N Santiam	Jun 12, 1954	1	20,700	–	–	–	–	–	–	1	20,700
Black Canyon	H	WPRS Idaho	Payette	Dec 1925	2	10,200	–	–	–	–	–	–	2	10,200
Boise River Div	H	WPRS Idaho	Boise	May 1912	3	2,250	–	–	–	–	–	–	3	2,250
Bonneville	H	C of Eng Ore-Wash	Columbia	Jun 6, 1938	10	574,000	8-2	576 000	–	–	–	–	18-2	1,150,000
Chandler	H	WPRS Washington	Yakima	Feb 13, 1956	2	13 000	–	–	–	–	–	–	2	13,000
Chief Joseph	H	C of Eng Washington	Columbia	Aug 20 1955	27	2,412,120	–	–	–	–	13	1,808,950	40	4,221,070
Cougar	H	C. of Eng Oregon	S Fk McKenzie	Feb 4, 1964	2	28,750	–	–	1	40,250	–	–	3	69,000
Detroit	H	C of Eng Oregon	N Santiam	Jul 1, 1953	2	115,000	–	–	–	–	–	–	2	115 000
Dexter	H	C of Eng Oregon	M Fk Willamette	May 19, 1955	1	17,250	–	–	–	–	–	–	1	17,250
Dworshak	H	C of Eng Idaho	N Fk Clearwater	Sep 18, 1974	3	460,000	–	–	3	759,000	–	–	6	1,219,000
Foster	H	C of Eng Oregon	South Santiam	Aug 22, 1968	2	23 000	–	–	–	–	–	–	2	23 000
Grand Coulee	H	WPRS Washington	Columbia	Sep 28, 1941	23-2	5,852,400[3]	1	805,000	–	–	6	4,830 000	30-2	11 487 400
Grand Coulee PG[6]	PG	WPRS Washington	Columbia	Dec 30, 1974	2	100,000[7]	4	200 000	–	–	–	–	6	300,000
Green Peter	H	C of Eng Oregon	Middle Santiam	Jun 9, 1967	2	92,000	–	–	–	–	–	–	2	92,000
Hills Creek	H	C of Eng Oregon	M Fk Willamette	May 2 1962	2	34 500	–	–	–	–	–	–	2	34,500
Hungry Horse	H	WPRS Montana	S Fk Flathead	Oct 29 1952	4	328,000	–	–	–	–	–	–	4	328,000
Ice Harbor	H	C of Eng Washington	Snake	Dec 18, 1961	6	693,300	–	–	–	–	–	–	6	693,300
John Day	H	C of Eng. Ore-Wash	Columbia	Jul 17, 1968	16	2,484,000	–	–	4	621 000	–	–	20	3,105 000
Libby	H	C of Eng Montana	Kootenai	Aug 29 1975	4	483,000	4	483,000	–	–	–	–	8	966,000
Libby Reregulating	H	C of Eng. Montana	Kootenai	–	–	–	3	87,700	–	–	–	–	3	87,700
Little Goose	H	C of Eng Washington	Snake	May 19, 1970	6	931 500	–	–	–	–	–	–	6	931,500
Lookout Point	H	C of Eng Oregon	M Fk Willamette	Dec 16 1954	3	138 000	–	–	–	–	–	–	3	138,000
Lost Creek	H	C of Eng Oregon	Rogue	Dec 1, 1977	2	56,350	–	–	–	–	–	–	2	56,350
Lower Granite	H	C of Eng Washington	Snake	Apr 15, 1975	6	931,500	–	–	–	–	–	–	6	931 500
Lower Monumental	H	C of Eng Washington	Snake	May 26, 1969	6	931,500	–	–	–	–	–	–	6	931,500
McNary	H	C of Eng Ore-Wash	Columbia	Nov 6 1953	14	1,127,000	–	–	10	1,207,500	–	–	24	2,334,500
Minidoka	H	WPRS Idaho	Snake	May 7, 1909	7	16,000	–	–	–	–	–	–	7	16,000
Palisades	H	WPRS Idaho	Snake	Feb 25, 1957	4	135 000	–	–	–	–	2	155 250	6	290,250
Roza	H	WPRS Washington	Yakima	Aug 31, 1958	1	12,900	–	–	–	–	–	–	1	12,900
Strube	H	C of Eng Oregon	S Fk McKenzie	–	–	–	–	–	1	5,175	–	–	1	5,175
Teton	H	WPRS Idaho	Teton	–	–	–	–	–	3	30 000[4]	–	–	3	30,000
The Dalles	H	C of Eng Ore-Wash	Columbia	May 13, 1957	22-2	2,015,000[5]	–	–	–	–	–	–	22-2	2,015,000
Total Number of Units and Peaking Capability					**190-4**	**20,121,720**	**20-2**	**2,151,700**	**22**	**2,662,925**	**22**	**6,811,450**	**254-6**	**31,747,795**
Total Number of Projects					**–**	**30**		**1**		**2**		**0**		**33**

[1] Bur Rec is now Water and Power Resources Service

[2] Grand Coulee PG is not included in the total number of projects

[3] Includes two Grand Coulee station service units at 11 300 kW each that are available for load, 18 units of 126 100 kW each three Third Powerplant units of 650 000 kW and two units at 805 000 kW

[4] Teton Dam ruptured June 5 1976 Future status is unknown

[5] Includes two fishway units at The Dalles of 15 100 kW each 14 units of 89 700 kW each, and 8 units of 98,900 kW each. Due to high tailwater the plant capability is reduced 28 300 kW with 21 units and 62 200 kW with 22 units generating

BPA—Branch of Power Resources April 1980

TABLE 2-1

TABLE 2-2

PACIFIC NORTHWEST REGION
EXISTING GENERATION IN KILOWATTS
MARCH 31, 1980

PLANT	NAMEPLATE RATING HYDRO	THERMAL	TOTAL	PEAKING CAPABILITIES
FEDERAL AGENCIES				
CORPS OF ENGINEERS:				
ALBENI FALLS	42,600	0	42,600	49,000
BIG CLIFF	18,000	0	18,000	20,000
BONNEVILLE	518,400	0	518,400	574,000
CHIEF JOSEPH	2,069,000	0	2,069,000	2,412,120
COUGAR	25,000	0	25,000	28,750
DETROIT	100,000	0	100,000	115,000
DEXTER	15,000	0	15,000	17,250
DWORSHAK	400,000	0	400,000	460,000
FOSTER	20,000	0	20,000	23,000
GREEN PETER	80,000	0	80,000	92,000
HILLS CREEK	30,000	0	30,000	34,500
ICE HARBOR	602,880	0	602,880	693,300
JOHN DAY	2,160,000	0	2,160,000	2,484,000
LIBBY	420,000	0	420,000	483,000
LITTLE GOOSE	810,000	0	810,000	931,500
LOOKOUT POINT	120,000	0	120,000	138,000
LOST CREEK	49,000	0	49,000	56,350
LOWER GRANITE	810,000	0	810,000	931,500
LOWER MONUMENTAL	810,000	0	810,000	931,500
MCNARY	980,000	0	980,000	1,127,000
THE DALLES	1,807,000	0	1,807,000	2,015,000
	11,886,880	0	11,886,880	13,616,770
WATER & POWER RESOURCES SERVICE:				
ANDERSON RANCH	27,000	0	27,000	34,500
BLACK CANYON	8,000	0	8,000	10,200
BOISE RIVER DIV.	1,500	0	1,500	2,250
CHANDLER	12,000	0	12,000	13,000
GRAND COULEE	5,463,000	0	5,463,000	5,852,400
GRAND COULEE PG.	100,000	0	100,000	100,000
HUNGRY HORSE	285,000	0	285,000	328,000
MINIDOKA	13,400	0	13,400	16,000
PALISADES	118,750	0	118,750	135,000
ROZA	11,250	0	11,250	12,900
	6,039,900	0	6,039,900	6,504,250
PUBLIC AGENCIES				
BONNERS FERRY, CITY OF	2,380	2,240	4,620	5,040
CENTRALIA, CITY OF	10,000	0	10,000	11,400
CHELAN COUNTY PUD	1,883,850	400	1,884,250	1,999,327
COWLITZ COUNTY PUD	70,000	0	70,000	77,000
DOUGLAS COUNTY PUD	774,300	0	774,300	820,000
EUGENE WATER ELEC. BD.	111,500	390,200	501,700	528,920
GRANT COUNTY PUD	1,619,750	0	1,619,750	1,895,000
GRAYS HARBOR CO. PUD	0	56,000	56,000	52,520
MCMINNVILLE, CITY OF	0	1,250	1,250	1,250
ORCAS POWER & LIGHT COOP.	0	2,310	2,310	2,310
PEND OREILLE CO. PUD	60,560	0	60,560	81,800
SEATTLE, CITY OF	1,193,556	142,000	1,335,556	1,611,040
SNOHOMISH COUNTY PUO	0	112,000	112,000	105,040
SPOKANE, CITY OF	3,900	0	3,900	4,925
TACOMA, CITY OF	659,700	112,000	771,700	880,765
WASHINGTON PUBLIC POWER SUPPLY	26,125	860,000	886,125	893,500
	6,315,621	1,678,000	8,094,021	8,089,072
PRIVATE UTILITIES				
IDAHO POWER CO. 1/	1,535,245	734,902	2,270,147	2,518,891
MONTANA POWER CO. 1/	202,140	358,372	560,512	554,500
PACIFIC POWER & LIGHT CO. 1/	862,383	2,111,805	2,974,188	3,025,957
PORTLAND GENERAL ELECTRIC	539,850	1,715,750	2,255,600	2,436,494
PUGET SOUND POWER & LIGHT 1/	297,090	642,722	939,812	916,660
WASHINGTON WATER POWER CO.	740,530	299,400	1,039,930	1,405,300
	4,177,238	5,862,951	10,040,189	10,857,802

1/ Only generation on the west slope of the Continental Divide is included, plus Colstrip and Jim Bridger.

BPA-Branch of Power Resources
7/1/80

TABLE 2-3

PACIFIC NORTHWEST STATES
EXISTING GENERATING CAPACITY

July 1, 1980

State	Hydro	Thermal	Total
WASHINGTON 1/			
Federal	13,420,830	0	13,420,830
Public	6,301,741	1,341,400	7,643,141
Private	893,860	1,280,900	2,174,760
OREGON 1/			
Federal	3,189,700	0	3,189,700
Public	111,615	391,450	503,065
Private	1,189,296	1,750,000	2,939,296
IDAHO 1/			
Federal	611,250	0	611,250
Public	5,380	2,240	7,620
Private	1,746,645	56,825	1,803,470
MONTANA 2/			
Federal	705,000	0	705,000
Public	0	0	0
Private	607,670	756,944	1,364,614
TOTAL	28,782,987	5,579,759	34,362,746
Federal	17,926,780	0	17,926,780
Public	6,418,736	1,735,090	8,153,826
Private	4,437,471	3,844,669	8,282,140

1/ On border - each state has half of the total generation.

2/ This table includes only the west slope of the Continental Divide plus Colstrip.

BPA - Branch of Power Resources
July 21, 1980

2.3.1 The Current Power Situation

Annually the region prepares load and resource forecasts based on studies and estimates of the power supply compared with projected consumption. Resource forecasts are derived from performance of hydro plants based on critical period planning and thermal plant operations. Table 2-4 shows the energy load/resource balance for the period 1980-81 through 1990-91.

TABLE 2-4

West Group Area Loads and Resources
Critical Hydro Conditions
Average Energy—Megawatts

	1980-81	1981-82	1982-83	1983-84	1984-85	1985-86	1986-87	1987-88	1988-89	1989-90	1990-91
LOADS											
1 Area Energy Load	17491	18168	18943	19854	20510	21158	21786	22425	23122	23838	24566
2 Exports	666	556	339	203	205	207	209	211	181	177	174
3 Total Energy Load	18157	18724	19282	20057	20715	21363	21995	22636	23303	24015	24740
RESOURCES											
4 Existing	14782	14823	14779	14338	14290	14171	14190	14261	14252	14139	14159
5 Imports	1425	1475	1459	1325	1270	1214	994	720	625	570	532
NEW HYDRO											
6 Grand Coulee Pump Generator	–	–	–	–	–	–	–	–	–	–	–
7 High Ross	–	–	–	35	35	35	35	35	35	35	35
8 Bull Run	–	–	9	9	9	9	9	9	9	9	9
9 Mayfield Addition	–	–	–	–	–	–	–	–	–	–	–
10 Pelton Reregulating	–	4	8	8	8	8	8	8	8	8	8
11 Bonneville 2nd Power Plant	–	47	47	47	47	47	47	47	47	47	47
12 Libby Additions	–	–	–	–	–	–	–	–	–	–	–
13 Libby Reregulating	–	–	–	–	–	10	29	29	29	29	29
14 Cougar Addition	–	–	–	–	–	–	–	–	–	–	–
15 Strube	–	–	–	–	–	–	2	2	2	2	2
16 Total New Hydro	0	51	64	99	99	109	130	130	130	130	130
RENEWABLE RESOURCES											
17. WTG (Wind)	0 15	0 16	0 16	0 16	0 16	0 16	0 16	0 16	0 16	0 16	0 16
18 Goodnoe Hills (Wind)	1 00	3 00	3 00	3 00	3 00	3 00	3 00	3 00	3 00	3 00	3 00
19 Kettle Falls (Wood)[1]	–	–	31 50	31 50	31 50	31 50	31 50	31 50	31 50	31 50	31 50
20 Total Renewable	1 00	3 00	35 00	35.00	35 00	35.00	35.00	35.00	35.00	35 00	35 00
NEW THERMAL											
21 Boardman	191	334	358	358	358	356	358	358	358	356	358
22 Whitehorn CT	12	18	18	16	18	18	18	18	18	18	18
23 Fredrickson CT	–	12	18	18	18	18	18	18	18	18	18
24 WNP No 2	–	–	329	742	825	825	825	825	825	825	825
25 Colstrip No 3	–	–	–	147	331	368	368	368	368	368	368
26 WNP No 1	–	–	–	–	81	749	938	938	938	938	938
27 Colstrip No 4	–	–	–	–	196	343	367	367	367	367	367
28 WNP No 3	–	–	–	–	–	62	759	930	930	930	930
29 WNP No 4	–	–	–	–	–	61	749	938	938	936	936
30 WNP No 5	–	–	–	–	–	–	62	759	930	930	930
31. Skagit No 1	–	–	–	–	–	–	–	–	–	–	773
32 Total New Thermal	203	364	723	1283	1807	2802	4462	5519	5690	5690	6463
33 Gross Resources	16411	16718	17060	17080	17501	18331	19811	20665	20732	20564	21319
34 Reserves	(294)	(309)	(309)	(352)	(412)	(382)	(493)	(831)	(752)	(677)	(640)
35 Net Resources	16117	16407	16751	16728	17089	17949	19318	19834	19980	19887	20679
36 Surplus or (Deficit)	(2040)	(2317)	(2531)	(3329)	(3826)	(3414)	(2677)	(2802)	(3323)	(4128)	(4061)
37 Surplus or (Deficit)—Percent of Load (Line 36 divided by Line 3)	(11 2)	(12 4)	(13 1)	(16 6)	(17 5)	(16 0)	(12 2)	(12 4)	(14 3)	(17 2)	(16 4)
36 Probability of insufficiency—percent[2]	17	23	34	53	48	43	42	42	55	63	69

[1] Kettle Falls is being reevaluated by the Washington Water Power Company and may be delayed
[2] Probability that resources will be insufficient to meet firm energy load in at least one period of year shown

For the sixth successive year, the region's utilities have reduced their forecasts of future energy needs for the coming decade. In spite of these lower forecasts, load-resource comparisons show resource deficits for nearly every year of the forecast. Deficits are especially severe in the mid- to late 1980's with probabilities of firm energy insufficiency in any single year ranging from 17 percent in 1980-81 to as high as 69 percent in 1990-91. The probability of a deficiency sometime in the 10-year period is now virtually 100 percent. With critical water conditions, which are exceedingly unlikely to occur in more than one year in the period, energy deficits exceed 11 percent of the total loads for all years, reaching a high of 17.5 percent in 1984-85. These probabilities indicate a high likelihood that expensive purchases of energy, if available, will be necessary to maintain a reliable supply for firm loads. Installation schedules for the resources used in the load resource comparisons in Table 2-4 are outlined on Tables 2-5 and 2-6. The bulk of the resources listed are conventional hydro additions, nuclear, or coal-fired thermal plants.

TABLE 2-5

New Thermal Generating Capacity Scheduled For Service 1980-81 Through 1990-91

Installation Schedule for Thermal Power Projects

Project	Percent Ownership Private	Percent Ownership Public	Fuel[1]	Capability Megawatts	Scheduled Operation Date[2]	Probable Energy Date[3]	Principal Sponsor[4]
Boardman Coal (Carty)[5]	90	10	C	530	Jul 1980	Nov 1980	PGE
West Group Area Resource	80	10					
Whitehorn CT	100	0	G/O	178	Nov 1980	Nov 1980	PSP&L
Fredrickson CT	100	0	G/O	178	Nov 1981	Nov 1981	PSP&L
WNP #2	—	100[7]	N	1100	Sep 1981	Jan 1983	WPPSS
Colstrip #3[6]	100	—	C	490	Jan 1984	Jan 1984	PSP&L
WNP #1	—	100[7]	N	1250	Dec 1983	Jun 1985	WPPSS
Colstrip #4[6]	100	—	C	490	Nov 1984	Nov 1984	PSP&L
WNP #3	30	70[7]	N	1240	Dec 1984	Jun 1986	WPPSS
WNP #4	—	100	N	1250	Jun 1985	Jun 1986	WPPSS
WNP #5	10	90	N	1240	Jun 1987	Jun 1987	WPPSS
Skagit #1	100	—	N	1288	Jul 1990	Jul 1990	PSP&L

[1] C = Coal, O = Oil, G = Gas, N = Nuclear

[2] Scheduled Commercial Operation Date is the date determined by the sponsoring utility for commercial operation

[3] Probable Energy Date is the later of the Scheduled Commercial Operation Date or the Milestone Date The Milestone Date is a realistic operation date delermined from a standardized schedule reflecting anticipated average planning and construction times

[4] Abbreviations are PGE = Portland General Electric Co , PSP&L = Puget Sound Power & Light Co , WPPSS = Washington Public Power Supply System.

[5] Boardman Coal unit is rated 530 MW, 10 percent has been sold to Idaho Power Company

[6] Colstrip Units No 3 and No 4 are rated 700 MW each, 70 percent will be used by West Group Area

[7] Project capability net-billed to Federal System

TABLE 2-6

Installation Schedule for Hydro Projects

Project Stream	Owner[1]	Unit Number	Nameplate Rating Megawatts	Scheduled Date of Commercial Operation	Status[2]
Grand Coulee	WPRS	P/G- 9	50	Dec 1980	UC
Pump Generators		P/G-10	50	Apr 1981	UC
Columbia River		P/G-11	50	Aug 1981	UC
		P/G-12	50	Dec 1981	UC
Post Falls	WWP		3.5	Nov 1980	UC
Spokane River					
Bonneville	USCE	18	66.5	May 1981	UC
2nd Powerplant		17	66.5	Jul 1981	UC
Columbia River		16	66.5	Sep 1981	UC
		15	66.5	Nov 1981	UC
		14	66.5	Jan 1982	UC
		13	66.5	Mar 1982	UC
		12	66.5	May 1982	UC
		11	66.5	Jul 1982	UC
(Fishwater Units)		F-1	13 1	May 1981	UC
		F-2	13.1	May 1981	UC
Bull Run	PORT	1	24	Oct 1982	UC
Bull Run River		2	12	Oct 1982	UC
Mayfield Addition	TAC	4	40.5	Oct 1982	UC
Cowlitz River					
Pelton Reregulating	WSI	1	22	Jan 1982	UC
Deschutes River					
High Ross Dam	SEA	—	*	1983-84	P
Skagit River					
Libby	USCE	5	105	Nov 1985	UC
Kootenai River		6	105	Nov 1985	UC
		7	105	Nov 1985	UC
		8	105	Nov 1985	UC
Libby Reregulating	USCE	Dam	—	Nov 1985	P
Kootenai River		1	15.4	Jan 1986	P
		2	30.5	Mar 1986	P
		3	30.5	May 1986	P
Cougar	USCE	3	35	Sep 1986	P
McKenzie River					
Strube	USCE	1	4.5	Sep 1986	P
McKenzie River					

*Modification of Ross Hydroelectric Project to increase height of dam and mechanical capability if licensed will provide 34 average megawatts more energy and 272 megawatts of increased capacity

[1] Ownership utility abbreviations
WPRS—Water & Power Resources Service
SEA—Seattle City of
PORT—Portland, City of
WSI—Warm Springs Indians
WWP—Washington Water Power
USCE—U S Corps of Engineers
TAC—Tacoma, City of

[2] Includes projects under construction and authorized or licensed for construction
UC- Under Construction, P- Planned

BPA—Branch of Power Resources
Power Investigations Section
April 1980

Approximately 10,800 MW of peaking capacity is scheduled for installation between July 1980 and June 1991. While new thermal plants will account for 9,183 MW (84.8 percent) of the new capacity, new hydro units are responsible for 1,594 MW (14.7 percent). Other scheduled renewable resources will provide only 42 MW of additional capacity. Scheduled peak resources are insufficient to meet peak load requirements in all of the 11 years studied. The largest forecasted deficit is 12.2 percent, or 4,227 MW in 1984-85.

Construction schedule slippages--not poor streamflows--lie at the heart of the region's power supply problems. In planning for resources sufficient to meet loads, neither BPA nor the region's utilities count on more hydro capability than can be produced under recurrence of critical streamflow conditions.

Delays in the scheduled completion dates of large thermal plants have occurred with regularity over the past several years. Labor, construction, and regulatory changes have caused projects which are well underway to be further delayed. Siting and licensing problems have caused Portland General Electric to delay the Pebble Springs plants and Puget Sound Power & Light to defer the Skagit units and move them to the Hanford Reservation.

Cumulative effects of these delays are a loss of 17,623 MW-years of energy (Table 2-7) between 1979 and 1980. Translated into kilowatthours (154,400,000,000), this is equivalent to the energy required to serve the cities of Seattle and Tacoma for 10 years or total West Group Area needs for 1 full year. This is nearly three times the loss due to delays of 6,480 MW-years projected in 1979.

TABLE 2-7

Thermal Power Project
Schedule Delays

Project	Principal Sponsor[1]	Nameplate Rating MW	Percent Complete[2]	Probable Energy Date Power Outlook 1979	1980	Delay Months	Energy Lost MW—YR
WNP #2	WPPSS	1100	82.5	Sep 1981	Jan 1983	16	1101
Colstrip #3	PSPL	490	2.5	Jul 1983	Jan 1984	6	158
WNP #1	WPPSS	1250	37.8	Dec 1983	Jun 1985	18	1407
Colstrip #4	PSPL	490	2.5	May 1984	Nov 1984	6	158
WNP #3	WPPSS	1240	20.8	Mar 1985	Jun 1986	15	1163
WNP #4	WPPSS	1250	15.0	Jun 1985	Jun 1986	12	938
WNP #5	WPPSS	1240	9.1	Jun 1986	Jun 1987	12	930
Skagit #1	PSPL	1288	X	Nov 1986	Jul 1990	44	3542
Pebble Springs #1	PGE	1260	X[3]	Mar 1987	Jul 1992	64	3906[3]
Skagit #2	PSPL	1288	X[3]	Nov 1988	Jul 1992	44	2383[3]
Pebble Springs #2	PGE	1260	X[3]	Apr 1989	Jul 1994	63	1937[3]
						Total	17,623

[1] Abbreviations are PGE—Portland General Electric Co., PSPL—Puget Sound Power & Light Co., WPPSS—Washington Public Power Supply System

[2] As of April 1980. X Not licensed for construction

[3] Delayed beyond the coming decade
Energy lost calculated only through 1990-91

BPA—Branch of Power Resources
Power Investigations Sec.
April 10, 1980

New generation of 6,628 megawatts of average energy is scheduled to come on line by 1990-91 (Table 2-4). Of this new generation, only 2 percent (165 average megawatts) is scheduled to come from hydro plants and other renewable resources. The remaining 98 percent (6,463 average megawatts) is scheduled from generation at thermal plants.

Additional delays in thermal plants will worsen an already serious energy situation. For example, a 1-year delay in large thermal plants scheduled to come on-line after July 1, 1981, would result in an 11-year average deficit of more than 3,200 average megawatts, and increase the maximum deficit from 4,128 average megawatts in 1989-90 to 4,834 average megawatts in 1990-91. The maximum deficit as a percentage of load would increase to 20.6 percent. With a 1-year delay in thermal plant installations, peak deficits occur in every year with the largest deficit being 5,876 megawatts in 1990-91, or 15 percent of the peakload.

The thermal project delays shown on Table 2-7 have a significant impact on the year-by-year peak resource availability. The sustained peak adjustment includes a reduction of peak capability at Grand Coulee due primarily to system hydro reductions associated with serving sustained peak needs. This latter adjustment also recognizes factors such as the inability of reservoirs to supply downstream ponds with sufficient water to serve extended peak loads, the necessity of complying with restrictions associated with fish runs, navigational requirements, and recreational needs. This operational adjustment is difficult to quantify and is still under analysis.

Reducing the possibility of curtailments will require conservation efforts of all Northwest users, installation of new generation facilities, and the help of Mother Nature in providing the region with better than critical water conditions. However, should BPA and the region become unable to meet remaining firm energy requirements, short-term regional curtailment guidelines developed in 1977 by the Pacific Northwest Regional Commission could be put into effect. These guidelines, which are applied equally to all classes of customers, would be implemented in voluntary to mandatory stages as necessary.

At best, electric power deficits cause inconvenience and hardship. They can substantially increase the cost of power to the extent any is available from outside the region to offset the shortage. They can cause production cutbacks for industrial and commercial users and in the long run slow economic growth. At worst they can result in brownouts, rotating blackouts, or cascading outages in which case the economic and social costs can be potentially enormous.

2.3.2 Planning Assumptions

Hydro resource planning uses critical water (streamflow) as the basis for calculating the firm energy capability of the system. This planning criterion has been in use since the 1940's and was formalized in a Coordination Contract among the generating utilities in 1964.

The critical period is defined as that interval of lowest streamflows in the 40-year historical record which will produce the lowest level of energy from the total coordinated power system and is a measure of the energy which can be assured to be available for delivery from the hydro system to serve firm loads. In making the determinations of energy available to the system under critical hydro conditions, all reservoirs are assumed full at the beginning of the critical period and are drafted empty by the end of the critical period. The critical water period used in the PNUCC Planning Studies (West Group Forecast, Blue Book) is a 42-1/2 month period (August 16, 1928, through February 1932).

The probability of recurrence of critical level streamflows currently used in Northwest planning has been calculated to be about 1 in 300. However, water conditions which produce very little more energy than critical water conditions (the 20-1/2 month period August 16, 1943 to April 1945) have a probability of occurrence of 1 in 60. In addition to the 4-year (1929-1932) and 2-year (1944-1945) low streamflow periods, the region experienced low streamflows in 1936-37, thus making a total of 7 years out of the 40 years studied which presented problems in providing a firm energy supply. Taking these factors into account, together with the need to have firm power available at all times to serve firm loads and, thus, fulfill their utility responsibility, power suppliers base firm energy planning on critical water conditions. They recognize, of course, that in most years the hydro system will produce some nonfirm energy. The nonfirm energy is used by BPA's direct-service industries to serve the restrictable components of their loads, and by Northwest utilities to restore depleted reservoir storage and displace high-cost thermal generation. Some of the latter may continue to be operated for sale outside the region, resulting in increased revenues for Northwest utilities, and oil and cost savings for Southwest utilities. Even during years of low runoff, surplus hydrogeneration may also be available for sale in the Southwest because of the timing of the runoff.

Critical period planning is used in regional load-resource comparisons to determine the probabilities of critical hydro conditions materializing. As a part of these basic studies, an average hydro system capability for the 40 years of record can be determined. The difference between this 40-year average capability and the critical period average is a measure of the gross secondary energy available to the system. However, because of the seasonal nature of this 40-year average (much below the annual average in the late summer and fall months and much above average in the late spring and early summer months), not all of this secondary energy would be available to offset forecasted deficits.

2.3.3 Energy Reserves and Reliability

Utilities provide reserves to assure continuous service to firm loads. The amount of reserves available determines the degree of reliability for the region.

BPA's contracts with its direct-service industrial (DSI) customers permit the restriction of power to one-fourth of their total requirement (top quartile) at any time, for any reason and for any length of time. A form of load management in use since the 1940's, the restriction of delivery of nonfirm energy is a useful short-term operational method to offset the seasonal effect of low water conditions. Beyond the top quartile of industrial power, the next quartile can also be restricted to serve firm loads during shortages resulting from construction delays of certain generation facilities or less than planned performance. Of course, there are adverse economic consequences associated with any interruptions of this industrial power supply.

Uniform Regional Planning Assumptions, reflecting the consensus of utilities participating in the PNUCC, specify that energy reserves will consist of a half year's worth of utility-type load growth expected in the West Group Area. This is the only energy reserve explicitly included in the Uniform Regional Planning Assumptions, and it is intended to provide for either of two contingencies: load growth exceeding the forecast or slippages in commercial operation dates for large thermal plants. (See Appendix C of the Draft Role EIS, II.B.4., for further discussion of load growth reserves.)

PNUCC reports provide for other energy reserves indirectly: energy associated with thermal plant forced outages is accounted for with annual capacity factors; energy lost due to plant schedule slippages is accounted for with a procedure for determining plant construction times; and DSI contracts provide reserves for plant scheduling delays under certain conditions.

2.4 The Nature of Current Marketing and Transmission Policies, Programs, and Practices

BPA policies are expressed through a variety of mechanisms, including published statements, news releases, oral presentations at customer and public meetings, and contracts. Policies are based on statutory requirements, Executive Orders, Secretarial Directives and Orders, the requirements of system operations, agreements with other agencies or organizations, past experience, and comments offered by the public. Policymaking at BPA has been influenced by those portions of the Administrative Procedure Act incorporated in the Department of Energy Organization Act. Since publishing the BPA Procedure for Public Participation in Marketing Policy Formulation, 42 F.R. 62950, December 14, 1977, major power marketing policies have included a Public Involvement Process, which includes publication of the proposed policy, opportunity for public comments, and the consideration of public comments prior to final policy determination.

2.4.1 Preference and Priority

The Bonneville Project Act requires that preference and priority in marketing power be given to public bodies and cooperatives. Preference and priority to public bodies and cooperatives has been reaffirmed in the Regional Act. In addition, geographical preferences are established by the Hungry

Horse Dam Act of 1944 and by the Pacific Northwest Regional Preference Act of 1964. These preference requirements, particularly the preference to public bodies and cooperatives, have great significance on BPA policy.

The preference clause of the Bonneville Project Act was included to assure that the benefits of public power were not locked up by investor-owned utilities and large industry. Power was to be distributed as widely as possible among the general public, with specific mention made of the needs of domestic and rural consumers. Rural electrification of areas not served by investor-owned utilities was a paramount concern but it was recognized that it would take time to form these new service entities. However, because there was a surplus of firm power, sales could be made to both preference and non-preference customers. Since that time, the clause has become more significant as the region's electrical demand has outstripped available Federal electric resources. The definition of a preference customer and the ramifications of the clause are now matters of regional significance.

Since the 1976 Notice of Energy Insufficiency, nonpreference customers have known that without additional resources, BPA would not be able to offer them new contracts. The Bonneville Project Act is unambiguous about preference and priority for public bodies and cooperatives. As noted in a legal opinion of March 20, 1948, by the BPA General Counsel, "the language of section 4(a) is sweeping in its terms. It demands that the policy of preference and priority be followed without limitation and 'at all times'".

However, the Act is silent as to how or whether BPA should distinguish between preference customers. BPA presently relies on court decisions which indicate that the Administrator has plenary discretion to allocate among preference customers, and that while public entities have preference over private entities, the clause does not require that all preference customers be treated equally or that all preference applicants receive an allocation, or that a distinction be made between existing preference customers, new preference customers, or preference applicants.

Additionally, there are two aspects of geographical preference established by law. The first concerns the Hungry Horse Dam Act of 1944, and the second is the result of the Regional Preference Act.

The Hungry Horse Act of 1944 gives geographical preference to Montana for power generated at the Hungry Horse project. The "Montana Reservation" in the Hungry Horse Act does not require any specified amount of Hungry Horse power to be guaranteed to Montana. In 1950, within the discretion provided by the Act and by the power marketing authority granted to him under Interior Secretarial Order No. 1994, BPA Administrator Raver determined that the amount of energy to be reserved for the State of Montana's needs was to be 221,000 average kilowatts (221 average MW). This amount has remained the same since that time. The State of Montana has, to a limited extent, pressed for the establishment of similar reserves from other FCRPS dams located in Montana, most notably Libby.

The Pacific Northwest Regional Preference Act of 1964, 16 U.S.C. 837-837h, guarantees to the Pacific Northwest customers the first call on the electric energy generated at Federal hydroelectric plants located in the region. Under the Regional Preference Act, only surplus power, that is, power for which there is no Pacific Northwest market or which cannot be conserved for later sale within the region, may be sold outside the region.

Section 5(a) of the Regional Act states that all power sales under the Act are subject at all times to the preference provisions of the Bonneville Project Act.

2.4.2 Classes of Customers

Within the general policy of giving preference and priority to preference customers in the sale of available power, BPA enters into power sales contracts with public bodies and cooperatives which qualify as preference customers under the Bonneville Act. Bonneville is negotiating new power sales contracts under the Regional Act. The Act requires that 20-year contracts be offered to public and private utilities, Federal agencies, and direct-service industries within nine months of enactment or by September 1, 1981. The new contracts will require Bonneville to meet the load growth of utilities including the rural and domestic loads of private utilities.

2.4.2.1 Federal Agency Customers

In 1979, the Federal agency customers represented about 1 percent of the total energy sales of BPA. BPA Federal agency customers are served either as ultimate consumers or as utility-type customers that resell power and energy to an ultimate consumer. In either case, Bonneville has customarily attempted to provide major electric power and energy requirements of its Federal agency customers, with some limitations.

Bonneville provides under appropriate rates, both "contract demand" and "demand limit" contracts. The first provides a block of electric power and energy under the appropriate rates; the second allows the customer to purchase its power and energy requirements up to a given limit.

Under the Notice of Insufficiency issued in June 1976, BPA notified some of its Federal agency customers that it would no longer be able to meet their firm energy requirements after July 1, 1983. As early as the fall of 1975, Bonneville notified the U.S. Navy at Bangor and Bremerton, Washington, the Energy and Research Development Administration at the Hanford Project, and the Bureau of Indian Affairs at Kerr, Montana, that their existing power sales contracts did not provide for power and energy in excess of the amount currently provided in their contracts as of that date. The continued level of service to these agencies will depend on BPA's other power supply obligations and on power availability conditions in the Pacific Northwest.

Remaining Federal agencies' contracts--with the U.S. Air Force, the Bureau of Mines, the WPRS, and the Bureau of Indian Affairs--provide firm power requirements to a specified demand limit. These demand limits establish BPA's obligations in present Federal agency contracts.

2.4.2.2 Investor-Owned Utility Customers

Prior to 1953, BPA sold some firm power to investor-owned utilities up to specified contract demand limits. In 1953, BPA and Northwest investor-owned utilities entered into 20 year power sales contracts under which the utilities were served on a computed demand basis commencing in 1958. As required by law, these contracts contained provisions for BPA to pull back all or a portion of the firm power on five years' notice if BPA resources would not be sufficient to meet preference customer loads. These contracts terminated in August 1973 and were not renewed. A contract with The Montana Power Company, reflecting the Montana Reservation, provides for the sale of firm power and firm capacity, terminating in 1987. Firm energy will be delivered to The Montana Power Company through 1982 in decreasing amounts. Firm capacity is to be supplied in increasing amounts up until 1981-82 as firm energy decreases and then at a flat amount until 1986-87, after which there will be no more firm capacity supplied.

Under the Regional Act the cost benefits of Federal hydropower will be made available to residential and small farm customers of investor-owned utilities, but this must be done in ways that do not adversely affect the cost and supply protections now enjoyed by preference customers of BPA. The residential and farm customers of private utilities are now paying, on average, more than twice as much for electricity as the customers of publicly owned utilities. The primary reason for this price difference is that private utilities had to rely more heavily on thermal generating plant to supply much of their customers' needs after they lost access to Federal firm hydropower in 1973. Having access to Federal firm power again, under terms of the Act, will mean rate relief for residential and farm customers of investor-owned utilities.

In order to receive power at the lower Federal rate, an investor-owned utility must offer to exchange with BPA an amount of energy equal to the utility's residential and farm load. In what is essentially a bookkeeping transaction, BPA would buy the power at the utility's average wholesale cost, and sell the same amount back to the utility at the lower Federal rate. BPA will exchange no more power than the investor-owned utility sells to BPA. The private utility must pass on the savings from this exchange directly to its residential and rural customers, and is not allowed to profit from the transaction.

The increases in rates paid by direct-service industrial customers of BPA--called the DSIs--will cover all the costs of this exchange until 1985 and a substantial part thereafter. BPA will supply them with power at a higher rate than they pay under their existing contracts--a rate that reflects costs of power sold to BPA by the investor-owned utilities.

The private utilities will exchange their higher cost resources for lower cost Federal power in steps between now and 1985. The utilities will acquire enough electricity at low rates to serve 60 percent of their rural and residential loads initially, and the remainder in 10-percent increments until 1985. The DSIs will assume the costs of the exchange on the same schedule.

The calculation of average system cost is an important aspect of the exchange agreements between the private utilities and BPA. This cost will be averaged with the costs of other power resources available to BPA to determine wholesale rates for all customers of Bonneville in the region. BPA will develop a formula for determining the average system cost of the private utilities, in consultation with the Council, State public utility commissions and the region's utilities. The average system cost will include the costs of both hydropower and thermal plant resources the investor-owned utilities would otherwise use to serve their loads. The method is subject to approval by the Federal Energy Regulatory Commission, with the assistance of a board with representation from the States.

The Congress excluded from this computation some costs that would otherwise inflate the average. Specifically excluded are the costs of additional resources needed to serve new large single loads (10 or more average megawatts per year), costs of serving a utility's load growth outside the region, and the costs of any generating project that fails to get into operation.

Investor-owned utilities may terminate power exchange agreements on five years' notice. The private utilities could exercise this option if power sold by BPA reached a price higher than their own average system cost.

Except for various transfer and transmission services, deliveries to other investor-owned utilities now consist of Hanford Exchange Energy and the sale of nonfirm energy and firm capacity, in addition to special short-term arrangements, involving resources in excess of preference customer and other firm contract requirements or the exchange of energy or capacity.

The amount of the BPA sales of peaking capacity to investor-owned utilities, including requirements for forced outage reserves, is determined by the balance remaining after subtracting the total of firm loads and reserves for unanticipated load growth from the total of assured resource capability, which includes the capacity which can be made available by the addition of units under construction at authorized Federal projects.

2.4.2.3 Industrial Customers

BPA's direct-service industrial customers (DSI) may purchase power under two different rate schedules: IF (Industrial Firm Power) and MF (Modified Firm Power). Industrial Firm is subject to more restrictions than Modified Firm, but when IF is restricted, the industrial customer receives a billing credit for the lack of availability. MF contracts have not been renewed and most will expire during the 1980's. The contracts providing for industrial firm power are "interim" contracts, terminable on 30 days notice by either

party. Their "interim" contracts will be terminated on or before the date of termination of the MF contracts with which they are associated. Furthermore, if a DSI terminates an IF contract, BPA has agreed to revert to the MF contract, which, by the way, provides no Advance Energy.

Under the Regional Act the DSIs make possible the rate relief for customers of investor-owned utilities by their willingness to trade in the remaining years of their existing low-cost power contracts. In turn they get new 20-year contracts at higher rates. The price of power sold to the industries by BPA will increase in yearly steps during a "ramping" period until July 1, 1985. Congress provided the gradual raising of rates to give the industries time to absorb higher costs.

The industries will gain the security of long-term contracts, which will enable them to continue doing business in the region and to plan plant improvements. Importantly, the DSIs will continue to play the unique and important role they assumed early in the development of the hydropower system--to provide electricity reserves for the region. Service to portions of their loads can be interrupted by BPA to make up for scheduled or unscheduled plant outages or transmission failures, or to make up for failure of planned generating resources to come online as scheduled.

Under the Act, BPA may not take on new direct-service industrial customers. It also bars BPA from selling to existing DSIs more power than they are entitled to under existing contracts. This is further incentive for the industries to improve the efficiency of their processes if they wish to increase production.

BPA entered into a contract in 1966 to serve directly a new aluminum plant proposed by Northwest Aluminum Co. This company sold out to Alumax Pacific Corp., which ultimately decided to locate a plant near Umatilla, Oregon. A court order enjoined BPA from delivering power to Alumax pending completion of an environmental impact statement. The aluminum plant has not been constructed. The Act allows BPA to serve Alumax if the company builds the plant and if BPA determines it can acquire adequate resources to serve that load.

2.4.2.4 Distribution of Nonfirm Energy to Customers in the Northwest

Nonfirm energy is available when the combination of streamflows, reservoir elevations, and thermal generation have the potential to produce generation in excess of the Federal System's firm energy contractual commitments.

Nonfirm energy is sold, first, on the basis of any preferences for classes or types of customers, and secondly, on an "energy use" priority basis within such preference classes or types of customers. Nonfirm energy distribution priorities are listed below:

1. Firm energy loads will be served if any are not being met.

2. New reservoirs will be filled, or depleted reservoirs will be restored, by serving customer loads with nonfirm energy.

3. Generation from customers' thermal plants will be displaced with nonfirm energy. Displaced generation from thermal plants will later become available for sale to other utilities or industries.

2.4.2.5 Distribution of Nonfirm Energy to Customers Outside the Pacific Northwest

The Northwest preference law (P.L. 88-552) limits the sale of hydro generated energy to the Southwest to that which is surplus to the needs of the Pacific Northwest. Preference customers in the Southwest have preference rights on Federal energy exported to the Southwest, but have no preference rights over utilities in the Northwest, preference or otherwise.

The means of allocating surplus energy delivered to the Southwest is described in BPA's current contracts with Southwest utilities. The contracts provide that, within classes, energy be apportioned among these utilities in a ratio which reflects the California Intertie capacity each has available to receive energy to the total California Intertie capacity available for all such utilities.

The Exportable Energy Agreement (Contract No. 14-03-73155) enables the utilities of the region and BPA to share in the disposition of surplus energy pursuant to the BPA and other utility power sales contracts and exchange agreements with the various California utilties, both public and investor-owned. The surplus energy to be delivered from the Pacific Northwest under those agreements may actually be supplied from exportable energy of a non-Federal utility, public or investor-owned, made available to BPA under the Exportable Energy Agreement.

The Exportable Energy Agreement also provides for equitable sharing of imports of nonfirm energy (excess from California companies). Under the Priority Agreement (Contract No. 14-03-83066), all imported energy is to be made available on a proportional basis to all Pacific Northwest entities in accordance with a specified priority among the types of uses; i.e., meeting firm load, refilling reservoirs to energy content curves, steam displacement, and other uses. For example, all Pacific Northwest utilities needing excess energy under the highest priority would share available energy proportionately before any entity could obtain excess energy for a lower priority use.

Pacific Southwest utilities are also able to acquire non-Federal energy from Pacific Northwest utilities either through a trust fund agreement, with BPA acting as their agent, or through a direct contract, or "bilateral" agreement, with the Pacific Northwest utilities.

2.4.3 Repayment of FCRPS Investment

2.4.3.1 Self-Financing Authority

With the passage of the Federal Columbia River Transmission System Act of 1974, P.L. 93-454, BPA became a self-financed agency; that is, BPA operates using its own revenues and the proceeds from bonds sold to the Treasury of the United States, and does not require appropriations authorized by Congress. The Act established in the Treasury a Bonneville Power Administration Fund, into which is deposited all revenues, bond proceeds, and miscellaneous receipts. BPA prepares an annual budget which it presents to the Congress for approval, and the Administrator may then make expenditures from the BPA Fund without fiscal year limitations. The expenditures, which are subject to statutory direction, finance BPA's operating costs, its construction program, related research, purchased power, the repayment of the FCRPS, irrigation assistance, and other related expenses. The Transmission System Act also restated the requirement that power sales and wheeling rates be established so as to recover the cost to the government of generating, purchasing, transmitting, and marketing electric power.

The purpose of self-financing is to enable BPA to operate as a business, thus allowing the agency to respond in an orderly way to the electric needs of the region without being dependent on appropriations. BPA's ability to construct needed regional transmission facilities without the potential delays that may be associated with the appropriations process can be of benefit with respect to bringing newly constructed generating projects to market.

The Regional Act expands Bonneville's borrowing authority from the Federal Treasury.

2.4.3.2 Current BPA Repayment Policy

BPA's legal mandate is to set rates to collect revenues sufficient to recover the cost to the Government of generating, purchasing, transmitting, and marketing electric power. The basic requirement to recover costs is found in Section 7 of The Bonneville Project Act of 1937, as amended, 16 U.S.C. 832f, which states that rate schedules must take into account the cost of producing and transmitting electric energy, including amortization of the capital investment. The requirement is restated in Section 9 of the Federal Columbia River Transmission System Act.

Simultaneously, however, both the Flood Control Act of 1944, which applies to the marketing of power from all Corps of Engineers projects, and the Transmission System Act of 1974, require that BPA market Federal energy "at the lowest possible rates to consumers consistent with sound business principles . . . ." Therefore, on the one hand, rate levels must be set sufficiently high so as to produce revenues adequate to recover the costs, but at the same time, the rates overall must be set sufficiently low to provide the lowest possible rates to consumers.

The adequacy of revenues is determined by preparing a repayment study, which consists of a forecast of both revenues and costs over the 50-year repayment period. To be adequate, the revenues must be sufficient over the repayment period to:

1. Pay the cost of obtaining power through purchase and exchange agreements.
2. Pay the cost of operating and maintaining the power system.
3. Pay interest on and amortize outstanding revenue bonds sold to the Treasury to finance transmission system construction.
4. Pay interest on the unamortized investment in power facilities financed with appropriated funds. (Federal hydroelectric projects and BPA transmission facilities constructed prior to BPA's authorization to finance its construction program with the sales receipts and revenue bonds, were financed with appropriated funds.)
5. Repay, with interest, any outstanding unpaid annual expenses, such as purchased power cost, operation and maintenance costs, bond amortization, and interest expense, carried over from the previous year.
6. Repay each increment of the power investment at the Federal hydroelectric projects within 50 years after such increment becomes revenue producing.
7. Repay each annual increment of the investment in the BPA transmission system previously financed with appropriated funds within the average service life of the transmission facilities (currently 35 years).
8. Repay the investment in each replacement of a facility at a Federal hydroelectric project within its service life.
9. Repay the portion of construction costs at Federal reclamation projects which is beyond the ability of the irrigation water users to repay, and which is assigned for repayment from commercial power revenues, within the same overall period available to the irrigation water users for making their repayments. These periods range from 40 to 66 years, with 60 years being applicable to most of the irrigation repayment assistance.

In the repayment study, the estimated revenues are applied to cover each year's expense for: (1) operation and maintenance, (2) purchased power, (3) interest, and (4) amortization of BPA's bonds. All remaining revenues are applied to the repayment of the capital investment financed with appropriated funds and, in the years in which irrigation repayment assistance is due, to the amortization of the irrigation costs assigned for repayment from power revenues. A comparison is made, year by year, of the unamortized, or unpaid, amount of each investment during each year of the study with what is allowed to be unamortized, given the established criteria of the repayment study. If the unamortized investment exceeds the amount allowed for any investment for any year, this indicates that the repayment criteria are not being met and that an increase in revenues will be necessary to assure complete recovery of all power costs within the expected repayment periods.

The repayment study prepared for each proposed rate adjustment includes the costs and the revenues that will be produced from all Federal power projects scheduled to be in service during the proposed rate period, the irrigation repayment assistance which has been authorized by Congress, and the costs to BPA of purchasing plant capability and power during the rate period.

As the FCRPS is operated as an integrated power system and power rates are based on system average costs, new hydroelectric projects which may be added to the FCRPS will be repaid from system revenues. This feature enhances the financial feasibility of adding new hydroelectric projects, because a newly added project need not produce revenues equal to its own costs. If a new project is above system average costs, which would be the likely result given the current level of construction costs, it most likely would require at least a slight increase in the system rates. The resulting system rate level, however, would be lower than an individual rate level that would have to be set for the new project if it were not integrated into the FCRPS.

2.4.4 Wholesale Power Rates

2.4.4.1 Legal Requirements Affecting BPA's Rates

Widespread Diversified Use. The Bonneville Project Act states that rate schedules "shall be fixed and established with a view to encouraging the widest possible diversified use of electric energy," (16 U.S.C. 832e). Bonneville chose to implement this directive by adopting "postage stamp" wholesale rates. Under Bonneville's postage stamp rate, all customers receiving similar service pay the same rate regardless of the customer's physical location. Thus, for example, rural communities are not faced with the prospect of paying excessively high transmission rates in order to receive Federal power. Electrification of rural communities throughout the Pacific Northwest was further aided by BPA's developmental discount established in December 1959, which was discontinued in 1974 since the goal of electrification of rural communities had been largely accomplished.

Lowest Possible Rate. Another legislatively imposed criterion is that BPA's power should be priced at the "lowest possible rates to consumers consistent with sound business principles," 16 U.S.C. 838g. Bonneville accomplishes this task by conducting a repayment study to arrive at its revenue requirement. In the repayment study, all of BPA's costs are examined and the lowest possible revenue level adequate to recover those costs is determined. A set of rates is then designed to recover the specified revenue.

The Public Utility Regulatory Policies Act of 1978 (PURPA), which is applicable to Bonneville, requires utilities with annual sales to the ultimate consumer of over 500 million kWh to consider six ratemaking standards in the process of developing power rates. BPA has held public hearings on the matter and has adopted the standards. The standards include cost of service, declining block rates, time-of-day rates, seasonal rates, interruptible rates, and load management techniques. In developing wholesale rate schedules, Bonneville considers all six ratemaking standards with respect to conservation, efficiency, and equity. More detail on Bonneville's consideration of the standards may be found in the Summary of Record.

The Bonneville Project Act requires that BPA execute contracts which allow BPA to review the adequacy of its power rates at least every 5 years and, if necessary, adjust them. Most of the power sales contracts executed before December 1977 provided that the rates could be changed only on December 20 of every fifth year. Bonneville was thus effectively "locked into" a 5-year rate review period. Until recently, this limitation posed no problems for either BPA or its customers, for the power rates were essentially unchanged between 1938 and 1965. In recent years, however, several factors, including inflation, construction of new Federal generation and transmission facilities, and the purchase costs of thermal power, have combined to cause BPA's costs to increase dramatically. In the face of such rapid cost escalations, the increase in costs over a period as long as 5 years would require an extremely large rate increase every 5 years. As a result, BPA and all of its utility, industrial, and Federal agency customers amended the power sales contracts to allow BPA to review its wholesale power rates on an annual basis and, if necessary, adjust them on July 1 of every year, beginning July 1, 1981.

Smaller, more frequent rate increases enable BPA to track its costs more closely, avoiding serious revenue surpluses or deficits. They also mitigate the impact on consumers' abilities to pay BPA's increased rates.

2.4.4.2 Wholesale Power Rate Development Process

The Secretary of the Department of Energy (DOE) has, under current law, the responsibility to confirm and approve BPA's rates. This responsibility is delegated to the Assistant Secretary of Energy for Resource Applications for interim approval and the Federal Energy Regulatory Commission (FERC) for final approval. In evaluating the appropriateness of the rate proposal, the Assistant Secretary and FERC consider the effectiveness of the proposed rates in satisfying Bonneville's repayment obligations.

The actual rate review process is, of course, more complex than described above. Bonneville begins by conducting a number of studies related to repayment requirements (See 2.4.3), cost analysis, and rate design.

In developing wholesale power rates, Bonneville is guided by basic rate design and legislative objectives. These objectives are: (1) revenues must be adequate to meet Bonneville's repayment obligation; (2) in meeting the revenue requirements, the burden should be distributed in an equitable manner among recipients of the service; (3) rates should be designed to encourage conservation and minimize environmental impacts; (4) rates should be designed to encourage efficient use of the Federal Columbia River Power System by reflecting costs incurred and benefits received; and (5) rates should encourage the widest possible diversified use of electricity.

The Regional Act establishes a rate-setting policy for three types of customers. The first type includes cooperatives, publicly owned utilities and Federal agencies. The other two types are investor-owned utilities and direct-service customers of BPA.

Preference Customers--BPA's wholesale rates for Federal agencies, publicly owned utilities and co-ops cannot be higher than would have been the case without the Act--the Act specifies a formal rate test. The rates of publicly owned utilities and co-ops will increase in the future, but the Act should help keep the increases lower than they would otherwise have been. Generally this class of customers will receive the lowest Federal wholesale power rate available, except for new large loads.

Investor-owned Utilities--Investor-owned utilities may exchange power with BPA to receive at the same low wholesale rates as preference customers for wholesale power in an amount needed to serve their residential and farm customers. The investor-owned utilities will pay a higher rate for whatever additional power they choose to buy from BPA to serve their other loads.

The availability of electricity at BPA's low wholesale rate to investor-owned utilities for their residential and farm customers will not mean equality in retail prices charged by publicly owned and investor-owned utilities. In arriving at its own retail price per kilowatthour, each utility must add its own costs of doing business, such as distribution, operating and maintenance costs.

After power contracts with BPA are signed in 1981, wholesale rates for residential and farm customers of investor-owned utilities will be lower than they otherwise would be to the extent that the power from BPA costs less than the electricity exchanged by the investor-owned utilities.

Direct-service Industries--The rate relief for the residential and farm customers of the investor-owned utilities is made possible by the higher rates paid by the direct-service industrial customers of BPA. The Act requires that prior to July 1, 1985, BPA rates for DSIs must cover the costs of serving them, plus the costs of power exchanges between BPA and the investor-owned utilities.

After July 1, 1985, when the residential and farm customers of investor-owned utilities are receiving the full benefit of Federal base rates, the DSI rates must be at a level commensurate with the retail rates paid by industrial customers of publicly owned utilities in the region. The DSI rate is expected to be several times greater than it is today.

2.4.5 Short-Term Power Purchases

Continuing Fund Purchases. Throughout its history, BPA has purchased power on a short-term basis when faced with forecasted energy or peak deficiencies caused by delays in new generation facilities, drought-induced critical streamflows, or unanticipated increases in power demands.

Purchases generally are arranged just prior to or during an operating year if planning studies show a need for additional power. In some cases, long-range planning studies reveal short-term deficits in certain years during the planning term. In other cases, current operation planning studies indicate an immediate need for more power.

Prior to October 18, 1974, when the Federal Columbia River Transmission System Act (P.L. 93-454) was signed into law, BPA's short-term purchases were effected through use of the "continuing fund" for emergency situations, as provided in the Bonneville Project Act. Because constraints on use of the continuing fund were vague, only small amounts of power were obtained.

Projected Future Deficits. When a deficit is indicated, BPA and Northwest utilities generally attempt to purchase short-term power to fill it. This has been an efficient approach to handling forecasted short-term deficits.

The alternative is to curtail load or add ready-to-install thermal generating plants such as combustion turbines, diesel-electric generators, or small steam-electric plants. Long-range resource development plans usually do not include this type of resource because these plants are expensive to operate and their use is limited by the Powerplant and Industrial Fuel Use Act of 1978.

Power may be available for purchase on a short-term basis from utilities with temporary surpluses of peaking capacity or energy. Because new resource developments currently involve large 1,000 to 1,500 MW plants and initial service dates of the new plants tend to deviate from schedules, individual systems may have a short-term surplus or deficit. Short-term purchases by systems with deficiencies from systems with surpluses permit operating economies and use of all new resources. In the future, fewer temporary surpluses are expected to be available for short-term purchases because all utilities are experiencing delays in construction of new generating resources.

In 1979, BPA assisted the industries to serve their interruptible load by arranging for the short-term purchase of hydro energy from B.C. Hydro and Cominco, cogeneration from Weyerhaeuser and Longview Fibre, nuclear power from Hanford, and by BPA advancing energy from Federal reservoirs. The industries paid as much as 35 mills/kWh for the Canadian hydro and as much as 27 mills/kWh for the cogeneration. These sources are also available to BPA to meet its customers' firm energy requirements.

2.4.6 Transmission Reliability

BPA transmission lines link the generation centers of the Pacific Northwest with the distribution facilities of customer utilities, with large industrial users, and also with the systems of other utilities. The Northwest power system is complicated by multiple ownerships operating within the same service area. Over a period of years, BPA and the other utilities have planned facilities to minimize the overall costs as if the whole system had a single ownership. This has resulted in planning lines for technical and economic efficiency and multiple ownership and construction responsibilities.

BPA's authority to finance and construct transmission facilities and to enter into contractual agreements is stated in the Bonneville Project Act and the Transmission System Act, as discussed in section 2.1.1. The use of Federal transmission lines to transmit non-Federal power eliminates costly duplication. Multipurpose lines also minimize economic and environmental impacts.

The Administration enters into long-range contracts to transmit power from non-Federal power plants to the customer utility's load centers. The contract can be up to the life of the generating project. BPA will construct system additions as required by the contract. The division of ownership, construction, operation and maintenance is negotiated. The user of BPA facilities is expected to compensate BPA for services and investment.

Transmission reliability criteria are defined in terms of contingencies, response times, and system performance. A contingency occurs when an element of the transmission service is not functioning either because of mechanical failure or because it is isolated for maintenance or safety. The transmission system is designed and operated so that it can respond to the more common contingencies without widespread outage to customers.

Since the incremental cost of system reliability can rise with the standards of reliability, it is necessary to compare the criteria of a PNW utility with those of other utility systems. BPA's standards are comparable with the national guidelines proposed by FERC. BPA is also an active participant in national and regional organizations concerned with power system reliability namely, the National Electric Reliability Council, Western System Coordinating Council, and Northwest Power Pool.

BPA plans for an adequate power supply by pooling resources with other utilities. The strong system interconnections between various powerplants and principal substations provide the support to avert power outages during the nonavailability of a generation or transmission facility. Interconnections with other utilities and regions provide additional resources. However, delay in planned facilities may jeopardize reliability of service. (See 2.2.4.)

SECTION 3 EFFECTS OF ADDITIONAL POWER SUPPLIES ON BPA PROGRAMS

3.1 Markets for Additional Capacity and Energy

Projected firm energy and capacity deficits provide a measure of the extent of the unsupplied Northwest market for additional power. As discussed in Section 2.3.1, firm energy deficits during the 1980's range from a low of 2040 MW in 1980-81 to a high of 4128 MW in 1989-90. Deficits of greater magnitude are also projected for the 1990's. Therefore, the Pacific Northwest utilities provide a prime market for additional hydro power supplies developed at costs competitive with other generation sources.

In addition, the Pacific Northwest has a substantial market for secondary energy and capacity which is used to displace thermal generation, serve the interruptible portion of the electro process industries, and to export when power is available in excess of Pacific Northwest needs. Secondary markets provide an additional outlet for power should circumstances develop such that this power would not be needed to meet firm loads (a situation not likely to develop during the 1980's).

3.2 Pacific Northwest Electrical Demand

In the Pacific Northwest, each year a forecast of future years of the total loads is compared with the current schedule of existing and planned generating resources to determine the need for additional generating facilities. The load-resource tables, which extend 20 years into the future, are used as a guide to help determine the optimal size of such additional generation, the time that it would be required to meet forecasted demands, and whether the planned new facilities should provide peaking capacity or energy, or both. Load forecasts are also used by investor-owned utilities and public agencies for planning for transmission and distribution facilities in much the same way they are used in planning generating facilities.

In addition, both types of utilities use demand forecasts for revenue forecasting and rate making. By comparing the forecasted revenues based on present rates with anticipated costs (which are also based indirectly on load forecasts), the need for adjustments in rates to increase (or lower) the revenues can be anticipated in advance. Forecasts by class of customer can then also be used with appropriate cost analyses in the design of the new rates to ensure that not only are sufficient revenues received to recover all costs, but also that the rates are structured equitably so that individual customers or classes of customer do not pay excessively high or unreasonably low rates, compared to the utilities' costs of serving them.

Regulatory and administrative government agencies also make load forecasts, in order to carry out their responsibilities for regulating construction and operation of generating facilities, rates, and reliability of service.

The demand for electricity in the Pacific Northwest Region is dependent on the same technological, social, economic, and policy factors as are found throughout the United States. In the Northwest, however, there are some seasonal factors unique to the region.

A number of types of load which contribute to total demand exhibit seasonal variations. Electric space heating and air conditioning loads vary with seasonal differences in temperature. Irrigation loads also vary with types of crops, growing schedules, and seasonal precipitation patterns. These seasonal variations do not usually change significantly over the long run, so power planners and schedulers can anticipate with a certain degree of confidence that the annual peak demand for the Pacific Northwest will occur between December and February due to the high saturation of electric space heating.

3.2.1 Comparison of Load Growth Forecasts

Several electric energy load forecasts have been made for the Pacific Northwest in the 1970's. Figure 3-1 and Table 3-1 show certain of these forecasts that were made by Federal Agencies, utilities, special commissions, and conservation organizations during the years 1977-80.

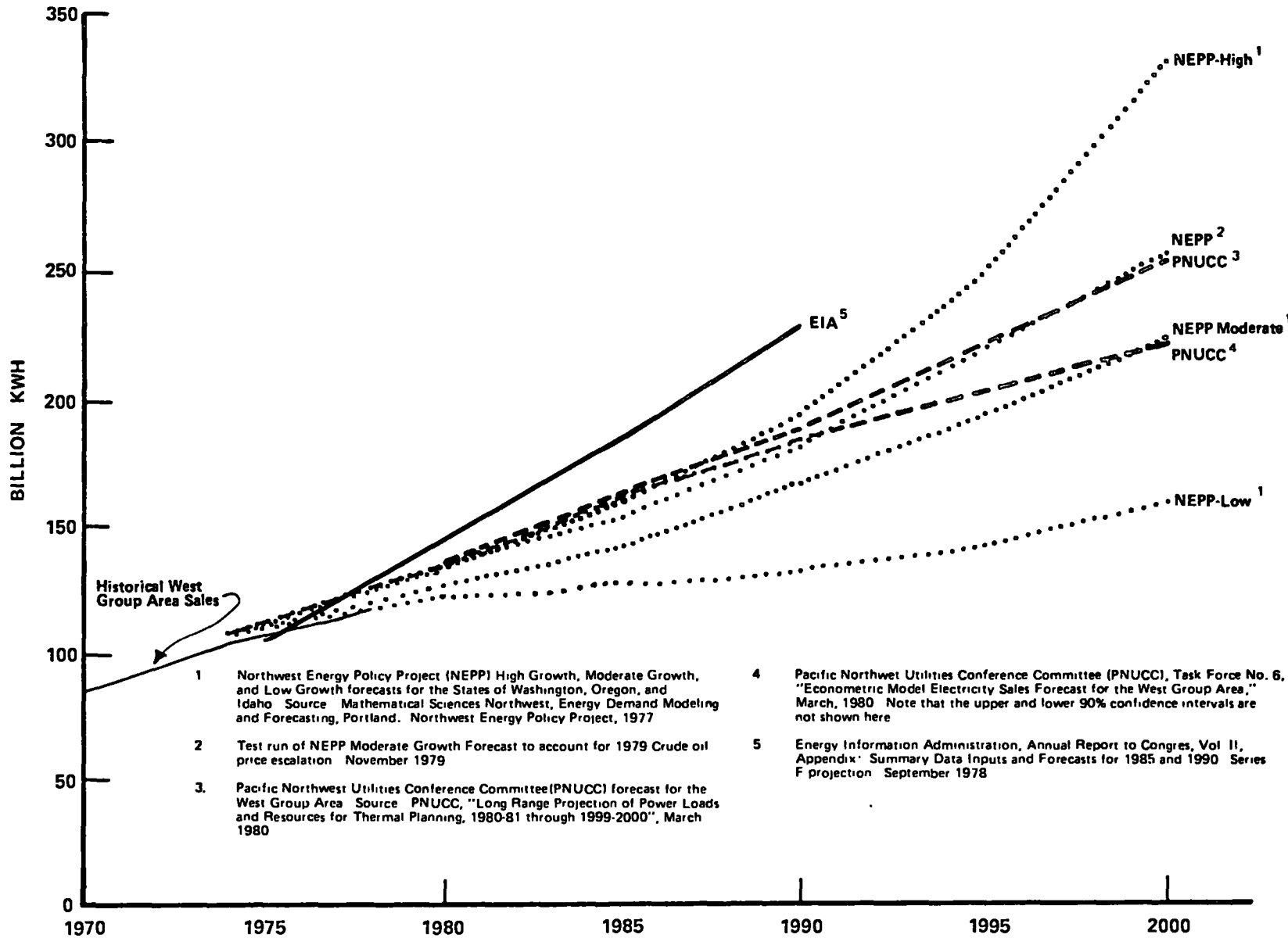
Table 3-1

LOAD FORECAST COMPARISONS - PACIFIC NORTHWEST

		1980	1985	1990	1995	2000
PNUCC-West Group (Blue Book)						
Ave. MW		17490	20509	24565	27600	32029
Million kWh		153210	179660	215190	241780	280570
PNUCC Econometric Model (West Group Area)						
High	Million kWh	137591	176057	210344	246749	272547 1/
Medium	Million kWh	135119	165082	190474	217176	234535 1/
Low	Million kWh	132647	154106	170605	187602	196523 1/
Northwest Energy Policy Project (PNW Area)						
High	Million kWh	132189	156700	193787	249108	330657
Medium	Million kWh	126814	142943	164795	191970	228960
Low	Million kWh	120510	124745	131400	142538	156060
Harza Engineering Co. (Northwest Power Pool Area)						
Median	Million kWh	--	240700	297700	359900	435700

1/ 1998

ELECTRICAL ENERGY LOAD FORECASTS FOR THE PACIFIC NORTHWEST



1 Northwest Energy Policy Project (NEPP) High Growth, Moderate Growth, and Low Growth forecasts for the States of Washington, Oregon, and Idaho Source Mathematical Sciences Northwest, Energy Demand Modeling and Forecasting, Portland. Northwest Energy Policy Project, 1977

2 Test run of NEPP Moderate Growth Forecast to account for 1979 Crude oil price escalation November 1979

3. Pacific Northwest Utilities Conference Committee(PNUCC) forecast for the West Group Area Source PNUCC, "Long Range Projection of Power Loads and Resources for Thermal Planning, 1980-81 through 1999-2000", March 1980

4 Pacific Northwet Utilities Conference Committee (PNUCC), Task Force No. 6, "Econometric Model Electricity Sales Forecast for the West Group Area," March, 1980 Note that the upper and lower 90% confidence intervals are not shown here

5 Energy Information Administration, Annual Report to Congres, Vol II, Appendix· Summary Data Inputs and Forecasts for 1985 and 1990 Series F projection September 1978

FIGURE 3-1

BPA cooperates with nongenerating public utilities, Federal agencies, and its direct-service industrial customers in preparation of their load forecasts. The summation of these individual load forecasts constitutes the "Federal System Load" in the Pacific Northwest. Investor-owned utilities and public agencies with generation independently prepare load estimates for their respective service areas. The total of the Federal system load and these individual estimates constitutes the regional load forecast.

BPA participates directly in the preparation of load forecasts for approximately 100 public agency electric utility systems, which represent less than half of the estimated regional load.

PNUCC. The Pacific Northwest Utilities Conference Committee (PNUCC) West Group Forecast has been prepared annually since 1954 by the PNUCC Subcommittee on loads and resources. In 1968, the forecast was extended from 10 to 20 years because of greater lead time required to place new resources on line. Each year the PNUCC publishes an 11-year load and resource forecast (Black Book) and a 20-year load and resource forecast (Blue Book). The Subcommittee on Loads and Resources of the PNUCC annually prepares new long-range load-resource analyses based on the current regional forecast.

The PNUCC "Blue Book", or more formally, the "Long-Range Projection of Power Loads and Resources for Resource Planning 1980-1981 through 1999-2000," estimates an 18-year load growth of energy requirements of 3.24 percent annually. A 3.46 percent annual rate of load growth is foreseen for the years 1980-1990 and a 2.69 percent annual growth for 1990-2000.

PNUCC Econometric Model. The PNUCC Model Review Subcommittee prepares an annual electric energy sales forecast for the West Group Area using an econometric model. Preliminary findings indicate an 18-year (1980-1998) medium projection annual growth rate of 3.10 percent. Annual growth rates for the periods 1980-1990 and 1990-1998 are 3.5 percent and 2.6 percent, respectively.

Growth rates by sector are listed below:

	Residential	Commercial*	Industrial	Total
1980-1990	3.37	3.74	3.47	3.50
1988-1998	1.91	2.85	3.14	2.68
1980-1998	2.66	3.29	3.34	3.10

* Includes street, highway lighting, and irrigation.

In this forecast, industrial usage is identified as being the area of highest growth with the commercial and residential sectors ranking second and third, respectively.

Northwest Energy Policy Project (NEPP)

The official version of the NEPP model forecast of electricity growth rates (moderate growth scenario) in the Pacific Northwest was 3.0 percent for the period of 1980-2000. Ten-year growth rates were 2.65 percent for the years 1980 to 1990 and 3.34 percent for the 1990 to 2000 period.

Individual sector growth rates for the moderate growth scenario are listed below:

	Residential	Commercial*	Industrial	Total
1980-1990	3.92	2.31	2.13	2.65
1990-2000	3.76	2.63	3.50	3.34
1980-2000	3.84	2.47	2.81	3.00

* Includes irrigation and miscellaneous sales.

Residential sector electricity demand growth rates are highest, followed by industrial and commercial sectors.

Harza Engineering Company

The Harza Engineering Company has developed a range of national and regional electricity projections (March 1980) from published information and data on electricity demand forecasts.

One projection was derived from and based on data provided by the utilities through the regional National Electric Reliability Council (NERC), which is required to forecast electricity demand.

A second projection was derived from forecasts made by the Institute for Energy Analysis (IEA) at the Oak Ridge Associated Universities.

A third projection of electricity demand was based on a "consensus forecast" which was an average of 15 separate forecasts made by various Federal agencies and private organizations in the post-1973 oil embargo period. These forecasts were conservation oriented, and differ from the historical growth forecasts that were made in the pre-embargo period.

The three projections were intended to encompass a reasonable range of future demands for electricity. The range of the high and low projections reflect different assumptions concerning population, economic growth, conservation, legislative action, and regulatory policies for the projection period.

From the three projections, a "median" electric energy demand projection was selected to be used as representing national, regional, and subregional demands.

The "median" electric energy demand for the United States is anticipated to increase from 2,210 billion kWh in 1978 to 5,550 billion kWh by the year 2000, which represents an annual compound growth rate of 4.3 percent.

"Median" electricity demand for the Northwest Power Pool Area is forecasted to increase from 165.3 billion kWh in 1978 to 435.7 billion kWh in the year 2000, an annual average growth rate of 4.5 percent. Demand forecasts for the seven year period 1978-1985 show an increase of 5.5 percent annually, decreasing to 4.3 percent for the period 1985-1990 and 3.9 percent for the period 1990-2000.

The methodology used to project regional power demand may well result in some distortions when regional population and national per capita electricity use figures are linked to projected regional electric energy demands.

Using the projected Northwest Power Pool region per capita consumption of electricity as shown in the Harza report for the year 2000 and the West Group Area population forecast for that year results in an electric energy demand total for the West Group Area that exceeds the current forecast by over 30 percent. Perhaps the West Group Area is an exception in that electricity (principally hydropower) has supplied a large portion of the areas' total energy needs in the past; however, this calculation illustrates the type of distortion that can result from this methodology when a region's electricity consumption pattern differs significantly from that of the national average.

3.2.2 Impacts of Load Forecasting Inaccuracy

The impacts of underforecasting loads are potentially quite significant. Because load forecasts provide the basis for advance planning of generation, transmission, and distribution facilities, load forecasts which err on the low side could result in the lack of adequate facilities to meet consumer demands for electrical service. Overforecasting provides reserves, but can have impacts on capital investments, the environment, power rates, and consumption rates. However, despite apparent overforecasting in the past in this region, hydrogeneration and other resources have not been overbuilt; primarily because of the failure of resources to come online as projected.

A shortage of adequate facilities could result in a number of alternative situations, ranging from isolated, unscheduled short-term interruptions or reductions in service, to planned "rotating blackouts" or complete curtailment of service to particular sectors of the economy. The total economic and social costs of such situations would depend upon their severity and duration and on allocation and other government policies developed to cope with periods of shortage. (See 2.4.6 for BPA's authority to enter into short-term power purchases.)

Since load forecasts are reviewed and revised periodically, significant underforecasts can usually be detected before shortages actually occur. However, in the attempt to shorten the time required to design and construct facilities, utilities may be forced to accept relatively high-cost facilities because they can be constructed rapidly, or sites which are less than optimally located because they can be developed more rapidly. Such deviations from optimum size, design, location, and timing can result in increased costs and environmental impacts. Furthermore, if built-in delays in facility siting or licensing procedures hinder development, the ultimate effects could include increased costs and environmental impacts and actual power shortages.

Long-range planning for power facilities includes reserve margins to offset potential unanticipated load growth (as well as other contingencies); as a result, neither of the potential adverse impacts discussed above may always result from underforecasting. If the underforecast is greater than the reserve for unanticipated load growth, however, and one of the other contingencies for which reserves are maintained occurs, service interruptions could result. Over the long run, consistent underforecasting or reduction of reserve margins in planning would eventually result in power shortages or serious inefficiencies in resource planning.

In recent years, there has been much more concern about potential overforecasting than underforecasting of loads. Utilities, electric power consumers, and environmental interest groups have all been concerned about potential overforecasting, for related but slightly different reasons.

Utility managers have long been sensitive to potential overforecasting of loads because of the potential resultant overbuilding of power facilities. This sensitivity has been enhanced in recent years by rapidly escalated construction and capital costs, increased public pressure, and sharpened regulatory scrutiny for investor-owned utilities.

In the extreme case, overforecasting of loads could result in the completed construction of needless generation, transmission, and distribution facilities which would then remain idle until forecasted loads equivalent to those which the facilities were intended to meet actually developed. What is more likely than completed construction of excess capacity is that construction would be slowed or stopped before the facilities were completed, as a result of detection of the overforecasting during one of the forecast reviews prior to the facilities' scheduled energization. While the fixed costs which would have to be borne by a utility unnecessarily in such a case would not be as great as if the facilities were actually completed, the utility's costs would still be greater than otherwise, to the extent that design and early construction were undertaken sooner than required. In addition, the commencement of design and construction would commit the utility to a particular location and type of facility that might not be as efficient in the long run as what would have been developed at a later time.

Consumers of electric power and regulatory bodies have become sensitive to potential overforecasting of loads because of the effects such overforecasting can have on rates.

Environmental interest groups are particularly critical of potential overforecasting of electrical loads. Such groups and related individuals believe that overforecasts could lead to self-fulfilling increases in loads. Most economists, load forecasters, and utility managers, however, contend that without deliberate programs to increase loads, forecasts do not produce loads.

3.3 Future Pacific Northwest Resources

3.3.1 Resource Additions Under Active Consideration

Listed on Table 3-2 are the additional major conventional resources which are under active consideration for early installation by some of the regional utilities. Most of those listed are hydroelectric plants which will provide peaking capability but will add little to the region's firm energy supply. How much of the added capability will be available by the end of the decade is speculative. For example, the total leadtime required to secure FERC licenses (which has been reduced for certain sized projects), complete design work and construct the plants may preclude the availability of any of these projects before about 1987. Table 3-3, following, shows various leadtimes.

Table 3-3

LEADTIMES FOR VARIOUS ENERGY RESOURCES

	Years
Cogeneration	2 - 4
Wind/Biomass (forest or mill residues)	3 - 6
Pumped Storage	5 - 7
Small Hydro (new impoundment)	6 or more
Large Hydro	8 - 10
Coal	10 - 12
Nuclear	12 - 14

3.3.2 Hydropower Potential

The preliminary inventory dated July 1980, prepared by the Corps of Engineers for the National Hydro Study identified 589 hydropower projects in the Northwest Power Pool (which includes the BPA service area plus Utah, Wyoming, and eastern Montana) which meet certain technical, economic, and environmental criteria. These projects represent nearly 12,450 average annual MW, located primarily in Oregon, Washington, and Idaho. The output of the projects range from an undeveloped site on the Snake River capable of generating about 4,660 average annual MW to a small hydro project in Washington which would add about .08 average annual MW to the region's generation.

TABLE 3-2

Potential Projects Under Active Consideration

Project Location	Owner[1]	Type of Unit[2]	No. of Units	Nameplate Rating MW
Federal				
Anderson Ranch S. Fork Boise River Idaho	WPRS Addition	H	1	30
Ben Franklin Ringold Washington	USCE	H	16	848
Dworshak Ahsahka, Idaho	USCE Addition	H	1	220
Lucky Peak Boise Idaho	USCE[3]	H	3	75
Lynn Crandall Heise, Idaho	WPRS	H	4	240
McNary Umatilla Oregon	USCE Additions	H	10	1050
Palisades Palisades, Idaho	WPRS Additions	H	2	90
Grant County PUD				
Priest Rapids Mattawa, Washington	Additions	H	6	473
Wanapum Beverly, Washington	Additions	H	6	499
Northern Lights, Inc.				
Kootenai Falls Troy, Montana	—	H	2	140
Pacific Power & Light Company				
Klamath River Development Klamath River, Oregon	—	H	—	230
Pend Oreille County PUD				
Sullivan Creek Metaline Falls Washington	—	H	—	14
Seattle City Light				
Copper Creek Rockport, Washington	—	H	—	120
Tacoma City Light				
Mossyrock Mossyrock, Washington	Addition	H	1	150
Washington Water Power				
Upriver (City of Spokane) Spokane, Washington	Addition	H	—	—
Creston Near Creston, Washington	Additions	C	3-4	1500-2000
Portland General Electric				
Boardman # 2 Boardman, Oregon	Addition	C	1	500

[1] WPRS—Water and Power Resources Service
USCE —U S Corps of Engineers

[2] H = Hydro, C = Coal

[3] May be constructed by Boise Board of Control

Considerable interest has been expressed by the region's utilities in developing small hydro projects. Table 3-4 lists hydro projects currently in the FERC licensing process.

The most likely sites for developing additional hydropower capacity will come from adding units to existing projects, where prior congressional authorizations allowed the Corps to make advance provision for skeleton bays, knockout bulkheads, and future penstocks during initial construction. In some cases, applications of axial flow technology may enhance economic feasibility of additional hydro development at certain other sites. Generation on irrigation canals is also possible and is under active consideration.

However, realization of the region's hydropower potential is complicated by technical, economic, and environmental constraints.

The ability of the FCRPS to provide storage, especially for small hydro plants may be a limiting factor. Because of the variability of intermittent streamflow patterns on upper reaches of tributaries of the Columbia River, added hydro facilities may provide only seasonal energy. Generation will be more seasonal in nature, and these sites will not be able to contribute to the system's capability to shape energy and to provide dependable peaking or reserves.

In addition, the region has significant potential for pumped storage development to provide additional peaking capacity. The 12 sites which have received the closest attention could add a total of 35,000 MW peaking capacity. Pumped storage projects have a planning-licensing-construction leadtime of 5 to 7 years. The technology for pumped storage is available commercially at the present time. The development of specific pumped storage sites will depend on the need for additional peaking capacity, economic and environmental factors, and the availability of energy for pumping.

Achieving full hydro potential will involve tradeoffs with environmental concerns. In initial screenings, the Corps found that nearly half of the economically feasible sites would not be environmentally acceptable. At many sites, major conflicts exist between hydro development and the region's anadromous fishery resource. In recent years, requirements for improved fish passage facilities at dams, minimum streamflows, tailwater and forebay fluctuation limits, and other limitations have impacted the generating potential and increased the costs of hydroelectric facilities. (Section 3.6.1 describes these conflicts in detail.)

3.3.3 Conservation and Renewable Resources

3.3.3.1 Conservation

Conservation Potential. An independent study completed in 1976 for BPA (Skidmore, Owings and Merrill) concluded conservation could cut by more than one-half the growth in Northwest energy consumption projected for the period 1974-1995. The projected maximum savings of 90 billion kilowatthours of electricity per year would be equivalent to the output of about thirteen 1,000-MW thermal power plants operating at 75 percent capacity factors.

TABLE 3-4

SMALL HYDRO PROJECTS

Name of Project	Location (County, State)	MW Capacity	Status
Pelton	Jefferson, Oregon	15	All of the projects in this group have received a FERC license enabling them to be constructed and operated.
Potholes East Canal	Adams, Washington	5	
Dry Creek	Mineral, Montana	12	
Idaho Falls	Bonneville, Idaho	24.6	
Cascade Dam	Valley, Idaho	12.42	All of the projects in this group have applied for a FERC license or amendment to a license which, if granted, would enable them to be constructed and operated.
Moyie River	Boundary, Idaho	1.5	
Upriver Dam	Spokane, Washington	10.65	
Barstow	Perry & Stevens, Wa.	15	All of the projects in this group have received a FERC preliminary permit giving the applicants the sole right to investigate the sites.
Cascade Dam	Valley, Idaho	*	
Dryden	Chelan, Washington	4	
South Columbia Basin	Adams, Grant & Franklin, Washington	9.3	
Tumwater	Chelan, Washington	4	
Gemstate	Bonneville(?), Idaho	2.39	
Blue River	Lane, Oregon	8	All of the projects in this group have applied for a FERC preliminary permit which, if granted, would give the applicants the sole right to investigate the sites.
Fall Creek	Lane, Oregon	6	
Lower Ashton	Fremont, Idaho	5	
Rock Creek	Whatcom, Washington	3	
Tolt River	King, Washington	20	
Dorena	Lane, Oregon	4	
Island Park	Fremont, Idaho	5	
Quincy Chute	Grant, Washington	3.75	
Sunnyside	Lane, Oregon	23.9	
Upriver Dam**	Spokane, Washington	12	
Tyge Valley or White River	Wasco, Oregon	6.042	

* Capacity listed in a higher category
** Not a duplicate

The accompanying table (Table 3-5) compares various estimates of potential energy savings via conservation. The overall average of the ranges shown under the BPA study is about 24 percent. Twenty-four percent of the July 1977-June 1978 coordinated system annual load, for example, would be approximately 30 million MWh of electricity.

TABLE 3-5

COMPARISON OF ESTIMATED POTENTIAL ENERGY SAVINGS VIA CONSERVATION[1]

BPA Study (1995 savings)	*Other Studies*	
Residential Sector		
14-48%	24.8%	Energy 1990 (City of Seattle, 1976)
	38-49%	U. of Calif. (Goldstein, 1975)
	30-40%	Oak Ridge National Lab (1973)
	11.3-42.7%	Arthur D. Little, Inc. (1976)
Commercial Sector		
22-44%	30%	Energy 1990 (City of Seattle, 1976)
	30-80%	American Institute of Architects (Stein, 1974)
	30-50%	U.S. General Services Administration (1973)
	59.6%	Arthur D. Little, Inc. (1976)
Industrial Sector		
5-10%	31.7%	Energy 1990 (City of Seattle, 1976)
	24%	West German Industries (Stanford Research Institute, 1975)
	15-30%	National Bureau of Standards (1974)
	30%	Federal Energy Administration (1974)

[1]Bonneville Power Administration — study conducted by Skidmore, Owings and Merrill.

According to the study, this level of energy savings could be accomplished using available conservation measures and technology, and ". . . would have no significant effect on comfort and customary lifestyles . . ." and, would not ". . . require curtailment of energy-using practices."

Among other things, the suggested energy conservation program would "provide" electrical energy at less than one-sixth the cost of that produced by thermal power plants, result in virtually no environmental degradation, create more jobs--particularly for unskilled labor--than thermal plant construction, and increase individual disposable income.

Current Programs. BPA's existing conservation programs consist of information programs which have been developing since 1973, and pilot programs which are being implemented in the 1980's.

BPA's information program includes pursuing in-house energy savings and publicizing those savings to set an example, preparing and distributing pamphlets and other publications which provide advice on energy conservation, providing speakers on conservation for community organizations and other groups, conducting aerial infrared surveys of utility service areas to provide information on heat losses to consumers, and holding annual Energy Conservation Conferences which provide opportunities for interested parties to exchange information on the progress and future avenues of conservation in the region.

Curtailment programs helped to bring about significant short-term reductions in power requirements during the acute power shortages of 1973 and 1977. The reductions in those years were 7 and 10 percent, respectively, from forecasted loads. The long-term effects of conservation programs are undetermined, due to lack of information, overlapping programs, and external effects such as rising energy prices and changing economic conditions.

Pilot programs now underway at BPA include irrigation pump testing, installation of small wind energy conversion systems, residential weatherization, and solar water heating. Although energy savings from these programs at the pilot level may be modest (less than 2 average MW), the experience gained from implementing pilot programs will facilitate significant conservation of energy as these programs are applied on a regional basis.

Planned Programs. Eight new or expanded conservation programs are under development by BPA. These are expanded irrigation pump testing, an expanded residential weatherization pilot program, solar water heating workshops, an expanded small wind energy conversion system program, an electric water heating load management pilot project, a conservation voltage regulation pilot program, commercial energy audits, and a passive solar home demonstration program. Other programs under consideration include short-term purchase of conservation savings from BPA's utility customers, bonuses to consumers for solar savings, mobile home weatherization, reduction of transmission losses by utilities, and direct use of geothermal energy.

As with existing programs, utility, state, and Federal programs complement or supplement BPA programs. Program development will be conducted in cooperation with these other agencies to minimize duplication of effort. Generally, BPA's role as the region's largest electricity supplier and primary source of power to publicly-owned utilities makes it well suited to develop and coordinate programs principally for publicly-owned utilities, but also for the region as a whole.

3.3.3.2 Renewable Resources

In addition to planning conventional resources, the region's utilities are investigating the potential for renewable resources.

Biomass Generation. Using wood for energy production is well known in the Northwest and the conversion equipment is commercially available. However, the potential and costs of using wood for generating electricity can only be estimated now because of incomplete information about the fuel supply. While the current availablity and costs of mill wastes are fairly well known, future uses for these wastes will be affected by competing uses. Logging residues are not now widely recovered, and information on availability and costs of recovery is lacking. Institutional constraints associated with obtaining long term fuel supply contracts may limit the ability to obtain financing for powerplants. A future source of wood might come from energy farms using fast growing tree species. The Pacific Northwest climate is particularly well suited for growing trees.

Although there are many proposed projects being discussed, no plants are now under construction.

Cogeneration. In a study commissioned by BPA, the Rocket Research Company found that over 1430 MW of industrial cogeneration potential currently exists in the Northwest. Of this amount, there are over 400 MW installed, of which about 200 MW of existing cogeneration in the Pacific Northwest are unutilized or underutilized. From a subsequent economic analysis by Rocket Research, it was predicted that at least 50 percent of the potential cogeneration would be cost competitive with new thermal generation. Most operating projects are in the forest products industry and use wood residues as a potential fuel supply. Cogeneration projects under investigation are shown on Table 3-6.

Geothermal. To date, all geothermal reservoirs identified in the Pacific Northwest belong to the liquid-dominated hydrothermal system and are near 150°C or less. Present commercial equipment for electrical generation is available only for direct steam such as at the Geysers units in California, and require temperatures of at least 210°C. Special equipment is being developed to utilize hot water resources, but is still in the pre-commercial demonstration phase. This equipment is being tested in the Northwest at the DOE experimental installation at Raft River, Idaho, where a binary cycle installation with supply and reinjection wells is scheduled to come on-line later this year. BPA has recently signed a contract with DOE to purchase the net energy output from this plant until 1983, at a cost of 25 mills/kWh. Anticipated net output will vary from 2.2 MW during the summer to 3.8 MW during the winter.

TABLE 3-6

COGENERATION PROJECTS

Project Name & Location	Potential Capacity Cogeneration (MW Capacity)	Potential Capacity Total (MW Capacity)	Status	Proposed On-Line	Actions to Bring On-Line
Great Western Malting Vancouver, WA	9	9	Feasibility study		Need variance from Fuel Use Act
Tacoma, WA		50-65	Feasibility study	1984	
Lewis County Morton-Randle-Packwood, WA	8	25	Predesign Feasibility Study. Complete fuel supply phase in progress	1982	Unknown time delay due to Mount St. Helens situation
Kinzua Lumber Heppner, OR		6-24	Predesign Feasibility Study complete		Need to obtain fuel supply contracts and financing

The regional potential for geothermal energy cannot be accurately estimated until more test data on the size and temperatures of the reservoirs is available. Commercial generating projects, if viable, will probably not appear until after 1992.

Solar. At this time, it is not known if solar electricity can be practical and economical in the BPA marketing area. There is a limited amount of data available on direct sunlight availability in the Northwest particularly west of the Cascades and it is not extensive enough to estimate resource potential.

Wind. Studies of the potential in the BPA marketing area for large-scale wind turbine generators of at least 100 kW capacity are underway. In addition, BPA is conducting integration studies to determine how much wind generation can actually be utilized when integrated into the present generating system. Since wind generation is random, varying with the wind, and changing rapidly and frequently, it will pose special problems for schedulers responsible for operating the FCRPS.

BPA is participating in an experimental wind generation project with DOE in order to gain experience related to operational characteristics and environmental impacts. BPA will purchase the net energy produced by 3 wind turbines at Goodnoe Hills, Washington, (estimated at 8-9 million kWh annually) at a rate of 25 mills/kWh.

Most potential suppliers of wind turbine equipment believe their equipment will be commercially available in the mid-1980's. Current projects are shown on the following Table 3-7.

Table 3-7

PACIFIC NORTHWEST WIND PROJECTS

Project and Sponsor	MW Capacity	On-Line Date
Goodnoe Hills Mod-2 DOE/BPA	7.5 Boeing Mod II	July 1981
Agate Beach EWEB	0.5 Alcoa Darrieus	1980/81
Whiskey Run (S. of Coos Bay) PP&L	0.5 Alcoa Darrieus	1980/81

3.4 Utilization of Renewable Energy Potential

The ability of the Pacific Northwest to utilize intermittent renewable resources which become available to it will depend to a large extent on the ability of the Columbia River System to provide storage and backup for these resources.

3.4.1 FCRPS Storage

The Columbia Basin is unique among the nation's major basins with regard to the compatibility of storage requirements for the multiple purposes being served. The major goal of power development in the Pacific Northwest in relation to river operations is to utilize the storage capability of the system to regulate the discharge of the hydro projects so as to maximize the usability of the hydro generation.

Existing United States storage on the Columbia River, its tributaries, and other Northwest streams, including non-Federal installations, totals 26.6 million acre-feet--all usable for power production, of which 16.9 million acre-feet are usable for flood control. Total storage is now some 42 million acre-feet, including 15.5 million acre feet in Canada. About 25 million acre-feet is usable for flood control, as shown in Table 3-8.

Table 3-8

FCRPS Storage

	Usable for Power	Usable for Flood Control
	(million acre-feet)	
Existing Columbia River Storage in the U.S.	26.6	16.9
Three Canadian Treaty Dams	15.5	8.450 1/
Total	42.1	25.350

1/ Under the Treaty the United States has paid for the use of 8,450,000 acre-feet of storage for flood control. Additional storage may be used on an "on-call" basis for control of large floods with additional payment to Canada.

The Pacific Northwest region is clearly limited in its ability to store and shape energy by the amount of storage capability. For comparison, the Columbia River Basin has nearly 8 times the average annual runoff of the Missouri River Basin; yet has only one-half of the storage capability of the Missouri to regulate and control runoff which is so much greater. Similarly, the Northwest has less storage capability than the Colorado Basin; yet the average annual runoff is 13 times greater. The limited amount of storage capability restricts the level of firm energy that the system can achieve.

The major annual flood on the Columbia River occurs within the period from May to July; and as early as the first of April, the volume of flood runoff can be predicted with an error of less than 10 percent. The principal cause of the annual spring floods is the melting of snow which has accumulated during the winter. During those months when the precipitation at high elevations is being stored as snow rather than contributing to the river's flow, the electric loads are highest. To obtain the required generation, the low natural flows are supplemented by releases from stored water and thus the reservoirs which are operated for power normally reach their lowest levels before the spring and early summer flood flows. Once the flood flows are stored, the reservoirs may be held full for recreational use until the storage is again required for power or other uses. Good storage operation for power and flood control serves also to improve navigation where open river conditions remain, by increasing depths of flow during the low water months. Irrigation requires the storing of floodwaters but unlike power and navigation, the need for storage release occurs during the warm dry growing season. Thus water stored and diverted for irrigation, although assisting in flood control, does not contribute directly to the increased production of power. However, a significant part does return to the river through underground channels to improve the winter supply.

3.4.2 Capability of FCRPS to Provide Shaping and Backup

The FCRPS has the potential of "shaping" a variable resource, such as small hydro or wind, to produce generation at times and in amounts which conform to a utility's load. Essentially, this "shaping" function is accomplished by storing energy in the FCRPS reservoirs by reducing hydrogeneration when intermittent resources are operating. The ability of the system to provide this service is limited by the amount of storage available, the variability and magnitude of the resource being integrated, the capability of the system to provide automatic generation control, and competing uses of the river system.

In addition, the pattern of generation of a variable resource can impose certain requirements on the power system. In the case of wind, the impact will be felt on system generation scheduling, reserve requirements and stability. Through system flexibility, the power system provides backup for the addition of alternate resources. Some alternate resources consume system flexibility; others increase it, depending on the pattern of their generation.

Each new energy resource will have its own particular set of impacts on the operation of the system. When various combinations of new resources are added to the power system, they significantly impact each other. While some of these impacts may be fairly obvious, an accurate assessment of their effects on the operation of the power system cannot really be made until detailed integration studies of each separate resource or combinations of them are made. To date, only wind energy integration has been studied in any detail.

The development of large amounts of renewable resources in the Pacific Northwest may bring about significant changes in the operation of the power system. The already complex operations will become still more complex as the unpredictable patterns of intermittent resources such as solar and wind energy are superimposed on the load and resource cycles of the existing system. Detailed studies of the historical and prospective availability of these resources in relation to each other and to the existing system are necessary to perform analyses of the resource potential. This information will be used to integrate intermittent resources and prepare estimates of their costs and effects on the system.

Wind generation is one area where data is available. A preliminary study completed at BPA investigated the feasibility of integrating a simulated 3,000 megawatt wind energy conversion network into the Pacific Northwest hydro-thermal generation system. The specific purpose of the preliminary study was to identify those significant effects which require planning consideration and further study prior to extensive development of wind energy. The study simulated the hourly operation of a wind farm network and then included the total output as a resource during a planning year. Comparisons were then made of the system operation with and without wind. The following areas were identified for preliminary analysis: (1) seasonal power planning (regulation), (2) secondary energy (surplus), (3) energy reserve planning, (4) peak reserves, and (5) hourly planning.

The researchers concluded that generation from the wind should be considered a firm energy resource during a critical water year but that little capacity credit can be granted for the network under study which was designed to maximize energy production.

3.5 Expansion of the Transmission System

Transmission projects in BPA have generally been classified, depending on their scope, into the following groups: (1) Customer Service, (2) Area Service, (3) Main Grid Additions, and (4) Industrial Service. Small hydro additions, with possibly a few exceptions, are not likely to affect the second or third category.

In Customer Service, BPA cooperates to plan and install larger or additional capacity equipment to handle the growing loads of a customer utility. This new equipment is necessary to prevent overloading of existing equipment, to avoid low voltage levels, or to integrate small hydro projects. These facilities operate in the range of 4 kV to 230 kV. The new generation may be connected to BPA facilities or to those of BPA customers.

Planning for Future Additions. Transmission planning is a continual process. Although the timing for energization may change due to unforeseen circumstances, BPA prepares tentative plans for a 10-year period. BPA is also involved in conceptual planning for 20 years or more in the future.

Although it is not yet clear what impact new resources, including small hydro, will have on transmission system planning, it is highly probable that much of the generation will come from widely scattered decentralized locations which may or may not require additional BPA transmission facilities.

The owner of a generating unit may use the added generation on its own system or sell it to a different utility. If the purchaser does not have direct connection to the generation, the power will have to be wheeled over the system of a third party. For example, Seattle City Light and Tacoma City Light have purchased the output of the six small hydro plants to be built in eastern Washington by the South Columbia Basin Irrigation District. The power is expected to be wheeled over the BPA system.

BPA may not be required to add physical facilities to integrate the added generation from renewable resources if the project owner supplies the needed facilities. It is possible that the generation could be directly tapped into an existing low voltage line owned by a BPA customer. However, if an existing line or customer transformer is not large enough, BPA may need to update its customer service facilities. When the costs of constructing transmission facilities to remote sites are added to project costs, small-scale generation in scattered sites may not appear as cost-effective as less isolated sites might be.

The integration of alternative and renewable resources, including small hydro generation, may have some effects on financial and contractual transactions. The owners or users of the generation are likely to have contracts with BPA for various services such as wheeling, load shaping, peaking capacity, and reserves. Since small hydro development is more than likely to provide energy, the owner may have to alter some of the arrangements it has with BPA for load shaping and reserves.

3.6 The Challenge of Marketing Hydropower

3.6.1 Marketing Small-Scale Hydropower

Small hydro has been defined by BPA, DOE, and the Corps as new or additional hydroelectric generating installations in the range of 0.05 to 25 MW.

It is generally known that the economics of hydropower are becoming increasingly attractive because of the rising costs of generating electricity. The value of hydropower is measured as a composite of dependable capacity, firm energy, and secondary energy. A large percentage of small hydro developments (other than add-ons to existing mainstem projects and

possibly some adjoining plants) would probably be "run-of-river" type plants, with only limited storage capacity. To the extent that tributary streams would be subject to marked seasonal and annual variations in flow, the absence of large storage reservoirs restricts the amount of dependable capacity.

Due to their intermittent nature, even small run-of-river projects will require at least daily, if not weekly, pondage in order to produce reasonable patterns of hydroelectric generation. When either storage or pondage is required to regulate natural streamflow for power production, the analysis of hydroelectric potential and the determination of reasonably accurate capacity and energy outputs become substantially more complex. In general, studies of hydroelectric potential - as they move from simplified assumptions and criteria - tend to result in elimination of projects rather than addition of projects; i.e., closer scrutiny almost always shows that many projects which seem to be feasible under simplified assumptions do not prove to be feasible when examined in detail. Consequently, adoption of a more realistic basis for examination of potential is likely to result in the elimination of many prospective projects. Costs for pondage or storage as well as mechanisms for integrated system operation are significant matters requiring detailed, site-specific investigations.

Therefore, to a large extent, the role of such new (or even reclaimed) small hydro plants would be to provide replacement energy, i.e., when flows are adequate, thermal plants could shut down and conserve costly and relatively scarce fossil fuels. Where nuclear or coal-fired baseload power can be used to displace such fuels, or are used in lieu of such fuels, the value of hydroelectric power in run-of-river plants is diminished. In addition, such plants may serve to preclude construction of non-hydroplants as long as their limited dependable capacity and firm energy is compatible with the region's load. Most small hydro plants would add an increment of firm energy, but a major portion of their output would be nonfirm.

The electric rate structure tends to encourage hydro as peaking power, regardless of the operating entity. Small utilities which operate hydro as baseload plants to meet municipal and industrial needs do so because the sizes of their installations are often small in relation to flows, and the plants run nearly continuously to avoid spilling energy. Due to load growth beyond plant capability, such plants become only one source of baseload generation within a system -- municipals generally do not have peaking capability. Where private utilities have developed hydropower (including low load factor peaking power), it is because: (a) a major portion of the cost of hydro development is in items other than the power facilities themselves, and as plant capacity is increased (and plant factor decreases) the cost per kilowatt installed decreases to a point, and (b) the "hydroelectric advantage," the capability of quick starting and stopping of hydro machinery, is particularly well-suited to peaking.

Incorporating small hydro in the BPA grid does not present significant difficulty and will not require new main grid transmission line additions in the foreseeable future. It is likely that most of the small hydro plants can be integrated into the nearest distribution lines operating at voltages in the range of 12-115 kV. The low capacity generators do not present stability problems to the system.

Under the new Water Resources Council Principles and Standards published in December 1979, it is possible to streamline planning and reporting requirements in cases involving proposed hydro facilities under 25 MW. It is not clear at this time how such Federal project proposals will actually be handled. However, energy planners and others hope a national approach similar to the Corps' existing Small Projects Programs (flood control, navigation, beach erosion, etc.) can be established. Such a program would more readily permit timely Federal implementation of needed small hydro projects.

FERC has modified its standard hydropower licensing procedure for projects of 1.5 to 15 MW at existing dam sites. For such projects, the text of the standard license application has been cut by 80 percent, and the number of exhibits required has been reduced from 23 to 7. The changes are expected to reduce the preliminary permit process from 18 months to between 3 and 6 months. Federal licensing procedures for small-scale hydro development at new sites, however, require that the standard application be used. A less detailed application, called the short form, is used for projects of 1.5 MW or less at either new or existing dam sites. Licensing procedures at the State level are cumbersome and vary from State to State.

3.6.2 Competing Uses for Columbia River Water

The major consideration in producing and marketing additional hydroelectric power in the Pacific Northwest are the competing uses for Columbia River water. Table 3-9 describes the major purposes of some of the existing projects.

The Corps of Engineers manages the water resources development projects (WRDP'S) under its control to benefit authorized purposes and other water resource needs. Multiple-use conflicts and trade-offs raise the issue of re-examining the original authorizations of multiple-purpose WRDP's in light of current patterns of usage and evolving needs. The hydroelectric power generation function of the mainstem projects is now becoming inceasingly sensitive to consumptive offstream water withdrawals as well as instream flow requirements for navigation, water quality, fisheries, and other purposes.

These authorizations may ultimately require revision, confirmation, or enforcement. In light of the impending regional power deficits, it may be necessary to establish priorities among competing uses and, when necessary, restrict the utilization of water for certain purposes in some areas. For example, reservoir releases provided for navigation water supply during low river flows may be incompatible with requirements for other uses. Hydro electric power releases, even for peaking power purposes, can be redistributed over time through downstream reregulating dams to aid in maintaining navigation flows during periods of low flows. Flood control storage can also reduce extreme variations in river flows and distribute stored water at reduced flows over time.

TABLE 3-9

Federal Columbia River Power System
Major Authorized Purposes[1]

Project (Constructing Agency)[2]	Power	Irrigation	Navigation	Flood Control	Fish and Wildlife	Recreation
Albeni Falls (CE)	X		X	X		X
Boise-Black Canyon-Anderson Ranch (WPRS)	X	X		X		
Bonneville (CE)	X		X			X
Chief Joseph (CE)	X					X
Cougar (CE)	X		X	X		X
Detroit-Big Cliff (CE)	X	X	X	X		X
Dworshak (CE)	X		X	X		X
Grand Coulee (WPRS)	X	X	X	X		
Green Peter-Foster (CE)	X	X	X	X		X
Hills Creek (CE)	X	X	X	X		X
Hungry Horse (WPRS)	X	X	X	X		
Ice Harbor (CE)	X	X	X			X
John Day (CE)	X	X	X	X		X
Libby (CE)	X		X	X		X
Little Goose (CE)	X		X			X
Lookout Point-Dexter (CE)	X	X	X	X		X
Lost Creek (CE)	X	X		X	X	X
Lower Granite (CE)	X	X	X			X
Lower Monumental (CE)	X	X	X			X
McNary (CE)	X		X			X
Minidoka-Palisades (WPRS)	X	X		X		
Roza-Chandler (WPRS)	X	X				
The Dalles (CE)	X		X			X

1/ Authorized purposes allocated more than 3 percent of total plant investment.

2/ CE = Corps of Engineers, WPRS = Water and Power Resources Service

BPA, Branch of Power Resources
July 1980

With ever-increasing offstream and instream demands being made on the region's water resources, proposals to develop additional hydroelectric generating facilities must recognize the increasing resource competition, and must be evaluated in the context of cost-effective use of limited water and related land resources.

As water demand continues to increase in the future, possible shortfalls in water availability may occur which will introduce competition into what are now complementary relationships between authorized project purposes and other instream uses. Many multiple-use conflicts and trade-offs involve relationships between water and related land resources that are very complex.

Irrigation. About 7.5 million acres of cropland are under irrigation in the Columbia River Basin. Water for the irrigated lands is withdrawn from rivers, reservoirs, and groundwater through direct pumping, gravity flow, or combinations of both. Withdrawals generally coincide with the growing season--about mid-March to mid-October. The maximum rates of water application occur during June and July.

All of the western states have laws governing the withdrawal of water for various uses, including irrigation. Recent actions by the Washington State Department of Ecology have reserved large blocks of water for irrigation purposes in future years.

The bulk of the irrigation projects in the region have been developed by the Federal government. Most of the irrigation pumping plants and gravity supply systems have been designed to operate with the fluctuating water levels that occur at the supply points. Some intake elevations, however, are too high for irrigation pumps to operate when reservoirs are down, especially in the middle and upper Columbia Basin.

Fisheries. Another major use of the river is for instream flows for anadromous fish. To support anadromous fish migrations, water must be available in the river in adequate quantity and quality for the fish to survive, and in a timely manner that will provide for both upstream and downstream passage; i.e. spilled over the dams for downstream passage and passed around the dams through fish ladders for upstream passage. Water passing through turbines kills many of the juvenile fish migrating to the ocean. Therefore, allowing a certain percentage of the water to flow over the dams provides a safer route for downstream passage of the juvenile fish, but reduces the amount of water available to generate electric energy.

The Regional Act requires that BPA and the Council carefully weigh environmental impacts of proposed projects and to protect, mitigate and enhance fish and wildlife resources. It establishes effective procedures and authorities to ensure that Columbia River fish and wildlife resources receive equitable treatment in relation to power purposes.

On the Federal Columbia River Power System, approximately $200 million has been invested by the Federal Government in fish enhancement, protection, and mitigation. A major portion of these revenues are charged to Federal power operations and are repaid from BPA revenues. BPA has directly funded research intended to improve operating flexibility of the hydroelectric facilities. To

date, over $3 million has been provided to the region's fishery agencies for studies to measure the effects of power peaking operations, the success of transporting fish around dams, and other research which will provide more compatible operation of the hydro system for fish and power.

Hydropower projects possess a number of advantages - they utilize a renewable resource, rely on a proven, reliable technology, and possess operational flexibility. Once the initial capital investment is made, hydro projects are relatively resistant to increasing costs (they account for 3.5 percent of the rate increase for July 1, 1981). Conversely, hydro also has some inherent disadvantages--the potential energy realized is subject to considerable variation for run-of-the-river projects, the land (for storage) and capital requirements are considerable, water-use conflicts may arise, and adverse environmental impacts may occur.

Many potential sites recently identified in various inventories pose environmental trade-off questions, such as closing off free-flowing sections of rivers, degrading fish spawning areas, wildlife habitat and nesting areas, or inundating portions of rivers under consideration for inclusion in the Wild and Scenic Rivers system under the jurisdiction of the Department of the Interior.

Some of these impacts are more severe than others. Hydropower projects can deplete water resources through evaporation from reservoir storage surface areas. Such depletions and seasonal, weekly, and daily reservoir fluctuations result in varying streamflows and downstream impacts on water quality, fish and wildlife habitat, navigation, recreation, irrigation, streambank integrity, groundwater storage, and offstream uses. Water stored and subsequently released for power generation may vary in temperature, oxygen, and biochemical oxygen demand. It may also contain toxic substances from accumulated sediments. Fluctuating water levels at the site of generation or upstream may also conflict with recreation uses of the river and fish and wildlife habitat maintenance.

SECTION 4 THE PACIFIC NORTHWEST ELECTRIC POWER PLANNING AND CONSERVATION ACT (PL 96-501)

The Regional Act establishes six broad purposes:

1) to encourage, through the unique opportunity provided by the FCRPS, (a) conservation and efficiency in the use of electric power and (b) renewable resources development in the Pacific Northwest (PNW);

2) to assure an adequate, efficient, economical and reliable regional power supply;

3) to provide for widespread public and governmental participation and consultation in (a) the development of effective plans and programs for energy conservation, renewables, other resources, and fish and wildlife protection, mitigation, and enhancement; (b) facilitating orderly regional power planning, and (c) providing environmental quality;

4) to provide that BPA customers and regional ratepayers continue to defray all costs to produce, transmit and conserve required resources, including the amortization of the Federal investment in the FCRPS;

5) to insure, subject to the Act's provisions, that (a) the authorities and responsibilities of State and local governments, electric utilities, water management agencies and other non-Federal entities for regulation, planning, conservation, supply, distribution and use of electric power are construed to be maintained, and (b) the ability of customers to plan, develop and operate resources and to achieve conservation in accordance with other applicable Federal and State law, continues undiminished; and

6) to protect, mitigate and enhance the fish and wildlife, including related spawning grounds and habitat of the Columbia River and tributaries (CR&T), particularly the anadromous fish resource whose well-being depends on suitable environmental conditions which are substantially obtainable from the management and operation of the FCRPS and other facilities on the CR&T.

4.1 Summary of Act

The Pacific Northwest Electric Power Planning and Conservation Act will help the Pacific Northwest achieve an adequate power supply, hold utility rates lower than they would otherwise be and place maximum reliance on conservation and renewable sources of energy in responding to growing demand for electricity.

The Act provides the planning and financial tools to deal with these matters more effectively than they can be dealt with under existing power supply arrangments. The following has been excerpted from a report titled "A Summary" Pacific Northwest Electric Power Planning and Conservation Act published by Bonneville.

4.1.1 The Planning Council

The Act establishes an eight-member Pacific Northwest Planning and Conservation Council comprising two voting members representing each State--Washington, Oregon, Idaho, and Montana. Each member would serve a term of three years, although initially Governors will designate one of their two representatives to serve only two years. The Congress, convinced that regional electric energy planning snould be firmly in the hands of the people of the Pacific Northwest, made the Council members officers of their respective States, and subject to removal in accordance with State laws.

The major task of the Council is to adopt a Regional Electric Power and Conservation Plan within two years of the Council's formation and to update it periodically. The plan, requirements of which are described in more detail later in this summary, must contain an energy conservation program, a 20-year power demand forecast, an analysis of which resources BPA should acquire to meet forecasted loads, recommendations for research and development, and an analysis of reserve and reliability requirements. It also must contain a program for protecting and enhancing--and mitigating the damage to--fish and wildlife in the Columbia River and its tributaries.

The region will go through a period of transition in which the Council forms and takes up its duties. BPA must negotiate contracts with utilities and mechanisms must be established for carrying out the Act with a greater level of regional cooperation.

The plan adopted by the Council becomes the basis for BPA's actions in meeting the loads of its customers in the Pacific Northwest. Congress would still exercise budget review of all proposed BPA expenditures, just as it does now. If BPA finds it necessary to acquire resources not consistent with the plan, specific Congressional approval would be required prior to any commitment by BPA.

If for some reason the States fail to appoint a Council, or if for some reason the Council is unable to act legally as a State-appointed body, planning for the region would not come to a halt. The Act provides a fallback plan, whereby the Secretary of Energy would appoint Council members from each State to adopt the initial regional plan, which must be updated periodically. The Act provides that if three of the four governors request the Secretary of Energy to do so, he must terminate the Federally appointed Council after the initial plan has been adopted. This would happen if a way had been found to overcome the problems that required Federal appointments in the first place, or if the governors wished to abolish the Federally appointed Council and force a new solution.

The Act sets out voting procedures designed to protect the interests of each State, while also avoiding deadlocks. For adoption of the regional energy plan--the Council's most important task--the Council must agree either by a simple majority, with at least one member from each State voting in favor of adoption, or by six votes if both members from a particular State vote "no."

The Council may appoint its own staff and request the help of personnel from Federal agencies on a reimbursable basis. The Bonneville Power Administration plans to provide technical services if requested.

BPA must provide funds for the Council from the Bonneville budget. The Act specifies that the total amount of funds be 0.02 mills (two one-thousandths of one cent) times the kilowatthours forecast to be sold by BPA during the year to be funded, unless the Council shows the Administrator that it cannot fulfill its obligations under that spending limitation, in which event the Administrator may raise the ceiling to as much as 0.10 mills (one one-hundredth of one cent). Based on projected 1981 sales, the highest expenditures at 0.02 mills would be $1.342 million. Given projected 1981 sales, the Council would have up to $6.71 million to spend at the 0.10 mills per kilowatthour level. The money necessary to finance the operations of BPA and the Council comes from wholesale power rates, not from taxes.

4.1.2 Regional Planning

The Council's goal under the Act is to gather all the information necessary to draw up and adopt a blueprint for meeting the region's electrical energy needs. The body has two years to complete the task. Congress did not envision the plan as a static document--the Council may amend it from time to time, and must review its provisions at least every five years.

Public Involvement--The Act provides that the public be given opportunities to present information and views to the Council before any major decisions are made. The Council must regularly inform the public of its objectives, organization, and activities. Before adoption of the plan, the Council must hold hearings in Washington, Oregon, Idaho, and Montana, and in any other State where energy resources for the region might be located.

In formulating the plan, BPA and the Council must consult with utility customers of BPA and include their comments in the record relied on as a basis for decisions. The plan and BPA actions under it would not override State laws governing resource siting and regulation of utilities.

The Act requires public involvement in the process leading to adoption of a load growth forecast for the region, and in any decision by BPA to acquire a major resource (over 50 average megawatts of electric plower and acquired for 5 or more years). The public must also be given opportunity to participate when new wholesale power rates are proposed.

The Council must maintain a comprehensive program to insure widespread public involvement in policy-making. It must inform the public of major power issues, obtain public views and solicit advice from utilities.

Planning Priorities--Congress made very clear that it expects the Council to adopt a plan which requires investment in all cost-effective conservation and renewable resources before investment in conventional resources, such as fossil-fuel and nuclear plants. The Act sets the following order of priorities: (1) conservation; (2) renewable resources; (3) generating resources relying on waste heat recovery or on fuel burned by highly efficient methods; and (4) other resources, such as coal and nuclear plants.

The Act states further that when BPA compares the costs of conservation with those of conventional generating resources, in carrying out the plan, the agency must give conservation a 10 percent advantage. For example, even if a program to save kilowatthours by weatherizing homes would cost 110 percent as much as a thermal project capable of producing those kilowatthours, BPA must choose the weatherization project. The 10 percent advantage is to be evaluated by the Council in 5 years to determine whether it is still needed to assure that all cost-effective conservation is indeed being achieved.

The Act requires that the plan outline ways to conserve energy throughout the region and provide new resources. The Council must make sure that residential and small business consumers are given opportunities to get involved in programs to save energy.

Essential Planning Considerations--Congress directed in the Act that in pursuing important energy goals, the Council and BPA protect the environment. In preparing a plan and carrying it out, the Council and Bonneville must examine all options in light of the following issues:

--Environment. The Act requires that the Council carefully weigh environmental impacts of proposed projects and adhere to the principles and procedures of the National Environmental Policy Act. Likewise, BPA's new authority to acquire resources does not override existing State laws pertaining to zoning and land and water management. The Congress intended that the Council and BPA in all of their decisions strike a healthy balance between the environment and energy needs.

--Fish and Wildlife. Because the question of migratory fish in the Columbia River has been before the region for many years, fish policy became an important issue when the Act was written. Congress provided the means for interested parties to help work out a plan for enhancing fish and protecting fish and wildlife habitat. The Council must, in completing the regional plan, seek recommendations from Federal and State fisheries agencies and Indian tribes for a fish management program, and adopt a fish and wildlife program.

The Act directs that the recommendations be made available for public comment, and that they become the basis of the program. The program must complement activities of fish and wildlife agencies and Indian Tribes and must reflect the best available scientific knowledge for improving conditions for anadromous fish in the river. It must be consistent with the legal rights of Indian Tribes. The Council must report annually to the appropriate Congressional committees its progress and plans for carrying out the program.

--Compatibility with the Regional Energy System. The Council must consider whether proposed resources are compatible with operating realities, that is, reliability, predictability and need for reserves.

4.1.3 The Plan

Planning Elements--The Act sets forth a number of elements which must appear in the plan. They include:

--An energy conservation program. The Council must outline ways for BPA, the region's utilities, and State and local governments to establish conservation programs and assist the development of renewable energy resources. The Act requires that the Council develop model conservation standards addressing such matters as building codes for reducing heating and cooling needs, taking into account geographic and climatic variations.

--Recommendations for research and development. The Council must identify promising technologies, and recommend to the Administrator for investment those that have the potential for being cost-effective when in full production and wide use.

--A methodology for measuring environmental costs and benefits. A given impact on the environment is sometimes given different weight by different observers. The Council must set up criteria for quantifying the physical and social costs of energy projects, to aid in the making of decisions.

--A 20-year demand forecast for the region. Completion of a forecast will involve reaching a regional consensus on matters such as regional economic growth, population and other social questions. The Council will determine the forecast methodology, but the work of the Council is not intended to supplement individual utility and local government responsibility to make their own forecasts. With 10- to 15-year lead times on the construction of major generating facilities, a good demand forecast is imperative. The forecast will include the Council's estimate of the potential of conservation and renewable resources available to meet demand.

--An analysis of cost-effective methods of providing reserves. The Council must analyze the lowest cost resources that the region might acquire to back up the primary generating capacity of the region. Reserves include not only generating resources, but also rights to restrict loads which can be relied on to meet short-duration shortages caused by scheduled or unscheduled outages of generating facilities, or longer term shortages due to planning and construction delays. Large aluminum companies now purchase energy which provides a regional energy reserve. That is, portions of their firm power can be interrupted either to serve other customers in times of outage or when planned projects do not come on line as early as scheduled.

--Conservation surcharges. The Act contains carrot-and-stick provisions to encourage conservation. The Council may recommend surcharges as a means of inducing local governments, customers, and utilities to adopt conservation programs. The Administrator may impose the recommended surcharge if he determines that a given customer failed to achieve a level of conservation that could have been reached if model conservation standards had been followed. BPA must reduce bills by credit to a customer which undertakes conservation activities which are not part of the BPA program or the plan.

The Act directs the Council to review the conservation resources it buys to find out if they have been as cost-effective as anticipated. With this information, the Council would be able to update the conservation cost-effectiveness test it applies in the future and determine by October 1, 1987 whether the 10 percent advantage for conservation is still necessary.

Bonneville need not wait until the plan is adopted to launch far-reaching conservation and renewable energy projects. BPA may provide financial help to local utilities and governments to institute conservation programs and to provide seed money for sponsors of renewable resources projects of up to 50 average megawatts each. The Act directs BPA to plan for and purchase as much conservation, renewable energy and generating projects as are needed to meet the Administrator's obligations. The agency must, however, follow the purchase priorities established by Congress. Even if BPA were to find it necessary to acquire a generating resource, the agency cannot let up in the vigorous pursuit of conservation and renewable energy projects.

The Council may formally ask BPA to take specific actions to implement the regional energy plan. Within 60 days of such a request, BPA must respond in writing as to what it intends to do to with regard to the requested action.

The planning requirements of the Act do not set BPA and the Council above State and local governments in the region. The law leaves in place State and local laws governing siting and environment. The local utility has the option to act on its own and can thereby limit the need for BPA to acquire resources.

4.1.4 Sales of Electric Energy

The Act seeks to avert a regional legal battle over the allocation of a short supply of low-cost Federal power by providing a formula for sale of available resources and by setting up the machinery to prevent shortages.

BPA may put the financial weight of the Federal Columbia River Power System behind conservation and generating projects, thus reducing financial risks and making possible lower financing costs. The Act mandates that BPA acquire electrical resources sufficient to serve the total loads of new preference customers in the region--something BPA could not do before passage of the Act.

This is the way BPA would market power under the Act:

Preference Customers--All power sales by BPA must continue to comply with the preference clause of the Bonneville Project Act of 1937. The heart of the clause is the guarantee that public bodies have first call on available Federal power.

The Act makes it possible for BPA to serve the residential loads of private utilities without increasing the cost of power to preference customers, or diminishing Federal resources available to the preference customers.

The Act contains several layers of protection for the preference status of publicly owned utilities. One provides that sales to preference customers must not be restricted to less than the full amount of power produced by the Federal base system. So, BPA must, if necessary, terminate on 5 years' notice the power exchange sales from the Federal system to investor-owned utilities, if BPA anticipates an insufficiency of power supply. This enables preference

customers to call on the full amount of Federal base resources if necessary. Currently, the base resources consist of all Federal hydropower, some of the power from the N-reactor at Hanford, and 30 percent of the Trojan nuclear plant's output. It also includes the power to be produced by Washington Public Power Supply System's nuclear units 1 and 2, and 70 percent of unit 3, when those plants are completed.

The pull-back provisions of Federal resources provide for protection of the preference clause by which public systems get first call on Federal power.

The Act contains a rate test insuring that the exchange agreements with investor-owned utilities or any other result of the Act will not raise the cost of power to BPA's preference customers above what it would have been without the Act. If the test shows rates are climbing higher than they would have been without the law, BPA must put a ceiling on its wholesale rates for preference customers and obtain the additional revenue it needs from other customers.

The Act authorizes BPA to continue to sell electricity to Federal agencies in the region which depend on BPA for service.

Contracts--The Act requires that BPA offer its customers--public, private, and direct-service industrial--20-year contracts within nine months of enactment of the law. The customers have one year to accept the offers. The new contracts would require BPA to meet the load growth of utilities to the extent that they request it when they apply. However, BPA is obligated to supply electricity only to meet demand that customers are unable to satisfy with their own existing firm power resources and those that they later commit to their own loads.

Periods of Insufficiency--If after a reasonable startup period, BPA sees that it cannot plan to acquire enough resources to meet the electrical needs of the region over the long term, BPA may declare a "period of insufficiency."

The Act requires that BPA have a reasonable period of experience with resource purchases before it notifies its customers of insufficient resources. Right now, the Pacific Northwest faces potential shortages of from 2,000 to 4,000 average megawatts in the 1980's if water is critically low. If these short-term shortages cannot be met by conservation and power purchases from inside and outside the region, existing State and utility procedures for curtailment would apply.

4.1.5 Providing for the Region's Electric Energy Needs

With new responsibility to acquire the resources necessary to meet the Pacific Northwest's electricity needs, BPA must purchase conservation and generating resources that are consistent with priorities contained in the Act. Congress affirmed the importance of developing all cost-effective conservation, and made regional investment in conservaton the top priority. Energy from renewable resource projects--those relying on sun and wind and biomass, for example--must come next in BPA's purchase scheme. Systems that

use waste industrial heat are next in priority, followed by highly efficient fuel-conservation systems such as fuel cells and MHD (magnetohydrodynamics). Non-renewable resource projects, such as nuclear plants and coal-fueled facilities and all other fossil fuel resources, are last.

BPA will in effect purchase the electricity that a given conservation project saves. The reason BPA will pay for such savings is that tney allow the agency to avoid having to buy costly new generation instead.

In acquiring electricity, BPA may not own or construct any generating facilities to serve regional load. Bonneville may purchase the capability of a project built by anybody else, or buy a specific amount of power from a plant, if the resource is consistent with the priorities and goals of the Act and the regional plan.

Major Resources--Congress wanted to make sure that any decision by the Administrator to invest in a major resource (larger than 50 average megawatts and acquired for more than 5 years) be made only after full review of all options. For each proposal to invest in a project larger than 50 average megawatts, the Administrator must:

--Publish notice with copies to the Council and to the Governor of the State in which the project is proposed;

--Hold one or more public hearings and establish a record of testimony supporting or disapproving the acquisition;

--Prepare a written document showing that the purchase is consistent with the plan and is needed to fulfill BPA's obligations to provide electric energy.

Before BPA can sign a contract for purchase of a major resource, the purchase must be proposed in BPA's budget submitted to Congress. "Major resource" means not only a project capable of generating 50 average megawatts or more, but a conservation or renewable resource substitute for electricity capable of saving 50 average megawatts or more. If Congress does not reject this proposal in the budget process, BPA can sign the contract. If no regional plan is in effect and if either the Administrator or the Council decides purchase of a major resource runs counter to the purchase criteria of the Act, BPA may not proceed to spend money on tne resource until Congress specifically approves the acquisition. Specific Congressional approval is necessary if at any time BPA proposes to make a purchase declared by the Council to be inconsistent with the plan.

The law allows BPA to acquire experimental, demonstration, or pilot projects, but the expenditure must be included in BPA's budget submitted to Congress for approval.

Renewables and Other Resources--Potential sponsors of renewable energy projects desiring to launch programs that have regional value might find it difficult to do so because of risks involved and State constitutional limits on "lending of credit." As an encouragement, the Act allows BPA to pay for feasibility studies and preliminary engineering for renewable projects of less than 50 average megawatts when the Administrator determines that there is an unequitable hardship to the consumer of such a renewable resource sponsor. This provision protects the sponsoring utilities against losses for resources that should be fully investigated for possible regional benefit.

BPA may reimburse sponsors for preconstruction costs associated with major renewable or with non-renewable resource projects such as coal-fired plants, but with significant limitations. Among the limitations are a determination by the Administrator that failure to reimburse would impose an unequitable hardship on the sponsor's consumers; a stipulation that BPA may buy the capacity of the resource; and an agreement that if the resource is later developed by the sponsor for its own use the sponsor will repay BPA any amount advanced by BPA.

Billing Credits--BPA can help any customer--public agency or private utility, local government or others--finance projects consistent with the Act by paying the customer for the energy saved or power produced by the projects undertaken independently from BPA or the plan. The principle at work here is that customers taking the initiative to provide new energy resources relieve BPA of some of its obligation to purchase power to meet regional needs. BPA must compensate customers for costs of such projects by granting credits against energy bills of the sponsoring customers for the amount of energy actually saved or produced.

The amount of the credit covers the costs avoided through purchase of the conservation, not to exceed the rate impact the customer would have experienced if BPA had been obligated to acquire some other resource. For resources other than conservation that either substitute for electricity or generate electricity, the credit will equal the net cost actually incurred by the customer, but no more than the rate impact experienced if BPA had been obligated to buy some other resource. However, BPA must first determine that a given project will reduce Bonneville's obligation to acquire other resources to meet loads. Further, the credits can be granted only on the condition that the costs, which BPA spreads among all customers in the region, will be no higher than the costs of other resources BPA might purchase for regional use (taking into account the 10 percent advantage for conservation).

Before granting any credit, BPA must notify the public and explain the method proposed for determining the amount of credit. The costs of the credit must be included in BPA's annual or supplemental budget. BPA must also require that a generating project from which BPA will acquire electricity is operated in a way compatible with the regional power system.

Billing credits are intended to provide an incentive for utilities to institute strong conservation programs for consumers and to develop renewable resources.

BPA Borrowing Authority--The Act expands BPA's authority to borrow from the Federal Treasury, but BPA must continue to repay the Treasury entirely from its revenue. The Federal Government does not guarantee BPA's obligations with its tax revenue.

By law, BPA cannot borrow money except by selling its bonds to the Treasury. At present, BPA is limited to borrowing for the purpose of building transmission lines. Under the new Act, BPA will be able to borrow for five additional purposes: first, to finance conservation and renewable resources; second, to carry out improvements for fish and wildlife in the Columbia River Basin; third, to provide financial assistance for generating projects of less than 50 average megawatts, from which BPA will buy power; fourth, for research and development projects; and fifth, to implement PNEPPCA generally.

The Act specifically prohibits BPA from borrowing to support its purchase of power from large generating facilities, such as coal and nuclear plants. But the costs of borrowing as well as all of BPA's operating costs including purchases will paid by the region's ratepayers, not by the nation's taxpayers.

The Act establishes $1.25 billion in new borrowing capacity, which becomes available October 1, 1981, to invest in conservation and renewables. It also opens up for such investments the existing transmission construction borrowing authorization of $1.25 billion. About $570 million of uncommitted borrowing capacity is currently projected to remain under the transmission authorization by September 30, 1981, which could be used initially for funding conservation and renewables.

The Act also makes possible a lower interest rate on funds BPA borrows for financing conservation and renewable resources. BPA previously paid a rate equivalent to triple-A private utility bonds, but now will pay the lower rate available to government corporations, such as the Tennesse Valley Authority.

Again, BPA must repay the money it borrows from the Treasury with revenue from power sales. The Act further states that if BPA fails to increase its rates by enough to cover all of its costs, including repayment of the Federal investment in Northwest power resources, then the agency must pay a one percent interest penalty.

All expenses associated with the planning, engineering, construction and operation of a plant may be covered under a purchase agreement between a sponsoring utility and BPA.

If BPA purchases the capability of a major generating resource, the costs of the project will be borne regionwide by the consumers through BPA's wholesale rates whether or not the plant ever produces a single kilowatthour. The ratepayers will receive the plant's benefits if it produces electricity, and those who stand to benefit must take the risk that it might fail to operate. With the benefits go the risks, and the ratepayers assume both, just as they do now when the utility serving them builds a new generating facility to serve their needs. When the risks are spread regionwide, it usually means lower interest rates than otherwise obtainable, and that in turn means lower power costs.

No projects can be acquired unless they are expected to work and the decision to acquire is based on deliberations of the Council, BPA, developers, and licensing authorities. There must be broad public involvement in the decisions, and Congress would review the proposed projects.

Retail rate structures which utilities voluntarily adopt to encourage conservation activities or customer-owned renewable resources may qualify for billing credits. For example, if a utility adopted rates which encourage conservation by its customers, BPA would be required to provide a wholesale billing credit to the utility equal to the savings from BPA not having to buy as much electric power.

BPA must investigate opportunities for joining in cooperative efforts to develop renewable resources outside the region, and acquire such resources if they are consistent with the Act and if they are needed to meet demand in the Pacific Northwest.

BPA may also agree to exchange power with utilities outside the region when such exchanges are of benefit to BPA's Pacific Northwest customers. BPA now exchanges power with utilities in California, to the advantage of both BPA's customers and the California utilities. The Act would allow BPA to expand such arrangements if exchanging or buying power helps meet loads in the Pacific Northwest and relieves the region's utilities of some of the need to construct new generating facilities. California utilities experience high demand during the summer because of air-conditioning loads, and Pacific Northwest utilities experience high winter peaks because of space heating. Cooperation between the regions on timely exchanges of power could avoid the construction of plants that would otherwise sit idle during respective low-demand seasons.

The Act requires that all utilities be given the opportunity to acquire a financial interest in plants from which BPA will purchase power to meet regional needs. The Act thus gives each utility a chance to acquire enough power resources to meet its own needs. Each utility's entitlement to power from BPA during a period of insufficiency will be based in large part on the amount of power the utility has sold to BPA to meet regional needs.

Any utility remains free to build plants and not sell the output to BPA, without endangering its rights to get from BPA any additional power supply it may wish. Nothing in the Act prohibits utilities from acting on their own to provide conservation, renewables, or generating resources.

BPA will not simply buy the capability of new generating resources without regard for the speed and cost with which the facilities are installed or built. The Act gives BPA the tools necessary to oversee project construction schedules and costs.

BPA's purchase contracts must contain requirements for timely completion of projects at the lowest costs possible, giving BPA authority to approve major modifications in construction scheduling or operation of projects.

4.1.6 Rates

The Act establishes a rate-setting policy for three types of customers. The first type includes cooperatives, publicly owned utilities and Federal agencies. The other two types are investor-owned utilities and direct-service industrial customers of BPA.

Preference Customers--BPA's wholesale rates for Federal agencies, publicly owned utilities and co-ops cannot be higher than would have been the case without the Act--the Act specifies a formal rate test. The rates of publicly owned utilities and co-ops will increase in the future, but the Act should help keep the increases lower than they would otherwise have been. Generally this class of customers will receive the lowest Federal wholesale power rate available, except for new large loads.

Investor-Owned Utilities--Investor-owned utilities may exchange power with BPA to receive at the same low wholesale rates as preference customers for wholesale power in an amount needed to serve their residential and farm customers. The investor-owned utilities will pay a higher rate for whatever additional power they choose to buy from BPA to serve their other loads.

The availability of electricity at BPA's low wholesale rate to investor-owned utilities for their residential and farm customers will not mean equality in retail prices charged by publicly owned and investor-owned utilities. In arriving at its own retail price per kilowatthour, each utility must add its own costs of doing business, such as distribution, operating and maintenance costs.

After power contracts with BPA are signed in 1981, wholesale rates for residential and farm customers of investor-owned utilities will be lower than they otherwise would be to the extent that the power from BPA costs less than the electricity exchanged by the investor-owned utilities.

Direct-service Industries--The rate relief of the residential and farm customers of the investor-owned utilities is made possible by the higher rates paid by the direct-service industrial customers of BPA. The Act requires that prior to July 1, 1985, BPA rates for DSIs must cover the costs of serving them, plus the costs of power exchanges between BPA and investor-owned utilities.

After July 1, 1985, when the residential and farm customers of investor-owned utilities are receiving the full benefit of Federal base rates, the DSI rates must be at a level commensurate with the retail rates paid by industrial customers of publicly owned utilities in the region. The DSI rate is expected to be several times greater than it is today.

BPA must, from time to time, adjust rates to cover the costs of the Federal investment in the Columbia River Power System, plus the costs of resources purchased to meet regional electrical needs as well as other costs incurred under the law. This responsibility does not change under the Act.

The Act provides for public involvement in the ratemaking process. BPA must call public hearings and allow reasonable cross examination of witnesses. Participants in hearings must be given adequate opportunity for rebuttals. After hearings, BPA may propose revised rates and must publish them in the Federal Register. More hearings can be held, and a final decision must be made on the basis of the record. The new rate becomes final after approval by the Federal Energy Regulatory Commission, but the Commission may allow rates to take effect on an interim basis, pending a final decision.

4.2 Implications of the Regional Act on Hydro Development

Under the Regional Power Act BPA's involvement in measures to protect, mitigate, and enhance fish and wildlife affected by the operation and development of the region's hydroelectric facilities will be greatly expanded. Consultation between the region's fish and wildlife agencies, and those agencies and utilities responsible for the management, operation, or

regulation of hydroelectric facilities, would identify critical fishery and other environmental issues. Further, BPA can finance the research and development necessary to solve problems associated with fishery and environmental issues. With such mandated requirements, the current ad hoc approach to the fishery/hydroelectric conflict would be replaced by a formalized structure striving to provide equitable treatment for fish and wildlife compatible with other purposes for which hydroelectric facilities are managed and operated.

The Regional Power Act encourages additional hydroelectric development in preference to all other types of resources except conservation. The resource priority established in the Act gives conservation the highest priority, with renewable resources second, high efficiency conventional resources third, and all other resources fourth. Renewable resources include those resources using only regenerative, or essentially inexhaustable energy sources for electric power generation, or resources which reduce a customer's electric power requirements through direct application by consumers. Included in this category are solar, wind, hydro, geothermal, biomass or similar energy sources. This means that hydroelectric development would be preferred over other forms of conventional resources, including high fuel conversion efficiency resources, where both are equally cost-effective.

Purchase authority allowing Bonneville to acquire hydro resources enhances their feasibility by providing a mechanism to integrate these resources into the regional power system. The sporadic output of small hydro facilities which have no reservoir capacity could be firmed through backup by the FCRPS, and the economics of such facilities would be benefited. The regional and new resource rate pools would meld the costs of resources within those pools and spread their costs over those customers with access to that rate. This melding would make new resources, including hydro resources, more attractive than if a single utility system were required to absorb their incremental cost.

In addition, the Act requires that the Administrator grant billing credits to customers if, by undertaking the development of "independent" resources after the effective date of the Act, such customers reduce Bonneville's obligations to aquire additional resources. Such provisions encourage development of additional hydroelectric generating facilities which might not otherwise be undertaken.

In summary, these provisions provide for the development of hydroelectric power resources over most other types of resources and certainly over conventional resource alternatives. The intent, in part, is to remove remaining institutional impediments which currently face small hydro and other forms of hydroelectric development. Hydroelectric resources would be developed within the context of the Regional Electric Power and Conservation Plan developed by a Council.

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NATIONAL HYDROELECTRIC POWER RESOURCES STUDY

Marketing and Transmission of Hydroelectric Power

Part 4

Western Area Power Administration Appendix

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LIST OF ACRONYMS AND ABBREVIATED REFERENCES

BPA	Bonneville Power Administration
Corps	Corps of Engineers, Dept. of the Army
CRSP	Colorado River Storage Project
CVP	Central Valley Project
IBWC	International Boundary and Water Commission, Dept. of State
JTS	Joint Transmission System
MARCA	Mid-Continent Area Reliability Coordinating Agreement
NERC	National Electric Reliability Council
P-SMBP	Pick-Sloan Missouri Basin Program
Service	Water and Power Resources Service (formerly the Bureau of Reclamation), Dept. of the Interior
SWPA	Southwestern Power Administration
TVA	Tennessee Valley Authority
Western	Western Area Power Administration
WPRS	Water and Power Resources Service (see "Service" above)
WSCC	Western Systems Coordinating Council

CHAPTER 1

THE CURRENT MARKETING AND TRANSMISSION SYSTEM

1.1 THE WESTERN AREA POWER ADMINISTRATION

Mission and Functions

The primary mission of the Western Area Power Administration (Western) is to transmit and market power from Federal resources to preference customers in a businesslike manner at rates sufficient to meet annual operating expenses and repayment obligations while balancing economic, technical, and environmental considerations.

Inherent in this mission is the operation and maintenance and modification of existing facilities to assure system reliability at the lowest possible costs and the planning and construction of new facilities to meet future demands. Western must also protect and enhance the environment, conserve energy, promote renewable resources, and manage its allocated assets (facilities, dollars, and personnel) in a judicious manner.

The execution of the mission must be carried out in conjunction with legislative requirements such as the Department of Energy Organization Act (Public Law 95-91), the National Energy Act, Executive Orders, and departmental policies.

Western's functions include:

o Power operation and maintenance programs for all of Western's transmission, substation, communication, and attendant facilities.

o Comprehensive power planning programs for Western's load and resource development activities.

o Developing coordinated power marketing programs with customers and other power entities within Western's power marketing area and other power marketing administrations and power entities outside Western's power marketing area.

o Initiating, developing, and implementing electric power and transmission service rates and rate adjustments for power and energy transmitted and marketed by Western.

o Initiating, developing, executing, and administering electric power contract agreements for power sales, power purchases, power system interconnections, and power pooling.

o Working with other power marketing agencies, other utility systems, and reliability councils in the development of general power utility standards.

o Planning, designing, and constructing new transmission, substation, communication, and attendant facilities to enhance power system reliability and efficiency.

o Initiating, formulating, developing, reviewing, coordinating, and analyzing comprehensive power planning studies of water and land resource requirements relating to electric power development. Participating with Federal, State, and regional organizations is a major part of such studies.

o Preparing and recommending schedules for new Federal multipurpose resource development, consistent with forecasted power requirements and resource capabilities, after examining project and unit feasibility.

Authorities and Laws Governing Power Marketing and Transmission

Western was established in December 1977 pursuant to Section 302(a)(3) of the Department of Energy Organization Act of 1977 [42 U.S.C. 7101 et seq., 7152(a)(3)] which provides:

> The functions transferred in paragraphs (1)(E) and (1)(F) of this subsection shall be exercised by the Secretary, acting by and through a separate and distinct Administration within the Department which shall be headed by an Administrator appointed by the Secretary. The Administrator shall establish and shall maintain such regional offices as necessary to facilitate the performance of such functions. Neither the transfer of functions effected by paragraph (1)(E) of this subsection nor any changes in cost allocation or project evaluation standards shall be deemed to authorize the reallocation of joint costs of multipurpose facilities theretofore allocated unless and to the extent that such change is hereafter approved by Congress.

Paragraphs (1)(E) and (1)(F) of Section 302 transfer to, and vest in, the Secretary of Energy the following functions of the Secretary of Interior:

> (E) the power marketing functions of the Bureau of Reclamation, including the construction, operation and maintenance of transmission lines and attendant facilities; and
>
> (F) the transmission and disposition of the electric power and energy generated at Falcon Dam and Amistad Dam, international storage reservoir projects on the Rio Grande, pursuant to the Act of June 18, 1954, as amended by the Act of December 23, 1963. [Marketing of Power from Falcon and Amistad Dams Acts]

All of Western's current statutory authority regarding marketing and transmission systems was transferred authority which the Department of Interior exercised through the Bureau of Reclamation (now the Water and Power Resources Service). Thus, to define Western's authority, one must look to the statutes and regulations governing the marketing of power by the former Bureau of Reclamation. This body of law which has been developed over the last century is commonly known as Federal Reclamation law.

The earliest statute which authorized the marketing of Federal power was Section 5 of the Town Sites and Power Development Act of 1906 (34 Stat. 116, 43 U.S.C. 522). This act is still the basic authorization for the sale of power from most of Western's projects. However, subsequent acts, particularly Section 9(c) of the Reclamation Project Act of 1939 [53 Stat. 1187, 43 U.S.C. 485h(c)] have changed some of the conditions under which the Secretary is authorized to contract for the sale or exchange of Federal power.

The Town Sites and Power Development Act provided for leases of power or power privileges for periods not to exceed 10 years. Longer contract periods were authorized for certain projects, such as the Rio Grande Project (36 Stat. 930), and the Boulder Canyon Project (45 Stat. 1057, 1060). The Reclamation Project Act extended the allowable power sales contract period for reclamation projects to 40 years.

The Federal power which is marketed by Western is produced at dams and powerplants owned and operated by the Corps of Engineers (Corps), the International Boundary and Water Commission (IBWC), and the Water and Power Resources Service (Service). The power available for sale is that which is not required for project uses (which is frequently defined or specified in the acts authorizing each project). Both as a matter of statute and, where statute is not directly applicable, as a matter of policy, Federal power is marketed in a manner to encourage the most widespread use at the lowest possible rates to consumers consistent with sound business principles. See, for example, the Fort Peck Project Act (52 Stat. 403) and the Flood Control Act of 1944 (58 Stat. 890). Current practice and policy are to produce the greatest practicable amount of power and energy that can be sold at firm power and energy rates. For the Colorado River Storage Project (CRSP), this principle is mandated by Congress (70 Stat. 109).

In the marketing of Federal power, one of the most important conditions or limits on the Secretary's authority has been the preference concept. This concept had its origins in the Town Sites and Power Development Act. The preference clause which currently applies to most of Western's projects is the clause in section 9(c) of the Reclamation Project Act which states:

> That in said sales or leases preference shall be given to municipalities and other public corporations or agencies; and also to cooperatives and other nonprofit organizations financed in whole or in part by loans made pursuant to the Rural Electrification Act of 1936 and any amendments thereof.

Similar preference clauses are found in acts authorizing specific projects, such as the Fort Peck Project Act of 1938 (52 Stat. 403) and the Acts for Marketing of Power From Falcon and Amistad Dams (68 Stat. 255 as amended by 77 Stat. 475). In addition to the general preferences for public bodies and cooperatives, special preferences are found in a few of the authorizing acts for certain projects; for instance, the Boulder Canyon Project Act of 1928 (first preference to the States of Arizona, California and Nevada, 45 Stat. 1060), the Trinity River Division, Central Valley Project Act of 1955

(first preference to the extent of 25 percent of the added energy to preference customers in Trinity County for use in that county, 69 Stat. 719), the Flood Control Act of 1958 (up to 50 percent of power attributable to new dams in the Missouri River Basin is reserved to the States in which such dams would be located, 72 Stat. 311), and the Flood Control Act of 1962 (first preference up to 25 percent of the energy made available by the New Melones Dam shall be granted to preference customers in Tuolomne and Calaveras Counties, 76 Stat. 1191).

Another statutory principle applicable to reclamation projects is that "[n]o contract relating to . . . electric power or power privileges shall be made unless, in the judgment of the Secretary, it will not impair the efficiency of the project for irrigation purposes." (See Section 9(c) of the Reclamation Project Act of 1939, 53 Stat. 1194.) This principle has been a part of reclamation law since the Town Sites and Power Development Act of 1906. This principle follows from the priority of use of reclamation projects which has been first, for river regulation, improvement of navigation, and flood control; second, for irrigation and domestic uses; and third, for power. (See 50 Stat. 850 and 45 Stat. 1061.)

Pursuant to Section 9(c) of the Reclamation Project Act of 1939, any sale of power shall be made at "such rates as in [the Secretary's] judgment will produce power revenues at least sufficient to cover an appropriate share of the annual operation and maintenance cost, interest on an appropriate share of the construction investment at not less than 3 per centum per annum, and such other fixed charges as the Secretary deems proper." Specific project authorization acts provide for various repayment periods and interest rates. For most projects, power revenues also repay costs which were allocated to irrigation which are beyond the irrigation customers' ability to repay. These and other fixed costs vary from project to project, and depend primarily upon congressional intent and the legislation authorizing the project.

The Fort Peck Project Act (52 Stat. 405) and the Marketing of Power from Falcon and Amistad Dams Acts (68 Stat. 255 as amended by 77 Stat. 475) provide that rates for these projects shall become effective after confirmation and approval by the former Federal Power Commission. The Department of Energy Organization Act transferred the Commission's confirmation and approval authority to the Secretary of Energy, who has since delegated authority to the Assistant Secretary for Resource Applications to approve and place in effect all of Western's power and transmission rates (including Fort Peck and Falcon-Amistad) on an interim basis and to the Federal Energy Regulatory Commission the authority to confirm and approve such rates on a final basis.

To the extent the Reclamation Fund established by the Reclamation Act of 1902 (32 Stat. 388) and other funds established for particular projects are used for power marketing and transmission purposes, Western is authorized to utilize those funds. (See Section 701 of the Department of Energy Organization Act of 1977.) Thus, for example, Western has available to it funds authorized under the Emergency Fund Act (62 Stat. 1052), Upper Colorado River Basin Fund (70 Stat. 107), Colorado River Dam Fund (45 Stat. 1057, 54 Stat. 774), Colorado River Development Fund (54 Stat. 774), and the Lower Colorado River Basin Development Fund (82 Stat. 894).

Lastly, Western, as a Federal agency, is subject to all Federal laws applicable to Federal agencies. Those specifically worth mentioning with respect to the marketing and transmission of Federal power are the Administrative Procedure Act (5 U.S.C. 551 et seq.), the National Environmental Policy Act (42 U.S.C. 4321 et seq.), and the Public Utility Regulatory Policies Act (16 U.S.C. 2601 et seq.). Not specifically mentioned here, but just as important to the business of marketing Federal power and the construction, operation, and maintenance of a Federal transmission system are all Federal laws relating to Federal agencies, such as those relating to money and finance (see 31 U.S.C.), public property (acquisition and disposition, see 40 U.S.C.), public contracts (see 41 U.S.C.), public health and welfare (see 42 U.S.C.), public lands (see 43 U.S.C.), judiciary and judicial procedure (see 28 U.S.C.), conservation (see 16 U.S.C.), and Government organization (see 5 U.S.C.).

Organization and Administration of System

Western's marketing area covers approximately 1,252,000 square miles that include all or parts of 15 States generally west of the Mississippi River to the coast of California, north to the Canadian border, and south to the Mexican border. Five area offices, which are located in Billings, Montana; Boulder City, Nevada; Fort Collins, Colorado; Sacramento, California; and Salt Lake City, Utah, have jurisdiction within identifiable geographic boundaries (table 1-1 and figure 1-1).

The Billings Area Office is responsible for marketing power from the Service and the Corps powerplants of the Pick-Sloan Missouri Basin Program (P-SMBP) in the States of Montana (east of the Continental Divide), North Dakota, South Dakota, western Minnesota, western Iowa, and eastern Nebraska. The Billings Area also maintains a tie at Maryville, Missouri, to the system of the Southwestern Power Administration (SWPA).

The Boulder City Area Office markets power from the Service's hydroelectric powerplants of the Colorado River Storage Project (CRSP), Boulder Canyon Project, and the Parker-Davis Project, and the United States' entitlement to the Navajo steam plant. The Navajo plant is part of the Lower Colorado River Basin Project (Central Arizona Project). The marketing area includes the States of Arizona (except for the northeastern corner), southern California, the southern one-third of Nevada, and a small portion of western New Mexico.

Marketing by the Denver Area Office is done for the Service powerplants of the P-SMBP integrated projects and the CRSP. In FY 1981, the first unit of the Mt. Elbert Pumped-Storage Powerplant of the Fryingpan-Arkansas Project will become an available resource. The marketing area for the Denver Area Office includes the States of Colorado and Wyoming east of the Continental Divide, western Nebraska, and western Kansas. Both the CRSP and the P-SMBP resources are marketed east of the Continental Divide in the States of Colorado and Wyoming; however, the P-SMBP resources are also marketed in western Nebraska.

Table 1-1
SYSTEM STATISTICS
FY 1979 Actual

	Total	Billings	Boulder City	Denver	Sacramento	Salt Lake City
Circuit Miles of Transmission Line 1/	15,765.88	7,348.10	2,011.17	3,573.07	1,319.62	1,513.92
Service Area in Square Miles	1,252,000	378,000	181,000	200,000	175,000	318,000
Number of Substations 1/	213	80	35	72	1	25
Installed Generating Capacity (MW)	8,050	2,398	2,192	401	1,709	1,350
Energy Sales (MWh) 2/	36,166,416	12,419,975	9,799,655	3,944,430	7,080,429	2,921,927
Electric Service Revenues 2/	$306,269,150	$104,530,149	$91,399,095	$27,360,434	$60,375,610	$22,603,862

1/ Does not include WPRS facilities

2/ Includes sales to interproject, private utilities, and WPRS

The marketing area for which the Sacramento Area Office is responsible includes northern and central California and northern Nevada. Power resources are the Central Valley Project (CVP) hydroelectric powerplants of the Service and the Corps, plus power purchased under contract from the pacific northwest and identified as part of the CVP resource.

Marketing area responsibility for the Salt Lake City Area Office includes the States of Utah, the northeast corner of Arizona, New Mexico, portions of Colorado, Wyoming (west of the Continental Divide), and western Texas. The area office markets the output from the hydroelectric powerplants of the CRSP (including participating projects), Collbran, and Rio Grande Projects, as well as the plants of the IBWC Falcon-Amistad Project.

Relationship with Regional Reliability Councils and Power Pools

The National Electric Reliability Council (NERC) was formed by the electric utility industry in 1968 and consists of nine regional reliability councils. Western has been a member of the Western Systems Coordinating Council (WSCC) and the Mid-Continent Area Reliability Coordinating Agreement (MARCA) since their inception, although the original participation was under the former Bureau of Reclamation before formation of Western. These two councils cover about 90 percent of Western's marketing area and all of Western's present transmission system. Western actively participates on all of the major committees of both councils. Planning and operation of Western's transmission system is guided by the reliability criteria of these councils.

Western is also an active participant in several power pools which vary considerably in their scope and effect. They range from noncontractual, informal organizations to very formal, intricately structured organizations that provide for the sharing of reserve requirements and coordination of the installation and operation of generation and transmission facilities.

Western participates in these pooling arrangements primarily to coordinate planning and operations to further enhance reliability and other benefits of interconnected operations.

Customers and Classes of Service

In FY 1979, total power sales were reported as 36,166 GWh to 464 customers, with revenues of $306,269,150. These totals include sales of firm and nonfirm energy, those made directly to ultimate consumers, sales for resale, and those for oil conservation. Various rates for wholesale firm and nonfirm power, peaking power, oil conservation, and project pumping power are utilized. Rates for replacement sales, rates for maintenance service, and other special rates are provided by contract. Table 1-2 reflects the type and number of Western's customers, table 1-3 shows the sales and revenues by customer type, and table 1-4 is sales of power by State.

Table 1-2
TYPE AND NUMBER OF CUSTOMERS

Type of Customers	Number of Customers	Percent of Total
Municipalities	206	45
Cooperatives	41	9
Federal Agencies	42	9
State Agencies	39	8
Public Utility Districts	4	1
Irrigation Districts	34	7
Private Utilities	20	4
Other	5	1
Interproject	3	1
WPRS	70	15
Totals	464	100

Table 1-3
SALES AND REVENUES BY TYPE OF CUSTOMER

Type of Customer	Percent of Total Western Energy Sales by Type of Customer	Percent of Total Western Revenues by Type of Customer
Municipalities	26	22
Cooperatives	25	21
Federal Agencies	4	4
State Agencies	10	10
Public Utility Districts	10	10
Irrigation Districts	5	3
Private Utilities	16	28
Other	1	1
Interproject	1	1
WPRS	3	1
Totals	36,166,416,000 kWh	$306,269,150

Table 1-4
SALE OF POWER BY STATE
FY 1979

State	Municipalities	Rural Electric Cooperatives	Federal Agencies	State Agencies	Public Utility Districts	Irrigation Districts	Private Utilities	Western Total
Arizona								
Energy Sales (MWh)	129,273	152,857	254,589	2,053,479	0	237,266	219,593	3,047,057
Revenue $	860,232	1,015,139	1,797,203	21,034,034	0	1,645,715	4,638,532	30,990,855
California								
Energy Sales (MWh)	3,140,419	74,193	1,205,470	112,951	1,926,101	1,698,769	3,260,827	11,418,730
Revenue $	26,537,576	576,392	10,315,966	920,695	14,924,081	7,126,180	49,869,645	110,270,535
Colorado								
Energy Sales (MWh)	1,163,598	1,436,869	13,172	0	0	0	0	2,613,639
Revenue $	7,859,860	10,568,390	128,112	0	0	0	444,691	19,001,053
Iowa								
Energy Sales (MWh)	648,935	919,143	0	0	0	0	374,219	1,942,297
Revenue $	4,118,134	7,505,491	0	0	0	0	6,196,453	17,820,078
Minnesota								
Energy Sales (MWh)	1,381,359	1,490,501	0	41,679	0	0	1,622,708	4,536,247
Revenue $	8,226,296	11,763,166	0	232,943	0	0	18,916,341	39,138,746
Montana								
Energy Sales (MWh)	0	480,207	2,173	3,564	0	1 690	99,753	587,387
Revenue $	0	2,800,367	5,433	16,862	0	4,224	1,027,372	3,854,258
Nebraska								
Energy Sales (MWh)	526,027	201,779	0	138,028	1,557,394	0	0	2,423,228
Revenue $	4,088,259	1,583,923	0	801,672	16,459,214	0	0	22,933,068
Nevada								
Energy Sales (MWh)	84,772	1,020	6,036	1,065,772	0	0	98,424	1,256,024
Revenue $	363,284	7,375	29,905	5,899,648	0	0	1,642,675	7,942,887
New Mexico								
Energy Sales (MWh)	114,662	690,401	75,230	0	0	0	0	880,293
Revenue $	923,852	4,902,185	745,783	0	0	0	0	6,571,820
North Dakota								
Energy Sales (MWh)	187,300	1,129,360	3,226	78,395	0	0	36,787	1,435,068
Revenue $	1,244,831	8,292,301	19,348	443,148	0	0	464,794	10,464,422
South Dakota								
Energy Sales (MWh)	676,315	889,600	36,256	109,115	0	0	44,456	1,755,742
Revenue $	4,527,740	5,473,274	211,039	652,218	0	0	902,504	11,766,775
Texas								
Energy Sales (MWh)	0	0	0	0	0	0	145,470	145,470
Revenue $	0	0	0	0	0	0	2,045,911	2,045,911
Utah								
Energy Sales (MWh)	1,133,138	530,411	15,071	0	0	0	0	1,678,620
Revenue $	8,137,174	3,620,549	117,892	0	0	0	0	11,875,615
Wyoming								
Energy Sales (MWh)	96,520	880,424	21,158	0	0	351	0	998,453
Revenue $	669,995	6,333,673	158,087	0	0	4,829	0	7,166,584
Total [1]								
Energy Sales (MWh)	9,282,318	8,876,765	1,632,381	3,602,983	3,483,495	1,938,076	5,902,238	34,718,256
Revenue $	87,557,233	64,442,225	13,528,768	30,001,220	31,383,295	8,780,948	86,148,918	301,842,607

[1] Totals do not include sales to interdepartmental, interproject, and Water and Power Resources Service

Resource Capabilities of System

Power Suppliers. Electric power marketed by Western is generated at Federal powerplants operated by the Service, the Corps, and the IBWC.

The existing Federal projects from which Western receives power and energy, surplus to project use, consist of 47 hydroelectric powerplants and one thermal powerplant, with a total installed capacity of 8,050 MW. Table 1-5 lists these projects which are located within 10 of the 15 western States that comprise Western's marketing area.

Integration with Other Generation Sources. Within Western's marketing area, there are over 260 power entities that own generation facilities. These 260 power entities are investor-owned utilities, municipal departments or utilities, rural electric distribution and generation and transmission cooperatives, governmental agencies, and power districts. They vary in generating resource capability from a small municipal district in Utah with a 150-kW hydrogenerator to the Southern California Edison Company with a total generating resource of over 12,000 MW. Western's generating resources are integrated with almost all of these 260 power entities within its marketing area and numerous other generating systems adjacent to its marketing area. The integration represents Western's total coordinated effort of operating with the multi-owned interconnected generation and transmission systems in and adjacent to its marketing area through such activities as:

- o participating in existing power pools and advancing further coordination and integration through additional pooling agreements and planning activities;

- o marketing the power available to Western to permit the most widespread use, and;

- o operating the system to assist in national goals such as oil conservation.

Current Power Situation. The present and 10-year anticipated electric load/resource perspective within Western's marketing area is primarily based on load/resource reporting and forecasts by WSCC and MARCA member utilities, which report over 90 percent of Western's marketing area, as was mentioned earlier. The councils analyze and forecast electric load/resource requirements of essentially all existing and anticipated bulk power transactions within their reporting areas. Western, as a member of these councils, assists in the load/resource analyses.

WSCC, excluding Canadian systems, reported a 1979 summer peak-hour demand of about 71,000 MW, with Western contributing about eight percent of this total requirement. WSCC is forecasting a demand rate of growth for the next 10 years of about four percent per year. That means generation capacity will have to increase by about 3,000 to 4,000 MW per year in the WSCC area to meet load requirements and provide adequate reserve margins.

Table 1-5
GENERAL SPECIFICATIONS
PROJECTS EXISTING 9-30-79

Area Office/Project	Plant Name	Type	Operating Agency	State Location	Stream	Initial Date in Service	Existing Number of Units	Existing Installed Capacity kW
Billings								
Fort Peck	Fort Peck	Hydro	USCE	MT	Missouri	Jun 1943	5	185,250
P-SMBP	Big Bend	Hydro	USCE	SD	Missouri	Oct 1964	8	468,000
P-SMBP	Fort Randall	Hydro	USCE	SD	Missouri	Mar 1954	8	320,000
P-SMBP	Garrison	Hydro	USCE	ND	Missouri	Jan 1956	5	430,000
P-SMBP	Gavins Point	Hydro	USCE	SD	Missouri	Sep 1956	3	100,000
P-SMBP	Oahe	Hydro	USCE	SD	Missouri	Apr 1962	7	595,000
P-SMBP	Canyon Ferry	Hydro	WPRS	MT	Missouri	Dec 1953	3	50,000
P-SMBP	Yellowtail	Hydro	WPRS	MT	Big Horn	Aug 1966	4	250,000
Total Installed Capacity-kW								2,398,250
Total Number of Plants								8
Boulder City								
Boulder Canyon	Hoover	Hydro	WPRS	AZ-NV	Colorado	Sep 1936	19	1,344,800
Parker-Davis	Davis	Hydro	WPRS	AZ	Colorado	Jan 1951	5	240,000
Parker-Davis	Parker	Hydro	WPRS	CA	Colorado	Dec 1942	4	60,000 1/
Navajo	Navajo	Fossil	Salt River	AZ	-	May 1972	3	546,750 2/
Total Installed Capacity-kW								2,191,550
Total Number of Plants								4

1/ Total installed capacity of 120,000 kW of which Metropolitan Water District of Southern California is entitled to one-half
2/ Represents United States share out of a total of 2,250,000 kW

Table 1-5 (Continued)

Area Office/Project	Plant Name	Type	Operating Agency	State Location	Stream	Initial Date in Service	Existing Number of Units	Existing Installed Capacity kW
Denver								
Colorado-Big-Thompson	Big Thompson	Hydro	WPRS	CO	Trans Mtn Diverson	Apr 1959	1	4,500
Colorado-Big Thompson	Estes	Hydro	WPRS	CO	Trans Mtn Diverson	Sep 1950	3	45,000
Colorado-Big Thompson	Flatiron	Hydro	WPRS	CO	Trans Mtn Diversion	Jan 1954	3	73,000
Colorado-Big Thompson	Green Mtn	Hydro	WPRS	CO	Blue	May 1943	2	21,600
Colorado-Big Thompson	Mary's Lake	Hydro	WPRS	CO	Trans Mtn Diversion	May 1951	1	8,100
Colorado-Big Thompson	Pole Hill	Hydro	WPRS	CO	Trans Mtn Diversion	Jan 1954	1	33,250
Kendrick	Alcova	Hydro	WPRS	WY	N. Platte	Jul 1955	2	36,000
Kendrick	Seminoe	Hydro	WPRS	WY	N. Platte	Aug 1939	3	40,400
North Platte	Guernsey	Hydro	WPRS	WY	N. Platte	Jul 1927	2	4,800
P-SMBP	Boysen	Hydro	WPRS	WY	Wind	Aug 1952	2	15,000
P-SMBP	Fremont Canyon	Hydro	WPRS	WY	N. Platte	Dec 1960	2	48,000
P-SMBP	Glendo	Hydro	WPRS	WY	N. Platte	Dec 1958	2	24,000
P-SMBP	Kortes	Hydro	WPRS	WY	N. Platte	Jun 1950	3	36,000
Shoshone	Heart Mtn	Hydro	WPRS	WY	Shoshone	Dec 1948	1	5,000
Shoshone	Shoshone	Hydro	WPRS	WY	Shoshone	Apr 1922	3	6,012
Total Installed Capacity-kW								400,662
Total Number of Plants								15

Table 1-5 (continued)

Area Office/Project	Plant Name	Type	Operating Agency	State Location	Stream	Initial Date in Service	Existing Number of Units	Existing Installed Capacity kW
Sacramento								
Central Valley	Judge F. Carr	Hydro	WPRS	CA	Lewiston Tunnel	May 1963	2	141,444
Central Valley	Folsom	Hydro	WPRS	CA	American	May 1955	3	198,720
Central Valley	Keswick	Hydro	WPRS	CA	Sacramento	Oct 1949	3	75,000
Central Valley	Nimbus	Hydro	WPRS	CA	American	May 1955	2	13,500
Central Valley	O'Neill	Hydro	WPRS	CA	San Luis Creek	Nov 1967	6	25,200
Central Valley	San Luis	Hydro	CA 1/	CA	San Luis Creek	Mar 1968	8	202,000 2/
Central Valley	Shasta	Hydro	WPRS	CA	Sacramento	Jun 1944	7	497,662
Central Valley	Spring Creek	Hydro	WPRS	CA	Clear Creek Tunnel	Jan 1964	2	150,000
Central Valley	Trinity	Hydro	WPRS	CA	Trinity	Feb 1964	3	105,906
Central Valley	New Melones	Hydro	WPRS	CA	Stanislaus	Jun 1979	2	300,000
Total Installed Capacity-kW								1,709,432
Total Number of Plants								10

1/ Operated by State of California for WPRS
2/ Eight 53,000-kW units for a total installed capacity of 424,000 kW of which the WPRS share is 202,000 kW

Table 1-5 (Continued)

Area Office/Project	Plant Name	Type	Operating Agency	State Location	Stream	Initial Date in Service	Existing Number of Units	Existing Installed Capacity kW
Salt Lake City								
Collbran	Lower Molina	Hydro	WPRS	CO	Pipeline Facility	Dec 1962	1	4,860
Collbran	Upper Molina	Hydro	WPRS	CO	Pipeline Facility	Dec 1962	1	8,640
Colorado River Storage	Blue Mesa	Hydro	WPRS	CO	Gunnison	Sep 1967	2	60,000
Colorado River Storage	Flaming Gorge	Hydro	WPRS	UT	Green	Nov 1963	3	108,000
Colorado River Storage	Glen Canyon	Hydro	WPRS	AZ	Colorado	Sep 1964	8	950,000
Colorado River Storage	Morrow Point	Hydro	WPRS	CO	Gunnison	Dec 1970	2	120,000
Colorado River Storage	Crystal	Hydro	WPRS	CO	Gunnison	Sep 1978	1	28,000
Provo River	Deer Creek	Hydro	WPRS	UT	Provo	Feb 1958	2	4,950
Seedskadee	Fontenelle	Hydro	WPRS	WY	Green	May 1968	1	10,000
Rio Grande	Elephant Butte	Hydro	WPRS	NM	Rio Grande	Nov 1940	3	24,300
Falcon	Falcon	Hydro	IBWC	TX	Rio Grande	1955	3	31,500
Total Installed Capacity-kW								1,350,250
Total Number of Plants								11
Grand Total Installed Capacity-kW								8,050,144
Grand Total Number of Plants								48

MARCA reported a 1979 summer peak-hour demand of about 18,000 MW with Western contributing about 11 percent of this total requirement. MARCA is forecasting a demand rate of growth for the next 10 years of about 4.9 percent per year. That means generation capacity will have to increase by about 1,000 MW per year in the MARCA reporting area to meet load requirements and provide adequate reserve margins.

Power Purchases. Western's annual power purchases are estimated 18 to 20 months before the budget fiscal year begins. These estimates are based on projected average water supply conditions in various river basins. Should adverse water conditions occur, causing less than average generation, Western's annual purchase power and wheeling requirements could range from $60 to $80 million. Such purchase arrangements allow Western to meet firm contractual obligations and participate in the oil conservation program.

Through the oil conservation program, hydroenergy is provided to utilities to displace oil-fired generation at peak times. Energy is purchased by Western to meet its loads during off-peak hours from coal-fired generation plants. The success of this program relates directly to the amount of water available in a particular river basin and the availability of off-peak coal-fired generation to couple with the hydrosystem for displacement of oil-fired generation. During the past 9 years, Western has conserved the equivalent of over 40 million barrels of oil through its oil conservation program.

1.2 THE NATURE OF CURRENT MARKETING AND TRANSMISSION PROGRAMS AND PRACTICES

Policies, Legal Directives, and Interpretations

The amounts of hydroelectric power which Western determines to be marketable on a long-term commitment basis are the capacity available under adverse (not necessarily the historic worst) water conditions and energy available under average water conditions. This minimizes Western's need to purchase capacity and energy to meet its commitments. The capacity and energy available for long-term commitment are then marketed as firm power at some load factor. The load factor varies from project to project, but generally is in the range of from 58 percent to 65 percent for a 6-month season. Under this arrangement, either the capacity or the energy determines the amount of firm power available. Normally, it is the energy which is limiting, and the capacity available in excess of firm capacity is marketed as peaking power.

Firm power is normally delivered at approximately the customer's hourly or monthly load pattern, so that the customer receives the most power at the time of its seasonal peak load and proportionately lesser amounts at other times. Since Western does not supply the total requirements of most of its customers, those customers must obtain supplemental or auxiliary power from other resources.

Because the demand for firm power and for long-term peaking power exceeds the supply, the firm power and peaking power are allocated to preference customers (see preference and priority below). The amounts allocated are then placed under contract for delivery to the allottees.

Normally, Western delivers its firm and long-term peaking power to the customer's system. Often this involves construction of transmission facilities by Western, and sometimes it involves making arrangements for the transmission (wheeling) of Western's power over third-party transmission systems. Western's arrangements with its customers served from third-party transmission systems normally include an upper limit on the monetary rate and power losses which Western will pay to the third party for such transmission service, and the customer is required to reimburse Western for such costs and losses in excess of the upper limits.

Western, through its power marketing program, must secure revenues sufficient to meet the annual costs of power operation and maintenance, replacements, purchased power, and wheeling expenses. In addition, it must repay the project's power investment with interest and all nonpower investments assigned to power for repayment without interest. Normally, the project investment must be repaid within 50 years.

Pursuant to its power marketing policies, Western transmits and disposes of power and energy in a manner designed to encourage the most widespread use thereof at the lowest possible rates consistent with sound business principles.

Preference and Priority

Numerous Federal statutes provide that power generated in excess of project requirements should be sold first to certain types of entities. These laws, which serve to establish a system of priorities in the distribution of Federal power, are collectively referred to as the "preference clause." Illustrative of the statutory classification of preferred entities in the sale of power is the Reclamation Project Act of 1939. That statute, formally known as the Act of August 4, 1939, chapter 418, section 9(c), 53 Stat. 1194, requires that "preference shall be given to municipalities and other public corporations or agencies, and also to cooperatives and other nonprofit organizations financed in whole or in part by laws made pursuant to the Rural Electrification Act of 1936 and any amendments thereof."

Other laws, many of which specifically relate to individual projects rather than power marketing in general, contain substantially the same language as the Reclamation Project Act of 1939. Under these statutes, power may be distributed to investor-owned utilities only after the needs of preference customers have been met. It is in accordance with these laws, and judicial opinions construing these laws, that the Western Area Power Administration determines to which entities power should be sold.

Wholesale Power Rates

Postage Stamp Rate. Western's current practice is to establish "postage stamp" power rates for each of its marketing systems. Current marketing systems are:

Boulder Canyon Project
Central Valley Project
Collbran Project
Colorado River Basin Project (Navajo)
Colorado River Storage Project
Falcon-Amistad Project
Parker-Davis Project
Pick-Sloan Missouri Basin Program
Rio Grande Project

"Postage stamp" power rates mean that the same rate applies to all customers, no matter how far away from the generating resource they may be, as long as they are served from the Federal transmission system at transmission voltage.

Cost-Based Rate. A determination is made annually, for each of the various projects, to determine if the current power rates are adequate to pay annual costs. For three of the nine power projects (Boulder Canyon, Navajo, and Falcon-Amistad Projects) for which Western has repayment responsibility, rates are adjusted periodically (annually for Boulder Canyon and Falcon-Amistad, monthly for Navajo) pursuant to prearranged formulas which are established by contract or other agreement.

With the requirement that power sales revenues must be adequate to pay for certain nonpower investments as well as power investments, Western's rates do not reflect true "cost of service." Also, the requirement for repayment in 50 years when service lives for some facilities are normally much longer than 50 years means that rates are set more for cash flow than for "costs."

Transmission Rates

Western has transmission rates that are associated with three types of transmission service: (1) long-term firm service, (2) long-term and short-term nonfirm service, and (3) joint transmission system (JTS) wheeling.

The majority of firm transmission arrangements are made on a long-term basis. The rates for such use are a capacity charge based on annual cost of the transmission facilities. Similarly, a component of transmission cost is included in rates for power and energy.

Basically, nonfirm transmission service is made available on an if, as, or when available basis, with a rate which is applied to energy transmitted. Generally, transmission rates used by Western are "postage stamp" rates.

Table 1-6

RATE SCHEDULES & MARKETING DATA

PROJECT/SCHEDULE	Effective Date	Class of Service	Monthly Demand Charge ($/kW)	Energy Charge (mills/ kWh)
Central Valley				
CV-F4	11-1-79	Firm	2.00	5.11
CV-P3	11-1-79	Comm. Irr.	2.00	5.11
CRSP				
SP-F1	1-23-81	Firm	1.6555	4.0
SP-FP1	1-23-81	Peaking	1.6555	4.0
Falcon	1978		0	14.0
Rio Grande				
SW-F2R	4-80	Firm	3.20	8.5
Parker-Davis				
PD-F1	6-16-80	Firm	1.82	4.15
Boulder Canyon	1/		1.55	2.068
Pick-Sloan--ED				
UM-F2	1977	Firm	1.20	3.17 60% LF 5.18 above 60% LF
UM-P12	1977	Comm. Irr.	1.20	3.17 60% LF 5.18 above 60% LF
UM-FP3	1977	Peaking	1.20	3.33 Del. w/o return
Pick-Sloan--WD				
LM-F2	1977	Firm	1.34	4.0
LM-FP2	1977	Peaking	1.34	4.0
LM-P1	1975	Comm. Irr.	0	7.0

1/ General regulation - Boulder Canyon Project Adjustment Act - Effective 1941 through 1987.

Rates which apply to JTS arrangements, like firm transmission service rates, are developed on the basis of the annual cost of all facilities dedicated to the JTS. Such rates are then applied on a capacity use basis.

Marketing

Markets for Capacity and Energy. Western's market for its Federal hydroelectric capacity and energy, in terms of its customers, is fairly well defined. Generally, this marketing takes place within the boundaries of a river basin, or within some economical transmission distance of the generation as determined by the power marketing agency.

Due to the price differential, which results from the fact that the Federal hydro facilities were all constructed some time ago at relatively low cost, Federal hydropower is greatly in demand. Western's principal "market" consists of preference customers which were defined earlier. These customers contract for most of the firm classes or types of service (capacity and energy) which Western has to offer. Because the market demands more than Western's resources can supply, Western has no difficulty in finding ready, willing, and able preference customers. However, certain circumstances and system conditions do produce situations under which sales are made to nonpreference customers. This occurs when there are no preference customers with their own available generation and a nonpreference customer is the only entity with the capability of utilizing the type of service Western has to offer, such as fuel replacement energy service or short-term nonfirm peaking capacity.

Generally, all firm capacity and energy is committed to preference customers. Peaking capacity (with or without energy) is first offered to preference customers and, if they decline, then to nonpreference customers. Thus, the market to which Western has access includes all utilities within the defined market area.

Rate Structure. Western, as a marketer of hydroresources, basically uses a 50:50 split of revenues between capacity and energy to achieve the rate of return necessary for project repayment. However, rate schedules subsequent to the initial project rate tend to utilize the energy component for the greater part of any change. The relationship between the power rate (revenue) and the cost of service is distorted, on the whole, by the impact of certain nonpower costs that are the responsibility of power repayment.

A typical wholesale firm-power rate schedule would include a demand charge, energy charge, general definition of billing demand, general definition of energy obligation, provision for a minimum bill, and provision for various adjustments regarding delivery voltage, transformer losses, and power factor requirements.

For transmission (wheeling) rates, most schedules have in the past been incorporated in contracts or agreements. Recently, one of Western's area offices promulgated transmission rate schedules for a project for which it markets power (i.e., the rate schedules are separate from but are applicable

under contracts for transmission service). Transmission rate schedules as opposed to contractually stated rates are expected to be used more and more in the future. Transmission rates are reflective of transmission facilities costs and operation and maintenance expenses.

Pricing Procedures. Western utilizes embedded costs to determine the rate requirements for project repayment. The embedded costs are those costs which are for past years, the current year, and projected for future years for the express purpose of project repayment. Embedded costs are not in all cases the same as costs that appear on the financial accounting statements. For project repayment, both historic and future costs are used. Future costs are outside the realm of financial accounting statements. Also, for repayment, facilities that are retired do not reduce the investment. The investment remains to be paid for. Financial accounting, however, utilizes depreciation accounting so that retirements reduce plant-in-service and consequently reduce investment.

Generally, the capacity component is associated with the fixed costs of the power production facility whereas the energy component is associated with the variable costs of such facility. Fixed costs are those costs that must be paid whether or not the operation of the facility produces energy and are therefore associated with the capacity component of the rate. Variable costs are those costs incurred by the operation of the facility in order to produce energy and are therefore associated with the energy component of the rate. With regard to a pumped storage plant, the energy rate would include the cost of purchased pumping energy.

The use of embedded costs, instead of marginal costs, to determine rate requirements allows Western to fulfill its statutory requirement of marketing its power and energy in such a manner as to encourage the most widespread use thereof at the lowest possible rates consistent with sound business principles.

Contract Terms and Conditions. The contract arrangements (terms and conditions) for the sale of Federal hydroelectric resources vary from project to project. Each project has a defined resource in terms of capacity and energy. Transmission arrangements, service rates, and delivery conditions also are unique for each separate project.

Power sales contracts specify the obligations and entitlements of the United States and the contractor. Provisions for transmission service, interconnection arrangements, and facilities use are often included. These arrangements aid in the efficient use of the Federal transmission system and provide revenues to assist in project repayment.

Financial Performance. The Service, Corps, and IBWC projects, or portions thereof, from which Western markets hydroelectric power, are financed and owned by the U.S. Government and funding is primarily through congressional appropriations from the Reclamation Fund.

Originally, the Reclamation Act of 1902 contemplated that the entire reclamation program would be financed from the Reclamation Fund which was made up of monies received from the sale and disposal of certain public lands. Subsequent acts authorized additional receipts collected from the reclamation program to be credited to the Reclamation Fund, the most important to Western being the acts which provide for crediting receipts from power operations. However, it became apparent that receipts to the fund were not adequate to finance completely a program of the scope desired. Beginning with appropriations in 1930 for the Boulder Canyon Project, the annual reclamation program has been financed by appropriations in part from the Reclamation Fund and in part from the General Fund of the Treasury. Notwithstanding the transfer of functions from the Department of the Interior and the Bureau of Reclamation to the Department of Energy and the Western Area Power Administration, the Reclamation Fund and the General Fund are the only sources, through annual appropriations, of financing for most of Western's projects.

Subsequent to the Reclamation Act of 1902, other reclamation acts have created other funds which have affected the financing for particular projects. A good example is the Upper Colorado River Basin Fund which is used for the Colorado River Storage Project. All appropriations for that project and all revenues from that project are credited to the fund. In general, revenues can be used for operation, maintenance, and replacement costs without further appropriation, as well as for repayment obligations. However, neither revenues nor any other credits to the fund may be used for construction unless specifically authorized and appropriated therefor by Congress.

The financial accounting for and the repayment of Federal power projects for which Western has marketing responsibility are accomplished under guidelines set forth by DOE Order No. RA 6120.2 dated September 20, 1979.

That order establishes financial reporting policies, procedures, and methodology except where deviations therefrom are specifically approved by the Secretary, authorized by statute, or identified and explained in a transmittal memorandum or in the footnotes to the reports.

Sound businesslike financial management and accounting practices are pursued in the preparation of power project financial statements. Generally accepted accounting principles are utilized and the accounts, to the extent practicable, are maintained in accordance with the Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission for public utilities. Annual financial statements are designed to fairly present the financial position of each power project.

A power repayment study is prepared annually for each project. Such studies consist of two parts, historical data and future data or forecasts. Forecasts, including revenues, expenses, and investments, are done using sound consistent techniques. Repayment of Federal projects is normally within 50 years with repayment of the highest interest-bearing investment first.

1.3 THE TRANSMISSION SYSTEM

Transmission of Power from Generation Source to Customers

Western is responsible for the operation and maintenance of 15,766 circuit miles of high-voltage transmission line and 213 substations. The "transmission facilities" (figure 1-2) lie primarily in the States of North Dakota, South Dakota, Montana, Wyoming, Colorado, Arizona, and California. Western's transmission system has 94 miles of 500-kV line, 1,274 miles of 345-kV line, 6,213 miles of 230-kV line, 316 miles of 138-kV line, 5,685 miles of 115-kV line, and 1,148 miles of 69-kV and below transmission line.

Initially, the transmission network was built to transmit 7,500 MW of power from 47 hydroelectric plants to preference customers throughout the system. Much of this transmission system has the capability to transmit additional peaking power from Federal hydro projects. Western continues to promote joint planning and operation of existing and future facilities with the numerous utilities with which it is interconnected.

The Federal Government, through the Water and Power Resources Service and the Western Area Power Administration, has provided a system by construction and wheeling arrangements for the transmission of power from generation sources to loads (including "project" loads) throughout each of the power marketing areas under the administrative control of Western. More efficient use of the Federal transmission facilities in transmitting power to load has been brought about through pooling, interconnection, and interchange arrangements with other utilities. Western has numerous arrangements for the wheeling of electric power and energy over the transmission systems of other utilities and for the wheeling by other utilities over the Federal system. These arrangements fall into two general categories: firm wheeling and surplus capacity wheeling. Firm wheeling involves a commitment or guarantee to transmit power and energy in amounts up to the customer's total system requirements or up to some specified level. Surplus capacity wheeling arrangements provide for transmitting power and energy only to the extent of available transmission capability in excess of that required by the wheeling agent for its own use. Wheeling service provided over the Federal system is generally limited to surplus capacity wheeling as the Federal system was authorized, designed, and constructed for the purpose of delivering Federal power.

Transmission Constraints on Marketing

As discussed above, Western's transmission system was originally constructed to deliver power from numerous individual Federal hydroprojects within its marketing area. Eventually, several of the various separate project systems were interconnected for additional operational flexibility and reliability. Recent developments in the energy field have produced conditions which make transfers of large blocks of power desirable from the standpoint of energy conservation, fuel economy, and integration of resources. Most of these transfers take effect during off-peak periods. At that time, the loads near many large generators are lower and the power from inexpensive and plentiful

generation sources is transmitted to areas of high fuel cost generation. These transfers are normally over long distances, stressing the transmission system beyond what was taken into consideration during system planning; and a number of system constraints presently exist for these conditions.

On-peak constraints also exist due primarily to continuing changes in location of generation, load, and transmission on an interconnected system. These changing conditions cause both increases and decreases in power flows on the various Western transmission lines from those for which the lines were originally designed. When the net increases are significant, system constraints arise.

Transmission limitations exist internally to Western's interconnected system, between the disconnected Western systems in MARCA and WSCC, between Western's California system and its Arizona-Utah-Colorado-Wyoming system, and externally to other adjoining power marketing administrations.

A large percentage of the internal constraints on Western's systems are being eliminated or reduced through addition of new transmission lines, transformers, or other system equipment. Some constraints are being removed through use of interconnected utility systems by contractual arrangements while others require such major expenditures that changes cannot be presently justified.

The western United States and eastern United States transmission systems are operated independently. The common border between the two systems bisects Western's area with adjacent systems at three locations along the border of the separate systems. For technical reasons, the western and eastern systems cannot be operated on a synchronous basis without construction of a multi-circuit EHV transmission interconnecting system. The inability to transfer power between Western's systems on either side of the separation has a significant impact on operating flexibility. Western is considering direct-current connections at several locations to correct this situation.

Western's system in California is connected to Western's Arizona-Utah-Colorado-Wyoming systems through several intermediate utility systems. These utility systems are fully utilized and are therefore a constraint to transfers between these portions of Western.

Western continues to examine the feasibility of increasing transfer capability between its system and that of BPA through construction of a direct-current transmission line from Oregon to Arizona. Arrangements for use of spare capacity on the existing transmission systems of intermediate utilities is also being pursued.

Transmission capacity between Western and SWPA is limited to that of a 161-kV interconnection. An evaluation is being made of the benefits which would result from providing additional intertie capability.

Reliability

Power Pooling. The reliability of the interconnected transmission system is enhanced by power pooling arrangements. These arrangements provide, among other things, for the sharing of reserve requirements and coordination of the installation and operation of new generation and transmission facilities. Basically, a power pool is an organization of two or more electric utilities which coordinate planning and/or operations to achieve economies of scale, minimize operating costs, conserve fuel, and improve service reliability.

Each of Western's areas participates actively in such pooling arrangements with the exception of the Sacramento area which obtains similar benefits through integration with the Pacific Gas and Electric Company's system.

Interregional Interties. Western's Denver, Salt Lake City, and Boulder City Area systems are directly interconnected; however, no such connections exist between that interconnected system and either of the Sacramento or Billings Area systems. While Western has two 345-kV ties between the Salt Lake City and Boulder City Area systems, the transfer capability is extremely limited by 230-kV facilities within the Salt Lake City Area's system. One 345-kV and two 230-kV lines tie the Salt Lake City and Denver Area systems. Again, while Western's Sacramento Area system and the BPA system are interconnected at 500-kV, direct transfer capability is limited by 230-kV facilities. There is no direct Federal transmission interconnection between BPA and the rest of Western's major interconnected system. A 161-kV intertie connects Western's Billings Area system with the SWPA.

In addition to Western's interconnections between areas, there are a number of lines between the areas owned by private and public utilities (figure 1-3). Most of the capability of these interties is presently committed to firm power transfers from generation sites to load centers.

Interconnection and Integration of Resources. Initially, Western's transmission system was constructed to deliver power from numerous individual Federal hydroprojects within its marketing area. The various separate projects systems are presently integrated and interconnected through Western's extensive high-voltage transmission system which is interconnected at numerous points with many other electric utility systems to provide for greater operational flexibility, reliability, and seasonal exchange of power.

In certain instances, where advantageous and desirable, arrangements have been made to provide for the integration of Federal hydroelectric resources with thermal generating units, specifically the integration of the CVP system in California with the system of PG&E.

Funding and Construction of Transmission Lines. Western's transmission system was originally designed to provide capacity for hydroelectric projects that operated at 40 to 60 percent plant factor. Today the best method of utilizing hydroelectric power resources is to add peaking capability where practical so that the plant is operated at 10 to 25 percent plant factor. Such generation additions would increase capacity requirements for some of Western's transmission lines above that for which they were designed. To maintain reliability on the transmission system and provide additional capacity, new transmission lines must be funded and constructed.

Total elapsed time from transmission planning to facility in-service is normally about 4 years, with certain activities being concurrent. Approximately 2 years are required to make cost/benefit type planning studies, environmental impact studies, design studies, and possibly arrange for joint financing. If the specifications for the new lines are written concurrent with the budget process, the line can be constructed in 1 or 2 years once congressional authorization and funding are received.

Planning and budgeting for transmission system additions is a continuing function on a 5-year forecast and must be coordinated with hydroelectric development.

CHAPTER 2

EFFECT OF ADDITIONAL FEDERAL HYDROPOWER SUPPLY ON PROGRAMS AND PRACTICES

2.1 DEMAND FORECASTS FOR REGIONS AND SYSTEMS

As discussed in previous sections of this report, two of the nine regional councils in the National Electric Reliability Council cover over 90 percent of Western's marketing area. These two councils are the Western Systems Coordinating Council (WSCC) and the Mid-Continent Area Reliability Agreement (MARCA). The remaining area is in two other council areas, the Electric Reliability Council of Texas (ERCOT) and the Southwest Power Pool (SPP).

The National Hydro Study (NHS) supply and demand projections contained in the draft report titled "The Magnitude and Regional Distribution of Needs for Hydropower, the National Hydropower Study, Phase II - Future Electric Power Demand and Supply" followed council boundary areas. That supply and demand study was made for the Institute of Water Resources and U.S. Army Corps of Engineers under Contract No. DACW 72-78-C-0013.

The April 1980 MARCA load/resource projections report (based on 1979 actual data) is nearly identical to the NHS forecasts. Planned generation additions during the next 10 years are a number of coal-fired units, a nuclear unit, and a small combustion turbine unit. Unit additions during future 10- to 20-year periods are in conceptual planning stages with few if any commitments being made. No hydro additions are included in immediate 10-year planning reports. Should hydro additions occur as a result of the NHS, those renewable units would substitute or delay the on-line dates for the presently planned coal-fired generating units in the MARCA area. Although this specific conclusion is not stated in the NHS load/resource study, it is indicated in the report in such statements as:

o Part of the conventional hydropower could be developed and hydropower energy could maintain a better share of the energy produced in MARCA mainly for intermediate and peaking demand.

o With large nuclear and coal-fired baseload plants (in the MARCA area) the market potential for pumped storage peaking plants could be as much as four percent of the total capacity by the year 2000.

The latest WSCC load/resource projections (based on 1979 actual) data show a lower expected demand and energy forecast than is presented in the NHS forecast. The difference amounts to about 0.5 percent per year in the immediate 10-year projections. The NHS forecasts were based on earlier projections made by WSCC. Projections made by WSCC for recent years have slightly lowered expected load growth rates in the overall WSCC area. Although the above projection difference is minor and causes only minor

effect on the NHS load/resource study conclusions, it is recommended the NHS study be updated to reflect the latest WSCC forecasts. The NHS load/resource study states that "between 1978 and 1985, large additions of nuclear and coal capacity are planned by utilities in the WSCC area. After 1985, system additions are expected to be mainly coal, nuclear, hydroelectric and geothermal." The latest WSCC load/resource studies are in agreement with this statement. Should hydro additions occur (other than presently planned) as a result of the NHS, these additional units would substitute or delay the on-line dates for presently planned coal-fired generation in the WSCC area. The NHS load/resource study states similar conclusions as follows:

o Considering the developments (conventional hydropower) already under construction, licensing or planning, as much as 15,000 MW of the total potential of 60,810 MW could be developed by the end of the century.

o With low-cost off-peak thermal energy available from large nuclear and coal-fired baseload plants, pumped-storage becomes more attractive. The energy output will serve the peaking demand and help reduce the dependence on oil. By the end of the century, pumped-storage could represent as much as five percent of the total capacity in WSCC.

2.2 INCREASE IN CUSTOMERS SERVED

Western is currently preparing and seeking public input on plans for the marketing of Federal power when existing contracts expire, the majority being in the 1981-1990 time frame. Informal customer meetings and formal public forums provide the valuable open lines of communication necessary in the planning process to assure that full consideration is given to all customers and public comments and interests regarding the allocation and reallocation of our resources and to allow our customers sufficient time to prepare for any potential changes in their power supply programs.

These plans involve developing definitive criteria for the optimum marketing of Federal resources within Western's purview as power becomes available and providing guidelines under which applications for power will be accepted.

As developed in those marketing criteria, a proposed reallocation, considering additional long-term firm power, from existing and/or new resources exhibits the present trend toward first offering to renew the existing commitments, in their same proportions, to existing customers. A portion of any uncommitted power and new resources would be available to potential new preference customers.

Presently, Western cannot assume responsibility for the future power needs of its customers beyond the capabilities of the Federal system under its administrative control, including the benefits of integration and firming wherever feasible. As a result, the deficiency between Federal firm power

supply and the demand creates not only the problem of allocation but also the problem for customers of how best to supplement their power supply to meet growing demand. Since the demand for purchase of Federal hydropower resources has far exceeded the availability, the number of customers to be served would be dependent upon the amounts of power that might become available from additional resources.

2.3 INCREASE IN LARGE-SCALE HYDROPOWER RESOURCES

Western presently markets about 8,050 MW of Federal power of which about 95 percent is from hydropower resources. This power is marketed to over 450 preference customers in the 15 States comprising Western's market area. The majority of these customers have other power and energy sources in addition to Western; however, a few customers rely on Western as their only power source.

Western markets its power through a wide range of selling techniques. These techniques were developed from many years of experience in hydro-resource operating practice that matches hydrogeneration to a wide range of load requirements. Western's sales include commitments based on adverse water conditions for capacity and average water conditions for energy, such as:

- Long-term firm capacity and energy
- Seasonal firm capacity and energy
- Short-term firm capacity and energy
- Peaking capacity with and without energy

Western sales also include surplus capacity and energy based on water conditions that are less severe than used for the above firm commitments. These sales include:

- Replacement
- Maintenance
- Secondary
- Surplus

In addition, Western's operation of load control areas furnishes such services as:

- Load shaping (ramping)
- Load regulation
- Load dispatching and scheduling, including such arrangements for many of our customers in which our resource may not be involved

Because of Western's on-going marketing program, the effect of including additional large-scale hydropower resources (including pumped storage) would have a very positive impact. Such additions would fit into present and future marketing programs.

Pumped Storage Development The Mt. Elbert Pumped Storage Powerplant of the Fryingpan-Arkansas Project was authorized in October of 1974. Western's Loveland-Ft. Collins Area Office is in the process of developing a marketing plan for the two 100 MW units which are scheduled to be in service July 1981 and August 1983, respectively. Public information meetings began in September 1980, and a final plan is expected in June 1981.

2.4 UTILIZATION OF SMALL-SCALE HYDROPOWER RESOURCES

Small-scale hydro resources could fit well into Western's present and future marketing program. Our present program includes marketing and transmission for the output of hydroplants ranging in size from 4.5 MW to 1,345 MW. Western's market and transmission planning can accommodate plants larger or smaller than this existing range of sizes included in its present hydroplant list of about 8,050 MW of installed capacity, which includes approximately 547 MW of thermal generation. (table 1-5)

2.5 EXPANSION OF THE FEDERAL TRANSMISSION SYSTEM

Normally, the addition of any significant amount of Federal hydropower within Western's marketing area would require additional Federal transmission. However, if small-scale hydropower resources are developed, it may be advantageous to arrange for wheeling of all or portions of such new power to load centers over existing or new non-Federal systems.

CHAPTER 3

EFFECT OF NEW ENERGY TECHNOLOGY ON PROGRAMS AND PRACTICES

Small-scale hydropower, as defined by the "Preliminary Inventory of Hydropower Resources" dated July 1979 and issued in a six-volume report by the U.S. Corps of Engineers, ranges in size from 0.05 to 15 MW. Potential power development of small-scale hydro is further divided into "incremental and undeveloped." Incremental is defined as existing dams and/or other resource projects with the potential for new and/or additional hydroelectric capacity. Undeveloped is defined as undeveloped sites where no dam or other engineering structure presently exists.

In the following discussion we do not distinguish between "incremental" and "undeveloped" small-scale hydropower. It is recognized that water constraints on incremental sites may be greater than for undeveloped sites. Water constraints at an existing dam may be greater because the dam was constructed for purposes other than power. At an undeveloped site, water availability and power production will be included in total project construction design. Both categories will undoubtedly have water constraints that would restrict ideal operation for power production. The extent of water constraints on power production will need to be evaluated for each individual site.

There are many factors which influence whether or not the small-scale hydropower potential may be developed. Much of this development may not be economically feasible when compared to costs of alternative sources. Some of the potential may not be acceptable due to environmental and social criteria. However, as construction costs of thermal-electric generation units have sharply risen in recent years and escalation in fuel and maintenance costs have increased, many small hydroelectric sites have become a relatively attractive source, economically, of power and energy. Also, many small hydroelectric developments are considered more acceptable environmentally than most alternatives. This is especially true if the small hydroelectric site is an existing water resource development facility.

One of the major challenges of small hydroelectric development will be separating sites economically, environmentally, and socially between acceptable and unacceptable. To make such a separation, studies will be required comparing the cost of developing each small hydro site to the cost of alternative generating resources. If small hydro cost development exceeds alternative costs (which includes transmission costs to load centers), the hydropower production may not be easily marketed.

Most of the small-scale hydro sites will have restrictions on power production at times during a day, month, or season that will not match load requirements. These restrictions on idealy timed power production could be caused by water releases for other than power use and/or lack of water storage capacity. This presents a challenge of how to "firm" the small-scale hydrogeneration energy and capacity. This is not a new challenge to Western, as we have scheduled and operated hydroelectric generation with similar water constraints for many years. This challenge can be met by integrating a new small-scale hydroelectric development into a total electric system. This requires factoring in many planning items such as load/generation shaping, regulation, maintenance, and reserves. Such a challenge would have to be met within the "firming" capability of Western's existing facilities and customer commitments. Should a large number of small hydro developments need firming capability beyond Western's limits, Western could meet the additional challenge of arranging with other power generating entities and customers for assistance.

CHAPTER 4

EXPANDED ROLE WITH NEW LEGISLATION

One of the purposes of the DOE Organization Act was to "promote maximum energy conservation measures," and certain authorities were given to the Secretary of Energy for this purpose. In addition, the act transfered authorities from other agencies. While the Secretary may delegate certain authorities, carrying through with these powers is dependent upon various factors--primarily those of funding and political support, which are inseparable issues. Therefore, the following new Western activities, which would expand Western's role, may require new legislation, funding, and/or political support:

- Provide integration services from new generation by:

  -- Planning and developing additional transmission facilities to expand Western's existing marketing program for renewable resources. This would be especially applicable to the present oil conservation program.

  -- Designing and constructing transmission facilities from renewable resource development projects (e.g., solar, geothermal, low-head hydro, etc.).

- Provide long-term purchase arrangements for capacity and energy, up to Western's alternative cost, from renewable resource development projects.

CHAPTER 5

PROGRAMS AND PRACTICES FOR THE FUTURE

5.1 RATE STRUCTURE AND PRICING PROCEDURES

Western may, in the future, use more rates with the so-called "tip-up" feature. This means that the energy charge is greater for energy use in excess of a certain load factor each month. For example, the energy charge for energy at 60 percent or less load factor per month may be 4 mills per kilowatt-hour, and the energy charge for all energy taken in excess of 60 percent load factor may be 8 mills per kilowatthour. Such a rate is appropriate because the water available for energy production is limited, and increased use of energy by the customers may require Western to purchase energy from other resources, at additional cost to Western.

In the past, Western has tended to market all firm power from any one marketing system at one rate, and to market the peaking power from the system at the same rate as the capacity component of the firm-power rate. This has been done without regard for particular resources used. However, Western is now moving toward increased use of unique types of service, such as pumped-storage peaking power. The service supplied from such unique resources may mean that Western will move toward rates which are matched to the particular resource involved.

5.2 TRANSMISSION RATES

By design, Western is attempting to expand the so-called "joint transmission system" (JTS) concept into geographic areas where it does not presently exist. Under this concept, all the major transmission facilities, regardless of ownership, within a geographic area are pooled. A cost is then established for the use of the pooled transmission system, and all parties using the system pay the pool prices into a pool fund. The owners of the components are reimbursed from the pool fund. This is an overly simplistic description, but such arrangements overcome many of the difficulties associated with transmission system planning and use for wheeling when several utilities are involved.

NATIONAL HYDROELECTRIC POWER RESOURCES STUDY

Marketing and Transmission of Hydroelectric Power

Part 5

Southwestern Power Administration Appendix

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PREFACE

The history, current activity and future role of the Southwestern Power Administration are described. Emphasis is given to the current and future activities as a federal power marketing agency. The resources and facilities are discussed in terms of power and energy supplied to customers. Particular attention is given to the potential for development and utilization of new hydroelectric and other alternate energy resources.

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CHAPTER I

INTRODUCTION

1.1 HISTORY

The Southwestern Power Administration (SWPA) was established by the Secretary of the Interior in 1943 as a Bureau of the Department of the Interior. On October 1, 1977, in accordance with Public Law 95-91, 91 Stat. 565; 42 U.S.C. 7101, the Department of Energy Organization Act dated August 4, 1977, the SWPA was transferred from the Department of the Interior to the new Department of Energy. It is under the direction of an Administrator with delegated authority to carry out the responsibilities of the Secretary under Section 5 of the Flood Control Act of 1944 to market the electric power and energy produced at certain multipurpose reservoir projects constructed by the Department of the Army, Corps of Engineers, in the Southwest.

The Southwestern Federal Power System is the name applied to the facilities and operation of SWPA and the hydro electric generating plants constructed and operated by the Corps of Engineers for which SWPA has been designated the marketing agent.

The SWPA markets power generated at hydroelectric projects located in the States of Arkansas, Missouri, Oklahoma, and Texas. The power is marketed in those four states, plus Kansas and Louisiana.

Historically, those customers who are preference customers under Section 5 of the Flood Control Act of 1944 (i.e., cooperatives and public bodies) have received a majority of the electric power and energy marketed by the SWPA. This policy has greatly benefited public power development in the six-state region served by the SWPA.

1.2 PRESENT AND FUTURE ROLE

The SWPA, as a power marketing agency is supplying a relatively smaller portion of the total electric load in the Southwest. This trend is of major concern to SWPA customers, who see it as diminishing the stabilizing force the Government has exerted in the past on rates changed for power and other related services in the SWPA area of operation. However, SWPA's future role in supplying services promoting

conservation and developing new energy sources from other renewable resources will result in its continuing to provide a strong voice in the electrical industry in the Southwest. In addition SWPA will use its facilities to provide transmission under third party arrangements where needed. SWPA is a member of the Southwest Power Pool Regional Council and in addition to the Administrator serving on the Board of Directors, members of the SWPA staff serve on various SWPP committees. The Administrator is placing increased emphasis on Pool activities and expects to continue to be a strong force enhancing reliable electric service in the region.

The present intraagency relationship between the Department of Energy and the SWPA is set forth in Section 302(a)(1) of the Department of Energy Organization Action (42 U.S.C. 7101), which states:

> "Sec. 302.(a)(1) There are hereby transferred to, and vested in, the Secretary all functions of the Secretary of the Interior under Section 5 of the Flood Control Act of 1944, and all other functions of the Secretary of the Interior, and officers and components of the Department of the Interior, with respect --
> . . . (B) The Southwestern Power Administration. . . ."

The SWPA is to be preserved as a separate and distinct organizational entity within the Department of Energy. The Secretary is to appoint an Administrator who is to carry out the functions transferred to the Secretary of the Department of Energy. Each Administrator is to maintain his principal office at a place located in the region served by his respective federal power marketing entity. The Administrator shall establish and maintain necessary regional offices to facilitate the performance of his functions.

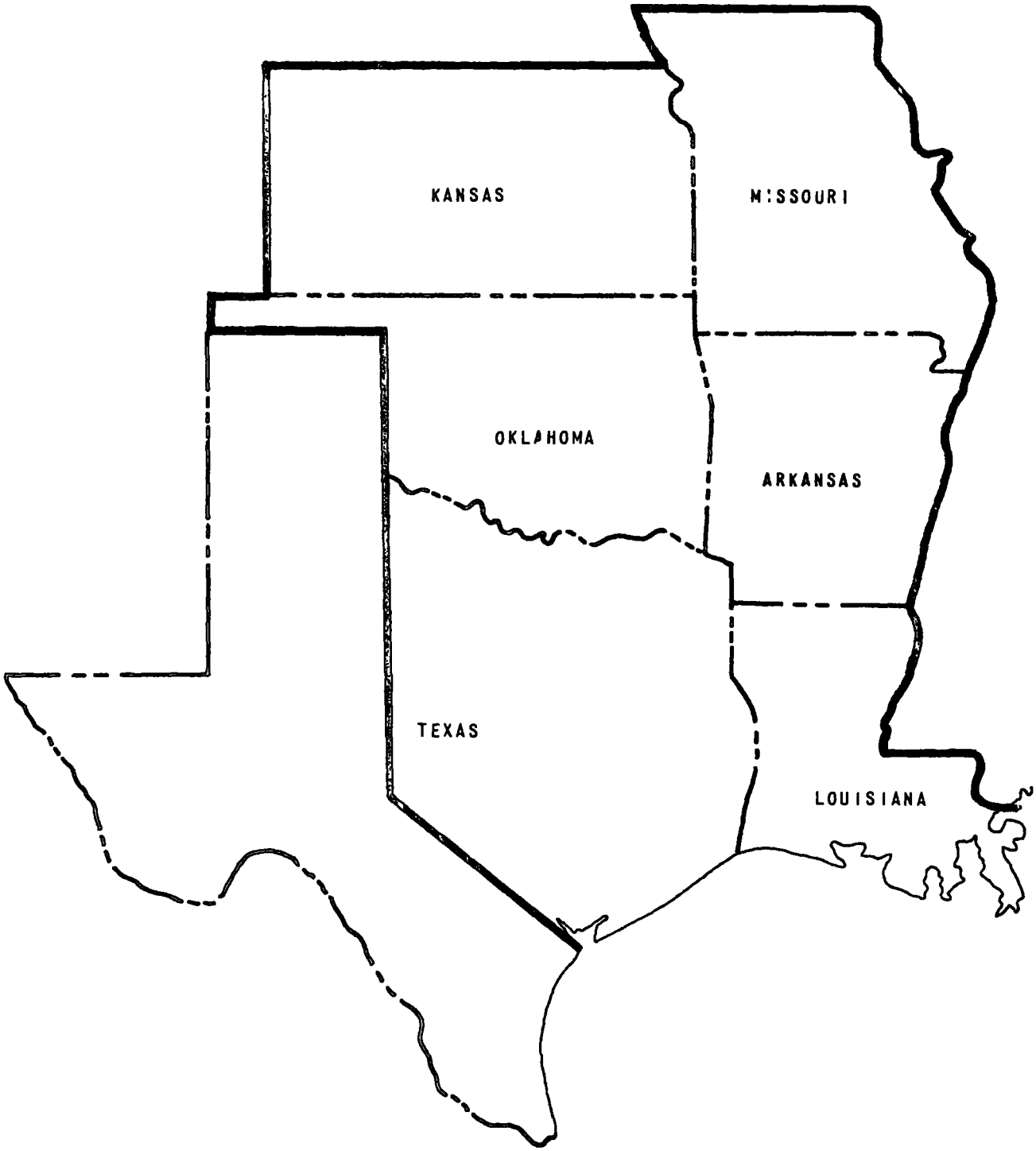


Figure I-I
SWPA POWER MARKETING AREA

CHAPTER 2

THE CURRENT MARKETING AND TRANSMISSION SYSTEMS

2.1 POWER MARKETING ADMINISTRATION

Mission and Functions

The mission and functions of the SWPA are set forth in Section 5 of the Flood Control Act of 1944 (16 U.S.C.A., Section 825s), which states:

> SEC. 825s. SALE OF ELECTRIC POWER FROM RESERVOIR PROJECTS; RATE SCHEDULES; PREFERENCE IN SALE; CONSTRUCTION OF TRANSMISSION LINES; DISPOSITION OF MONEYS
>
> Electric power and energy generated at reservoir projects under the control of the Department of the Army and in the opinion of the Secretary of the Army not required in the operation of such projects shall be delivered to the Secretary of the Interior, who shall transmit and dispose of such power and energy in such manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles, the rate schedules to become effective upon confirmation and approval by the Federal Power Commission. Rate schedules shall be drawn having regard to the recovery (upon the basis of the application of such rate schedules to the capacity of the electric facilities of the projects) of the cost of producing and transmitting such electric energy, including the amortization of the capital investment allocated to power over a reasonable period of years. Preference in the sale of such power and energy shall be given to public bodies and cooperatives. The Secretary of the Interior is authorized, from funds to be appropriated by the Congress, to construct or acquire, by purchase or other agreement, only such transmission lines and related facilities as may be necessary in order to make the power and energy generated at said projects available in wholesale quantities for sale on fair and reasonable terms and conditions to facilities owned by the Federal Government, public bodies, cooperatives, and privately owned companies. All moneys received from such sales shall be deposited in the Treasury of the United States as miscellaneous receipts.

The SWPA has historically carried out the functions mandated by Section 5 of the Flood Control Act of 1944. Currently these functions are being performed pursuant to the direction of the Secretary of the Department of Energy by the terms of Section 302(a)(1) of the Department of Energy Organization Act.

Authorities

The primary authorities by which the SWPA operates have been set forth above, i.e., Section 5 of the Flood Control Act of 1944 (16 U.S.C.A., Section 825s) and Section 302(a)(1) of the Department of Energy Organization Act (42 U.S.C., 7101). The newest statute governing the transmission policy is set forth below and will be discussed separately.

The Flood Control Act of 1944 (16 U.S.C.A., 825s) was one of a series of pieces of legislation passed by the Congress to develop, market, and transmit electricity produced at hydroelectric facilities by the U.S. Army Corps of Engineers. The purpose of the legislation was to benefit public power by providing a source of reasonably priced energy in wholesale quantities. The House had enacted both the Rivers and Harbors Bill and the Flood Control Act of 1944 without making provisions for the disposition of power from the public works projects which were authorized by the legislation. Section 5 of the Flood Control Act of 1944 had its genesis in an amendment reported by the Senate Commerce Committee to the Flood Control Act of 1944. The Congress adopted the suggestions of various members of Congress and then Secretary of the Interior, Harold L. Ickes, which became Section 5 of the Flood Control Act of 1944.

Governing Laws

The statutory authority for the SWPA's marketing function is set forth above in Section 5 of the Flood Control Act of 1944 (16 U.S.C.A., Section 825s) and Section 302(a)(1) of the Department of Energy Organization Act (42 U.S.C., 7107).

Statutory law governing transmission policies is set forth in 16 U.S.C.A., 825s-3, as follows:

> SOUTHWESTERN AREA SALE AT UNIFORM SYSTEM-WIDE RATES OF ELECTRIC POWER OVER TRANSMISSION LINES CONSTRUCTED WITH APPROPRIATED FUNDS OR USED UNDER CONTRACTUAL ARRANGEMENTS
>
> Power and energy marketed by the Southwestern Power Administration pursuant to Section 825s of this title shall be sold at uniform systemwide rates, without discrimination between customers to whom the Southwestern Power Administration delivers such power and energy by means of transmission lines or facilities constructed with appropriated funds, and customers to whom the Southwestern Power Administration delivers such power and energy by means of transmission lines or facilities, the

use of which is acquired by lease, wheeling, or other contractual arrangements. Pub.L. 95-456, Section 1, Oct. 13, 1978, 92 Stat. 1230.

There are no cases or Attorney General's opinions interpreting this statute, which will not become effective until Contract No. 14-02-0001-1002, between the United States of America and Associated Electric Cooperative, Inc., has been amended in a manner mutually agreeable to the parties. Currently, negotiations are being conducted.

Organization and Administration

The SWPA has the responsibility for planning, administration, operation, and marketing for the Southwestern Federal Power System. The SWPA carries out its responsibilities through a headquarters office in Tulsa, Oklahoma, four construction and maintenance facilities located in Muskogee, Oklahoma; Springfield, Missouri; Jonesboro, Arkansas; and Ada, Oklahoma; and a central system control and dispatch facility in Springfield, Missouri. The names and locations of the hydroelectric power plants are shown with the SWPA transmission system on the map in Figure 2-1. The entire Southwestern Federal Power System is shown interconnected with neighboring utility systems on the Southwest Power Pool map in Figure 2-2. The hydroelectric generating plants and the SWPA transmission system will be described in greater detail in subsequent discussion.

The SWPA headquarters functions are conducted by five major organizational elements. These elements are the Office of the Administrator, the Division of Power Marketing, the Division of Power Facilities, the Division of Administrative Management, and the Office of Chief Counsel. Within the Office of the Administrator, the Administrator, aided by the Deputy Administrator, plans, directs, and controls all programs of the SWPA as determined by Congressional actions and the policies, regulations, and procedures of the United States Department of Energy.

The Division of Power Marketing is responsible for the evaluation of and participation in the sale, interchange, wheeling, and purchase of electric power. The activities of this division are conducted by the branches of Customer Service, Rates and Repayment, Power Resource Production, and Power Operations. The Branch of Customer Service is involved in the planning, evaluation, negotiation and administration of all contract relationships with SWPA customers. The Branch of Rates and Repayment is involved in the allocation of costs, the determination of financial performance, and the development of proper rates for adequate repayment of SWPA projects. The Branch of Power Resource Production is involved in the integration of SWPA hydroelectric and other power resources through forecasting of both load and resources in conjunction with extensive evaluation of alternative resource development plans. The Branch of Power Operations is involved in the operation, power accounting, scheduling, and dispatching of the SWPA interconnected transmission

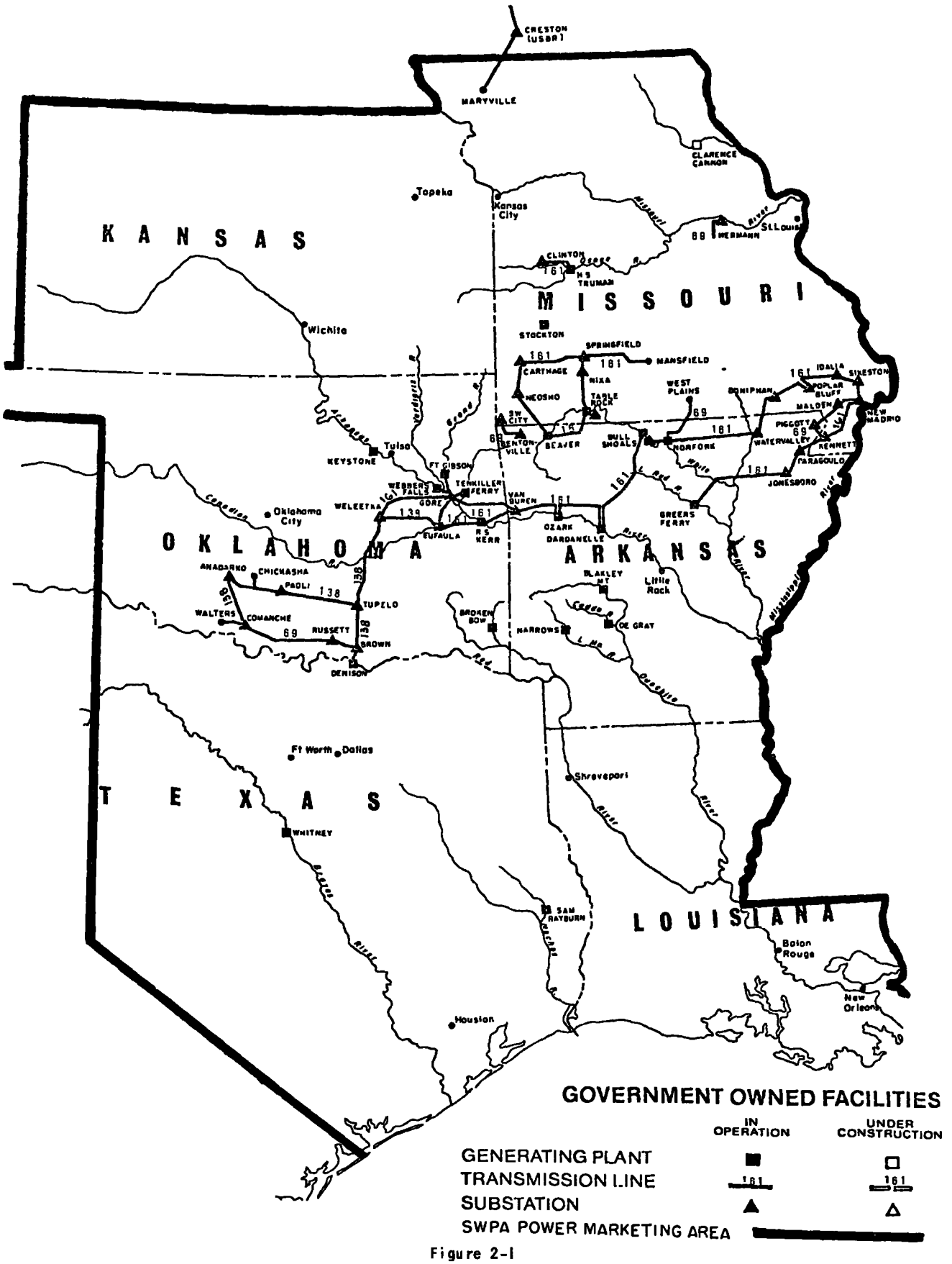


Figure 2-1
SWPA POWER FACILITIES

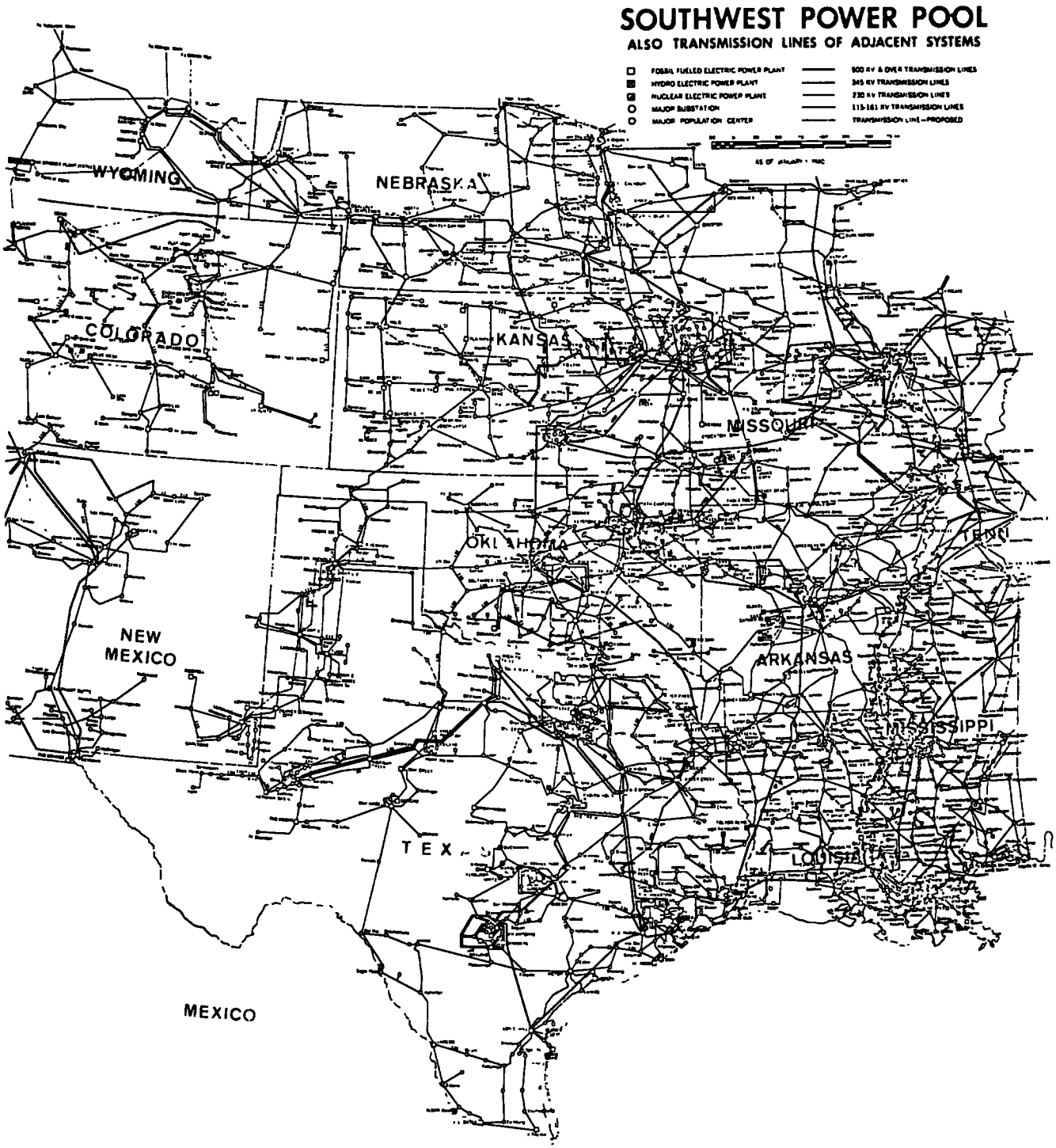


Figure 2-2

TRANSMISSION SYSTEMS IN SWPA AREA

system and the effective integration of SWPA hydroelectric and other power resources for effective and efficient fulfillment of current SWPA load requirements.

The Division of Power Facilities administers policies and programs for the transmission facilities that are necessary to implement the SWPA marketing program. The responsibilities of this division are carried out by the branches of Engineering and Maintenance. The Branch of Engineering is involved in the planning, design, and evaluation of the SWPA transmission system as well as the protection of that system. The Branch of Maintenance provides functional supervision for maintenance, modification and force account construction of transmission lines and related facilities, as executed in the field under the direction or supervision of area engineers operating from the construction and maintenance facilities.

The Division of Administrative Management plans, develops, coordinates, and administers programs for financial accounting, budgeting, computer systems, property management, real property acquisition, and office services. The activities in this division are carried out by the branches of Finance and Accounts, Computer Services, and General Services. The Branch of Finance and Accounts is involved in the functional supervision of financial accounting activities for all segments of the SWPA. The Branch of Computer Service performs analysis and programming for automatic data processing applications throughout the SWPA system, including financial accounting, budget, hydraulic engineering, electrical engineering, inventory control, billing, rate and repayment studies, power operations, and special management assignments. The Branch of General Services provides functional supervision for the procedures and schedules of the SWPA procurement and contracting program, personal and real property program, acquisition of land and interest of land for construction purposes, record management program, printing and reproduction services, forms management, and office communication.

Finally, the Office of Chief Counsel provides legal advice and services to the SWPA staff. The Chief Counsel and Attorney Advisors, along with clerical support, are involved in all aspects of land acquisition including condemnation suits, the negotiation and legal review of power sales contracts, tort claims, labor law, and litigation arising from the administration of all phases of SWPA operations.

Relationships With Regional Reliability Councils and Power Pools

The Southwestern Federal Power System has both generation and transmission facilities in the Southwest Power Pool (SWPP) and generation facilities in the Electric Reliability Council of Texas (ERCOT). SWPP is strongly interconnected with other reliability council systems to the north and east, but ERCOT is electrically isolated from the rest

of the nation. Both of these reliability groups are loosely organized to coordinate their overall internal operations, but have no formal binding agreements applicable to all members regarding power supply and reliability. More formal detailed reliability and coordination agreements are on a system-to-system basis and are usually between members of more closely coordinated groupings, such as Middle South, MOKAN Pool, Texas Electric Cooperatives, Inc., and other associations and organizations. The resources and transmission facilities of the SWPA are utilized by its customers in accordance with their agreements with the applicable reliability councils and other associations. There are no formal written agreements of cooperation and coordination between the SWPA and either of the two applicable reliability groups.

An interesting issue in the relationship of the SWPA with SWPP and ERCOT involves the inability of the SWPA to be actively connected by transmission facilities to both reliability groups. This results from the electrical isolation of ERCOT from the rest of the national utility grid. As a result, the SWPA must allocate its resources to customers in ERCOT separately from its customers in SWPP. This can cause difficulty in the determination of a fair and equitable allocation of SWPA resources on the basis of the customer load in Texas as related to the customer load outside of Texas. The Federal Energy Regulatory Commission is currently considering a proposal whereby ERCOT would be connected to the national grid by two asynchronous DC links. This would not greatly simplify the procedure for the SWPA to allocate resources within ERCOT and SWPP because of the limited capacity of the DC ties and the exclusion of other AC ties between ERCOT and the national grid.

Customers and Classes of Service

The SWPA markets power generated at hydroelectric projects located in the States of Arkansas, Missouri, Oklahoma, and Texas, to customers who are located in these four states plus Kansas and Louisiana. In keeping with Section 5 of the Flood Control Act of 1944, the SWPA gives marketing priority to preference customers. Although the SWPA does serve a few non-preference customers in its service area, these will be essentially phased out by 1983 so that all marketing will be only to preference customers. Power is marketed primarily through the integrated SWPA transmission system. However, a few customers receive power directly from isolated projects. A summary of customers, as determined by the 1980-1988 power allocations, is shown in Table 2-1. Individual customer power allocations, by year, can be found in the Final Power Allocations as published on March 24, 1980, in the Federal Register (45 F.R. 19032).

The SWPA markets power to its customers in four basic classes. These classes are firm power, peaking power, interruptible capacity, and excess energy. The firm power service supplies all of the energy needs of customers solely dependent upon the SWPA for power supply, and energy limited to quantities generally paralleling the normal load factor for those customers having an auxiliary power supply. The SWPA is phasing out the firm power service as contracts expire since its hydraulic resources

Table 2-1

SWPA CUSTOMERS

Based on 1980-88 Contracts and Power Allocations

	1980		1988	
	Number of Customers[1]	Allocation MW	Number of Customers	Allocation MW
Arkansas				
Municipalities	7	184.6	7	187.0
REA Cooperatives	1	189.0	1	189.0
Private Utilities	1	150.0	0	0.0
Kansas				
Municipalities	1	25.0	30	70.0
REA Cooperatives	1	60.0	3	107.0
Louisiana				
Municipalities	0	0.0	12	66.0
REA Cooperatives	2	17.0	3	112.0
Missouri				
Municipalities	12	188.7	14	197.7
REA Cooperatives	1	478.0	1	478.0
Oklahoma				
Municipalities	17	94.6	17	103.2
REA Cooperatives	1	260.0	1	260.0
Government Agencies	3	43.8	3	45.3
Texas (Interconnected)				
REA Cooperatives	2	177.5	2	177.5
Texas (Non-Interconnected)				
REA Cooperatives	2	45.0	2	80.0
Private Utilities[2]	1	35.0	1	35.0

1 A formal association of cooperatives is considered one customer.

2 Serves Tex-La Cooperative from Denison Dam.

are not well suited to such service. The peaking power service typically guarantees a minimum yearly usage of 1,200 hours per kW of peaking power, although additional kWh (i.e., supplemental peaking energy) may be offered to the customer when it is available to the SWPA. These two classes of service, peaking power and firm power, are the principal classes for the SWPA system. Interruptible capacity service may be made available, usually when good water conditions exist, with a capacity guarantee that ranges from a few hours during a given day to a number of days. Energy that can neither be marketed under any of the three previously mentioned classes nor be banked for future use is marketed in the excess energy class. The marketing of this excess energy is determined solely by the SWPA, and there is no requirement for the customer to buy it. Excess energy is marketed for short times only to prevent excess resource spillage at reservoirs and only then until other arrangements can be made. Some combination or adaptation of the four service classes can be used, by contract, to serve any customer through the integrated SWPA system or from an isolated project.

Resource Capabilities

The SWPA has marketing responsibility for the power facilities of twenty-three multi-purpose reservoir projects which are constructed and operated by the United States Army, Corps of Engineers. The hydro-electric facilities have a total power rating of approximately 2.1 million kW. Because of the nature of the hydraulic resources, the primary product of these projects is low plant-factor peaking power. The hydro-electric production is supplemented by purchased energy from other suppliers, particularly during periods of low hydraulic resource availability. The quantity of supplemental purchased energy varies over time in accordance with the availability of hydraulic resources. Hydro-electric generation, in conjunction with supplemental purchased energy, makes up the total marketable product for the SWPA.

The geographic location of the hydroelectric facilities has been shown in Figures 2-1 and 2-2. A more detailed description of these facilities is provided in Table 2-2. All but two of the hydroelectric facilities deliver their power into the integrated SWPA transmission system. The remaining two facilities are isolated from the SWPA transmission system and are marketed under contracts through which the customer purchases the entire power output of the project at the dam. These projects are remote to our grid and are not integrated through government-owned transmission lines to our integrated system. The power from the SWPA facilities is delivered by contract or other agreement to SWPA customers in accordance with the previously described customer classes.

The SWPA may integrate supplemental purchased energy with its hydroelectric generation in order to meet contract obligations. This may be done on an emergency basis or as the result of longer-term adjustments for variable hydraulic resources. Some purchased energy has been obtained through interchange agreements with the Western Area Power Administration (WAPA) which take advantage of the resource diversity between the WAPA and the SWPA. Energy has also been purchased

Table 2-2

HYDROELECTRIC POWER FACILITIES

Project	State	FY On-Line	Nameplate Capacity MW	Average Annual Generation GWh
Beaver	AR	1965	112.0	172
Blakely Mountain	AR	1956	75.0	163
Broken Bow	OK	1970	100.0	129
Bull Shoals	AR	1953	340.0	785
Clarence Cannon	MO	1982	58.0	90
Dardanelle	AR	1965	124.0	613
DeGray	AR	1972	68.0	97
Denison	TX	1945	70.0	219
Eufaula	OK	1965	90.0	260
Fort Gibson	OK	1953	45.0	191
Greers Ferry	AR	1964	96.0	189
Harry S Truman	MO	1980	160.0	282
Keystone	OK	1968	70.0	228
Narrows*	AR	1951	25.5	30
Norfork	AR	1944	80.6	184
Ozark	AR	1973	100.0	429
Robert S. Kerr	OK	1972	110.0	459
Sam Rayburn*	TX	1967	52.0	114
Stockton	MO	1973	45.2	55
Table Rock	MO	1959	200.0	495
Tenkiller Ferry	OK	1954	36.5	95
Webbers Falls	OK	1974	60.0	213
Whitney	TX	1955	30.0	73
Total			2,147.8	5,565

* Isolated Project

from cooperatives (e.g., Associated Electric Cooperative) and from private utilities (e.g., Oklahoma Gas & Electric, Public Service Company of Oklahoma, and Texas Power & Light). The energy purchase agreements may sometimes involve only stand-by or reserve capacity and/or energy.

Not only does the SWPA make use of other energy sources when hydraulic resources are not sufficient to meet contract obligations, but the SWPA may also make use of other energy supplies to optimize its hydroelectric generation usage. This may be done in the form of energy banking. That is, the SWPA may forego the revenue from interruptible capacity and excess energy in favor of delivering hydroelectric energy to a neighboring utility in return for thermal energy at some future time when hydroelectric energy is not available. This banking is done only after all system firm and peaking commitments are met. Regular banking arrangements have been made with the WAPA, various cooperatives and municipalities, and investor-owned utilities.

The power marketed by the SWPA is integrated with other generation sources by its customers in several ways. Those firm power customers which are not solely dependent upon the SWPA for their power supply schedule SWPA power with supplemental power in order to meet their complete base load and all intermediate and peaking requirements. This type of firm power customer receives energy from the SWPA in proportion to capacity in the same fraction as the overall capacity factor of its supplemental generation. Such a customer might typically receive 4,000 hours per year of energy at rated firm power capacity. The peaking power customer schedules the SWPA peaking power in such a way as to minimize operational costs and/or maximize system reliability. A synergism often exists between the SWPA peaking power and the customer's other power supplies. That is, operational costs may be less for a combination of SWPA peaking power and other power supplies than for an equivalent amount of either type of power used alone. A customer may use interruptible capacity, with its short-term notice of availability and corresponding short-term guarantee, to displace peaking capacity and energy in day-to-day operation. The excess energy customer uses the SWPA generation purely as a fuel displacement. These procedures, though beneficial, require complex and flexible operations to coordinate the hydroelectric generators with other power sources, especially considering the operational constraints due to environment and other use obligations inherent in a multi-purpose project system.

Current utility operating requirements and energy costs have caused most hydroelectric generation to be used in a peaking mode. However, hydroelectric generation is well-suited, in an operational sense, for base load capacity, intermediate load capacity, and peaking capacity. As a result, hydroelectric generation as marketed by the SWPA can be successfully integrated with any conventional generation or alternate energy technologies.

The resource capabilities of the Southwestern Federal Power System cannot be discussed independently of the transmission system which is used to move energy from the generation resource to the customer. The SWPA transmission system, in combination with the wheeling services of neighboring utilities, will be discussed in detail in Section 2-3.

2.2 MARKETING AND TRANSMISSION PROGRAMS AND PRACTICES

Policies

The SWPA has made executive interpretations governing its marketing and transmission practices in accordance with the federal statutes setting forth the SWPA's duties and functions. For example, the SWPA, while giving priority to preference customers in power allocations, considers all preference customers as being co-equal. Further, contracts that require more than 1,200 kWh/kW per year are being reallocated as peaking power with 1,200 kWh/kW per year.

Preference and Priority

The preference customers of the SWPA have priority access to electric energy marketed and/or transmitted by the SWPA as mandated by the Flood Control Act of 1944 (16 U.S.C.A., 825s). This priority is reflected in the current marketing practices. During 1980, certain contracts with non-preference customers will expire and new generation resources will become available. These "new" power resources will be allocated on an equitable basis to preference customers with regional needs being emphasized.

Wholesale Power Rates

The SWPA is responsible for marketing of federal hydroelectric resources throughout its region of operation in a manner that will ensure its widespread use. The SWPA currently attempts to ensure that this widespread use results from a fair and equitable distribution of resources to preference customers throughout its service area. This distribution is pursued through marketing activity that is designed to recover all of the fixed and variable costs of service to SWPA customers. However, it is important to note that all revenues collected by the SWPA are deposited into the general fund of the United States Treasury. The funds for construction and operation of all power facilities are generated by annual Congressional action. So, even though the financial accounting methods for revenue generation are based on fixed and variable costs, the revenue/expenditure loop is not a closed loop as is the case with other electric utilities.

The rates under which SWPA markets power are expected to recover facilities investment costs, annual costs (e.g., O&M, purchased energy, service charges, G&A), and replacement costs. The objective of SWPA in rate design is to charge all customers the same rate for the same class of service. This objective is simple to state, but it has been somewhat difficult to realize since the SWPA has entered into a variety of different contractual agreements relating to power sales and power

services. Rate structures can generally be described on the basis of the four previously discussed customer classes.

The firm power and peaking power customers pay a rate which consists of a capacity charge, an increasing block rate energy charge, and a surcharge for power delivery at voltage levels below the voltage levels of the integrated SWPA transmission system. The increasing block rate energy charge is designed to reflect the increasing fraction of more expensive purchased energy inherent in higher load levels on the SWPA system. A substantial penalty is charged on the basis of demand or energy if the customer exceeds the maximum contract demand for capacity or energy. The interruptible capacity rate has a capacity charge and an energy charge, but does not have the increasing block rate energy structure nor the surcharge that the previously discussed rates have. In addition, the interruptible capacity rate has a provision for a type of energy banking wherein the SWPA requires the customer to accept the energy accompanying interruptible capacity with a provision for paying back the energy at some time within a twelve-month period after accepting such energy. The excess energy rate consists of a simple energy charge. Some combination or adaptation of these four rates may be used in serving a customer by contract from the integrated SWPA system or a customer by contract from one of the isolated projects.

The relative magnitudes of the capacity and energy charges for the firm power, peaking power, and interruptible capacity rates are determined by the relative cost of service of each class and the revenue requirements which are determined in repayment studies. In this sense, these rates are cost-based rates, although they are not truly marginal cost rates since they are not adjusted for seasons or time of day. The excess energy rate is simply a postage stamp rate with no cost provisions for time of use, distance of transfer, or demand level. A great percentage of all SWPA marketing is done via the firm and peaking power rates.

It might be expected that the rates in any hydroelectric power system should approximate postage-stamp rates because of the lack of variation in O&M costs and fuel costs. Yet, it is important to realize that, in the SWPA system, cost of service does vary as a result of changes in the hydraulic resource over time which result in the need to purchase energy from neighboring utilities to meet contract obligations. Furthermore, the SWPA must rely on the transmission system of neighboring utilities to deliver some of its hydroelectric generation to its customers. This also causes variations in the cost of service for class and location of customer.

The SWPA, through on-going rate analysis and design, attempts to continue to reflect the costs of service in its wholesale power rates. Inherent in this effort is the recovery of the actual costs of energy and/or capacity purchased for a customer from external suppliers, as well as the recovery of the transmission costs inherent in delivering

power to a customer through the transmission system of a neighboring utility. These and other variations in the cost of service will continue to be reflected in cost-based rates as a result of on-going SWPA rate design activities.

Transmission Rates

As has already been mentioned in the discussion on wholesale power rates, it is necessary to recover the costs of transmission capacity and service in addition to the costs of generation capacity and energy production. It should be noted that a portion of the capacity charge in each rate having a capacity charge is allocated to the cost of transmission capacity. A portion of the energy charge in each of the rates is allocated to the operational costs of the transmission system. In addition, the surcharge for service at voltage levels lower than the SWPA transmission voltage has already been mentioned. This surcharge is designed to recover costs of transformation facilities for serving customers at lower than transmission network voltages.

The SWPA incurs other transmission service charges through wheeling of power over neighboring utilities' transmission systems. These costs are currently passed on to SWPA users where applicable by transmission service charges. These charges may be billed directly to the SWPA customer by the neighboring utility to which it is connected, or they may be billed to the SWPA for customers for whom the SWPA has wheeled power through a neighboring utility transmission system.

As is the case with wholesale power rates, the SWPA, through continuing analysis and rate design, attempts to properly allocate applicable transmission costs to each class of customer. It is important to note that Public Law 95-456, Section 1, as discussed in Section 2.1, may change the nature of transmission rate design for the SWPA.

Marketing

The demands from existing and prospective customers for power and energy from the SWPA currently far exceed the supply. This is true for both firm capacity and energy as well as undependable capacity and energy. The trends and conditions that have caused this strong demand are not only likely to continue, but may intensify so that the demands will even further exceed the supply.

The SWPA furnishes an ever declining fraction of the total electric load of even its preference customers. Even if the overall customer electric load is not increased, the desirable operating characteristics and costs of hydroelectric generation would lead to a growing demand for this generation. This is due to the fact that, as existing capacity is retired, it must be replaced with power supplies that have high capital and/or O&M costs in comparison with hydroelectric generation. Since the total electric load in the SWPA region is not remaining

constant, but is growing rapidly, the demand for hydroelectric generation is increasing all the more.

The SWPA cannot presently supply even the total peaking power requirements of its existing and prospective customers, so that, even though most existing and potential SWPA generation is to be offered as low plant-factor peaking power, the demand for such power will still far exceed the supply. This is because the alternative sources of peaking power have higher O&M and fuel costs as compared with hydroelectric generation and because the current increasing electric load has a low load factor which places a premium on peaking power.

Not only is there a strong and growing market for all SWPA existing and potential capacity, but the demand for energy in the form of firm contract energy or undependable capacity will also probably exceed the supply in the foreseeable future. This is because incremental energy supply tends to displace the most expensive generation in the economic dispatch of the customer. This generation is likely to continue to be more expensive than the hydroelectric power that the SWPA supplies. This would not be the case only if the customer has a more economically desirable alternative generation supply available, or the amounts of energy and/or undependable capacity offered by the SWPA become very large in relation to the total load of that customer.

The strong market for the SWPA product is basically a result of the economic desirability of that product. This economic desirability can continue to exist only as long as the rate structures utilized by the SWPA properly reflect the costs of the hydroelectric generation, and only as long as this hydroelectric generation is less costly than the alternatives with which it competes. In other words, innovative rate structures and artificial pricing signals to the SWPA customers are not likely to have significant desirable effects in terms of resource conservation and demand reduction in the SWPA region.

As has already been mentioned, the relatively small contribution of the SWPA to the total power requirements of the customers makes it unlikely that great success will be attained in forcing conservation, load reduction, or alternative resource implementation through rate design and policy action. However, with adequate funding, facilities, and staffing levels, the SWPA could be an effective agency for education of its customers with regard to conservation and alternative resources, and could participate effectively in experimental and demonstration projects involving conservation, load management, and alternative energy resource implementation. These would be particularly appropriate activities for the SWPA since its primary product is derived from a renewable resource which is, in fact, an application of solar energy. The existing close relationship of SWPA to its customers would greatly enhance the cooperation and coordination required to make a success of this endeavor.

Financial Performance

All funds for the operation, maintenance, improvement, and expansion of the SWPA system come from Congressional appropriations. The SWPA must forecast expenses in order to make a yearly appropriation request. The SWPA currently estimates its budget for the purchase of energy two years prior to the planned expenditure year. The forecasting of expenses must take into account not only fixed and predictable expenses but also contingencies and variable expenses resulting from changes in hydraulic resources. The requested appropriation must be large enough to avoid the necessity of obtaining emergency appropriations as a result of contingencies for resource variations but not too large so as to commit substantial amounts of federal funds that are not needed during good resource years.

Although all regular and emergency funds come from Congressional appropriation and although all revenues are deposited into the United States Treasury, the SWPA is subject to the same financial accounting and bookkeeping constraints of any other public, non-profit electric utility. That is, the revenues must exactly cover the expenses. The SWPA generates revenue through rates and service charges for the power and energy which it sells. These rates and service charges must cover not only yearly expenses but also repay, with interest, to the United States Treasury, those capital investments made through Congressional appropriation for power facilities.

The levels and composition of the rates and service charges utilized by the SWPA are determined by periodic repayment studies. In a repayment study, the SWPA staff analyzes and allocates the yearly costs and repayment requirements for the SWPA system. Any changes or increases in the existing rates are then submitted by the Assistant Secretary for Resource Applications to the Federal Energy Regulatory Commission (FERC). The Assistant Secretary has the power to approve interim rates, but the final rates must be approved by the FERC as is the case for any other electric utility within FERC jurisdiction. Any approved rate changes can be applied to existing contracts.

The SWPA most recently submitted a rate revision on the basis of a repayment study in fiscal year 1979. The new approved rates that resulted from this process enable the SWPA to adequately recover its costs of doing business and fulfill its repayment obligations as set forth by the United States Department of Energy. This rate revision was the first system-wide rate revision in twenty-two years. Table 2-3 lists these rate schedules.

2.3 TRANSMISSION SYSTEM

The SWPA delivers power and energy to its customers through both its integrated transmission system and the transmission facilities of neighboring utilities. The SWPA integrated transmission system includes 1,402 miles of 138 kV and 161 kV high-voltage transmission lines, 234 miles of 69 kV transmission lines, 32 bulk power

substations and switching stations, and various communication and other facilities. The SWPA integrated transmission system has 61 interconnections with the transmission systems of other utilities.

The transmission facilities of neighboring utilities are used to deliver SWPA power to its customers, to obtain supplemental purchased energy for SWPA customers, and to participate in interchange agreements and energy banking. The SWPA regularly makes use of the transmission facilities of neighboring cooperatives such as the Associated Electric Cooperative of Springfield, Missouri, investor-owned public utilities such as Texas Power & Light and the Oklahoma Companies, and federal agencies such as the Western Area Power Administration. Just as the SWPA makes use of the transmission facilities of other utilities when necessary, it may also market excess capacity on its own transmission facilities to neighboring utilities.

The effective marketing of federal hydroelectric resources for widespread use in the SWPA region is not currently limited in any way by the existing transmission system, either of the SWPA or of its neighboring utilities. It is not likely that the transmission system will cause physical constraints to be placed on this marketing of federal resources in the future since the current and planned transmission systems in ERCOT and SWPP are more than adequate and since major new hydroelectric facilities are not presently foreseen. Yet there may be constraints placed on power marketing by the SWPA due to the economics and loading of the transmission facilities of neighboring utilities. That is, if neighboring utilities place excessive charges on the use of their transmission facilities, these charges may eliminate the competitiveness of SWPA power to those customers who must purchase it through the transmission facilities of these neighboring utilities. Also, as neighboring utilities more completely load their transmission facilities in delivering power to their customers, they may not choose to have as much capacity available for wheeling SWPA power and hence may limit the paths through which the SWPA may deliver power to its customers. In these cases, the SWPA would either have to market power and energy to customers on the basis of transmission constraints rather than on the basis of its power allocation or seek relief from these transmission constraints through legal action. However, if the existing transmission facilities can be shown to be physically inadequate, the SWPA can request a Congressional appropriation for new facilities or the upgrading of existing facilities. In the event that the SWPA finds it necessary to construct new transmission facilities or upgrade existing facilities in order to deliver power and energy from new hydroelectric projects or to overcome constraints on the existing transmission system, the transmission facilities must be funded by Congressional appropriation. The federal investment in these facilities is then repaid, with interest, to the United States Treasury through revenues generated by wholesale power rates, transmission rates, and service charges to SWPA customers.

TABLE 2-3

SOUTHWESTERN POWER ADMINISTRATION RATES

RATE	DESCRIPTION
P-3[1]	Capacity - At 138-161 kV - $1.40 per kW per month ($1.30 before Harry S Truman) At 69 kV - $1.60 per kW per month ($1.50 before Harry S Truman) Below 69 kV - $1.95 per kW per month ($1.85 before Harry S Truman) Energy - First 1200 hours use per year - $.0035 per kWh - Over 1200 hours use per year - $.007 per kWh - Supplemental - $.0035 per kWh
F-2[2]	Capacity - At 138-161 kV - $1.40 per kW per month ($1.30 before Harry S Truman) At 69 kV - $1.60 per kW per month ($1.50 before Harry S Truman) Below 69 kV - $1.95 per kW per month ($1.85 before Harry S Truman) Energy - First 100 hours use per month - $.0035 per kWh - Next 340 hours use per month - $.007 per kWh - Over 440 hours use per month - $.014 per kWh
F-3[2]	Capacity - $1.95 per kW per month ($1.85 before Harry S Truman) Energy - $.0035 per kWh for all federally generated energy - Actual cost per kWh for all thermal-generated energy
EE-2[3]	Capacity - None Energy - $.003 per kWh
IC-2[4]	Capacity - $.050 per kW per day Energy - $.0035 per kWh or return
TDC-2[5]	Capacity - At 138-161 kV - $.25 per kW per month At 69 kV - $.40 per kW per month Below 69 kV - $.55 per kW per month - 5% of amounts above per kW per day for the interruptible transmission demand at a given delivery voltage as applicable Energy - $.008 per kW hour
SPECIAL	Tex-La Electric Cooperative Capacity - $1.86 per kW per month ($1.73 before Harry S Truman) Energy - First 100 kWh/kW/month - $.00309 - Next 340 kWh/kW/month - $.00459 - Over 440 kWh/kW/month - $.00659
SPECIAL	Arkansas Power & Light Firm Energy Charge Energy - First 22,000,000 kWh per month - $.00735 per kWh Remaining 8,000,000 kWh per month - $.00368 per kWh Secondary Energy Charge Energy - $.002 per kWh

TABLE 2-3 (Cont'd)

SPECIAL Sam Rayburn Dam Electric Coop.

Energy - $1,388,300 per year

1] P-3 - Peaking Power

2] F-2, F-3 - Firm Power

3] EE-2 - Excess Energy

4] IC-2 - Interruptible Capacity

5] TDC-2 - Transmission Demand Charge

CHAPTER 3

NEW HYDROPOWER DEMAND AND SUPPLY

Forecasts

Approximate energy demand and peak demand forecasts from the National Hydropower Study for SWPP and ERCOT are shown on Table 3-1.

TABLE 3-1

ENERGY AND POWER DEMANDS

	1978	1985	1990	2000
SWPP				
Energy (GWh)	191,600	277,600	348,000	498,700
Power (MW)	39,191	56,000	-	100,000
Load Factor (%)	55.8	57.0	57.0	57.0
ERCOT				
Energy (GWh)	147,400	206,200	-	409,700
Power (MW)	28,645	41,300	-	82,200
Load Factor (%)	58.8	57.0	-	57.0

Estimates of undeveloped hydropower potential from the National Hydropower Study for SWPP and ERCOT are shown in Table 3-2.

TABLE 3-2

UNDEVELOPED HYDROPOWER POTENTIAL

	SWPP		ERCOT	
	Capacity MW	Average Annual Energy GWh	Capacity MW	Average Annual Energy GWh
Potential at undeveloped sites (< 5 MW)	1,670	3.88	1,070	1.57
Potential at existing dams	5,910	16.90	750	1.88

These demand and supply predictions are consistent with SWPA staff forecasts in showing that the SWPA will continue to supply a decreasing portion of the total energy and power demand of its existing and potential customers. Furthermore, forecasts of population growth and per capita load growth in the SWPA region indicate that, even if the SWPA is able to market undeveloped resources in the future to more preference customers, it may, in fact, supply a smaller fraction of the total customers and their loads in its service region.

The undeveloped hydropower potential resources shown in Table 3-2 are concentrated in a relatively few sites in SWPP and ERCOT. Undeveloped sites with significant potential in SWPP are located primarily in Oklahoma and Arkansas, with the main potential developments on the Little, Kiamichi, Ouachita, and White Rivers. These two states have a potential of about 1,250 MW with an average annual generation of 2,200 GWh at undeveloped sites. The great majority of potential additional hydropower at existing dams would come from dams with a potential capacity of less than 5 MW. Two new combination hydroelectric generation and pumped storage facilities are currently under development. The Harry S Truman facility is on line, but not all units will be operating until 1985 because of required downstream improvements. The Clarence Cannon units should be operational in 1982. There are currently no firm plans for utilization of the undeveloped hydropower resources in SWPP.

The limited magnitude of undeveloped potential hydropower resources in ERCOT would involve the Brazos River, the Neches River, or the Red River, each of which already has one hydroelectric facility. At the present time, the only pumped storage is at Buchanan on the Colorado River, and it has not been used for pumping basically due to the large-scale use of gas generation which has not been favorable for pumped storage. As is the case with SWPP, there are currently no firm plans for utilization of undeveloped hydropower resources in ERCOT.

Small-Scale Hydro

Small-scale hydroelectric resources (e.g., low-head and run-of-river facilities) can be used throughout the SWPA region to displace oil and natural gas consumption. However, the potential sites for small-scale hydroelectric facilities are often not matched with transmission facilities. The expense of connecting some small-scale hydroelectric facilities through the necessary transmission might cause significant economic constraints on the utilization of the small-scale hydropower. On the other hand, the rising costs and risks inherent in conventional generation facilities are likely to cause the development of new hydroelectric resources to be economically competitive at higher and higher costs.

SWPA Transmission System Expansion

The relatively limited potential for new hydropower resources and the continued reliance on the transmission facilities of existing neigh-

boring utilities make it unlikely that the SWPA integrated transmission system will experience any significant expansion in the future. This would in no way limit the continuing effectiveness of the SWPA in promoting the widespread use of federal hydroelectric facilities unless the use of neighboring utility transmission facilities becomes prohibitively expensive or otherwise limited through contractual or physical constraints.

CHAPTER 4

ENERGY CONSERVATION AND NEW ENERGY TECHNOLOGY

Conservation

The small contribution of the SWPA to the total demand for energy and power in its region has already been discussed. This characteristic makes it unlikely that any conservation, load management, or demand reduction programs will have a significant effect on the demand for the SWPA product. Furthermore, this characteristic makes it unlikely that the SWPA will be able to force any of its customers or utility partners to implement programs for conservation, demand reduction, or load management. However, with adequate staffing levels, funding and facilities, the SWPA could be an effective agency for the implementation of such programs. The SWPA could accomplish this through promotional media activities, seminars, demonstration projects, experiments, and even low-interest financing projects for customers. The SWPA staff has expertise in all areas of electric utility planning and operations and could provide valuable service to both the National Energy Program and SWPA customers in the implementation of conservation programs and technologies.

New Energy Resources

The potential important contribution that the SWPA could make in the area of conservation also exists for new energy technologies. The SWPA could engage in promotional activities, demonstrations, and experiments in wind, solar, and other alternate energy technologies. The fact that the SWPA currently markets a renewable energy resource that is an application of solar energy makes the SWPA a logical choice for the marketing of other solar energy technologies as the federal government promotes their commercialization through public funding.

The SWPA geographic region is noted for its significant wind resource and a correspondingly significant solar resource. If the SWPA is to become involved in the promotion, demonstration, and implementation of alternative energy, then the obvious choices for activity by the SWPA are wind energy and solar energy. The SWPA could incorporate solar and/or wind generation in its marketing base with relative ease. The versatility of hydroelectric generation for base load, intermediate load, or peaking ensures that new alternate

energy resources, with their varied requirements for system storage, fast response peaking or firming power, can be integrated into the SWPA system. If the federal government is to continue to participate in the development and demonstration of solar and wind energy, it is clear that the SWPA provides an already existing expertise in electric power systems and an institutional framework within which the federal government can pursue these programs, particularly in the areas of wind energy and solar energy. Expansion of staff, funding, and facilities within the SWPA would be a most effective way to utilize federal energy program funds in the evaluation, demonstration and implementation of new energy technologies.

The SWPA would experience the same challenges in marketing small-scale hydropower that it would experience in marketing wind and solar energy. The value of these random generation sources for displacement of energy has already been stated. Oil and gas is used extensively in the Southwest for electric generation, and so energy displacement by alternate energy resources and/or small-scale hydroelectric resources would have maximal value. Some difficulty might be presented by the necessity to interconnect new alternate resources with the existing system through expensive transmission. Additional difficulty might be experienced in the incorporation of large market penetrations of the undependable capacity presented by alternate energy resources.

The most significant problem associated with the implementation of alternate energy technologies is related to their high cost in comparison with conventional generation. The alternate energy technologies tend to be capital-intensive technologies, so that the initial investment for capacity is very large in relation to the recurring costs through the lifetime of the facility. These initial capital costs are currently higher per kW than any of the alternative conventional generation technologies. This economic disadvantage will be offset as alternate conventional resources become more expensive and as their fuel supplies become more scarce. In addition, the use of federal subsidy by policy action or direct funding can overcome much of the economic disadvantage of new technologies if their use for fuel displacement and/or reliability enhancement is deemed sufficiently important.

CHAPTER 5

FUTURE PROGRAMS AND PRACTICES

New Legislation and DOE Directives

Two basic changes in the nature of SWPA activities that are considered desirable in the future can be implemented only as the result of new Congressional legislation and/or DOE directives. The first of these two activities is the funding of operations through a revolving fund. The revenues collected by the SWPA through its rates and service charges could be placed in a revolving fund that is available for funding of operating expenses at the discretion of the SWPA Administrator. This would provide additional flexibility in meeting the costs of operation that vary, sometimes significantly and rapidly, with the varying hydraulic resources or operational contingencies. This revolving fund would be even more desirable if the SWPA is to become involved in the use of more random alternate energy resources such as wind and solar. The revolving fund would enable the SWPA to operate on a more business-like basis while preserving Congressional oversight for the agency's activities since the implementation of a revolving fund would require new Congressional legislation.

The second potential area of activity for the SWPA is involvement in the demonstration and implementation of alternative energy resources. In particular, the SWPA could build and operate wind generators, solar thermal generation facilities, or solar photovoltaic generation facilities and market the power from such facilities. Involvement in this sort of program would require at least new directives from the DOE and might also require legislation for federal funding of such programs. This expansion of SWPA activity is particularly desirable if the National Energy Program continues to include a goal of utilizing renewable energy resources as extensively as possible because of the wind and solar resources available in the SWPA region.

Rates

Since the rates and rate structures used by the SWPA are adequate for recovering costs and since innovative rate design is not likely to have significant effects on SWPA customers, it is not likely that the SWPA will seek any notable changes in its design and collection of wholesale power rates, transmission rates, and other service charges. Rate design in the SWPA will continue to be subject to the goals of charging the same rate to the same class of customer and adequately recovering the proper costs from all customers.

Allocation

The SWPA will continue to allocate federal power resources to preference customers and exclude non-preference customers. The SWPA has voluntarily begun to allocate the federal power resources not only for widespread use but also to accomplish a fair and equitable distribution of these resources throughout its service area. This allocation is currently based on preference customer load by region. No basic changes in the methods or goals of federal resource allocation are expected in the future. The SWPA will continue to promote extensive public participation in the determination of power allocations.

Marketing

The SWPA will continue to market the power resources in its area to customers in its area. This is because the demand for federally-generated hydroelectric power in SWPA's service area far exceeds the available resources so there is no reason to seek customers outside the SWPA service area. The SWPA will continue to maintain a reliable and viable power system for the marketing of federal power resources under the laws and directives of the United States Congress and the United States Department of Energy.

NATIONAL HYDROELECTRIC POWER RESOURCES STUDY

Marketing and Transmission of Hydroelectric Power

Part 6

Southeastern Power Administration Appendix

I. INTRODUCTION

A. History of Southeastern Power Administration's Marketing and Transmission Program

In 1950 the Secretary of the Department of the Interior established the Southeastern Power Administration to carry out his responsibilities under Section 5 of the Flood Control Act of 1944 with respect to the transmission and disposition of electric power and energy produced at U. S. Corps of Engineers hydroelectric projects located in the 10 Southeastern States of West Virginia, Virginia, North Carolina, South Carolina, Georgia, Florida, Alabama, Mississippi, Tennessee, and Kentucky. Southeastern's headquarters was established in Elberton, Georgia, primarily due to the influence and work of then Congressman Paul Brown of Elberton.

When Southeastern was first established in March of 1950, two hydroelectric projects with a total installed capacity of 110,000 kw were in existence as were two contracts executed by the Washington staff of the Department of the Interior which covered the sale of this power to two customers. In addition to the two operating projects, the U. S. Corps of Engineers had under construction six additional projects scattered throughout the area which were scheduled to begin operation within one to three years, and there were an additional 15 projects authorized for construction. In short, on the day it was born, Southeastern had extensive power in being, much more power very rapidly coming up, and an extremely broad base of expectation for future power development.

With this backdrop, Southeastern was established and a nucleus organization was staffed with personnel from the Bureau of Reclamation, Bonneville Power Administration, and the Washington staff of Interior. Southeastern was off to a running start to prepare for the sale of power which was immediately upon it from a time standpoint.

One of the first areas of examination by the new Power Administration was to determine where high voltage transmission facilities needed to be constructed as backbone facilities for the integration of the power output of various projects and for service to wholesale power consumers who had requested power from the projects. Several transmission lines were proposed to be built from the Buggs Island Project (later named John H. Kerr Project) and from the Clark Hill Project.

The construction of transmission lines by Southeastern was strenuously opposed by investor-owned utilities in the area. The final result of the interplay between the involved parties was agreements by the various companies to transmit or "wheel" power from the Government projects to SEPA's preferred customers, and the one transmission line constructed by Southeastern from Clark Hill to Greenwood, South Carolina, was sold to the Greenwood County Electric Power Commission.

An important landmark in shaping the direction of Southeastern's marketing arrangements was a July 1955 Opinion of Attorney General Herbert Brownell dealing with proposed marketing arrangements for the sale of Clark Hill power in the State of Georgia. The "Brownell Opinion" reinforced the rights of preference customers to obtain power generated at Federal projects and, subsequent to this decision, marketing arrangements with power companies and preference customers in the Southeast were consummated following generally similar patterns.

The basic pattern for the marketing arrangements provides for three-way agreements between SEPA, the investor-owned utilities, and preference customers located in the utilities' service areas. The contracts provide for:

a. Sale by SEPA of specified amounts of power directly to preference customers in the area.

b. Payment of a transmission service charge by SEPA to the private utilities for "wheeling" the Federal power to preference customers.

c. The supply of supplemental steam energy by the private utilities for preference customers in those months when project hydro energy was below normal. This was accomplished either by purchase of such energy by the Government for resale to preference customers or by arrangements under which the utility supplied this "deficiency" energy directly to the preference customer at SEPA energy rates.

d. Agreement by the utilities to supply all additional power needs of preference customers at the Company's applicable rate schedule.

e. Sale by SEPA of a portion of the hydropower output not usable by preference customers to the utilities as peaking power, and

f. Agreement by SEPA to allow each utility to schedule the entire power output of the projects which was marketed in its area in a way which would maximize the power benefits available from the project.

By 1957, SEPA had contracts with approximately 125 customers and the installed capacity of the 10 projects in operation exceeded 1,200,000 kw. During the 1960's, four additional hydropower projects were completed with an installed capacity of some 600,000 kw, and in the 1970's, seven more projects were completed with an installed capacity of an additional 900,000 kw.

B. Present and Expected Future Role of PMA's

1. & 2. As a Viable Agency Within DOE

The development of the hydroelectric projects in the Southeast by the U. S. Corps of Engineers has been in conjunction with other project purposes such as flood control, navigation, water supply, and recreation. As each project is formulated, it is designed to maximize net benefits over an extended period of time. As a result of this development criterion, most of the power marketed by SEPA is peaking power, and under adverse water conditions energy is produced at a low plant factor. This peaking power must be scheduled into a relatively large power system in order to obtain the full power benefits from the power. In general, the peaking power available in its raw state might be utilized only to serve the top 15 to 25 percent of preference customer load curves.

In the past, total preference customer loads in the areas selected for the sale of power have not been large enough so that all project power, as generated, could be placed in the peaks of the preference customer loads. Additionally, due to prevailing rates from the private utilities to preference agencies, it was not economically feasible for the preference agencies to purchase low load factor power from SEPA and purchase its remaining high load factor requirements from the company. As a result of these two conditions, most preference customers in the past could not use and did not want the project power as generated.

Both of the above conditions have changed such that preference customer loads can now absorb the peaking power produced, and rate structures by the private utilities have changed to recognize the value of capacity purchased by preference customers. Additionally, overall rate levels by the utilities have more than tripled during the last several years as a result of rapidly escalating construction and fuel costs causing extreme pressures from public bodies and cooperatives located near and remote to the projects to purchase the substantially cheaper Federal power.

As a result of the changed conditions over the past few years, SEPA has been deluged with requests for the purchase of power from preferred agencies located outside SEPA's selected marketing areas and also from preferred agencies located within the marketing areas who had previously elected not to buy power from SEPA. Added to these requests, those preferred agencies who are already SEPA customers desire to purchase additional amounts of power. All these requests for additional power are coming at a time when only one new project, the Richard B. Russell Project, is scheduled to begin operation and add additional power resources during the next 10-year period. The net result of these actions and the basic problem facing SEPA at this time are not only that preferred agency requests for power from SEPA far exceed the power available to SEPA for sale but that the additional requests for power come at a time when additional new power is not available, and the total energy available at existing projects is already allocated to preference customers.

In recognition of the above marketing problems and in keeping with the letter and spirit of the DOE Organization Act, SEPA decided early in 1978 to adopt for the future a more formal process in the development of power marketing policy which would underlie future power contracts. SEPA therefore developed and finalized a public participation procedure which allows interested parties to present and SEPA to obtain desired public comments in an orderly, timely, and adequate fashion.

SEPA is now in the process of systematically developing its power policies for its different power systems under its public participation procedures. This policy development will extend for several years into the future before being finalized for all systems.

After a new power marketing policy has been finalized for each of the power systems, new contracts will be negotiated with preference customers and with private utilities to provide for the transmission and sale of power in accordance with the developed policies. It is now anticipated that the new contracts will be for terms of approximately 10 years.

Another aspect of SEPA's future role in power marketing is related to the overall energy conservation and renewable resources program of the Department of Energy. While SEPA has played a very minor role with respect to these activities in the past, it is anticipated that its role will be substantially enlarged in the future.

In the immediate future SEPA proposes to go forward with its present conservation programs of coordinating dispatch of power from existing hydroelectric projects to provide for a reduction in oil usage at utility oil-fired plants in the Southeast and to allow the maximum power generation that can be accomplished at downstream non-Federal projects. Additionally, SEPA would purchase energy produced by renewable resources, where appropriate, as determined on a case-by-case basis. SEPA also proposes that its conservation authority be expanded with respect to providing financial and technical assistance to and working cooperatively with and through SEPA preference customers to reach the ultimate energy consumers.

II. THE CURRENT MARKETING AND TRANSMISSION SYSTEMS

A. Power Marketing Agencies

1. Mission and Functions

The Southeastern Power Administration performs the functions assigned to the Secretary of Energy by the Department of Energy Organization Act of 1977 and by Section 5 of the Flood Control Act of 1944, with respect to the transmission and disposition of electric power generated at reservoir projects under the control of the Corps of Engineers in the States of Virginia, West Virginia, North Carolina, South Carolina, Georgia, Florida, Alabama, Mississippi, Tennessee, and Kentucky. Southeastern transmits and disposes of the power in such manner as to encourage the most widespread use, at the lowest possible rates to consumers consistent with sound business principles, giving preference in the sale of such power to public bodies and cooperatives.

Southeastern performs its functions through (1) negotiation, preparation, execution and administration of applicable contracts, (2) preparation of wholesale rates and repayment schedules, (3) construction or acquisition of the use of transmission and related facilities to interconnect project power stations and serve customer loads, and (4) operation of power facilities to meet contractual requirements and to insure continuity of service to customers.

The Administrator performs his mission with the assistance of the Office of General Counsel and the Divisions of Power Sales, Power Operations, Fiscal Operations, and Administrative Management.

2. Authorities (statutes, executive orders, and legislative history)

Section 5 of the Flood Control Act of December 22, 1944, 16 U.S.C. 825s.

Section 302(a)(1) and (2) of the Department of Energy Organization Act, 42 U.S.C. 7152, Public Law 95-91. Southeastern Continuing Fund, 16 U.S.C. 825s-2.

3. Laws Governing Power Marketing and Transmission

Section 5 of the Flood Control Act of December 22, 1944, 16 U.S.C. 825s.

Southeastern Continuing Fund, 16 U.S.C. 825s-2.

4. Organization and Administration of Systems

For power contracting and rate purposes, the projects are grouped into five separate and distinct systems of projects. These groups are: (1) Kerr-Philpott Projects, which include the named projects; (2) Georgia-Alabama Projects, which consist of the Clark Hill, Allatoona, Buford, Hartwell, Walter F. George, Carters, Jones Bluff, West Point, and Millers Ferry Projects; (3) Cumberland Basin Projects, which consist of the Dale Hollow, Center Hill, Wolf Creek, Old Hickory, Cheatham, Barkley, J. Percy Priest, and Cordell Hull Projects; (4) Jim Woodruff Project, which consists of the named project; and (5) Laurel Project, which consists of the name project. Although marketing of power from each of these groups of projects is independent of the other groups with respect to power rates, contract term, and specific contractual content, the overall contractual framework in one area may well affect the pattern of marketing in another area.

In none of these systems can SEPA furnish the entire energy needs of the preference customers. The Government obligates itself to serve a certain pro rata part of the load of the contracting preference customers in a utility's area of service with the utility or some other source to furnish the remainder of the preference customers' load.

The transmission of SEPA power from the projects to SEPA preference customers is accomplished through contractual arrangements with area power utilities for wheeling and transfer of SEPA power over existing lines.

(Map showing the five SEPA systems)

5. Relationship with Regional Reliability Councils and Power Pools

SEPA participated with other bulk power suppliers in the Southeast in the formation of the Southeastern Electric Reliability Council (SERC) in 1970. SEPA also takes an active role in proceedings of SERC's Technical Advisory Committee. SEPA participated in and provided input into the Federal Energy Regulatory Commission (FERC) Power Pooling Study for the SERC region.

6. Customers and Classes of Service

Southeastern Power Administration markets the output of 21 projects to 198 purchasers. One hundred (100) of these purchasers are distribution electric cooperatives, eighty (80) are municipalities, eight (8) are private companies, seven (7) are generation and transmission cooperatives, one is a state agency, one is a county agency, and one is the Tennessee Valley Authority.

7. Resource Capabilities of Systems

The installed capacity of the 21 projects for which SEPA has marketing responsibility is 2,712,375 kw with average annual generation of approximately seven billion kwh. In an effort to make optimum use of the resources of the region, SEPA markets 2,966,000 kw (including overload) from these projects. In four of the SEPA systems, an average of 14 percent above installed capacity is sold. The output of the fifth group system is sold on the basis of prevailing streamflows, rather than measured power quantities.

In operating the projects, close coordination with the area utilities is maintained. The Government projects are scheduled by the utilities as an integral part of their resources in meeting system demands. Response to utility emergencies is considered a priority item in operating the projects. Every effort is made to coordinate releases from the projects so that maximum use can be made of the water at downstream projects--both Federal and private.

B. The Nature of Current PMA Marketing and Transmission Programs and Practices

1. Policies, Legal Directives, and Interpretation

Southeastern's basic policy document at this time is Section 5 of the Flood Control Act of 1944. This Act as modified by the Department of Energy Organization Act provides that:

a. Electric power and energy generated at reservoir projects under the control of the Department of the Army and not required in the operation of such projects will be delivered to the Secretary of Energy.

b. The Secretary of Energy will transmit and dispose of such power and energy in such manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles.

c. The power rates shall become effective upon approval by the Secretary.

d. Rate schedules shall be drawn having regard for the recovery of the cost of producing and transmitting such electric energy including the amortization of the capitol investment over a reasonable period of years.

e. Preference in the sale of power and energy shall be given to public bodies and cooperatives.

f. The Secretary of Energy is authorized to construct or acquire only such transmission lines and related facilities as may be necessary in order to make the power and energy generated available in wholesale quantities for sale on fair and reasonable terms.

The DOE Organization Act further provides that the above functions of the Secretary (except for 1c) will be exercised by the Secretary acting by and through the Administrators of the various power administrations. The Secretary has delegated the rate approval function to the Assistant Secretary for Resource Applications (interim approval) and to the Federal Energy Regulatory Commission (final approval).

Southeastern is also guided by its Final Procedure - Public Participation in Formulation of Marketing Policy and by DOE Order RA 6120.2 in preparation of its Financial Statements and Repayment Studies.

2. Preference and Priority

As indicated in II.B.1. above, preference in the sale of power is given to public bodies and cooperatives.

3. Wholesale power rates

SEPA adopted a two-part Demand and Energy rate structure from its inception. While different systems have rates with different demand and energy components, this general rate pattern has been utilized consistently throughout SEPA's history. The one exception to this rate form relates to the sale of power generated by projects located in the Cumberland River Basin and marketed in part directly to the Tennessee Valley Authority. Power marketed to TVA is sold for annual amounts which are dependent only upon the flow of water into the Wolf Creek Reservoir. The payments are such that the average annual costs of the projects are recovered but the payments are not directly related to the power generation at the projects.

Southeastern's wholesale power rates have consistently been in the form of a monthly rate for capacity availability plus an energy rate based on declared, contract, or metered energy quantities. An example of this type rate is a charge of $1.50 per kilowatt per month plus 4.5 mills per kilowatt-hour. SEPA has also utilized a "postage stamp" rate concept under which rates are the same for the delivery of similar types of power in an area irrespective of the delivery conditions. For example, two customers located at different distances from the project and receiving power at two different voltages would both pay SEPA for power at the same rates. Also, private utilities purchasing power at the projects generally pay the same rates for power that preference customers pay. The third aspect of rate-making deals with the overall rate level. SEPA has a different rate level for each of its power systems and the level for each system is directly related to the repayment requirements for that system. Thus, from each system of projects the power is sold to customers who repay the costs of the projects producing the power as well as all associated costs.

Under Section 5 of the Flood Control Act of 1944, power must be disposed of "at the lowest possible rates to consumers consistent with sound business principles." This practice has been followed in the past, and SEPA is repaying all costs including the investment in power facilities in an orderly and timely fashion. A survey of current wholesale power rate schedules is appended to this report.

4. Transmission rates

SEPA does not own any transmission facilities and accomplishes its delivery of power by contracting with power utilities in the area to wheel power for SEPA's account to SEPA customers. In the past the SEPA wheeling rates paid for transmission service have been based on distances of SEPA customers from the project producing the power and under existing contracts are as follows:

Up to 100 miles	1.00 mill per kilowatt-hour
100 to 150 miles	1.75 mills per kilowatt-hour
Over 150 miles	2.50 mills per kilowatt-hour

5. Marketing

a. Markets for Capacity and Energy (including non-dependable capacity)

The demand of preference agencies in the 10-state area in which SEPA has power marketing responsibility is estimated at over 35,500 mw. To respond to this demand, SEPA has only 2,972 mw available for sale, or 8.4 percent of the total requirement. With the completion of the Richard B. Russell Project and a fifth unit at the Hartwell Project, SEPA will have an additional 410 mw for sale. But assuming 3.5 percent per year load growth, the preference agency load will have grown by an additional 8,000 mw when the Richard B. Russell Project is scheduled to have all units

on line. SEPA's part will then be reduced to 7.8 percent. This fact along with the present small percentage available to meet preference customer needs shows the area's need for and usability of additional hydro power.

c. Conservation

During these critical energy shortage times, SEPA continues to upgrade its management of the Government's water resources. The agency is, with cooperation and assistance of other parties, continually seeking ways to produce power generation which will save fossil fuel. Some of these are changes in methods of operations that will provide water discharge patterns that can be better utilized by downstream hydro projects and reassessment of previously written operating guidelines to ascertain if they can be changed to produce more generation from water which was previously lost by spillage. A most recent example of this was during the coal strike that occurred in the winter of 1977 and 1978. SEPA arranged, in conjunction with the Corps of Engineers, to expand hydroelectric generation to serve those utilities that had severe coal shortages at certain plants and to cooperate closely with all the utility customers in the areas that might impact on near-future coal supplies.

d. Alternative Resources

SEPA currently markets power only from hydroelectric facilities constructed and operated by the U. S. Corps of Engineers.

e. Rate Structure and Pricing Procedures

Rate schedules for each of SEPA's five systems were prepared initially as integral parts of carefully balanced negotiated arrangements involving SEPA, private utilities and preference customers.

The rate structure and the pricing procedures are designed to be as low as possible but still produce revenues which are sufficient to recover:

(1) All costs of operating and maintaining the power system during the year in which costs are incurred; plus,

(2) The costs of acquiring power through purchase and/or exchange agreements, the costs of transmission service, and other costs during the year in which such costs are incurred; plus,

(3) Expensed interest on the unamortized investment in Federal power facilities in the years for which the interest charges are assessed, except that recovery of the annual interest expense may be deferred in unusual circumstances for short periods of time; plus,

(4) Each dollar of power investment within 50 years after it becomes revenue producing; plus,

(5) The costs of each replacement of a unit of property within its expected service life up to a maximum of 50 years.

Examples of SEPA's two-part rates for different power systems are: $1.02 per kw and 3.65 mills per kwh in the Southern Company area of the Georgia-Alabama System, $1.50 per kw and 4.50 mills per kwh to public bodies and cooperatives in the Jim Woodruff System, $1.37 per kw and 4.20 mills per kwh at the Laurel Project, and $1.25 per kw and 5.00 mills per kwh to public bodies and cooperatives in the John H. Kerr-Philpott System.

f. Contract Terms and Conditions

The Cumberland Basin Projects, exclusive of the Laurel Project, are all physically located within the TVA service area and are interconnected with the TVA transmission system. Due to these unique characteristics, the contractual arrangements for power sold from the Cumberland Basin Projects bear no resemblance to the marketing pattern used elsewhere in the Southeast.

The entire output of the Cumberland Basin Projects is actually delivered into the TVA transmission system. A portion of the power is retained by SEPA for sale to preference customers outside and to the north of the TVA service area with the balance being sold to TVA. Presently, of the 853 mw of installed capacity and 3,053 gwh average annual energy, 175 mw of peaking power with 262.5 gwh of energy and 100 mw of standby power with the necessary accompanying energy are retained for sale to four generation and transmission cooperatives located north of the TVA service area in Kentucky, Indiana, and Illinois. The retained power is a part of the integrated output of the Cumberland Basin Projects and is transmitted for SEPA by TVA to its borders for delivery to SEPA customers. TVA purchases the total output less the retained power.

The Jim Woodruff Project is a low-head high plant factor project. The installed capacity is 30 mw with average annual energy of 250 gwh.

The power availability is reduced to zero at times due to the loss of head resulting from high water conditions on the Apalachicola River. Power from the project was initially offered to all preference agencies located within 150 miles

of the project that are served by the transmission facilities of the Florida Power Corporation and to the West Florida Cooperative located in the vicinity of the project. Of the eight preference customers to whom the power was offered, six elected to purchase power. Initially, the entire load of these customers was served by SEPA. At the present time, however, due to the load growth of these customers, SEPA supplies only about 26 percent of the load with Florida Power Corporation supplying the remainder.

Although the Jim Woodruff Project has a nameplate capacity of 30 mw, a total of 36 mw is marketed to preference customers through the use of overload capacity at the project. Excess energy generated at the project is sold directly to Florida Power Corporation and during times of low generation due to high water on the Apalachicola River, both capacity and energy are purchased from Florida Power by SEPA to meet preference customer requirements.

Power available from the Kerr-Philpott Projects is peaking power. To make its maximum contribution to the area power supply, the projects must be operated as part of the supply of large power systems. The utilities in the area are the Virginia Electric and Power Company (VEPCO) and the Carolina Power & Light Company (CP&L). Power from John H. Kerr is divided between the VEPCO and CP&L service areas in the ratio of two to one, respectively. This breakdown is based on the relative portions of service area of each of the companies located within approximately 150 miles of the project. All Philpott power is allocated to the VEPCO area.

The division of power sales between preference customers and private utilities is such that the preference customers are allocated at least the entire average annual energy available in the projects. Firming energy is purchased from VEPCO and deficiency energy is furnished directly to preference customers by CP&L to assure a dependable supply of load-factor power available to the preference customers from the Government.

Power marketed to preference customers is sold to 16 cooperatives located within 150 miles of Kerr Project in Virginia and North Carolina and connected to the VEPCO system and 15 cooperatives and one municipality in North Carolina connected to the CP&L system. The contract with CP&L provides for wheeling up to 165 miles from the State line point of interconnected transmission.

Substantial changes have taken place over time in the marketing of the Georgia-Alabama System power. Power sales to preference customers change over time during the contract period from the

furnishing of load-factor power to the sale of intermediate or peaking-type power. The nine projects of the Georgia-Alabama System are all connected to the transmission system of one or more of the operating companies of the Southern Company and thus have an integrated common transmission system. The two projects, Clark Hill and Hartwell, located on the Georgia-South Carolina border are also connected with Duke Power Company, and Clark Hill is additionally connected to the transmission system of South Carolina Public Service Authority, a state agency. The power output of the Clark Hill and Hartwell projects has historically been split 50-50 between customers located to the east and west of the Savannah River. The power marketed to the east of the Savannah is sold to customers located within the service areas of Duke Power Company and South Carolina Public Service Authority. The amount of power going into the Duke area is approximately one-half the power available from the Hartwell Project plus 7-1/2 percent of the power from the Clark Hill Project. The remainder of one-half the Clark Hill power is sold in the SCPSA area.

The energy sold to preference customers in the Duke area is based on the average annual energy made available from the projects, and the capacity made available is based on a preference customer annual use of 4500 kwh per kw. Power was offered to all preference agencies located within 150 miles of the project and within the Duke service area.

The South Carolina Public Service Authority is a preference customer in its own right and additionally provides transmission service to SEPA for serving other preference customers. Power was offered to preference customers located throughout the SCPSA service area. The split of power between SCPSA and the other preference customers was based on providing the distribution-type customers on the SCPSA System SEPA power, representing approximately the same proportion of their total loads that similar customers in South Carolina received from SEPA under the Duke contract, with the remainder of the power being sold to SCPSA.

Power produced by the Georgia-Alabama projects and sold west of the Savannah River is marketed to two generation and transmission cooperatives (Alabama Electric Cooperative and South Mississippi Electric Power Association) and to distribution-type preference customers located in the service areas of the four privately-owned companies (Georgia, Alabama, Mississippi, and Gulf Power Companies) that comprise the Southern Company System. A portion of the dependable capacity from the projects, without energy, is sold to these private utilities who provide the transmission services for the Government.

The power allocated to Alabama Electric and SMEPA is based on the usability of project power into the load curves of the two G&Ts. Of the remaining power, all the project energy is assigned to the distribution-type preference customers with a capacity allocation which increases over time such that the energy allocation which equated to 4600 hours use of capacity in 1976 will equate to only 3000 hours in 1983 when the contracts terminate. The private utilities progressively purchase a correspondingly lower amount of project capacity as the preference customer allocation increases.

The allocation of power between preference customers is based on the relationships of actual peak loads established prior to the beginning of the present contract.

The Laurel Project is a multipurpose reservoir project having an installed generating capacity of 61 megawatts (nameplate) in a single unit with annual firm energy of approximately 37 gwh and average energy of approximately 67 gwh. It is located in southeastern Kentucky, and is the ninth and most upstream project constructed by the Corps of Engineers in the Cumberland River Basin. The Laurel Project is located entirely outside the TVA area in the service area of East Kentucky Power Cooperative (East Kentucky), a generation and transmission cooperative, having power supply responsibility for 18 distribution cooperatives serving in 86 of Kentucky's 120 counties. By agreement, East Kentucky has constructed transmission facilities into the project adequate to receive the total output.

Termination dates for contracts in the Kerr-Philpott System of Projects have been extended from June 30, 1980, until June 30, 1981, to allow completion of new written marketing policy being prepared for that system of projects.

Contracts in the Jim Woodruff System of Projects expire or are eligible for cancellation as of July 20, 1982.

Contracts for the Georgia-Alabama System of Projects expire on May 31, 1983, or before. (South Carolina Public Service Authority area, June 30, 1981; Duke Power Company area, November 20, 1980)

Contracts in the Cumberland and Laurel System of Projects expire on June 30, 1983.

As present contracts expire, it is expected that all power now sold to private utilities will be marketed to preference agencies.

g. Financial Performance

(1) Federal Funding

Funding of the marketing program for SEPA is accomplished through funds appropriated by Congress and through arrangements for the netting of bills on a monthly basis whereby SEPA firming and wheeling expenses are offset against revenues due from private electric utilities.

(2) Repayment, Financing and Accounting

Federal activities associated with the production, transmission, and disposition of all Federal power marketed under Section 5 of the Flood Control Act of 1944 in the ten Southeastern States are accomplished by two separate Government agencies, the Southeastern Power Administration and the U. S. Army Corps of Engineers (Corps). These agencies are separately managed, financed, and maintain separate accounting systems. However, by combining activities related to electric power marketed under the 1944 Flood Control Act, financial statements are prepared showing the financial results of the total Federal power program in the area administered by SEPA and the Corps.

Appropriations are made by Congress to construct multipurpose projects which include purposes such as hydroelectric power, flood control, navigation, etc. When power is a project purpose, allocations of costs, both as to capital investment and operation and maintenance, are made between purposes to determine power's appropriate percentage of joint costs of a project.

Revenues from the sale of power produced at these projects are used to repay annual operation and maintenance costs of both the power marketing administration and power's allocation of the Corps' costs including interest and allocated power investment costs.

The Southeastern Power Administration prepares two types of repayment studies each year. A power repayment study for historical years is prepared for each project showing how repayment has progressed in the past. Also, a power repayment study is prepared for each power system which presents both historical and forecasted data and shows how SEPA expects to repay the power investment in the future. The development of future data requires the forecasts of power revenues, expenses, and investment. One of the purposes of the repayment study is to demonstrate that each dollar of power investment will be repaid with interest within a period

not to exceed 50 years. To the extent possible, while still complying with the repayment periods established for each increment of investment, amortization of the investment is accomplished by application of revenues to the highest interest-bearing investment first. Through the end of F. Y. 1979, SEPA had repaid all the annual costs associated with the 21 projects and had amortized $219,000,000 of the $989,000,000 investment allocated to power. All five of the system studies demonstrate payout by the end of the repayment period.

C. The Transmission System

It has been the policy and practice of Southeastern to utilize the facilities of other utilities in lieu of constructing transmission facilities. Most of the private and public utilities in the area have negotiated with Southeastern equitable wheeling arrangements. As a result of this policy, all power marketed to non-generating and transmitting preference customers is marketed at the project bus bar or moved over transmission facilities owned by others.

III. EFFECT OF ADDITIONAL FEDERAL HYDROPOWER SUPPLY ON PMA PROGRAMS AND PRACTICES

A. Demand Forecasts for PMA Regions and Systems (compare and contrast with NHS supply and demand projections)

With the increase in number of completed hydro projects, SEPA has steadily been increasing the number of customers and the area served in conformance to the Section 5 provision of the Flood Control Act of 1944 which mandates the most widespread use of the power consistent with sound business practices. Upon the completion of the Richard B. Russell Project and the addition of a fifth unit at the Hartwell Project, SEPA will be able to extend its area of coverage and offer power to 26 new potential customers. (See II,B,5,a)

B. Increase in PMA Customers Served

In 1978, SEPA marketed almost 2.4 million kw to non-TVA customers (3.0 million including TVA). However, the preference customer load in its service area (including a G&T cooperative in southern Illinois and one in southern Indiana, but excluding the TVA area) was over 12 million kw. In addition, there is another 5.7 million kw of preference customer load outside the area served by SEPA but within the 10-state area (excluding the TVA area) in which SEPA has responsibility for marketing Federal power. Only the Richard B. Russell Project (300,000 kw in 1984) and a fifth unit (80,000 kw in 1982) at the Hartwell Project are active in this area to meet preference agencies' ever increasing demands. Even with the inclusion of the Russell Project and the fifth unit at Hartwell, assuming a customer load growth of 5 percent per year, Government capability will decrease from 13 percent in 1978 to under 12 percent of the preference customer capacity by 1984.

C. Increase in Large-Scale Hydropower Resources, Including Pumped Storage

SERC projects that loads in the Southeast will increase by 109 million kw over the next 20 years, an increase of about 125 percent. SERC further projects that hydro will comprise almost 10 percent of the additional capacity required in 20 years. Obviously, the addition of this much hydro would involve the construction of some large projects. The adaptability of hydropower to peaking demands makes it an ideal choice to meet part of these future needs.

Pumped storage of water is the only currently available means of storing large amounts of energy and capacity. Its importance is just now being fully realized. An example in the SEPA area is the Corps' Carters pumped storage project, which has played an important part in meeting the power needs of the region. Under present arrangements, Southeastern sells the pumping capacity at Carters to area utilities. They are allowed to schedule the facilities to pump water during off-peak periods and receive the energy equivalent of that water when they schedule generation during on-peak hours. The project will generate approximately seven kwh for each ten kwh consumed in pumping.

The importance of large-scale hydroelectric projects, including additional Federal projects, to meet future power needs is seen by SEPA to be extremely important.

D. Utilization of Small-Scale Hydropower Resources

Additionally, SEPA believes that strong consideration should be given to the development of feasible small-scale and low-head hydropower resources. Development of these resources is expected to be predominantly accomplished, however, by non-Federal interests with SEPA being a factor in marketing of some of the power.

IV. EFFECT OF ENERGY CONSERVATION AND NEW ENERGY TECHNOLOGY ON PMA PROGRAMS AND PRACTICES

A. Effect of Conservation Policies

As indicated in Section I.B., SEPA anticipates an enhanced role in promoting energy conservation in the Southeast. This role would include technical and financial assistance to SEPA customers in both conservation planning functions and in implementation of conservation programs. SEPA would necessarily require some additional staff and some modification of its present operations to accomplish this new role.

The demand for peaking power from preference customers now substantially exceeds the availability of Government hydro. Even though conservation efforts have caused load growth for electric energy to decline, it is doubtful that it can ever be reduced to zero; however, even if this were achieved, it does not negate the need to develop all feasible hydro sites, both low-head energy projects and high-head peaking projects. It should be emphasized that while hydro projects have an estimated economic life of 100 years, this is

not the case for other types of generation which can be expected to generate for periods of from as little as 20 years for small gas turbines to probably 40 years for coal, oil, and nuclear generation. Given the current shortages and cost of non-renewable fuels, the construction of non-fuel consuming generation such as hydro will always be needed even if the no growth scenario should actually be realized. For this reason, we believe that there is no question that any conventional hydropower project located in the Southeast however small or large will find a ready market as rapidly as it can be developed. Such projects can materially reduce the need for construction of new thermal plants to replace outdated and inefficient fuel consuming generation that must be replaced in the future, thus making a real contribution to conservation of fuel resources.

B. Effect of New Energy Resources. (Wind, Solar, Geothermal, energy storage systems, etc.)

SERC's projections of capacity additions for the 10-year period beginning in 1990 are fossil, 54.2 percent; nuclear, 21.6 percent; hydro, 9.5 percent; and other, 14.7 percent. The capacity additions represented by "other" amount to between 8 and 9 million kw. This segment of additional capacity is greatly dependent on the development of some new sources of power. It is evident from this that the future anticipates the development on a large scale of solar, wind, and/or other power methods not yet available.

C. The Challenge of Marketing Small-Scale Hydro

SEPA would welcome the opportunity to market economically feasible small-scale hydro. The use of hydropower does not deplete our energy resources as do fossil and nuclear power. To the contrary, unused power in streams does not remain in reserve as do other fuels. Water power not harnessed is lost forever.

V. EXPANDED ROLE OF PMA's WITH NEW LEGISLATION

SEPA has no new legislation under consideration which would expand its power marketing role.

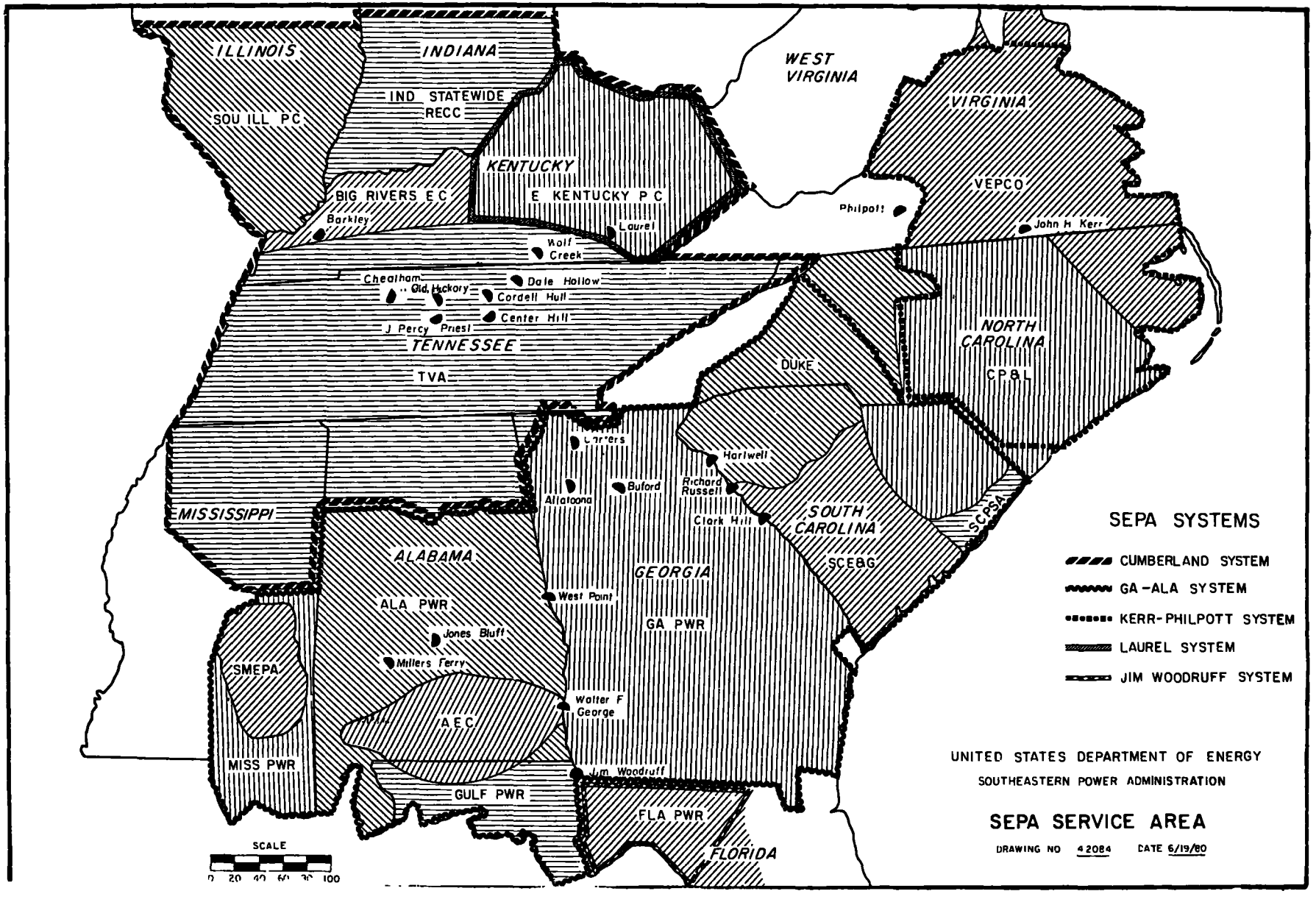
VI. PMA PROGRAMS AND PRACTICES FOR THE FUTURE

As indicated in Section I.B., SEPA's power marketing program for the future will be based on the systematic development of power marketing policy through a public participation process. The results of this policy development are obviously not known at this time, and conjecture as to what policies may emerge from the process serves no useful purpose here.

Summary of Current Wholesale Power Rate Schedules

Schedule	Type of Power Available	Principal Users	Rate: Capacity $/KW Mo.	Rate: Energy Mills/KWH	Other & Special Conditions
K-P System					
KP-1-B	Capacity & Energy	Pref. customers within VEPCo Area	1.25	5.00	
KP-2-B	Capacity & Dump Energy	CP&L & VEPCO	1.25		80% of savings in fuel for Companies operating units
JHK-1-B	Capacity & Energy	Pref. customers within CP&L Area	1.25	5.00	
Cumberland System					
CR-1-D	Energy & Capacity	Tenn. Valley Auth.			$18,450,000/year. If unregulated flow less than 8,500 or greater than 9,250 cfs an adjustment is made.
CR-2-D	Peaking Power, Standby Power Special Emergency Standby Power	Big Rivers EC, Ind. Statewide REC, Sou. Ill. Pwr. Coop, East Ky Pwr. Coop.	1.40	4.20 Peaking 3.26 Maint. Standby 5.32 Emergency Standby	4.26/yr. for contract standby capacity. $.064/KW/day for emergency standby, Nov., April, May, June, Sept. & Oct. $.099/KW/day for emergency standby for all other months.
Laurel System					
LP-1	Capacity & Energy	E. Ky. Power Coop.	1.37	4.20	
Ga.-Ala. System					
GAMF-1-B	Capacity & Energy	Pref. customers in Ga., Ala., Miss., & Gulf Pwr. Companies areas	1.02	3.65	

Schedule	Type of Power Available	Principal Users	Rate: Capacity $/KW Mo.	Rate: Energy Mills/KWH	Rate: Other & Special Conditions
Ga., Ala., System (Cont'd)					
GAMF-2-B	Capacity	Ga., Ala., Miss., & Gulf Power Companies	1.02		
Ala-1-B	Capacity & Energy	Ala. Elec. Coop	1.02	3.00	$.28 per KW of standby capacity +.0035/KW/day, for standby capacity used
Miss-1-B	Capacity & Energy	S. Miss. Elec. Pwr. Assn.	1.02	3.65	
SC-1-B	Capacity & Energy	S.C. Pub. Serv. Auth.	1.02	3.00	$.28 per KW of standby capacity +.0035/KW/day for standby capacity used.
SC-2-B	Capacity & Energy	Pref. Cust. within S.C. Pub. Serv. Auth.	1.02	3.65	$10.15/unit/hr. at Hartwell for condenser oper. $5.65/unit/hr. at Clarks Hill for condenser operation.
Car-1-B	Capacity & Energy	Pref. customers in Duke Area.	1.02	3.65	
Car-2-B	Capacity & Energy	Duke Power Co.	1.02	3.00 Peak 2.25 non-peaking 2.25 dump	
Jim Woodruff					
JW-1	Capacity & Energy	Pref. Customers served by Fla. Pwr. Corp.	1.50	4.5	
JW-2-B	Energy	Fla. Pwr. Corp.			Energy 60% of savings in companies cost of fuel, energy in excess of pref customers need


ILLINOIS
INDIANA
WEST VIRGINIA
VIRGINIA
SOU ILL PC
IND STATEWIDE RECC
KENTUCKY
BIG RIVERS E C
E KENTUCKY P C
VEPCO
Barkley
Laurel
Philpott
John H Kerr
Wolf Creek
Cheatham
Old Hickory
Dale Hollow
Cordell Hull
Center Hill
J Percy Priest
TENNESSEE
TVA
DUKE
NORTH CAROLINA
CP&L
Carters
Hartwell
Richard Russell
Allatoona
Buford
Clark Hill
SOUTH CAROLINA
SCPSA
MISSISSIPPI
ALABAMA
GEORGIA
SCE&G
West Point
ALA PWR
GA PWR
Jones Bluff
Millers Ferry
SMEPA
Walter F George
AEC
MISS PWR
Jim Woodruff
GULF PWR
FLA PWR
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SCALE
0 20 40 60 80 100
SEPA SYSTEMS
CUMBERLAND SYSTEM
GA-ALA SYSTEM
KERR-PHILPOTT SYSTEM
LAUREL SYSTEM
JIM WOODRUFF SYSTEM
UNITED STATES DEPARTMENT OF ENERGY
SOUTHEASTERN POWER ADMINISTRATION
SEPA SERVICE AREA
DRAWING NO 42084 DATE 6/19/80

NATIONAL HYDROELECTRIC POWER RESOURCES STUDY

Marketing and Transmission of Hydroelectric Power

Part 7

Alaska Power Administration Appendix

I. INTRODUCTION

A. History

The Alaska Power Administration (APA) was set up in June 1967, as a bureau of the Interior Department with responsibilities for operation, maintenance and power marketing for Federal hydroelectric projects in Alaska and investigation programs in future water and power development. Between 1948 and 1967, these functions were carried out by the Bureau of Reclamation's Alaska District Office. APA and its functions were transferred to the Department of Energy by the DOE enabling act.

Initial establishment of the Reclamation program in Alaska was a part of Federal post World War II efforts to establish a viable economy in the then - Territory of Alaska. This reflected recognition of power as a critical development need and general knowledge of the substantial undeveloped hydroelectric resources in Alaska. The Bureau's activities included an initial survey of the hydro resources completed in 1948, a number of basin and project studies, and the work to obtain authorization of the Eklutna Project near Anchorage in 1950 and the Snettisham Project near Juneau in 1962. A third project authorization was obtained in 1962 as a result of Corps Investigations, that being the Bradley Lake Project near Homer, Alaska.

The Bureau completed construction of Eklutna in 1955; the Corps completed the initial stages of Snettisham in 1973; the two Federal Projects now provide about 8 percent of Statewide utility requirements and represent about two-thirds of the developed hydro in the State.

Pursuant to a 1962 agreement between the Departments of Army and Interior, the Corps of Engineers has design and construction responsibilities for Federal hydro projects in Alaska, and APA has responsibility of operation, maintenance and marketing.

II. CURRENT MARKETING AND TRANSMISSION SYSTEMS

This Chapter briefly describes the six regions of Alaska, and the existing generation and transmission systems. Electric power statistics data for each region are presented in Appendix A.

A. Regions

Figure 1 outlines the six major regions. They are Southeast, Southcentral, Interior, Southwest, Northwest, and Arctic.

Southeast--This region stretches nearly 600 miles along the border of British Columbia. The terrain is typified by high mountains and small drainage basins that lead directly to the ocean. Heavy precipitation with high runoff rates contributes to the opportunity for numerous hydro developments throughout the entire region. The region has about 13 percent of the State's population located in the State capital in Juneau plus several of the States's centers of population, as well as many small villages. The prime industries are government, forest products, fishing, and tourism. Because of the steep terrain, glaciers, and many islands, there are no interconnecting highways. Consequently, transportation is dependent upon air travel and the Alaska State ferry system. Historically, electric generation for the larger communities has been furnished by local hydropower supplemented by diesel generation or all diesel. Most of the smaller towns are fully dependent upon diesel generation.

Southcentral--This region is characterized generally by much lighter runoff, colder climatic conditions, and less steep topography than Southeast Alaska. These conditions result in hydropower sites located mainly on the large river systems. There are several very significant power potentials, such as on the Copper River and Susitna River. This area of the State contains approximately 57 percent of the population. Major industries are associated with oil and gas production around Cook Inlet, fishing, seafood processing, government, and trades. Most of the towns in the region are interconnnected with good highway and air transportation systems. The major portion of the electric generation in the Anchorage-Cook Inlet area is provided from natural gas. The area is interconnected with a power transmission system between Homer at the south end of the Kenai Peninsula to Talkeetna, north of Anchorage at the north end. Service in the Anchorage-Cook Inlet area is provided by five separate utilities. Electric service to other isolated communities is provided by individual utilities, generally from diesel generation. The economy of the region has been typified by boom or bust situations, the latest of which was the construction of the Alaska pipeline which brought in a large influx of new jobs and population. The current economy has stabilized and is proceeding to grow again slowly. Anticipation of construction of the Alaska gas line may again produce significant numbers of jobs.

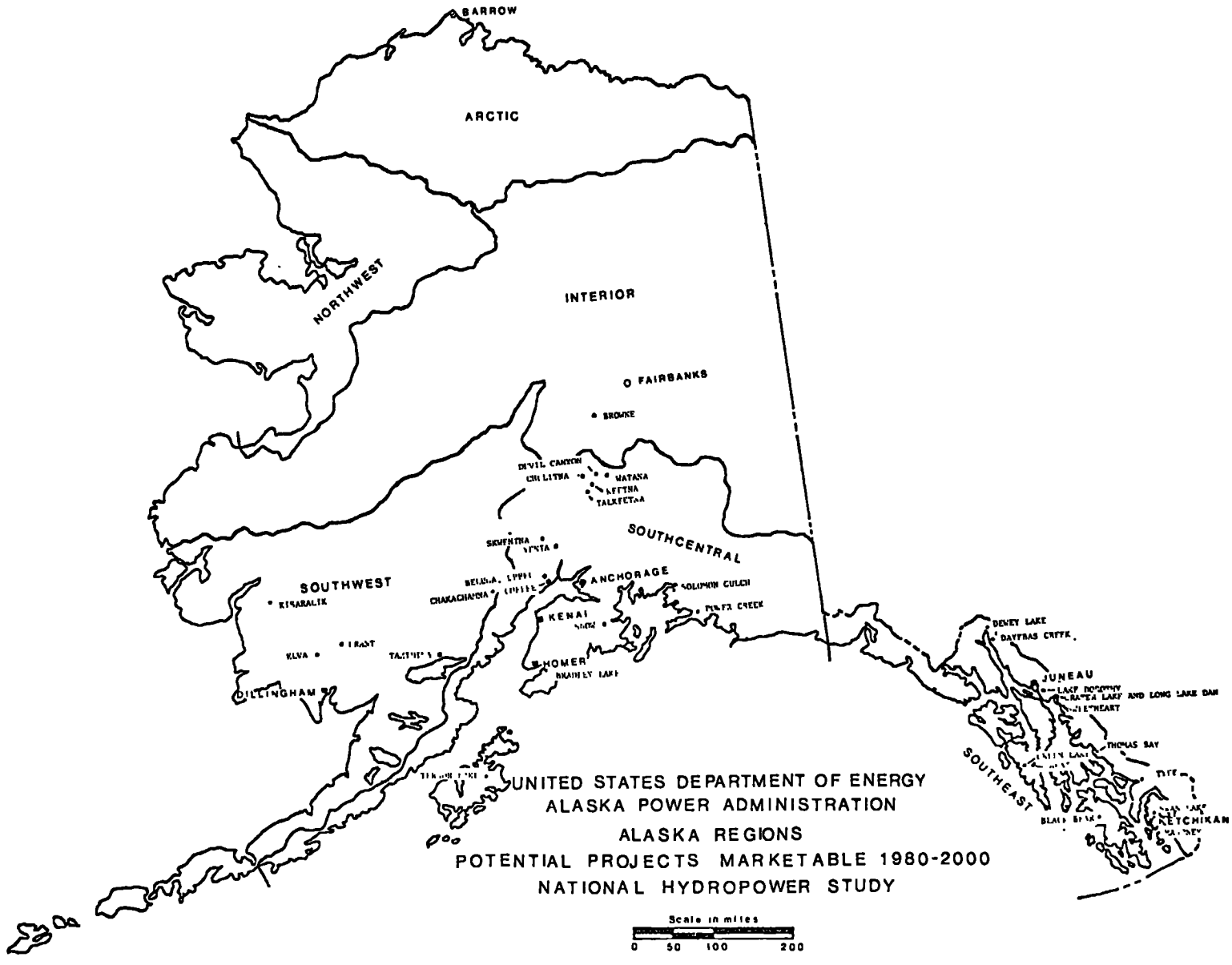

BARROW
ARCTIC
NORTHWEST
INTERIOR
FAIRBANKS
BROOKE
DEVIL CANYON
GULKANA
WATANA
KETTNA
TALKEETNA
SOUTHCENTRAL
SKWENTNA
VENTA
SOUTHWEST
BELUGA, UPPER
LOWER
CHAKACHAMNA
ANCHORAGE
SOLOMON GULCH
PORTAGE CREEK
KENAI
KISARALIK
ELVA
TRADE
TALKEETNA
HOMER
BRADLEY LAKE
DILLINGHAM
DEVEY LAKE
DAVERAS CREEK
JUNEAU
LAKE DOROTHY
AND LONG LAKE DAM
THOMAS BAY
SOUTHEAST
KETCHIKAN
UNITED STATES DEPARTMENT OF ENERGY
ALASKA POWER ADMINISTRATION
ALASKA REGIONS
POTENTIAL PROJECTS MARKETABLE 1980-2000
NATIONAL HYDROPOWER STUDY
Scale in miles
0 50 100 200

Figure 1

Interior--The Interior region is the largest of the six regions with an area about 204,000 square miles--approximately 35 percent of the area of the State. The topography is typified by expansive valleys and low rolling hills. Hydropower potentials only exist on the Yukon River system and its tributaries. There are no good sites north of the Alaska range due to lack of storage sites. The region has only a few other sites that could be physically developed in the entire Yukon basin. Most of the better sites on the mainstem river systems have been precluded by existing or pending Alaska Lands legislation. Roughly 20 percent of the State population lives in this region. Fairbanks constitutes the main population center in the region. The economic base is primarily government, the military, and the University of Alaska. Fairbanks also experienced rapid growth during the construction of the Alaska pipeline and a severe economic decline after the pipeline completion. Fairbanks is connected to the Anchorage area by a highway system and to the south 48 states through Canada by the Alaskan Highway. It is also served by several airlines and the Alaska Railroad which connects Fairbanks to seaports by two electric utilities from the coal-fired generation and oil-fired gas turbine generation. Outlying villages in this area are dependent upon diesel engine generation for their electrical needs.

Southwest--The Southwest region is about 109,000 square miles in area. The region consists of major river drainage areas of Kuskokwim, Nushagak, and Kvichak, plus the western flank of the Alaska Peninsula, and the Aleutian Islands. Few good hydro potentials exist within reasonable transmission distances of the major population centers of Bethel, Dillingham, and Naknek. Roughly 5 percent of the State's population lives in this region. The major portion of the economy is based on commercial fishing and fish processing, with government and recreation being other important industries. The streams and lakes in the region support the world's most productive red salmon fisheries. Recent exploration indicates potential for significant oil deposits in the Bristol Bay area; however, immediate development is being delayed for environmental reasons, primarily due to the huge quantities of bottom fish, shellfish, and the red salmon fishery. Currently, main population centers plus the numerous scattered villages are entirely dependent upon diesel generation for meeting electric energy needs.

Northwest--This region is similar to the Interior region with the hydro potentials being generally limited to the mainstem systems. This region has roughly 3 percent of the population of the State. The major towns are Nome and Kotzebue. Primary industries in this region include commercial fishing, fur trapping, and government, with subsistance being the primary method of livelihood in the outlying areas. The primary transportation system year-round is by air, with the addition of water transportation in the short summer months. Electric power is furnished entirely by isolated diesel generation systems.

Arctic--This region of Alaska is severly restricted on hydropower potentials due to lack of head, water supply, climate, and economical dam and reservoir sites. The area north of the Brooks Range has roughly 2 percent of the State's population. The largest industry, at the present time is

oil production at Prudhoe Bay. Oil and gas development, construction, and government services are other principal industries. Subsistence living constitutes the remainder of the economic livelihood for this region. Transportation is restricted to air travel for year-round basis and an occasional summer barge or ship during the late summer. Electric generation in the Barrow and Prudhoe Bay oil development area consists of fossil fuels. The outlying villages depend on diesel generation.

Electric Power Statistics

Appendix A contains statistics on the installed capacity and net generation in 1979 for major towns in the regions of Alaska. Data on industrial and national defense installations are also included. A breakdown of the net energy generated by the utilities, national defense, and industry, is also presented by the types of fuel used for each area of the State.

Transmission

Alaska's population is primarily urban, concentrated in a few principal cities and many smaller towns and villages. There are fairly extensive interconnected systems serving the population centers in the Anchorage-Cook Inlet and Fairbanks-Tanana Valley areas. Over 60 percent of the State's population is served by the interconnected transmission system in the Anchorage-Cook Inlet area. Five utilities, several industries, and two national defense installations are tied to this system. In the Fairbanks area, two utilities and three military bases are intertied. The rest of the State's power systems are isolated, with electric service usually limited to the immediate urban and suburban areas. There are small communities scattered throughout the State that have interties between local utilities, industries, and military bases.

B. Role of Alaska Power Administration

1. APA is responsibile for operation, maintenance, and power marketing for Federal hydroelectric projects in Alaska, and for certain investigation programs in future water and power development.

2. APA operates under the following legislative authorities:

- Sections 5 and 8 of the Flood Control Act of 1944, 58 Stat. 890, 16 U.S.C. 825s, 58 Stat. 891, 43 U.S.C. 390. Section 5 assigned to Interior responsibilities for transmission and marketing of power from Corps of Engineers' projects; section 8 determines need for irrigation facilities of Corps' projects.

- The Eklutna Project Act of July 31, 1950, 64 Stat. 382, as amended, provides for construction (completed) and operation, maintenance, and power marketing for the Eklutna Project.

- The Act of August 9, 1955, 69 Stat. 618, authorizes an Interior Department investigation program for Alaska water and power resources development.

- Section 204 of the Flood Control Act of 1962 (Crater-Long Lakes Division, Snettisham Project), 76 Stat. 1194, assigns operation, maintenance, and power marketing responsibilities to Interior.

Section 201 of the Water Resources Development Act of 1976 concerns determination of Snettisham Project's reimbursable costs and repayment terms.

- Public Law 95-91--August 4, 1977, 91 Stat. 565, section 302, transfers these functions from the Department of Interior to the Department of Energy.

- Annual appropriation acts, starting in FY 1949, cover APA and Bureau of Reclamation's Alaskan programs.

3. Specific laws governing transmission and marketing for APA are the Snettisham and Eklutna Project authorizations cited above and Section 5 of the 1944 Flood Control Act.

4. APA's two projects are operated as independent systems (see attached maps). The functions of general supervision and power marketing are handled by the APA headquarters office in Juneau. APA receives direct, annual appropriations from the Congress for O. and M. activities.

5. Alaska does not presently have an active regional reliability council, although informal efforts are currently underway to establish one.

6. APA provides wholesale power to five utility customers, (three in the Anchorage area and two in the Juneau area) including three REA cooperatives, one municipal, and one private system.

7. APA's present resources total 77,160 kilowatts (30,000 kW at Eklutna and 47,160 kW at Snettisham) all of which is under APA's direct control. Operations are closely coordinated with utility generating systems in each area.

   Eklutna operates in a market area for which about 90 percent of utility generation is provided by natural gas. Eklutna's full capability is used under the present situation.

Snettisham's operation is in an isolated power market area (Juneau) and there presently is a significant surplus in both capacity and energy. APA is making excellent progress in marketing the surplus resulting in significant oil savings. With anticipated load buildup in the Juneau area, the next increment of Snettisham capacity will be needed in the 1986 - 1987 time frame.

APA does not presently have active power purchase programs.

B. Current APA Marketing and Transmission Programs and Practices

1 and 2. APA observes the letter and intent of the laws governing our transmission and marketing programs, and is pursuing policies of (a) maximizing energy production, (b) assuring long-term viability and repayment of investment, and (c) maximizing project benefits for other purposes where this is consistent with the project authorizations.

3. Wholesale power rates are established pursuant to applicable DOE procedures on the basis of power repayment studies for each project. We use the postage stamp concept and rigorously follow legislative direction with respect to "lowest cost to consumers" consistent with good business principles.

4. APA's Eklutna transmission facilities are receiving increasing use for wheeling of non-Federal power. APA charges a nominal wheeling fee. The wheeling rate is currently under review. Revenues from wheeling are comparatively minor, but have the effect of reducing the long-term rates for power from that project.

5. APA markets power from both projects under long-term (10 to 20 years) wholesale contracts. Each project has a single rate for firm energy with capacity, and a separate rate for non-firm energy. Rate schedules for both projects

Both projects are meeting repayment criteria under existing law and over one-third of the initial investment for Eklutna has been repaid. Portions of the Snettisham Project interest are being deferred under provisions of the 1976 Water Resources Development Act -- the period of interest deferral ends in 1985.

C. Existing APA Transmission Systems

1. APA's Eklutna transmission lines are part of an interconnected transmission system serving Anchorage, the Matanuska Valley, and the Kenai Peninsula. Except for the APA lines, all other transmission in the area is utility-owned.

APA's Snettisham transmission line presently serves the single purpose of delivering project power to the Juneau market area.

2. Lack of transmission interconnections between Southeast Alaska is a constraint in marketing of the Snettisham power and of utilizing additional hydro resources in this part of the State. APA investigations are addressing this constraint. Studies indicate it may be feasible to establish the needed interties by about 1990.

   APA transmission studies for the Bradley Lake Project indicate need to increase transmission capability between this project and Anchorage to market the full output of that project. This can best be handled by expanding utility-owned systems.

   The State of Alaska is pursuing detailed feasibility and design studies for a much needed intertie between Anchorage and Fairbanks. This intertie is considered a key to long-term utilization of the undeveloped hydro resources in the Southcentral region of Alaska.

3. Alaskan power systems generally lack the necessary redundancy in transmission lines and diversity of generating resources to accomplish highest levels of reliability. Few systems are able to maintain spinning reserves to cover largest unit outage. Given the circumstances, reliability levels are quite good. Outlook for improvement is also good along with development of diversified generating sources and additional interties.

III. POWER REQUIREMENTS AND

This Chapter includes APA's estimates of future Alaska power requirements through year 2000, by geographic region.

For purposes of this study, APA made a set of mid-range load forecasts through the year 2000, drawn from several sources. The main sources are:

1. Upper Susitna River Project Power Market Analysis, APA, March 1979.

2. Chilkat River Basin Region Reconnaissance Assessment of Energy Alternatives, CH2M/Hill for Alaska Power Authority, February 1980.

3. Green Lake Project Evaluation Report, R. W. Beck for City of Sitka, June 1977.

4. Hydroelectric Potentials for Ten Southeast Alaska Towns, R. W. Retherford Associates for Alaska Power Authority, 1977.

5. Power Market Analysis for the towns of Juneau, Ketchikan, Metlakatla, Petersburg, and Wrangell, APA, 1979-1980.

6. Bristol Bay Energy and Electric Power Potential, R. W. Retherford Associates for APA, December 1979.

7. Energy Study for Barrow, R. W. Beck for APA, August 1977.

8. Electric Power Needs Assessment, Southcentral Alaska Water Resources Study (Level B), APA, March 1979.

The projections include utility, self-supplied industry, and national defense needs.

The summary totals are listed below by region:

Region	1990 MW	1990 GWh	2000 MW	2000 GWh
Southcentral	1,442	5,640	2,541	10,560
Interior	600	1,364	675	2,072
Southeast	296	896	349	1,131
Southwest	108	252	134	358
Remainder of State	304	848	301	879
Total	2,800	9,000	4,000	15,000

The year 2000 energy requirement of 15,000 GWh is roughly a three-fold increase over estimated 1980 requirements, and would represent an average growth of 6 percent per year for the 20-year period.

APA recognizes there is likelihood that actual requirements may be substantially higher or lower depending on pace of development of the Alaska economy and effectiveness of various energy conservation programs.

Harza Engineering Company, in connection with the National Hydro Study, prepared three projections of future electric power demands. Year 2000 estimates of energy use excluding national defense and industrial use were: Projection 1--14.5 billion kWh; Projection 2--5.8 billion kWh; and Projection 3--7.5 billion kWh. Projection 1 of 14.5 billion kWh is very close to APA's estimate of 15 billion kWh. However, APA believes the projections underestimate Alaska power demands due to (1) omitting national defense and industrial needs and (2) the use of the 1972 OBERS population projections, which is generally recognized as being inappropriate for Alaska conditions.

CHAPTER IV. EXISTING, PLANNED, AND POTENTIAL HYDROPOWER SITES

This Chapter presents and discusses briefly the Alaska hydropower resource sites that are existing, under construction, planned, and potential for development by the year 2000.

Table 2 lists the sites existing, under construction, and planned for development by 1990. Their location is shown in Figure 1. There are presently 124 MW of developed hydropower generation, and with the addition of the sites under construction, and planned, will total about 325 MW by the year 1990. Only the Snettisham and Eklutna Projects are Federally-owned. Two of the projects planned for construction by 1990 have existing Federal authorizations, they are the Bradley Lake Project and the Snettisham Crater Lake and Long Lake Dam additions. For the listed sites under construction and planned, the national hydroelectric study criteria of 1 MW has been used as the minimum cutoff size. There are several other sites under active consideration throughout the State which are under this 1-MW size, but have not been included.

The Corps of Engineers Alaska work for the National Hydro Study produced a new inventory of 59 hydroelectric projects in Alaska for which the Corps considers there is some potential for economic feasibilty. This listing includes expansion of existing projects, as well as the projects now under construction and in advanced planning stages. Criteria for the Corps study included:

- Sites of 1 MW or larger potential
- Preliminary design and cost estimates based on 1979 price levels.
- Benefit cost ratio of 0.7 or higher, using a 50 - year analysis and 7 1/8% discount rate to calculate energy cost.
- Development not precluded by land designations such as National Parks, Monuments, Refugees, Wild and Scenic River or Wilderness.
- Environmental factors recognized by other agencies.

The Corps study does not include transmission costs.

Presently developed hydroelectric projects in Alaska total 124 MW with an annual energy capability of approximately 611 GWH. Projects now under construction plus those that are in advanced planning stages or authorized may increase these totals to about 318 MW and 1,565 GWH per year by 1990.

	MW	GWH
Existing	124	611
Under Construction - 1980	28	129
Planned by 1990	166	825
	318	1,565

Data from previous Alaska Power Administration inventory studies was provided to the Corps, and APA generally agrees that the Corps listing reflects potentially economical sites that may be available for development.

Based on very rough estimates of transmission costs, and alternative costs of power for various regions of the State, APA estimates that the Corps listing also represents potentially viable projects from the viewpoint of power marketing. This is, of course dependent upon the timing and extent of future Alaskan power requirements.

APA compared estimated future power requirements on a regional basis with the potential hydroelectric projects with the following results:

- Electric power needs of the Southeast, Southcentral, Southwest and part of the Interior regions could be fully met by the identified hydropower sites with exceptions for scattered villages.

- The Arctic, Northwest and part of the Interior regions do not have hydropower potentials to meet any of their electric power needs, due to climate, terrain, and population distribution.

APA also compared the energy costs of potential sites with costs of providing energy from alternative sources. APA added transmission line costs to Corps costs to obtain total cost of power delivered to the market areas. This generally added about 10 percent to the total cost, but did not result in any of the Corps projects being dropped from consideration.

A summary of the hydropower sites under construction, planned by 1990, and potential by the year 2000 from the Corps list is presented in Table 1.

It was noted that because of the Nationally established criteria used by the Corps for Alaskan project evaluation, inaccuracies occured for several projects that have been studied previously. This is particularly true for the Chakachamna Project. The Corps results indicate a much cheaper cost of power for Chakachamna than the Susitna Project--a serious misrepresentation not supported by detailed studies of either project. Therefore, it is important to keep in mind that the cost of energy for projects on the Corps list not be considered realistic unless verified by previous studies.

Table 1: Summary Listing of Hydropower Sites Under Construction, Planned by 1990, and Potential Projects by 2000

Under Construction

Region	Name	Region Served	MW	GWh
Southcentral	Solomon Gulch	Valdez	12	65
Fairbanks-Tanana Valley Area	None		0	0
Southeast	Green Lake	Sitka	16	64
Southwest	None		0	0
		Subtotal	28	129

Planned by 1990

Region	Name	Region Served	MW	GWh
Southcentral	Bradley Lake	Kenai Peninsula	70	322
	Terror Lake	Kodiak	20	128
	Power Creek	Cordova	7	26
		Subtotoal	97	476
Fairbanks-Tanana Valley Area	None		0	0
Southeast	Swan Lake	Ketchikan	22	85
	Tyee	Petersburg/ Wrangell	20	114
	Snettisham--Crater Lake & Long Lake Dam		27	143
	Black Bear	Craig-Klawock	5	22
	Dewey Lake	Skagway	1	3
		Subtotal	82	393
Southwest	Elva	Dillingham	1	8
		Subtotal	166	825
Total of Sites Planned and Under Construction			202	980

Table 1 (continued): Hydropotentials With Energy Marketable by Year 2000

Region	Name	Area Served	MW	GWh
Southcentral and Fairbanks-Tanana Area	Browne	Anch. & Fbks.	200	566
	Chulitna	Anch. & Fbks.	34	166
	Keetna	Anch. & Fbks.	74	324
	Skwentna	Anch. & Fbks.	98	490
	Talkeetna	Anch. & Fbks.	90	406
	Watana	Anch. & Fbks.	792	3,480
	Devil Canyon	Anch. & Fbks.	766	3,410
	Yentna	Anch. & Fbks.	219	960
	Beluga, Upper	Anch. & Fbks.	48	210
	Coffee	Anch. & Fbks.	37	160
	Snow	Anch. & Fbks.	63	278
	Chakachamna	Anch. & Fbks.	366	1,300
		Subtotal	2,787	11,750
Southeast	Mahoney	Ketchikan	14	56
	Sweetheart	Juneau	29	127
	Takatz	Sitka	20	97
	Thomas Bay	Petersburg/ Wrangell	50	217
	Lake Dorothy	Juneau	34	150
	Dayebas Creek	Haines	5	18
		Subtotal	152	665
Southwest	Kisaralik	Bethel	30	131
	Tazimina	Dillingham/ Naknek	51	224
	Grant	Dillingham/ Naknek	3	13
		Subtotal	84	368
Remainder of State			0	0
Total			3,023	12,783

CHAPTER V. ALTERNATIVE POWER COSTS

This chapter dicusses the comparison of costs of developing a selected group of potential hydropower sites with the cost of the likely alternatives. Corps costs were used for the selected hydro sites in addition to costs developed by APA to deliver the power to the power market area. These costs were then compared with the cost of alternative power at the power market.

Basically, the Corps procedures screened the hydroelectric potentials larger than 1 MW against these criteria: physical potential, social impact, environmental impact, institutional aspects, and economic criteria. Costs of individual sites were estimated and rates derived to develop a benefit/cost ratio using Corps criteria. These sites were further screened by APA and the Corps and resulted in the selected group of sites presented in Table 3.

APA then took the cost per kWh from Table 3 and added transmission costs to deliver the power to the market area. The market delivery point was considered to be either a city or a point on an interconnection between cities. Interconnections were assumed to exist in Southeast Alaska from Ketchikan to Skagway excluding Sitka. In the Southcentral region, an intertie was assumed to exist from Fairbanks to Anchorage to the Kenai Peninsula and from Anchorage to Glennallen and Valdez.

Transmission line costs for some of the hydropower sites are included in more detailed studies along with other project costs. These detailed costs were used for comparison with costs of the alternatives wherever they were available. Where these detailed reports were not available, specific calculations of transmission costs were made to the nearest town or intertie. The costs per mile were calculated for the appropriate size of transmission line and the total cost of the transmission system using the FY 1980 8-percent-interest rate and a 50-year project repayment period.

Transmission costs were generally found to amount to less than 10 percent of the total project costs. The results were that none of the sites dropped out due to the addition of transmission costs.

It appears the criteria of 0.7 benefit/cost ratio for screening sites is overly conservative for Alaska where the alternative is primarily fuel-oil based. APA has suggested to the Corps that a b/c ratio criteria of 0.5 to 0.55 be used. This is based on the assumption that the fuel component will increase at a rate of 3 percent above inflation (for 20 years) or (1.03)20 = 1.81 relative cost. (b/c = 1/1.81 = 0.55). Several additional potential sites would be available for further consideration under these criteria.

The following tabulation presents the cost of energy for the likely alternative generation:

Region and Alternative	¢/kWh	Data Source
Communities Accessible to Railbelt Intertie		
Coal-Fired Steamplant	5.9	Upper Susitna River Project Power Market Analysis, APA March 1979.
Southeast and Isolated Gulf of Alaska Communities		
Diesel Engine	9.3	Ketchikan Power Market Analysis, APA September 1979; and 1980 fuel prices.
Southwest Region		
Diesel Engine	13.1	Bristol Bay Energy and Electric Power Potential, prepared for APA, December 1979.

CHAPTER VI. LOAD/RESOURCE COMPARISON

The purpose of this chapter is to compare the estimated power load with the potential hydroelectric resources on the Corps selected list and determine which of the powersites are marketable within the given time frame. The most economical projects were considered to come on-line first.

Table 3 presents a tabulation of the power load and hydropower resources. The market for hydropower for the year 2000 is estimated to be the total requirement less existing and new generation expected to be on-line by 1990. This assumes natural gas and oil-fired generation will be displaced in as many cases as possible. The identified resources were taken from the Corps' list utilizing as many sites as were needed to fulfill the energy demands of the area. The Southeast region has an excess of economical powersites to meet their needs. The Southcentral and Interior regions have enough sites to meet 99 percent of the available market for hydropower, providing every site on the Corps' list is used. The Southwest region of the State has three sites that could meet all the regions energy needs, however, many of the isolated villages are beyond economical reach of transmission lines.

The net result is that by the year 2000 there would still be 626 GWh energy demand Statewide that could not be met by hydropower. This is due primarily to isolated power loads being outside the reach of interconnections or located in an entirely different part of the State from where the hydropower potentials exist. The following tabulation presents the percent of the electric energy demand that could be met by hydropower in the year 2000.

Area	Percent
Southeast Region	100
Southcentral Region and Fairbanks/Tanana River	99
Southwest Region	100
Remainder of State	0

Table 1 presents a list of the potential hydropower sites that would be required to meet the energy needs as outlined on Table 3. Their locations are shown on Figure 1. These are the sites that appear marketable by meeting the economics and size of the market criteria.

The National Hydro Study was based on criteria standardized for use of computers on a nationwide basis and, therefore, some discrepancies between these studies and more detialed studies may be expected. This was noted particularly in the comparison of costs for the Chakachamna Project and Susitna Project. The Susitna Project has been studied in detail over the last 20 years and has consistently been more economical

Table 3: Comparison of Loads and Hydro Resources

Area	Power Requirement (midrange) Year 2000		Existing & Planned Hydro by 1990		Net Market for Hydro for Year 2000		National Hydro Study Identified Resources		Excess Hydro	
	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh
Southeast	349	1,131	170	812	179	319	152	665*	-27	346*
Southcentral & Interior	3,216	12,632	154	771	3,062	11,861	2,787	11,750	-275	-111
Southwest	134	358	1	8	133	350	84	368	-49	-18
Remainder of State	301	879	---	---	301	879	---	---	-301	-879
	4,000	15,000	325	1,591	3,675	13,409	3,023	12,783	-652	-626

Southeast Alaska has several additional economical projects capable of meeting unforeseen needs.

than the Chakachamna Project. It is felt the project costs included on the list should only be considered a general measure of acceptability, and not a measure of feasibility. All identified project costs should be verified by other studies.

For clarity, the Southcentral-Fairbanks area potentials listed are not intended to be alternatives to the Watana or Devil Canyon sites of the Upper Susitna River Basin project now under active consideration by the State of Alaska. The unit costs of energy from the other alternative hydro sites are two to three times as high as costs for Watana and Devil Canyon.

The plant factor criteria used by the Corps (based on their national guidelines) appears to APA to be too low for Alaska conditions. The low plant factors result in unrealistically high capacity for powerplants which make them unmarketable because of the broad-energy-intensive-peak demands that occur in Alaska.

CHAPTER VII. CONSTRAINTS

APA believes there are several major constraints to further hydroelectric development in Alaska.

1. Large investments needed for the new hydros.

2. Similarly large investment needed in transmission system to utilize the hydro.

3. High interest rates tend to favor alternatives with lowest initial investment cost.

4. Land use constraints now precludes over 90 percent of the potential, including a number of projects, both large and small, which are potentially more attractive than the remaining resource.

5. Federal assistance programs geared to existing dams and low-head projects are of little use in Alaska which has so few existing dams and where the best high head projects have yet to be developed.

CHAPTER VIII EFFECT OF ENERGY CONSERVATION

A. We expect substantial downward modification of future power requirements estimates to occur as the conservation potential is better understood by utilities and individuals.

A major State effort in implementing and financing conservation measures was initiated in 1980.

Significant energy conservation will result from shifting from dependence on oil to electricity for portions of the State having ready access to hydro.

B. The potential for wind resource applications is good, particularly for many remote regions of the State, such as Bristol Bay. As soon as the technology is perfected, we'll see substantial use in State.

Direct solar power is of less interest because of extremely limited potential in winter when power demands are highest.

We expect the geothermal potential is good in selected areas. However, sufficient resources of high enough quality for power, close to load centers, have not yet been identified.

The tidal resources in the Cook Inlet area are very significant - second only to the Bay of Fundy. The State has studies under way to better identify this resource.

Work to date on biomass applications, especially in Southeast Alaska is not too promising. Because of the abundant resource there has been considerable interest, but the costs are not competetive with other energy sources.

C. We see little likelihood of extensive Federal development of very small (under 1,000 kW) hydro's in Alaska. Non-Federal development mechanisms will likely be more effective.

CHAPTER IX

A. Present and Future Roles

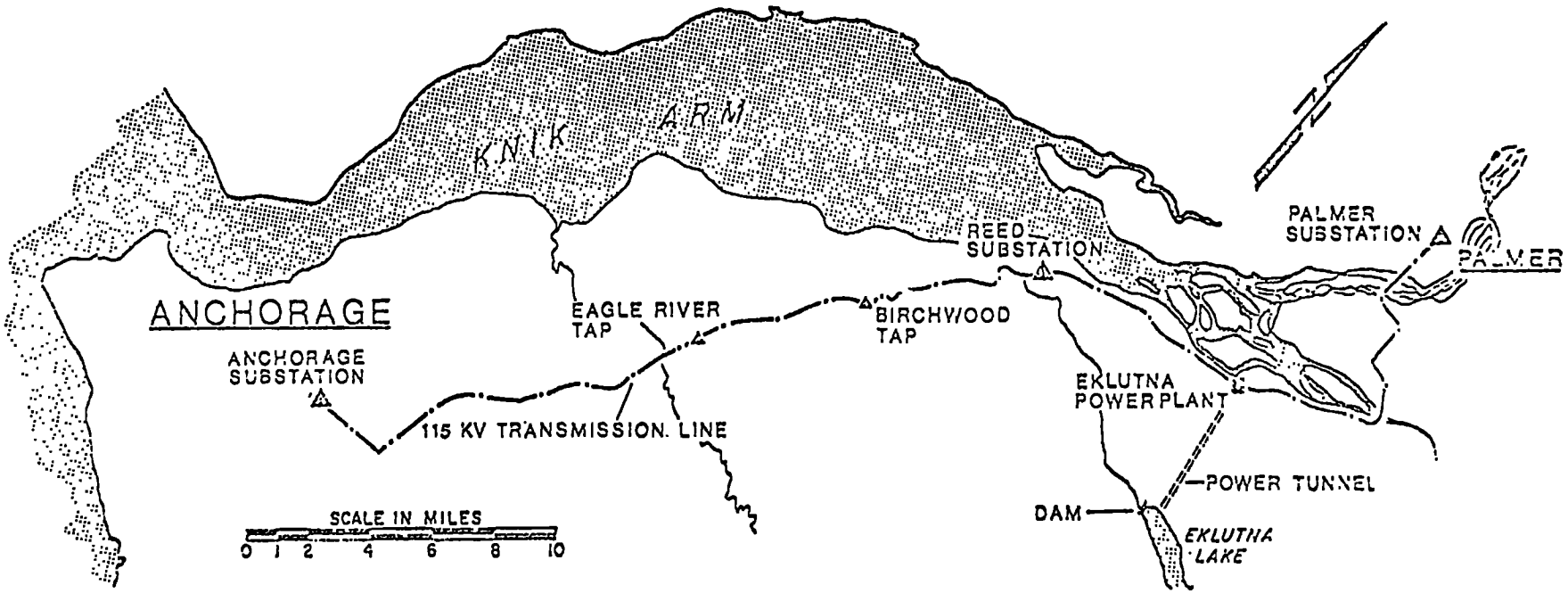
APA is continuing its assignments to operate and market power from the existing projects, and investigation programs in future power development, transmission systems, and power market studies, all in close cooperation with the State of Alaska, the utilities, the Corps of Engineers, and other entitites.

Within existing Federal authorization, APA has recommended the Corps proceed with installation of the Crater Lake Stage, Snettisham Project, for power deliveries in the 1986 - 1987 time frame. APA is cooperating closely with the Corps in further work on the authorized Bradley Lake Project near Homer, for which the General Design Memorandum is scheduled in late 1981.

APA is also pursuing investigation of possible transmssion interconnections in Southeast Alaska as well as studies of conservation and other renewable power resource options.

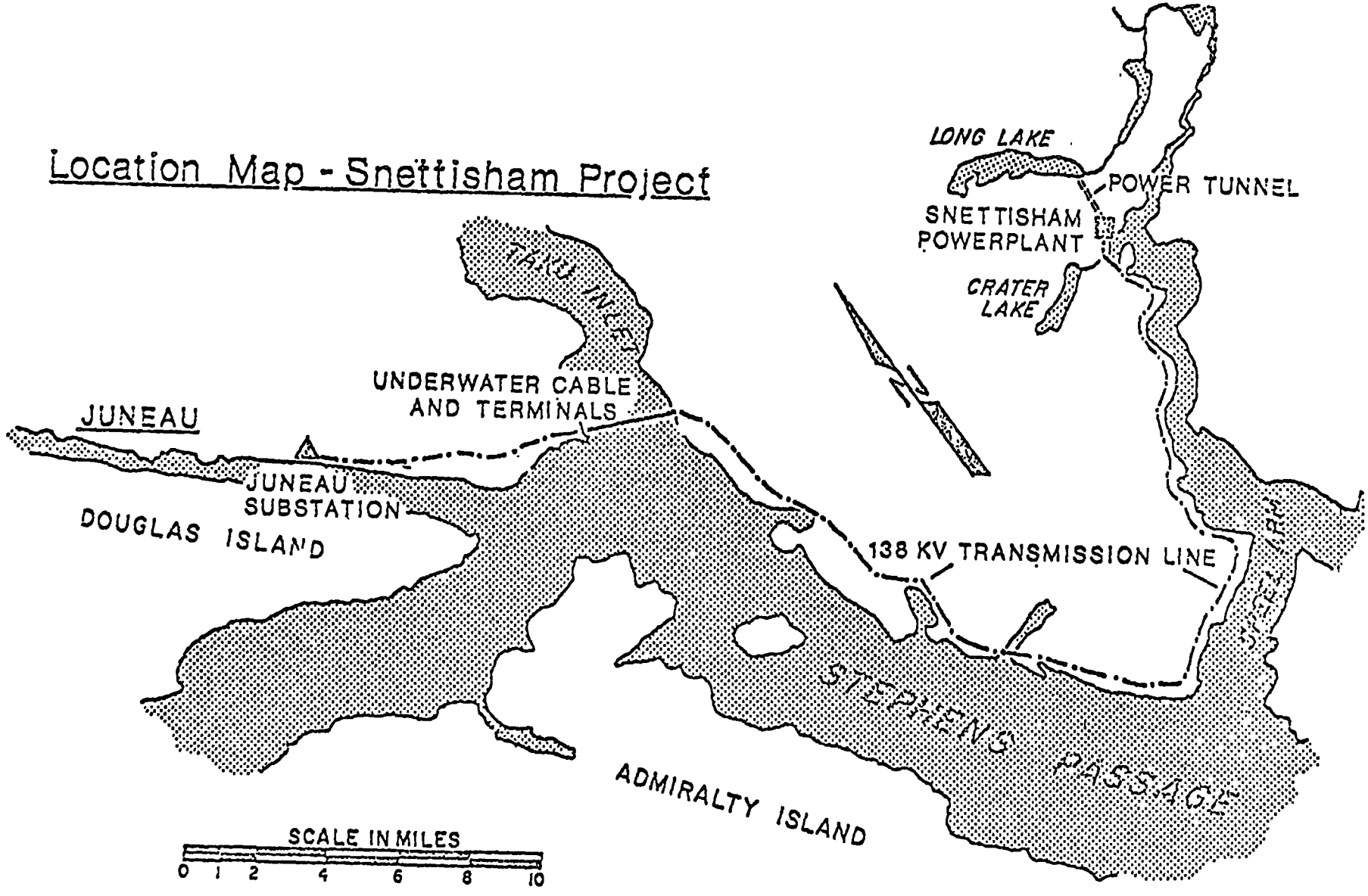
The State of Alaska has major initiatives underway toward additional hydro development, and it is likely the State will become the major agent for financing and developing the State's hydroelectric resources.

APPENDIX



Location Map-Eklutna Project

Location Map - Snettisham Project



UNITED STATES
DEPARTMENT OF ENERGY
ALASKA POWER ADMINISTRATION

Eklutna Project, Alaska

SCHEDULE OF RATES FOR WHOLESALE FIRM POWER SERVICE

Effective:

January 1, 1980.

Available:

In the area served by the Eklutna Project, Alaska.

Applicable:

To wholesale power customers for general power service.

Character and Conditions of Service:

Alternating current, sixty cycles, three-phase, delivered and metered at the low-voltage side of substation.

Monthly Rate:

CAPACITY CHARGE: None

ENERGY CHARGE: All energy at 12.5 mills per kilowatt-hour.

Minimum Annual Capacity Charge:

None.

Billing Demand:

Not Applicable.

Adjustments

For Transformer Losses:

If delivery is made at the high-voltage side of the customer's substation but metered at the low-voltage side, the meter readings will be increased 2 percent to compensate for transformer losses.

For Power Factor:

None. The customer will normally be required to maintain a power factor at the point of delivery of between 90 percent lagging and 90 percent leading.

For Auxiliary Power Service:

Auxiliary power supplies may be used in conjunction with the service hereunder if the parties hereto, prior to the Contractor's utilization of any such auxiliary power supply, have entered into a written operating agreement defining the procedure by which the amount of power and energy supplied by the United States will be determined.

UNITED STATES
DEPARTMENT OF ENERGY
ALASKA POWER ADMINISTRATION

Eklutna Project, Alaska

SCHEDULE OF RATES FOR NONFIRM SERVICE

Effective:

January 1, 1980.

Available:

In the area served by the Eklutna Project, Alaska.

Applicable:

To firm power customers normally maintaining generating facilities or other sources of energy sufficient to supply their requirements.

Character and Conditions of Service:

Alternating current, sixty cycles, three-phase, delivered and metered at points of delivery and voltage to be determined by the Alaska Power Administration.

Monthly Rate:

DEMAND CHARGE: None.

ENERGY CHARGE: 6.0 mills per kilowatt-hour for all energy under this schedule.

Minimum Bill:

None.

Adjustments

For Character and Conditions of Service:

None.

For Transformer Losses:

If delivery is made at the high-voltage side of the customer's substation but metered at the low-voltage side, the meter readings will be increased 2 percent to compensate for transformer losses.

UNITED STATES
DEPARTMENT OF ENERGY
ALASKA POWER ADMINISTRATION

SNETTISHAM PROJECT, ALASKA

SCHEDULE OF RATES FOR WHOLESALE FIRM POWER SERVICE

Effective:

December 1, 1973.

Available:

In the area served by the Snettisham Project, Alaska.

Applicable:

To wholesale power customers for general power service.

Character of Service:

Alternating current, 60 hertz, three-phase.

Monthly Rate:

CAPACITY CHARGE: None

ENERGY CHARGE: All energy at 15.6 mills per kilowatt-hour.

Minimum Annual Capacity Charge:

None

Minimum Annual Energy Charge:

As provided for under appropriate contract terms.

Adjustments:

For Transformer Losses:

If delivery is made at the high-voltage side of customer's substation but metered at the low-voltage side, the meter readings will be increased two percent to compensate for transformer losses.

For Power Factor:

The customer will normally be required to maintain a power factor at the point of delivery of no less than 90 percent. Adjustments for low power factor will be provided for under appropriate contract terms.

For Auxiliary Power Service:

Auxiliary power supplies may be used in conjunction with the service hereunder if the parties hereto, prior to the Contractor's utilization of any such auxiliary power supply, have entered into a written operating agreement defining the procedure by which the amount of power and energy supplied by the United States will be determined.

PRELIMINARY - 1979 ENERGY AND POWER DATA - PRELIMINARY

Type - Place	Installed Capacity (KW)	Net Generation (MWH)
SOUTHEAST		
Utility - Juneau	73,282	141,134
Ketchikan	29,623	84,800
Haines/Skagway	6,905	12,521
Petersburg	7,150	21,546
Wrangell	7,745	13,994
Sitka	14,600	49,872
Other Southeast	17,430	32,060
Total	156,735	355,926
Industrial - Total	67,125	305,265
TOTAL SOUTHEAST	223,860	661,191
SOUTHCENTRAL		
Utility - Anch/Cook Inlet	664,299	2,030,604
Glennallen/Valdez	17,746	41,264
Kodiak Island	25,903	60,520
Other Southcentral	9,585	17,998
Total	717,533	2,150,386
National Defense - Anch. Area	49,726	133,878
Kodiak Area	6,000	22,526
Total	55,726	156,404
Industrial - No. Kenai	24,980	94,520
Valdez	40,000	54,750
Other	48,705	226,658
Total	113,685	376,028
TOTAL SOUTHCENTRAL	886,944	2,682,818
YUKON		
Utility - Fairbanks Area	280,331	443,736
Other Yukon	14,801	20,389
Total	295,132	464,125
National Defense - Fairbanks Area	77,000	181,247
Other Yukon	9,625	26,006
Total	86,625	207,253
Industrial - Total	16,825	37,853
TOTAL YUKON	398,582	709,231
ARCTIC-NORTHWEST		
Utility - Barrow	5,150	10,200
Kotzebue	4,825	10,432
Nome	5,880	14,398
Other Arctic-NW	10,256	13,265
Total	26,111	48,295
National Defense - Barrow	2,250	8,000(e)
Other Arctic-NW	3,940	10,254
Total	6,190	18,254
Industrial - Total	198,800	458,072
TOTAL ARCTIC-NORTHWEST	231,101	524,621
SOUTHWEST		
Utility - Bethel	8,400	16,560
Dillingham	2,900	7,016
Naknek	1,550	7,238
Other Southwest	11,802	16,891
Total	24,652	47,705
National Defense - Total	56,150	115,936
TOTAL SOUTHWEST	80,802	163,641
TOTAL ALASKA		
Utility	1,220,163	3,066,437
National Defense	204,691	497,847
Industrial	396,435	1,177,218
Misc. (Not included above)	45,575	94,500
TOTAL	1,866,864	4,836,002

APA 3/80

Net Energy (GWh) - 1979 Preliminary

REGIONS	Southeast	Southcentral	Yukon	Arctic Northwest	Southwest	Misc.	Alaska
UTILITIES							
Gas	0.0	1,837.5	0.0	10.2	0.0		1,847.7
Oil	86.5	120.7	152.8	38.1	47.7		445.8
Coal	0.0	0.0	311.3	0.0	0.0		311.3
	86.5	1,958.2	464.1	48.3	47.7		2,604.9
Hydro	263.9	192.2	0.0	0.0	0.0		456.1
Pulp (prchsd)	5.5	0.0	0.0	0.0	0.0		5.5
Total Region	355.9	2,150.4	464.1	48.3	47.7		3,066.4
GT	0.0	1,808.4	133.9	10.2	0.0		1,952.5
IC	86.5	120.7	18.3	38.1	47.7		311.3
ST	5.5	29.1	312.0	0.0	0.0		346.6
Total Thermal	92.0	1,958.2	464.1	48.3	47.7		2,610.3
NATIONAL DEFENSE							
Gas		133.8	0.0	8.0	0.0		141.8
Oil		22.6	29.5	10.3	115.9		178.3
Coal		0.0	177.7	0.0	0.0		177.7
Total Region		156.4	207.3	18.3	115.9		497.8
GT		0.0	0.0	8.0	0.0		8.0
IC		0.1	29.5	10.3	115.9		155.8
ST		156.4	177.7	0.0	0.0		334.1
Total Thermal		156.4	207.3	18.3	115.9		497.9
INDUSTRY*							
Gas		288.8	0.0	424.5			713.3
Oil		92.6	20.1	33.3			240.5
Coal		0.0	17.5	0.0			17.5
		381.4	37.6	457.7			971.2
Pulp	300.5	0.0	0.0	0.0			300.5
Total Region	300.5	381.4	37.6	457.7			1,271.7
GT	0.0	206.7	18.8	436.2			661.7
IC	0.0	119.9	1.3	21.5			237.2
ST	300.5	54.8	17.5	0.0			372.8
Total Thermal	300.5	381.4	37.6	457.7			1,271.7
TOTAL							
Gas	0.0	2,260.1	0.0	442.7	0.0	0.0	2,702.8
Oil	86.5	235.8	202.5	81.6	163.7	94.5	864.6
Coal	0.0	0.0	506.5	0.0	0.0	0.0	506.5
	86.5	2,496.0	709.0	524.3	163.7	94.5	4,073.9
Hydro	263.9	192.2	0.0	0.0	0.0	0.0	456.1
Pulp	306.0	0.0	0.0	0.0	0.0	0.0	306.0
	656.5	2688.1	709.0	524.3	163.7	94.5	4,836.0
GT	0.0	2,015.1	152.7	454.4	0.0	0.0	2,622.3
IC	86.5	240.6	49.1	69.9	163.7	94.5	704.3
ST	306.0	240.2	507.2	0.0	0.0	0.0	1,053.4
Total Thermal	392.5	2,496.0	709.0	524.3	163.7	94.5	4,379.9

* Industry is 1978 data—not much change in 1979 is expected.

June 1980

	HYDRO	DIESEL	GT-G	GT-O	ST-G	SI-C	TOTAL	% OF STA TOTAL
Southeast	78,190	78,545	------	------	-----	------	156,735	12.8%
Anchorage-Cook Inlet	45,000	12,791	589,208	2,800	14,500	------	664,299	54.4%
Fairbanks-Tanana Valley	------	29,475	------	197,356	------	53,500	280,331	23.0
Rest of State	------	112,998	4,000	1,800	------	------	118,798	9.
Total State	123,190	233,809	593,208	201,956	14,500	53,500	1,220,163	100
			795,164		68,000			
% of Total Capacity	10.1%	19.2%	65.2%		5.6%		100%	
Total State 1956 (kW)	50,005	19,738	0		30,575		100,318	
Avg. Annual Growth 1956-1979	4.0%	11.4%			3.5%		11.5%	

GT = Gas Turbine
ST = Steam Turbine
-G = Gas-fired
-O = Oil-fired
-C = Coal-fired

Sources: Energy Information Agency (DOE), utility contacts, Alaska Public Utilities Commission

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