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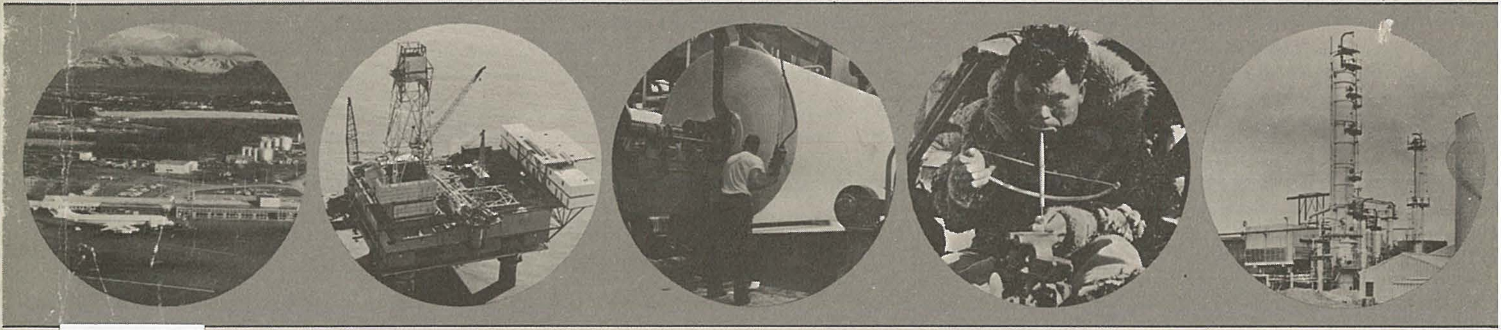
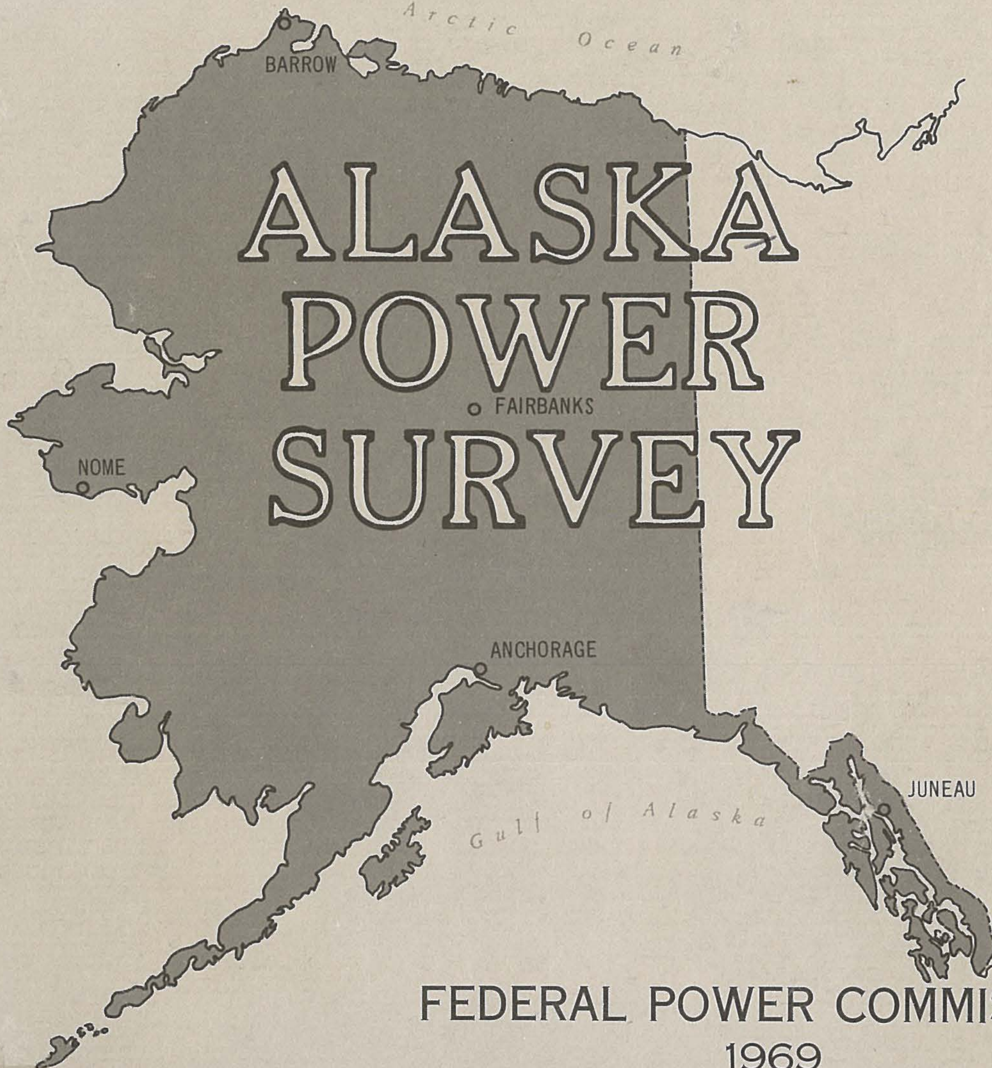
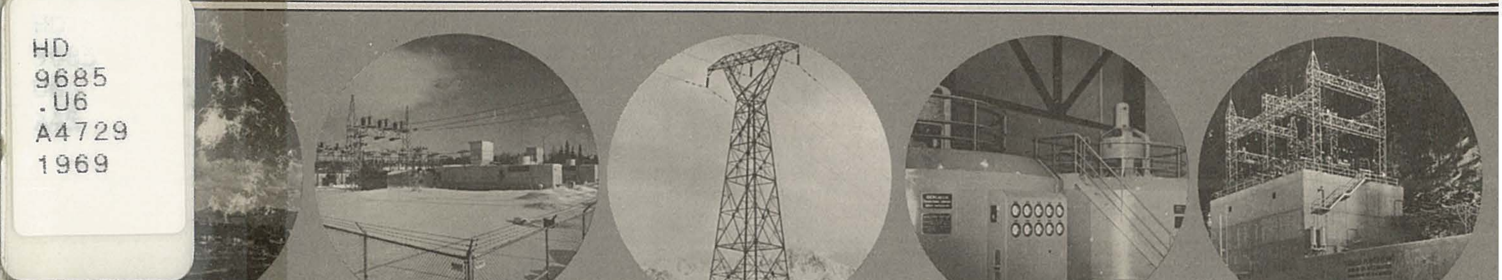


ALASKA POWER SURVEY



FEDERAL POWER COMMISSION

1969



ALASKA POWER SURVEY

A Report by

THE FEDERAL POWER COMMISSION

1969

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ALASKA POWER SURVEY

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PREFACE

On April 15, 1965, the Federal Power Commission announced its plan to undertake an electric power survey of Alaska to determine how best to meet the State's load growth during the years to 1985.

The Alaska Power Survey has examined both early and long-range opportunities for supplying Alaska's electric power needs in the most economical manner, including the opportunities for interconnection and coordination of existing systems to reduce the present high cost of electricity. It has also appraised and summarized various opportunities for major developments which could serve the long-range needs of the State.

The Survey Report was prepared largely by the Staff of the Federal Power Commission. The staff work was carried out under the direction of F. Stewart Brown, Chief Engineer and Chief of the Bureau of Power.

The Survey was conducted with the assistance and cooperation of appointed representatives of all segments of the electric power industry and of State and Federal agencies concerned with Alaska's economic and electric power development and growth. The names of those who served on the Commission's Advisory Committee and Subcommittees are listed in the acknowledgments at the end of the report.

The Commission wishes to express its appreciation to the Committees and to the many individuals who contributed to the work of the Survey and the preparation of this report.

INTRODUCTION

BACKGROUND AND HIGHLIGHTS OF THE SURVEY

Stimulated by statehood and an accelerated exploration and development of its many potential resources, Alaska is faced with an expansion in its supply of electric power in the next 15 to 20 years at a rate that is likely to exceed the rate of power growth in any other State.

The Alaska Power Survey explores both the immediate and the long-range electric power needs of the State, and alternative ways of improving the economy and reliability of its bulk power supplies.

Numerous opportunities have been examined for improvement of utility operation through the interconnection and coordination of the many electric facilities which comprise Alaska's power industry. One of the more encouraging indications for successful achievement of these goals is the manner in which representatives from Federal, State, and local agencies and the electric power industry have earnestly cooperated in the study to achieve meaningful and positive results.

A major goal of the Survey has been to suggest possible patterns of power system expansion which could result in lower costs and increased service reliability. The Survey visualizes patterns of possible development which, by 1985, could reduce the statewide average cost of electricity by about 65 percent, assuming a continuation of today's value of the dollar. The Survey encourages broader local and regional planning among Alaska's electric power utilities to the end that utilities of all segments will work together to meet their combined needs to the mutual advantage of themselves and their consumers.

The Survey was conducted by the Federal Power Commission as a means of carrying out the provisions of section 202(a) of the Federal Power Act which directs the Commission ". . . to promote and encourage . . . interconnection and coordination" of electric utility systems for " . . . the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to proper utilization and conservation of natural resources."

The future patterns for Alaska's electric power systems depicted in the Survey report are not suggested as firm patterns for any system or systems of electric powerplants or transmission lines. No one can adequately foresee all of the many changes in technology, operating conditions, or market potential that will occur in the years ahead. Therefore, the report does not set forth plans but only possible patterns for providing an economic and reliable system to supply future electric loads. The goal is to excite interest in the many opportunities for savings and increased service reliability that should be continually explored.

Growth in power consumption and closer coordination of power systems, particularly in the more populated sections, are twin ingredients in the formula for reducing future power costs. Power costs over the years have shown a downward trend. The goals of the Survey are to help continue and to accelerate the lowering of costs to the consumer, and to increase the reliability of electric service. The achievement of lower costs is in itself a stimulus to wider use of electricity.

The key to the future growth of Alaska's electric power industry lies largely in the willingness of its members to embark vigorously on a course of planning together for new power sources and system interties. Economies of scale in large generating units, coupled with low-cost energy transportation, suggest that many of Alaska's individual power systems could profitably join together in constructing new capacity, either through joint projects or by staggering their construction programs.

In areas where communities are of significant size, substantial reductions in the future cost of power appear possible. The total cost of generating, transmitting, and distributing power to customers of Alaska electric utilities in 1965 averaged about 2.69 cents per kilowatt-hour of power produced. No estimates of the equivalent costs are available for power produced by nonutility installations.

The Survey is concerned primarily with generation and transmission of power to the distribution substations, and projects that this bulk power supply part of the cost can be reduced by 65 percent. Guided by our previous studies of distribution costs in other parts of the United States, it appears that some reduction in the distribution costs should also be possible during the Survey period. The Survey projects that by 1985 not only will population have increased and more customers will be using more electricity individually than in 1965, but the cost of electric power before distribution to the ultimate customer could be reduced from the present average of about 1.98 cents to about 0.71 cents per kilowatt-hour. The study recognizes that the unit investments in production, transmission, and distribution facilities, as well as operating costs, are not the same in every location, and consequently, the possible reductions are greater in some areas than in others. As mentioned earlier, no direct comparison of possible cost differences for nonutility electric services is available. If comparable reductions are assumed, however, and the suggested reduction of 1.27 cents per kilowatt-hour is applied to the 5.3 billion kilowatt-hours considered for coordinated central utility service in 1985, it indicates that total savings could amount to as much as $67 million a year to Alaska's consumers. If the potential savings are calculated for utility served loads alone, the annual total is $45 million.

These savings will result from a greater number of customers using larger amounts of electricity for which unit costs will continue to decrease. Thus, the challenge facing Alaska's electric power industry is to continue the long-term trend of selling electricity to the consumer at steadily lower prices.

To compute the average cost of power, a composite fixed charge rate[1] was used to determine costs of power for all segments of Alaska's power industry. The use of such rates permits a reasonable economic comparison of alternative plans. It is recognized, of course, that actual fixed charges will vary, depending upon taxes or tax equivalents and the cost of money applicable to the constructing agency.

Analysis of the opportunities for lowering Alaska's power cost in the years ahead must begin with a knowledge of the State's geography and economy, and the present development of the electric power industry. Chapters I and II discuss the State's history, geography, economy, and resources, together with the makeup of its electric power industry and enough of its history to give some insight into the evolution of today's power industry structure.

The Survey, in chapter III, outlines the prospects for electric load growth, postulates that the predominant growth will occur in the areas of civilian use, and projects that civilian power demands in 1985 will require the production of 4,800 million kilowatt-hours of electricity, 6¾ times the 1965 production of 707 million kilowatt-hours. It is this large increase in energy use that enables the prediction of large reductions in costs of electricity suggested in this report. Conceivably, the very recent expansion in the discoveries of petroleum in the Arctic Region could result in even more rapid industrial and economic expansion than forecasted in the report.

Chapter IV discusses the availability and projected costs of Alaska's solid, liquid, and gaseous fuels for the generation of electric power. Also included is a projection of Alaska's future power generating plants, including possible types, locations, and costs, to meet both base load and peak power generating needs.

A summary of Alaska's developed and potential hydroelectric resources is presented in chapter V.

The heart of the report is in chapters VI and VII which include suggestions for improved economy and reliability through concepts of interconnection, coordination, the use of diversities in load patterns, and reductions in reserve requirements. Chapter VI discusses the transmission of electric power in Alaska today, and developments which are important to the expansion of power networks. It also presents illustrations of possible patterns of power generation and transmission, and suggests alternative ways in which system developments might occur. Chapter VII summarizes studies of various generation patterns and interconnections of the Anchorage and Fairbanks areas. Estimates are included of the savings which may be achieved with coordinated planning as opposed to uncoordinated individual system planning.

Chapter VIII attempts to bring into focus the economic significance of the patterns of growth visualized by the Survey. It projects the potential savings to consumers which will result from the growth and technological improvements projected in the report. The greatest savings are expected to take place in the Interior and Southcentral Regions

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[1] A percentage applied to the net investment in facilities to cover the annual cost of interest on the investment, depreciation or amortization, taxes, and insurance.

where low cost fuels, growth in loads, and the favorable geography offer many possibilities for improvement.

It is our sincere hope that the Alaska Power Survey will set a standard and serve as an encouraging guide for planning the future of Alaska's electric power industry. The goal proposed is an abundant supply of low cost electric power which will promote economic growth, add to the well-being of Alaska's population, and stimulate development which is not likely to be achieved without the ready availability of this resource.

CHAPTER I

GEOGRAPHY, RESOURCES, AND ECONOMY

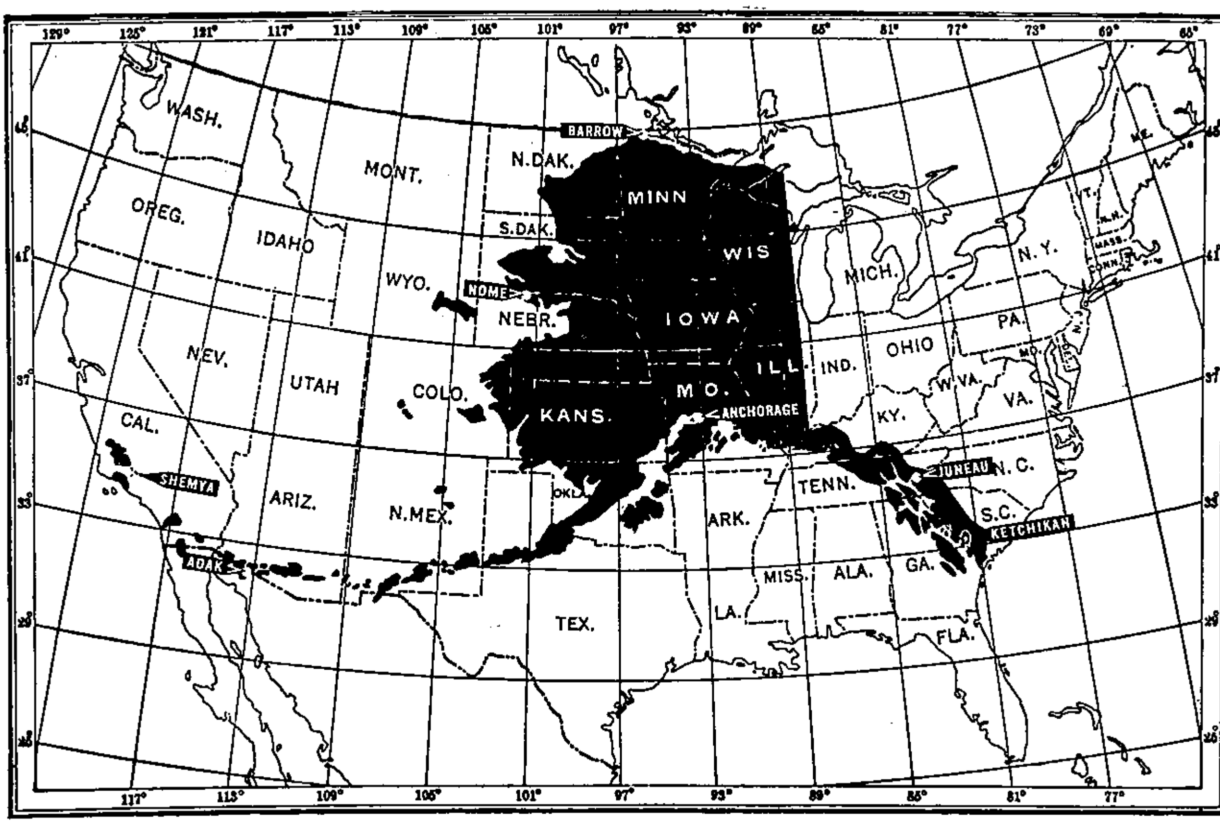
Any study of Alaska's electric power resources and needs over the years ahead must take into account the State's economy, geography, climate, and resources, all of which will help to shape its power needs and determine its potential for development.

Geography

Alaska is the largest peninsula of the North American Continent, approximately 586,400 square miles in area. It is a State of many long rivers—the longest, the Yukon, rises in Canada, flows through the State, and empties into the Bering Sea. Alaska's topography is marked by two great mountain systems; the Brooks Range above the Arctic Circle and the Pacific Mountain system, which sweeps in a great arc through the southern part.

Because of vast distances, climate, and rugged topography which hamper the building of roads and railways, air travel is a way of life. The general area map, figure 1, shows the many, widely distributed airports in contrast to the relatively limited highway and railway systems. In addition, there are 18 major and more than 50 smaller seaports in Alaska.

Alaska's land area is 365,481,600 acres, of which about 80 percent is composed of unreserved public domain and slightly more than 2 percent of land reserved by the Federal Government for the management and conservation of the State's major natural



This superimposed print of Alaska shows the relatively large size of the 49th State in comparison to the lower 48.

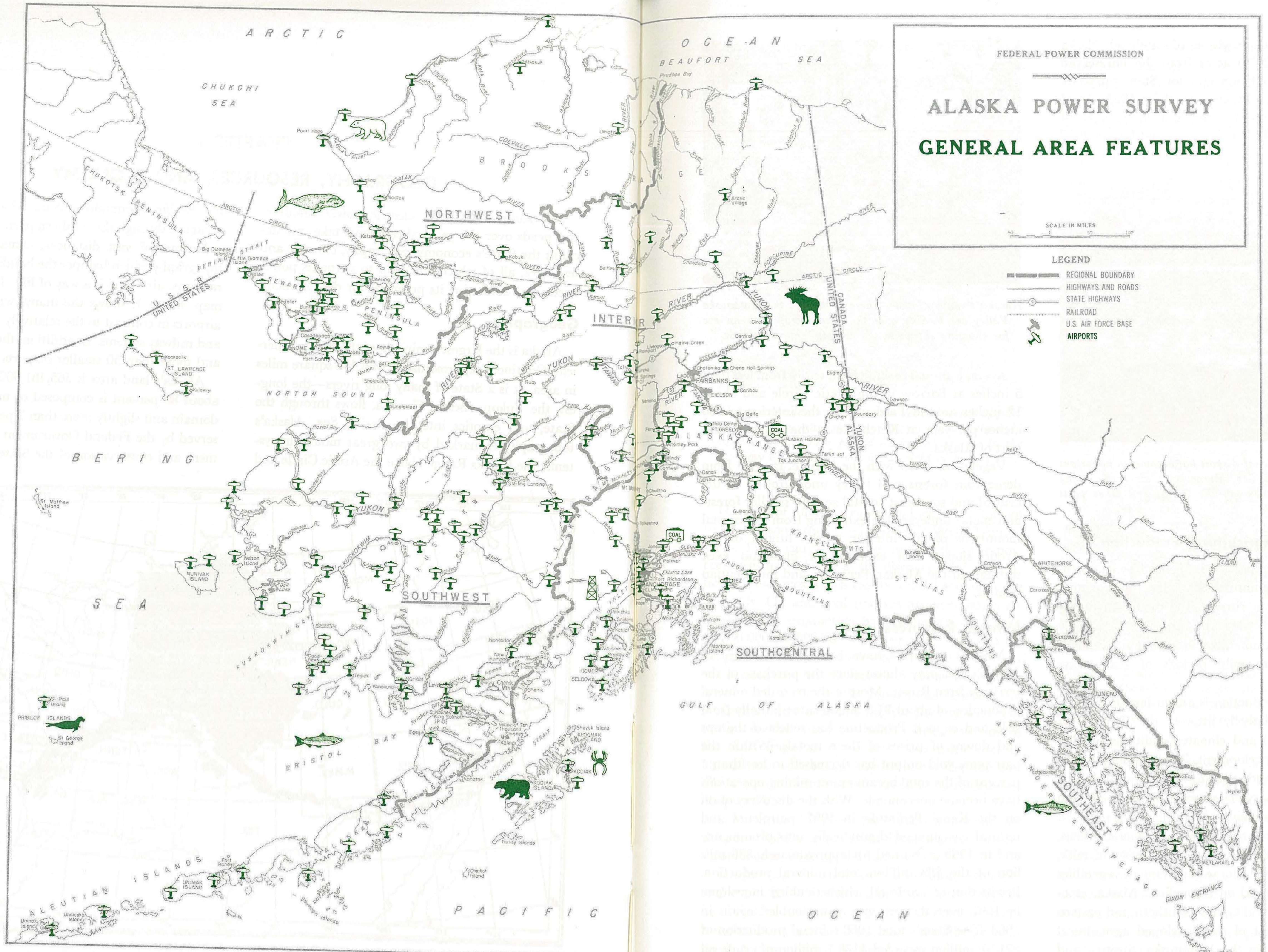
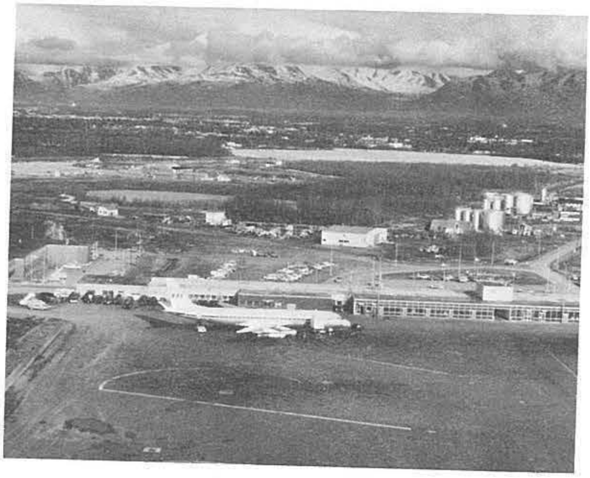

FEDERAL POWER COMMISSION
ALASKA POWER SURVEY
GENERAL AREA FEATURES
SCALE IN MILES
LEGEND
REGIONAL BOUNDARY
HIGHWAYS AND ROADS
STATE HIGHWAYS
RAILROAD
U.S. AIR FORCE BASE
AIRPORTS
ARCTIC OCEAN
BEAUFORT SEA
CHUKCHI SEA
BERING SEA
GULF OF ALASKA
PACIFIC OCEAN
NORTHWEST
INTERIOR
SOUTHWEST
SOUTHCENTRAL
SOUTHEAST
BROOKS RANGE
ALASKA RANGE
NORTON SOUND
BRISTOL BAY
ALEUTIAN ISLANDS
ALEXANDER ARCHIPELAGO
SEWARD PENINSULA
CHUKOTSK PENINSULA
BERING STRAIT
U.S.S.R.
UNITED STATES
CANADA
ST. LAWRENCE ISLAND
NUNIVAK ISLAND
PRIBILOF ISLANDS
KODIAK ISLAND
DIXON ENTRANCE
FAIRBANKS
ANCHORAGE
JUNEAU
WHITEHORSE
COAL

Figure 1

resources. Under the provisions of statehood, Alaska can select 104,582,745 acres from the unreserved and unappropriated acreages for State purposes. The selection must be completed by 1984. As of 1967, Alaska had selected only 17,606,803 acres, of which working title had been secured for some 13 million acres.



Anchorage International Airport has become an important intermediate point for international air traffic using the polar routes between the Orient and other parts of the world.

Climate and Agricultural Production

The climate of Alaska is influenced by its northerly latitude, its peninsular character, the proximity of the warm Japan current, the mountain ranges running east and west and prevailing southerly winds. Within innumerable variations of weather, Alaska experiences mild periods of many days duration.

Agricultural production is aimed largely at local consumption. Relatively little of the State's vast land area has soil and climate conditions suitable for agricultural development. These disadvantages, in addition to land clearing problems and high labor and machinery costs, make the price of local farm products relatively high.

Farming centers around the raising of chickens, cattle, and vegetables, and the production of milk, eggs, and field crops. Home gardening of vegetables and flowers is carried on throughout Alaska, especially in the river valleys and southern and eastern coastal areas. Most of the developed agricultural lands are located in the Matanuska, Susitna, and Tanana Valleys.

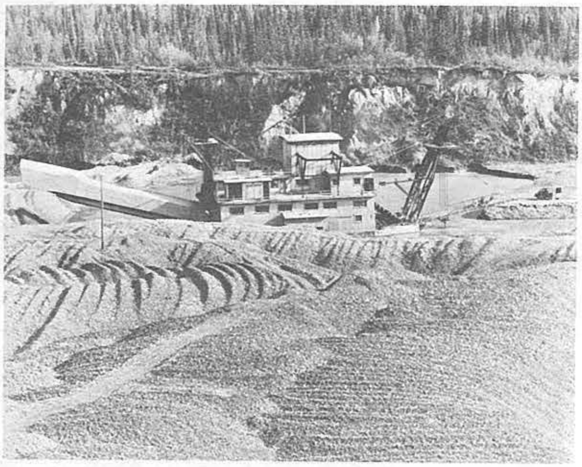
Harvest time in Alaska—These farmers in the Matanuska Valley are looking over the potato crop with an eye for choosing entries in the annual Matanuska Fair.

Average annual precipitation varies from less than 5 inches at Barrow in the Arctic Circle and about 12 inches around Fairbanks in the interior to 150 inches per year at Ketchikan in the southernmost part of Alaska.

Vegetation varies with the climate, ranging from dense rain forests and heavy undergrowth in the central and southeast coastal zone to smaller forests and sparse undergrowth extending from the coastal mountains of the interior to the tundra of the Arctic slope. Vast expanses of grassland exist throughout the Alaskan Peninsula and the Aleutian Islands.

Mineral Resources

Mineral resources have been the mainstay of Alaska's economy almost since the purchase of the territory from Russia. Most of the recorded mineral production of about $1.5 billion came initially from gold and copper. Production has reflected the ups and downs of prices of these metals. Within the past year, gold output has decreased to less than 1 percent of the total because most mining operations have become uneconomic. With the discovery of oil on the Kenai Peninsula in 1957, petroleum and natural gas jumped dramatically into prominence and in 1965 accounted for approximately $36 million of the $83 million total mineral production. Production of crude oil which doubled in volume in 1967 over the previous year doubled again in 1968. The State's total 1968 mineral production of $212.1 million included $178.7 million of crude oil and almost $3 million of natural gas. The recent discovery of a large oil province on the North Slope, roughly estimated to exceed 10 billion barrels, augurs well for the future of oil and gas as a principal element in the State's economy.



Alaska monster devours whole river beds in search of gold. These dredges, though dwindling in number throughout the North, have played an important role in the economy of Alaska. Truck at far right of picture gives an idea of size.

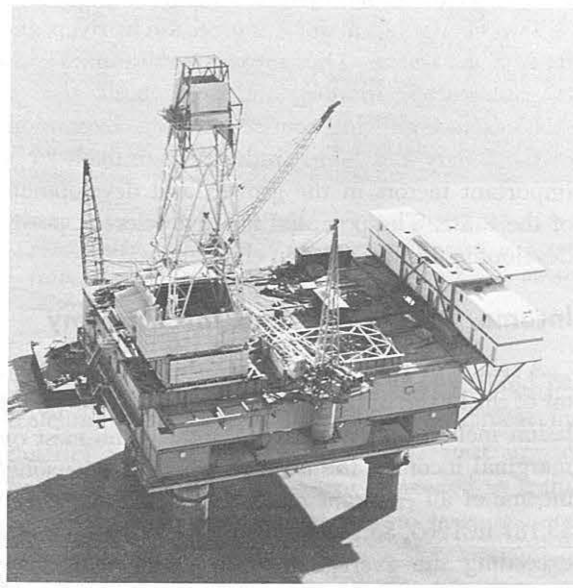
Deposits of all the strategic minerals are known to exist in some quantity in Alaska's 586,000 square miles. These can be expected to provide an important basis for industry as the discovery and verification of resources which can be mined economically proceeds. Oil and coal reserves are very large. At present, coal production has stabilized in the area of 800,000 to 900,000 tons per year of which 70 percent is used in power production. The natural gas production, which has risen along with oil, is now starting to reach commercial markets in Anchorage and is also being used for power generation on the Kenai Peninsula. The conversion of the Anchorage area military bases from coal to natural gas will be an important market for gas. These considerations are discussed in more detail in chapter IV.

It has been estimated that Alaska's mineral production could increase from 10 to 100 fold as development activity accelerates.

Copper deposits are known to be quite extensive and exploration is active. The Ruby Creek deposit near Kobuk is being reappraised to determine the potential for year-round mining and milling operations. A target of 5 years for the start of production has been mentioned.

In a very recent report, the Department of the Interior announced the discovery of lead, zinc, and silver in the remote Bowser Creek area about 150 miles northwest of Anchorage. Preliminary examinations are reported to indicate locally rich mineral deposits which, however, may be tedious to explore because they are small, terminate abruptly, and are irregularly distributed.

No iron ores have been mined in Alaska, but titaniferous magnetite deposits have been discovered in the Chenik Mountain area. One deposit is estimated to contain 1 billion tons of ore, with 15 percent recoverable iron, and represents a good possibility for future development.



Petroleum production from beneath the sea is a major part of Alaska's booming post-statehood economy. This is one of several units producing oil from under the waters of Cook Inlet near Anchorage.

Alaska has an abundance of construction minerals, such as sand and gravel. During 1965, about 30 million tons of these two minerals, with a value of about $34 million, were extracted. Production in 1966 amounted to $22 million, and in 1967, an estimated $28 million.

The only known tin deposit in North America is located in the western part of the Seward Peninsula and may become of economic and strategic importance in the future. Some prospecting and mining is carried on for other minerals, precious and semiprecious.

Other Resources

The most attractive and most active commercial lumber areas in Alaska are the forest regions in the southeastern Panhandle, south-central coastal area, and the eastern half of the Kenai Peninsula. Although the interior forests occupy about 34 percent of the land surface, commercial development has been limited to supplying local needs. Forest surveys indicate that 119 million acres sustain forest growth and, of this total, 28 million acres are classed as commercial forest land. The major product of the timber harvest is wood pulp. Construction timber and green veneer are also important marketable products. Expansion of timber harvesting can be expected, and will have considerable influence on the economy of the State.

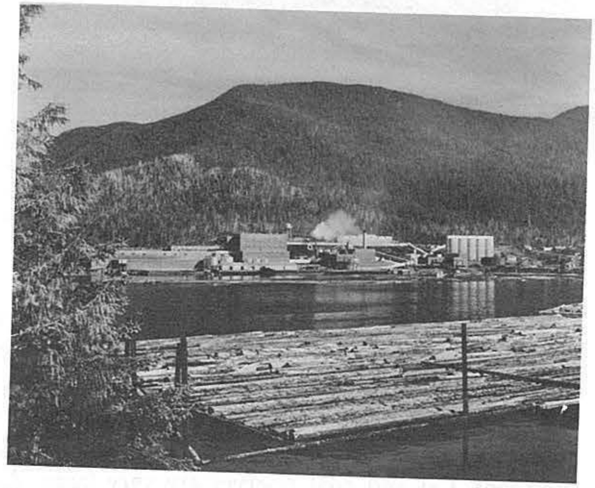
Two of Alaska's major resources are its rivers and its adjacent oceans. They support a substantial commercial seafood industry and are a basic asset to Alaska's fast growing tourist industry. Expansions of the fishery and tourist industries are likely to be important factors in the growth and development of the State. The potential for hydroelectric power development is discussed in chapter IV.

Income, Population, and the Economy

A steady increase in personal income is an indicator of the health of the economy. Although the population includes many native Alaskans who exist on marginal incomes, the average per capita personal income of all Alaskans rose from $2,842 in 1956 to $3,187 in 1965, $3,346 in 1966, and $3,430 in 1967, exceeding the average for the United States by more than 15 percent. The rate of increase in both employment and income supports an increasing rate of power consumption. This, in turn, suggests an ever-expanding market for electric appliances and equipment for farms, homes, businesses, and industries.

From 1880 to the start of World War II, the population of Alaska rarely exceeded 70,000. It reached a peak of about 225,000 in 1943. With the cessation of hostilities and withdrawal of many of the defense oriented personnel, the population decreased to about 100,000 in 1946. In 1950, the resident population stood at 138,000, of which approximately 20,500 were defense personnel. There has been no let-up in population growth since then. In 1960, 226,000 persons were in residence in Alaska, of whom about 47,500 were military personnel and their dependents. In a September 1968 news release, the Census Bureau reported that Alaska's resident population had reached 277,000—a 22 percent increase over 1960 and the greatest percent increase of any State.

Tidewater logging in southeast Alaska.



Log rafts await processing in the Pacific Ocean waters of Ketchikan, Alaska's pulp mill. Southeast Alaska's greatest natural resource—timber—surrounds this industrial site.

Average employment in nonagricultural activities was 77,200 in 1967, approximately 35 percent above 1960. Farmworkers have remained for some time at a level of about 650 persons. The Federal, State, and local governments are the largest employers (32,200 persons), and wholesale and retail trade establishments are the next largest (11,700). Construction and manufacturing employed a total of 12,800 while transportation employment was 7,400. Mining employment has risen from about 1,000 in 1965 to 2,000 in 1967.

Loans and investments increased more than 31 percent from around $175 million in 1963 to over $230 million in 1966. Public construction increased in the same period from an average of $100 million to $110 million. Federal contributions to Alaska's construction program have been substantial, ranging from 30 percent to over 60 percent of the total.

Although fisheries provide seasonal employment for more than 10,000 residents and 5,500 nonresident fishermen, in addition to over 8,700 cannery and wholesale workers, the average number employed fulltime is very low. Most of the approximately 24,000 seasonal fishery workers are not counted in computing average employment. This is true also for other seasonal activities. Expansion of the fishery industry to include harvesting and processing presently unexploited stocks in the Gulf of Alaska on a year-round basis would provide employment for a large number of these seasonal workers.

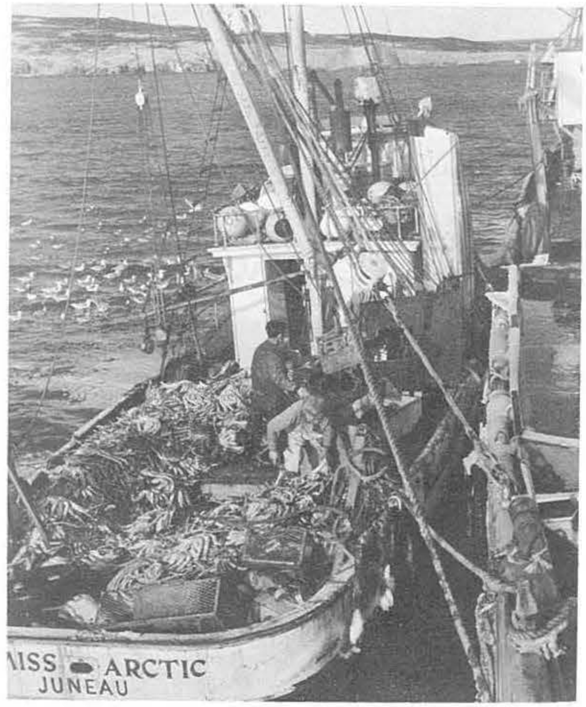
Present and Future Development

The activities which have and are likely to continue to shape Alaska's development are those concerned with national defense and with the development and exploitation of natural resources.

Expansion in the use of the State's timber resources, which are now only partially utilized, is expected to continue. Production of oil and gas is economically attractive and can be expected to increase; with it, certain manufacturing industries will develop, such as urea processing, ammonia, and compressed gas for shipment to foreign as well as domestic markets.

With salmon runs returning to their former size, and development of a substantial king crab market, a healthy expansion of the fishing industry is occurring in southeast Alaska and in the Gulf of Alaska as far as the Aleutians. Finally, in terms of input to the civilian economy and the number of persons which will be affected, the tourist business promises to become the largest single industry.

Extensive exploration for many of Alaska's solid minerals and significant expansion of mining operations appear to be some time off. However, the development of Alaska's large natural gas and petroleum resources and related petrochemical industries is expected to have the greatest impact on the economy. Improvement is needed in transportation facilities to gain access to large mineral deposits. Federal assistance in the development of adequate transportation is a necessity.



Alaska king crab is unloaded for processing at island community of Kodiak. The giant crustacean is taken from Alaska's gulf during the winter months, an otherwise-quieted season for northern fishermen.

Major improvements in price structure are needed to make economic activity in Alaska more competitive. The costs of basic services and facilities (transportation, electric power, and communications) must be reduced to make Alaska's economy strongly competitive nationally and internationally. Long-range economic development depends on establishing new trade patterns, such as trade with Japan and Canada.

CHAPTER II

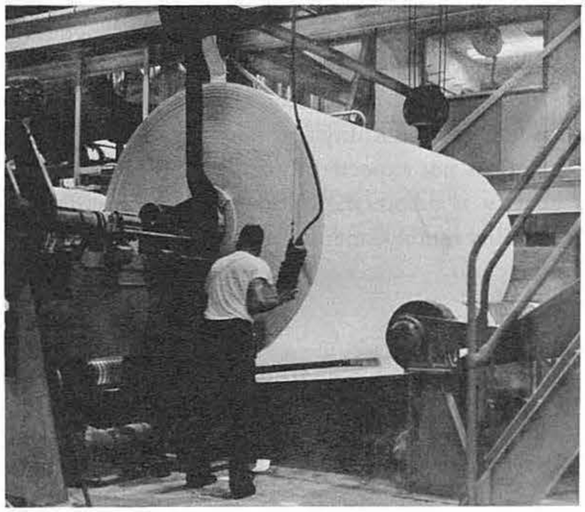
THE ELECTRIC POWER INDUSTRY TODAY

Alaska's electric power industry was oriented, originally, to mining and refining operations, fish canneries, lumber mills, trading posts, and the like. For many communities, industrial and commercial power installations were the only sources of electricity. Some of Alaska's present utility systems are derivatives of these earlier industrial and commercial enterprises.

This report considers the needs for both utility and nonutility electric power. Utilities are defined as those who generate, transmit, distribute, and sell electric energy. Nonutilities generate electric energy for their own use, such as for lumber and pulp mill operations, hospitals, schools, railroads, communication centers, and defense installations. A detailed tabulation showing generating-plant capacities for both utilities and nonutilities by types of prime mover, location, and ownership of record in 1965 forms appendix A of the report.

Water was first used to produce substantial amounts of power for a mining operation in 1882. For many years thereafter, no appreciable use was made of Alaska's hydropower potential. The first hydroelectric project of significant size began operation in 1901, and supplied electricity to the city of Ketchikan. Many of the original hydroelectric plants are still in operation, as are a number of steam-electric and internal-combustion engine generating units which were installed in the early 1900's.

During the twenties and thirties, electric generating capacity additions continued to be of modest size in keeping with the slow growth in utility and industrial power requirements. Power for Alaska's defense installations marked the beginning of a new demand for power in Alaska. During a subsequent 20-year period ending in 1965, electric utilities added capacity at an average rate of about 11,000 kilowatts per year, and total utility capacity at the end of the period was about 249,000 kilowatts.



Making a giant roll of paper-like pulp is the final stage of production for pulp mill processing at this plant near Sitka, Alaska.

It was 257,000 kilowatts in 1967. Approximately 60 percent of the capacity is located in the south-central region around Anchorage, and on the Kenai Peninsula.

The maximum buildup in generating capacity at defense installations occurred between 1955 and 1960. Since then, it has leveled off, standing now at about 207,000 kilowatts. Nonutility and nondefense capacity is approximately 61,400 kilowatts, the largest part of which is located in lumber and pulp mills in the southeast region. As of 1967, nonutility capacity (including defense) totaled 275,000 kilowatts. The general composition of capacity installed throughout Alaska from 1945 through 1967 is shown in table 1.

The electric generating capacity installed by Alaska utilities is shown on the map, figure 2, which locates the electric utilities and shows the extent of their dispersion. The major communities served by the various systems are listed in appendix A; however, there are a number of small communities and trading posts of fewer than 100 persons, such as Chitina (15 kw.), Hughes, Teller (30 kw.), Dot Lake (60 kw.), Lake Minchumina, Manley Hot Springs (48 kw.), Northway (480 kw.), and Rampart which have electric service. Complete data on these small sources of power are not available.

The electric power industry includes more than 50 separate utility systems. Their installed capacities range from less than 100 kilowatts to approximately 100,000 kilowatts. Nonutility electric facilities are widely distributed. Capacity installations range from a few kilowatts to 54,000 kilowatts.

Although total capacity is now about evenly divided between utility and nonutility segments, this balance is not expected to continue. Electric utility capacity is advancing, while capacity installed in nonutility establishments appears to have leveled off and could decrease as utility central station power becomes available at more attractive rates. The opportunities for coordination between utility and nonutility systems, and possibilities for serving eventually some portion of the nonutility loads from utility sources are discussed in chapter VI.

Ownership of Utilities

Alaska's electric power industry comprises four distinct ownership segments—private (investor owned), municipal, cooperative, and Federal. The largest segment is the cooperative group and more than half of the 58,821 retail customers in Alaska are served by Alaska's 15 cooperatively owned systems (table 2). As shown in table 3, 12 cooperatives owned generating plant in 1965 which accounted for 41 percent of the State's total electric

TABLE 1

Total Generating Capacity by Prime Mover Alaska Electric Power Industry

Items	1945 capacity (kw)	1950 capacity (kw)	1955 capacity (kw)	1960 capacity (kw)	1965 capacity (kw) [4]	Percent of total, 1965	1967 capacity (kw) [4]	Percent of total 1967
Utility capacity:								
Steam-electric [1]	10, 300	13, 800	27, 500	32, 500	32, 500	6	32, 500	6
Internal-combustion	3, 600	12, 080	25, 110	33, 550	59, 219	12	73, 335	14
Gas-turbine	0	0	0	0	74, 810	15	74, 810	14
Nuclear	0	0	0	0	0	0	0	0
Hydroelectric [2]	16, 880	20, 450	54, 400	59, 030	82, 300	16	76, 675	14
Total utility	30, 780	46, 330	107, 010	125, 080	248, 829	48	257, 320	48
Nonutility capacity: [3]								
Steam-electric		21, 500	41, 500	157, 350	140, 785	29	156, 660	29
Internal-combustion		8, 170	8, 170	59, 590	121, 739	22	115, 336	22
Gas-turbine		0	0	0	0	0	0	0
Nuclear		0	0	0	2, 000		2, 000	
Hydroelectric		2, 980	2, 110	1, 190	1, 197		1, 197	
Total nonutility capacity		32, 650	51, 780	218, 130	265, 721	52	275, 193	52
Summary—Utility and nonutility capacity:								
Steam-electric		35, 300	69, 000	189, 850	173, 285	35	189, 160	36
Internal-combustion		20, 250	33, 280	93, 140	180, 958	34	188, 671	35
Gas-turbine		0	0	0	74, 810	15	74, 810	14
Nuclear		0	0	0	2, 000		2, 000	
Hydroelectric		23, 430	56, 510	60, 220	83, 497	16	77, 872	15
Total installed capacity		78, 980	158, 790	343, 210	514, 550	100	532, 513	100

[1] Includes capacity of U.S. Smelting, Refining & Mining Co. which sold power to city of Fairbanks.

[2] Hydroelectric capacity installed in A. J. Industries (industrial) included; of late years output sold to utilities.

[3] Data incomplete for nonutilities for 1945.

[4] Coverage almost 100 percent compared with prior years.

installation. In contrast to the 48 States, where more than 75 percent of all generating capacity is privately owned, only 9.5 percent of retail customers in Alaska are served by private utilities.

As shown in table 3, only two utilities—one municipal and one cooperative—had energy requirements in 1965 of over 100 million kilowatt-hours and neither of these exceeded 200 million kilowatt-hours. The requirements of seven others ranged between 25 and 99 million kilowatt-hours.

Utility Electric Power Supply

By 1965, Alaska's electric utilities had developed 82,300 kilowatts of hydroelectric and 166,529 kilowatts of steam-electric, diesel, and gas-turbine capacity amounting to a total capacity in electric utility plants of 248,829 kilowatts. Between 1965 and 1967, 14,116 kilowatts of diesel capacity were added, but 5,625 kilowatts of hydroelectric capacity were destroyed in 1967 by the Fairbanks area flood. At the end of 1967, capacity in utility generating plants was 257,320 kilowatts, as shown in table 1.

The relative shares of energy produced by utility hydroelectric and thermal-electric generating sources for the years 1960 and 1965 are shown in figure 3. Hydroelectric plants produced almost two-thirds of the 381 million kilowatt-hours of total production in 1960. In 1965, all utility plants generated about 694 million kilowatt-hours, approximately 1.8 times the energy produced in 1960, but hydroelectric plants produced less than 47 percent of the total.

Alaska's single Federal hydroelectric plant of 30,000 kilowatts accounted for more than 73 percent

TABLE 2

Electric Utility Systems, Principal Operations and Retail Customers By Ownership Segment

(Systems of Record—1965)

Ownership	Total number systems	Number engaged in generation, transmission and distribution	Number engaged in generation, transmission and wholesaling	Generating capacity percent of total	Number engaged in distribution only	Retail customers served	
						Number	Percent
Private	15	11	3	12	1	5, 561	9. 5
Municipal	13	12	0	35	1	23, 471	40. 0
Cooperative	15	12	0	41	3	29, 789	50. 5
Federal	1	0	1	12	0	[1] 0	0
Total	44	35	4	100	5	58, 821	100. 0

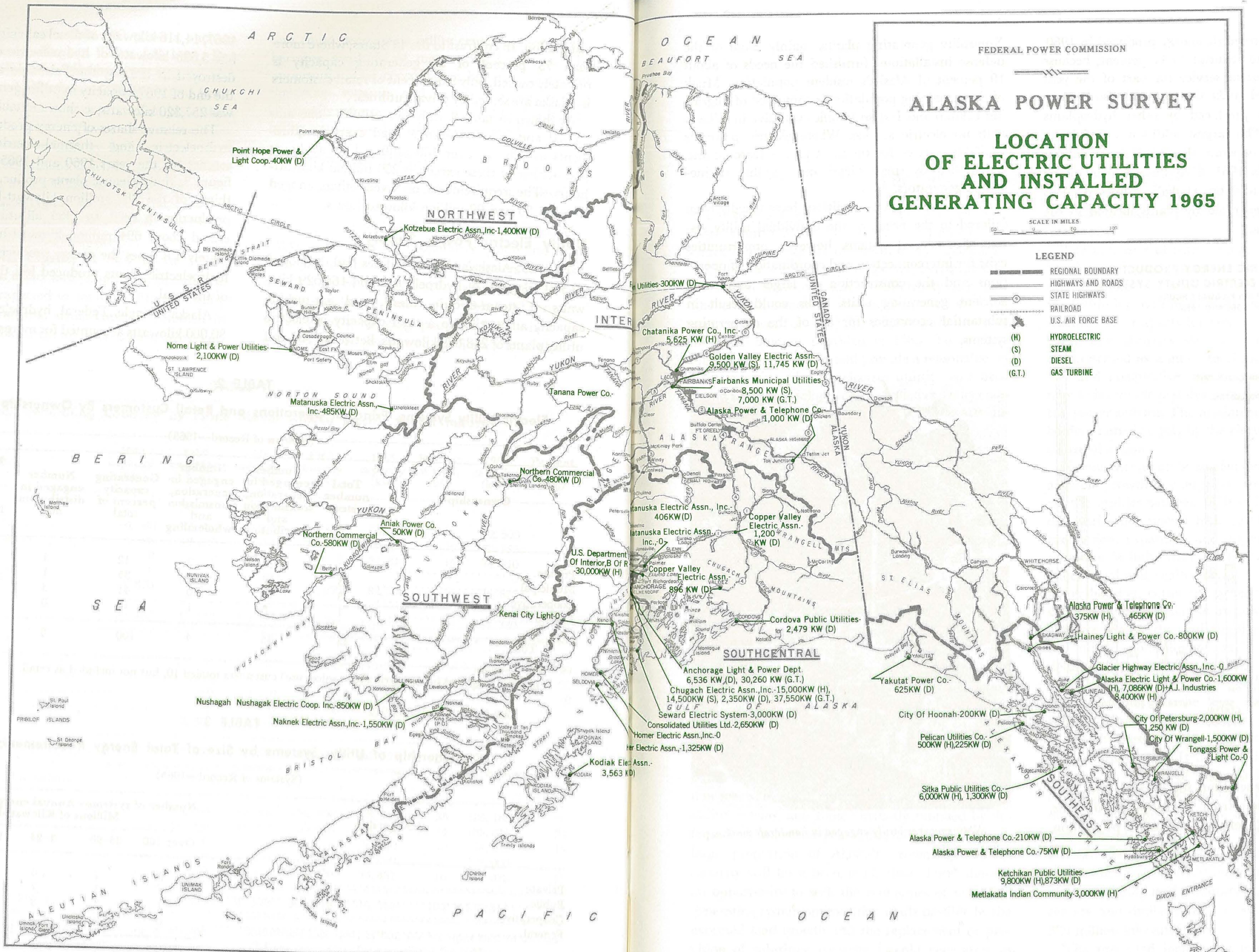
[1] Project camp and interdepartment (project use) customers totaled 10, but not included as retail.

TABLE 3

Ownership of Utility Systems by Size of Total Energy Requirements

(Systems of Record—1965)

Ownership	Number of systems—Annual energy requirements—Millions of Kilowatt-hours				
	Over 100	25–99	1–24	Under 1	Total
Private	0	1	6	8	15
Public	1	3	7	2	13
Cooperative	1	3	8	3	15
Federal	0	0	1	0	1
Total number	2	7	22	13	44



FEDERAL POWER COMMISSION
ALASKA POWER SURVEY
LOCATION OF ELECTRIC UTILITIES AND INSTALLED GENERATING CAPACITY 1965
SCALE IN MILES
LEGEND
REGIONAL BOUNDARY
HIGHWAYS AND ROADS
STATE HIGHWAYS
RAILROAD
U.S. AIR FORCE BASE
(H) HYDROELECTRIC
(S) STEAM
(D) DIESEL
(G.T.) GAS TURBINE
ARCTIC OCEAN
BEAUFORT SEA
CHUKCHI SEA
BERING SEA
PACIFIC OCEAN
GULF OF ALASKA
NORTHWEST
SOUTHWEST
SOUTHCENTRAL
SOUTHEAST
INTER
Point Hope Power & Light Coop.-40KW (D)
Kotzebue Electric Assn.,Inc-1,400KW (D)
Nome Light & Power Utilities-2,100KW (D)
Matanuska Electric Assn., Inc.485KW (D)
Northern Commercial Co.-480KW (D)
Aniak Power Co. 50KW (D)
Northern Commercial Co.-580KW (D)
Kenai City Light-0
Nushagah Nushagak Electric Coop. Inc.-850KW (D)
Naknek Electric Assn.,Inc.-1,550KW (D)
Kodiak Elec Assn.- 3,563 KD)
Tanana Power Co.-
Utilities-300KW (D)
Chatanika Power Co., Inc.- 5,625 KW (H)
Golden Valley Electric Assn.- 9,500 KW (S), 11,745 KW (D)
Fairbanks Municipal Utilities- 8,500 KW (S), 7,000 KW (G.T.)
Alaska Power & Telephone Co.- 1,000 KW (D)
Matanuska Electric Assn., Inc.- 406KW(D)
Matanuska Electric Assn. Inc.,-0-
U.S. Department Of Interior,B Of R- -30,000KW (H)
Copper Valley Electric Assn.- 896 KW (D)
Copper Valley Electric Assn.- 1,200 KW (D)
Cordova Public Utilities- 2,479 KW (D)
Anchorage Light & Power Dept. 6,536 KW (D), 30,260 KW (G.T.)
Chugach Electric Assn.,Inc.-15,000KW (H), 14,500KW (S), 2,350KW (D), 37,550KW (G.T.)
Seward Electric System-3,000KW (D)
Consolidated Utilities Ltd.-2,650KW (D)
Homer Electric Assn.,Inc.-0
Electric Assn.,-1,325KW (D)
Yakutat Power Co.- 625KW (D)
Alaska Power & Telephone Co.- 375KW (H), 465KW (D)
Haines Light & Power Co.-800KW (D)
Glacier Highway Electric Assn., Inc.-0
Alaska Electric Light & Power Co.-1,600KW (H), 7,086KW (D)+A.J. Industries 8,400KW (H)
City Of Hoonah-200KW (D)
Pelican Utilities Co.- 500KW (H),225KW (D)
City Of Petersburg-2,000KW (H), 1,250 KW (D)
City Of Wrangell-1,500KW (D)
Tongass Power & Light Co.-0
Sitka Public Utilities Co.- 6,000KW (H), 1,300KW (D)
Alaska Power & Telephone Co.-210KW (D)
Alaska Power & Telephone Co.-75KW (D)
Ketchikan Public Utilities- 9,800KW (H),873KW (D)
Metlakatla Indian Community-3,000KW (H)

Figure 2

of the total hydroelectric energy produced in 1960. In 1965, its share reduced to 41 percent, because the plant was out of service for part of the year for repair of earthquake damage and also because the total energy produced by other hydroplants had increased. The largest addition was from a 15,000 kilowatt cooperatively owned plant that began generating in 1961. Sixty-three percent of all the energy produced by Alaska's utilities in 1960 and 1965 was generated by plants located in the south-central area.

TOTAL ELECTRIC ENERGY PRODUCTION BY ALASKA ELECTRIC UTILITY SYSTEMS
MILLION KILOWATT-HOURS
1960 AND 1965

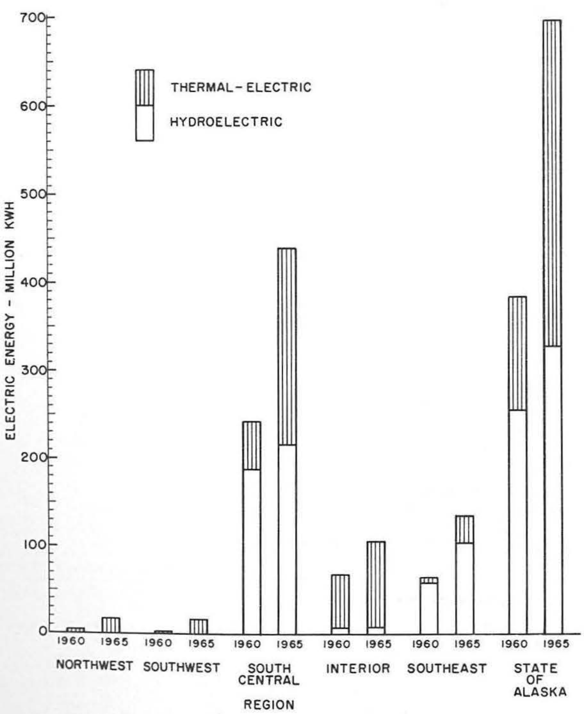


Figure 3

Utility plant generation, supplemented in some areas by generation from industrial installations, supplied about 62 percent of Alaska's population. Nonutility generating plants, mainly those of the defense installations, furnished the needs of about 19 percent of Alaska's resident population. Much of the remaining population is composed of migrating Eskimo and Indian families who live in villages with no electric service. Where electric power is available, service for the most part is seasonal and is supplied by small diesel and gasoline engine-driven generators.

Generating capacity additions have usually been tailored to the needs of the individual utility system. For several systems, however, opportunities exist for interconnection and coordination of operations and the construction of larger and more efficient generating units. This could result in substantial economies for all of the cooperating systems.

Native worker busily engaged in handcraft work.

CHAPTER III

PROSPECTS FOR LOAD GROWTH

The Survey's projection of the electric power industry's future foresees electricity as a prime energy source in the daily life of almost every Alaskan. By 1985 the State's economy is expected to require over 6.1 billion kilowatt-hours of electricity annually. The civilian sector of the economy will probably need in excess of 4.8 billion kilowatt-hours—6¾ times the amount provided in 1965. To produce this energy dependably and provide a reasonable reserve margin, Alaska's electric utilities will need about 1.3 million kilowatts of installed capacity compared with approximately 249,000 kilowatts installed in 1965.

Underlying the market projection for electric power is the assumption that the utilities will undertake in a thoroughly coordinated manner, the development of the most economical and reliable supplies of power, and will pursue the advantages of selling electric power at the lowest possible price. Doing so will open the way for an expanded application and use of electricity.

Alaska has the resources and mechanisms for supplying power to its more populated areas at costs which could be on a par with the lower levels of cost in the 48 States. By contrast with Alaska's higher average cost of living, its electric power will be an even greater bargain. Such possibilities are fundamental to appraising the opportunities for a greatly expanded power economy in the State.

This chapter presents estimates of electric power requirements through 1985 of the total electric power industry. Projections include both the loads now served by Alaska's privately and publicly owned utility systems, and those currently supplied by defense and industrial generating plants. By 1985, a large proportion of Alaska's present generating capacity will have become obsolete. Thus, there is an opportunity to seek the economies of scale and generating system optimization made possible by the expected load growth and the replacement or provision of substitute capacity for old generators in many existing plants. Utility central station service could become an attractive alternative to some existing sources.

The estimates of future power requirements are based on a careful study of past trends of power usage, economic growth and opportunities for the future inherent in Alaska's economy, and an assessment of prospects for changes in the nonutility loads. The estimates are not a precise forecast, but are presented as a guide to aid in the comprehensive and imaginative long-range planning needed now to insure the best development of Alaska's electric power systems. The attainment of this goal will be determined largely by the electric industry's own course of action.

No one factor can be singled out as the reason for a sixfold growth in energy requirements of Alaska's electric utilities between 1950 and 1965. Statehood, discoveries of mineral fuels justifying commercial production, expansion and improvement in transportation facilities with resulting lower costs, better educational and health services, increased incomes, better housing, better utility services, higher living standards, and population increases all contributed.

In addition to the loads supplied by Alaska's electric utilities, nonutility generating capacity supplies defense loads, and the industrial loads of the lumber and pulp mills, fish processing and cold storage establishments, and the like. Total load supplied from the larger industry-owned generating plants in 1965 has been estimated in the order of 240 million kilowatt-hours. It has remained at about this level for a number of years, and only a small increase is expected. The power requirements for most defense establishments were estimated to be over 302 million kilowatt-hours in 1960 and 360 million kilowatt-hours in 1965. Annual requirements of the many small and scattered industrial establishments, aircraft landing fields, military and communication centers, and similar loads are estimated to be about 320 million kilowatt-hours.

The projected increase in total electricity consumption by customers of the electric utilities from

1965 to 1975 is about 156 percent; from 1975 to 1985, approximately 162 percent. Over the 20-year span from 1965, the projected increase represents an average growth rate of approximately 10 percent. This corresponds quite closely with the 15-year actual rate of growth from 1950 to 1965, and provides a sound basis for the industry's long-range planning, but will require continued updating to keep it in line with the ever-changing circumstances of the industry's and Alaska's growth. The above projections reflect growth from 1965 rather than some later date because reports are obtained from many of the Alaska utilities only at 5-year intervals.

Population Patterns

The size of the population to be served at any location is an important factor in planning and developing a reliable and economic electric power supply. Population data and a description of population fluctuations during the World War II period have been given in chapter I.

Over one-fifth of the population is composed of the three-principal native groups—Eskimos, Aleuts, and Indians. The civilian population of Alaska grew at an annual average rate of about 5.2 percent from 1950 to 1960 period, compared with a growth rate of about 1.7 percent in the rest of the United States.

Before World War II, the largest population concentration, approximately 30 percent of the State's total, was in southeastern Alaska. By 1950, the population had shifted and was concentrated around Anchorage and on the Kenai Peninsula in south-central Alaska. During the next decade, this trend continued so that by 1960 over 43 percent of all persons resided in that area.

Population projections for geographic regions and for the State have been developed using the growth rate experienced since 1950, tempered by anticipated development in the durable and nondurable goods sector and expansion in tourist-oriented services. The projected 1985 total population of 550,000 reflects an annual growth of 3.9 percent, or almost 2½ times the anticipated growth rate of the remainder of the United States. It is, however, substantially lower than the 1950–60 growth rate of 5.2 percent.

The total population estimate of 550,000 is considerably higher than a projection of 400,000 made by the Bureau of the Census in October 1967. The estimate used here, however, was adopted by the Alaska Advisory Committee after detailed studies of specific situations in Alaska, and is believed by the Committee to represent a realistic view of probable population growth by 1985.

Estimates of the 1965, 1975, and 1985 population for the State and for each of the five regions are given in table 4. The locations of the areas of significant population concentration are keyed to numbered circles on the population and load center map, figure 4. By far, the largest concentration is in the south-central region. Most of the region's population is in and around the city of Anchorage, fanning southward through the Kenai Peninsula and northward into the Matanuska Valley area. The population in the south-central region was about 107,730 in 1965 and is estimated to be 270,540 in 1985. The population of the southwest region is the smallest. In 1965, it was about 3,630 and in 1985 will be about 6,670. The numbers residing on defense bases and in small scattered villages are given in the table as a total, not identified with specific areas and not shown on the map.

Metropolitan Anchorage, largest of Alaska's cities, boasts an increasing number of many-storied office, apartment, and hotel buildings.

Projection of Power Requirements

Electric power requirement projections for geographic regions and for the State were developed using guidelines established by the Federal Power Commission's Alaska Power Survey Advisory Committee. The Committee, in establishing guidelines, considered the growing petrochemical industry on the Kenai Peninsula, the rapidly growing tourist travel and recreational potential, the general pop-

TABLE 4

Alaska Resident Population—1965, 1975, 1985 Estimated

Geographic study region	Population and load center number	1965	1975	1985
Northwest	1, 2, 3	5, 600	7, 010	8, 400
Southwest	4, 5, 6	3, 630	5, 100	6, 670
Southcentral		107, 730	187, 260	270, 540
(a) Anchorage-Kenai	9, 10, 11, 12, 13	101, 840	178, 890	258, 690
(b) Other areas	7, 8, 14, 15	5, 890	8, 370	11, 850
Interior	16	25, 000	37, 500	56, 250
Southeast	17 through 24	35, 730	51, 500	72, 380
Total population of centers [1]		177, 690	288, 370	414, 240
Other civilian and on-base military population		108, 810	121, 630	135, 760
Total resident population		286, 500	410, 000	550, 000

[1] Excludes military and civilian population located on military bases.

ulation support services, the potential for developing a year-round fisheries industry in the Gulf of Alaska, the possible growth of mining and processing of mineral resources, and expansion of forest products industries, including manufacture of finished goods for domestic consumption.

Historic power requirement data assembled over the years by the Federal Power Commission were used to obtain guideline-related trends to set the course of the projections of the energy and peak demands for the future. The growth trend of Alaska electric utility loads from 1945 through 1965 is shown in figure 5. During this period, the growth rate was such that loads about doubled every 5½ years. Projections were correlated with the population estimates. Actual 1965 total annual energy requirements and peak demands and estimates for the years 1975 and 1985 are shown in the electric power requirements table 5. No estimates of power requirements were attempted for those utilities in small-scattered villages and in trade, communication, and airfield centers, the operations of which are, for the most part, seasonal or part time.

The smallest annual increase in power requirements—between 6 and 7 percent—is projected for the Southwest Region. This region is sparsely settled and its economy is presently dependent on fishing, with defense and communications offering some employment. Some minerals in the region have been exploited, such as those of the platinum group, but the overall mineral resources are of undetermined potential. Tourism is of minor, but growing importance, mainly for hunters and fishermen. There is no indication at the present time of any dramatic surge in the economy of the area, and load growth is expected to be relatively slow.

Until very recently, the Northwest Region seemed to be faced with conditions somewhat similar to those in the southwest. The principal differences were exploration and development of copper deposits at the Ruby Creek site, and oil and gas exploration on the Arctic Slope. Recent discoveries have led to speculation that the region may be one of the richest in petroleum reserves in the world. There is some thought that very rapid industrial and commercial expansion could accompany these developments and result in a similar expansion of the economy of the region. Under the most pessimistic outlook, these activities should provide some expansion of the economy along with the service-oriented tourism industry, and power needs may be expected to increase at a somewhat faster rate than in the southwest. There are enormous coal deposits in northwest Alaska which might be readily marketable in Japan if other developments should revolutionize the transportation facilities out of the Arctic region.

The Southeast Region's economy is expected to undergo a relatively steady rate of growth. The region already has well-developed and thriving fishery and forest product industries, which are expected to continue, and in the case of forest prod-

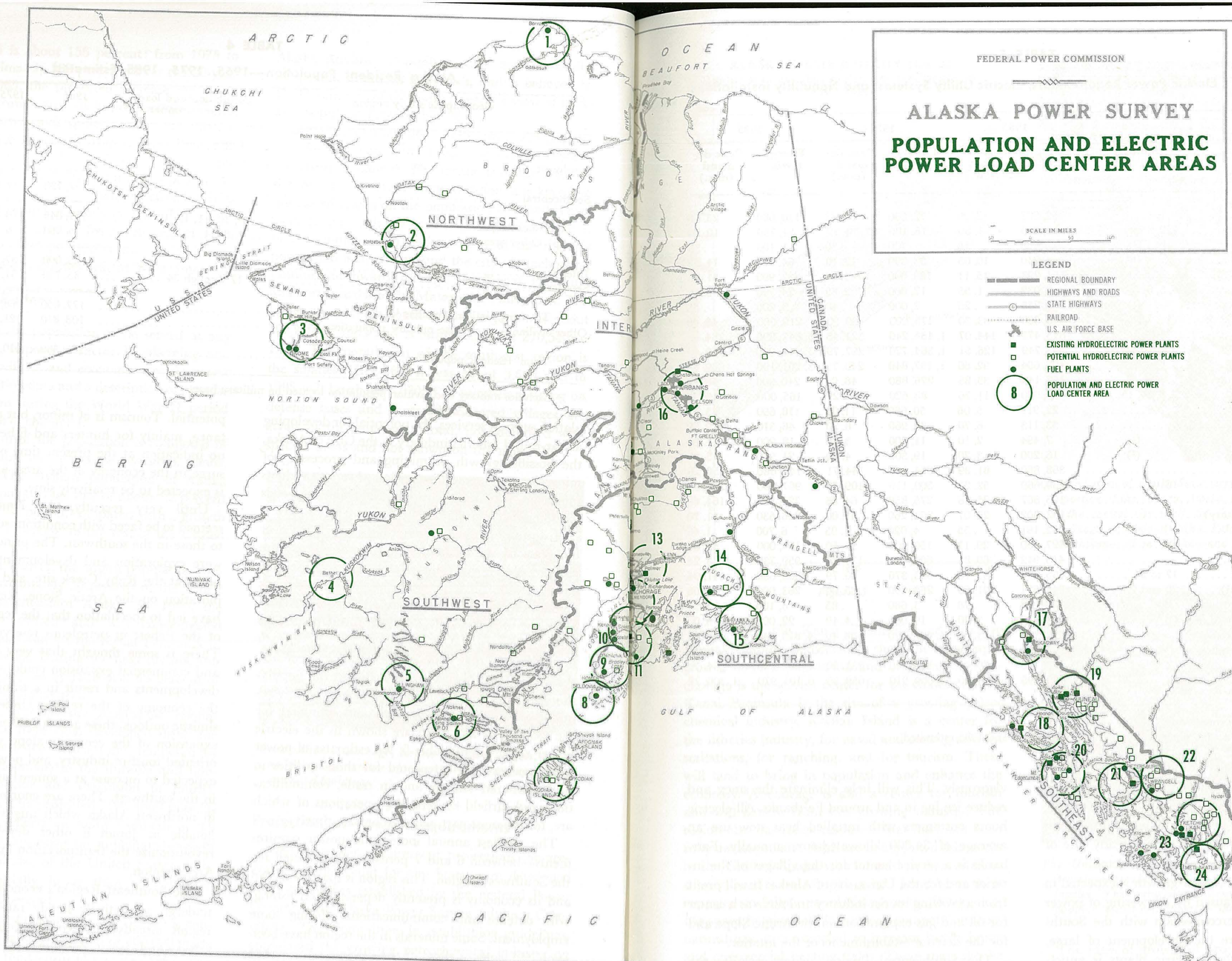

FEDERAL POWER COMMISSION
ALASKA POWER SURVEY
POPULATION AND ELECTRIC POWER LOAD CENTER AREAS
SCALE IN MILES
LEGEND
REGIONAL BOUNDARY
HIGHWAYS AND ROADS
STATE HIGHWAYS
RAILROAD
U.S. AIR FORCE BASE
EXISTING HYDROELECTRIC POWER PLANTS
POTENTIAL HYDROELECTRIC POWER PLANTS
FUEL PLANTS
POPULATION AND ELECTRIC POWER LOAD CENTER AREA
NORTHWEST
SOUTHWEST
SOUTHCENTRAL
SOUTHEAST
ARCTIC OCEAN
BEAUFORT SEA
CHUKCHI SEA
BERING SEA
NORTON SOUND
BRISTOL BAY
GULF OF ALASKA
PACIFIC OCEAN
ALEUTIAN ISLANDS
ALEXANDER ARCHIPELAGO
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Figure 4

TABLE 5

Projection of Alaska's Electric Power Requirements, Electric Utility Systems, and Nonutility Installations

Region and type of load	Load center number (fig. 4)	1965 Energy mwh.	1965 Peak demand (mw.)	1975 Energy mwh.	1975 Peak demand (mw.)	1985 Energy mwh.	1985 Peak demand (mw.)
Northwest		52, 927	12. 09	72, 690	16. 52	110, 680	25. 19
Utility	1, 2, 3	8, 219	1. 86	18, 100	4. 12	44, 790	10. 24
Do	(1)	468	. 18	700	. 30	1, 100	. 35
Nonutility	(1)	44, 240	10. 05	53, 890	12. 10	64, 790	14. 60
Southwest		154, 293	35. 11	189, 800	43. 15	237, 990	51. 06
Utility	4, 5, 6	7, 038	1. 55	12, 800	2. 85	24, 790	5. 51
Do	(1)	1, 255	. 26	2, 000	. 40	3, 200	. 55
Nonutility	(1)	146, 000	33. 30	175, 000	39. 90	210, 000	45. 00
Southcentral		643, 473	144. 07	1, 484, 240	324. 48	3, 647, 890	784. 94
Anchorage-Kenai	9 to 13	563, 749	126. 51	1, 364, 720	297. 79	3, 442, 090	739. 49
Utility		406, 604	92. 66	1, 137, 840	249. 79	3, 201, 190	689. 49
Nonutility (military)		157, 145	33. 85	226, 880	48. 00	240, 900	50. 00
Other areas	7, 8, 14, 15	56, 030	11. 76	88, 620	19. 29	165, 000	35. 85
Utility		22, 917	5. 06	50, 660	11. 09	118, 690	25. 95
Nonutility		33, 113	6. 70	37, 960	8. 20	46, 310	9. 90
Utility	(1)	7, 494	2. 10	11, 600	3. 00	18, 900	4. 60
Nonutility	(1)	16, 200	3. 70	19, 300	4. 40	21, 900	5. 00
Interior		368, 860	81. 89	654, 130	144. 71	1, 145, 680	256. 29
Fairbanks	16	239, 669	52. 23	500, 110	109. 26	967, 980	215. 89
Utility		106, 867	25. 16	275, 850	64. 26	721, 350	164. 69
Nonutility (military)		132, 802	27. 07	224, 260	45. 00	246, 630	51. 20
Utility	(1)	2, 191	. 55	4, 020	. 95	6, 700	1. 40
Nonutility	(1)	127, 000	29. 11	150, 000	34. 50	171, 000	39. 00
Southeast		419, 942	69. 84	609, 050	111. 04	959, 730	183. 24
Utility	17 to 24	155, 023	33. 76	323, 370	70. 79	668, 630	141. 94
Nonutility (industrial)	20 and 23	246, 621	31. 60	263, 000	35. 00	263, 000	35. 00
Utility	(1)	2, 298	. 78	3, 680	. 85	6, 100	1. 30
Nonutility	(1)	16, 000	3. 70	19, 000	4. 40	22, 000	5. 00
Total utility requirement		720, 374	163. 92	1, 840, 620	408. 40	4, 815, 440	1, 046. 02
Total nonutility requirement		919, 121	179. 08	1, 169, 290	231. 50	1, 286, 530	254. 70
Total Alaska		1, 639, 495	343. 00	3, 009, 910	639. 90	6, 101, 970	1, 300. 72

[1] Scattered nonload center loads.

NOTE.—1965 utility actual, nonutility partly estimated; 1975 and 1985 estimated.

ucts to expand. Tourism is expected to become increasingly significant. None of these activities, however, is expected to result in marked upsurges in the region's economy, and thus a steady rate of growth in power requirements is predicted.

A somewhat higher rate of growth is expected in the Interior Region caused by a lowering of power costs through an interconnection with the Southcentral Region, where the development of large, low-cost, gas-fired, steam-electric plants is anticipated. Electric space heating is being promoted vigorously. This will help eliminate the smog and reduce ice fog in and around Fairbanks. All-electric home customers with installed heat now use an average of 34,000 kilowatt-hours annually. Fairbanks is a service center for the villages of the interior and for the University of Alaska. It will profit from a growing tourist industry and serve as a center for oil and gas exploration on the Arctic Slope and for the defense establishments of the interior.

The Southcentral Region, which includes the greater Anchorage borough, the growing com-

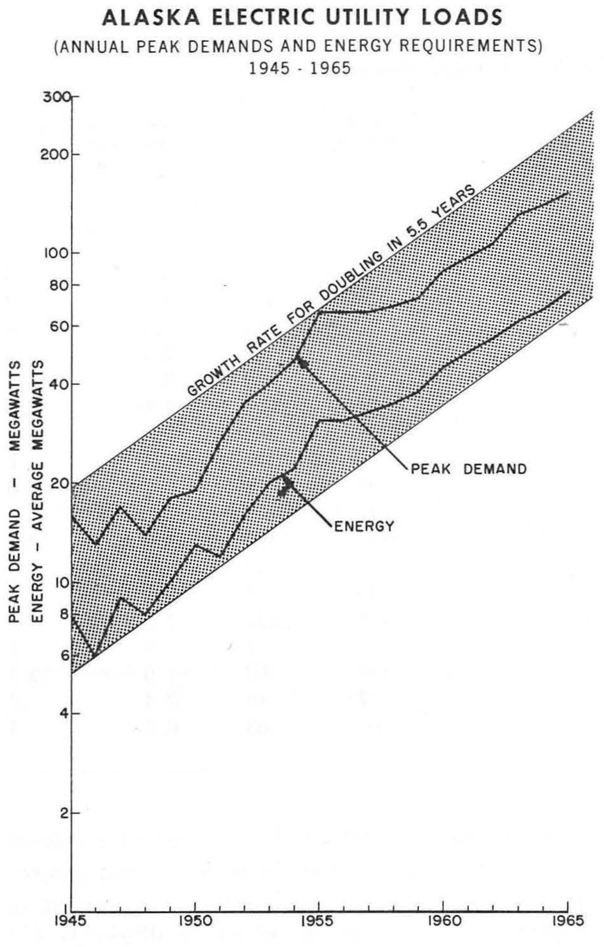
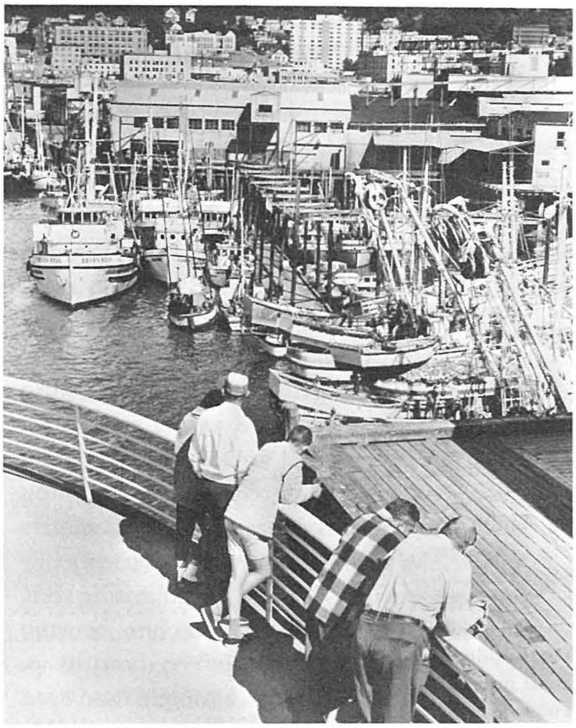


Figure 5



Over the stern of Alaska State ferry, visitors peer down on a portion of the Juneau, Alaska, fishing fleet and beyond it the capital city itself. Southeastern ferries also call at Skagway, Haines, Sitka, Petersburg, Wrangell, and Ketchikan—all in Alaska—and Prince Rupert, B.C.

munities on the Kenai Peninsula and offshore Kodiak Island, is expected to show the most rapid growth both in population and in power use. Anchorage is the service center for the State, and the Kenai Peninsula is the site of a growing petrochemical industry. Kodiak Island is a center for the fisheries industry, for naval and coast guard installations, for ranching, and for tourism. These will tend to bring in population and enhance the economy. Anchorage is also a center for tourism and will benefit from this growing industry. The region also has forest resources that have not been fully developed and there are unexploited fish stocks in the Gulf of Alaska which could be harvested to supply year-round employment. Load growth is expected to follow population growth. While electric space heating will face strong competition from natural gas, it is expected to increase in the home and commercial heating fields. There may also be limited applications for cooling and humidity control in the summer.

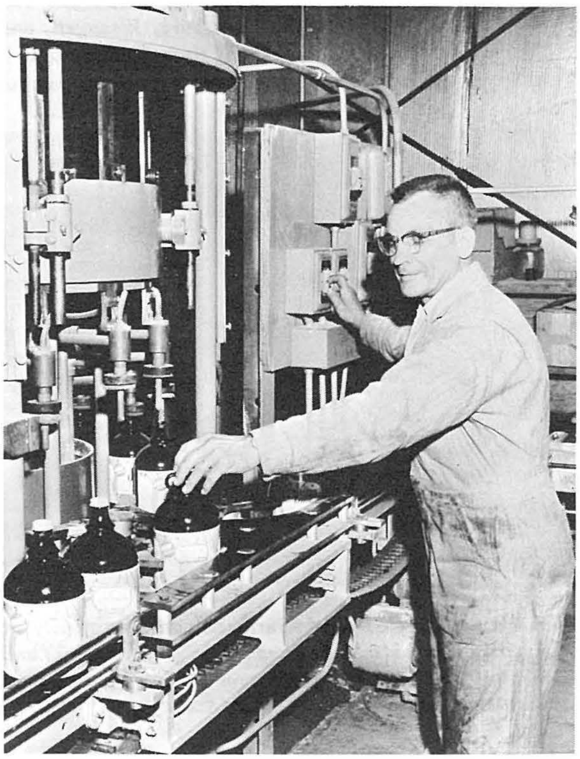
The University of Alaska—farthest north university in America—provides accredited educational facilities and faculty. The university museum is one of the most popular tourist attractions in the State.

The rates of growth of projected power requirements for each of the five regions are presented in table 6.

TABLE 6

Rates of Increase in Alaska Electric Energy Requirements

Geographic Region	Increase in generation (percent)		Average annual rate of increase (percent)	
	1965–75	1975–85	1965–75	1975–85
Northwest	37	52	3. 2	4. 3
Utility	117	144	8. 1	9. 3
Nonutility	22	20	2. 0	1. 9
Southwest	23	25	2. 1	2. 3
Utility	79	89	6. 0	6. 6
Nonutility	20	20	1. 8	1. 8
Southcentral	131	146	8. 8	9. 4
Utility	175	178	10. 5	10. 6
Nonutility	38	9	3. 3	. 9
Interior	77	75	5. 9	5. 8
Utility	156	160	9. 9	10. 1
Nonutility	44	12	3. 7	1. 2
Southeast	45	58	3. 8	4. 7
Utility	108	116	7. 6	8. 0
Nonutility	7	1	. 9	. 1
Total utility	156	162	9. 9	10. 1
Total nonutility	27	10	2. 4	. 9
Total Alaska	84	103	6. 3	7. 4



Alaska-made chemicals are manufactured by this Anchorage producer. Most of the several products made here are sold and utilized within the State.

Many factors and forces in Alaska's economy account for the variation in regional load projections. The prospects for increases in population support services and industrial employment are unique to each region. Where opportunities exist, the broadening of the manufacturing base to supply a greater share of goods for domestic use, and possibilities for the development of forest, fishery, water, and mineral resources were additional factors considered.

In projecting an almost sevenfold growth in electric power consumption between 1965 and 1985, the Alaska Power Survey is not simply charting the electric utility industry's growth potential. Implicit in this growth projection is a rise in the total civilian per capita consumption of electricity from about 1,060 kilowatt-hours in 1950 to 3,100 kilowatt-hours in 1965 and 9,700 kilowatt-hours in 1985. Expressed in relation to personal income the increase is from 0.37 kilowatt-hour of electricity per dollar of income in 1950 to 0.64 in 1965. In 1985, assuming that total personal income will increase at the 1950–65 rate of about 6.5 percent per annum, the kilowatt-hour consumed per dollar of income will be 1.34. During the 1945–65 period, the annual average growth rate of electricity use was nearly 1⅔ that in the 48 States.

Electric Power Markets

A breakdown of the energy requirement projection into major use categories, as shown in table 7, suggests the industrial energy usage doubling every 4.7 years. A more detailed tabulation of the annual electric power requirements by major use categories at 5-year intervals from 1950 to 1985 is shown in appendix B of the report.

The largest energy use is expected to lie in the residential category, doubling about every 8 years. Much of this is expected to come from increased use of electricity for space heating.

TABLE 7

Projected Increase in Electric Energy Requirements, by Categories of Use, Electric Utilities 1985

Category of use	Millions of kilowatt-hours increase over 1965	20-year average annual rate percent	Number of years to double usage
Residential (nonfarm)	1, 428	9. 4	7. 9
Farm [1]	20	8. 4	8. 8
Commercial	656	6. 9	10. 7
Industrial	1, 285	15. 6	4. 7
Other uses [2]	291	10. 2	7. 2
Losses and unaccounted for	415	9. 9	7. 5
Total	4, 095	10. 0	7. 4

[1] Includes relatively small percentage of irrigation and drainage pumping usage.

[2] Includes uses for municipal water pumping, oil and gas pipeline pumping, street and highway lighting, heating and power usage in public buildings, transportation, and all ultimate consumption usages not elsewhere classified.

Although commercial power usage in 1965 was second to residential, about 33 percent of the total, commercial requirements by 1985 will be in third place. Street and highway lighting and other usages are small, but are growing.

In long-range projections of electric power usage, it is difficult to predict the effect of new product developments. New uses have come into being and have created levels of consumption far higher than were thought possible only a few years ago. Today, household uses of electricity are manifold. In the next 20 years, technological advances can be expected to create new applications and bring about improvements in techniques which will provide methods of using electricity in ways not generally known or available today.

The projections for residential nonfarm electric utility customers assume a rise in average annual consumption of electricity from about 5,670 kilowatt-hours in 1965 to 14,000 in 1985. In many areas of other States, the present usage is already well over 10,000 kilowatt-hours.

Alaska's industrial electric-load growth is projected at 15.6 percent per year. The industrial market for power is expected to capture approximately 28 percent of total generation by electric utility systems in 1985, compared with about 10 percent in 1965. Whether this rate of growth is attained will depend on the success with which extraction and processing of Alaska's mineral resources are pursued, and on increases in manufacturing capacity to produce finished products which heretofore have been imported. The projection is not unreasonable, however, considering that manufacturing now requires over 40 percent of the power sold in the 48 States.

For the "flyingest State" in the United States, this Anchorage manufacturer produces airplane skis for use on the winter snow.

The commercial category of total electricity use has historically covered a multitude of services, some of which could be classed as small industrial functions. Load growth in the commercial market for power is projected at 7 percent per year. The estimates allow for an accelerated expansion of lighting and electric space heating, much more electric office equipment of all kinds, the growth of electric cooking in restaurants and institutions, greater use of outdoor signs, display lighting, lighting of recreational areas, and snow removal from business areas. Coupled with these uses is the anticipated construction of large numbers of all-electric hotels and motels. Low-electric rates will also be an incentive to modernize existing accommodations for use on year-round basis which should do much to improve the annual load factor of the Alaska power industry.

The power requirements of Alaska's growing goods and services industry have always been comparatively large, and comprise a substantial percentage of the utilities' total loads. The projections foresee for 1985 an increase of some 656 million kilowatt-hours over 1965 in this category. Although its projected share of the total Alaska market will be less than it was in 1965, the expectation that it will amount to almost 19 percent of total electrical requirements compares favorably with present commercial usage in the 48 States.

Utility Load Shapes and Diversity

A plot of the annual loads of Alaska's major electric utility systems resembles a hammock swung between January and December, maximum loads being experienced in the latter month.

Because of load growth, January peaks have usually been about 10 percent less than those occurring in the following December. From January, loads gradually fall off to minimum levels in June through August, about 65 percent of the December peaks. After August they climb sharply to their December maximums.

Load diversity occurs when loads on two or more power systems occur at different times. Diversity can be shared by interconnecting the systems and coordinating planning and operations. Thus, total capacity needed in the interconnected supply can be minimized by each system supplying a part of the peak load of the other.

Although no observable seasonal diversity exists in Alaska, two other kinds of diversity do exist—time zone and random. Since there are four time zones in Alaska, Panhandle loads peak one hour before the Yakutat area load, 2 hours ahead of loads in the vast central area, and 3 hours ahead of loads in the westernmost areas bordering the Bering Sea. Due to lack of zone-to-zone interconnections, however, there is no way at present to utilize time-zone diversity, nor does it appear that time-zone interties will be established during the survey period. The random diversity category includes all differences in timing and magnitude of loads, other than those attributable to seasonal or time-zone characteristics. It results from hour-to-hour and day-to-day load changes as affected by daylight, temperature cycles, living habits, kinds of industry, work schedules, and the like.

Some degree of random diversity exists within time zones. For example, in the Alaska standard time zone, there is evidence that the winter evening loads on the two largest systems serving the Anchorage-Kenai area peak 1 or 2 hours apart. Peak loads of the two systems in the Fairbanks area differ by an hour or more from the Anchorage peaks.

During summer months, peak loads on the Anchorage Municipal System have been experienced at noon or earlier, whereas the Chugach Electric Association, whose geographical service area is more extensive, experienced 6 o'clock evening peaks. In the Fairbanks area, the municipal system summer loads have consistently peaked from around 4 p.m. to 6 p.m. The Golden Valley Electric Association system has peaked rather erratically—sometimes before noon, at other times in the early afternoon and evening hours.

Available evidence indicates that random diversity exists. A detailed study of load pattern variations over an extended period of time would be required to establish the magnitude of load diversity and determine with some assurance whether it would continue to exist in future years.

Where significant diversity exists, sizable benefits can be achieved through coordinated planning for new capacity, local interties, and systems interconnections. Opportunities for bridging the Anchorage and Fairbanks areas are discussed in subsequent chapters.

Nonutility Growth Prospects

Projections of the future power requirements for nonutility establishments are more speculative than those in the utility category. Alaska's large nonutility power industry has found it advantageous to operate its own plants, particularly at some isolated locations or where there were opportunities to utilize low-temperature steam from a power turbine for heating or processing purposes. At many locations, no central station utility electric service is presently available. Therefore, no appreciable percentage of nonutility load could be transferred to utility power sources in the near future. Where utility service is available at attractive rates, however, or will be as system expansions progress, it is reasonable to expect that some of these nonutility loads will be transferred to central station sources of supply as an alternative to replacing old and obsolete installations. As shown in table 5, growth rates for nonutility loads are expected to be significantly lower than those of the utilities. By 1985, the nonutility power requirements are expected to be only about 20 percent of the total.

Consumer Power Costs

Any discussion of the prospects for growth in Alaska's electric utility industry would be incomplete without an appraisal of the costs to supply power to the ultimate consumer. Consumer rates for electricity are usually based on generation, transmission, and distribution costs—fixed and variable or operating components. The fixed cost component is made up of constant annual charges essentially unaffected by the number of kilowatt-hours generated. The variable expense component consists largely of the costs of fuel, operation and maintenance labor, material, and administrative and general expenses.

The percentage relationships between the cost components for Alaska systems are noticeably different from their counterparts in most of the United States, reflecting in part the predominance of publicly-owned utilities. Operating expenses are higher, and the generation function bears a much greater share of the total cost. The relative percentages of cost assignable to each function, based on currently available costs, are given in table 8.

Many factors operate to produce differences in electric power costs and consumer bills. Differences lie in production and distribution costs, and are affected by the proximity of the generating station to low-cost fuel, water, and loads served; type and sizes of generating units; customer density; utility ownership and management practices; effectiveness of regulatory bodies, and the like. It is important to note that where retail rates are substantially below average in the United States, the power supply sources are all hydroelectric or are a part of an integrated system with large thermal-electric generating sources.

Major reasons for high electric rates in many parts of Alaska, and in other States as well, are high labor costs and fuel prices, relatively small and inefficient generating units, low load densities owing to small population concentrations, the absence of developed hydroelectric power, and lack of a strong regulatory system.

The long-term trend in rates for residential service has been downward in most Alaska communities as well as in other parts of the United States. For the Anchorage-Spenard area, for example, with its relatively large population served by municipal and a cooperative system, the average cost for 100 kilowatt-hours per month was \$6.93 in 1948; \$4.75 in 1958; \$4.30 in 1966; and \$4.28 in 1968. The bill for a monthly usage of 500 kilowatt-hours—energy for lighting, refrigeration, cooking, other household appliances, and water heating—was \$17.08 in 1948; \$14.50 in 1958; \$12.95 in 1966; and \$12.35 in 1968.

In less populated areas and those remote from low-cost fuel or water power, and where transportation and labor prices are highest, rates are higher.

TABLE 8

Total Delivered Cost of Power—Composition in Percent

Function	Alaska			Contiguous States		
	Fixed cost	Operating expense	Total cost	Fixed cost	Operating expense	Total cost
Generation	17	51	68	28	23	51
Transmission	3	1	4	8	2	10
Distribution	12	16	28	23	16	39
Total	32	68	100	59	41	100

But as in the Anchorage area, rate reductions have been made by many systems over the years. At Fairbanks, an area served by municipal and cooperative systems, the 1968 bills for 100 kilowatt-hours and 500 kilowatt-hours were $7.50 and $25 (in 1948 the bills were $9 and $33). At some locations, there have been rate increases. For example, at Kodiak City, the 1968 typical bills for 100 and 500 kilowatt-hours were $9.15 and $24.65 (in 1948 the bills were $8 and $24.10), respectively. Until recently, electric bills for residential service in Ketchikan, served by Ketchikan Public Utilities, were Alaska's lowest. The 1968 bill for 100 kilowatt-hours was $4.60; for 500 kilowatt-hours, $12.03 (in 1948 they were $4.50 and $9.50). In southeastern Alaska communities where hydroelectric generation exists and fuel prices are less, bills have been consistently 25 to 60 percent lower.

Decreases in bills have usually reflected changes in fuel costs, taxes, surcharges, amortization charges, or rate brackets.

The geographic pattern of spread in retail rates in effect January 1, 1968, is indicated by the bills for residential, commercial, and industrial service computed for Alaska communities of 2,500 population or more. These are shown in table 9 (residential), table 10 (commercial), and table 11 (industrial). It is noted that each increment of increased use involves a lower unit cost which is possible because the kilowatt-hour cost becomes less as more electricity is used.

As energy usage increases, use of lower rate blocks reduces average costs per kilowatt-hour. For example, the average cost per kilowatt-hour for Anchorage and Spenard for a 100 kilowatt-hour per month residential usage is 4.275 cents; for a usage of 500 kilowatt-hours per month, the cost per kilowatt-hour is 2.47 cents. For Ketchikan, the average

TABLE 9

Typical Monthly Electric Bills, Residential Service—Jan. 1, 1968

Community	Population	Minimum bill Amount		100 kwh.[1]	250 kwh.[2]	500 kwh.[3]	750 kwh.[3]	1,000 kwh.[3]	Utility Serving Community
Anchorage	44, 237	$2. 00	36	$4. 25	$8. 75	$11. 75	$14. 75	$17. 75	Anchorage Municipal Light & Power Department.
Do		2. 00	36	4. 30	8. 95	12. 95	16. 95	20. 95	Chugach Electric Association Inc.
Chugiak Eagle River	2, 500	5. 00	72	6. 25	13. 00	19. 25	25. 50	31. 75	Matanuska Electric Association Inc.
Fairbanks	13, 311	1. 80	22	7. 50	15. 00	22. 50	30. 00	37. 50	Fairbanks Municipal Utilities System.
Do		5. 00	50	7. 50	15. 00	25. 00	32. 50	40. 00	Golden Valley Electric Association Inc.
Juneau	6, 797	3. 00	60	5. 00	10. 00	14. 40	20. 15	25. 90	Alaska Electric Light & Power Company
Ketchikan	6, 483	3. 00	20	4. 60	7. 60	12. 03	15. 50	18. 63	Ketchikan Public Utilities.
Kodiak	2, 628	3. 00	27	9. 15	15. 25	24. 65	34. 00	43. 40	Kodiak Electric Association Inc.
Sitka	3, 237	5. 00	100	5. 00	11. 00	19. 00	24. 40	28. 40	Sitka Public Utilities.
Spenard	9, 074	2. 00	36	4. 25	8. 75	11. 75	14. 75	17. 75	Anchorage Municipal Light & Power Department.
Do		2. 00	36	4. 30	8. 95	12. 95	16. 95	20. 95	Chugach Electric Association, Inc.

[1] Lighting, small appliances and refrigeration.
[2] Lighting, appliances, refrigeration, and cooking.
[3] Lighting, appliances, refrigeration, cooking, and water heating.

TABLE 10

Typical Monthly Electric Bills, Commercial Service—Jan. 1, 1968

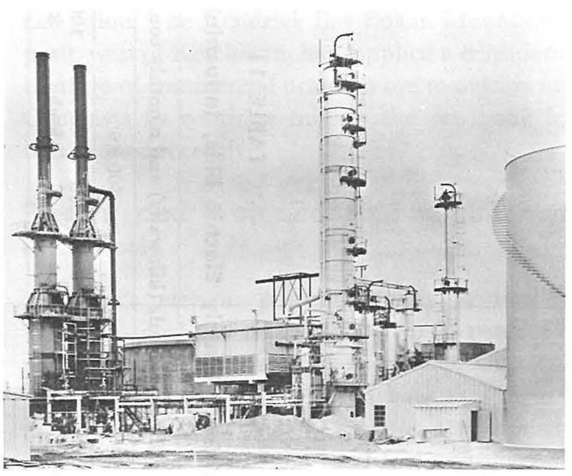
Community	Billing Demands (kilowatts) and Monthly Consumptions (kilowatt-hours)					Utility Serving Community
	3.0 kw. 375 kwh.	6.0 kw. 750 kwh.	12.0 kw. 1,500 kwh.	30.0 kw. 6,000 kwh.	40.0 kw. 10,000 kwh.	
Anchorage [1]	$12.16	$21.16				Anchorage Municipal Light & Power Department
Do [2]			$44.64	$138.60	$211.05	
Anchorage	13.00	23.50	47.00	176.00	268.00	Chugach Electric Association, Inc.
Fairbanks [3]	24.00	44.00	76.50			Fairbanks Municipal Utilities System
Do [4]			81.60	294.00	452.00	
Fairbanks	30.00	49.50	82.00	252.00	372.00	Golden Valley Electric Association, Inc.
Spenard [1]	12.16	21.16				Anchorage Municipal Light & Power Department
Do [2]			44.64	138.60	211.05	
Spenard	13.00	23.50	47.00	176.00	268.00	Chugach Electric Association, Inc.

[1] Rate schedule 21.
[2] Rate schedule 23.
[3] Rate schedule B1.
[4] Rate schedule B2.

cost per kilowatt-hour for a 100 kilowatt-hour per month usage is 4.6 cents; for 500 kilowatt-hours, it is 2.41 cents.

Trends in rate reductions for commercial service have been generally the same as residential. Large usage customers classified as industrial and billed accordingly are not numerous in Alaska. Only in a few cases is electric power sold wholesale for resale, and special terms and conditions usually apply in such instances.

While further reductions in rates can be expected as operational improvements are instituted, the promise for significant reductions throughout the whole rate spectrum is brightest for utilities serving the Railbelt area. It is here that the largest load growth is projected and where the greatest benefits of an interconnection between the Anchorage and Fairbanks load centers would be expected.



Alaska's first oil refinery at Kenai on the Kenai Peninsula processes oil produced from 49th State wells. Most of the final product is sold for use in Alaska.

TABLE 11

Typical Monthly Electric Bills, Industrial Service—Jan. 1, 1968

Community	Billing demands (kilowatts) and monthly consumption (kilowatt-hours)										Utility Serving Community
	75 kw.		150 kw.		300 kw.		500 kw.		1,000 kw.		
	15,000 kwh.	30,000 kwh.	30,000 kwh.	60,000 kwh.	60,000 kwh.	120,000 kwh.	100,000 kwh.	200,000 kwh.	200,000 kwh.	400,000 kwh.	
Anchorage [1]	$338	$523	$662	$1, 033	$1, 310	$2, 052	$2, 174	$3, 411	$4, 334	$6, 809	Anchorage Municipal Light & Power Department
Do [2]					977	1, 436	1, 598	2, 363	3, 150	4, 680	
Do [3]	380	642	740	1, 243	1, 447	2, 436					Chugach Electric Association Inc.
Do [4]							1, 723	2, 548	3, 397	5, 046	
Fairbanks	735	1, 185	1, 470	2, 370	2, 940	4, 740	4, 900	7, 900	9, 800	15, 800	Fairbanks Municipal Utilities system.
Spenard [1]	338	523	662	1, 033	1, 310	2, 052	2, 174	3, 411	4, 334	6, 809	Anchorage Municipal Light & Power Department.
Do [2]					977	1, 436	1, 598	2, 363	3, 150	4, 680	
Do [3]	380	642	740	1, 243	1, 447	2, 436					Chugach Electric Association Inc.
Do [4]							1, 723	2, 548	3, 397	5, 046	

[1] Rate schedule 23. [2] Rate schedule 22. [3] Large power schedule. [4] Large power 42.

CHAPTER IV

FUELS AND THERMAL-ELECTRIC GENERATING PLANTS

Alaska is not lacking in raw fuel resources, but natural gas and coal are the only ones produced in quantity and processed locally for use in Alaska. Thus far, the major exploitation of mineral fields has been in the Interior and Southcentral Regions. Alaska's oil and gas industry has been through cyclic stages of development since about 1902. The Swanson River field on the Kenai Peninsula, south of Anchorage, came into production in 1957, and the first refinery was built in 1963. Production from its 20,000 barrel per day crude oil capacity is limited to supplying heating oil for Alaskan homes, diesel distillates for the trucking industry, and jet fuel for transport planes. Most of Alaska's crude, naphthas, and residual oils are exported to west coast refineries in the lower 48 States. Consequently, diesel and other liquid fuel products needed to supply the bulk of the requirements of Alaska's transportation and electric power industries must be imported. Another refinery is planned, and will constitute another step toward self-sufficiency of the Alaska fuel economy. Recent discoveries in the Prudhoe Bay area indicate the presence of large oil reserves on the Arctic slope.

The discovery of natural gas on the Kenai Peninsula and the spread in exploration through the Cook Inlet and the rich Beluga fields has placed natural gas in the foremost position in the Southcentral Region's fuel economy. Natural gas transmission and distribution facilities now serve the greater Anchorage, Soldotna, and North Kenai areas. Greater utilization of natural gas is hindered by long distances and sparse, scattered population. The total demand for energy so far has not been sufficient to justify the extension of gas pipelines beyond the Anchorage-Kenai Peninsula area.

Conversion to natural gas has been relatively rapid in the civilian, domestic, and electric utility markets in the Anchorage area, and similar conversions are now under way in defense installation steam plants. The conversion of the Fort Richardson and Elmendorf Air Force Base steamplants from coal to natural gas and the conversion of family quarters at Elmendorf to natural gas was accomplished during 1968.

Some natural gas is used for heating and power generation at Barrow on the Arctic Ocean. The gas is moved by a 5-mile Federally-owned pipeline from U.S. Navy wells on the north slope.

Refuse wood in conjunction with fuel oil and concentrated wood pulp liquor serves as fuel for pulp and paper mill operations and for byproduct generation of electric energy in southeast Alaska.

There are scattered uranium deposits in Alaska, but there has been no large commercial production to date and the deposits are of unspecified commercial value. The Kendrick Bay-Bokan Mountain deposit, west of Ketchikan, has supplied a considerable tonnage of commercial uranium ore to outside mills. Contracts to continue mining the ore body have been signed recently.

Present and Projected Fuel Requirements and Costs

Alaska's electric power industry is fossil-fuel oriented—coal and oil accounted for 73 percent and natural gas 8 percent of electricity production in 1965. Projections of fuel use show that by 1985 natural gas will produce 74 percent, coal 4 percent, and oil 17 percent of the total fuel-produced electricity. The remaining 5 percent will be from nonfossil fuels almost wholly in lumber-based industrial plants. These estimates are predicated on the production of electric power from Beluga natural gas at a cost of 15¢/million British thermal units. The Beluga coal field contains billions of tons of known reserves, including presently known strippable coals of several hundred million tons. It has been suggested that the coal could be produced at a cost low enough to have an important bearing on an onsite generating plant.

The average cost of fuel for Alaska's electric powerplants during 1965 was approximately 72 cents per million British thermal units, almost three times the average cost in the other States. By 1985, the average price of all fuel delivered to Alaska's sources of generation is projected to drop to about 34 cents per million British thermal units. This projected price reflects possible decreases in exploration, production, processing, and transportation costs coupled with sizable increases in demands for most of the conventional fuels, led by an eighteen to twentyfold increase in the requirement for natural gas.

Two different assumptions were used in projecting Alaska's fuel requirements for generation of electric power. The first was that there would be no change in the present number of interties between electric utilities and nonutilities. The second was that loads and power sources in the Anchorage and Fairbanks areas would be interconnected, operations coordinated, and the bulk of the total load requirement supplied from natural gas-fired electric generating plants located largely in gas fields near Anchorage. Coal use would be confined to fueling a relatively small plant in the Healy area coal field near Fairbanks and a small steam-electric military plant near Anchorage at Whittier. Furthermore, it was assumed that some diesel and gas-turbine equipment would be converted to less costly fuels, some capacity would be retired or used as standby, and conversions from coal to gas-firing would be made in all south-central stations but one. With the Anchorage and Fairbanks power production sources interconnected, it was assumed that almost all of the load which had been supplied by coal-fired defense base plants would be served by large scale modern and more efficient sources in the south-central gas fields.

Fuel requirements for electric power generation, which totaled 23,500 billion British thermal units in 1965, are expected to exceed 63,000 billion British thermal units by 1985 if the Anchorage and Fairbanks area utility and defense suppliers become interconnected. Should present intersystem relations not change, total British thermal units requirements would increase by 8 to 9 percent. Interconnection of the Anchorage and Fairbanks areas would, by 1985, produce an annual saving in the cost of fuel alone of $2.6 million.

Higher thermal efficiencies of new generating units will also reduce the average amount of fuel needed to produce a kilowatt-hour of electric energy. The average heat rate of Alaska's steam-electric and internal-combustion engine generating plants during 1965 was about 18,200 British thermal units/kilowatt-hour. Under the premise of more interconnections and larger units as suggested, the system heat rates could be reduced to approximately 11,000 British thermal units/kilowatt-hour in 1985.

During 1965, the average cost of all fuel used in Alaska was about 13.1 mills per kilowatt-hour. The comparable cost by 1985 is projected to be approximately 4 mills per kilowatt-hour, representing a cost reduction of about 70 percent below 1965 levels.

Fuel requirements and costs for Alaska's electric power industry in 1965 and 1985 are shown in table 12.

Other Uses of Natural Gas

Natural gas is a highly desirable petro-chemical used not only for space, industrial process and power plant boiler heating but also in the manufacture of other products, such as plastics, detergents, and fertilizers.

A $50 million fertilizer manufacturing complex using Kenai field natural gas as the chemical raw material for synthesis of anhydrous ammonia is being completed at Nikiski on the Cook Inlet. Production, beginning near the end of 1968, will be about 1,500 tons per day of ammonia and 1,000 tons per day of prilled urea. The urea fertilizer is for export to Southeast Asia, and the remaining ammonia production will be marketed in the lower 48 States.

A $57 million liquefaction plant is being constructed on the Kenai Peninsula by Japanese and American interests to liquefy natural gas for export to Japan. Deliveries by huge refrigerated tankers are expected to begin in mid-1969. The abundance of natural gas in Alaska will probably encourage the development of additional industries to compete with electric power generation for the gas.

Interfuel Competition

It appears that the most active competition between fuels can be expected in the Interior and Southcentral Regions. In the Northwest, Southwest, and Southeast regions, oil is expected to continue to be the only practical fuel for electric power generation, although butane and propane gases may become available as products of the liquefaction plant at prices which would be competitive in these areas. Oil presently used in these regions is imported, and this will continue until more refinery operations are available in Alaska. Liquefied natural gas may also compete if transportation and storage facilities can be developed at sufficiently low costs.

Natural gas reserves largely in the Anchorage-Kenai fields and coal reserves in the Matanuska and Healy fields ample to meet Southcentral and Interior Region generating plant requirements during the period of the survey. Other gas, oil, and coal reserves could be produced commercially if needed. The refining of sufficient quantities of crude oil in Alaska to supply most of the State's internal-combustion generating plants can now be considered a future economic certainty.

TABLE 12

Alaska Electric Power Industry, Utilities and Nonutilities Combined

Fuel energy sources	Electric energy (Gigawatt-hours)	Fuel requirement (billion British thermal units)	Unit cost (cents per million British thermal units)	Total cost (dollars)	Energy fuel cost (mills/ per kilowatt-hour)	Cost reduction (percent)
FUEL REQUIREMENTS AND COSTS BY ENERGY SOURCES, 1965						
Coal	454	8, 750	51	4, 460, 000		
Natural gas	105	2, 037	40	815, 000		
Oil	485	6, 663	130	8, 660, 000		
Nuclear	11	181	30	54, 300		
Other fuels	235	5, 865	50	2, 930, 000		
Total	1, 290	23, 495	[1] 72	16, 919, 300	13. 12	
Total coal, gas, and oil	1, 044	17, 450	[1] 80	13, 935, 000	13. 35	
NO INTERREGION SYSTEM INTERCONNECTION, 1985						
Coal	1, 005	13, 890	31	4, 310, 000		
Natural gas	3, 126	36, 718	15	5, 510, 000		
Oil	903	11, 523	100	11, 523, 000		
Nuclear	12	192	30	56, 600		
Other fuels	256	6, 400	40	2, 560, 000		
Total	5, 302	68, 723	[1] 35	25, 939, 600	4. 52	66
Total coal, gas, and oil	5, 034	62, 131	[1] 34	21, 343, 000	4. 24	68
ANCHORAGE AND FAIRBANKS AREA SYSTEMS INTERCONNECTED, 1985						
Coal	215	2, 670	30	801, 000		
Natural gas	3, 916	42, 644	15	6, 400, 000		
Oil	903	11, 523	100	11, 523, 000		
Nuclear	12	192	30	56, 600		
Other fuels	256	6, 400	40	2, 560, 000		
Total	5, 302	63, 424	[1] 34	21, 340, 000	4. 03	69
Total coal, gas, and oil	5, 034	56, 837	[1] 33	18, 724, 000	3. 72	72

[1] Average.

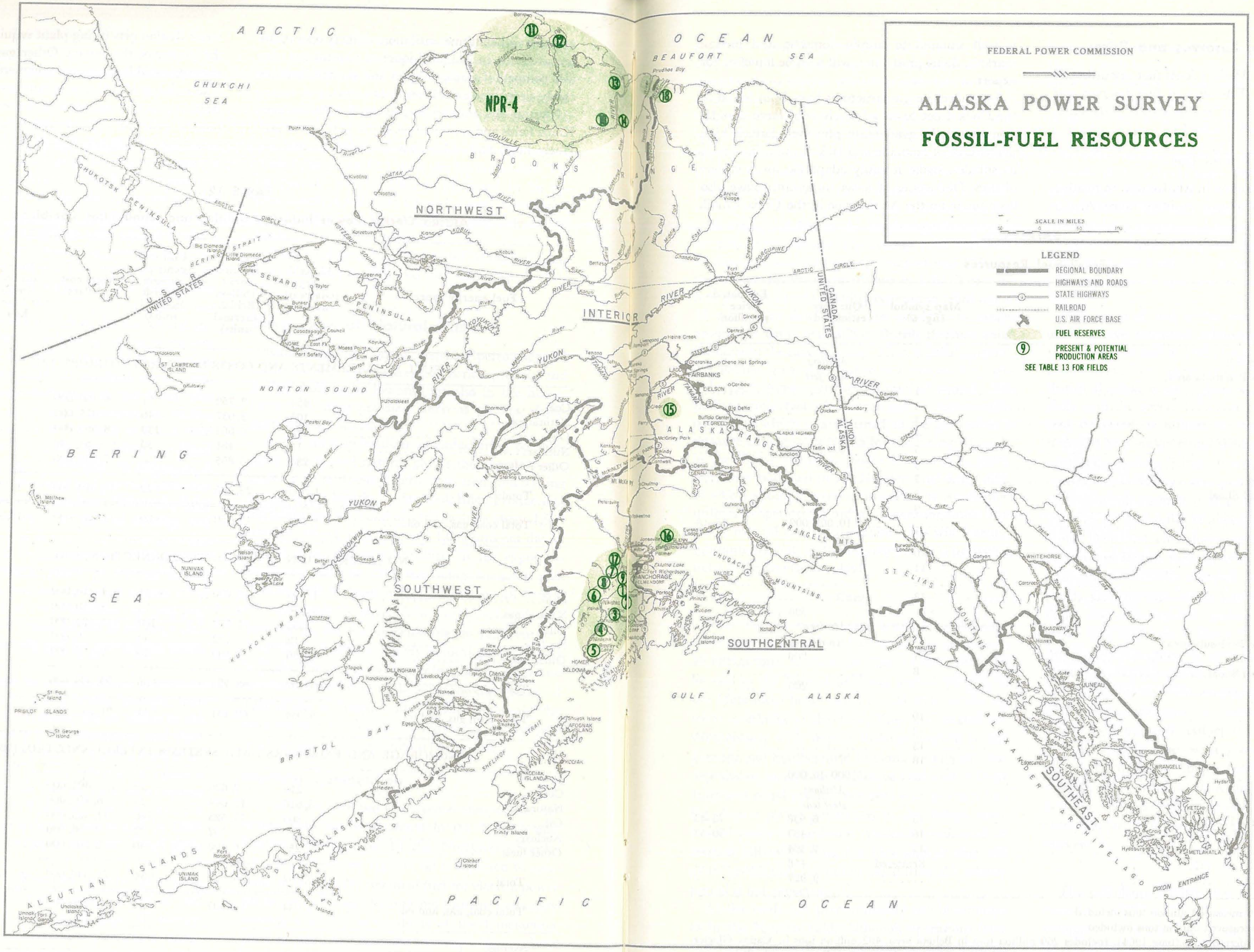

FEDERAL POWER COMMISSION
ALASKA POWER SURVEY
FOSSIL-FUEL RESOURCES
SCALE IN MILES
50 0 50 100
LEGEND
REGIONAL BOUNDARY
HIGHWAYS AND ROADS
STATE HIGHWAYS
RAILROAD
U.S. AIR FORCE BASE
FUEL RESERVES
PRESENT & POTENTIAL PRODUCTION AREAS
SEE TABLE 13 FOR FIELDS
NPR-4
ARCTIC OCEAN
BEAUFORT SEA
CHUKCHI SEA
BERING SEA
NORTON SOUND
BRISTOL BAY
GULF OF ALASKA
PACIFIC OCEAN
NORTHWEST
INTERIOR
SOUTHWEST
SOUTHCENTRAL
SOUTHEAST
BROOKS RANGE
ALASKA RANGE
WRANGELL MTS
CHUGACH MOUNTAINS
ST. ELIAS MOUNTAINS
SEWARD PENINSULA
ALASKA PENINSULA
ALEUTIAN ISLANDS
ALEXANDER ARCHIPELAGO
YUKON RIVER
KUSKOKWIM RIVER
FAIRBANKS
ANCHORAGE
JUNEAU
NOME
U.S.S.R.
UNITED STATES
CANADA
ARCTIC CIRCLE

Figure 6

Fuel Production, Reserves and Prices

The locations of Alaska's fossil-fuel resources are shown in figure 6. Estimates of fuel reserves and price ranges in present and potential production areas are summarized in table 13.

Natural Gas

Natural gas production in Alaska, now in relative infancy, is destined to grow in importance. Alaska is well situated to supply domestic and foreign markets. Some production will soon be liquefied for export.

Several major gas structures have been found in the Cook Inlet basin relatively near large population centers. Its availability, plus the relatively high percentage of methane and lack of impurities, such as sulfides, make it easily adaptable for a variety of uses. Discoveries of lesser importance have also been made on the Arctic slope in the Umiat-Gubik

TABLE 13

Fossil-Fuel Resources

Field	Map symbol (fig. 6)	Quantity (estimated)	Estimated price ¢/million B.t.u.
Natural gas (unprocessed):		*Millions*	
Anchorage-Kenai Peninsula area:		*cubic feet*	
Swanson River	1	...	...
West Fork	2	...	...
Sterling	3	...	...
Kenai	4	...	...
Falls Creek	5	...	...
West Foreland	9	...	...
Beluga River	7	...	...
Middleground Shoal	8	...	...
Cook Inlet	9	...	...
Total gas		10, 000, 000	15–18
North slope area:			
Umiat	10	...	...
Barrow	11	...	...
Gubik	14	...	...
Prudhoe	18	...	...
Total gas		500	...
Crude petroleum:		*Millions*	
Anchorage-Kenai Peninsula area:		*barrels*	
Swanson River	1	200	...
Middleground Shoal	8	...	...
Total oil		200	...
North slope area:			
Umiat	10	...	...
Simpson	12	...	...
Fishcreek	13	...	...
Prudhoe	18	...	...
Total oil		5, 000–10, 000	...
Coal:		*Millions short tons*	
Nenana (Healy) [1]	15	6, 938	23–45
Matanuska [2]	16	137	30–53
Susitna [3]	17	2, 394	...
Other	Scattered	458	...
Total coal		9, 927	...

[1] 1946 base, 861.6 measured million tons included.

[2] 1946 base, 6.6 measured million tons included.

[3] Indicated and inferred only (base 1964). Includes 260 million tons in Beluga area, 402 million tons in Capps Glacier District, and 1,540 million tons in the Chuitna River field—a total of 2,394 million tons in an area adjacent to the Beluga gas generation site.

area. The resources of the Cook Inlet, Kenai Peninsula and Beluga gas fields are conservatively estimated to be as high as 10 trillion cubic feet in terms of economically producible gas stocks. Estimates have been revised upward each year and deposits appear adequate to supply competing petro-chemical requirements as well as fuel needs of the electric utilities for many years. Yearend reports for 1967 put Alaska's "proved" natural gas reserves at 3.635 trillion cubic feet, eighth highest of State reserves.

Eleven gas fields in the Anchorage-Kenai area are now in production. The average price delivered by pipelines to the Anchorage market was 40 cents per million British thermal units in 1965. The current price as a fuel for utility generating plant use is 38 cents. Gas field prices are expected to range around 15 cents per million British thermal units throughout the survey period. Thus, Alaska's natural gas assumes great significance as a competitive fuel.

In 1965, Alaska produced a total of some 11,373 million cubic feet of natural gas, a considerable portion of which was returned to the ground as a pressure maintenance media for producing oil sands in the Kenai Peninsula. Some 5,000 million cubic feet were marketed in the Greater Anchorage area of which about 18 percent was used by Anchorage utilities to operate gas-turbine generating units. The use of natural gas by gas-turbine units will increase substantially, but, by far, its greatest use is projected to be by steam-electric plants.

Coal

Coal reserves in producing areas of Alaska have barely been disturbed, and are estimated to be about 10 billion tons. As shown in table 13, most of this is located in the Nenana field and a small percent in the Matanuska field, which are the only producing fields in Alaska at this time. They are located advantageously with respect to large markets in the Interior and Southcentral Regions. Significant coal deposits are located in the Susitna field west of Cook Inlet and could possibly compete with gas as a fuel for electric power generation in the Beluga area. Coal deposits in northwest Alaska are estimated to contain billions of tons, but here and in other regions production for utility use during the Survey period is not expected.

Alaska coals are predominantly sub-bituminous as in the Nenana field. Although operations have been discontinued in the Matanuska field, the coal in that area is high volatile bituminous in rank. Both underground and strip mining is used in the Healy Creek beds of the Nenana field. The Wishbone Hill District on the north side of the Matanuska Valley has a large number of bituminous beds ranging from a few inches to about 23 feet in thickness.

In 1965, Alaska mined 860,000 tons of coal, an increase of 17 percent over 1964. Electric utilities used only 150,000 tons or 17 percent of the total. About 25,000 tons were used for steam heating by the utilities. The defense bases used 638,000 tons or 74 percent during 1964, but this amount will be reduced in the future due to the conversion of the military steam-electric plants from coal to natural gas.

The prices of coal to the two Fairbanks electric utilities have remained relatively constant for the past few years and in 1965, f.o.b. the Healy mining area, ranged from about 34 to 45 cents per million British thermal units. Delivered to Fairbanks, the price is in the order of 52 to 64 cents. In the past, coal delivered to utilities in the Anchorage area from the Matanuska mines averaged about 50 to 60 cents per million British thermal units. Defense agency contracts have averaged about 27 cents per million British thermal units at the Healy mines and 29 cents for Jonesville-Matanuska area coal at the mine. Delivered costs have been about 42 cents per million British thermal units at Fairbanks defense plants and 39 cents at Anchorage defense plants. Coal for the Golden Valley Electric Association's new steam-electric generating plant in the Healy coal field area is about 29 cents per million British thermal units. At present, the cost of coal burned in Alaska's plants is about double the price paid by utilities in the contiguous 48 States, but any material increases in tonnage would be expected to significantly reduce this difference. Mine costs vary, of course, with geological conditions, labor costs, degree of quality control, mining methods and volumes mined. It is anticipated that competition from gas and oil fuels might cause some reduction in coal prices during the period of the Survey.

Oil

The petroleum industry has, since statehood, invested over $850 million in its search for and development of productive oil and natural gas areas in Alaska. The value of the oil produced in 1967 alone was more than $88 million. In 1967, year end ranking by states placed Alaska eighth in crude oil reserves with a proved reserve of 380 million barrels.

Since the initial discovery of the Swanson River field on the Kenai peninsula in 1957, several additional oil structures have been discovered and are being developed in the offshore area of Upper Cook Inlet. Oil production during 1965 amounted to around 11,100,000 barrels. In 1967, total production was 39,927,000 barrels and the prospects are that production in this and other fields will greatly increase.

In an effort to aid and stimulate exploration in Naval Petroleum Reserve No. 4 (NPR–4), U.S. legislation now permits production and sale of crude oil to exploration companies operating on the North Slope, at a price not to exceed twice that of the monthly average of daily posted prices of marine diesel fuel in Seattle.

Kenai Peninsula oil well in winter. This well produces crude oil, most of which is processed at the Kenai refinery. Some is transported south by ship (as in lower photo).

Alaska has numerous large sedimentary basins as well as extensive Continental Shelf lands. Consequently the State is regarded as a likely area for the discovery of more oil and gas deposits. Recent successes by oil companies drilling in the Prudhoe Bay area indicate highly significant oil reserves on the Arctic Slope. Some geologists feel that this area has the greatest petroleum potential of any geological province within the United States, possibly from 5 to 10 billion barrels.

Until recently, crude oil was not refined in Alaska. Diesel and internal combustion engine fuels were shipped to Alaska ports from refineries in California or Washington and for inland use were transshipped by railway and truck. The cost of all grades of fuel oil used in electric utility plants in 1965 averaged $1.30 per million British thermal units.

Further development of oil refineries will undoubtedly reduce the future price of all grades of fuel oil. The future use of diesel and gas turbine fuel is expected to increase throughout Alaska except where there are lower cost natural gas sources.

Other Fuels

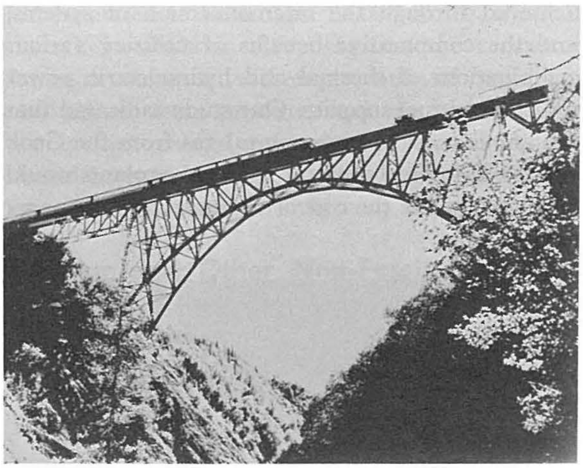
A small nuclear unit generates heat and power to supply part of the requirements for a military installation in the Interior. The cost of the nuclear fuel for this installation has been estimated to be about one-fourth the price of fuel oil. However, the high-capital cost of small nuclear plants is expected to preclude their application during the Survey period, except possibly in special situations.

Some lumber and pulp mills in the southeast Panhandle area use oil mixed with wood refuse for fuel, but mainly woodpulp liquor resulting from the breakdown of the wood into pulp materials. This has been estimated to cost about 40 percent of the local fuel oil price. Compared with available fossil fuels, these other fuels are expected to play only a minor role in the development of Alaska's power resources by 1985.

Transportation of Fuels

Transportation cost is a significant component of the present price of most fuels in Alaska. The price of oil in some areas is doubled by the cost of transportation. The transportation costs account for about 30 percent of the average price of coal for steam-electric plants in the Southcentral and Interior Regions and 60 percent of the price of the natural gas piped into thermal plants in the Anchorage area.

Coal is transported by rail from the Healy fields to Fairbanks and Anchorage. It was also moved from the Matanuska fields to Anchorage by rail when the Matanuska fields were in operation. Coal is trucked to the Fairbanks area at about the same cost as by rail. For the past several years, the cost for moving coal from the Healy field to Fairbanks' utilities has been about $3.30 per ton (about 19 cents per million B.t.u.) and the cost from the Matanuska field to Anchorage, $2.54 per ton (about 10 cents per million B.t.u.).



Alaska Railroad bridge, high above Hurricane Gulch, near the Chulitna Valley, north of Anchorage.

Prior to the destruction of the Seward and Whittier commercial oil storage facilities in the 1964 earthquake, the Alaska Railroad was used to transport fuel oil from Kenai Peninsula ports to Anchorage, Fairbanks, and way stations. The rail freight cost of transporting fuel oil by tank car to Fairbanks was $2.80 per barrel (about 47 cents per million B.t.u.). The Alaska Railroad is still used to ship oil from Anchorage to Fairbanks.

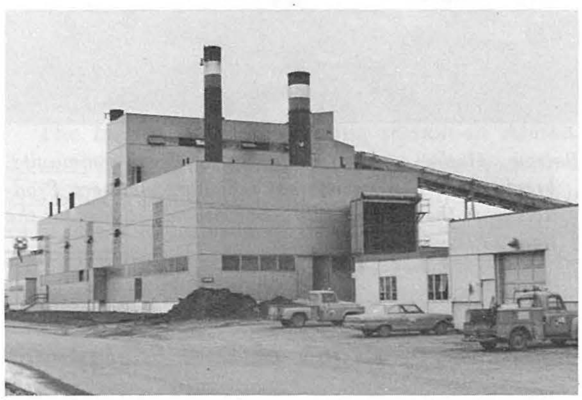
It is anticipated that movements of coal will not increase sufficiently during the Survey period to bring about a significant reduction in coal transportation costs. The delivered coal price for the Healy steam-electric generating station is lower than elsewhere because of its location near the mine.

Although coal slurry transmission by pipeline has been undertaken in other parts of the Nation, it would encounter obstacles in Alaska because of terrain, water availability, and adverse weather conditions. Coal for use by the electric power industry is not presently shipped by water transportation, and it is not expected to be during the Survey period.

More and probably larger pipelines from the petroleum fields will be needed to supply the future fuel requirements of the Anchorage-Kenai area. The average price of natural gas delivered to Anchorage by pipeline for gas-turbine use in 1965 was about 40 cents per million B.t.u. Major future generating capacity in this area is expected to be constructed near the gas fields where little transportation of fuel will be required.

It is not economically feasible to transport gas by pipeline to Fairbanks for demands foreseen by 1985. Transmission would add an estimated 44½ cents per million B.t.u. to the field price, resulting in a delivered cost some two to three times the delivered cost of coal from the Healy fields.

Two Department of the Defense petroleum pipelines serve military facilities in the Interior and Southcentral Regions. One 8-inch line extends 626 miles from tanker unloading facilities at Haines in the Southeast Region to Fairbanks. A second 8-inch line extends 60 miles from the port of Whittier on the Southcentral coast to Anchorage bases. Both receiving ports are open the year around. Fuel oil transportation and storage facilities can serve as a backup source of fuel if coal deliveries and stocks should be impaired for any reason. Under the present arrangements, these two pipelines are not available for other than military use.



This generating plant of Fairbanks Municipal Utilities System includes three coal-fired steam units with a total capacity of 8,500 kilowatts and a 7,000-kilowatt gas turbine.

A Federally owned and operated 5-mile pipeline on the Arctic Slope supplies gas for heat and power at Barrow.

A small commercial pipeline extends from Skagway in southeast Alaska to Whitehorse in Yukon Territory. This 110-mile line, the majority of which is in Canada, can provide fuel for convoys traveling the Alaska Highway or for aircraft operating out of Whitehorse. It is not used to supply fuel for generation of power.

Although the cost of water transportation is high, it is still the least expensive and in many instances the only method available to move fuel oil in large quantities. Transportation by open water to northern ports of the State is usually limited to 3 or 4 months. Fuel is distributed inland by tank truck, rail or barge and to some remote interior locations by aircraft or dog sled. In 1965, the price of diesel fuel at Ketchikan (delivered from San Francisco) was as much as 70 percent more than the price in San Francisco. With quantity production by Alaska refineries, the price of diesel and fuel oil in Alaska markets should become substantially less.

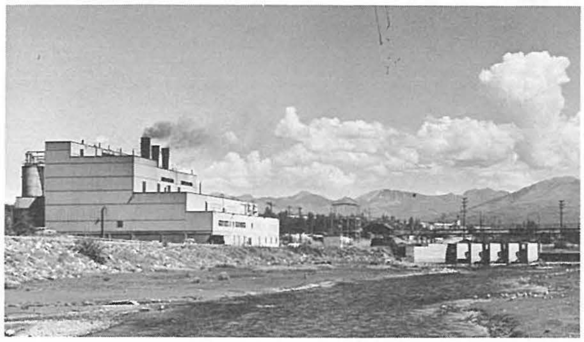
Barrow, Alaska, is America's most northern community, braving severe arctic winters and short summers. Products from the sea and wild game provide staples for the town's Eskimo residents.

Transportation of Fuels Versus Electric Transmission of Fuel Energy

The lowest kilowatt-hour electric energy cost to the customer often depends on whether it is cheaper to ship the fuel to generating plants in the vicinity of the load or transmit electric energy from generating plants near the source of the fuel. This may be the determinant for location of an electric generating station when there is a choice among locations that satisfy other requirements, such as cooling water or atmospheric criteria.

Comparative studies in two areas of Alaska disclose that energy can be moved at lower cost by electrical transmission than by shipment of fuel. Construction of wellhead and mine-mouth plants and transmission facilities is under way in these areas which will enable electricity generated in the Beluga natural gas field to be brought to Anchorage, and electricity produced in the Healy coal field to be transmitted to Fairbanks. The benefits to be gained by these developments should provide the incentive to undertake further expansions in system facilities.

The Survey program also included numerous studies to determine the savings which could be achieved through the interconnection of systems, and the comparative benefits of utilizing various combinations of thermal and hydroelectric power sources and fuel supplies. One study indicated that the annual cost to pipe natural gas from the Cook Inlet field to Fairbanks for local powerplants would be about double the cost of transmitting the energy as electricity.



Knik Arm powerplant on the Chugach Electric Association's system is a coal-fired plant with five units having a combined generating capacity of 14,500 kilowatts.

Steam-Electric Generating Plants

Historically, many of Alaska's utility and nonutility electric generating plants have also produced steam for space heating, the processing of lumber products, and for mining operations. Combined production can result in modest economies in the supply of both heat and power.

Generating units in utility steam-electric plants range in size from 500 to 5,000 kilowatts, in pressures from 400 to 850 pounds per square inch, and in temperatures from 700 to 900° F. This low range in pressures and temperatures, results in high heat rates (the number of British thermal units required to generate 1 kilowatt-hour). Average heat rates of utility steam-electric plants in Alaska have dropped from about 22,600 British thermal units in 1945 to 17,500 British thermal units in 1965. By comparison, the average 1965 heat rate in the contiguous United States was 10,453 British thermal units.

Generating units in defense base plants vary in size from 500 to 7,500 kilowatts and in pulp mills from 7,500 to 10,000 kilowatts. During operation, turbine throttle pressures and temperatures are typically quite variable, 100 pounds per square inch to 850 pounds per square inch and 325° to 825° F., providing for balancing steam production and electric generation requirements. Plant heat rates are estimated to be around 22,000 British thermal units/killowatt-hour. Assuming that the course of future development will employ units of larger size and higher steam pressures and temperatures, the average heat rate of steam-electric plants in Alaska should be reduced to about 11,000 British thermal units/kilowatt-hour by 1985.

Nuclear and Other Non-Fossil Fuel Generating Plants

Only one nuclear-fueled plant is in operation in Alaska. It is located at a military base and its rated electrical output is 2,000 kilowatts. Because nuclear plants of a size adapted to Alaska's needs are not competitive with alternative types, the development of any significant amount of nuclear power within the period of the projection is not foreseen.

Steam-electric plants using byproduct fuels such as wood waste and pulp byproducts may expand their capacity to a degree, but the power produced is not expected to reach the domestic market.

Gas-Turbine Electric Generating Plants

Gas-turbine electric units were first installed by Alaska utilities in 1962 for base load operation as well as for peaking. Plants are presently operating in the Anchorage and Fairbanks areas, varying in size from 8,850 to 16,000 kilowatts.

Natural gas or oil are used as fuels. Gas turbines are not as efficient as internal-combustion engines; in 1965, utilities experienced an average heat rate of 20,300 British thermal units/kilowatt-hour for gas-turbine operation. Improved units are available with a heat rate of 13,500 British thermal units for operation at 30° F. ambient temperature and 50 feet above mean sea level. A reduction in operating costs can be effected by "waste heat recovery" in which the exhaust from the gas turbine is used to make steam for a second generator driven by a steam turbine.

Prepackaged gas-turbine units which can be shipped preassembled, are on the market with ratings up to 30 megawatts. In the larger sizes, which must be field assembled, unit capacities up to 132 megawatts are available. These are powered by multiple aircraft-type jet engines. The capability of a gas turbine is higher at lower air temperatures. Accordingly gas turbines in Alaska are able to produce their greatest power during the predominant winter peak demands.

International Station of the Chugach Electric Association, Inc. is located near Anchorage. The photograph shows two gas-turbine generating units and a third was added in 1968.

During 1968, a 32,000-kilowatt two-unit gas turbine plant went into service in the Beluga gas field on the west side of Cook Inlet. The use of gas turbines will continue to grow where the increments of load are relatively small and fuel costs are not a major consideration.

The largest single generating station in Alaska, located in Anchorage, has three gas turbines with a combined rating of 48,000 kilowatts and six diesels of 1,000 kilowatts each. A 22,000-kilowatt steam turbine will be added in 1971, the steam to be generated by waste heat from the gas turbines.

Internal-Combustion Engine Generating Plants

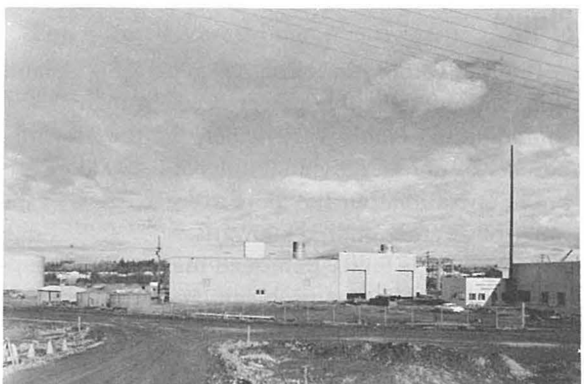
Internal-combustion engine generating plants will continue to supply power needs in many small communities. Plants vary widely in the size and number of units. Individual units of 2,500 kilowatts are in operation, but the more average size is in the range of several hundred kilowatts.

Package-type units minimize many of the shipping and installation problems and are available in a sound-suppressed weatherproof housing. These units can be brought to full load from cold start within 60 to 90 seconds and are well suited to meeting many of Alaska's widely dispersed smaller load demands. Heat rates vary from 13,000 to 10,000 British thermal units/kilowatt-hour for most diesel plants, depending on kinds of fuels, unit sizes, and operating conditions.

The Alaska Village Electric Cooperative Association, formed in 1967 as a statewide REA borrower, will use a $5.2 million loan from the Rural Electrification Administration to install 9,650 kilowatt of diesel capacity in 59 villages to serve primarily some 20,000 Eskimos, Aleuts, and Indians. The program may ultimately provide package-type diesel plants and underground distribution systems in some 206 presently unserved villages. These villages have populations ranging from 75 to 400 and have power requirements in the range of about 25 to 75 kilowatts. They are generally separated by many miles of unfavorable terrain, and fuel costs are between 4½ and 6 cents per kilowatt-hour. Delivered power costs would range from 9 to 16 cents per kilowatt-hour. The recent REA loan will permit starting a program which, under present plans, would provide power to about two-thirds of these communities by the end of 1980.

Siting Considerations for Large Electric Generating Stations

Many factors must be considered in deciding where to locate a large generating station. The choice is usually based on a series of engineering and economic studies for a number of alternative sites. Important considerations include relation of plant to load, system and intersystem configuration and reliability of bulk power supply, transmission line losses, land, foundation conditions, fuels and fuel transportation costs, cooling water, air quality effects, and esthetics.



Municipal generating plant of the city of Anchorage, with three gas turbine and six diesel units, was the largest single generating station in Alaska at the end of 1968.

Not all of Alaska's principal electric power needs are located where the State's abundant fuel resources are readily accessible but fortunately the Anchorage and Fairbanks areas are within reasonable proximity of abundant economic fuel supplies. The Anchorage area has the greatest opportunity for accommodating large plants of the future. These are expected to be natural gas-fired, steam-electric installations in the Cook Inlet gas fields where ample supplies of fuel and cooling water are readily available.

A large supply of cooling water is required to condense steam leaving the turbines for re-use in the boilers of large conventional fossil-fuel fired steam-electric generation stations. For this reason, plants are located near sizeable rivers and lakes and at tidewater. Plant size, heat rate, and temperature rise determine magnitude of required water flow. For a cooling water temperature rise of 13° F. from condenser inlet to outlet, a flow of about 650 gallons of water per minute is required per megawatt of generating capacity. Apart from icing problems, Alaska poses no difficulty in finding adequate water supplies.

With the increase in population, however, and the growing concern with esthetic consideration, each proposed new plant should be judged in terms of its probable effect on the environment, biologically and esthetically. While it is understandable that Alaska has had less reason to be concerned about such problems in the past, regard for preserving natural habitats for fish and wildlife and for the prevention of air pollution will warrant careful consideration of potential impacts in the location and design of new generating facilites.

Geography and weather conditions may combine to produce temperature inversions with resulting concentrations of pollutants and formation of ice fog. The Fairbanks area has long experienced smog and ice-fog problems and such conditions could be aggravated by operation of cooling towers or ponds. The sulphur content of fuel burned and the efficiency of combustion and of a plant's air-cleaning equipment play important roles in reducing air pollution to an acceptable level.

Trends in Fuel-Electric Plant Actual Power Production Costs

The average total production costs of power generated by Alaska's coal, gas, and oil-burning electric utility plants are shown in table 14. Similar costs for the nonutility segment of Alaska's power

TABLE 14

Electric Power Production Expenses [1]

(Mills/Kilowatt hour)

Type	1960	1961	1962	1963	1964	1965
Steam-electric: [2]						
Fuel	9.3	11.9	10.5	12.6	10.9	10.1
Operation and maintenance	10.7	8.2	6.7	7.5	8.8	9.0
Total steam-electric	20.0	20.1	17.2	20.1	19.7	19.1
Gas-turbine: [3]						
Fuel				8.5	8.9	9.1
Operation and maintenance				3.1	2.2	2.2
Total gas-turbine				11.6	11.1	11.3
Internal-combustion:						
Fuel	16.2	16.7	17.3	15.0	16.2	14.3
Operation and maintenance	24.8	19.1	16.8	12.7	11.6	12.4
Total internal-combustion	41.0	35.8	34.1	27.7	27.8	26.7

[1] Data include information from reports filed with the Federal Power Commission and additional information submitted by the utilities for this report. Fixed charge costs are not included.

[2] Excludes cost of coal used for steam heat production.

[3] 1963 first full year of operation. Data include both oil and gas-fired turbines.

industry are not available but would be expected to be somewhat higher. Fuel costs, however, have tended to be lower and because a large percentage of plant capacity is on military bases, operation and maintenance costs could be less. As indicated, costs per kilowatt-hour for steam-electric generation have remained fairly constant over a 6-year period. During this time, the size and efficiency of steam plant facilities changed very little, and operation and fuel costs remained fairly constant.

Production costs for utility gas-turbine generation were 41 percent lower than steam-electric costs and 58 percent lower than internal-combustion costs in 1965. The greatest difference is in the operation and maintenance costs. The low operating costs of gas-turbine units and the proximity of the large load areas to natural gas sources explain why gas-turbine capacity in 1965 amounted to 45 percent of the total capacity in utility fuel plants.

The many small plants have kept average generation costs at higher levels than those in other States. Larger units and plants, lower cost fuels, and interconnection and coordination among utilities should affect substantial reductions in production costs.

Comparison of Costs for Large and Small Plants

Lower investment cost per kilowatt of generating capacity can be achieved by increasing the unit size. Further savings can be achieved through improved heat rates obtainable from large thermal units and through optimization of steam conditions. For a steam-electric plant designed to burn only natural gas or oil, the absence of coal and ash-handling facilities results in substantial savings. Unitization has also brought down the costs of internal-combustion installations.

Cost estimates of the components of electric power production for four types and a range in sizes of generating plants, are shown in table 15. Particularly notable is the effect of size on the production costs of coal and gas fired steam-electric plants. Capital investment costs used in developing the component costs of table 15 are indicated in the table. Some new diesel unit designs now coming into use for combination peak and base load service are available at about one-half the costs of heavy duty units.

TABLE 15

Estimated Power Production Costs

Items	2-unit 400-mw. plant: Dollars per kilowatt	2-unit 400-mw. plant: Mills per kilowatt-hour	Single unit 40-mw. plant: Dollars per kilowatt	Single unit 40-mw. plant: Mills per kilowatt-hour	Savings (mills per kilowatt-hour
Coal-fired steamplant: [1]					
Assumed capital investment	195		350		
Fixed charges		3.2		5.9	2.7
Fuel		2.5		3.4	0.9
Operation and maintenance		0.8		2.7	1.9
Total		6.5		12.0	5.5
Gas-fired steamplant: [2]					
Assumed capital investment	155		275		
Fixed charges		2.6		4.6	2.0
Fuel		1.4		1.7	0.3
Operation and maintenance		0.5		2.5	1.9
Total		4.5		8.7	4.2

Items	Single unit 25-mw. plant: Dollars per kilowatt	Single unit 25-mw. plant: Mills per kilowatt-hour	Single unit 10-mw. plant: Dollars per kilowatt	Single unit 10-mw. plant: Mills per kilowatt-hour	Savings (mills per kilowatt-hour
Peaking service: [2] Gas-turbine plant:					
Assumed capital investment	115		130		
Fixed charges		2.0		2.2	0.2
Fuel		2.6		3.0	0.4
Operation and maintenance		1.4		1.9	0.5
Total		6.0		7.1	1.1

Items	Single unit 10-mw. plant: Dollars per kilowatt	Single unit 10-mw. plant: Mills per kilowatt-hour	Single unit 2-mw. plant: Dollars per kilowatt	Single unit 2-mw. plant: Mills per kilowatt-hour	Savings (mills per kilowatt-hour)
Base load: Internal-combustion engine plant: [3]					
Assumed capital investment	280		350		
Fixed charges		4.7		5.8	1.1
Fuel		11.3		13.5	2.2
Operation and maintenance		5.0		12.5	7.5
Total		21.0		31.8	10.8

[1] Fuel at 28¢ per million B.t.u.
[2] Fuel at 15¢ per million B.t.u.
[3] Fuel at 110¢ per million B.t.u.

Assumption: Estimates are based on a composite fixed charge rate of 7.3 percent (table 24, ch. VIII) and a 50-percent capacity factor.

Summary and Conclusions

To keep pace with the projected growth in electric loads, thermal and hydroelectric capacity presently in service will need to be quadrupled by 1985. During this period of expansion, fossil-fuel prices are expected to decrease from an average of 80 cents per million British thermal units in 1965 to 33 cents in 1985. Reductions are anticipated in fixed charges and nonfuel related production expenses. The achievement of potential cost reductions hinges largely on the willingness of utilities to interconnect and coordinate the planning and operation of their systems.

The use of large natural gas-fired steam-electric generating units holds the greatest promise for improved economic benefits within the study period. Lesser but still significant savings can be expected by the use of effective application and use of diesel and gas-turbine equipment in some of the future plant designs.

Admittedly, power costs in many Alaska communities cannot be greatly reduced because generating facilities are necessarily small and serve relatively isolated areas. Maintenance costs in some instances are increased by climatic conditions, and distribution costs are higher because of the small loads and fewer customers. Nevertheless, where large generating plants with improved thermal efficiencies and lower capital, operation, maintenance and fuel costs can be used, the outlook is bright for reductions in electricity costs for over 75 percent of Alaska's population.

CHAPTER V

HYDROELECTRIC POWER RESOURCES

Alaska's rugged topography presents innumerable opportunities for the development of hydroelectric power, varying from small projects in steep valleys with high heads to broad valleys on large rivers with low to moderate heads.

Many of the sites, however, which appear physically attractive have limited utility because of low winter stream flows and lack of adequate storage for seasonal regulation. Others are remote from load centers and some of the broader valley sites would require extensive dams. Estimates of dependable energy yield are often hampered by an absence of long-term meteorological and hydrological records.

Among the resources which supplied power in 1950 for Alaska's utility, defense and industrial uses, hydroelectric installations supplied 30 percent of the total capacity, steam-electric plants 45 percent, and internal combustion engines the remaining 25 percent. In 1965, hydro supplied 17 percent, steam 35 percent, and internal-combustion and gas-turbines, almost 48 percent. Hydroelectric capacity increased from 23,400 kilowatts in 1950 to 83,500 kilowatts in 1965.

History of Hydroelectric Power in Alaska

Most of the early hydroelectric developments in Alaska provided power for mining or other industrial uses, such as fish processing. Developments were frequently associated with direct use of hydraulic power. The first development for utility use was undertaken by the city of Ketchikan public utilities in 1901. Ketchikan is the only utility system with multiple hydroelectric developments and is still largely dependent on hydroelectric power to supply its requirements. A. J. Industries, successor to Alaska Juneau Gold Mine Co., also operates a multidevelopment hydroelectric system and sells energy to Alaska Electric Light and Power Co. in Juneau. The largest existing hydroelectric installation in the State is the Alaska Power Administration's 30,000-kilowatt Eklutna plant, 32 miles north of Anchorage, and the second largest, located on the Kenai Peninsula, 60 miles southeast of Anchorage, is the 15,000-kilowatt Cooper Lake plant of Chugach Electric Cooperative Association, Inc. Construction has been started by the Corps of Engineers on the first phase (46,700 kilowatts) of the 70,000-kilowatt Snettisham project on Long Lake, 28-miles southeast of Juneau. Many of the existing hydroelectric plants are small installations of less than 50 kilowatts, and generate power for fish canneries.

Hydroelectric Projects, Developed, Under Construction, and Authorized

There are 41 hydroelectric developments in Alaska, existing, under construction, or authorized. These range in size from 1.5 kilowatts to 46,700 kilowatts, based on the initial capacity of the Snettisham project. Total capacity is 196,515 kilowatts. Several are not in operation; two are under construction; one is licensed by the Federal Power Commission, but not yet under construction; and one is authorized for Federal construction. The plants, ownership, and construction status are shown in table 16.

Hydroelectric Developments Under License

Under provisions of the Federal Power Act, the Federal Power Commission issues licenses for definite terms not to exceed 50 years to non-Federal entities, authorizing the construction, operation, and maintenance of hydroelectric developments which affect public lands, are located on streams over which Congress has jurisdiction, or where the power produced is used by a licensee operating in interstate or foreign commerce.

The Act specifies that, in the judgment of the Commission, the project adopted shall be best adapted to a comprehensive plan for improving or developing a waterway or waterways for the use or benefit of interstate or foreign commerce, for the improvement and utilization of water-power development, and for other beneficial uses, including recreational purposes.

TABLE 16

Hydroelectric Developments Existing—Under Construction—Authorized, December 31, 1968

System	Plant Name or FPC Project No.	Location	Capacity kilowatts	Status: Ownership	Status: Construction	Remarks
Southeast Region:						
Utilities—						
Alaska Electric Light and Power Co.	Gold Creek	Juneau	1,600	P	E	
Alaska Power and Telephone Co.	1051	Skagway	338	P	E	
Pelican Utility Co		Pelican	500	P	E	Plant is being operated under a Forest Service permit.
Ketchikan Public Utilities	420	Ketchikan	4,200	NF	E	
Do	1922	do	5,600	NF	E	
Do	1922	do	2,100	NF	UC	Beaver Falls addition was completed in 1968.
Metlakatla Indian Community.	Purple Lake	Metlakatla	3,000	NF	E	
City of Petersburg	201	Petersburg	2,000	NF	E	
Sitka Public Utilities	2230	Sitka	6,000	NF	E	
U.S. Army, Corps of Engineers	Snettisham	Speel River (near Juneau).	46,700	F	UC	Capacity of 70,000 kilowatts is authorized. 46,700 kilowatts represents first phase of construction.
Subtotal utilities			72,038			
Nonutilities—						
A. J. Industries	2307	Juneau	2,800	P	E	
Do	2307	do	2,800	P	E	
Do	2307	do	2,800	P	E	
Alaska Lumber and Pulp Co.	2267	Sitka	900	P	L	Licensed, but not yet under construction.
Bahovec, Fred	1185	Baranof Island	3	P	E	
Buchan and Heinen Packaging Co.	Skeckley Creek	Port Armstrong	14	P	E	
Keku Canning		Kupreanof Island	30	P	E	Operating under Forest Service permit issued Sept. 4, 1959.
Libby, McNeill and Libby Co.	206	Ketchikan	67	P	E	Columbia Ward Fisheries, successor to Libby (1959).
O'Neill, F. W. and Sarah		Baranof Island	3	P	E	Application has been made for a Forest Service permit.

Pacific American Fisheries		Linkum Creek	17	P	E	
Stofold and Grondahl Packaging Co.		Kuiu Island	15	P	E	Operating under Forest Service permit issued Oct. 14, 1963.
Sheldon-Jackson Jr. College		Sitka	50	NF	E	
Swanson, Ernest		Chicagof Island	7	P	E	Operating under Forest Service permit issued Feb. 15, 1961.
Subtotal nonutilities			9, 506			
Subtotal Southeast			81, 544			
Southcentral Region:						
Utilities—						
Chugach Electric Association	2170	Cooper Landing	15, 000	NF	E	
Alaska Power Administration	Eklutna	Eklutna	30, 000	F	E	
U.S. Army, Corps of Engineers.	Bradley Lake	Bradley River	64, 000	F	A	Project is being re-evaluated for lower plant factor, higher capacity design.
Subtotal utilities			109, 000			
Nonutilities—						
Alaska Packers Association	620	Indian Creek	50	P	E	
Chatham Straits Fishing Co		Crab Bay	5	P	E	
Intercoastal Packing Co	2026	Near Kodiak	30	P	E	
Kennecott Copper Co	1949	Latouche Island	37	P	E	License transferred to James Sumpter, May 7, 1963.
Parks Canning Co.[1]		Kodiak Island	7. 5	P	E	
San Juan Fishing and Packaging Co.	2251	Latouche	100	P	E	
Kodiak Fisheries [1]	1909	Kodiak Island	12. 5	P	E	Project has been sold to CWC Fisheries. License renewal application pending.
Do [1]	1432	do	75	P	E	Project has been sold to CWC Fisheries. License renewal application pending.
New England Fish Co	1299	do	8	P	E	
Estes Brothers, Inc	1196	Moose Pass	21	P	E	
Subtotal nonutilities			346			
Subtotal Southcentral			109, 346			

See footnote at end of table.

TABLE 16

Hydroelectric Developments Existing—Under Construction—Authorized, December 31, 1968—Continued

System	Plant Name or FPC Project No.	Location	Capacity kilowatts	Status		Remarks
				Ownership	Construction	
Interior Region:						
Utilities—						
Chatanika Power Co., Inc.	2264	Chatanika		P	E	Plant destroyed by Fairbanks flood. Application has been filed for surrender of license.
Subtotal utilities						
Nonutilities—						
Subtotal Interior						
Northwest and Southwest Regions:						
None						
Total—Alaska			190, 890			

[1] 1968 records of the State Department of Revenue and the State Department of Fish and Game indicate these are the only canneries presently operating in the Southcentral region.

NOTES.—Status designations: F=Federal; NF=Nonfederal; P=Private; E=Existing; L=Licensed; A=Authorized, UC=Under Construction.

At the end of December 1968, 17 licenses were in effect and two renewals were pending covering 22 developments. Of this total, 19 are existing projects, one is under construction, one is yet to be constructed [1] and one has been destroyed.[2] The total installed capacity in the 19 existing projects at the end of December 1968 was 41,942 kilowatts. The ownership, size, and status of all projects for which licenses are outstanding is summarized in Table 16.

The city of Ketchikan was authorized by amendment of license for project No. 1922, Beaver Falls, to add 2,100 kilowatts of capacity. Work on features covered by the amendment was completed in 1968.

A license application is pending on one proposed development as follows:

Project	*Owner*	*FPC project No.*	*Installed capacity kw.*
Terror Lake......	Kodiak Electric Assoc.	2434	30, 000

License applied for May 29, 1967, to construct and operate an initial installation of two 10,000-kw. generators.

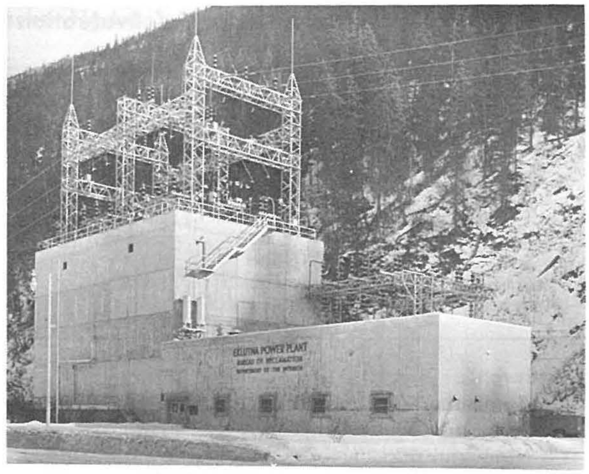
A preliminary permit is outstanding for one proposed project as follows:

Project	*Owner*	*FPC project No.*	*Installed capacity kw.*
Power Creek......	Cordova Public Utilities.	2656	3, 000

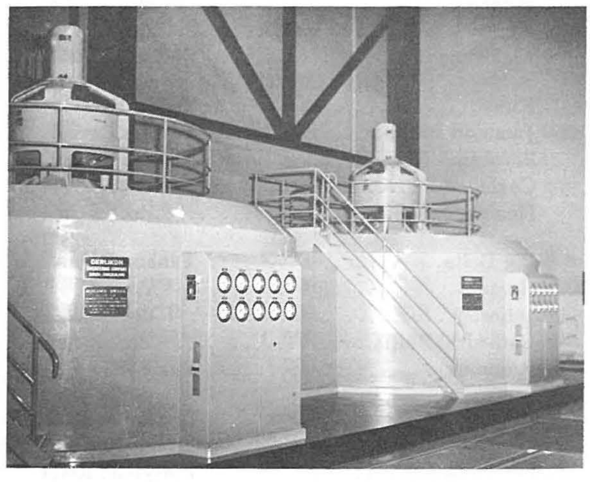
Many of the outstanding licenses are for projects classified as minor under present Commission rules and which could operate under permits issued by the Forest Service upon expiration of present FPC licenses.

Hydroelectric Development by Federal Agencies

At the present time, there is only one Federal power project in operation in Alaska, the 30,000-kilowatt Eklutna project of the Alaska Power Administration. The first phase, 46,700 kilowatts, of the 70,000-kilowatt Snettisham project is under construction by the Corps of Engineers. The 64,000-kilowatt Bradley Lake project has been authorized for construction by the Corps of Engineers, but construction funds have not been requested and the project is to be restudied to determine whether it should be redesigned for operation at about 25-percent load factor which would call for increasing the project capacity to about 187,000 kilowatts.



The Alaska Power Administration's Eklutna powerplant near Anchorage has two 15,000-kilowatt hydroelectric units.



Interior view of Alaska Power Administration's 30,000-kilowatt Eklutna powerplant near Anchorage.

The Corps of Engineers is completing a feasibility report on the 5,040,000-kilowatt Rampart project on the Yukon. It has appeared unlikely that power from the Rampart project could be made available to serve loads before 1985, the end of the projection

[1] The 900-kilowatt plant, project No. 2267, Alaska Lumber and Pulp Co., was licensed in 1960, but is not yet under construction.

[2] The 5,625-kilowatt plant of the Chatanika Power Corp. was destroyed in the Fairbanks flood in 1967 and the corporation has applied for a surrender of license.

period of this Survey. A further exploration during the early years of the Survey projection period of Alaska's natural resources and the opportunities for the economic development of these resources to serve U.S. and foreign markets should help to clarify the market for and the economic feasibility of a major hydroelectric power development in Alaska of the magnitude of the Rampart Canyon project.

Hydroelectric Surveys by Federal Agencies

Table 17 presents data concerning a large number of hydroelectric developments in Alaska con-

TABLE 17

Summary of Initial Evaluation of Alaska Hydroelectric Potentialities

[Lowest priced projects with prime power capacities in excess of 2,500 kilowatts as evaluated on basis of

Project	Stream	Major features in addition to powerplant (dam is concrete unless noted)	Drainage area (square miles)[4]	Maximum regulated W.S. elevation (feet)
Northwest:				
Agashashok (Igichuk)	Noatak River	Dam, Earth Dike	12, 700	150
Misheguk (Upper Canyon)	do	Dam, Earth Dikes	8, 750	550
Nimiuktuk	do	Dam	7, 000	750
Kobuk River	Kobuk River	Earth Dam	7, 840	150
Tuksuk (Imuruk Basin)	Tuksuk Channel	Dam	4, 275	190
Interior:				
Holy Cross	Yukon River	Earth Dam	320, 000	137
Dulbi	Koyukuk River	do	25, 700	225
Hughes	do	Dam	18, 700	320
Kanuti	do	do	18, 000	500
Melozitna	Melozitna River	do	2, 659	550
Ruby	Yukon River	do	256, 000	210
Junction Island	Tanana River	Earth Dam	42, 500	400
Bruskasna	Nenana River	Dam	650	2, 330
Carlo	do	do	1, 190	1, 900
Healy (Slagle)	do	do	1, 900	1, 700
Big Delta	Tanana River	Earth Dam	15, 300	1, 100
Gèrstle	do	do	10, 700	1, 290
Johnson	do	Dam, Earth Dikes	10, 450	1, 470
Cathedral Bluffs	do	Earth Dam	8, 550	1, 650
Rampart	Yukon River	Dam	200, 000	665
Porcupine (Campbell River)	Porcupine River	do	23, 400	975
Woodchopper	Yukon River	do	122, 000	1, 020
Fortymile	Fortymile River	do	6, 060	1, 550
Southwest:				
Crooked Creek	Kuskokwim River	do	31, 100	500
Nuyakuk (Nuyakuk-Tikchik)	Nuyakuk River	Dam, Tunnel, Penstock	1, 530	342
Lake Iliamna	Kvichak River	Earth Dam	6, 440	150
Tazimina	Tazimina River	Earth Dam, Tunnel Penstock	346	725
Ingersol (Lackbuna Lake)	Kijik River	do	300	1, 460
Kukaklek	Alagnak River	Dam, Tunnel, Penstock	480	825
Naknek	Naknek River	Earth Dam	2, 720	150

See footnotes at end of table.

sidered by the Subcommittee for Hydro Resources. Many of these have been reported on by the Corps of Engineers and the Department of the Interior. The Corps' findings are included in seven interim reports, bearing dates from 1950 through 1959, on Southeastern Alaska, Cook Inlet and Tributaries, Copper River and Gulf Coast, Tanana River Basin, Southwestern Alaska, Northwestern Alaska, and the Yukon and Kuskokwim River Basins. The most recent Department of the Interior findings are included in its January 1965 report entitled, "Field Report—Rampart Project, Alaska—Market for

TABLE 17

Summary of Initial Evaluation of Alaska Hydroelectric Potentialities

data available. Based upon data currently available to Bureau of Reclamation and Corps of Engineers]

Active storage (1,000 AF)	Range in static head (feet)	Average head (feet)	Average annual runoff (1,000 AF)	Percent regulation	Continuous power (1,000 kw.)	Firm energy (kwh. x 10^6)	Installation at 50% load factor		Installation at 25% load factor	
							Installed capacity (1,000 kw.)	Construction cost (dollars per installed kilowatt [16])	Installed capacity (1,000 kw.)	Construction cost (dollars per installed kilowatt [16])
7, 500	140–118	132	[3] 7, 500	100	93	820	186	800	372	600
3, 200	240–120	199	[3] 5, 600	83	87	760	174	1, 000	348	700
4, 900	200–100	166	[3] 4, 500	100	70	613	140	1, 200	280	800
6, 600	120–90	114	[3] 5, 700	100	60	526	120	1, 500	240	900
3, 800	190–184	187	[3] 1, 880	100	33	289	66	1, 800	132	1, 000
([6])	([6])	94	[1] 160, 000		1, 400	12, 300	2, 800	800		
22, 200	78–51	68	[2] 19, 200	100	122	1, 070	244	1, 400	488	800
([6])	([6])	49	[1] 12, 300		55	482	110	1, 000	220	700
13, 800	180–141	166	[2] 11, 900	100	184	1, 612	368	1, 200	736	700
1, 800	325–160	270	[1] 1, 400	91	32	282	64	1, 100	129	700
([6])	([6])	72	[1] 109, 000		730	6, 400	1, 460	400		200
29, 000	125–95	114	[2] 25, 000	100	266	2, 330	532	1, 500	1, 060	800
840	250–140	212	[1] 826				40		80	
53	200–100	166	[14] 1, 670	83	96	840	30	1, 000	60	600
310	350–175	291	[14] 2, 675				130		260	
6, 450	120–60	99	[1] 12, 500	98	113	987	226	1, 600	452	900
([6])	([6])	59	[1] 9, 500		50	438	100	1, 600	200	1, 000
5, 300	180–100	149	[1] 7, 830	97	105	920	210	1, 600	420	900
4, 900	160–120	146	[1] 5, 800	100	79	693	158	1, 500	316	900
142, 000	457–436	445	[1] 81, 000	100	3, 904	34, 200	[9] 5, 040	[9] 200		
9, 000	315–312	313	[3] 9, 100	100	265	2, 320	530	500	1, 060	300
39, 000	360–190	300	[1] 57, 600	[8] 100	1, 620	14, 200	[9] 2, 160	[9] 500		
1, 610	390–200	324	[3] 3, 230	84	83	723	166	800	332	500
30, 000	355–349	352	[1] 32, 400	100	1, 070	9, 400	2, 140	500		300
2, 200	202–172	176	[1] 4, 300	90	63	555	127	1, 500	253	1, 200
11, 700	120–115	114	[2] 14, 600	100	156	1, 370	313	1, 100	626	600
420	455–385	393	[2] 724	96	26	224	51	1, 500	102	1, 000
472	1200–1080	1, 120	[2] 695	99	72	630	144	1, 300	288	800
710	365–350	326	[3] 870	100	27	232	53	1, 000	106	700
4, 600	130–115	124	[3] 4, 600	100	54	473	108	1, 200	216	800

TABLE 17—Continued

Summary of Initial Evaluation of Alaska Hydroelectric Potentialities—Continued

Project	Stream	Major features in addition to powerplant (dam is concrete unless noted)	Drainage area (square miles)	Maximum regulated W.S. elevation (feet)
Southcentral:				
Crescent Lake	Lake Fork of Crescent River.	2 Diversion Dams, Canal, Tunnel, Penstock.	200	599
Chakachamna	Chakachatna River	Tunnel, Penstock	1, 120	1, 127
Coffee	Beluga River	Dam	860	210
Upper Beluga (Beluga River)	do	do	840	375
Yentna	Yentna River	Dam, Earth Dike	6, 400	150
Talachulitna (Shell)	Skwentna River	Dam	2, 250	350
Skwentna (Hayes)	do	do	950	1, 000
Lower Chulitna	Chulitna River	do	2, 600	500
Tokichitna	do	Dam, Earth Dikes	2, 560	725
Keetna (Talkeetna)	Talkeetna River	Dam	1, 250	950
Whiskers	Susitna River	do	6, 320	490
Lane	do	do	6, 280	660
Gold	do	do	6, 160	850
Devil Canyon	do	do	5, 810	1, 450
Watana	do	do	5, 180	1, 905
Vee	do	Dam, Earth Dike	4, 140	2, 355
Denali	do	Dam Earth	1, 260	2, 552
Snow	Snow River	Dam, Earth Dike, Tunnel, Penstock	84. 7	1, 250
Bradley Lake	Bradley Creek	Dam, Diversion Dams, Canals, Tunnel, Penstock.	87. 8	1, 195
Lowe (Keystone Canyon)	Lowe River	Dam	190	800
Million Dollar	Copper River	Earth Dam	24, 200	200
Cleave (Peninsula)	do	Dam	21, 500	420
Wood Canyon	do	Dam, Saddle Spillway	20, 600	1, 400
Southeast:				
Chilkat	Chilkat River	Dam, Earth Dike, Tunnel, Penstock.	190	600
Lake Dorothy	Dorothy Creek	Tunnel, Penstock	11	2, 422
Speel Division, Snettisham	Speel River	Dam, Earth Dike, Tunnel, Penstock.	194	325
Tease Creek	Tease Creek	Dam, Tunnel, Penstock	11. 4	1, 100
Sweetheart Falls Creek	Sweetheart Falls Creek	do	35. 2	684
Houghton	Unnamed	do	39. 2	550
Scenery Creek	Scenery Creek	Tunnel, Penstock	21. 1	957
Thomas Bay (Cascade Creek)	Cascade Creek	do	18. 9	1, 514
Stikine River	Stikine River	Dam	20, 000	350
Goat	Goat Creek	Dam, Tunnel, Penstock	14. 0	1, 298
Tyee Creek	Tyee Creek	Tunnel, Penstock	14. 6	1, 387
Spur	Unnamed	do	10. 2	1, 889
Leduc	Leduc River	do	7. 1	1, 384
Rudyerd	Unnamed	do	7. 9	1, 775
Punchbowl Creek	Punchbowl Creek	Dam, Tunnel, Penstock	13. 6	650

See footnotes at end of table.

TABLE 17—Continued

Summary of Initial Evaluation of Alaska Hydroelectric Potentialities—Continued

Active storage (1,000 AF)	Range in static head (feet)	Average head (feet)	Average annual runoff (1,000 AF)	Percent regulation	Continuous power (1,000 kw.)	Firm energy (kwh. x 10^6)	Installation at 50% load factor: Installed capacity (1,000 kw.)	Installation at 50% load factor: Construction cost (dollars per installed kilowatt [16])	Installation at 25% load factor: Installed capacity (1,000 kw.)	Installation at 25% load factor: Construction cost (dollars per installed kilowatt [16])
306	599–500	517	[3] 454	98	20	179	41	900	82	700
1,700	942–820	793	[1] 2,460	100	183	1,600	366	600	732	500
([6])	([6])	109	[2] 1,800		18	160	37	1,100	73	800
1,800	163–97	142	[2] 1,800	100	24	210	48	1,000	96	700
2,850	100–50	82	[2,4] 12,750				145		290	
575	150–75	124	[1,4] 4,500	79	159	1,390	75	1,000	150	700
860	350–175	291	[1,4] 1,900				98		196	
([6])	([6])	89	[1] 6,350		45	394	90	800	180	600
2,700	225–112	186	[1] 6,200	85	92	806	184	800	368	600
675	345–173	286	[2] 1,740	82	37	324	74	1,100	148	700
([6])	([6])	59	[1] 7,500		42	368	84	1,100	168	700
([6])	([6])	169	[1] 7,500		120	1,052	240	800	480	500
([6])	([6])	189	[1] 7,327		130	1,139	260	1,300	520	800
([6])	([6])	575	[1,4] 6,840				738		1,476	
1,960	435–330	425	[1,4] 6,040				478		956	
				100	801	7,000		[14] 500		300
1,550	450–235	430	[1,4] 4,730				386		772	
5,000			[1,4] 2,310							
354	750–550	653	[2] 535	97	32	278	63	1,000	127	700
372	1195–1041	1,155	[1] 445	93	47	410	94	[15] 600	187	400
420	402–201	334	[3] 1,400	66	29	254	58	1,100	116	700
([6])	([6])	89	[2] 38,000		220	1,927	440	1,400	880	800
([6])	([6])	165	[2] 28,000		410	3,600	820	1,300	1,640	700
21,000	980–905	950	[1] 26,700	100	2,500	21,900	[10] 3,600	[14] 300		
335	390–190	320	[2] 870	80	21	180	41	950	82	680
125	2406–2251	2,248	[1] 81	100	17	150	34	600	68	500
330	325–223	273			31	275	63	800	126	500
33	1080–986	1,034	[3] 110	75	8	70	16	1,400	32	900
250	684–543	612	[1] 250	100	14	125	29	800	57	600
333	550–361	457	[2] 370	98	15	136	31	1,000	62	700
60	697–564	620	[2] 147	90	8	67	15	800	31	500
72	1499–1350	1,442	[1] 160	88	19	166	38	600	76	500
26,000	350–175	291	[3] 45,000	90	1,130	9,900	2,260	900	4,520	500
47	1098–1040	1,056	[3] 112	90	10	87	20	1,200	40	800
66	1372–1185	1,275	[1] 123	93	14	120	27	600	55	500
27	1859–1670	1,766	[3] 83	87	12	105	24	900	48	600
61	1284–1184	1,241	[3] 61	100	7	62	14	1,100	28	700
61	1675–1525	1,600	[3] 63	100	9	83	19	800	38	600
100	650–596	622	[1] 126	99	7	64	15	800	29	500

TABLE 17—Continued

Summary of Initial Evaluation of Alaska Hydroelectric Potentialities—Continued

Project	Stream	Major features in addition to powerplant (dam is concrete unless noted)	Drainage area (square miles)	Maximum regulated W.S. elevation (feet)
Southeast—Continued				
Red	Red River	Dam, Tunnel, Penstock	44.0	400
Lake Grace	Grace Creek	do	28.6	500
Swan Lake (Lower Swan Lake)	Falls Creek	Dam, Penstock	36.4	326
Maksoutof River	Maksoutof River	Dam, Earth Dike, Tunnel, Penstock	23.8	[17] 630 [18] 800
Deer	Unnamed	Tunnel, Penstock	7.4	374
Takatz Creek	Takatz Creek	Dam, Tunnel, Penstock	10.6	1,040
Green Lake	Vodopad River	Dam, Penstock	29	400
Yukon-Taiya	Yukon River	Dam, Channels, Tunnel, Penstocks	25,700	2,200

[1] Streamflow records at or near site.
[2] Estimated from streamflow records for similar drainages.
[3] Estimated from basin precipitation records and judgment.
[4] Calculated from area maps.
[5] Operating as a system.
[6] Reservoir held essentially full for operation with upstream plants.
[7] Estimated reservoir yield after allowing 1,500 cfs release from Hootalinqua Reservoir.
[8] Operated in conjunction with downstream storage.
[9] Based on 75 percent load factor.
[10] Based on 69.4 percent load factor.
[11] Exclusive of Fish and Wildlife mitigation costs, unless otherwise noted.

Power and Effect of Project on Natural Resources," and its June 1967 report entitled, "Alaska Natural Resources and the Rampart Project." As presented in the latter report, the projects which appear to be more attractive, economically, include Wood Canyon on Copper River; Yukon-Taiya near Skagway; Holy Cross, Woodchopper, and Ruby on the Yukon River; Crooked Creek on Kuskokwim, and Upper Susitna River. The list includes the Denali, Vee, Watna, and Devil Canyon units. Of these projects, the Yukon-Taiya project is currently receiving consideration by the United States and Canada for possible joint study as an international development. This project would involve regulation of the flows of the upper Yukon River in Canada and diversion of those flows to a powerplant in the United States near Skagway in Southeastern Alaska.

The Alaska Power Administration has recently completed feasibility studies and reports on the Lake Grace and Takatz Creek projects in the Southeastern Region. The feasibility reports show the projects to be economically justified and financially feasible, but authorization of their construction was not requested because of the high per kilowatt investment costs of the projects and the possibility of development of diesel alternatives with somewhat higher annual power costs.

A proposal which would divert Alaska waters through British Columbia, eastward to the Great Lakes and Hudson Bay, and south through the arid western United States into Mexico, was advanced by the Ralph M. Parsons Co. in 1964 as the North American Water and Power Alliance. The NAWAPA plan includes major storage projects on the Tanana, Susitna, and Copper Rivers in Alaska. Considering all of the pertinent factors, it appears

TABLE 17—Continued

Summary of Initial Evaluation of Alaska Hydroelectric Potentialities—Continued

Active storage (1,000 AF)	Range in static head (feet)	Average head (feet)	Average annual runoff (1,000 AF)	Percent regulation	Continuous power (1,000 kw.)	Firm energy (kwh. x 10[6])	Installation at 50% load factor		Installation at 25% load factor	
							Installed capacity (1,000 kw.)	Construction cost (dollars per installed kilowatt [16])	Installed capacity (1,000 kw.)	Construction cost (dollars per installed kilowatt [16])
105	400–300	347	[3] 410	89	12	104	24	1,000	47	700
150	475–405	413	[1] 290	96	11	94	21	[12] 700	43	500
132	326–240	275	[1] 336	91	8	69	15	900	30	700
141	630–615	615	[1] 272	91	14	124	28	900	57	600
67	374–300	339	[1] 114	96	3.5	31	7	900	14	600
82	1026–886	969	[1] 129	95	11	97	21	900	42	600
106	400–230	333	[1] 212	88	6	51	12	1,000	23	600
21,000	2100–2050	1,913	[7] 13,500	100	[13] 2,400	21,000	[9] 3,200	[14] 300		

[12] Includes fish and wildlife mitigation measures.

[13] Diversion of Yukon-Taiya flow from Yukon River would reduce continuous power at downstream sites, by the following amounts: (1) Woodchopper 380,000 kw (2) Rampart 610,000 kw (3) Ruby 90,000 kw (4) Holy Cross 120,000 kw (5) Unevaluated amounts in other reaches of the Yukon River.

[14] Department of Interior Rampart Project January 1965 Field Report (table 59).

[15] House Document No. 455, 87th Congress, 2d Session, cost estimate indexed to October 1965 prices plus additional powerplant and diversion costs for plan revisions.

[16] Rounded to nearest $100.

[17] Maksoutof.

[18] Khvostof.

that the NAWAPA, or any other similar alternative plan, lies in the more distant future, beyond the period covered by this Survey.

Trends in Ownership of Hydroelectric Plants

Many of the early hydroelectric developments in Alaska provided energy for mining or cannery operations and were constructed with private capital. The development of electric service for public use was usually the result of community action. Most of the utility distribution systems are municipally owned and the generating facilities were developed by the municipalities. New hydroelectric plants have been constructed mainly with public financing, Federal or non-Federal. As a result, the percentage of privately financed hydroelectric generation has declined. Public ownership accounted for only 41 percent of the installed capacity in 1950. In 1965, the public share had increased to 79 percent of which the Federal Eklutna project alone accounted for 46 percent.

Evaluation and Use of Hydroelectric Capacity

Hydroelectric power is unique in that it does not require fuel for the generation of energy, but depends on the renewable energy resource provided by the recurring hydrologic cycle of rainfall, runoff, evaporation, and transpiration. Since hydropower depends on the hydrologic cycle, the amount of generation varies from year to year. Hydroelectric plants are also relatively expensive to build, since massive structures or long pipelines, or both, are required to create or utilize head and regulate the flow of water to the generating machinery. Since plant sites are frequently remote from load centers, expensive transmission facilities are often a major cost factor.

In comparison with thermal-electric plants, hydroelectric projects have several distinct advantages. They do not consume or heat the water they use, and they do not contribute to air pollution. Maintenance costs are relatively low, and it is possible to design the plants for virtually complete automatic or remote-control operation. Since they have long life, depreciation charges are low, and future costs are relatively predictable. Generating units are more reliable than steam-electric equivalents because they operate at relatively low speeds and are not subject to severe temperature stresses. Outage rates for hydroelectric units are normally about one-fourth those of modern steam-electric machines.

Hydroelectric development frequently provides opportunities for other related benefits, such as flood control, water supply, recreation, water-quality control, fish and wildlife enhancement, and cooling water for steam-electric and industrial plants. Multipurpose uses make possible developments which would be uneconomic for single-purpose hydropower development.

The 15,000-kilowatt Cooper Lake hydroelectric plant of the Chugach Electric Association is located in the central section of the Kenai Peninsula.

Capacity to be installed at hydroelectric projects is judged on the basis of head and streamflow. Minimum flows are estimated statistically from historical records. Installations are often increased by construction of storage reservoirs. From the standpoint of power requirements, installations may also be sized on the basis of kilowatt-hours of energy to accompany kilowatts of capacity.

Most projects operating in Alaska have been developed to serve specific loads. Some were planned to serve hydraulic mining loads and were intended to operate only during the summer months. Others were constructed to serve small cannery operations, while the A. J. Industries plants were built to provide power for a very large underground mining and refining operation. Plants built to provide utility service were usually sized to operate at the annual load factor of the system to be served.

In recent years, hydroelectric generation has been supplemented, and in some instances replaced, by other types of generation, and the operation of the hydroelectric plant has been changed to conform to the needs of the owner. Thus, some plants without water storage now operate more or less continuously using the available water so as to reduce the amount of fuel burned in other plants. Others with storage available to regulate flows are operated to supply system peakloads as well as to reduce fuel use.

In Alaska, with an abundant supply of low-cost natural gas near the major load centers, the chief role of many hydroelectric plants may well be to serve peakloads. However, some of the larger hydro projects may be considered favorably in later years when greatly expanded loads must be served.

Projected Hydroelectric Developments

An appraisal of the undeveloped powersites in Alaska was made for purposes of this survey by a committee which included representatives of the Corps of Engineers, Alaska Power Administration, and Alaska Department of Natural Resources.

From a list of some 700 sites which were screened by quick approximation of construction requirements and power potential, some 245 locations were found to be worthy of further investigation. Water supply, power production, and cost estimates were made for each of the 245 sites to determine probable costs of firm energy. This further appraisal reduced the number of sites which appear to offer the best potential for development to the 76 sites listed by areas in table 17 and shown on the hydroelectric map, figure 7.

This group of potential plants range widely in capacity from as little as 7,000 kilowatts to as much as 5,040,000 kilowatts; estimated costs range from \$200 to \$1,800 per kilowatt of installed capacity, assuming installations designed to operate at 50 percent annual plant factor or greater.

Summary and Conclusions

Hydroelectric projects have many favorable characteristics which warrant strong consideration of the many potential sites in Alaska. These plants have very long lives and low operation and maintenance costs, use a renewable resource, permit regulation of streamflows to enhance conditions for fish and wildlife, offer possibilities for recreational development, and provide flood control. They operate at relatively slow speeds, respond quickly to changing power requirements, and have a high degree of reliability.

Some sites are suitable for the development of pumped storage and for the production of low plant factor peaking power. Such service would appear to be particularly appropriate for projects located near the railbelt which could be connected to a transmission network serving the Anchorage load area or the interconnected load areas of Anchorage and Fairbanks, and supply relatively short-term daily and seasonal peak load demands in coordination with baseloaded thermal-electric plants.

Investment costs for hydroelectric projects in Alaska are relatively high. It is reasonable to expect that most of the hydroelectric projects that may be developed in the future will be for multipurpose use and that the larger projects will be Federally financed. A few of the more favorably located smaller sites may be found attractive for development by private, cooperative, or municipal systems. Development of more of the major sites may be economical when powerloads have expanded sufficiently to utilize the potential output of such installations.

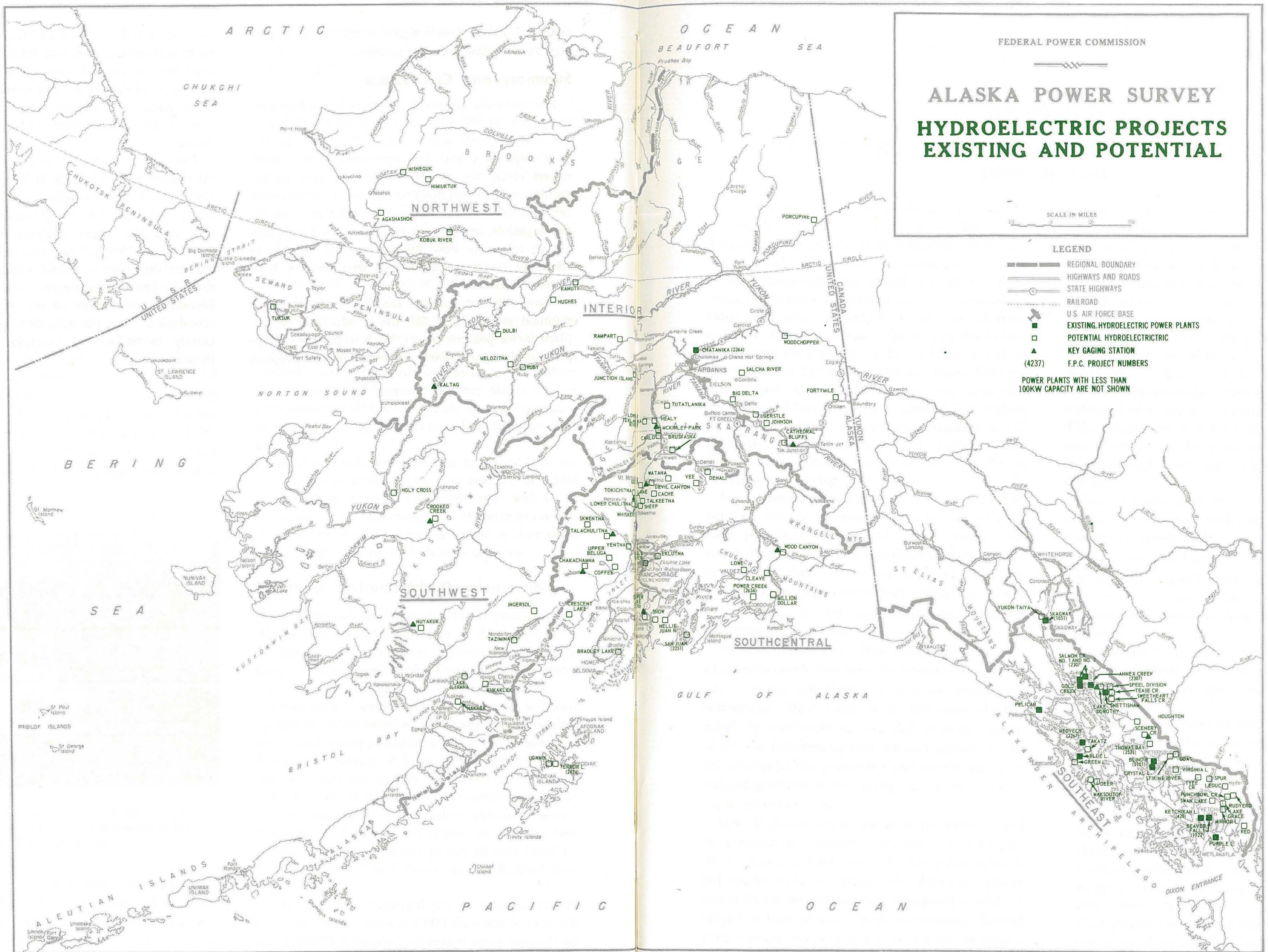

FEDERAL POWER COMMISSION
ALASKA POWER SURVEY
HYDROELECTRIC PROJECTS EXISTING AND POTENTIAL
SCALE IN MILES
LEGEND
REGIONAL BOUNDARY
HIGHWAYS AND ROADS
STATE HIGHWAYS
RAILROAD
U.S. AIR FORCE BASE
EXISTING HYDROELECTRIC POWER PLANTS
POTENTIAL HYDROELECTRICTRIC
KEY GAGING STATION
(4237) F.P.C. PROJECT NUMBERS
POWER PLANTS WITH LESS THAN 100KW CAPACITY ARE NOT SHOWN
ARCTIC OCEAN
BEAUFORT SEA
CHUKCHI SEA
BERING SEA
NORTON SOUND
BRISTOL BAY
GULF OF ALASKA
PACIFIC OCEAN
NORTHWEST
INTERIOR
SOUTHWEST
SOUTHCENTRAL
SOUTHEAST
ALEUTIAN ISLANDS
ALEXANDER ARCHIPELAGO
DIXON ENTRANCE

Figure 7

CHAPTER VI

PRESENT AND PROSPECTIVE PROGRAM FOR COORDINATED DEVELOPMENT

Principal electric service in Alaska is centered in the State's three more populous areas—Anchorage, Juneau, and Fairbanks. Interconnections of limited capacity and use have been constructed among some of the utilities and some nonutility systems in these areas, but because of distance, limited magnitude of loads, and other factors, there are no interconnections between areas. These principal load centers and the transmission lines which serve them are shown in figure 8. Interconnections between utilities and major nonutilities and their capacities and principal uses are listed in table 18. The highest transmission voltage in service in Alaska was 115 kilovolts until the Chugach and Golden Valley Electric Associations each placed new 138-kilovolt lines in service during 1968.

Even though physical connections are available between most of the systems serving each of these more populated centers and their adjoining suburban and rural sections, coordinated planning and operation of these systems has not received full attention. To a large extent, each utility has moved independently to develop its own power resources and transmission system.

Alaska's growth has followed the general pattern of an early developing area. Its gradual but continuous economic unfolding has been supported by a widespread fishery industry, by the uncertain but relatively continuous construction or improvement of defense facilities, by new resource discoveries, by innovation in the processing and marketing of its natural products, some for export, and by an exciting increase in tourism.

Electric power has grown with the economy and in a randomly responsive manner. Early electric service was provided largely by struggling municipal systems or by companies who developed power primarily for mining or fish canning and shared the output of their plants with the community. Several rural electric cooperatives were started in Alaska beginning in the late 1940's. Cooperative systems are now among the principal suppliers of electricity in Anchorage and Fairbanks load areas.

Service territories are not always clearly defined and expansion of municipal boundaries into outlying areas has sometimes resulted in a competitive struggle to capture new loads or load areas. As in many other locations in the United States, parallel distribution facilities in the outlying areas are not uncommon. Competition can be stimulating and beneficial if it does not result in duplicate service facilities and entrenched conflicts which impede coordinated planning and operation of utility systems. This chapter outlines some of the ways in which power service can be aided, economically and reliably, through closer association of Alaska's utility systems.

Benefits accruing to utilities which are interconnected and coordinate their planning and operation can be very substantial:

Important savings in capacity investments are nearly always possible through the joint or staggered construction of larger, more economical, generating plants and from a sharing in system reserves.

Diversity in the occurrence of peakloads and the coordination of maintenance schedules may be sources of further savings in generation investments.

The various forms of peaking and base load generation may be more efficiently utilized in supplying the total load if coordination is effected.

Reliability is enhanced through interconnections by making available to each of the interconnected systems a larger mass of rotating machinery which can instantly help to overcome the shock of a sudden large loss in generating capacity or the interruption of a segment of the transmission network. Agreements to utilize the more efficient generating units of the interconnection at any given time will save on fuel and operating expense.

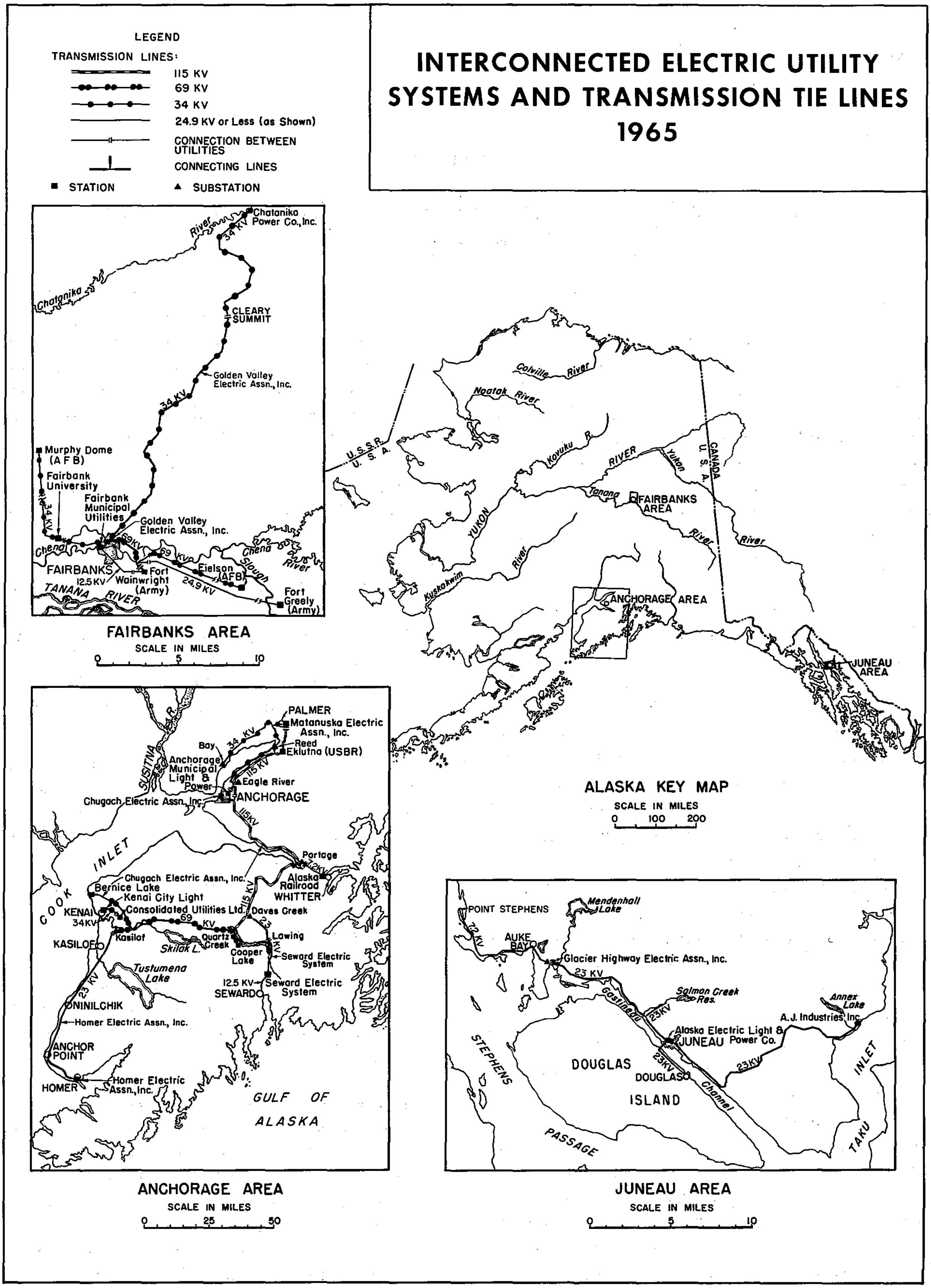

INTERCONNECTED ELECTRIC UTILITY SYSTEMS AND TRANSMISSION TIE LINES 1965
LEGEND
TRANSMISSION LINES:
115 KV
69 KV
34 KV
24.9 KV or Less (as Shown)
CONNECTION BETWEEN UTILITIES
CONNECTING LINES
STATION
SUBSTATION
Chatanika Power Co., Inc.
34 KV
River
Chatanika
CLEARY SUMMIT
Golden Valley Electric Assn., Inc.
34 KV
Murphy Dome (A F B)
Fairbank University
Fairbank Municipal Utilities
Golden Valley Electric Assn., Inc.
69 KV
Chena
FAIRBANKS
12.5 KV
Fort Wainwright (Army)
Eielson (AFB)
24.9 KV
Chena River
Slough
Fort Greely (Army)
TANANA RIVER
FAIRBANKS AREA
SCALE IN MILES
0 5 10
Colville River
Noatak River
Koyukuk R.
RIVER
Yukon
U.S.S.R.
U. S. A.
CANADA
U. S. A.
Tanana
FAIRBANKS AREA
YUKON
River
River
Kuskokwim
River
ANCHORAGE AREA
JUNEAU AREA
ALASKA KEY MAP
SCALE IN MILES
0 100 200
PALMER
Matanuska Electric Assn., Inc.
Bay
34 KV
Reed
Eklutna (USBR)
SUSITNA
R.
Anchorage Municipal Light & Power
115 KV
Eagle River
Chugach Electric Assn., Inc.
ANCHORAGE
115KV
INLET
Portage
12KV
Chugach Electric Assn., Inc.
Alaska Railroad
Bernice Lake
WHITTER
Kenai City Light
115 KV
COOK
KENAI
Consolidated Utilities Ltd.
Daves Creek
34KV
69
KV
23
KASILOF
Kasilof
Quartz Creek
Lawing
Skilak L.
KV
Cooper Lake
Seward Electric System
Tustumena Lake
23 KV
12.5 KV
Seward Electric System
SEWARD
NINILCHIK
Homer Electric Assn., Inc.
ANCHOR POINT
HOMER
Homer Electric Assn., Inc.
GULF OF ALASKA
ANCHORAGE AREA
SCALE IN MILES
0 25 50
POINT STEPHENS
Mendenhall Lake
72 KV
AUKE BAY
Glacier Highway Electric Assn., Inc.
23 KV
Salmon Creek Res.
Gastineau
23KV
Annex Lake
A. J. Industries, Inc.
Alaska Electric Light & Power Co.
JUNEAU
23KV
STEPHENS
DOUGLAS
23KV
DOUGLAS
INLET
ISLAND
Channel
PASSAGE
TAKU
JUNEAU AREA
SCALE IN MILES
0 5 10

Figure 8

TABLE 18

Interconnections Between Utilities and Major Nonutility Installations, 1965

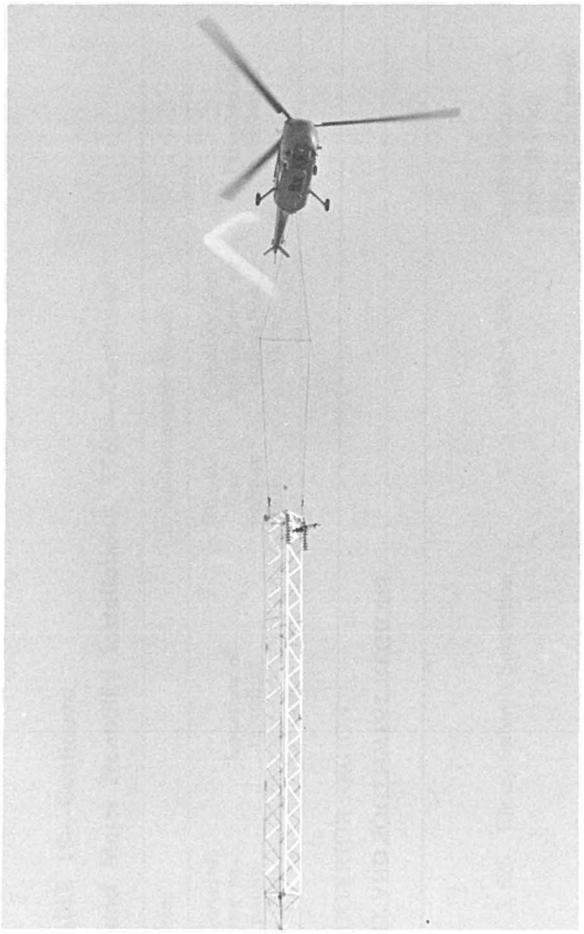
Principal generating utility		Other utilities and nonutilities		Interconnection details			
Name	Generating capacity (kw.)	Name	Generating capacity (kw.)	Location of terminal	Bus-tie line voltage (kw.)	Capacity terminal, line, or substation (kva.)	Purpose of installation
SOUTHCENTRAL REGION							
Utilities and nonutilities which maintain direct connections:							
Consolidated Utilities, Ltd.	2, 654	Kenai City Light	0	Consolidated Utility Plant Substation.	2. 4/33. 0	(Sub) 3, 700	Firm power delivery to Kenai City.
Chugach Electric Association Inc.	69, 400	Eklutna Project, USBR	30, 000	USBR Anchorage Substation.	34. 5	(Lines) 40,000	Interchange firm and nonfirm.
Do	69, 400	City of Seward	3, 000	C.L.A. Daves Creek Substation-Seward line at Lawing.	24. 9	(Sub) 3,000	Firm power delivery to Seward.
Do	69, 400	Homer Electric Association Inc.	0	Kasilof Substation	69. 0	(Sub) 3,750	Firm power delivery to Homer.
Do	69, 400	Alaska Railroad	4	Whittier near Portage Substation.	12. 5	(Sub) 2,500	Nonfirm power receipt from Alaska Railroad.
Anchorage Municipal Light and Power Department.	36, 769	Eklutna Project, USBR	30, 000	USBR Anchorage Substation.	34. 5	(Line) 20,000	Firm power receipt from USBR.
Eklutna, USBR	30, 000	Matanuska Electric Association Inc.	0	USBR Palmer substation M.E.A./USBR Reed substation.	12. 5 34. 5/12. 5	(Sub) 5,000 (Sub) 1,500	Firm power delivery to Matanuska Electric Association.
Utilities and nonutilities for which common terminals are available but direct connections are not maintained:							
Chugach Electric Association Inc.	69, 400	Anchorage Municipal Light and Power Department.	36, 796	USBR Anchorage Substation	34. 5	Switching	Emergency.
Do	69, 400	Elmendorf Air Force Base	24, 100	do	34. 5	do	Do.
Eklutna Project, USBR	30, 000	do	24, 100	do	34. 5	(Line) 20,000	Do.
Anchorage Municipal Light and Power Department.	36, 769	do	24, 100	do	34. 5	Switching	Do.
Do	36, 769	Chugach Electric Association Inc.	69, 400	do	34. 5	do	Do.

TABLE 18—Continued

Interconnections Between Utilities and Major Nonutility Installations, 1965—Continued

Principal generating utility		Other utilities and nonutilities		Interconnection details			
Name	Generating capacity (kw.)	Name	Generating capacity (kw)	Location of terminal	Bus-tie line voltage (kw.)	Capacity terminal, line, or substation (kva.)	Purpose of installation
INTERIOR REGION							
Utilities and nonutilities which maintain direct connections:							
Golden Valley Electric Association Inc.	21, 245	Chatanika Power Co.	5, 625	Cleary Summit Substation	34. 5	(Sub) 4,500	Nonfirm wholesale receipt from Chatanika.
Do	21, 245	University of Alaska	3, 000	University Substation through Sheep Creek breaker.	34. 5	(Sub) 7,500	Nonfirm wholesale receipt from University.
Do	21, 245	Fort Wainwright—Army	22, 000	Fort Wainwright Substation.	69. 0	(Sub) 7,500	Nonfirm transfers.
Do	21, 245	Fort Greely—Army	5, 000	Through Highway Park Substation.	69. 0	(Sub) 2,500	Do.
Do	21, 245	Murphy Dome—Air Force Base.	1, 160	Near University Substation through Sheep Creek breaker.	34. 5	(Sub) 1,000	Do.
Do	21, 245	Eielson—Air Force Base	9, 000	Eielson Substation	69. 0	(Sub) 5,000	Do.
Fairbanks Municipal Utilities System.	15, 500	Fort Wainwright—Army	22, 000	Fairbanks 19th St. Substation.	12. 5	(Sub) 7,500	Nonfirm emergency standby from fort.
Utilities and nonutilities for which common terminals are available but direct connections are not maintained:							
None (Golden Valley and Fairbanks not directly interconnected).							

SOUTHEAST REGION							
Utilities and nonutilities which maintain direct connections:							
Alaska Electric Light and Power Co.	8, 686	Glacier Highway Electric Association.	0	Juneau Mile 11 Glacier Highway and Upper Mendenhall River Bridge on Loop Road.	22. 0	(Sub) 1,050	Firm power delivery to Glacier Highway Electric Association.
Do	8, 686	Alaska-Juneau Industries	8, 400	Various	22. 0	Line	Firm power receipt from Alaska-Juneau (6,700 kw.).
Sitka Public Utilities	7, 300	HEW (Japonski Island Hospital) 3,000 kw. (S); Sitka Cold Storage, 250 kw. (D); Pioneer Nome, 50 kw. (D); Sheldon Jackson School, 75 kw. (H); Alaska Lumber and Pulp Mill, Inc., 15,000 kw.					Emergency interchange and dump power.
Ketchikan Public Utilities	10, 673	Ketchikan Spruce Mills, 900 kw.; Ketchikan Pulp Mill, 20,750 kw.; New England Fish Co., and miscellaneous other canneries and cold storage plants.					Emergency interchange and dump power.
NORTHWEST AND SOUTHWEST REGIONS							
None							



A typical corner structure element placed by helicopter on the Golden Valley Electric Association's 138-kilovolt transmission line between Healy and Fairbanks.

There are many precedents elsewhere in the United States of coordination agreements, joint ventures, and other types of cooperative efforts among private, public, municipal, and industrial utility interest which operate to the mutual advantage of all concerned. Similar types of arrangements would seem to offer potential benefits for a number of the Alaska utilities. Some examples of joint ventures and coordinating arrangements now in operation are listed below:

A joint venture in which one State-owned and five investor-owned utilities have undivided interests in two 750-megawatt steam generating units in the Four Corners plant near Farmington, N. Mex. The ownership, by participants, is Southern California Edison Co., 48 percent; Arizona Public Service Co., 15 percent; Public Service Co. of New Mexico, 13 percent; Salt River Project (a publicly owned system), 10 percent; Tucson Gas & Electric Co., 7 percent; and El Paso Electric Co., 7 percent.

A similar joint venture in which two investor-owned utilities, two municipal-, and one State-owned system will have undivided interests in two 750-megawatt units now under construction at the Mohave plant in southern Nevada. Percent ownership will be: Southern California Edison Co., 50 percent; Los Angeles Department of Water and Power, 20 percent; Nevada Power Co., 16 percent; Salt River project, 10 percent; and Glendale Public Service Department, 4 percent.

An agreement under which the Rushmore Electric Power Cooperative, Inc., owns a generating unit in the Osage plant of the Black Hills Power & Light Co. The unit is leased to, and operated by, Black Hills.

A contract under which two 615-megawatt units were constructed and are being operated by Ohio Power Co. at the Cardinal plant. Ownership of one of the units was transferred to Buckeye Rural Electric Cooperative, Inc., upon completion. Buckeye financing in this instance came from the open market.

An arrangement between the Garden City, Kansas Municipal Utilities, and the Wheatland Electric Cooperative, Inc., whereby the municipal generating plant is interconnected with and operated by the Cooperative.

A joint venture in which the Duane Arnold 538-megawatt nuclear plant near Cedar Rapids, Iowa, will be owned by one investor-owned utility and two cooperatives. Ownership is: Iowa Electric Light & Power Co., 80 percent; Central Iowa Power Cooperative, 10 percent; and Cornbelt Power Cooperative, 10 percent.

There are numerous examples of coordinated construction of transmission lines. Generally, each utility constructs, owns, and operates the section of the line in its own service area. If connection costs are not reasonably in balance with use of the line by individual utilities, equalizing payments are made.

Many power-pool agreements encompass different ownership segments in a single-pool agreement. A few examples include:

The Texas Municipal Power Pool which includes the cities of Bryan, Garland, and Greenville, Tex., and the Brazos Electric Power Cooperative, Inc.

An upper Michigan group composed of the cities of Grand Haven and Traverse City, the Northern Michigan Electric Cooperative, Inc., and the Wolverine Electric Cooperative, Inc.

A Louisiana group composed of the city of Lafayette Utilities System, the Louisiana Rural Electric Corp., and the Dow Chemical Co.

The Missouri Basin Systems group which includes a large number of organizations under Federal, municipal, and cooperative ownership.

Within the period of development covered by the Survey, many of the small scattered utilities are unlikely to find economic ways to join even with their closest neighbors because of problems of intervening terrain, water, weather, and distance. An appraisal has been made, however, of the possibilities for interconnections between utilities and villages most likely to be benefited. Interties, other than those required to interconnect the Anchorage-Kenai and Fairbanks load centers, likely would be at voltages lower than 115,000. A system using single-phase, single-conductor with earth return, at 79,000 volts has been suggested to provide electric service to small communities in the outlying Fairbanks area. Underground direct-current cable has also been suggested for some areas.

The Rural Electrification Administration (REA) has recently allocated $5 million for beginning a project to supply electric power to some of the larger native villages, generally with populations in excess of 200, which do not have electric service. Most of the villages are widely separated and are not in position to be interconnected. The Alaska Village Electric Cooperative was originated in 1967 as a statewide REA borrower to serve these scattered villages. It is contemplated that power would be supplied by diesel-electric generating units which could be flown into a central repair shop for necessary servicing and maintenance. Construction and maintenance would be handled by a small centralized staff using native workers. Day-to-day servicing and maintenance of underground distribution facilities would be performed by an on-the-job trained resident of the village on a part-time basis. At best, the cost of electric service will be high, tentatively projected to be in the range of 15 cents per kilowatt-hour for residential service and 10 cents per kilowatt-hour for small commercial service.

Planning by Regions

The following sections discuss the various regions of Alaska in terms of present electric power facilities, potential for growth, and suggestions for future development.

Southcentral Region

Load Distribution

In 1965, the nonmilitary population of the Southcentral Region was estimated to be 108,000, making up 60 percent of the nonmilitary population for the entire State. The principal concentration of population and industry in this area is in the Kenai Peninsula, the greater Anchorage area, and the Matanuska Valley.

The discovery of oil and gas in the Cook Inlet area, the construction of an oil refinery and petrochemical plant, and the prospects of a liquified gas market portend, by far, the largest economic evolutions in Alaska's history. This exploration and accompanying production activity has resulted in an unprecedented load growth in the Kenai Peninsula and greater Anchorage areas. The loads of the Homer Electric Association have grown from a peak of 450 kilowatts in 1956 to nearly 5,000 kilowatts in 1965, for an average annual growth of 31 percent. The Chugach Electric Association and the Anchorage Municipal Light & Power systems have also enjoyed very substantial load growths. Their combined loads in 1956 totaled 28,800 kilowatts; their 1965 total was approximately 82,000 kilowatts. The load growth in the Matanuska Valley area, served by the Matanuska Electric Association (MEA), has also been exceptional, although not as steady as in the Kenai Peninsula or greater Anchorage areas. The MEA load in 1965 was 7,900 kilowatts.

In addition to the loads of the four major utilities mentioned above, there are smaller isolated loads served by the Cordova Public Utility, Seward Electric System, Copper Valley Electric Association of Glenallen and Valdez, and the Kodiak Electric Association.

Existing Interconnected Operations and Power Pools

Existing system interconnections in Southcentral Alaska are, at present, maintained for the purpose of mutual assistance in times of emergency, rather than for broadly planned pooling benefits.

In the past, Alaskans have been inclined to accept power interruptions as something to be expected and tolerated as a way of life in the far north. If service was restored within an hour or so, there was little, if any, complaining. Now, however, as in the lower States, electricity has become a commodity in which great dependence is placed on a minute-by-minute basis, and generation and transmission reliability must be emphasized in planning system additions.

The utilities in Southcentral Alaska are especially cognizant of the need for an organized power pool, not only for the purpose of improving overall reliability, but also to enable them to obtain energy at the lowest possible cost. Much cooperation and detailed study in the midst of rapidly growing power systems is required to set up areawide scheduling of power sources in order that full advantage may be taken of the inherent characteristics of the various types of prime movers and fuels available.

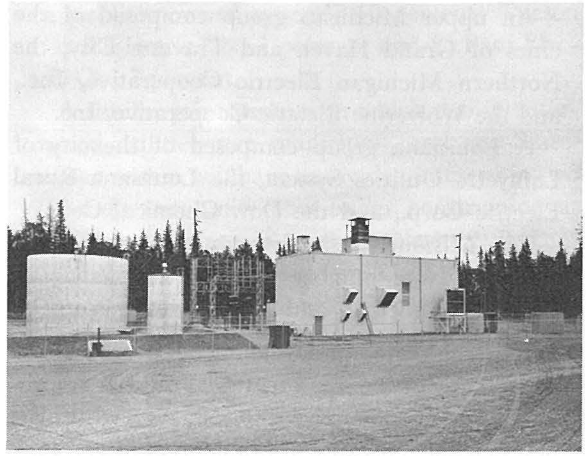
Present Generating and Transmission Facilities

Appendix A lists, by location and total installed 1965 capacities, the various utilities serving Southcentral Alaska. Through initial necessity, individual systems have grown in increments of relatively small generating units. Even at this time, units in the 15-megawatt class are still the largest sizes being installed. This practice results in high-basic generating costs. Many of these existing small package-type units will continue to serve a useful role as a source of peaking and standby capacity even after large (100 megawatts and up) steam or hydro units come into operation.

There is presently only one backbone transmission system in operation in Southcentral Alaska. This is the interconnected 115-kilovolt line of the Alaska Power Administration (APA), serving Palmer and Anchorage, and the Chugach Electric Association's line from Anchorage to its Cooper Lake hydroelectric project.

Possible Programs of Development by 1975 and 1985

The Chugach Electric Association (CEA) in early 1968 completed and placed in service a 138-kilovolt transmission line which will transmit power from its new 32-megawatt well-head gas-turbine powerplant in the Beluga gas fields. This line crosses the Knik Arm from near Point McKenzie to Anchorage via submarine cables. The line continues overhead to the Chugach Electric's International substation to provide an interconnection with Cooper Lake and the APA Eklutna hydroplant. The CEA's Beluga plant constitutes the largest expansion of generating facilities under construction in the region at the present time. The initial installation is two 16,000-kilowatt gas turbines with gas commitments for an ultimate 125-megawatt capacity. Expansion of generation at Beluga should consider gas-fired steamplants with their lower production costs.



This 8,850-kilowatt Bernice Lake gas-turbine generating plant on the Chugach Electric Association System is located on the western side of the Kenai Peninsula.

The Anchorage Municipal Light & Power System installed a third 16-megawatt gas turbine during the fall of 1968. There are also plans to add a 22-megawatt steamplant by 1975 which would utilize waste heat from the turbine units.

The Bradley Lake Hydro project on the Kenai Peninsula was authorized in 1962 for Federal construction. However, funds have not been provided to date. New hydrology data suggest that bus-bar generation costs can be reduced. Generation from the Bradley Lake project can be attractive, particularly for peaking purposes. Consideration is being given to a 25-percent load factor, 187-megawatt plant design.

The above plants are essentially peaking-type installations and because of their small size do little to produce low-cost, baseload energy required to meet projected powerloads. Large low-cost generation sources must be developed if there is to be a reduction in rates and improvement in reliability of service to the ultimate consumer.

In order to justify the initial investment in these larger baseload generating plants, this study suggests that large, well-head gas-fired central steamplants be built near the Kenai and Beluga gas fields and that interconnections with Interior Alaska be considered for the purpose of absorbing the surplus energy and augmenting plant reserves, while at the same time making lower cost energy available in the Fairbanks area.

Reinforcement of the present interconnection between Homer, Kenai, Seward, Anchorage, and the Matanuska Valley is necessary. The addition of a 230-kilovolt tie between the Kenai Peninsula and Anchorage and a 115-kilovolt line to Palmer will be necessary to meet systemwide reliability and electrical stability under assumed 1985 loads.

The Copper Valley Electric Association is studying an intertie between Valdez and Glenallen. This system will ultimately (beyond this study period) tie into the railbelt system at Palmer or at the Susitna River power complex.

Summary of Southcentral Region

With practically unlimited gas reserves in the Cook Inlet area and attractive hydro sites on the Kenai Peninsula and on the Upper Susitna River, every effort should be made to take full advantage of these natural resources. To do so requires that the thermal generation be accomplished with the largest central station gas-fired steam units that anticipated loads will justify. Once this baseload energy resource is established, the most attractive hydro sites should be fully explored as a source of low-cost peaking capacity for coordinated operation with a gas-fired unit.

With the development of these energy resources, the operating utilities and other entities have an obligation to unify their individual efforts through joint planning of transmission systems and interconnections to establish a basis for the pooling of these resources and facilities for the maximum benefit of the ultimate consumer. Southcentral Alaska utilities are in a most favorable position to make substantial contributions to the overall economy of a large segment of the State of Alaska.

Interior Region

Load Distribution

The Interior Region is characterized by concentration of population, commerce, and Federal facilities along the main transportation route following the Tanana and Nenana Rivers. The principal population center is the city of Fairbanks. Much smaller concentrations occur along the transportation belt in the small cities of Delta Junction, North Pole, Nenana, and Healy. The principal Federal installations include Fort Greely, Eielson Air Force Base, Fort Wainwright, Clear Air Force Base, and McKinley National Park. North of this main transportation belt are numerous very small military and FAA installations. With very few exceptions, central station electric service is not available in these outlying communities. Small isolated diesel generating units, at or near the loads, provide essential electricity.

The concentration of population and commerce in the immediate vicinity of the city of Fairbanks means, of course, that the use of electricity is also concentrated in this same area. It is expected that, over the period of this study, electrical loads will continue to grow at a rapid rate, but with no significant change from the basic pattern of concentration in the vicinity of Fairbanks and scattered distribution along the transportation route.

Two peculiarities of the Interior Region may have considerable effect on the development of the Region's electric systems. The present utilities in this Region were established in the early 1950's. Consequently, the military bases and industries established before 1950 (and in some instances, much later than 1950) of necessity had to provide their own generating facilities. The larger complexes utilized coal for fuel and extraction steam for space heating. Coal is still the lowest cost source of thermal energy for space heating. However, the utilities are making rapid progress in reducing the price of electricity, and it is conceivable that before long, electricity may replace coal as the principal source of thermal energy, even for the relatively large military and industrial installations.

Local climatic conditions result in the production of ice fog from combustion products during many days of the winter, and public recognition of the undesirable results could bring about the substitution of electricity for onsite combustion somewhat in advance of the dictates of pure economics. The Fairbanks public has become familiar with ice fog and the University of Alaska has been conducting research studies on the problem. Perhaps the ice fog situation, coupled with a promotional rate structure and the decision of many residents to move to higher ground after the 1967 flood, accounts for the fact that Fairbanks already has 400 electrically heated homes.

Operating Utilities

Appendix A lists the principal operating utilities in the Region. In addition, very small electric utilities certified by the Alaska Public Service Commission are in operation at Tok, Fort Yukon, Hughes, Manley Hot Springs, Northway, Lake Minchumina, Dot Lake, and Rampart.

The Fairbanks Municipal Utilities System generally serves the city of Fairbanks, and the Golden Valley Electric Association, Inc., provides electric service in the suburbs, such as College, where the University of Alaska is a major power purchaser. Golden Valley also operates an extensive subtransmission system to connect with military bases, and serves outlying communities, such as Delta Junction, Nenana, and Healy.

Existing Interconnected Operation and Power Pools

The two utilities, Fairbanks Municipal and Golden Valley, have since their inception, been interconnected by ties of relatively small capacity. In recent years, the previously isolated military installations of Fort Wainwright, Eielson Air Force Base, and Fort Greely have been interconnected through the subtransmission and distribution facilities of Golden Valley. The principal use of this military interconnection has been to wheel energy from Fort Wainwright to the other military installations. There are no true power pools at present though rapid progress is being made toward the establishment of a Fairbanks pool.

Present Generating and Transmission Facilities

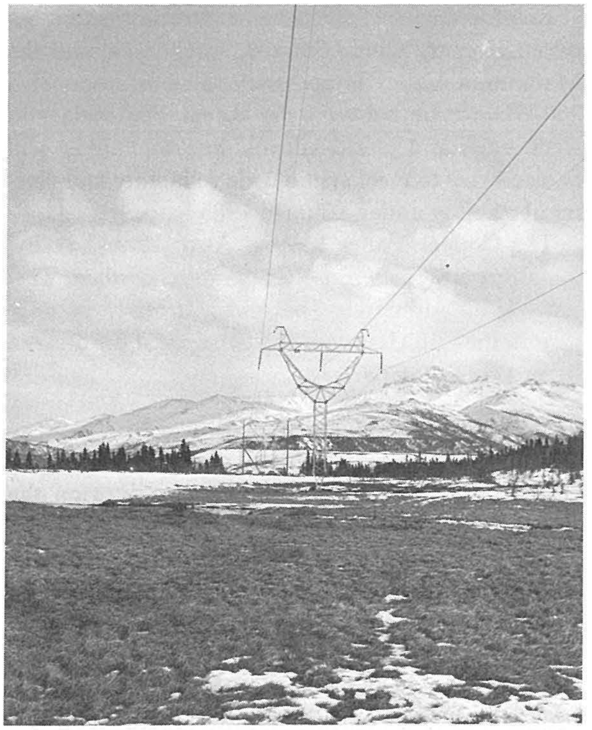
Present generating and transmission facilities, by ownership, are as follows:

Fairbanks Municipal	8.5 mw. steam, 7.0 mw. I.C.
Golden Valley Electric	22.0 mw. steam, 9.5 mw. steam,[1] 11.7 mw. I.C.
Fort Wainwright	22.0 mw. steam.
Eielson Air Force Base	9.0 mw. steam.
Fort Greely	5.0 mw. I.C.
Clear Air Force Base	22.5 mw. steam.
University of Alaska	3.0 mw. steam.
GVEA	69-kv. subtransmission Fairbanks to Eielson Air Force Base via Fort Wainwright, 138-kv. Healy to Fairbanks.

[1] Used as reserve and scheduled for early retirement.

Possible Programs for Development by 1975 and 1985

Assuming that the Interior Region remains isolated electrically from the rest of Alaska, as is now the case, the best known source of additional electrical energy through 1985 appears to be mine-mouth coal-fired steamplants at Healy. By 1975, there should be 110 megawatts of installed capacity



Typical tangent structure with conductors in stringing sheaves on the Golden Valley Electric Association, Inc. 138-kilovolt transmission line from Healy Generating Plant to Fairbanks.

at the Healy Power Plant. Energy will be transmitted to the load center at Fairbanks by two 138-kilovolt transmission lines. Standby and peaking capacity will be furnished by diesel and gas-turbine units. By 1985 steam capacity at Healy will need to be increased to about 220 megawatts and the transmission facilities to the Fairbanks load center will include three (138- and/or 230-kilovolt) transmission lines. By this time, the principal secondary load centers and Federal installations should be interconnected with the facilities of the utilities by 138- and 69-kilovolt subtransmission lines.

It appears desirable and possible, however, for a 230-kilovolt transmission interconnection to be constructed between the Interior Region and the Southcentral Region by 1975. In all probability, major generating facilities for both regions, when operated on a coordinated basis, will be located in the Southcentral Region. In this event, total installed steam capacity at Healy in the Interior Region would probably be limited to about 66 megawatts. It is possible that by 1985, 230-kilovolt transmission lines linking the two regions will be over two routes, one the direct route along the railroad between Healy and Anchorage and the other through Delta Junction and Glennallen to Anchorage.

A preliminary examination of the possibility of providing electric service to the following small scattered communities near Fairbanks has been considered.

Community	*Assumed load for study-kilowatts*
Manley Hot Springs-Baker	600
Tanana	1,800
Livengood	600
Rampart	400
Stevens	800
Total	4,200

The proposed service consists of single-phase, single-conductor, earth return, 79-kilovolt (L–G) tap lines from the existing Healy-Fairbanks 138-kilovolt transmission line (as indicated on fig. 9) via the following routes:

	Distance in miles
Route No. 1:	
Nenana (tap) Zitziana River (junction)	50
Zitziana River-Manley Hot Springs, Baker	18
Zitziana River-Tanana	57
Route No. 2:	
Fairbanks (tap)-Livengood	62
Livengood-Fish Creek (junction)	20
Fish Creek-Stevens	24
Fish Creek-Rampart	38
Total routes 1 and 2	269

Line construction and equipment capital costs are estimated to be:

1. Single-pole, single-conductor (Penguin), pole-top, station post-type insulator, ½-inch ice loading, 22-foot ground clearance, 6¾ structures per mile at $6,930 per mile.
2. Single-phase, 79-kilovolt/4.2-kilovolt (or other convenient distribution voltages) 1,000-kilovolt-ampere transformer at $10 per kilovolt-ampere.
3. Single-pole, 79-kilovolt, 3-megavolt-ampere load-break disconnect switches at $15,000.
4. Cost of miscellaneous facilities, such as relaying, land acquisition, surveying, etc., at $2,500 per load terminal.
5. Some phase-balancing equipment may be needed on the three-phase system from which these small single-phase loads are to be served, but the cost has not been estimated.

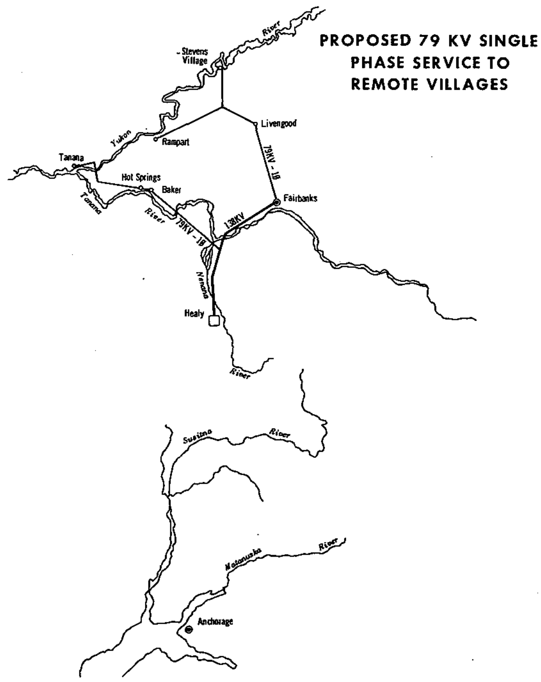


Figure 9

All of the above-cost estimates include an "Alaska factor" of 1.4. The capital investment and annual costs for the above routes were estimated to be:

	Investment	Annual cost [1]	Assumed load—kilowatts	Dollars per kilowatt	Dollars per kilowatt per year
Route No. 1	$916,000	$57,940	2,400	382	24.15
Route No. 2	1,060,000	67,150	1,800	589	37.30
Total	1,976,000	125,000	4,200	470	29.80

[1] Assumes Rural Electrification Administration financing.

Regulation and losses are summarized below:

	Percent regulation at end of line for 0.9 power factor load	Peak losses (kilowatts)
Route No. 1	2.4 at Tanana	15.4
Route No. 2	3.1 at Stevens	24.8

An interesting alternate plan of service (which has been suggested but not examined) is 15-kilovolt d.c. underground cable or overhead line with earth return.

Summary for the Interior Region

Plans for isolated development of electrical facilities in the Interior Region have been exhaustively studied by operating utilities. Coal-fired steam generation at Healy, backed up by internal combustion standby and peaking units at the load centers, is recognized as the most feasible and economical method of providing local generation for the immediate future.

There are two fields of study that deserve immediate and concentrated attention. One is the transmission interconnection between the Interior and Southcentral Regions and the installation of large, low-cost gas-fired steamplants to achieve the economic benefits available to both regions. The other is finding a practical means of providing electric service to the relatively small and dispersed settlements in the northern portion of the Interior Region, such as the 79-kilovolt single-phase, ground-return transmission scheme discussed above.

Southeast Region

The southeastern Alaska coastal region is a very rugged area with peaks on the mainland and islands rising to an elevation of 5,000 to 10,000 feet in just a short distance from tidewater. A tremendous icecap is located near the international boundary about 40 miles inland and parallels the Region for most of its length. This icecap feeds many glaciers and fjords. Bays and inlets indent all coastlines resulting in difficult and expensive roadway and transmission system construction and maintenance.

The coastline climate of the Region is mild. Rainfall is heavy with typical annual averages of 152 inches at Ketchikan and 90 inches at Juneau. Dense forests with heavy undergrowth extend up to an elevation of about 2,500 feet. The more level areas are often poorly drained, resulting in bogs of muskeg interspersed among timber stands.

Load Distribution

Major load centers of southeast Alaska that might be served by interconnected power systems by 1985 include Juneau-Sitka, Petersburg-Wrangell-Kake, and Ketchikan-Metlakatla areas. Distances and terrain preclude system interties at this time with other load centers within this Region.

Construction of a large pulp mill somewhere in southeastern Alaska is a requirement under the terms of a timber sale involving an ultimate 8.75 billion board feet of timber. Historically, sawmills and pulp mills in Alaska generally produce their own power, either with diesel units or steam turbines fired with waste products. This is particularly true of the pulp mills which, in addition to chips, also have waste process liquors for fuel. The two dissolving pulp mills in southeast Alaska generate approximately 258 million kilowatt-hours and purchase only about 6 million kilowatt-hours annually. The mill and logging operations associated with a new pulp mill are expected to employ approximately 1,000 persons. A population increase of this magnitude, together with supporting facilities, might increase the power requirements by 16,300,000 kilowatt-hours per year with a peak increase of 3,400 kilowatts in 1975.

Total Southeastern Alaska Region

Year	Energy kilowatt-hours	Noncoincidental peak kilowatts
1965	147, 741, 000	32, 200
1975 [1]	355, 000, 000	74, 800
1985 [1]	841, 000, 000	174, 900

[1] Includes new pulp mill—related requirements.

Existing Interconnected Operation and Power Pools

The Juneau-Douglas area, consisting of the cities of Juneau and Douglas and surrounding rural area, is presently served by the Alaska Electric Light & Power Co. and the Glacier Highway Electric Association, with power supplied from the interconnected plants of AEL&P and the Alaska-Juneau Mining Co. The A–J company wholesales all power produced to the AEL&P. The Glacier Highway Electric Assoc. is presently a wholesale customer of the AEL&P company but will become a preference customer of the Alaska Power Administration (APA) upon completion of the Snettisham project.

Present Generation and Transmission Facilities

The Juneau-Douglas area, as mentioned above, is served by the AEL&P with power produced by A–J company in addition to its own facilities. A–J owns and operates three hydroelectric plants in the Juneau area. Each plant has two 1,400-kilowatt units. These three plants were constructed in 1915 to supply power for gold mining operations and the mining camps. Since all mining activities are now closed, the total output of these three plants is sold to the AEL&P. Power is delivered to the utility over the mining company's 23-kilovolt transmission system.

The AEL&P operates five diesel driven generators with a combined capacity of approximately 8,000 kilowatts and three run-of-stream hydro units totaling 1,600 kilowatts.

Petersburg and the surrounding rural area is served by the Petersburg Municipal System. It operates a two-unit diesel electric plant within the city of Petersburg and a remotely controlled hydroelectric plant at Crystal Lake, approximately 16 miles from the city. The installed capacities of the plants are 1,250 and 2,000 kilowatts, respectively.

The Wrangell area is served by the Wrangell Municipal Light Department. Its generation consists of a five-unit diesel electric plant with a total installed nameplate capacity of 1,735 kilowatts.

The Ketchikan area is served by the Ketchikan Public Utilities. They presently operate two hydroplants. The Beaver Falls plant, located 12 miles southeast of Ketchikan, has four hydro units totaling 6,000 kilowatts. The Ketchikan Lakes plant has three hydro units at 1,400 kilowatts each and three internal combustion generating units totaling approximately 800 kilowatts. An additional 2,000-kilowatt unit is being added. Under recent amendment to the Beaver Falls license, Ketchikan, in 1968, completed the installation of a 2,100-kilowatt plant between the Upper and Lower Silvis Lakes for an added firm capacity of 1,140 kilowatts. A 34-kilovolt line transmits the power to Ketchikan.

The Metlakatla Power & Light Co. serves the Annette Island area, which includes the city of Metlakatla, the Coast Guard station, the Annette Island Airport, and the adjoining residential area for airport related personnel. The company operates a 3,000-kilowatt hydroelectric plant and a 1,250-kilowatt diesel electric plant.

The Sitka area, consisting of the city of Sitka, Mount Edgecumbe (made up of the Bureau of Indian Affairs and PHS Alaska Native Health Service), and surrounding rural areas, is served by the Sitka Public Utilities. They operate the two-unit hydroelectric plant at Blue Lake with a total installed capacity of 6,000 kilowatts. In addition, they have a four-unit diesel plant with a total installed capacity of 1,300 kilowatts. The Bureau of Indian Affairs has a 250-kilowatt, steam-electric standby unit to supply the hospital in emergencies.

The city of Haines is served by the Haines Light & Power Co. It operates a five-unit 1,100-kilowatt diesel plant. The nearby city of Skagway is served by the Alaska Power & Telephone Co. which utilizes both diesel and hydro generation with a total installed capacity of 840 kilowatts.

Other small isolated communities operating diesel plants include Craig, Pelican, Hoonah, and Yakutat.

Possible Programs for Development by 1975 and 1985

Additional generation will have to be developed to meet the projected loads for southeast Alaska. With no known gas fields or coal supplies, the only source of low-cost, large-unit generation for this Region is hydro, or possibly nuclear if it should become reasonably competitive in sizes compatible with the relatively small loads involved.

One major project presently under construction is the Federal Snettisham project, located on the tide flat of the Speel Arm of Stevens Passage, approximately 28 air miles southeast of Juneau. It was authorized by Congress in 1962 and is being constructed by the Corps of Engineers. The project will be operated by the Alaska Power Administration (APA) and will ultimately furnish the Juneau-Douglas area with 331 million kilowatt-hours of firm energy and 20,800,000 kilowatt-hours of nonfirm energy annually. The ultimate installed nameplate capacity for the three-unit plant is 70,000 kilowatts. Two units will be installed in the first stage of construction with a total nameplate capacity of 46,700 kilowatts. Present scheduling is for the first unit to be on the line in December of 1972.

Power at Snettisham will be converted to direct current using solid-state technology and transmitted 45 miles to the Juneau-Douglas area through two high-voltage, direct-current submarine cables with provisions for emergency sea return. Direct-current tapping techniques may open the way to a direct-current power grid in southeastern Alaska with the most likely first step being an underwater intertie with Sitka on the west coast of Baranof Island. Approximately 125 miles of cable will be required and 20 miles of overhead construction across the island.

A possible source of additional generation to meet projected loads in the Ketchikan area is the Lake Grace hydro project, located on the eastern side of Rivallagigedo Island, approximately 32 air miles northeast of Ketchikan. The Lake Grace project could furnish 94 million kilowatt-hours of firm energy and 6,270,000 kilowatt-hours of nonfirm energy. Two units would be installed with a total capacity of 20,000 kilowatts. Power would be delivered at 115-kilovolts over a 42-mile overhead transmission line. From Ketchikan, power could be delivered to the Metlakatla area on Annette Island with a 34.5-kilovolt intertie requiring approximately 16 miles of overhead transmission line and approximately 1 mile of submarine cable. Another possible source of power for the Ketchikan-Metlakatla area to be explored in cooperation with Canadian authorities would be an intertie with the British Columbia Hydro Peace River project in Canada or power purchased from the Pacific Northwest with such energy being wheeled over Canadian facilities. British Columbia Hydro is presently building two 500-kilovolt lines, with the first now in operation, from Portage Mountain in British Columbia to the lower mainland. Lines are also under construction or planned to tap this backbone system at Prince George and extend the system westward to Prince Rupert and north to Alice Arm. Either of these terminals present feasible interconnection points with Ketchikan, Alaska, through approximately 100 miles of submarine cable or 120 miles of overhead line.

Because of the high investment cost of hydroelectric projects in Alaska, it is apparent that the immediate program for meeting future load growth for the Petersburg, Wrangell, and Kake areas will be the addition of diesel or gas turbine generation. Hydro projects, such as Thomas Bay (table 17), may become economical when loads develop beyond those projected to 1985.

A desirable alternative for Petersburg and Wrangell is a direct-current submarine cable system interconnection with Snettisham and/or Ketchikan. This could form the initial phase of an ultimate backbone transmission grid for the entire inland passage from Ketchikan to Skagway. The key to this proposal lies in the successful development of economical low capacity a.c./d.c. solid-state power conversion equipment. Direct-current submarine cable itself has a cost advantage compared with overhead transmission in the difficult terrain of Southeast Alaska.

To meet the projected loads in the Sitka area, the Takatz Creek hydro project has been proposed. This project, located on the eastern side of Baranof Island, approximately 21 miles northeast of Sitka, could furnish 96,850,000 kilowatt-hours of firm energy and 2,030,000 kilowatt-hours of nonfirm energy annually to the Sitka area with the installation of two 10,000-kilowatt units. Twenty-eight miles of 115-kilovolt transmission line would be required. An alternative to the high investment cost of the Takatz Creek hydro project would be a direct-current submarine cable installation from Snettisham as described earlier.

Summary of Southeast Region

Lacking fossil fuels, southeast Alaska must look to its water resources as the most economical alternative to power generation using fuels which are burdened with high shipping and handling costs. The relatively small area loads appear to preclude adoption of nuclear generation because of high unit costs of small package installations.

Good hydro sites abound throughout the Region, but full utilization of these sites is handicapped by the difficult terrain over which conventional transmission lines must be built and maintained. Most of the hydro potentials are small, relatively high-unit power cost developments.

Although probably beyond consideration as a potential resource which could be realized within the period of this projection, it is worthy of note here that the Yukon-Taiya project is reported to have a potential of 3,200 megawatts in the range of 2.4 to 4 mills per kilowatt-hour at the bus bar and is susceptible to stage development. Estimates indicate that the unit cost of a 1,200-megawatt initial stage development would be in the same range. The Governments of Canada and the United States have recently announced the initiation of preliminary joint examinations of the Yukon-Taiya possibilities, with initial emphasis to be placed on an exchange of data and views to assist both Governments in assessing power market possibilities which could justify further studies of the power development potential of the Upper Yukon watershed, including alternative water diversion schemes to supply power developments in either British Columbia or Alaska. A likely location of the principal hydroelectric plant would be on the Taiya River as it enters the Gulf of Alaska (Lynn Canal) in the general vicinity of Skagway.

Until low-capacity, solid-state, high-voltage, direct-current terminals are proven to be available at a competitive cost, and d.c. inline taps are acceptable, system interties appear to be limited to the Petersburg-Wrangell-Kake and Ketchikan-Metlakatla areas. There is also the possibility of interconnections with British Columbia Hydro in both areas. Planning beyond 1985 should anticipate the technical and economic feasibility of a direct-current power grid utilizing a bipolar system and submarine cable with emergency sea return, or a homopolar system with permanent sea return, either system giving dual-circuit capabilities.

Northwest and Southwest Regions

Load Distribution

The Northwest and Southwest Regions cover a land area of approximately 180,000 square miles. However, only six areas have sufficient population density to justify central station generating facilities. The 1965 population, excluding military bases, was estimated to be only 9,230 for the two Regions combined. Projections indicate a population of approximately 15,000 by 1985.

The 1965 total utility-type load for the combined regions was 3,400 kilowatts, largely concentrated in the principal villages of Point Barrow, Kotzebue, Nome, Naknek, King Salmon and Dillingham. Unless load growth is stimulated by petroleum and related commercial and industrial developments or presently unforeseen large-scale mining developments, the 1985 demand, excluding military and other nonutility-type loads, will probably not exceed 16,000 kilowatts.

Operating Utilities

Appendix A lists operating utilities in the two Regions and installed generating capacities, military, and other nonutility generating facilities. It is noted that all generation is with diesel-driven generators.

The military, Federal Aviation Agency, and the Bureau of Indian Affairs each maintain power generation to meet the needs of their individual installations. The FAA also procures energy from outside sources where it is economically available and also, under Public Law 647, may sell surplus energy to individuals.

Oil storage tanks at Kotzebue, above the Arctic Circle, emphasize the importance of the village not only as a tourist attraction but as a supply and trading "hub" for many thousands of square miles of Arctic area.

Present Transmission Facilities

The only existing transmission facility between villages in the Northwest-Southwest Regions consists of a 14-mile, 12.5-kilovolt line between King Salmon and Naknek.

Possible Programs for Development

Power development for these small widespread villages of northwest and southwest Alaska is expected to continue generally, as in the past, with small internal combustion or gas-turbine electric plants being added locally as needed.

There are areas within the Northwest and Southwest Regions where power interconnections between communities and the military would be mutually desirable. However, in view of the sensitivity of the military loads, it is unlikely that interties will be made until such times as the local utility loads develop to the point where utilities can justify the installation of relatively large central plant generation with the reserves and reliability required to satisfy the military requirements. Some study is being given to the possibility of reaching the small scattered loads in the Southwest Region by means of single-phase, ground return, transmission. An example of such a system was discussed for possible service to some of the small remotely located villages in the Interior Region.

Summary of Northwest and Southwest Regions

It is conceivable that the proposed extension of the Alaska Railroad and highways into the Northwest Region with accompanying expansion of mineral exploration and development could, within the study period, bring about a need for large central station power installations or extension of high-voltage transmission systems from the Interior or Southcentral Regions. Furthermore, the recent oil discoveries in the Prudhoe Bay area and the continuing explorations along the Arctic Slope could conceivably lead to much more rapid development than has been generally assumed in the survey. Pending such developments, limited extension of power facilities by such means as single-phase ground return transmission should be seriously considered.

CHAPTER VII

TRANSMISSION AND INTERCONNECTION STUDIES BETWEEN INTERIOR AND SOUTHCENTRAL REGIONS

As has been indicated in earlier chapters of the report, an analysis of the predicted loads, terrain, and power resources, together with the rapid load growth in the Anchorage, Kenai, and Fairbanks areas and the relatively short transmission distance (compared with Alaska distances in general) between major load centers, made it desirable to investigate the cost savings and other benefits associated with transmission interconnections between the Southcentral and Interior Regions.

To realize part of the survey's goal of bringing into focus the economic significance of interconnections and coordination among systems, eight different models of generation and transmission patterns were developed. On the basis of these models, costs were developed which indicate the relative economies of the several schemes for supplying the future power requirements of the Anchorage, Kenai, and Fairbanks areas. To simplify the comparisons, the model studies gave consideration primarily to the utility loads because of their predominance in the expected growth effects during the period of the study.

The eight possible generation and transmission plans, summarily studied by the Subcommittee on Coordinated System Development and Interconnection, included six combinations of gas-fired steamplants in the Beluga and Kenai natural gasfields, hydro peaking installations at Bradley Lake and Devil Canyon, and nuclear powerplants. For comparative purposes, two additional studies were made. One study (plan VII), provides for coordination within the Interior and the Southcentral Regions, but no interconnection between the two. The second study, plan VIII, represents a continuation of uncoordinated utility planning and operation very much as now practiced. In comparing this plan with the others, it should be noted also that it does not include defense base loads which are accounted for in plans I through VII.

General Considerations and Assumptions for Study Cases

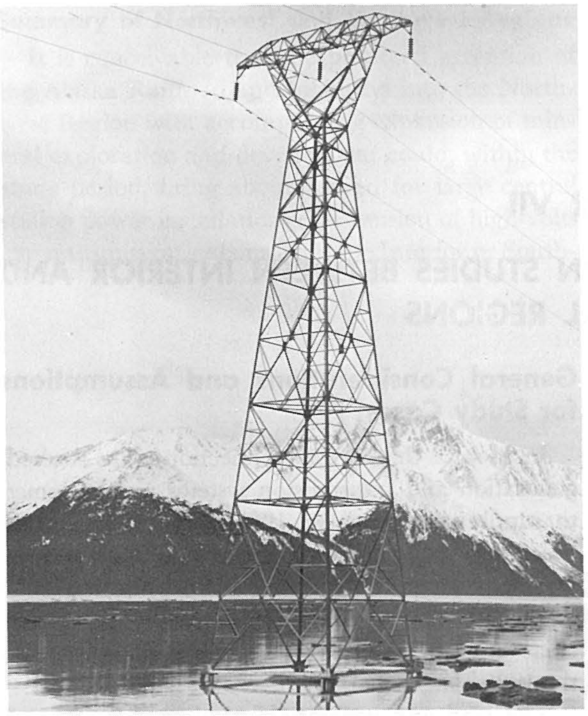
In each of the six interconnection plans studied, generation and transmission systems were assumed to supply the estimated 1985 loads. It should be noted that the generation and transmission systems assumed were not optimized. The projected 1975 load level was considered to determine an appropriate interim system that would be consistent with the 1985 plans investigated.

The load and generation requirements for each level of development considered the combined civilian and military systems operated on an integrated and coordinated basis for each of the interconnected plans. The generation and transmission installations were sized accordingly. In most cases, larger sized units and plants can be justified by 1985.

To the extent possible, the existing higher cost fuel-fired plants, together with their presently planned expansions, in the Interior and Southcentral Regions were assumed to be allocated to generation reserves and standby use. Stability and reliability were emphasized in the generation and transmission facilities assumed for these studies, but more detailed system analyses, voltage regulation, and stability studies will be required to determine the optimum plan of service before adopting a final generation and transmission system for future development.

While a detailed cost analysis was not made, it was considered reasonable to assume that it would be more economical and desirable to electrically transmit the low-cost gas energy from the Kenai and Beluga gas fields to the Interior rather than transport the gas directly by pipelines to thermal generation sites at the load centers.

The studies for each of the interconnection plans considered the cost benefits of: (a) reduced generating reserves, (b) maximum use of economy



115-kilovolt transmission line tower on Turnagain Arm.

energy, (c) installation of larger generating units, (d) larger total capacity in each generating plant, and (e) coordination of hydro and thermal generation. Other benefits that will also accrue, although not given a monetary evaluation, include: (a) daily and seasonal load diversity, (b) use of surplus secondary hydro energy for fuel displacement, (c) more efficient thermal plant operation, (d) effect of streamflow diversities, and (e) national defense.

Generation reserves were considered in arriving at the size of units assumed and the level of generation for each plan. With coordinated operation, the combined level of required reserves can be reduced. For these studies, peak generation reserves equivalent to the capacity of the largest unit were assumed. As mentioned above, such peaking reserves, to the extent possible, were assumed to be supplied from existing older and more expensive thermal capacity. A 5-percent energy reserve based on the estimated loads was included for all plans. In some of the cases, the standby capacity available from the older and more expensive thermal plants was used to provide backup for a single transmission circuit.

It is important in planning and operating a transmission system to have a completely reliable bulk-power supply system in order to eliminate the possibility of cascading failures and inadequacy in meeting peakload requirements. The foundation of reliability is an adequate transmission system with fully coordinated controls. Coordination among utilities in the planning and operation of their facilities and particularly in the development of adequate transmission networks and interconnections within each region is essential.

The peak and energy transmission losses vary with each different generation and transmission plan, and these losses were accounted for in determining the level of generation required for each of the 1975 and 1985 conditions studied.

In each plan analyzed, the generating plants and individual units were sized to match as nearly as possible the 1975 and 1985 load conditions. The 1975 load level was investigated to determine how the interim system would fit in with the 1985 system. Generating reserves were analyzed and applied for each individual plan. The reserve requirements vary with the different sized units assumed.

Capital and annual cost studies were prepared for each of the six interconnected plans and compared to similar cost studies for plan VII which, as stated earlier, "assumes interconnection and coordination by 1985 of all utilities, including military installations within each Region, but not interconnection between the two Regions."

Bases of Cost Estimates

In preparing the cost studies of each alternate generation and transmission plan, composite fixed-charge rates calculated by FPC where used. This FPC composite fixed-charge rate was based on the weighted average of existing private, municipal, REA, and Federal investment provided to supply utility electrical loads in Alaska.

An alternate financing method assumed Federal funds would be available for all generation and transmission facilities. Also, a weighted average interest rate was computed assuming 2 percent REA financing and 5 percent municipal financing. The weighted average was based on the 1965 existing loads of Chugach Electric Association, Golden Valley Electric Association, and the Fairbanks and Anchorage municipal systems. This calculated composite interest rate was 3.2 percent, or essentially the same as Federal financing at 3⅛ percent. Therefore, the alternate financing method assumed in the cost calculations can be construed to be typical of either Federal financing or composite municipal and REA cooperative financing.

Descriptions of Models Used for Planning Studies

The following sections describe the system representations used in the various planning studies for cost comparisons of the selected interconnection arrangements. In all cases, the planning studies were somewhat general in nature. Therefore, they are not suitable for direct application, and detailed system analyses and voltage regulation studies would be required before developing a final plan for an interconnected system. Simplified maps and power flow diagrams are included for plans II and III, the most economically attractive arrangements.

Plan I—Beluga and Devil Canyon Generation

A new gas-fired steamplant in the Beluga area, with two 150-megawatt units in 1975 and an additional 200-megawatt unit by 1985, will supply the base energy load for the interconnected system. Peaking capacity in 1975 will be supplied by the Healy coal-fired steamplant (assumed to have an installed capacity of 66 megawatts by 1975) and the 30-megawatt Beluga gas turbine plant. Peaking capacity in 1985 will be supplied by the 66-megawatt Healy plant and the four 100-megawatt hydro units at Devil Canyon. The Beluga gas turbine plant is assumed to be allocated to reserve and standby use by 1985.

The 1975 main 230-kilovolt transmission grid interties and intraties will connect major stepdown substations at Anchorage (250 megavolt-amperes), Healy (75 megavolt-amperes) and Fairbanks (250 megavolt-amperes). Series compensation totaling 30 megavars will be required at Healy to keep the electrical angle between points of generation and load within 30°–35°, in 1975, when any heavily loaded line in the system is removed from service. By 1985, an additional 230-kilovolt transmission line will tie Anchorage to Fairbanks while the Anchorage area substation capacity will have grown to 750 megavolt-amperes. A 120-megavolt-ampere capacity substation at Kenai and 70 megavars of compensation at Quartz Creek will be required by 1985 to serve loads and maintain stability under emergency operating conditions.

In this plan, 230-kilovolt submarine cables are used to transmit Beluga generated power to Anchorage via the Knik Arm underwater crossing while Devil Canyon power is fed into Susitna Switching Station, about midway between Anchorage and Fairbanks. Military loads and resources are assumed to be interconnected and coordinated for both the 1975 and 1985 levels of development.

Plan II—Beluga Generation

A new gas-fired steamplant in the Beluga area, with two 200-megawatt units in 1975 and two additional 250-megawatt units by 1985, will supply the base energy load and part of the peaking capacity. The remaining peaking capacity in 1975 and 1985 will be supplied by the Healy coal-fired steamplant which is assumed to have 66 megawatts by 1975. The Beluga gas-turbine plant is assumed to be allocated to reserve and standby use for both the 1975 and 1985 levels of development. Major stepdown substations will be constructed at Kenai (120 megavolt-amperes), Anchorage (250 megavolt-amperes), Healy (75 megavolt-amperes), and Fairbanks (250 megavolt-amperes). A major switching station will be located at Nancy, midway between Beluga and Anchorage. Most facilities will be connected together by 230-kilovolt transmission lines. Kenai will be tied to Anchorage by a 115-kilovolt line. These connections are shown on figure 10 and the companion power flow analysis is shown on figure 11. Series compensation of 30 megavars will be required at Healy in 1975 to maintain system stability during periods when any critical transmission line is removed from service. Local standby and reserve generation in the Fairbanks area will provide backup capacity for that part of the 1975 load which is being supplied from the single 230-kilovolt intertie line between Anchorage and Fairbanks.

By 1985, an additional 230-kilovolt intertie line will be required to provide reliable transmission capacity for Fairbanks. By 1985, series compensation of 120 megavars at Nancy and 45 megavars at Quartz Creek will be required to maintain system stability. (Figs. 12 and 13). Anchorage area substation capacity will have grown to 750 megavolt-amperes. Military loads and resources are assumed to be interconnected and coordinated for both levels of development.

Plan III—Kenai and Beluga Generation

Gas-fired steamplants at Kenai (150 megawatts) and Beluga (250 megawatts) in 1975 will supply the base energy load. Peaking capacity will be supplied by the Healy coal-fired steamplant, which is assumed to have 66 megawatts by 1975. By 1985, two additional units of 250-megawatt capacity at Beluga will be required to serve the increased load.

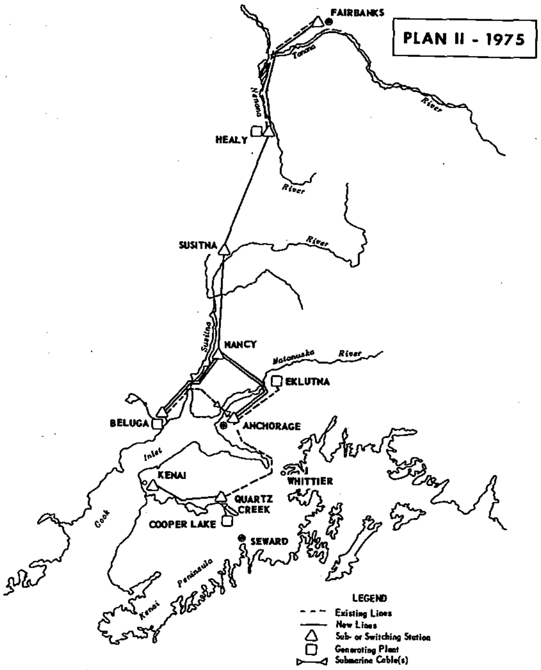


Figure 10

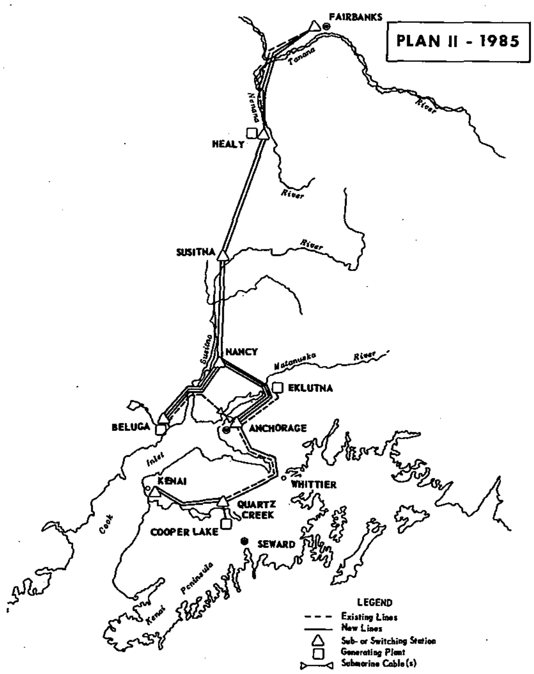


Figure 12

PLAN II - 1975 POWER FLOW DIAGRAM

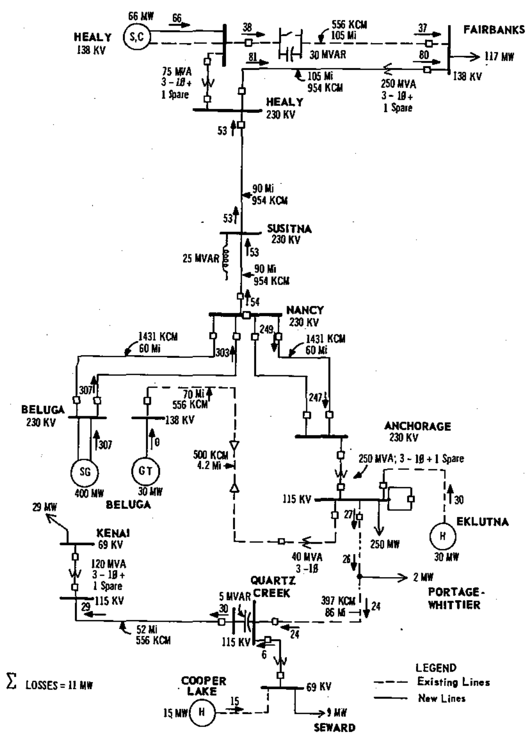


Figure 11

PLAN II - 1985 POWER FLOW DIAGRAM

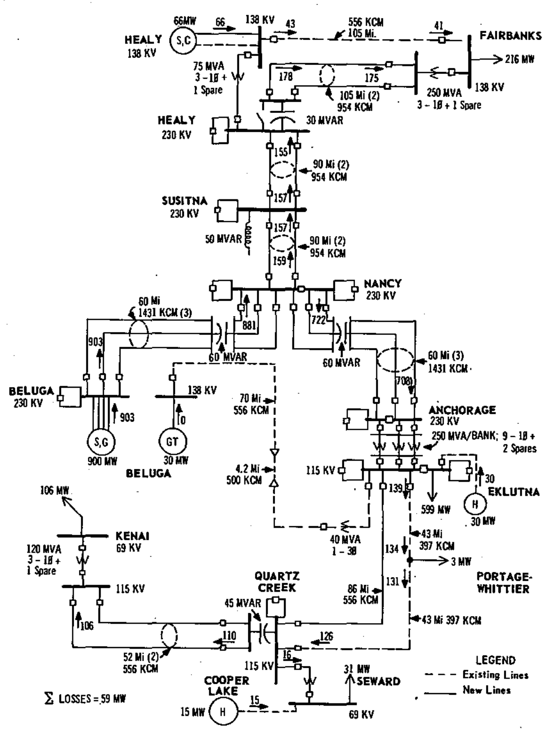


Figure 13

Peaking capacity in 1985 will be supplied by the 66-megawatt Healy plant.

Major stepdown substations will be constructed at Kenai (120 megavolt-amperes), Anchorage (300 megavolt-amperes), Healy (75 megavolt-amperes), and Fairbanks (250 megavolt-amperes) by 1975. All facilities will be tied together by 230-kilovolt transmission lines, except for a single Kenai-Quartz Creek-Anchorage tie which will be 115 kilovolts. Series compensation of 30 megavars at Healy will be required in 1975 to keep the electrical angle between Beluga and Fairbanks within 30°–35° when any critical transmission line is out of service. (Figs. 14 and 15.) Local generation allocated to reserves and standby will be used as a backup source to supply any portion of the 1975 Fairbanks load which would not otherwise be served, if it is necessary to interrupt the single tieline between Anchorage and Fairbanks.

By 1985, 40 megavars of series compensation will be required at Quartz Creek to maintain system stability under emergency operating conditions. A second 230-kilovolt intertie line will be required by 1985 to transmit reliable power from Beluga to Fairbanks. An additional 115-kilovolt line between Anchorage and Quartz Creek will be required for reliability purposes. Anchorage substation capacity will grow to 600 megavolt-amperes. (Figs. 16 and 17.) Military loads and resources are assumed to be interconnected and coordinated for both the 1975 and 1985 levels of development.

PLAN III - 1975 POWER FLOW DIAGRAM

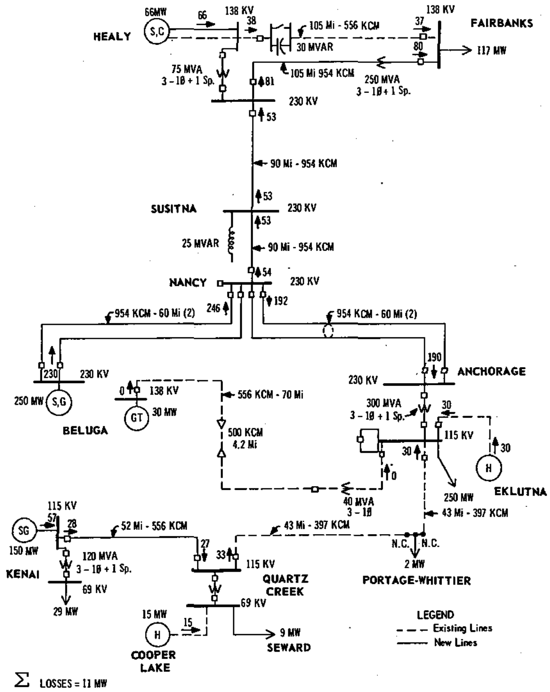


Figure 15

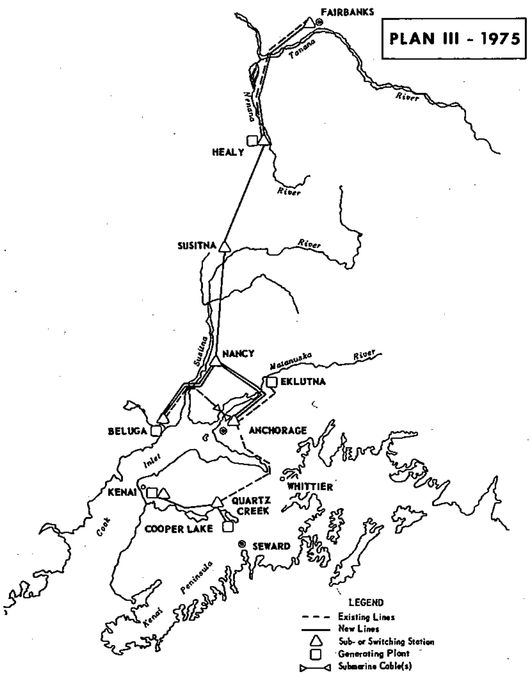


Figure 14

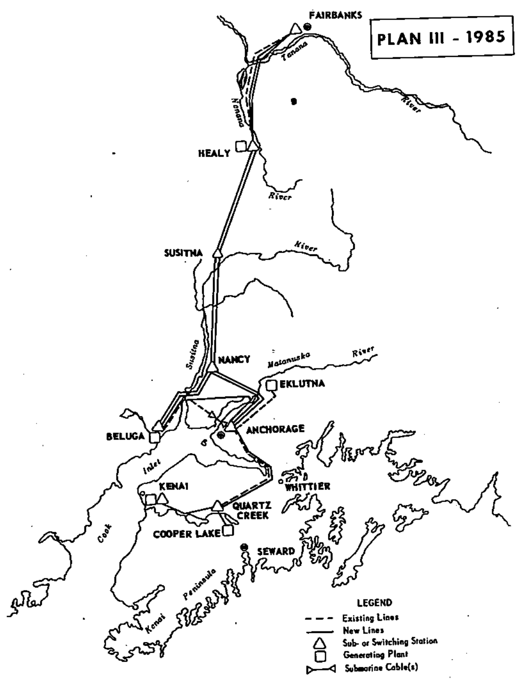


Figure 16

PLAN III - 1985 POWER FLOW DIAGRAM

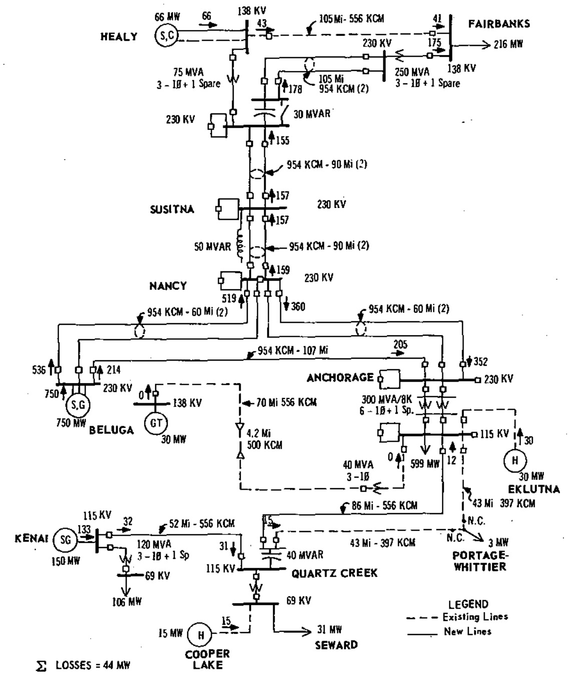


Figure 17

Plan IV—Kenai, Beluga, and Bradley Lake Generation

Kenai area gas-fired steam units of 150- and 200-megawatt capacity will supply the 1975 base energy load while the 30-megawatt Beluga gas turbine plant and Healy coal-fired steamplant (assumed to have 66 megawatts by 1975) will supply peaking capacity. An additional 250-megawatt unit at Kenai and a single-unit 100-megawatt gas-fired steamplant at Beluga will be required to serve the 1985 load. Peaking capacity in 1985 will be shared by two 93.5-megawatt hydro units at Bradley Lake and the 66-megawatt Healy plant. Bradley Lake will be tied in at Kenai substation via two 115-kilovolt transmission lines.

The main transmission grid voltage in 1975 and 1985 will be 230-kilovolts. Major substations will be constructed by 1975 at Anchorage (300 megavolt-amperes), Kenai (150 megavolt-amperes), Healy (75 megavolt-amperes), and Fairbanks (250 megavolt-amperes). Series compensation of 35 megavars at Healy will be required in 1975 to maintain system stability if any critical transmission line is removed from service. By 1985, additional compensation of 40 megavars at Kenai and 5 megavars at Nancy will be required to maintain a 30°–35° maximum electrical angle between point of generation and point of delivery during emergency operation. In 1985, two 230-kilovolt lines will tie Anchorage and Fairbanks together. The substation capacity at Anchorage will increase to 600 megavolt-amperes by 1985. A 230-kilovolt submarine cable will transmit part of the Beluga generation to Anchorage in 1985. All Kenai generation will be transmitted to Anchorage via 230-kilovolt submarine crossings at Fire Island. Military loads and resources are assumed to be interconnected and coordinated for both the 1975 and 1985 levels of development.

Plan V—Kenai, Beluga, Devil Canyon, and Bradley Lake Generation

Two new gas-fired steam units near the Beluga and Kenai gas fields with 100- and 200-megawatt capacities, respectively, will supply the load in 1975. Peaking capacity will be supplied by the Beluga 30-megawatt gas turbine plant and the Healy coal-fired steamplant, which is assumed to have an installed capacity of 66 megawatts by 1975. An additional 100-megawatt unit will be needed at Beluga by 1985 to supply the base energy load. Peaking capacity in 1985 will be supplied by four 100-megawatt hydro units at Devil Canyon, two 93.5-megawatt hydro units at Bradley Lake, and the Healy plant. The Beluga gas turbine plant is assumed to be allocated to reserve and standby use by 1985.

A 230-kilovolt main transmission grid will connect stepdown substations at Kenai (150 megavolt-amperes), Anchorage (300 megavolt-amperes), Healy (75 megavolt-amperes), and Fairbanks (250 megavolt-amperes) in 1975. By 1985, the substation capacity at Anchorage will grow to 600 megavolt-amperes. Series compensation of 30 megavars will be required at Healy to maintain system stability in 1975 if any critical transmission line is removed from service. Local generation at Fairbanks will pick up any loss of the main power supply if there should be an interruption of service over the single intertie line in 1975. In 1985, there will be two circuits to the Anchorage area. Devil Canyon power will enter the system at Susitna switching station, approximately midway between Anchorage and Fairbanks, and Bradley Lake will be tied in to the Kenai substation. Military loads and resources are assumed to be interconnected and coordinated for both the 1975 and 1985 levels of development.

Plan VI—Nuclear Generation

A single-unit, 200-megawatt nuclear steamplant will be located near both Anchorage and Fairbanks in order to supply the 1975 loads on the interconnected system. By 1985, nuclear steamplants of 200- and 250-megawatt capacity will be required in the Anchorage area to supply base energy load. Peaking capacity in 1985 will be supplied by a new 100-megawatt gas-fired steam unit near the Beluga gas fields. The Beluga gas turbine and Healy coal-fired steamplant are assumed to be allocated to reserves and peaking use in both 1975 and 1985. Major stepdown substations will be constructed at Kenai (120 megavolt-amperes), Anchorage (250 megavolt-amperes), Healy (75 megavolt-amperes), and Fairbanks (150 megavolt-amperes). A major switching station will be located at Knik near the proposed Anchorage nuclear plant. All facilities will be interconnected by 230-kilovolt overhead transmission lines. Series compensation of 5 megavars at Quartz Creek will be required, in 1975, in order to limit the electrical angle between generation and point of delivery to 30°–35° when any critical transmission line is removed from service. Existing higher cost thermal generation capacity in the Fairbanks and Anchorage areas will supplement power imported over the intertie line in the event of a local nuclear steamplant outage. Anchorage area substation capacity will increase to 750 megavolt-amperes by 1985. Series compensation of 20 megavars at Quartz Creek by 1985 will be required to maintain system stability during emergency operating conditions. Military loads and resources are assumed to be interconnected and coordinated for both the 1975 and 1985 levels of development.

Plan VII—Isolated Systems (No Transmission Interconnection Between Interior and Southcentral Regions)

Interior Region

The existing coal-fired steamplant at Healy, assumed to have 66-megawatt capacity by 1975, will need a new 44-megawatt unit by 1975 (and single 60- and 70-megawatt units by 1985) to supply the Fairbanks area load. An additional 138-kilovolt transmission line will be required by 1975 between Healy and Fairbanks and a total of three lines will be needed by 1985. Military loads and resources were not assumed to be interconnected and coordinated in the 1975 level of development due to the relatively small system. Military loads and resources were incorporated in the 1985 case, however, because the coordinated utility system was considered to be more reliable by that time.

Southcentral Region

The 1975 base energy load for the Anchorage area will be supplied by two, single-unit, 90-megawatt gas-fired steamplants near the Kenai and Beluga gas fields. By 1985, the Beluga plant will have an additional 135-megawatt unit and the Kenai plant will have three additional 135-megawatt units. Beluga power will be transmitted to Anchorage by two 230-kilovolt transmission lines. The output of the Kenai plant will be transmitted to Anchorage by two overhead transmission lines which cross the Turnagain Arm at Bird Point. In 1985, an additional 230-kilovolt line will be required to reliably transmit Kenai supplied power to Anchorage. Military loads and resources were not assumed to be operating on a coordinated basis with the utility system in 1975. They were, however, assumed to be fully coordinated with the local systems by the 1985 level of development.

Plan VIII—Isolated Systems—Individual Utilities

In order to measure the benefits, if any, accruing from coordination and interconnection within and between the individual Interior and Southcentral Regions (Plans I through VII), an estimate of the capital and annual costs of the two major utilities in each region is required. Plan VIII satisfies this requirement.

VIII–A City of Anchorage

In 1975, two additional 15-megawatt gas turbines will be required to serve the municipal base energy load and to supply peaking capacity. Substation capacity will be increased by four 10-megavolt-ampere distribution stepup transformers. By 1985, two more 15-megawatt gas turbines and four 10-megavolt-ampere distribution stepup transformers will be required. The 16-megawatt share of Eklutna hydro capacity allocated to the municipal utility is assumed to be utilized under both levels of development.

VIII–B Chugach Electric Association

Three 30-megawatt gas turbines and one 15-megawatt unit are assumed to be installed in the vicinity of the existing Beluga gas turbine plant by 1975 to serve base energy load and supply peaking capacity. New transmission required by 1975 would be a second 138-kilovolt line and submarine cable between Beluga and Anchorage and a 115-kilovolt line between Quartz Creek and Kenai where a new 120-megavolt-ampere substation is assumed to be constructed. Anchorage substation capacity will be supplemented by the installation of two 150-megavolt-ampere stepdown transformer banks. By 1985, gas-fired steamplants are assumed to be installed at Kenai (100 megawatts) and Beluga (360 megawatts) to satisfy the increased requirements. The new Beluga generation is assumed to be transmitted to Anchorage via two 230-kilovolt lines around Knik Arm. Near Palmer, a line tap and 75-megavolt-ampere substation will be needed to serve part of the Palmer-Matanuska load. Reliability of service to the Kenai area will be increased by construction of a second 115-kilovolt line from Anchorage through Quartz Creek to Kenai substation. The 9-megawatt share of Eklutna hydro capacity allocated to Chugach Electric Association is assumed to be utilized under both levels of development.

VIII–C City of Fairbanks

Two additional coal-fired steam units with capacities of 5 and 10 megawatts, respectively, will be required by 1975 to serve the base energy load and to supply peaking capacity. Substation capacity will be increased by adding two 10-megavolt-ampere distribution stepup transformer banks. By 1985, two more 10-megawatt coal-fired steam units will be required as will additional substation capacity of two 10-megavolt-ampere banks.

VIII–D Golden Valley Electric Association

The principle source of generation for this utility is the Healy coal-fired steamplant. By 1975, a second 22-megawatt unit will be needed to meet the growth of base energy load and capacity requirements. A second 138-kilovolt line between Healy and Fairbanks will be needed in order to increase reliability. Substations of 75-megavolt-ampere capacity each will be required at Healy and Fairbanks to handle the increased generation and load, respectively. By 1985, a third 22-megawatt unit and two 44-megawatt units will be needed as well as an additional 75-megavolt-ampere transformer bank at both Fairbanks and Healy. In an emergency, one transmission line can handle the power flow so no new construction will be required.

Conclusions From Interconnection Studies

The results of the cost benefit studies are summarized for each of the study plans. Annual utility cost benefits based on 1965 Alaska cost levels and totaling up to $9,098,000 in the single year of 1985 are estimated to be achievable with coordinated area operations and an interconnected generation and transmission system to supply the combined Interior and Southcentral Alaska loads as opposed to existing isolated utility operation. This combined level of 1985 annual cost savings represents the following individual utility system savings in that year.

Estimated Level of Cost Benefits in 1985 [1]

	Estimated 1985 energy load (kilowatt-hours)	Cost benefits (mills per kilowatt-hour)	Annual savings dollars[2]
Anchorage	526	4.45	2,341,000
Chugach	2,575	.36	927,000
Fairbanks	184	13.86	2,550,000
Golden Valley	543	6.04	3,280,000
Total			9,098,000

[1] Based on the difference in unit cost per kilowatt-hour with continued isolated utility operation as compared with plan III.
[2] Based on 1965 Alaska cost levels.

NOTE.—It is not intended that this study anticipate power rate arrangements or assume that small localized area rates should be established in preference to zoning rates.

These calculated annual cost savings can be expected to continue to increase beyond the 1985 level of development. Other benefits, mentioned earlier but not given a monetary evaluation, could further increase the savings from interconnected and coordinated operation.

The lowest cost plan (Plan III) for supplying the 1985 interconnected system involves the installation of gas-fired steamplants near the Kenai and Beluga gas fields. In determining the actual location and timing of future gas-fired steamplants, strong consideration should be given to the rate of load growth in the near vicinity of the generating plants. For example, the Kenai Peninsula loads have increased rapidly during the last 5 years and are expected to continue to increase rapidly during the next two decades. There are stability, reliability, and transmission line advantages to the location of gas-fired steamplants in both the Kenai and Beluga areas, even though the cost of a bulk power supply system is essentially the same with all the generating capacity near Beluga.

A 230-kilovolt transmission voltage was determined to be the minimum voltage that should be considered for interties between the two Regions. Series compensation will be required in the transmission circuits between the Southcentral and Interior Regions to transmit the magnitude of loads involved. Some shunt compensation may be required to control voltage under light load conditions.

In designing a system for the 1985 level of development, consideration should be given to the utilization of hydro peaking capacity to be operated on an integrated and coordinated basis with the steam generation. By this means, the gas-fired steamplants can be scheduled to operate at a high capacity factor, thus resulting in a lower unit generation cost. The sites considered for the development of hydro peaking capacity in these studies were Bradley Lake and Devil Canyon. Other sites should also be investigated and studied before a final plan for the installation of hydro peaking capacity is adopted. Bradley Lake is located in the fast growing Kenai Peninsula area and Devil Canyon is at a convenient midpoint between the Interior and Southcentral load centers.

Table 19 contains a summary of the estimated costs for plans I through VII based on the FPC computed composite annual cost ratios. Plan VIII was not included because the composite cost basis is not applicable to plan VIII assumptions.

Table 20 includes Plan VIII and presents similar summary type information, but is based on assumed Federal financing and does not include defense base loads. The figures in this table will also typify composite municipal and Rural Electrification Administration cooperative financing as previously discussed. Plans II and III each have a significantly lower level of annual costs by 1985 than the other interconnected plans or isolated regional operation. This assumes that the installed peaking capacity at Devil Canyon (plan I) is matched to just meet the 1985 level of development with an installed cost per kilowatt estimated at $605. This is considerably higher than the estimated $300 per kilowatt installed cost for the ultimate Upper Susitna project (Watana, Vee, and Devil Canyon)

TABLE 19

Summary of Estimated Capital and Annual Costs—1985

[FPC computed composite annual cost ratios]

Plans	Generation	Capital costs [1] dollars in millions		Annual costs, dollars in millions			Energy load		Mills per kilowatt-hour
		Generation	Transmission	Generation	Transmission	Total	Average Megawatts	Gigawatt hours	
	INTERCONNECTED REGIONS [2]								
I	Beluga Gas and Devil Canyon Hydro	321.0	79.7	27.059	6.175	33.234	503	4,406	7.54
II	Beluga Gas	136.5	76.7	18.133	5.995	24.128	503	4,406	5.48
III	Kenai and Beluga Gas	135.8	68.9	18.527	5.321	23.848	503	4,406	5.41
IV	Kenai, Beluga Gas, and Bradley Lake Hydro	184.2	98.0	20.455	7.316	27.771	503	4,406	6.30
V	Kenai, Beluga Gas, Devil Canyon, and Bradley Lake Hydro	382.2	89.1	30.315	6.821	37.136	503	4,406	8.43
VI	Nuclear	253.6	45.1	28.834	3.598	32.432	503	4,406	7.36
	ISOLATED REGIONS [2]								
VII	(a) Anchorage-Kenai and Beluga Gas	120.4	47.2	15.671	3.520	19.191	393	3,436	5.59
	(b) Fairbanks-Healy Coal	44.3	8.5	7.101	.654	7.755	110	970	7.99
	Total combined	164.7	55.7	22.772	4.174	26.946	503	4,406	5.64

[1] Based on 1965 Alaska cost levels.

[2] Utility and military loads and resources assumed to be coordinated within each region.

TABLE 20

Summary of Estimated Capital and Annual Costs—1985

[Annual cost ratios based on Federal financing [1]]

Plans	Generation	Capital costs [2] dollars in millions: Generation	Capital costs: Transmission	Annual costs dollars in millions: Generation	Annual costs: Transmission	Annual costs: Total	Energy load: Average Megawatts	Energy load: Gigawatt hours	Mills per kilowatt-hour
	INTERCONNECTED REGIONS [3]								
I	Beluga Gas and Devil Canyon Hydro	321.0	79.7	20.239	4,484	24.723	503	4,406	5.61
II	Beluga Gas	136.5	76.7	15.130	4.366	19.496	503	4,406	4.42
III	Kenai and Beluga Gas	135.8	68.9	15.540	3.860	19.400	503	4,406	4.40
IV	Kenai, Beluga Gas, and Bradley Lake Hydro	184.2	98.0	16.479	5.233	21.712	503	4,406	4.93
V	Kenai, Beluga Gas, Devil Canyon, and Bradley Lake Hydro	382.2	89.1	22.222	4.933	27.155	503	4,406	6.16
VI	Nuclear	253.6	45.1	23.256	2.650	25.906	503	4,406	5.88
	ISOLATED REGIONS [3]								
VII	(a) Anchorage-Kenai and Beluga Gas	120.4	47.2	13.021	2.521	15.542	393	3,436	4.51
	(b) Fairbanks-Healy Coal	44.3	8.5	6.127	.474	6.601	110	970	6.79
	Total combined	164.7	55.7	19.148	2.995	22.143	503	4,406	5.03
	ISOLATED UTILITY OPERATIONS [4]								
VIII	Anchorage	11.4	.7	4.506	149	4.655	60	526	8.85
	Chugach	93.1	29.6	10.280	1.965	12.245	294	2,575	4.76
	Fairbanks	13.1	.4	3.285	75	3.360	21	184	18.26
	Golden Valley	39.6	5.4	5.298	372	5.670	62	543	10.44
	Total combined	157.2	36.1	23.369	2,561	25.930	437	3,828	6.78

[1] Costs are also representative of composite municipal and Rural Electrification Administration cooperative financing.

[2] Based on 1965 Alaska cost levels.

[3] Utility and military loads and resources assumed to be coordinated within each region.

[4] Assumes no military-utility coordination and existing public agency utility financing.

as developed by the Hydro Resources Subcommittee for a peaking type installation. If this lower installed unit cost is assumed for Devil Canyon, plan I, the level of annual cost would, of course, be correspondingly lower.

By 1985, the two regions will just begin to reap the calculated savings achievable from interconnected and coordinated operation, and beyond 1985, the amount of benefits and savings will increase.

An alternative means to supply electric utility loads in the Fairbanks area, other than by an intertie with Anchorage area power sources or by burning coal (or oil) in the Fairbanks area plants, would be to use Cook Inlet natural gas piped to the Fairbanks plants. The cost of a pipeline, if constructed by private financing, would add an estimated 45 cents per million British thermal units to the field gas price. The delivered cost for quantities required by utilities and the military for the generation of electric power and to supply space heating and industrial demands would not be competitive with the cost of Healy field coal delivered to the Fairbanks area. Nor would it be more economical than to transmit the gas energy as electricity from the Kenai and Beluga gas fields to Fairbanks.

The patterns of generation and transmission discussed here are in no sense a program or blueprint, but they may prove helpful—especially to persons not intimately involved in power supply planning for a large area. In this and previous chapters, an attempt has been made to identify ways in which costs of electric system operations can be reduced. Few, if any, elements in the structure and operation of power systems remain constant. Even small changes in fuel costs, transportation, or other elements of various system expansion alternatives could substantially alter the kind of generation and transmission system to be built in the future. Hence, it is not possible to predict with assurance the pattern of generation and transmission that will eventually serve Alaska's projected loads. Only through planning which looks far beyond the requirements of a particular system or locality, however, can the most economical supply of power to all users be achieved.

It should be clearly understood that effective coordination of major power transfer facilities cannot be achieved through interconnections alone. Coordination must encompass mutual review of load projections, coordinated construction plans, and agreement on operating practices and safeguards. Once adequate transfer facilities exist, economy of bulk-power supply will be enhanced through exchanges of capacity and energy among systems, sharing of spinning and standby reserves, and transfer of emergency power to meet needs due to unusual weather conditions and other contingencies. Economy and reliability are closely associated objectives, but reliability must have priority. The transmission system should be carefully engineered and well-maintained so as to insure a high degree of service continuity. Particular attention must be paid to protecting the lines and line terminals against overloading, and the system against equipment failure. A program should be designed to match loads to the available power supply to provide for a minimum of interruptions of essential services. As a backup in the event of loss of power, utility supplied hospitals, water systems, police and fire protection centers, transportation and communication facilities, and related essential services should have available automatic-start, standby power supplies, continuously maintained for emergency use.

The full advantages can be achieved only by joint planning which extends beyond the bounds of a corporate or other entity, an area, or a region. Coordinated planning and operation must bridge differences in management philosophies. Reliability and economy should be available to all users of electric power, regardless of the nature of the systems serving them.

CHAPTER VIII

OUTLOOK FOR COST REDUCTIONS

The final consideration of the Survey, and the one of greatest significance to Alaska's electric power industry and its customers, is the influence of projected trends and patterns on the price of electricity in the future. The numerous factors that have a bearing, directly and indirectly, on electric power costs have been discussed earlier and can be grouped into the following principal categories applicable to the Survey's projections: (1) The generous growth in future electric power loads largely caused by expected increases in the use of electricity per customer and anticipated strong growth in the domestic and industrial segments of Alaska's economy, promoted by an agressive power marketing program; (2) the suggested use of large thermal-electric generating plants located at fuel sources; (3) the prospects for lower fuel costs and lower operation and maintenance expenses; and (4) the institution of affirmative coordinated planning for the construction and operation of regional sources of generation, including bulk power transmission facilities and appropriate interties.

This chapter offers estimates of average costs of electric power for the 1985 period in relationship to current costs, and evaluates potential cost reductions in terms of current dollar values.

Suggested Target for 1985

The 1965 average cost of electricity supplied by the utilities in Alaska before distribution to the ultimate consumer was estimated to be 1.98 cents per kilowatt-hour. Based on the same relative dollar value, the projected lowest Alaska average cost by 1985 is 0.71 cents per kilowatt-hour. This would be a 64-percent reduction and appears possible with cooperative and coordinated planning and operation of electric power facilities.

A target of less than ¾-cent power may seem to be an overly optimistic prediction of future developments. It is, however, a statewide average—a target which some Alaska utilities cannot approach within the survey period. Nevertheless, for most large utilities, the goal of less than 1-cent power by 1985 is within reach. This is roughly comparable to the average cost in the 48 States in 1962. A cost decrease of this magnitude would be consistent with the Alaska electric utilities history of accomplishment, particularly since the early 1950's.

Projected Power Costs—1985

Price inflation during and after World War II exerted strong upward pressures on all costs throughout Alaska. In this period, utility load growth and system expansion were rapid. The pressure of inflation on power costs was offset by improvements in technology, economies from installation of larger generating units, the addition of new hydroelectric sources, and use of interconnecting links between sources.

Electric power production costs vary widely in Alaska. In remote areas, without hydro power sources and far removed from bulk fuel supplies, costs are high. Where natural gas is economically produced and marketed, as in the Anchorage area, and coal, as in the Fairbanks area, their use predominates and power production costs are lower. Where hydroelectric power supplies a high percentage of the load and fuel is relatively low priced as in the Panhandle area, costs are also lower. Natural gas, as a hydrocarbon mixture, can be converted to other valuable products. Alaska's natural gas resources are potentially so great, however, that competing demands for its use are not expected to affect the price structure significantly. Costs of Alaska's liquid fuels are expected to decrease as the search for additional oil resources continues, sources of high-quality petroleum products are discovered, and the crude products are refined in Alaska.

Economic as well as environmental factors were considered in projecting the kinds and sizes of generating plants expected in the different regions. A definite downward trend in fuel, labor, and material costs is reflected in past years' fossil fuel generating plant power production expenses. This trend is expected to continue as larger, more efficient and more economic power production facilities are introduced into Alaska's power supply.

At present there are large differentials in average power costs among the five regions; table 21 shows average 1965 costs and projected 1985 costs. In 1965, the lowest cost was 1.65 cents per kilowatt-hour in the Southeast Region, which benefits from having a high proportion of low-cost hydroelectric sources and from being near to relatively low-cost sources of fuel used in its diesel plants. In addition, the average energy usage per customer is higher than in other regions. As expected, the highest costs are experienced in the Northwest and Southwest Regions where fuel prices are high and small internal-combustion engine generating units are in use.

TABLE 21

Cost of Electric Power 1965 and 1985 [1]

[Cents per kilowatt-hour]

Region and State	1965 estimated cost	1985 projected cost	Percentage reduction
Northwest	4.68	3.62	23
Southwest	4.68	3.51	25
Southcentral	1.80		
Without intertie [2]		.83	54
With intertie [3]		.56	69
Interior	2.84		
Without intertie [2]		1.42	50
With intertie [3]		.77	73
Southeast	1.65	1.37	17
Alaska average	1.98		
Footnote [2] conditions		1.04	47
Footnote [3] conditions		.71	64

[1] Annual average costs of power delivered to subtransmission and distribution points. (Based on costs of generating plants and transmission facilities in use and projected.)

[2] Anchorage and Fairbanks utility power sources separately integrated and coordinated; and not interconnected; utility loads only supplied.

[3] Anchorage and Fairbanks load center power sources interconnected, and system operations integrated and coordinated; utility and defense loads supplied.

Target estimates for the five regions reflect a considerable narrowing of cost differentials by 1985 as illustrated by figure 18. Reductions are projected for all regions, but the largest percentage reductions are foreseen for the Southcentral and Interior Regions.

The Southeast Region exhibits the least prospect for a sizable percentage reduction in power cost. As stated above, the average cost is now below other regions, and annual average energy usage per customer is generally higher. The numerous widely separated communities are relatively small with well-established economies and are expected to remain so. The need for, or opportunities to, install larger and more economic generating units are, therefore, not substantial.

The greatest prospects for sizable percentage reductions in power costs prevail in the Southcentral and Interior Regions. Although average costs are currently in the median range, the avenues open to the regional utilities for dramatic cost reduction programs are so numerous and varied that by 1985, average costs could well be 50 to 70 percent below today's levels.

In addition to the many economic prospects for cost improvements at sources of generation and through intraregional utility cost reduction programs, additional benefits can be realized through interregional interconnections. How such economies can be effected was discussed earlier in the report.

PROJECTED TRENDS IN POWER COSTS 1965 - 1985

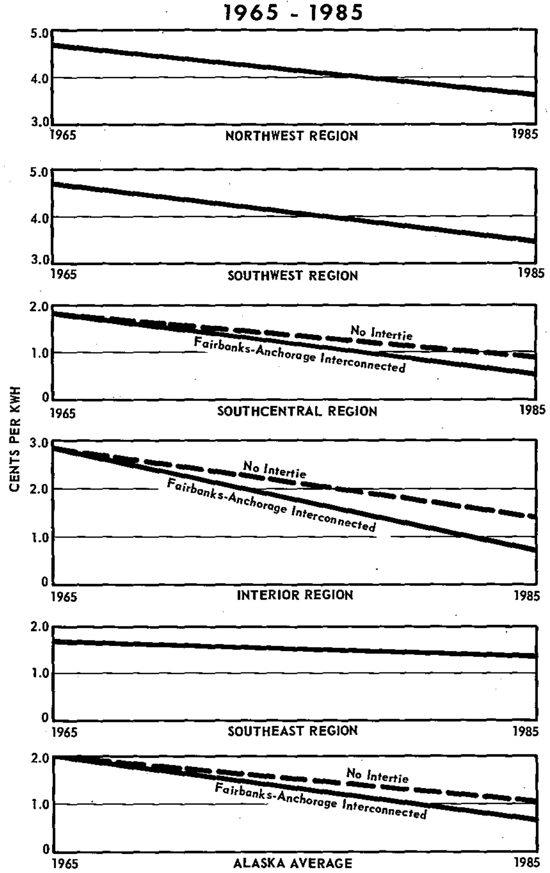


Figure 18

Many Alaska utilities will not have the opportunity to interconnect. Of the studies made during the course of the Survey, an Anchorage-Fairbanks area interconnection holds the greatest promise for achieving power economies. The economic attractiveness of the Anchorage-Fairbanks interconnection is illustrated by the cost differences shown in table 22, which compares the cost of providing power for the 1985 load requirements of the two areas with and without an interconnection. As indicated by the estimates, an annual cost reduction of more than $2½ million could be expected in an interconnected system. While the cost of transmission for an interconnected arrangement would be over $1 million more, the generation cost would be nearly $4 million lower with the two areas interconnected. Interconnections between some Panhandle utilities, although now marginally economic, may later prove feasible.

Evaluation of Cost Reductions

The projected lowest statewide unit power cost in 1985 of 0.71 cent per kilowatt-hour reflects the decrease in power costs by interconnecting the Anchorage and Fairbanks load centers and supplying both defense and civilian utility loads. Without the interconnection and with civilian utility loads separately supplied, the statewide average utility power cost in 1985 would be 1.04 cents per kilowatt-hour.

The differential between the Alaska average cost of power in 1965 of 1.98 cents per kilowatt-hour and the 0.71-cent cost for 1985, applied to the combined estimated defense and civilian power requirements of 5.3 billion kilowatt-hours in 1985, represents a gross reduction of $67 million a year. Without the interconnection and with civilian loads supplied separately, the average utility cost of 1.04 cents per kilowatt-hour would produce a gross reduction in power cost of $45 million annually.

Table 23 brings into focus the magnitude of the power cost reductions projected for each region. Reductions projected for the Southcentral Region by 1985 are substantial even if its utilities do not interconnect with those in the Fairbanks area, but are still more significant if a coordinated interconnection is established. Even greater benefits can be realized by utilities in the Fairbanks area.

While the cost reductions projected for the other regions are not of the magnitude suggested for the Anchorage and Fairbanks areas, they do suggest a relative high order of achievable savings.

Cost Estimating Assumptions

Costs are based on present price levels and on price-cost relationships estimated to exist between Alaska and the lower 48 States at the present time. Power cost estimates for 1965 were developed from actual costs and thus reflect a very modest degree of intersystem integration and coordination. Pro-

TABLE 22

Cost Differences in Delivered Power,[1] Anchorage and Fairbanks Load Centers, by 1985

	Projected annual costs[2]			Percentage reduction
	Non-interconnected[3]	Interconnected[4]	Cost difference	
GENERATION				
Dollars (1,000's)	$22,772	$18,527	$4,245	19
Mills/kilowatt-hour	5.17	4.20	.97	19
TRANSMISSION				
Dollars (1,000's)	$4,174	$5,321	$1,147	...
Mills/kilowatt-hour	.95	1.21	(.26)	...
Total dollars (1,000's)	$26,946	$23,848	$3,098	11
Total mills/kilowatt hour	6.12	5.41	.71	11

[1] Costs are based on FPC computed composite annual cost ratios and are for the bulk-power supply system only. Distribution costs are not included.

[2] Does not include annual costs for existing and presently planned expansion of thermal-electric plants and hydro sources.

[3] Anchorage costs are for natural gas-fired steam-electric plants in Kenai and Beluga gas fields; Fairbanks plant cost is for coal-fired steam-electric plant at Healy field only (table 19).

[4] Interconnected steam-electric plants: Beluga and Kenai natural gas-fired plant cost only (table 19).

TABLE 23

Reduction in Costs of Electric Power,[1] by 1985

Region and State	Condition	1985 energy megawatt-hours	Unit cost reduction (cents per kilowatt-hour)	Total cost reduction ($1,000's)
Northwest	N.I.	44, 790	1. 06	475
Southwest	N.I.	24, 790	1. 17	290
Southcentral	N.I.	3, 319, 880	. 97	32, 203
	I.	3, 607, 090	1. 24	44, 728
Interior	N.I.	721, 350	1. 42	10, 243
	I.	967, 980	2. 07	20, 037
Southeast	N.I.	668, 630	. 28	1, 872
Alaska total	N.I.	4, 779, 440	. 94	45, 083
	I.	5, 313, 280	1. 27	67, 402

[1] Reduction from 1965 in annual cost of power delivered to subtransmission and distribution points.

N.I.—No interties except existing and no interconnections between regions (defense load and nonload center loads excluded).

I.=Anchorage load center systems (Southcentral) interconnected with Fairbanks load center systems (Interior). Defense load included (1985). Nonload center loads are excluded.

jected power costs are those expected to obtain in a program dedicated to integrating, coordinating, and interconnecting as many systems as possible and, in all cases, reflect the use of larger size, lower unit cost generators, lower cost fuels, and reduced unit costs of operation and maintenance.

The cost of all equipment and facilities shown on the geographical diagrams, figures 12 and 16, and the power flow diagrams, figures 13 and 17, for study plans II and III, and similar diagrams (not included in the report) for the other plans have been included in the cost summaries, tables 19 and 20.

Hydroelectric power production costs are included in the total. Costs for existing plants were estimated on the basis of 1965 prices of salable hydro power. Costs of power from potential projects were based on available estimates.

Average power costs by region and for the State as a whole were based on energy production costs for the same kind of generating plants, taking into account each group's contribution to the present and future energy loads. Applicable transmission costs were included. Group power costs were developed from estimates of fixed and variable components reduced to manageable units to simplify the mass of detailed costs. Although the component costs are not given, a brief explanation concerning their relationship and value follows.

The fixed power cost component consists of annual fixed charges and fixed operating costs which are essentially unaffected by a generating plant's energy output. Estimates of annual fixed charges (the portion of total power cost directly related to investment in generating plants and transmission facilities) were developed by use of composite fixed-charge rates shown in table 24. Thus, the cost to all ownership segments of Alaska's electric power industry is placed on the same financial base. While the composite rate established fixed power costs on a uniform basis, we recognize the composition of and variation in the ownership structure of Alaska's electric utility industry.

The variable power cost component is the incremental cost associated with the generation of energy. With respect to thermal-electric plants, a large portion of the cost of fuel consumed and related labor and operating costs is considered to be a variable cost, with the cost of fuel being the major element. For a hydroelectric plant, the variable cost is that incurred when it is generating, and consists largely of operation and routine maintenance expenses.

TABLE 24

Composite Annual Fixed-Charge Rates, Electric Utility Generating Plants and Transmission Facilities

	Ownership weighting factors	Estimated fixed-charge rates (percent)	Composite (weighted) rate (percent)
HYDROELECTRIC PLANTS (75-YEAR LIFE)			
Mode of financing:			
Private	0. 1276	13. 08	1. 67
Municipal and other public non-Federal	. 3710	6. 03	2. 24
REA cooperative	. 3620	3. 49	1. 26
Federal	. 1394	3. 63	. 51
Hydroplant total annual fixed-charge:			
Rate			5. 68
Use			5. 70
CONVENTIONAL STEAM, INTERNAL-COMBUSTION AND GAS-TURBINE ELECTRIC PLANTS: AND GENERATING PLANT AND TRANSMISSION SUBSTATIONS (35-YEAR LIFE):			
Mode of financing:			
Private	0. 1276	14. 21	1. 81
Municipal and other public non-Federal	. 3710	7. 46	2. 77
REA cooperative	. 3620	5. 35	1. 94
Federal	. 1394	5. 34	. 74
Steam, I–C, and G–T and substations total annual fixed-charge:			
Rate			7. 26
Use			7. 30
TRANSMISSION LINES			
A. Wood pole (35-year life):			
Mode of financing:			
Private	0. 1276	13. 91	1. 77
Municipal and other public non-Federal	. 3710	7. 16	2. 66
REA cooperative	. 3620	5. 05	1. 83
Federal	. 1394	5. 04	. 70
Wood-pole total annual fixed-charge:			
Rate			6. 96
Use			7. 00
B. Steel tower (50-year life):			
Mode of financing:			
Private	0. 1276	13. 34	1. 70
Municipal and other public non-Federal	. 3710	6. 43	2. 39
REA cooperative	. 3620	4. 13	1. 50
Federal	. 1394	4. 18	. 58
Steel-tower total annual fixed-charge:			
Rate			6. 17
Use			6. 20

Conclusions

Growth in electric energy use is not readily separable from other factors which have a bearing on reductions in cost. Growth is both the result and cause of future economies. Maximum growth in electric power consumption in many localities in Alaska will occur only if electric rates are lowered as fast as cost reductions will permit. Cost reductions, in turn, will largely depend on the extent of growth in power usage.

The patterns and guidelines are not presented as an optimization of power planning for meeting Alaska's future loads, but it is believed that they represent a reasonable approach toward achieving economy in Alaska's power supply.

There are positive indications of significant savings which can be realized through coordinated planning, design, and operation of the electric systems. Furthermore, the availability of an abundant supply of low-cost electric power will promote economic growth and development which is not likely to be achieved without the ready availability of this resource.

We hope that the Survey will accelerate interest in more comprehensive electric utility industry planning and promote greater emphasis on the cooperative and coordinated efforts by which economic gains can be realized by both the suppliers and users of electricity in Alaska.

ACKNOWLEDGMENTS

The Federal Power Commission gratefully acknowledges the cooperation and assistance of the many people who have contributed to the Alaska Power Survey. In preparing the Survey report, we have depended largely upon the historical records, the future projections, and the many related materials assembled by the members of the Alaska Advisory Committee and its four special subcommittees without whose help a comprehensive Survey would have been impossible.

The names and affiliations of those who served on the Advisory Committee and Subcommittees at various times since their initial organization in August 1965 follow:

ALASKA POWER SURVEY ADVISORY COMMITTEE

Chairman: L. J. Schultz, Chugach Electric Association, Inc.

Co-Chairman: Carroll A. Oliver, Anchorage Municipal Light & Power Department

Members:

- Lt. Col. John Brewer, Alaskan Command, Department of Defense
- Morris Chertkov, Alaska Public Service Commission
- William Corbus, Alaska Electric Light & Power Co.
- E. N. Courtney, Alaska Department of Commerce
- Col. Clare F. Farley, Corps of Engineers, U.S. Army
- Joseph H. FitzGerald, Field Committee for Development Planning in Alaska
- Donald E. Hall, Alaska Public Service Commission
- Ernest L. Hardin, Jr., Corps of Engineers, U.S. Army
- James Hendershot, Alaska Public Service Commission
- Phillip R. Holdsworth, Alaska Department of Natural Resources
- Mark Hunt, Fairbanks Municipal Utilities System
- Lt. Col. David B. Keezell, Alaskan Command, Department of Defense
- Thomas E. Kelly, Alaska Department of Natural Resources
- Franz D. Nagel, Alaska Electric Light & Power Co.
- Gus Norwood, Alaska Power Administration
- George N. Pierce, Bureau of Reclamation
- Herbert Purcell, Golden Valley Electric Association, Inc.
- Burke Riley, Department of the Interior
- George Sharrock, Alaska Department of Commerce
- U. M. Staebler, Atomic Energy Commission
- Eugene C. Starr, Bonneville Power Administration
- Major Richard W. Towne, Alaskan Command, Department of Defense

Subcommittee for Economic Analysis and Load Projection

Chairman: E. N. Courtney, Alaska Department of Commerce

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P. R. Holdsworth, Alaska Department of Natural Resources

APPENDIX A

Generating Plant Capacity—Ownership and Location, Alaska Electric Power Industry, Utility-Installations, Dec. 31, 1965

Load center number and location	Installed kilowatts				
	Hydro	Steam	Diesel	Other	Total
Northwest:					
Private total	0	0	0	0	0
(1) Barrow Utilities, Point Barrow			250	....	250
(3) Nome Light & Power Utilities, Nome			2, 100	....	2, 100
Municipal total	0	0	2, 350	0	2, 350
(2) Kotzebue Electric Association, Inc., Kotzebue			1, 400	....	1, 400
Matanuska Electric Association, Inc., Unalakeet			485	....	485
Point Hope Power and Light Cooperative, Point Hope			40	....	40
Cooperative total	0	0	1, 925	0	1, 925
Federal total	0	0	0	0	0
Total Northwest Region	0	0	4, 275	0	4, 275
Southwest:					
Aniak Power Co., Aniak			[1] 50	....	50
(4) Northern Commercial Co., Bethel			[1] 580	....	580
Northern Commercial Co., McGrath			480	....	480
Private total	0	0	1, 110	0	1, 110
Municipal total	0	0	0	0	0
(6) Naknek Electric Association, Inc., Naknek			1, 550	....	1, 550
(5) Nushagak Electric Cooperative, Inc., Dillingham			850	....	850
Cooperative total	0	0	2, 400	0	2, 400
Federal total	0	0	0	0	0
Total Southwest Region	0	0	3, 510	0	3, 510
Southcentral:					
(10) Consolidated Utilities Ltd., Kenai			[2] 2, 650	....	2, 650
Private total			2, 650	....	2, 650
(12) Anchorage Light and Power Department, Anchorage			[2] 6, 536	[2] 30, 260	36, 796
(15) Cordova Public Utilities, Cordova			2, 479	....	2, 479
(10) Kenai City Light, Kenai					[3] 0
(11) Seward Electric System, Seward			3, 000	....	3, 000
Municipal total	0	0	12, 015	30, 260	42, 275

See footnotes at end of table.

Generating Plant Capacity—Ownership and Location, Alaska Electric Power Industry, Utility Installations, Dec. 31, 1965—Continued

Load center number and location	Installed kilowatts				
	Hydro	Steam	Diesel	Other	Total
(12) Chugach Electric Association Inc., Anchorage	15,000	14,500	2,350	[4]37,550	69,400
Copper Valley Electric Association, Glenallen			1,200		1,200
(14) Copper Valley Electric Association, Valdez			896		896
(9) Homer Electric Association, Inc., Kasilof					[5]0
(8) Homer Electric Association, Inc., Seldovia			1,325		1,325
(7) Kodiak Electric Association, Kodiak			3,563		3,563
(13) Matanuska Electric Association Inc., Palmer					[4]0
Matanuska Electric Association Inc., Talkeetna			406		406
Cooperative total	15,000	14,500	9,740	37,550	76,790
(12) USDI, Alaska Power Administration, Eklutna	30,000				30,000
Federal total	30,000				30,000
Total Southcentral Region	45,000	14,500	24,405	67,810	151,715
Interior:					
(16) Chatanika Power Company, Inc., Chatanika	5,625				5,625
Fort Yukon Utilities, Fort Yukon			300		300
Alaska Power and Telephone Co., Tok			1,000		1,000
Private total	5,625	0	1,300		6,925
(16) Fairbanks Municipal Utilities, Fairbanks		8,500		[4]7,000	15,500
Municipal total	0	8,500	0	7,000	15,500
(16) Golden Valley Electric Association, Fairbanks		9,500	11,745		21,245
Cooperative total	0	9,500	11,745	0	21,245
Federal total	0	0	0	0	0
Total Interior Region	5,625	18,000	13,045	7,000	43,670
Southeast:					
(19) A. J. Industries,[7] Juneau	[7]8,400				8,400
(19) Alaska Electric Light & Power Co., Juneau	1,600		7,086		8,686
Alaska Power & Telephone Co., Craig			210		210
Alaska Power & Telephone Co., Hydaburg			75		75
(17) Alaska Power & Telephone Co., Skagway	375		465		840
(17) Haines Light & Power Co., Haines			800		800
Pelican Utilities Co., Pelican	500		225		725
Tongass Power & Light Co., Hyder					[8]0
Yakutat Power Co.,[9] Yakutat					0
Private total	10,875	0	8,861	0	19,736

See footnotes at end of table.

Generating Plant Capacity—Ownership and Location, Alaska Electric Power Industry, Utility Installations, Dec. 31, 1965—Continued

Load center number and location	Installed kilowatts				
	Hydro	Steam	Diesel	Other	Total
(18) Hoonah, city of, Hoonah			200		200
(23) Ketchikan Public Utilities, Ketchikan	9,800		873		10,673
(24) Metlakatla Indian Communications, Metlakatla	3,000				3,000
(21) Petersburg, city of, Petersburg	2,000		1,250		3,250
(20) Sitka Public Utilities, Sitka	6,000		1,300		7,300
(22) Wrangell, city of, Wrangell			1,500		1,500
Municipal total	20,800	0	5,123	0	25,923
(19) Glacier Highway Electric Association, Inc., Auke Bay					[10] 0
Cooperative total	0	0	0	0	0
Federal total	0	0	0	0	0
Total Southeast Region	31,675	0	13,984	0	45,659

[1] Estimate.

[2] Natural gas-fired, oil to start.

[3] Purchases all requirements from Consolidated Utilities, Ltd.

[4] Gas-turbine capacity.

[5] Purchases all requirements from Chugach Electric Association.

[6] Purchases all requirements from Bureau of Reclamation, Eklutna project.

[7] A. J. Industries, an industrial establishment, sells entire output of its hydroelectric plants to Alaska Electric Light & Power Co.

[8] Purchases all requirements from British Columbia Electric Co. at Stewart, British Columbia, Canada.

[9] Yakutat Power Co. started operations in 1966 with 625 kw. of diesel-engine capacity.

[10] Purchases all requirements from Alaska Electric Light & Power Co.

Generating Plant Capacity—Ownership and Location, Alaska Electric Power Industry, Nonutility Installations, Dec. 31, 1965

Organization and Location	Installed kilowatts				
	Hydro	Steam	Diesel	Other	Total
Northwest:					
National defense—					
FAA, AIR [1]			8,331.0		8,331.0
ACR, ACS, ACW [1]			2,888.0		2,888.0
Subtotal			11,219.0		11,219.0
Other—					
BIA			2,381.1		2,381.1
EDU, JOM			41.4		41.4
Subtotal			2,422.5		2,422.5
Total nonutilities	0	0	13,641.5	0	13,641.5
Southwest:					
National defense—					
FAA, AIR [1]			28,122.0		28,122.0
ACR, ACS, ACW [1]			3,655.0		3,655.0
U.S. Navy, Adak			15,900.0		15,900.0
Subtotal			47,677.0		47,677.0
Other—					
BIA [1]			3,516.5		3,516.5
EDU, JOM			305.0		305.0
Subtotal			3,821.5		3,821.5
Total nonutilities	0	0	51,498.5	0	51,498.5
Southcentral:					
National defense—					
FAA, AIR [1]			4,946.8		4,946.8
ACR, ACS, ACW [1]			6,115.0		6,115.0
U.S. Air Force, Elmendorf Air Force Base		22,500	1,600.0		24,100.0
U.S. Army, Fort Richardson		18,000	6,100.0		24,100.0
U.S. Navy, Kodiak		4,000			4,000.0
Subtotal		44,500	18,761.8		63,261.8
Other—					
BIA			80.0		80.0
EDU, JOM			474.0		474.0
Subtotal			554.0		554.0
Total nonutilities	0	44,500	19,315.8	0	63,815.8

See footnote at end of table.

Generating Plant Capacity—Ownership and Location, Alaska Electric Power Industry, Nonutility Installations, Dec. 31, 1965—Continued

Organization and Location	Installed kilowatts				
	Hydro	Steam	Diesel	Other	Total
Interior:					
National defense—					
FAA, AIR [1]			12,987.4		12,987.4
ACR, ACS, ACW [1]			4,155.0		4,155.0
U.S. Air Force, Eielson Air Force Base		10,000	5,000.0		15,000.0
U.S. Air Force, Clear Air Force Base		22,500		NU	22,500.0
U.S. Army, Fort Greely			3,800.0	2,000	5,800.0
U.S. Army, Fort Wainwright		23,500	3,500.0		27,000.0
Subtotal		56,000	29,442.4	2,000	87,442.4
Other—					
University of Fairbanks		3,000			3,000.0
BIA			377.5		377.5
EDU, JOM			128.5		128.5
Subtotal		3,000	506.0		3,506.0
Total nonutilities	0	59,000	29,948.4	2,000	90,948.4
Southeast:					
National defense—					
FAA, AIR [1]			1,619.7		1,619.7
ACR, ACS, ACW [1]			2,455.0		2,455.0
Subtotal			4,074.7		4,074.7
Other—					
BIA [1]			924.0		924.0
EDU, JOM			0		0
Alaska Lumber and Pulp, Sitka		15,000			15,000.0
Ketchikan Spruce Mills, Ketchikan		900			900.0
Ketchikan Pulp Co., Ketchikan		20,000	750.0		20,750.0
Subtotal		35,900	1,674.0		37,574.0
Total nonutilities	0	35,900	5,748.7	0	41,648.7
Alaska total:					
National defense [2]		100,500	104,474.9	2,000	206,974.9
Other		38,900	8,978.0	0	47,878.0
Total nonutilities	0	139,400	120,152.9	2,000	261,552.9
Small industrial (approximately)					4,167.1
Grand total, nonutilities					265,720.0

[1] Various remote sites. [2] Including Federal Communication sites.

FAA—Federal Aviation Agency.
AIR—Alaskan Air Command (AAC).
ACR—Alaskan Communication Region.
ACS—Alaskan Communication System.
ACW—Aircraft Control and Warning.
BIA—Bureau of Indian Affairs.
EDU—Department of Education.
JOM—Johnson O'Malley School.
NU—Nuclear.

Generating Plant Capacity—Ownership and Location, Alaska Electric Power Industry, Utility and Nonutility Installations, Summary—Dec. 31, 1965

Organization and Location	Installed kilowatts: Hydro	Steam	Diesel	Gas turbine and nuclear	Total
Northwest:					
a. Utility	0	0	4, 275	0	4, 275
b. Nonutility	0	0	13, 642	0	13, 642
Subtotal	0	0	17, 917	0	17, 917
Southwest:					
a. Utility	0	0	3, 510	0	3, 510
b. Nonutility	0	0	51, 499	0	51, 499
Subtotal	0	0	55, 009	0	55, 009
Southcentral:					
a. Utility	45, 000	14, 500	24, 405	[1] 67, 810	151, 715
b. Nonutility	0	44, 500	19, 316	0	63, 816
Subtotal	45, 000	59, 000	43, 721	67, 810	215, 531
Interior:					
a. Utility	5, 625	18, 000	13, 045	[1] 7, 000	43, 670
b. Nonutility	0	59, 000	29, 948	[2] 2, 000	90, 948
Subtotal	5, 625	77, 000	42, 993	9, 000	134, 618
Southeast:					
a. Utility	31, 675	0	13, 984	0	45, 659
b. Nonutility	0	35, 900	5, 749	0	41, 649
Subtotal	31, 675	35, 900	19, 733	0	87, 308
Small industrials throughout State:					
b. Nonutility (approximately)	1, 197	1, 385	1, 585	0	4, 167
Alaska:					
a. Total utility	82, 300	32, 500	59, 219	[1] 74, 810	248, 829
b. Total nonutility	1, 197	140, 785	121, 739	[2] 2, 000	265, 721
Total Alaska	83, 497	173, 285	180, 958	76, 810	514, 550

[1] Gas turbine. [2] Nuclear.

APPENDIX B

Annual Electric Power Requirements, Number of Customers and Use Per Customer, Electric Utility Systems, Total Alaska

Category of use	Customers [1] (number)	Annual average energy use per customer (kilowatt-hours)	Energy use (gigawatt-hours)	Energy use (percent of total)
1950:				
Residential (nonfarm)	19, 850	2, 700	54	47
Irrigation and drainage	0	0	0	0
Farm	408	1, 590	0. 65	1
Commercial	2, 621	11, 930	31	27
Industrial			3. 5	3
Other uses			13	11
Total consumption			102	89
Losses and unaccounted for			13. 0	11
Total energy for load			115	100. 0
1955:				
Residential (nonfarm)	37, 029	2, 690	99	40
Irrigation and drainage	0	0	0	0
Farm	445	4, 050	1. 8	1
Commercial	5, 351	16, 430	88	35
Industrial			18	7
Other uses			18	7
Total consumption			225	90
Losses and unaccounted for			25	10
Total energy for load			250	100
1960:				
Residential (nonfarm)	40, 580	4, 140	167	43
Irrigation and drainage	0	0	0	0
Farm	370	6, 900	3	1
Commercial	6, 446	16, 850	109	28
Industrial			56	14
Other uses			17	4
Total consumption			352	90
Losses and unaccounted for			40	10
Total energy for load			392	100

See footnote at end of table.

Annual Electric Power Requirements, Number of Customers and Use Per Customer, Electric Utility Systems, Total Alaska—Continued

Category of use	Customers [1] (number)	Annual average energy use per customer (kilowatt-hours)	Energy use (gigawatt-hours)	Energy use (percent of total)
1965:				
Residential (nonfarm)	49,672	5,677	282	39
Irrigation and drainage	0	0	0	0
Farm	425	11,764	5	0.7
Commercial	7,972	29,353	234	33
Industrial			75	10
Other uses			49	7
Total consumption			645	90
Losses and unaccounted for			75	10
Total energy for load			720	100
1975:				
Residential (nonfarm)	80,000	9,125	730	40
Irrigation and drainage				
Farm	627	14,350	9	0.5
Commercial	12,400	37,100	460	25
Industrial			350	19
Other uses			102	5.5
Total consumption			1,651	90
Losses and unaccounted for			190	10
Total energy for load			1,841	100
1985:				
Residential (nonfarm)	122,100	14,000	1,710	36
Irrigation and drainage				
Farm	830	30,120	25	0.5
Commercial	19,000	46,840	890	18.5
Industrial			1,360	28
Other uses			340	7
Total consumption			4,325	90
Losses and unaccounted for			490	10
Total energy for load			4,815	100

[1] Farm customer category adjusted in attempt to show number of farms actually served by electric utilities although billing may place them in residential and commercial categories.

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