State of Washington
ARTHUR B. LANGLIE, Governor

Department of Conservation and Development
JACK V. ROGERS, Director

and

Washington Public Service Commission
OWEN CLARKE, Chairman

DIVISION OF MINES AND GEOLOGY
SHELDON L. GLOVER, Supervisor

BULLETIN NO. 38

The Place of Steam-Electric Generating Stations in the Orderly Program of Electric Power Development in the Pacific Northwest

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By
HOLLAND H. HOUSTON

OLYMPIA, WASHINGTON
AUGUST, 1950

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FOREWORD

In 1949 Washington found itself faced with two particular problems that had a direct bearing on the industrial welfare of the state. One was of long standing and involved the decreasing utilization of the great coal supplies that should form one of the state's most valuable resources in the mineral field. The other was a possible shortage of electrical energy that could be expected to continue until such a time as new hydroelectric generating capacity should become available.

Governor Arthur B. Langlie, in July 1949, called a conference to consider these situations and to discuss the possibility of relieving the temporary power shortage through the use of coal in steam-operated generating plants. Whereas the coal production of the state was 4,128,424 tons in 1918, it was only 907,915 tons in 1949. The utilization of local coal in steam plants, if this were found to be economically feasible, would be a marked aid to the coal industry while at the same time supplementing the power supply. In the discussion it became evident that no worth-while conclusions could be formed until a complete study was made of the problems and their interrelations.

Mr. Holland H. Houston, Engineer with the Public Service Commission of the state, well qualified in training and experience, was chosen to make this study. He represents the Public Service Commissions of Idaho, Oregon, and Washington as one of the power coordinators in the Northwest Utility Conference Committee. His previous work with the Federal Power Commission between 1934 and 1937 in Washington, D. C., and in the San Francisco Regional Office, and his subsequent experience as an industrial engineer with the pulp industry of the Northwest gives him first-hand knowledge of the power-supply problems of this area. Mr. Houston is a member of the American Institute of Electrical Engineers and a professional engineer, qualified in the State of Washington in both mechanical and electrical engineering. His earlier work as a consulting engineer in Boston and New York enabled him to broaden the current study to include comparisons with recent electric-power developments in the Midwest and along the Atlantic Seaboard.

As any addition to the present power resources of the area must be coordinated with the Northwest Power Pool system, the report has been expanded to include an analysis of the electric-power requirements of the entire area.

July 1950

Jack V. Rogers, Director
Department of Conservation and Development

THE PLACE OF STEAM-ELECTRIC GENERATING STATIONS IN THE ORDERLY PROGRAM OF ELECTRIC POWER DEVELOPMENT IN THE PACIFIC NORTHWEST

By Holland H. Houston

I. INTRODUCTION

In July 1949, Governor Arthur B. Langlie requested the Department of Conservation and Development to study the problems relating to the shortage of electric power and energy in the Pacific Northwest. In particular, he was interested in knowing whether electric energy generated from fuel-burning electric plants using local Washington coal as fuel would constitute an economic solution to the immediate problem. The Governor also wanted to know whether these plants would have a continuing useful place in the orderly program of power development in this area.

Approximately 75 percent of the electric-power resources of the Northwest Power Pool are located in the State of Washington. Chart I, in the pocket of this report, shows the extent of the operation of the Power Pool. The generating resources of the Pool are integrated so as to give the most economic power supply to the entire area. Any study of the electric-power supply in the State of Washington must take into consideration the program of the entire area.

In this report a study has been made of the power requirement of the Pacific Northwest. An analysis has been made of the character of the present load and the distribution of the load over the area served by the Pool. The rate of growth of the area load in the past years has been examined and a forecast of future requirements suggested.

The program for development of the vast water-power resources of the Columbia River as proposed in the recent report of the Corps of Engineers, Department of the Army, North Pacific Division, to Congress has been studied in detail.

The availability of coal, fuel oil, and other sources of heat energy has been analyzed. The use of these fuels in a modern steam-electric generating station has been studied. Finally, an analysis has been made setting forth the economics of combined operation of water power and steam resources.

The cost studies in this report are for the purpose of determining the relative cost of serving additional electric loads from new hydroelectric and steam-electric projects. A comparison has been made between the cost of electric energy from the projects included in Phase C-2 of the Army Engineers' report which are scheduled for construction in the next several years, and a modern steam-electric generating station operating with fuel oil. In determining the fixed costs of both steam and hydroelectric plants, a property tax of 2 percent has been included. It appears that such a tax or its equivalent will be required to make many of the storage projects, on which the success of the entire program depends, more attractive to the people in whose areas the projects are to be located. Such a tax would also compensate local units of government for loss of revenue from forest and agricultural lands inundated by the projects.

The conclusions and a summary of the studies embodied in this report have been outlined in section II.

ACKNOWLEDGMENTS

The writing of an engineering report of this nature is a joint venture. Historically, it is based on the operating experience of the several systems comprising the present Northwest Power Pool. Technically, it summarizes the advancements in the art of power generation and transmission as determined from observation and as reported in the technical journals.

The writer wishes to acknowledge the assistance received from the following sources:

Corps of Engineers, Department of the Army, North Pacific Division
Bonneville Power Administration
Consultants of the Northwest Power Pool
Federal Power Commission
City of Tacoma Light Department
General Electric Company
Allis Chalmers Company
C. C. Moore -- Engineers
American Gas & Electric Company, New York
Pacific Gas and Electric Company, San Francisco

In addition the author wishes to acknowledge the valuable assistance given by the Army Engineers, Federal Power Commission, and Bonneville Power Administration in reviewing the manuscript and making suggestions which have added to the subject matter of the report.

II. CONCLUSIONS AND SUMMARY

CONCLUSIONS

1. The Phase C-2 program outlined in the Army Engineers' report for development of the water resources of the Columbia River includes some sixteen major and several smaller hydroelectric projects on the Columbia River and tributaries. Two of these, Grand Coulee and Bonneville, are now practically complete. If the total cost of the balance of this program, excluding costs chargeable directly to flood control and navigation, is charged to power together with the cost of transmission, the cost of electric energy delivered to the principal load centers in the Puget Sound area and on the lower Columbia River will be about 6 mills per kilowatt-hour.
2. The cost of producing an equivalent amount of electric power by the operation of modern steam-electric generating stations located in the load centers would be identical within the limits of accuracy of the calculation.
3. It is probable that the cost of producing the electric energy from the water-power projects on the Columbia River could be somewhat reduced by increasing the amount of upstream storage on the main stem and tributaries of the Columbia River above the Grand Coulee project. The amount of this reduction is between 1/2 and 1 mill per kilowatt-hour.
4. In choosing between the program of development of the power projects on the Columbia River and steam-electric generation, consideration must be given to the advantages and disadvantages of the two programs. In favor of the development of the Columbia River projects are the benefits of flood control, irrigation, and navigation. The construction of dams and the inundation of large areas adversely affects some of the natural resources in the area.

5. If the projects included in Phase C-2 of the Army Engineers' report are developed to meet the electric load growth in this area, practically all the lower-cost projects will be in service by 1965. It will be necessary at that time to consider the construction of fuel-burning electric plants to supplement the base-load operation of the hydroelectric resources of the area. In the meantime, the place of steam-electric generation in the power program of the Pacific Northwest will be one of supplementing the electric energy requirements of the area load during periods of adverse water conditions of the rivers in the area.
6. During the period that fuel-burning electric-generating plants are used to supplement the output of hydroelectric projects during adverse water conditions, fuel oil will most probably be the source of the major portion of heat energy for the fuel-burning plants of the area. At the present time it is lower in cost than any other fuel with the exception of by-product hogged fuel. Fuel oil is easy to store and is adaptable to intermittent operation. The boiler settings of any new steam-electric projects in the area should be so designed that fuel oil, natural gas, or powdered coal can be burned in the same boiler in accordance with the economics of fuel at the particular time.
7. When the electric load has grown to a point requiring the development of base-load fuel-burning plants, considerable study will be required to determine both the type of fuel and the location of the plant on the system. At the present time the cost of using a high-grade bituminous coal from Utah as a source of heat energy in a steam plant located in the Puget Sound area is 70 percent greater than the fuel cost if the operation were on fuel oil. However, if this same Utah coal were consumed in a fuel-burning plant located in Salt Lake City, the cost would be equal to fuel

oil operation in the Puget Sound area. When the base-load operation of steam-electric generating plants is required in the load areas west of the Cascades, the problem then will become one of comparing the relative costs of the several fuels available in the area at that time.

8. Before additional steam-electric generating resources are constructed to supplement the energy deficiency of the area resources during adverse water conditions, a means must be found to distribute the cost of the project over the total energy consumption of the area. Such steam-plant projects are insurance against adverse water conditions in the area and can best be so treated.

9. As of July 1950, there exist about 130,000 kilowatts of interruptible power contracts between the Bonneville Power Administration and certain large industries. The total of these interruptible contracts is increasing. The relation between the periods of operation under these contracts and the time of operation of any supplemental steam projects under adverse water conditions should be clarified.

SUMMARY

General

A program to provide additional electric-generating capacity to satisfy the rapidly growing electric requirements of the Pacific Northwest should meet several rather severe standards of economic and engineering soundness. Some of the standards are:

(1) Provide in the area a supply of electric power ample to serve the increasing demands of industrial, commercial, residential, and farm use.

(2) Provide that the maximum beneficial use of the water-power resources of

the area shall accrue to the industry, commerce, and the people living in the area.

(3) Require that power be sold without discrimination between classes of consumers, at rates proportional to the actual cost of serving the particular load.

(4) The program should include a promotion feature informing the electric customers in the area of the difference in availability and cost of prime power, dump power, and flood-flow power. Industries that can store by-product fuels during the period that flood-flow power is available should be allowed to benefit from the low cost of producing this power. Farmers should be allowed the benefit of low-cost flood-flow power for irrigation pumping. Packing companies could use flood-flow power for processing agricultural products.

Present electric load of the area

There is nothing unusual about the electric load of this area. The summation of the individual demands of all customers--industrial, commercial, and residential--results in a load-curve shape which is about the same as in other areas of the United States. There are the usual daily and seasonal variations.

The electric load of this area is growing. There is nothing unusual about the rate of growth. Figure IV is a plot of the load growth from 1915 to date on the systems that now comprise the Northwest Power Pool. The upper curve of figure IV shows the trend of system peaks. There are the peaks of 1918 and 1943, due to our war efforts. There is the peak of 1929, due to the inflation period. Even though system peaks declined in the period of deflation following 1929, load was accruing, only to show itself in the period from 1934 to 1943.

The average rate of growth from 1915 to date is about 6.8 percent per annum--a little less than the rate of growth in California and a little greater than the rate of growth in the nation as a whole. The evening system peak of the Pool of 4,690,000 kilowatts, occurring on January 30, 1950, due primarily to the sustained cold spell, falls almost exactly on the curve of peaks after adjustment for the British Columbia Electric Railway Company.

There is no reason to expect any unusual change in the rate of growth of load in the near future unless a poorly executed program of new construction leaves the area without sufficient generating capacity to carry the new loads of industry and commerce. Actually, the Pacific Northwest is the only area of the United States in which a power shortage exists today. The bringing into this area of 3,500,000 kilowatts of aluminum pot-line load, which supports very few man-hours of labor, and selling electric power for this purpose below the cost of production could conceivably have an adverse effect upon other industry and employment in the area. Such a program is outlined in Appendix N of the Army Engineers' report.

Table 1, page 31, of this report, shows the distribution of the electric load in the area served by the system of the Northwest Power Pool.

About two-thirds of the present load is in the area west of the Cascade Mountains on Puget Sound and along the lower Columbia River. There is no reason to expect any great change in the distribution of new load in the area.

With the ultimate development of the water power in the Northwest, the center of generation will be in the vicinity of the Grand Coulee project, some 180 miles east and north of the principal load centers along the coast. The average cost of transmission of power from the center of generation to the coastal areas will approach 2 mills per kilowatt-hour. The cost of transmission will constitute an ever-increasing handicap to even the cheapest water power in competition with modern steam generation located at the load centers.

The term "integration", when applied to electric-power generation and transmission, has a precise meaning. It may be defined as the scheduling of the power-supply program of two or more interconnected power systems so as to decrease the fixed charges and operating costs incurred in supplying the total load requirements of the combined system. The elements of integration are explained in section III under the subheading "The economics of integration."

Integration does not mean building a large number of high-capacity transmission lines. Still more important, it does not mean building long transmission lines to interconnect remote areas such as California and the Pacific Northwest. The power loss incurred in transmitting power from the Columbia River plants to San Francisco would amount to at least 28 percent of the delivered power, even over fully compensated high voltage circuits. If sizeable blocks of power were to be transmitted by interconnecting transmission systems designed to serve the Columbia River Basin or the northern half of California, losses might easily equal 40 percent of the delivered energy. Such schemes can only be undertaken if the power is undervalued at the sending end of the line and the construction of the transmission line itself subsidized. The average distance of power transmission in the United States today is less than 100 miles. Technically, long-distance transmission is possible; economically, it is unsound. When such programs are advocated, one must look outside the fields of engineering and economics to find the purpose of the program.

Present power resources

A summary in the 1949-50 water-year program of the Northwest Power Pool lists the present power resources and loads of the area. This summary has been included as table II. Data for the total Pool, taken from table II, are as follows:

	Median water Jan. 1950		Modified critical water Jan. 1950		Critical water Jan. 1950	
	Average energy	Peak capacity	Average energy	Peak capacity	Average energy	Peak capacity
Load	3,352	4,766	3,352	4,766	3,352	4,766
Resources:						
Hydro	3,194	4,167	3,051	4,046	2,692	4,046
Steam	60	372	203	372	273	372
Misc.	98	197	98	197	125	197
Total	3,352	4,736	3,352	4,615	3,090	4,615
Deficiency	0	30	0	151	262	151

In explanation of the headings in the above tabulation, a median water year is one the flow of which will be exceeded 50 percent of the time. A modified-critical water year is one the flow of which will be exceeded 75 percent of the time. A critical flow corresponds to the historic low flow.

In the above tabulation it will be noted that the average energy from water power decreases with the lower flows of the rivers in the area and must be supplemented by greater production from steam plants and miscellaneous purchases from industrial plants.

Actually, in the calculation for a critical water year, there is not sufficient water (natural flow and storage) to furnish the energy requirements of the load, and an energy deficiency exists. Fortunately, average water conditions or better have existed for most of the winter months in the last two years, so that the deficiency has been largely one of peaking capability. The impact of this peaking deficiency on the economy of the area has been minimized by load molding and voluntary curtailment of use during the winter evening peak periods.

The potential water-power resources of the Pacific Northwest

In 1932 and again in 1948 the Army Engineers presented to Congress a report setting forth a plan for the development of the Columbia River and its tributaries. This latest report is known as The Columbia River Review 308 Report. This report sets forth a "Main Control Plan" for the development of navigation, flood control, irrigation, and power development of the Columbia River.

This Army Engineers' report summarizes the total potential power capability of the Columbia River and tributaries in the form of a chart showing plant capability in millions of kilowatts as a function of water storage for power. It is included in this report as figure IX. This chart shows a possible ultimate development of 32 million kilowatts. However, the economic limit of development is more nearly 12 to 15 million kilowatts of installed capacity. Above this point it is probable that steam-electric plants will prove more economical.

The present program for development of the
water-power resources of the Pacific Northwest

The present program for development of the Columbia River is essentially the program outlined as the "Main Control Plan" of the Army Engineers. It includes some 12 major projects on the main stem and tributaries of the Columbia River, together with several smaller ones on the upper Snake River and on the Willamette River. These plants are listed in table V. The only important change from the Army program was the omission of the Glacier View project on the north fork of the Flathead River.

The completion of this program will bring into operation about 10 million kilowatts of additional generating capacity which, when added to the present resources of the Northwest Power Pool, will bring the installed capacity to approximately 14.25 million kilowatts.

The average energy available from these additional plants in a critical-water year during the controlled-flow period will average about 6 million kilowatts. This, added to the present system, will bring the average energy during the controlled-flow period to 9 million kilowatts.

There is a definite weakness in this entire program. There is not sufficient upstream storage to maintain flows during the low-flow periods of the river. The Hungry Horse storage, for which so much has been promised, is not good storage. The drainage basin above the Hungry Horse project does not have sufficient run-off to fill the storage each year unless precipitation has been heavy. Unless some changes can be made to obtain additional upstream storage, it looks as though the present energy deficiency will continue indefinitely into the future.

This energy deficiency could be eliminated by the installation of steam plants. However, this would not result in as economical a program and would ultimately result in higher electric rates.

If the electric load in the area continues to grow at 6.8 percent per annum, the entire output of the plants included in Phase C-2 of the Army Engineers' report will be absorbed by 1965.

In figuring the average cost of electric energy from the plants included in Phase C-2, it was assumed the entire output of these plants generated from the minimum regulated flow of the river would be usable. It was previously mentioned that two-thirds of the entire load of the Northwest Power Pool was in the area west of the Cascade Mountains. It was assumed that this condition would continue to prevail in 1965. Plants nearest the coast were assumed to feed their output to the coast.

Under the conditions assumed, the average cost of electric energy delivered at the principal load centers in the Puget Sound area and in the lower Columbia River area would be 6.0 mills per kilowatt-hour. Of this total, about 2 mills is figured as the cost of transmission. It must be kept in mind that this calculation assumes that all project costs are chargeable to power. It is probable that this cost could be lowered somewhat with an additional amount of upstream storage.

So far in summarizing the program of development of the waters of the Columbia River, nothing has been said of water use. Actually, the cost of furnishing the necessary electric power to supply the needs of the area is about the same whether generated from water power or steam. If there is economic and engineering justification for the program of development of water power over steam power, it must be found in the collateral advantages of such a program, i. e., flood control, navigation, and irrigation.

The water supply at Grand Coulee is typical of the problem which exists in the entire basin. The mean annual flow at Grand Coulee is about 78 million acre-feet. The flow in a critical-water year is about 58 million acre-feet, and the flow for a modified critical-flow year is about 68 million acre-feet.

The point of most economical development for upstream storage above Grand Coulee is about 30 percent of mean annual run-off, or 22.5 million acre-feet. This amount of storage would give a minimum regulated flow of 73,000 c.f.s. at the Coulee project. Under modified critical flow there would be left for irrigation about 14.4 million acre-feet of flood flow spanning the irrigation pumping season. These modified critical flow conditions can be expected to occur at least once every four years. Whenever the flow is less than modified critical, there would be insufficient water to fill the storage ponds and supply the needs of irrigation. Under these conditions the power requirements must be supplemented by steam generation, or interruptible power contracts must be enforced.

Any diversion of water from the upper reaches of the Columbia River or tributaries would increase the cost of power development and reduce the amount of low-cost power and water for irrigation. This is an extremely important subject. It has been discussed in greater detail in section VI, under the subheading "The limits of upstream storage."

Fuels available for steam-plant operation

Oil and coal are presently the only fuels available to the area in sufficient quantity to be considered as a source of heat energy for fuel-burning electric plants. In choosing between these two fuels, one must consider cost and availability. In an area like the Pacific Northwest, in which water power is the prime source of electric energy, steam-plant operation will be intermittent. Its principal role must be that of supplementing water-power generation in critical-flow years. Under these operating conditions the ability of a fuel to be stored without excessive deterioration is important.

Oil is readily available, can be stored, and presently is the lowest-cost fuel in this area. The only high-grade bituminous coal available in this area in quantity is shipped in from other areas. There is a large amount of subbituminous coal in this state. This coal can be burned satisfactorily but cannot be economically stored. It is fairly high in cost. The following tabulation gives the relative cost of fuels in this area. The cost is expressed in cents per million B.t.u., both "as fired" and "as steam."

Type of fuel	As fired	As steam
Fuel oil	26.8	30.5
Bituminous coal:		
Utah coal burned in Washington	45.4	52.0
Washington	38.8	44.5
Utah coal burned in Salt Lake City	26.0	29.8
Subbituminous coal:		
Intermittent operation	44.0	55.0
Base-load operation	34.1	42.7

Referring to the above tabulation, fuel oil is the most economical fuel in this area. It has good storing characteristics. Only after the better water power in the area has been developed and steam-electric projects are developed for base-load operation can there be any great demand for the subbituminous coals for steam-plant operation. Even then, if oil is available at the present relative price, preference would be given to oil.

Any new large steam-electric projects in this area would be built with boiler setting arranged for burning oil, coal, or natural gas.

The modern steam plant

The system peak of the Northwest Power Pool is about 4,700,000 kilowatts. A steam plant constructed to supplement the electric energy supply of this system during periods of low river flow should be designed to produce large blocks of electric energy with a minimum of fixed costs and production expense.

Just such a plant has recently been completed by the Pacific Gas and Electric Company. This plant is known as Station "P" and is located about 3 miles south of the East Bay Bridge in San Francisco. The new addition to this plant consists of two 100,000-kilowatt tandem-compound turbine generators. Steam is furnished to each unit from two boilers with a normal rating of 475,000 pounds of steam per hour. These installations are complete with station auxiliaries and controls so that one operator can control two turbine generator units and four boilers. A cross section of this plant is shown in figure XVIII.

At rated load this plant will consume approximately 10,300 barrels of fuel oil or 68 million cubic feet of gas per day.

At rated load, cooling water to the two main condensers will be required in an amount of 335 million gallons per day, which is over three times the total daily water consumption of the city of San Francisco. The cooling water is taken from the bay.

The efficiency of this plant from "as fired" to "send out" is about 12,000 B.t.u. per kilowatt-hour, or 520 kilowatt-hours per barrel of oil. At a cost of $1.60 per barrel of oil, as received, the fuel cost is 3.22 mills per kilowatt-hour. The total cost of operation is shown on figure XXIII. This total cost per kilowatt-hour is expressed in terms of the average hours per month operated during the year. An annual plant factor of 72 percent is equivalent to 526 hours per month of operation. Under this schedule of operation the total cost of operation will be between 5.7 and 6.3 mills per kilowatt-hour.

A comparison of the cost of operation of steam and water-power plants under different load conditions is discussed in section IX of this report under the subheading "Comparison of cost by types of load."

III. THE ELECTRIC POWER REQUIREMENTS OF THE PACIFIC NORTHWEST

AREA SERVED BY THE NORTHWEST POWER POOL

In 1936 the Federal Power Commission undertook a study to determine the areas in which there were economies in plant investment and operating costs accruing from the interconnection of the principal electric utility systems in the area. At that time an area, including the northwestern portion of Utah, western Montana, Idaho, Washington, and Oregon, was designated as Region VII. The Federal Power Commission considered that there were sufficient transmission-line interconnections between the several systems included in this area to allow a major saving in investment and operating expense to be made by reason of load diversity, reserve diversity, resource diversity, and economy flow of power. The transmission lines and generating stations in this area are shown on a map entitled "Pacific Northwest transmission system," prepared by the Bonneville Power Administration and included in the pocket in the back of this report as plate I.

In 1936 the maximum demand of all of the utilities in Region VII did not exceed 1.5 million kilowatts. Today the total demand of the systems in this same area is in excess of 4 million kilowatts. To assist in the orderly integration of the systems in the area, a voluntary organization, known as the Northwest Power Pool, has been developed. Presently, the Power Pool is coordinated at the policy-making level through the Northwest Utilities Conference Committee, of which Mr. Clifford A. Erdahl of Tacoma City Light is chairman. At the operating level, the Pool is coordinated through the operating committee, which consists of representatives of the 11 major systems comprising the Pool.

Mr. Lester Cowgill and Mr. Jack Mosely, consultants of the Pool, supervise the preparation of the annual operating program of the Pool. The several systems comprising the Pool submit each year load and resource information to the consultants. The consultants, using the information submitted by the individual systems, prepare an operating program for the particular water year. This program suggests an integrated method of system operating to produce maximum economies in supplying power to all the systems of the area.

THE ECONOMIES OF INTEGRATION

Integration may be defined as the scheduling of the power-supply program of two or more interconnected power systems so as to decrease the fixed charges and operating costs incurred in supplying the total load requirement of the combined system. Savings accruing from integration depend upon the reduction in installed generating capacity by reason of load diversity and reserve diversity, and savings in operating costs in proportion to the flow of steam-replacement power.

Transmission lines are constructed to transmit power from generating sources to loads and to obtain economies in power supply by taking advantage of the following system characteristics:

(1) Reserve diversity

(2) Load diversity

(3) Resource diversity

(4) Economy flow of power

The degree of integration may be measured by the extent to which the transmission lines of a system enable the operators to obtain the economies of power supply accruing by reason of load, reserve, and resource diversities and economy flow of power.

The multiplicity or large capacity of transmission lines does not *per se* indicate integration. Transmission lines cost money. The fewer circuits that can be used to accomplish integration, the greater the net savings accruing to the company.

Consider two isolated utility systems a considerable distance apart, each supplying a rapidly growing load having a peak of 100,000 kilowatts. Further, assume that each system has resources consisting of three 50,000-kilowatt generators. See figure I. Two units of each system would be fully loaded at time of system peak and one would be operating as spinning reserve. Such operation would satisfy the dictates of good operating practice.

However, due to the expanding load requirements, those responsible for the operation of these two systems would be faced with the problem of immediately supplying additional resources. Their choice might be additional generators, or engineering studies might show greater economies of power supply by interconnection. Let us examine the possible advantages accruing from interconnection, and the number and capacity of the circuits required to fully integrate the two systems. This analysis can be readily accomplished by assuming certain diversities and a few other system characteristics, such as the types of prime movers driving the several generators.

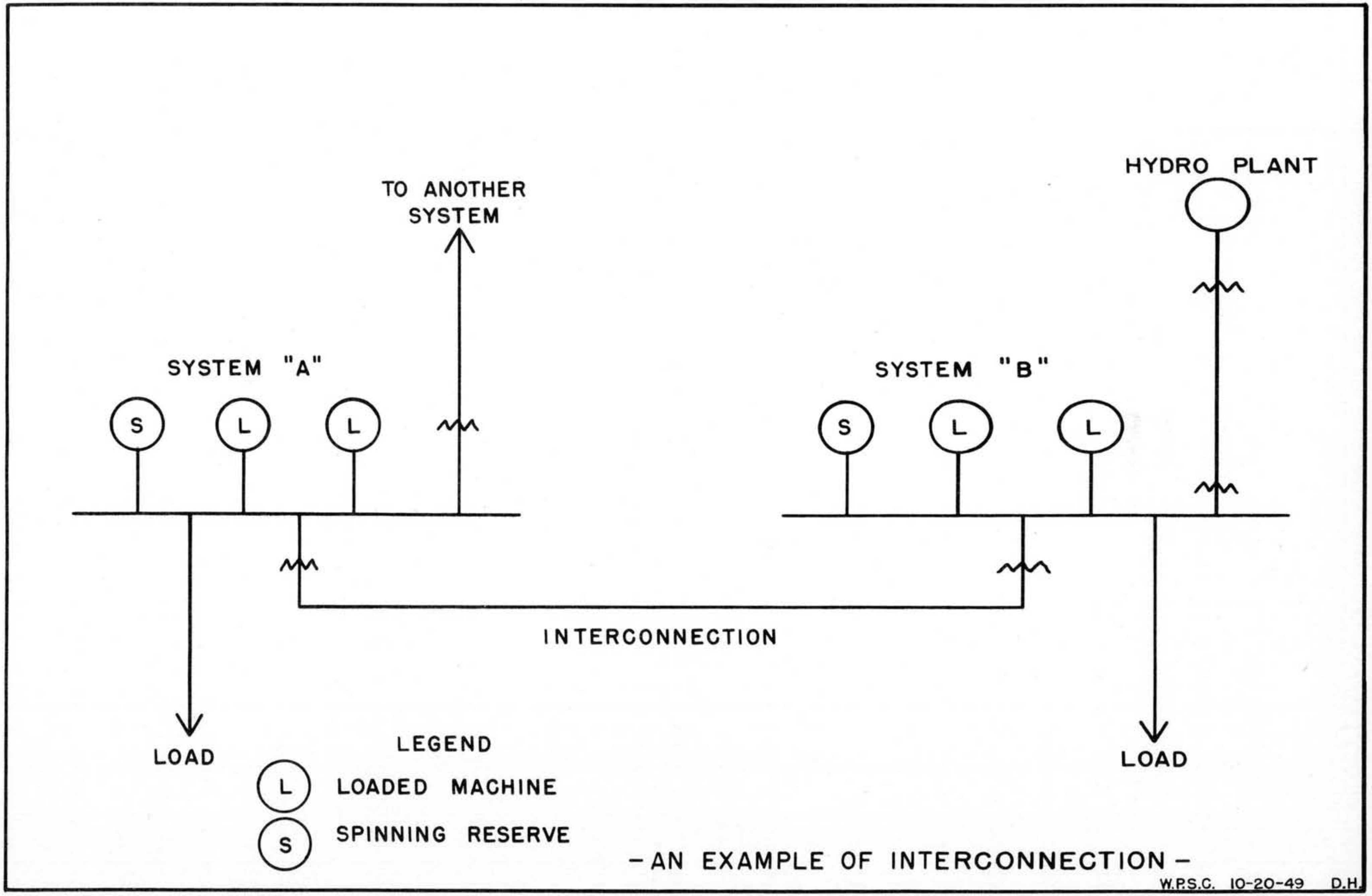
Let us discuss first the requirements for integration with respect to reserve diversity. How many transmission lines are required and what must be their capacity to accomplish integration of the two systems previously described so far as reserve diversity is concerned?

At first thought it might seem necessary to have two circuits, each with a capacity of 50,000 kilowatts. With the loss of one circuit, the two systems would still be interconnected. With this interconnection, an additional load of 50,000 kilowatts could be carried on the combined system and still retain spinning reserve equivalent to the largest unit. In case the largest unit on the system went out of service, the combined peak could still be carried without overload on any unit.

From an operating standpoint the above analysis seems reasonable. However, from the standpoint of plant investment it is too severe. It is considered good practice in utility-system engineering to protect service against a so-called "single fault," but also it is considered uneconomical to protect a system against a "double fault." The simultaneous loss of a generator and a line would be considered a "double fault." In short, as far as reserve diversity is concerned, a single circuit is sufficient for integration.

Now let us consider the capacity of this circuit. If one-half of the spinning reserve requirement is carried on each end of the tie line between the two systems, a capacity of 25,000 kilowatts would be sufficient to integrate the two systems. It is usual to spread the spinning reserves in the principal load centers of a system so as to reduce the transmission requirements to a minimum.

Consider next the load diversity. Assume that a study of the load data of the two systems discloses a scheduled load diversity of 10,000 kilowatts between systems A and B. System A serves an agricultural area. Its peak load is dictated by the pumping requirements for irrigation. The peak load occurs at 10:00 a.m. in July. System B serves a large metropolitan load on the coast. Its annual system peak occurs at 5:30 in the evening on December 22. The diversity between the two systems is seasonal and can be scheduled. This diversity will occur year after year, and the same generating capacity can carry the two peak loads if the two systems are interconnected. Here again, a single 25,000-kilowatt circuit is sufficient to allow the system operators to realize the economies accruing from load diversity. The system is protected against the loss of the tie line by spinning reserve.



- AN EXAMPLE OF INTERCONNECTION -

FIG. I

In an area where power resources are mostly in water-power plants, a considerable advantage can be derived from interconnecting two systems situated in drainage basins with diverse flow characteristics. Power resources on a stream with flood flow will be assigned to a position on the base of the load curve. Storage plants on streams with low flow will be assigned to peaking or regulation. At other seasons of the year the positions of the two plants on the load curve may be reversed by reason of the changes in the flow characteristics of the rivers in the two areas.

Oftentimes one drainage basin may approach a critical flow at the same time that a flood flow exists in another drainage basin. The interconnection of the resources and loads in two such areas result in major savings in the cost of providing power for the combined systems. Here again, as the difference in the output of plants in two basins is of rather small magnitude, the size of the transmission line interconnecting the two areas does not have to be large.

THE CHARACTERISTICS OF ELECTRIC LOAD

The total electric load or demand on a power system is the summation of a myriad of small demands for lighting, cooking, and heating, together with other commercial and industrial process demands. The total demand on a system is continually changing. Individual uses have certain daily patterns; in addition, they have seasonal variations.

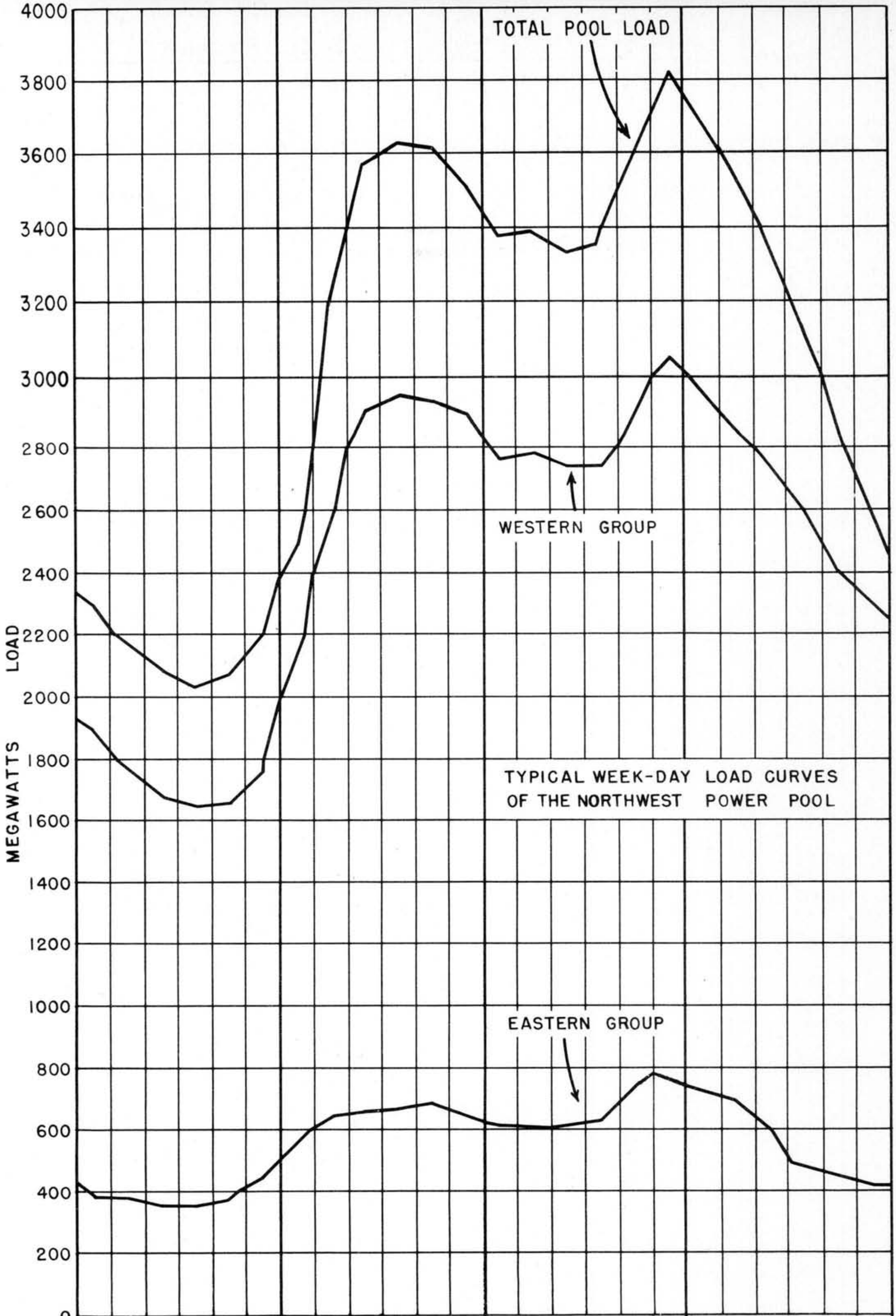
In considering the need for additional generating facilities on a power system, it is essential that a thorough understanding be had of the load characteristics of the system and the particular part to be played by the additional resources in satisfying the increasing demands of the load.

Let us consider first the daily variations in the load requirements. Figure II is a plot of three daily load curves. The upper curve shows the hour-to-hour variations in the electric load of the entire Northwest Power

Pool, not including the British Columbia Electric Railway Company. In short, it is the sum of the demands of ten power systems located in Utah, western Montana, Idaho, Oregon, and Washington. The next curve immediately below is the summation of the demands of the western group of the Northwest Power Pool, not including the British Columbia Electric Railway Company. This curve is the sum of the demands of the western group of the Pool; i.e., The Bonneville Power Administration, Washington Water Power Company, Puget Sound Power and Light Company, Pacific Power and Light Company, Portland General Electric Company, Seattle City Light, Tacoma City Light, and numerous small systems that are connected with and take a portion of or all their requirements from the above systems. The bottom curve on figure II is the sum of the demands of the eastern group of the Pool; i.e., Utah Power and Light Company, Montana Power Company, and Idaho Power Company. All this information is for Wednesday, December 15, 1948, and is taken from a report of the Northwest Power Pool.

Consider for a moment some of the variations of the daily load curve for the entire Pool as shown on figure II. From midnight until 5 o'clock in the morning, the total requirement of the system is gradually decreasing. From 5 o'clock in the morning until 11 o'clock, the load increases. There is a dip in the middle of the day, and the final peak requirement of the total system is reached about 5:30 in the evening. From this point the load gradually decreases until it reaches the next minimum demand of the system in the early hours of the following morning.

The top curve of figure II is a composite of the 11 systems comprising the Power Pool. The individual system curves differ from each other by reason of the variations in the industrial and agricultural developments in each area. The area of the eastern group of the Pool is on Mountain Time. The area of the western group is on Pacific Time.



REFERENCE-NORTHWEST POWER POOL LOAD CHARACTERISTICS PUBLISHED BY COORDINATING GROUP
NOTE-THE ABOVE DOES NOT INCLUDE BRITISH COLUMBIA ELECTRIC POWER

FIG. II

In discussing the energy requirements of the daily load curve, it is usual to break this requirement down into three parts. Referring to the load curve for the total Pool on figure II, there is a continuous demand of approximately 2 million kilowatts for 24 hours a day. This is known as the base-load component of the curve. Immediately above this block there is a demand for about 1,400,000 kilowatts of additional load between 6 o'clock in the morning and midnight. This is spoken of as the daytime energy requirement. Above these two blocks are numerous small peaks, the largest of which usually occurs at about 5:30 in the evening on the Pool system. The energy under these peaks and above the daytime energy block is usually spoken of as peaking energy.

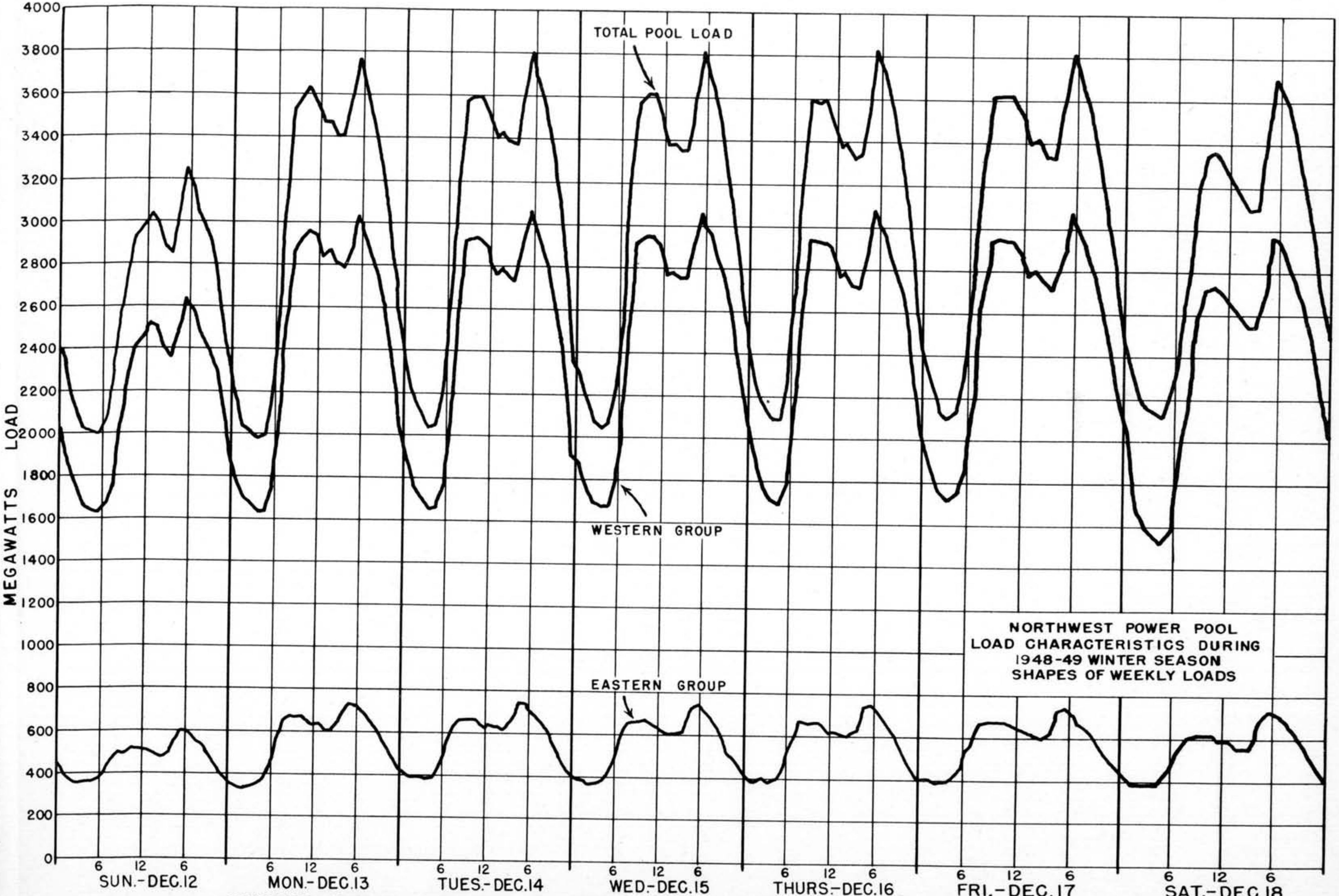
Figure III shows the daily load curves of the Power Pool system for a typical winter week. These curves are for the week beginning Sunday, December 12, 1948, and ending Saturday, December 18, 1948. Inspection of figure III discloses wide variation between the electric load requirements of weekdays, Saturdays, and Sundays. The load requirements for the five weekdays also show differences. These differences may be due to temperature variation or storms. They may be due to differences in industrial and commercial uses.

It would be an endless task to attempt to summarize the total requirements for a month or a year by assembling the individual daily load curves as shown in figure II. Methods have been developed in which typical weekdays, Saturdays, and Sundays are chosen to represent the system requirements for the period to be studied. A typical weekday, Saturday, and Sunday are chosen if the period of study is an individual month. Each hourly demand of the typical weekday is multiplied by the number of weekdays in the month, and, similarly, the requirements of Saturdays and Sundays are expanded so that the monthly load curve is obtained with a minimum of work. To further simplify the plotting and summarizing of this load information, it is usual to prepare a curve by assembling the hourly demands so that the maximum demand is on the left-hand portion of the page and the other demands are plotted in descending order of magnitude to the right. This curve so formed is known as a load duration curve. The load duration curve is an important tool in correlating electric resources and loads. It is usual to plot these data with hours or percent of time as abscissa of the curve. The vertical calibration or ordinates are plotted in kilowatts or percent of the peak kilowatts. These duration curves show the duration of the various demands for electrical power by the system load. Any one point on a duration curve expresses the hours or percent of time for which the load equals or exceeds a given kilowatt value.

GROWTH OF ELECTRIC LOADS

An understanding of the characteristics of the electric load growth in an area is essential to the proper determination of a program of new construction of generating and transmission facilities. Much has been said in recent years regarding the development of new sections of the Pacific Northwest, the aluminum industry, cattle raising, the integration of communities to develop diversified industrial and agricultural processes--all with the idea that such development can create a startling change in the electric load growth of the area. There are those who would tie the rate of load growth to increased population. Some say that cheap power brings in new industry and pyramids growth. These statements are plausible but do not stand the test of the fundamental facts of load growth.

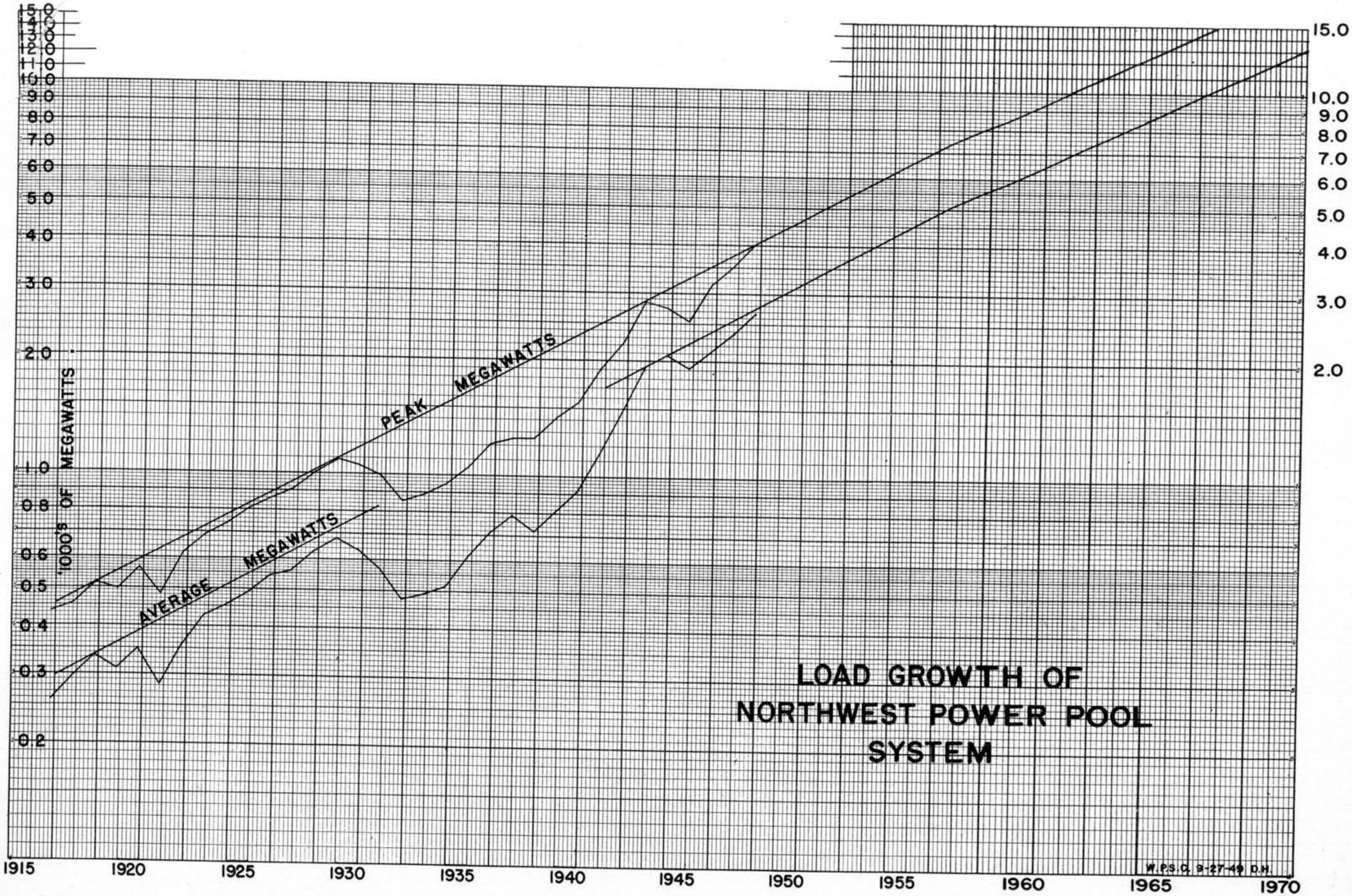
The forces which control the rate of growth of electric load in an area are myriad and defy identification to the extent that the secular trend of growth can best be considered as a characteristic of the area. Figure IV is a plot of the growth in peak and average megawatts in the area served by the generation and transmission facilities of the Northwest Power Pool. The



REFERENCE—NORTHWEST POWER POOL LOAD CHARACTERISTICS PUBLISHED BY COORDINATING GROUP

NOTE—THE ABOVE DOES NOT INCLUDE BRITISH COLUMBIA ELECTRIC POWER.

FIG. III



LOAD GROWTH OF
NORTHWEST POWER POOL
SYSTEM
PEAK MEGAWATTS
AVERAGE MEGAWATTS
1000's OF MEGAWATTS
15.0
10.0
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.8
0.6
0.5
0.4
0.3
0.2
1915
1920
1925
1930
1935
1940
1945
1950
1955
1960
1965
1970
W.P.S.C. 9-27-49 D.H.

FIG. IV

load growth is shown from 1915 to date. The influences of depression and the stimulus of war effort leave their marks on the transient variations of load growth. The basic long-time upward trend, however, continues to increase at a nearly constant rate.

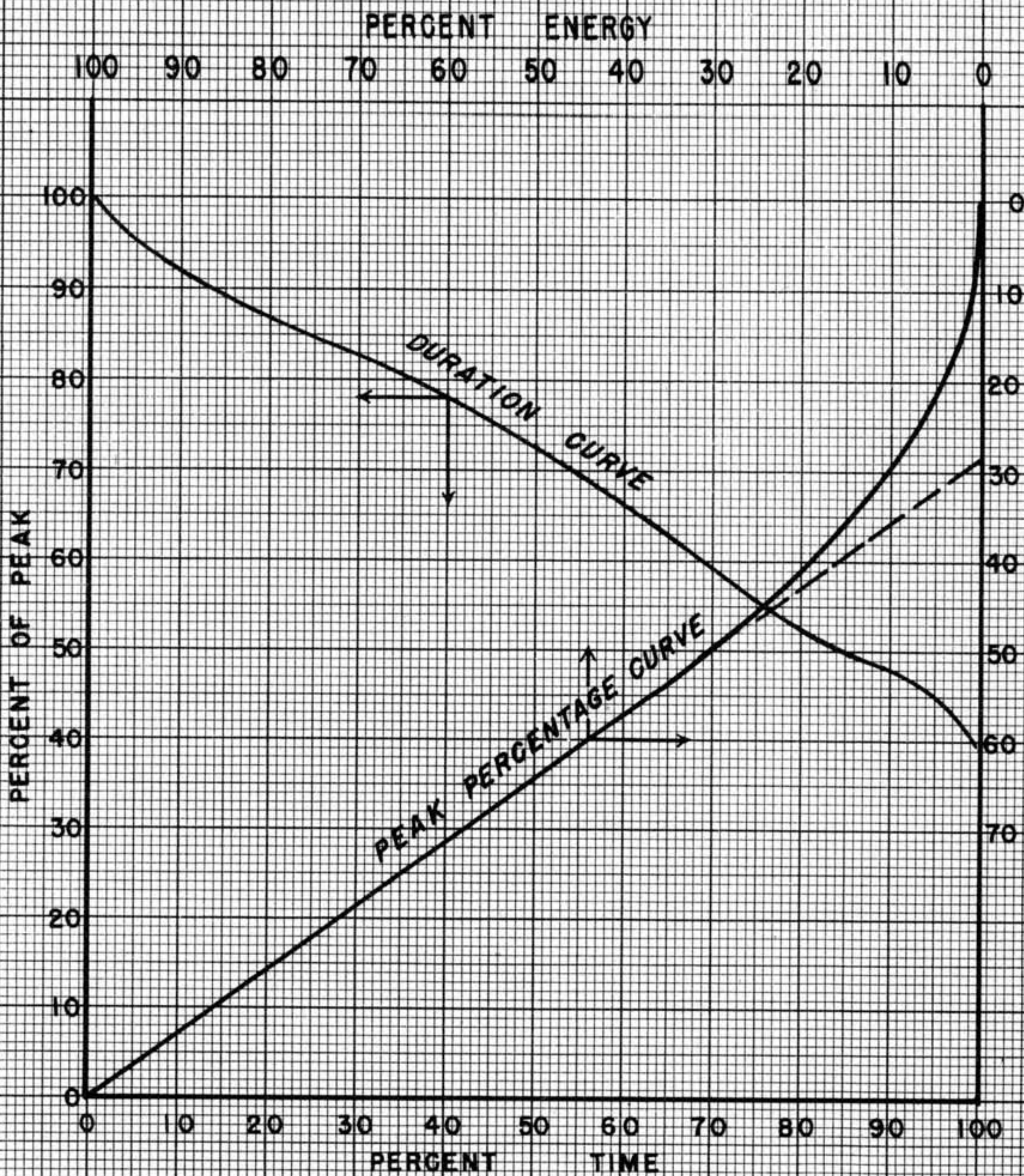
The top curve on figure IV shows the year-to-year change in the annual system peak of the Northwest Power Pool. The straight line through the tips of this curve is the envelope of the periods of maximum prosperity and war effort. Depression has retarded the growth of peaks, but periods of inflation and war effort have immediately released the potential demands for additional load and brought the year-to-year curve up to the envelope.

The slope of the line representing the envelope of the peak loads has a slope equivalent to a rate of growth of 6.8 percent per annum. This is a reasonable figure to use for the growth of load in the area. Care must be exercised, in using this figure of 6.8 percent per annum, to remember that it represents a secular trend rather than a short-time rate of growth. Recently published figures of the Edison Electrical Institute show that on the Pacific Coast, energy consumption is running about 1 percent ahead of the same period of last year. The slope of the curve in the period from 1945 through 1948 is about 14.75 percent per annum and represents a satisfying of the load demands accrued during and immediately following the second World War.

The lower curve on figure IV shows variations in the average annual energy consumption corresponding to the various peak loads. It will be noted that the average annual megawatts of a particular year does not always reach the envelope in the same year that the peak megawatts reach the envelope. The ratio of average megawatts to peak megawatts in a given year is, of course, the average load factor of the particular year. It is interesting to note that the envelope of average megawatts is coming nearer the envelope of peak megawatts on the right-hand end of the chart. This is very possibly due to the two points representing average megawatts in the years of 1943 and 1944. During these 2 years of war effort, we were short of generating facilities; and in this maximum effort, manufacturing plants operated 24 hours a day. This, of course, improved the load factor and may account for this narrowing of the two envelopes.

In an area served predominantly by waterwheel-driven generator units, it is not sufficient to determine that there is enough generating capacity on the system to carry system peak. In an area served by steam-electric generating plants, high load-factor loads can be served by operation of the plant more hours in the day. As long as the fuel supply is ample, the problem is relatively simple. In an area served entirely by waterwheel-driven generators, high load-factor loads must be served from units using the prime flow of the river as a source of power. When considering the possibility of an energy deficiency in the area, it becomes necessary to determine the plant peaking capability and the amount of electric energy which can be generated from the natural flow of the streams supplemented by draft from storage.

Figure V includes both a percentage duration curve and a peak percentage curve typical of total load of the Northwest Power Pool for the month of January. Both of these curves are used in describing the shape and duration of the demands upon the generating resources of the area. Perhaps the most important measurement taken from these curves is the load factor of the load. By load factor is meant the ratio of average load to peak load. The monthly load factor for the curves shown in figure V is 72 percent; that is, the ratio of average energy to peak energy is 72 percent. The percentage duration curve indicates that the load shape is such in January that for 100 percent of the time the load is equal to or greater than 39.5 percent of the monthly system



PEAK PERCENTAGE CURVE
NORTHWEST POWER POOL
JANUARY

FIG. V

peak. If we assume that new load growth conforms to the same characteristics as the present load, then about 40 percent of the new load in the area must be served by generating capacity available 100 percent of the time. Since the load factor of the total load is 72 percent, any program for the development of resources in the area must provide new capacity having at least the same ratio between average energy available and the peaking capability of the installed capacity.

A FORECAST OF FUTURE LOAD REQUIREMENTS

Reference to table A of the Northwest Power Pool Operating Program for the 1948-1949 water year shows the peak load for the Pool to be 4,009 megawatts. Under the operating conditions of modified critical water, it was estimated that there would be a peak deficiency of 145 megawatts and an average energy deficiency of 34 megawatts. In these calculations, the use of steam-generating facilities in the area is limited largely to peaking by reason of the shortage of fuel oil. The monthly load factor on the steam plants is shown as 28.7 percent.

The following tabulation shows subsequent annual system peaks based on growth of 6.8 percent per annum as determined from figure IV:

Water year	Kilowatts
1948-1949	4,000,000
1949-1950	4,272,000
1950-1951	4,562,500
1951-1952	4,872,800
1952-1953	5,204,200
1953-1954	5,555,000
1954-1955	5,940,000
1955-1956	6,345,000
1956-1957	6,770,000

The cumulative increase in system peak above that estimated for the water year 1948-1949 is shown in column 2 of the following tabulation:

Water year (1)	Estimated peak load growth (kilowatts) (2)	Peaking deficiency plus column (2) (kilowatts) (3)	New peaking capacity requirement including 7% reserve (kilowatts) (4)	Growth in average energy requirements in December and January at 72% monthly load factor (kilowatts) (5)
1948-1949				
1949-1950	272,000	422,000	451,540	304,000
1950-1951	562,500	712,500	762,375	513,000
1951-1952	872,800	1,022,800	1,094,396	736,000
1952-1953	1,204,200	1,354,200	1,448,994	972,000
1953-1954	1,555,000	1,705,000	1,824,350	1,230,000
1954-1955	1,940,000	2,090,000	2,236,300	1,500,000
1955-1956	2,345,000	2,495,000	2,669,650	1,790,000
1956-1957	2,770,000	2,920,000	3,124,400	2,100,000

The figures in column 3 are the same as column 2, only increased to allow for the 150,000-kilowatt peak deficiency indicated in table A of the Power Pool program. Nowhere in the analysis so far has there been any allowance for reserve capacity. There is no reserve in the 1948-1949 water year. If we add an amount of 7 percent to the figures in column 3 to allow for a reasonable operating reserve, the figures become those shown in column 4. Column 5 is calculated as 72 percent of column 3 and is the average energy requirement corresponding to the annual system peaks for the peak months of December and January as shown in column 3.

The above forecast of electric load growth is purely an extrapolation of the secular trend of the load of the Northwest Power Pool from 1915 to date. The determination of the average energy requirements corresponding to the growth in system peak has been determined by assuming that the load factor of the system in the critical months of December and January remains unchanged at approximately 72 percent.

There are those who prefer to forecast growth of load after the preparation of market studies which assume certain rates of growth for the several components of total load. A study is made of industrial growth and types of industry. Residential loads are assumed to have been expanded by reason of increase in population and increase in consumption by the already existing customers. Commercial loads are assumed to grow as the number of commercial enterprises increases, and the trend toward more elaborate lighting displays increases load requirements of existing commercial enterprises. This latter method of forecasting load growth, although quite spectacular and appealing to those with enthusiasm for the rapid expansion of industry and commerce, is subject to wide variations by reason of cumulative errors in judgment on the part of the forecaster. The summation of a large number of rather small errors in individual forecasts may give a total figure entirely out of reason and limited only by the imagination and desire of those making the forecast. For the purpose of this report, an extrapolation of existing trends appears conservative and reasonable.

DISTRIBUTION OF PRESENT ELECTRIC LOADS

Table I shows the distribution of electric loads in the areas served by the Northwest Power Pool. This information has been taken directly from the 1949-1950 water-year program of the Northwest Power Pool and is an estimate of peak loads and energy requirements for January 1950.

The portion of the Northwest Power Pool east of Burke, Idaho, and consisting of the systems of the Montana Power Company, Utah Power and Light Company, and Idaho Power and Light Company, is known as the eastern group of the Pool. The eastern group requirements for peak and energy constitute approximately 19 percent of that for the total Pool.

Another interesting division of total Pool requirements is the division between the portions of the load east and west of the Cascade Mountains. Approximately two-thirds of the entire peak and energy requirement is absorbed on the systems of the Pool west of the Cascade Mountains. With the further development of the Federal program for the Columbia River, the center of generation on the Pool system will be in the vicinity of the Grand Coulee project. As the system develops it will become necessary to build a considerable number of high-voltage transmission lines from the center of generation in the vicinity of Grand Coulee over the Cascade Mountains to the principal load centers of Puget Sound and the lower Columbia River area. As the better hydro projects are absorbed by the system and additional resources must be found, the cost of transmission may become the deciding factor in the choice between the construction of additional hydroelectric projects or the construction of fuel-burning steam plants adjacent to the principal load centers west of the Cascade Mountains.

TABLE I

DISTRIBUTION OF LOAD AND ENERGY IN THE AREA SERVED BY THE NORTHWEST POWER POOL

(Estimated data for January 1950)

System	Peak loads (megawatts)	Peak loads (percent)	Energy (av. megawatts)	Energy (percent)
Idaho Power Company	234	4.9	166	4.9
Utah Power & Light Company	262	5.5	166	4.9
Montana Power Company	385	8.1	303	9.0
Washington Water Power Company	319	6.7	231	6.9
Puget Sound Power & Light Co.	590	12.4	368	11.0
Seattle City Light	311	6.5	187	5.6
Tacoma City Light	232	4.8	156	4.6
Pacific Power & Light Company	283	5.9	184	5.5
Portland General Electric Co.	454	9.5	291	8.7
Bonneville Power Administration	1,423	29.9	1,143	34.2
British Columbia Electric Railway Company	273	5.8	157	4.7
Totals	4,766	100.0	3,352	100.0

IV. THE PRESENT ELECTRIC POWER RESOURCES AND LOADS IN THE PACIFIC NORTHWEST

THE PRESENT LOADS

The purpose of section III was to acquaint the reader with the load characteristics in the area served by the Northwest Power Pool. The methods and tools have been assembled whereby the reader can understand a discussion of the operation of the present Power Pool system. It will also be necessary, in determining the place of steam in the future program of the area, to understand the methods used in choosing between the several types of electric resources available in this area.

The present electric resources and loads, together with an understanding of current operations, would seem to be a reasonable starting point in the consideration of the coordination of future loads with the additional electric-generating facilities which will be required to serve these new loads. It is not sufficient that the new resources have peaking capability sufficient to carry the increment of system peak and that the energy available from the new plant is sufficient to supply the energy required by the additional load. Consideration must also be given as to the economies to be derived from the integration of the new load and the new resources with those already existing in the area.

A study of the 1949-1950 water-year operating program of the Northwest Power Pool is the best source of information for the purpose of understanding current operations.

Table II is the summary of operation taken directly from the Northwest Power Pool's 1949-1950 operating program. This summary presents information relating to load and resources of the Pool as a whole. Additional information is given relating to the load and resources of the eastern group, the western group, and the British Columbia Electric Railway Company. This information in each instance includes loads and resources for a median water year, a modified-critical water year, and a critical water year.

Referring to table II, the first line of figures gives the average and peak megawatt requirements of the entire Pool in January 1950. The ratio of average to peak megawatts is 0.706. This ratio is the system monthly load factor.

The following definitions of the water conditions used above to describe the varying flows of the streams in the area are taken directly from the operating program.

Median stream-flow conditions are on the basis of a fifty-fifty percent probability of occurring; that is, one-half of the historical flows have been greater than median, and the other one-half have been less than median.

Modified critical flows are the flows that have been equaled and exceeded 75 percent of the time, based upon historical records. Modified critical flows by definition can be expected to be equaled or exceeded in three years out of four.

Critical stream flows are on the assumption of flows equal to the worst historical condition that has occurred for the Pool as a whole. It is assumed that there is approximately a 100 percent probability that this amount of stream flow or better will occur. As an aid to careful thinking, it must be pointed out that the flows being considered are the flows of the numerous streams on which generating facilities are located. The importance of the flows of an individual stream are in direct proportion to the installed generating capacity of the stream.

Figures VI, VII, and VIII are graphic presentations of the data summarized in table II for median, modified critical, and critical water conditions.

TABLE II

NORTHWEST POWER POOL 1949-50 OPERATING PROGRAM

Comparison of resources used
in highest load month of the year
under assumptions of median, modified critical, and critical water

(Units are peak and average megawatts)

		Median water Jan. 1950		Modified critical water Jan. 1950		Critical water Jan. 1950	
		(avg.)	(peak)	(avg.)	(peak)	(avg.)	(peak)
POOL	Load	3352	4766	3352	4766	3352	4766
	Resources						
	Hydro	3194	4167	3051	4046	2692	4046
	Steam	60	372	203	372	273	372
	Misc.	98	197	98	197	125	197
	Total	3352	4736	3352	4615	3090	4615
	Deficiency	0	30	0	151	262	151
EAST GROUP	Load	635	881	635	881	635	881
	Resources						
	Hydro	539	757	506	757	472	757
	Steam	25	62	45	62	52	62
	Misc.	81	86	81	86	91	86
	Total	645	905	632	905	615	905
	Deficiency	-10	-24	3	-24	20	-24
WEST GROUP	Load	2560	3612	2560	3612	2560	3612
	Resources						
	Hydro	2483	3085	2355	2976	2059	2976
	Steam	35	310	158	310	221	310
	Misc.	17	111	17	111	34	111
	Total	2535	3506	2530	3397	2314	3397
	Deficiency	25	106	30	215	246	215
B. C. ELECTRIC	Load	157	273	157	273	157	273
	Resources						
	Hydro	172	325	190	313	161	313
	Total	172	325	190	313	161	313
	Deficiency	-15	-52	-33	-40	-4	-40

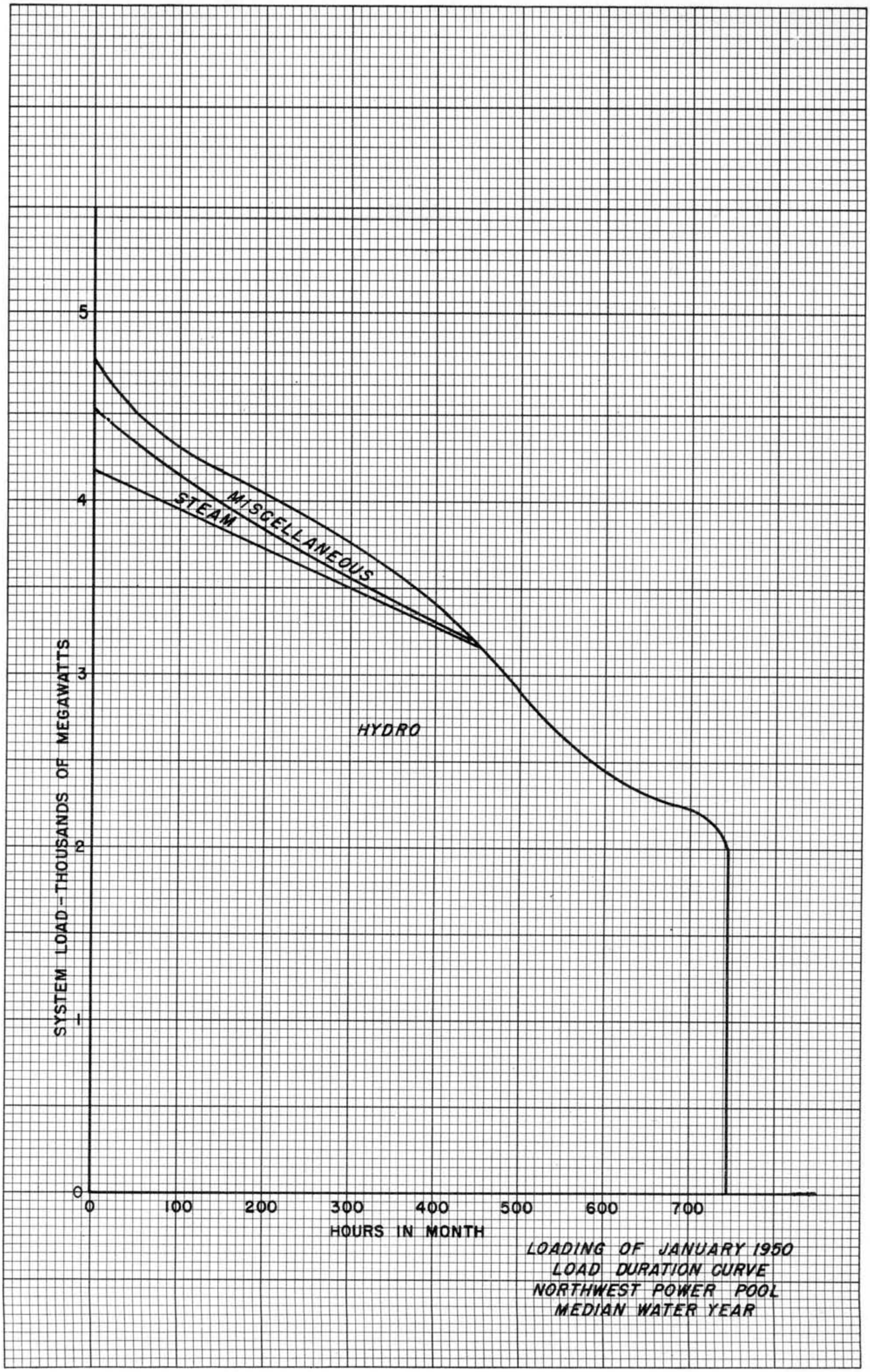

SYSTEM LOAD - THOUSANDS OF MEGAWATTS
5
4
3
2
1
0
0
100
200
300
400
500
600
700
HOURS IN MONTH
MISCELLANEOUS
STEAM
HYDRO
LOADING OF JANUARY 1950
LOAD DURATION CURVE
NORTHWEST POWER POOL
MEDIAN WATER YEAR

FIG. VI

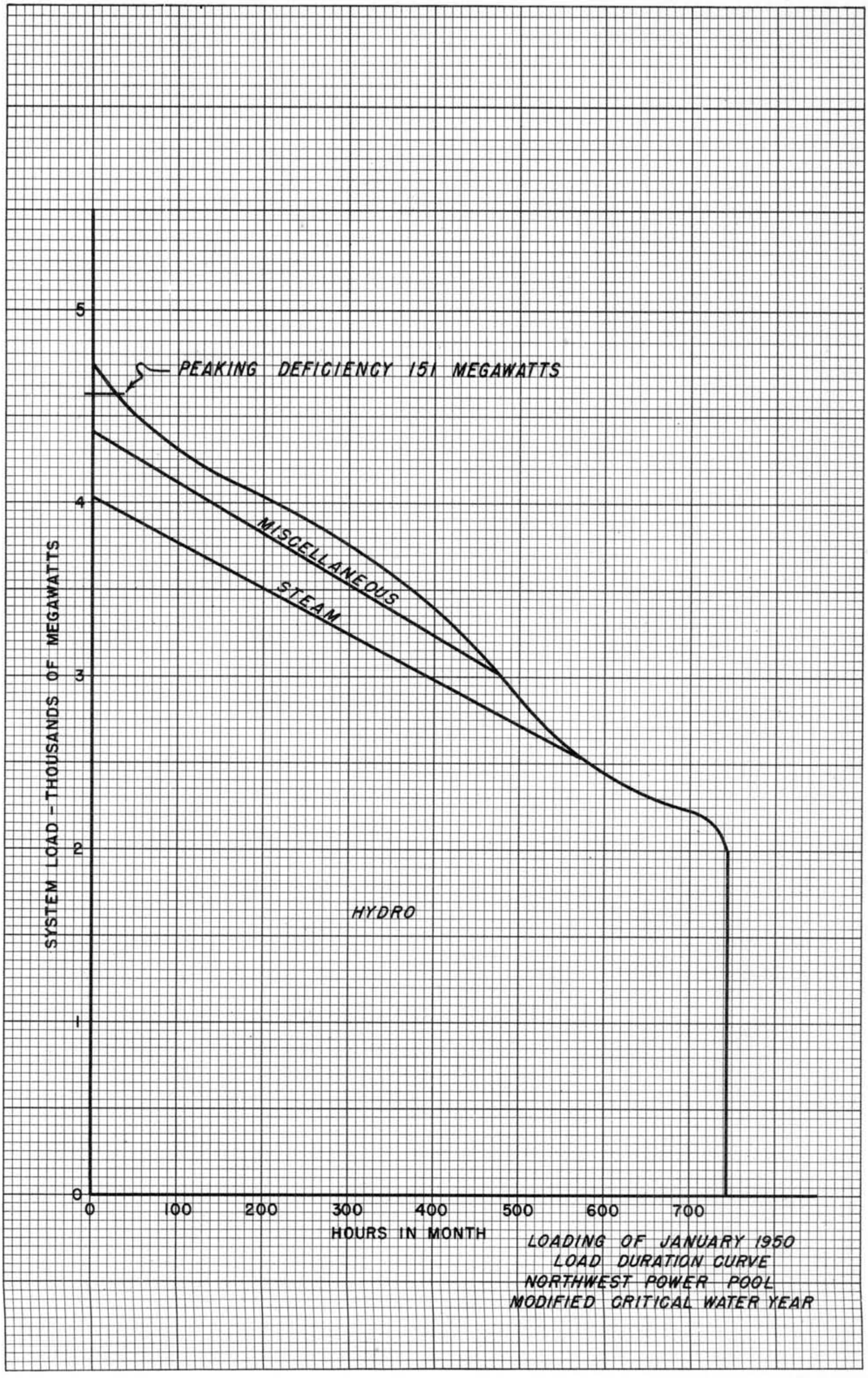
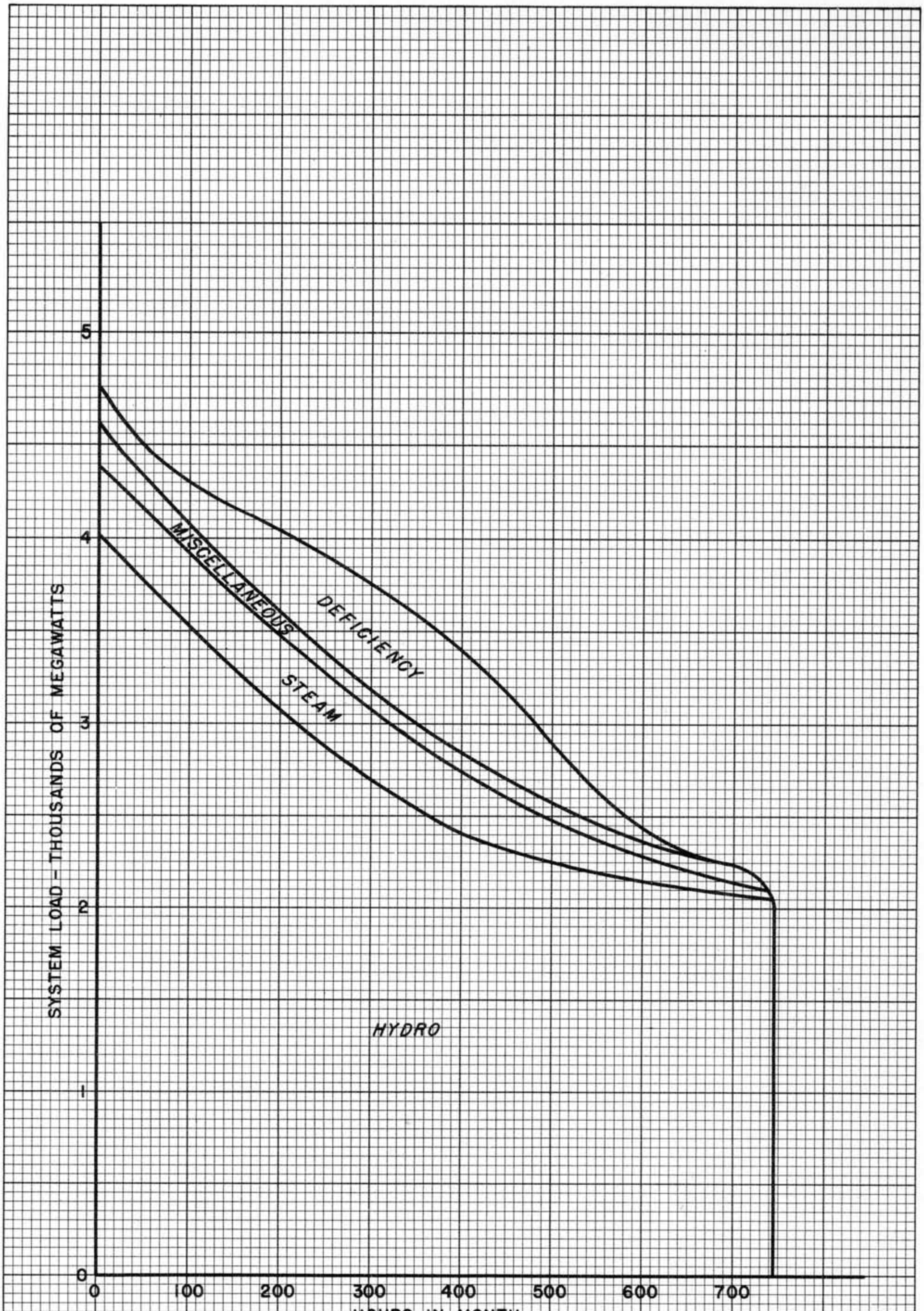

PEAKING DEFICIENCY 151 MEGAWATTS
MISCELLANEOUS
STEAM
HYDRO
SYSTEM LOAD - THOUSANDS OF MEGAWATTS
5
4
3
2
1
0
0
100
200
300
400
500
600
700
HOURS IN MONTH
LOADING OF JANUARY 1950
LOAD DURATION CURVE
NORTHWEST POWER POOL
MODIFIED CRITICAL WATER YEAR

FIG. VII



SYSTEM LOAD - THOUSANDS OF MEGAWATTS
0
1
2
3
4
5
0
100
200
300
400
500
600
700
HOURS IN MONTH
DEFICIENCY
MISCELLANEOUS
STEAM
HYDRO
LOADING OF JANUARY 1950
LOAD DURATION CURVE
NORTHWEST POWER POOL
CRITICAL WATER YEAR

FIG. VIII

The data summarized in table II are determined by placing on the load duration curve for January 1950 all the power resources of the Pool. It is a cut-and-try process, loading certain plants on the base of the load and operating 24 hours a day, operating others to supply daytime energy for 16 hours a day, and reserving still others for peaking purposes. Some plants operate on natural stream flow. The energy output of other plants comes from draft on storage. To these two sources must be added the output of fuel-burning plants and purchases from industry. The calculations all work toward the conservation and use of the maximum amount of energy from the natural flow and from storage reservoirs contributing to the output of each plant.

The amount of allowable drawdown is determined from the rule curves for the reservoirs. A rule curve for a reservoir is a curve determined from previous operating experience and indicates the amount that the reservoir level can be drawn down at any particular time in the water year without jeopardizing the plant capability during the remainder of the storage period.

In loading the load curves, consideration must be given to any or all physical limitations of a plant, capacities of transmission circuits, and the ability of a plant to use at a later date resources which may be presently stored.

Figure VI is a load duration curve for January 1950. It will be noted that the load characteristics of all three of the charts are identical. The difference comes in the amount of energy and plant capability which can be furnished from the hydro plants. In the median water year shown in figure VI, the hydro plants have a total peaking capability of 4,167 megawatts. The miscellaneous resources used amount to 197 megawatts, and the steam plants operating at full capacity furnish 372 megawatts of peaking capacity. Referring to table II, it will be seen that there is no change in the peaking capacity of steam and miscellaneous resources in any of the three areas. Under adverse water conditions the peaking capacity of the hydro becomes somewhat less.

Referring again to figure VI, the base load for January is 2 million kilowatts which operate for the total time of 744 hours in the month. The daytime energy component amounts to 1.5 kilowatts which must be available approximately 400 hours out of the month. Under median water conditions practically all this energy is available from natural flow of the streams together with scheduled draft from the storage reservoirs. Miscellaneous resources and steam are used principally for peaking purposes.

Figure VII shows exactly the same load characteristics as figure VI. It will be noted, however, that the energy available from the hydro plants is less. The peaking capability of the hydro plants has also decreased. The same amount of peaking capability is available from miscellaneous resources and steam as was available under median water conditions. This results in a peaking deficiency of 151 megawatts. There is sufficient energy available in hydro, together with steam and miscellaneous resources, to furnish all the energy requirement.

Figure VIII is a graphic presentation of the conditions as they would exist in a critical water year. The total load requirement is identical with the previous two charts. Peaking capability under critical water conditions is given as identical with those for modified critical water. The energy available to supply the demands of the system is greatly reduced under the adverse water conditions. After using all the water available from natural flow and storage and the energy available from steam and miscellaneous resources, there is an energy deficiency of 262 average megawatts.

Possibly some additional information should be given regarding the frequency of occurrence of the various water years as defined above.

By definition, a median water year or better may be expected 50 percent of the time. A modified-critical water year or better may be expected 75 percent of the time. A review of past history of the river flows in the area suggests that a critical water year may be expected about one year out of twenty. A modified-critical water year can be expected about one year out of four.

If we were giving consideration to the construction of additional generating facilities for the purpose of insuring the area against modified-critical water conditions, we would be planning to operate the plant about 250 hours per month for the months of December and January once every four years. This is shown on figure VII. If we were planning the construction of a plant to eliminate curtailment under critical water conditions, we would expect to operate this plant once every twenty years as a base load plant for a period of four to six months. This is on the basis that some of the present base load hydro could be operated higher on the load curve for daytime energy. In this planning we would be viewing the need of the plant entirely from a standpoint of existing resources and load and without giving consideration to the effect of further development of storage plants on the upper reaches of the main stem of the Columbia River or on its principal tributaries. This feature will be discussed in greater detail in section V.

Perhaps it should be repeated at this point in the discussion that the summary shown in table II and presented graphically in figures VI, VII, and VIII is based on the information of load and resources furnished to the Northwest Power Pool by its 11 member systems. This information is summarized by the consultants of the Pool and represents the best judgement of all the responsible operators in the area.

V. THE POTENTIAL WATER-POWER RESOURCES OF THE PACIFIC NORTHWEST

THE ARMY ENGINEERS' REPORTS

In the provisions of House Document No. 308, 69th Congress, first session, the Army Engineers were called upon to prepare a report which would accomplish "the formulation of a general plan for the most effective improvement of the Columbia River for the purposes of navigation, and the prosecuting of such improvement in combination with the most efficient development of the potential water power, control of the floods, and the needs of irrigation." House Document No. 308 was enacted into law, with modifications, in section 1 of the River and Harbor Act approved January 21, 1927.

The report of the Army Engineers was made to Congress and printed as House Document No. 103 of the 73rd Congress, first session, and submitted to Congress with a letter of transmittal by Patrick J. Hurley, Secretary of War, dated March 29, 1932.

More recently, under the authority of a resolution of the Committee on Commerce of the United States Senate, adopted September 24, 1943, the North Pacific Division, Department of the Army, Corps of Engineers has reviewed the original engineering report on the Columbia River and prepared what is known as the Columbia River Review 308 Report. This report, far more comprehensive than the original report, sets forth a "Main Control Plan" for the development of navigation, flood control, irrigation and power development on the main stem and tributaries of the Columbia River. One of the more important differences between the Review 308 Report and the original report on the Columbia River relates to the completeness and accuracy of the detailed engineering studies on specific projects. For each major power project, foundation exploration has been complete. This has included a thorough study of overburden and, to determine the quality of foundation rock, a similar study of drill cores. In most instances, the size and number of units to be installed in a project is determined after full consideration is given to the flow characteristics of the river and the relative location of the plant to other plants on the stream, and to river storage above the project. Public hearings were held at or near all the principal projects with a view to obtaining the attitude of the local groups affected by the development of the project. Where objections were raised to a particular project, these objections have been presented as a part of the information relating to the project and included in the review report.

The Army Engineers' Review 308 Report summarizes the total power capability of the Columbia River Basin in the form of a chart which shows plant capability in millions of kilowatts as a function of water storage for power in millions of acre-feet. This chart has been included in this report as figure IX.

Figure IX is a plot of two sets of data which summarize possible power developments in the Columbia River Basin. The first curve, marked "installed," shows the plant capability in millions of kilowatts as a function of water stored for power in millions of acre-feet, if the development is made in accordance with the major main control plan as set forth in the Review 308 Report. The curve marked "potential," shows, for any given water storage, the ultimate possible power development in the Columbia River Basin. As this latter curve indicates a condition that would be extremely uneconomical and wasteful of investment, it is only of passing interest.

The main control plan, as set forth in the Review 308 Report, is, in reality, a method of coordinating the projects on the Columbia River already completed or authorized, with such additional projects as are necessary to make possible reasonable flood control of the main stem and tributaries of the Columbia River. The Army Engineers have designated as Phase A the existing development at the Bonneville and Grand Coulee projects. Phase B includes present developments on the Columbia, together with other projects which have been authorized. Phase C-2 includes Phases A and B, plus such additional installations on the main stem and tributaries of the Columbia as are necessary to produce a well-rounded control plan. The details of the projects, together with other pertinent data in these first three phases, are given in tables III, IV, and V. These tabulations were taken directly from the Review Report.

In the studies that were necessary to insure the proper choice of projects for Phase C-2, a large number of other projects were considered and engineering studies were made. These projects have been included as a part of Phase D, with pertinent information, and are listed in table VI. These include the projects which show rather good promise from an engineering and economic standpoint, but which are not of the quality of the projects included in the main control plan. In some instances the projects in Phase D have been deferred by reason of local objection to their development.

The primary purpose in the preparation of the present report is to establish the place of steam in the orderly development of the power resources of the Pacific Northwest. The question has been asked as to the relationship between the economics of the main control plan and the economics of installation of a fuel-burning plant in the area. There is no exact separation that can be made in the plan for development of the Columbia River, where one would say, "These projects are more economical and these projects are less economical than steam." An approximate division can be made at the end of the main control plan, that is, after the completion of the projects included in Phase C-2. There are several reasons for this. In the first place, not all of the costs of the projects in the main control plan are chargeable against power. Certain

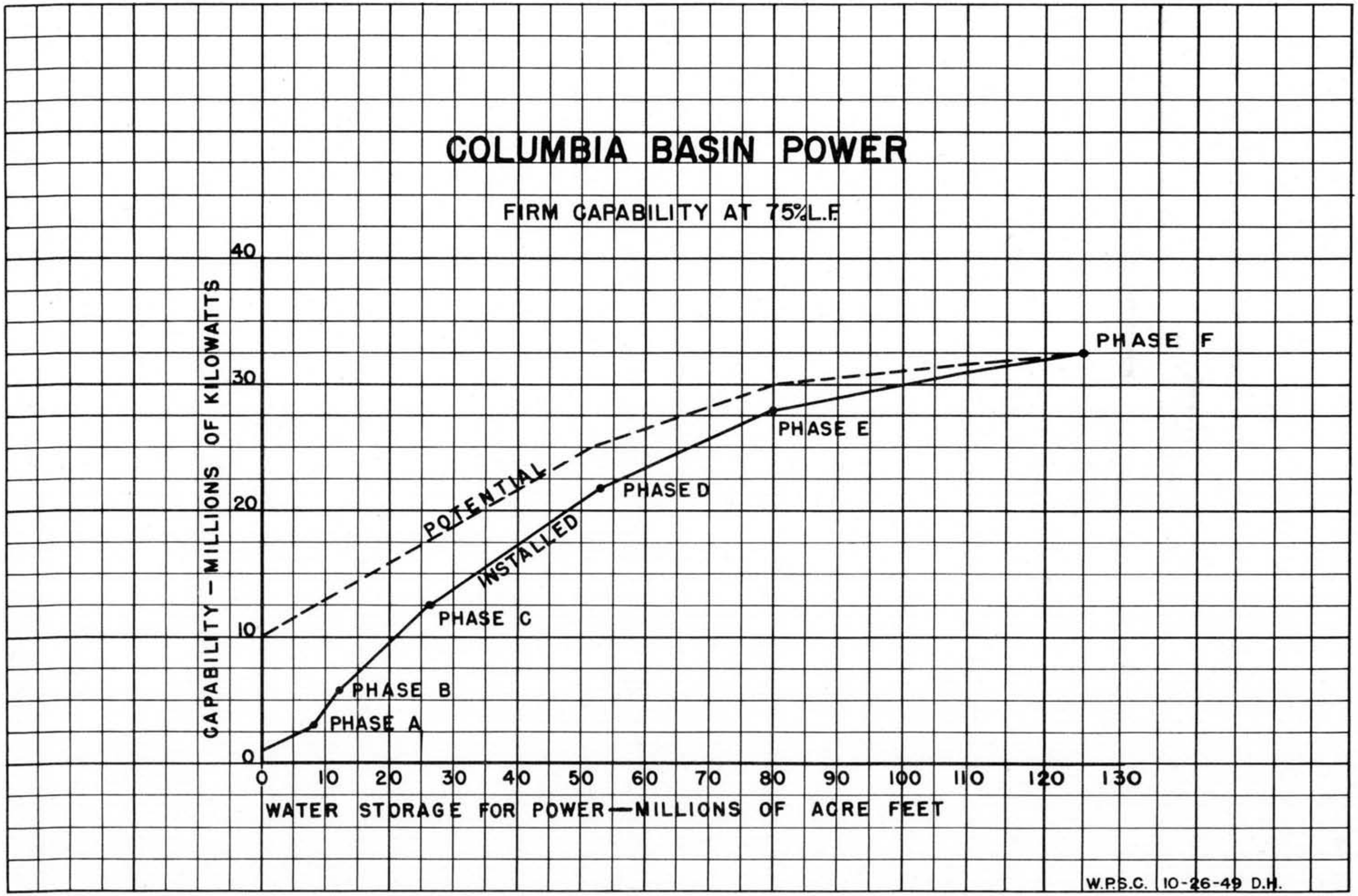

COLUMBIA BASIN POWER
FIRM CAPABILITY AT 75% L.F.
CAPABILITY — MILLIONS OF KILOWATTS
0
10
20
30
40
WATER STORAGE FOR POWER — MILLIONS OF ACRE FEET
0
10
20
30
40
50
60
70
80
90
100
110
120
130
POTENTIAL
INSTALLED
PHASE A
PHASE B
PHASE C
PHASE D
PHASE E
PHASE F
W.P.S.C. 10-26-49 D.H.

FIG. IX

TABLE III

POWER DATA, PHASE "A" SYSTEM

Project	River	Usable storage (acre-feet)	Number of units	Nominal prime capability (kilowatts)	Installed capacity (kilowatts,) (name plate)
Bonneville	Columbia	Pondage	10	391,000	518,400
Grand Coulee	Columbia	5,120,000	9	1,008,000	972,000
Total		5,120,000		1,399,000	1,490,400

TABLE IV

POWER DATA, PHASE B SYSTEM

Project	River	Usable storage (acre-feet)	Number of units	Nominal prime capability (kilowatts)	Installed capacity (kilowatts,) (name plate)
Bonneville	Columbia	Pondage	10	384,000	518,400
Grand Coulee	Columbia	5,120,000	18	1,198,000	1,944,000
Hungry Horse	South Fork Flathead	2,980,000	4	231,000	300,000
Foster Creek	Columbia	Pondage	16	653,000	1,024,000
McNary	Columbia	do	12	500,000	840,000
Lower Snake 1/	Snake	do	12	434,000	735,000
Total		8,100,000		3,400,000	5,361,400

1/ Development consists of 4 dams

TABLE V

POWER DATA, PHASE C-2 SYSTEM

Project	River	Usable storage (acre-feet)	Number of units	Nominal prime capability (kilowatts)	Installed capacity (kilowatts,) (name plate)
Major Federal projects:					
Bonneville	Columbia	Pondage	10	482,000	518,400
Grand Coulee	Columbia	5,120,000	18	1,677,000	1,944,000
Hungry Horse	South Fork Flathead	2,980,000	4	120,000	300,000
Foster Creek	Columbia	Pondage	20	876,000	1,280,000
McNary	Columbia	do	13	635,000	910,000
Lower Snake 1/	Snake	do	16	647,000	980,000
Glacier View	North Fork Flathead	3,160,000	3	96,000	210,000
Libby	Kootenai	4,250,000	6	244,000	588,000
Albeni Falls	Pend Oreille	1,140,000	3	26,000	42,600
Priest Rapids	Columbia	Pondage	23	774,000	1,219,000
John Day	Columbia	do	13	735,000	1,105,000
The Dalles	Columbia	do	14	701,000	980,000
Hell's Canyon	Snake	3,280,000	10	602,000 2/	980,000
Subtotal		19,930,000		7,615,000	11,057,000
Minor Federal projects:					
Willamette Basin 3/	Willamette	1,433,000		136,000	387,000
Upper Snake 4/	Snake	-		83,000	268,000
Total		21,363,000		7,834,000	11,712,000

1/ Four dams
2/ Figures include 100,000 kw. prime and 130,000 kw. installed at re-regulating dam.
3/ Eight plants, Corps of Engineers
4/ Nine plants, U. S. Bureau of Reclamation

TABLE VI

POWER DATA, PHASE D SYSTEM

Project	River	Usable storage (acre-feet)	Number of units	Nominal prime capability (kilowatts)	Installed capacity (kilowatts,) (name plate)
Paradise	Clark Fork	4,080,000	8	244,000	576,000
Canyon Creek	Flathead	Pondage	2	34,000	116,000
Coram	Flathead	Pondage	2	39,000	76,000
Ninemile Prairie	Blackfoot	960,000	2	18,000	74,000
Quartz Creek	Clark Fork	Pondage	2	37,000	82,000
Trout Creek	Clark Fork	Pondage	3	123,000	219,000
Noxon Rapids	Clark Fork	Pondage	3	93,000	150,000
Cabinet Gorge	Clark Fork	Pondage	3	116,000	216,000
Priest Lake	Priest	870,000	-	Storage only	-
Boundary	Pend Oreille	Pondage	9	482,000	918,000
Leland Glen	Coeur d'Alene	370,000	2	14,000	40,800
Springston	Coeur d'Alene	2,595,000	1	13,000	32,000
Katka	Kootenai	Pondage	4	205,000	368,000
Similkameen	Similkameen	1,620,000	2	23,000	84,000
Wells	Columbia	Pondage	8	398,000	392,000
Rocky Reach	Columbia	Pondage	9	567,000	585,000
Crevice	Salmon	1,030,000	4	206,000	400,000
Freedom	Salmon	180,000	3	96,000	195,000
Nez Perce	Snake	4,800,000	15	777,000	1,650,000
Asotin	Snake	Pondage	7	227,000	350,000
Clarkston	Snake	Pondage	4	75,000	180,000
Elksberry	North Fork Clearwater	1,690,000	2	110,000	210,000

TABLE VI (Continued)

Project	River	Usable storage (acre-feet)	Number of units	Nominal prime capability (kilowatts)	Installed capacity (kilowatts,) (name plate)
Bruce's Eddy	North Fork Clearwater	510,000	2	87,000	180,000
Kooskia	Clearwater	3,100,000	4	197,000	440,000
Yale	Lewis	230,000	2	40,000	80,000
Mossy Rock	Cowlitz	1,100,000	2	83,000	170,000
Mayfield	Cowlitz	Pondage	3	62,000	135,000

of the costs are chargeable against navigation, irrigation, and flood control. This fact gives these particular projects advantage, not only over a comparable steam project, but over other hydro projects included in Phases D, E, and F.

From discussion with the Army Engineers, it appears that the projects included in Phase D should all be checked against the cost of steam before assuming that they are the most economical development possible. In any such comparison, of course, the cost of transmission lines from the particular project to the load area to be served must be added to the project cost in making the comparison. A credit must also be given to the particular project for any increase in river regulation increasing the energy capability of other downstream projects.

One can say with reasonable accuracy that the projects included in Phase C-2, together with a portion of those in Phase D, have cost characteristics and other benefits such that they can be considered as more advantageous than a fuel-burning plant. The total plant capability of such projects approaches 16 million kilowatts. If we give consideration to the existing plants and other potential developments not in the Columbia River Basin but a part of the power resources of the area, it can be said that there are approximately 15 million kilowatts of electric power resources which should be developed before it will become reasonable to project base-load fuel-burning plants as a part of the power program.

Inspection of the rate of growth of load in this area, as shown on figure IV, suggests that this place in the program will be reached about 1965.

VI. THE PRESENT PROGRAM OF DEVELOPMENT OF THE WATER-POWER RESOURCES OF THE PACIFIC NORTHWEST

THE PRESENT PROGRAM

At the present time most of the program for the development of additional generating resources in the area served by the western group of the Northwest Power Pool is in the hands of the Federal Government. The present situation can be summarized by quoting from the "Advance program of transmission system development" of the Bonneville Power Administration, dated December 1948. The statement is made on page 43, "Lack of generating capacity is now a critical factor in the power-supply situation of the Pacific Northwest. At least five years are needed for the construction of multi-purpose hydro plants upon which the region is dependent for additional power supply * * * * Every effort must be made to install economical generating capacity wherever possible."

The concentration of materials and man power upon the war effort during the period of World War II resulted in the decrease of electric-power system reserve throughout the United States. At the conclusion of the war, power systems in many areas found themselves with little or no reserve generating capacity. The demand for use of electricity in peacetime pursuits which had been accruing over the period of the war was released almost immediately after the cessation of hostilities. Many utilities had difficulty building new generating resources fast enough to take care of the rapidly growing electric load. It must be borne in mind that this rapid growth of load was merely the release of demands which had been accruing throughout the period of the war. There was nothing spectacular in the secular trend of growth, for this trend had not changed materially. There was the necessity of curtailment in the use of electric energy in several areas of the United States. With the exception of the Pacific Northwest this situation has now been entirely overcome by the installation of additional generating facilities.

In the opening paragraph of this section the quotation from the 1949 advance program of the Bonneville Power Administration stated, "At least five years are needed for the construction of multi-purpose hydro plants upon which the region is dependent for additional power supply." It might be enlightening to inquire why the region is dependent upon "multi-purpose hydro plants." The question might be asked whether there was anything in the characteristics of the multi-purpose hydro plant that might *per se* contribute to our present power shortage. A multi-purpose hydro plant might be defined as a project built to serve the needs of navigation, irrigation, flood control, and power.

In accounting for such a project we find that a part of the costs are chargeable to navigation, irrigation, flood control, and downriver regulation, leaving the amount chargeable to power only a part of the total. Power, a by-product of the multi-purpose project, is sold at a fraction of the cost which it would have been necessary to charge if the total cost of the project had been chargeable to power.

In most instances the economics of this situation have been sufficient to preclude private industry and municipal systems from constructing additional generating facilities. Any one attempting to secure the necessary funds for additional construction in competition with the Federal projects finds the money market reluctant to risk funds for such a purpose. Where funds have been available, interest rates have been relatively high by reason of the added risk of competition from a multi-purpose project.

THE PRESENT SHORTAGE OF ELECTRIC ENERGY

As a witness before the Washington Public Service Commission in November 1948, in Cause No. U-8204, relating to power curtailment, Mr. William

Dittmer of the Bonneville Power Administration submitted as a portion of his testimony Schedule R, which is a schedule of generator installation for the Columbia River Power System. This schedule lists the name plate ratings and the dates of installation as scheduled on November 10, 1948, for all Federal projects in the Columbia and Willamette River Basins.

On the completion of the curtailment hearing in November 1948, the writer, using the information submitted at the hearing, attempted to correlate the data that were available relating to load growth and the construction schedule as outlined in Schedule R, supplemented by new resources to be installed by municipal and private systems in the area. Figure X shows graphically the relationship between the secular trend of load growth at 6.8 percent per annum, and the proposed schedule of construction of new generating facilities as it existed in November 1948. Referring to figure X, the peak requirement is the envelope of the actual peak loads as shown on figure IV, extrapolated through 1956. The dotted line marked "plant peaking capability" is a summation of plant capacities of existing and proposed new construction in the area.

Also on figure X is a line marked "energy requirement—average megawatts." This line represents the average energy requirement in megawatts for the month of January of each year, determined as 72 percent of the peak requirement. Also plotted on this chart is the usable energy available from average and critical water flows in the system of the Northwest Power Pool. The determination of usable energy is only approximate. The necessary data for accurate determination of this information are not available. In the figures presented by the Bonneville Power Administration as a part of the hearing exhibit were figures entitled "Nominal prime power during storage-control period." This information was given for both the median and minimum hydro years.

No attempt was made by the Bonneville Power Administration to determine the portion of this energy usable on the load curve of the Power Pool system.

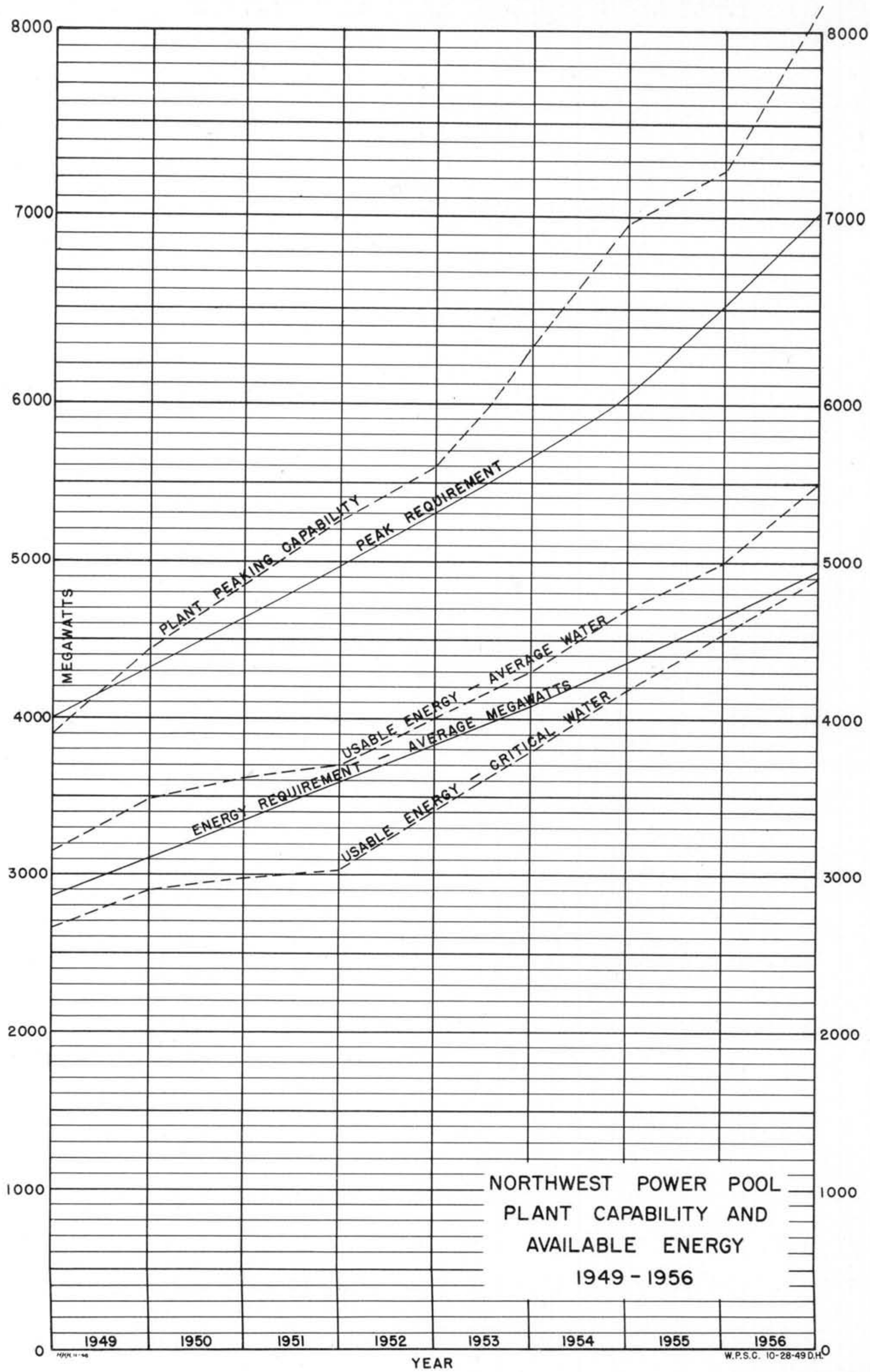
The writer has discounted the usable energy under average water conditions by 20 percent, and has assumed that the prime power under critical water conditions is all usable. This appears to check quite closely with the actual conditions which have been estimated for the 1949-1950 water year in the Power Pool program.

At the Northwest Utilities Conference Committee meeting on October 20, 1949, Mr. D. L. Marlett of the Bonneville Power Administration outlined the new Schedule S. This most recent schedule of construction indicates approximately one year's delay in the construction of the first units at McNary, Chief Joseph, and Ice Harbor projects. These factors have been taken into consideration in preparing figure X.

Referring to figure X, it appears that, even though the construction schedule can be maintained according to Schedule S, the generating facilities in the area will not be sufficient to carry the entire load requirement under critical water conditions in the near future. It appears that the schedule of new construction is sufficient to take care of the requirements of peaking capability of the system. The deficiency in the program appears to be one of average energy. Only two projects included in Schedule S have storage of sufficient amount to benefit the projects on the main stem of the Columbia above McNary Dam. These are Hungry Horse and Albeni Falls.

BENEFITS OF UPSTREAM STORAGE

It is entirely possible to develop "run-of-river" plants on the main stem and tributaries of the Columbia without the development of large amounts of storage. However, such a program would be uneconomical and unsound from an engineer's viewpoint. In fact, the possibility of a shortage of electric energy under critical water conditions at the present time is due in large part to



8000
7000
6000
5000
4000
3000
2000
1000
0
MEGAWATTS
PLANT PEAKING CAPABILITY
PEAK REQUIREMENT
USABLE ENERGY - AVERAGE WATER
ENERGY REQUIREMENT - AVERAGE MEGAWATTS
USABLE ENERGY - CRITICAL WATER
NORTHWEST POWER POOL
PLANT CAPABILITY AND
AVAILABLE ENERGY
1949 - 1956
1949
1950
1951
1952
1953
1954
1955
1956
YEAR
W.P.S.C. 10-28-49 D.H.

FIG. X

insufficient upstream storage. Before it is possible to discuss with reasonable accuracy the cost of the hydroelectric projects on the Columbia River, certain assumptions must be made as to the amount of beneficial storage above each project.

Mr. B. E. Torpen, Chief, Engineering Division, Corps of Engineers, North Pacific Division, Department of the Army, has prepared a report entitled "Storage for power, Columbia River Basin," dated August 1945. This report gives a splendid analysis of the storage requirements on the Columbia River. Mr. Torpen has included in his report a "typical storage-yield curve," which is an average, or composite, curve from several of the projects on the main stem and tributaries of the Columbia. Although there is a wide variance between the characteristics of flow of spring-fed streams such as the Snake River and streams which have their sources high in the mountain basins and are largely fed by melting snow and ice, the curve is sufficiently accurate for the present discussion. This curve has been included in the report as figure XI.

Referring to figure XI, the curve shows the regulated discharge of the river in percent of mean annual discharge as a function of upstream storage, stated as a percent of mean annual runoff. The use of this curve can be better understood when used with certain additional river characteristics also discussed in Mr. Torpen's report. The following tabulation has been taken from page 23 of Mr. Torpen's report and shows a comparison of the characteristics of several streams in the Columbia and Colorado River Basins:

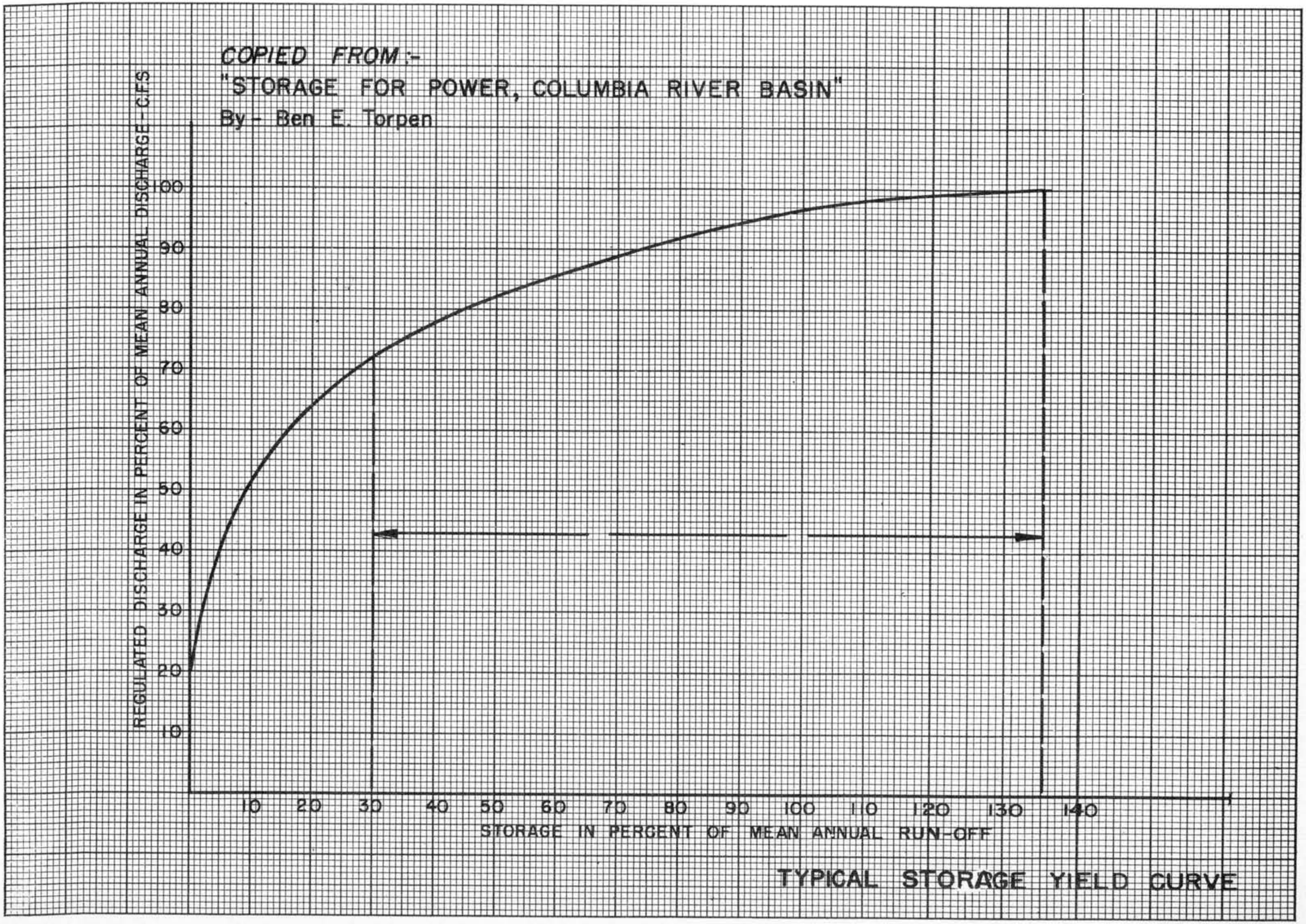
COMPARISON OF STREAMS

Stream	Area of drainage basin (square miles)	Mean annual flow (millions acre-feet)	Mean annual flow (cubic feet per second)
Clearwater	9,570	10	13,920
Clark Fork	25,200	17	23,850
Snake	103,200	31	43,130
Columbia at Grand Coulee	74,100	75	103,100
Columbia at Bonneville	240,000	125	173,000
Colorado at Boulder	137,800	13	18,080

Referring to the above tabulation, the mean annual flow at the Grand Coulee project is 103,100 cubic feet per second, which is equivalent to 75 million acre-feet.

Referring to figure XI, if the upstream storage at Grand Coulee is 30 percent of 75 million, or 22.5 million acre-feet of usable storage, the mean regulated flow which can be expected at Grand Coulee will be 71 percent of 103,100 cubic feet per second, or approximately 73,000 cubic feet per second. With storage equal to 22.5 million acre-feet constructed above Grand Coulee, a large portion of the benefits of upstream storage will accrue to the projects downstream. Any additional upstream storage on the streams above the Grand Coulee project will result in smaller and smaller increases in the minimum regulated flow of the river. The economic limit of such developments can be determined only after a careful study of the benefits to downstream projects.

The storage of 30 percent of the mean annual runoff will, in general, be sufficient for year-to-year regulation of the minimum flow of the stream. Storage in excess of this amount would be for so-called carry-over purposes and would represent storage which would be used for regulation of the river for


COPIED FROM:-
"STORAGE FOR POWER, COLUMBIA RIVER BASIN"
By - Ben E. Torpen
REGULATED DISCHARGE IN PERCENT OF MEAN ANNUAL DISCHARGE - C.F.S.
10
20
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140
STORAGE IN PERCENT OF MEAN ANNUAL RUN-OFF
TYPICAL STORAGE YIELD CURVE

FIG. XI

periods in excess of one year.

Referring to figure XI, it will be noted that with storage in excess of 30 percent of mean annual runoff, the curve flattens out quite rapidly. This means that the amount of storage required for a given increase in minimum regulated flow increases rapidly.

THE LIMITS OF UPSTREAM STORAGE

The benefits of upstream storage were discussed under the previous subheading. The relationship between storage and minimum regulated flow is shown by figure XI. In the discussion which follows, flow conditions at Grand Coulee will be used in presenting the problem. Similar factors apply, although to a somewhat lesser extent, to the drainage basin of the Snake River.

If the Columbia River were to be used for the development of power alone, the determination of the proper amount of upstream storage could readily be made by referring to figure XI. The use of a large quantity of water for irrigation and for generation of power for pumping related to irrigation interjects an entirely new factor in the determination of the correct amount of storage.

At Grand Coulee the mean annual runoff in an average water year is about 78 million acre-feet. Under critical water conditions this figure is reduced to 58 million acre-feet. The runoff under modified-critical water conditions is about 68 million acre-feet. It was pointed out previously that the storage of 30 percent of the mean annual runoff, or 22.5 million acre-feet, would increase the minimum regulated flow of the stream to approximately 73,000 cubic feet per second. A minimum regulated flow of 73,000 cubic feet per second is equivalent to an annual runoff of 53.3 million acre-feet.

In analyzing this problem it has been assumed that it will be essential for the development of the program of the Columbia River Basin to irrigate at least two million acres of land along the main stem of the Columbia. An amount of water twice that required for the Columbia Basin project and an equivalent amount of pumping power has been assumed as the requirements for irrigation. This total requirement, including both the water diverted and water used to generate power for pumping, is equivalent to about 14.4 million acre-feet each year.

Table VII lists the basic flow data for the Columbia River at Grand Coulee which were used in this study. These data were taken from the United States Geological Survey Water Supply Papers. Table VIII shows the distribution of the annual runoff at Grand Coulee under average water conditions. Referring to table VIII, column I shows the mean monthly flows of the river under average water conditions. Column 2 is the minimum regulated flow of the river at Grand Coulee with 30 percent storage. Column 3 shows the amount of water that would be required to irrigate 2 million acres similar to the land in the Grand Coulee project. Column 4 shows the amount of water which must pass through all the plants below the Canadian border under Phase C-2 to generate the necessary pumping power. It will be noted that pumping power is shown in months during which there is no diversion of water. This pumping power would be for pumping from wells for stock watering and other farm use during the winter months when the canals are drained because of freezing conditions. Column 5 shows the net flow for each month. Figures shown with minus signs indicate that the mean annual flow in the particular month is not sufficient to meet the requirements of that month. In table VIII the net of column 5 is a plus 166,000 second-foot months, which is equivalent to a 10 million acre-feet surplus.

Similarly, table IX shows the distribution of the runoff of the river under critical water conditions. It will be noted that there is a deficiency of approximately 10 million acre-feet. Both of these tables are based on a storage of 30 percent of the annual runoff for power purposes.

TABLE VII

COLUMBIA RIVER AT GRAND COULEE
DISCHARGE IN THOUSANDS OF SECOND-FEET

Year ending Sept. 30	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.
1913							67.7	190	436	279	156	100
1914	61.8	51.7	38.5	36.2	34.7	48.3	99.6	220	293	252	132	76.9
1915	62.5	65.7	48.3	32.7	28.9	36.7	86.6	175	188	184	156	91.2
1916	50.8	49.0	39.6	28.4	31.6	62.8	113	201	320	419	189	110
1917	60.6	46.2	32.3	26.2	26.0	25.4	55.9	183	368	313	149	80.9
1918	61.0	40.3	41.8	83.8	52.1	45.6	92.6	209	307	256	136	90.4
1919	64.8	47.6	37.8	35.5	43.4	42.6	88.3	204	294	226	138	80.7
1920	46.4	30.3	23.2	23.4	25.4	29.2	43.9	140	237	315	177	90.7
1921	86.8	64.3	46.1	47.3	46.4	62.3	92.6	222	390	250	138	70.1
1922	51.2	53.5	46.9	34.2	27.3	27.2	53.6	157	354	218	127	88.5
1923	54.7	39.2	26.3	38.3	26.3	28.3	74.3	189	342	257	136	92.5
1924	48.2	32.8	28.3	23.2	40.2	38.6	44.5	191	225	166	115	81.2
1925	47.0	46.0	40.6	41.9	62.7	55.1	143	285	330	244	136	75.3
1926	46.2	32.3	28.7	26.0	30.6	34.2	70.7	169	140	141	89.4	70.4
1927	60.3	61.7	59.4	40.9	39.4	42.8	64.5	190	372	296	159	124
1928	107	107	89.7	59.8	50.6	59.7	94.9	286	355	260	144	78.6
1929	52.0	41.3	32.1	25.2	21.3	25.6	38.8	116	270	168	111	69.5
1930	41.1	29.2	23.7	18.8	23.0	28.5	71.0	160	222	195	124	77.0
1931	45.1	32.6	26.8	22.6	24.3	32.1	55.5	158	221	166	104	77.9
1932	43.0	34.1	28.2	29.9	25.9	56.3	115	254	334	237	130	78.8
1933	47.5	48.2	51.2	42.6	30.8	37.5	68.7	194	392	337	167	93.1
1934	63.3	86.6	98.4	113.9	79.7	72.4	168.6	315.2	311.7	176.1	117.2	73.8
1935	45.2	56.9	51.0	42.8	50.2	47.8	67.3	178.1	322.0	259.4	145.0	80.6
1936	47.3	33.4	27.4	26.6	21.5	31.6	77.5	258.8	301.3	170.8	106.7	65.9
1937	42.0	28.5	23.2	18.2	18.2	23.8	44.1	135.5	243.8	194.5	109.5	67.8
1938	42.6	57.3	47.0	47.3	37.1	51.1	99.8	218.8	344.9	235.5	101.1	72.9
1939	54.7	37.7	31.1	32.8	30.5	35.2	86.2	234.2	235.1	188.5	110.2	67.4
1940	48.0	50.7	44.4	35.1	38.2	55.7	101.2	184.8	235.8	155.4	95.2	75.5
1941	59.4	48.0	36.7	37.2	36.5	48.3	81.4	147.6	180.2	130.6	91.5	83.2
1942	76.9	64.4	83.5	58.7	49.3	44.5	79.2	156.5	291.2	225.2	122.1	62.8
1943	48.1	42.4	40.1	37.3	40.7	38.5	142.7	197.0	286.7	270.9	128.5	62.5
1944	49.5	40.4	36.1	32.1	31.1	29.1	44.0	111.0	193.9	119.2	91.7	63.5
1945	52.4	44.0	33.6	34.5	38.0	42.7	51.5	166.0	278.5	184.1	92.3	57.3
1946	41.1	40.4	39.7	43.6	40.2	54.6	105.7	284.9	357.1	227.5	116.3	71.3
1947	47.2	40.5	54.8	46.4	51.9	62.4	95.5	273.9	315.4	206.4	106.8	66.2
1948	86.4	74.9	52.9	56.4	53.7	50.0	72.9	268.4	528.6	221.3	131.1	79.4
1913 (Highest	107	107	98.4	113.9	79.7	72.4	168.6	315.2	528.6	419	189	124
to (Average	55.5	48.5	42.6	39.4	37.4	43.0	82.0	200.6	300.4	226.2	127.2	79.1
1948 (Lowest	41.1	28.5	23.2	18.2	18.2	23.8	38.8	111.0	140	119.2	89.4	57.3

TABLE VIII

DISTRIBUTION OF WATER
UNDER AVERAGE WATER CONDITIONS
AT GRAND COULEE

Month	Mean flow (1000's cfs.) (1)	Minimum regulated flow a/ (1000's cfs.) (2)	Diversion for irrigation b/ (1000's cfs.) (3)	Pumping power c/ (4)	Net flow (5)
October	55.5	73	8	4	- 29
November	48.5	73		1	- 25
December	42.6	73		1	- 31
January	39.4	73		1	- 35
February	37.4	73		1	- 37
March	43.0	73		1	- 31
April	82.0	73	18	8	- 17
May	200.6	73	28	12	+ 88
June	300.4	73	31	13	+183
July	226.2	73	32	13	+108
August	127.2	73	29	12	+ 13
September	79.1	73	19	8	- 21
Total	1,281.9	876	165	75	+166,000

a/ 30 percent storage
All figures are 1000's of second-foot months.

b/ Sufficient diversion for irrigation for 2 million acres.

c/ River flow to generate pumping power assumed to pass through all Phase C-2 plants downstream and including Grand Coulee.

TABLE IX

DISTRIBUTION OF WATER
UNDER CRITICAL WATER CONDITIONS
AT GRAND COULEE

Month	1936-37 Critical flow (1000's cfs.) (1)	Minimum regulated flow a/ (1000's cfs.) (2)	Diversion for irrigation of 2 million acres b/ (3)	Pumping power c/ (4)	Net flow (5)
October	42.0	73	8	4	- 43
November	28.5	73		1	- 46
December	23.2	73		1	- 51
January	18.2	73		1	- 56
February	18.2	73		1	- 56
March	23.8	73		1	- 50
April	44.1	73	18	8	- 55
May	135.5	73	28	12	+ 23
June	243.8	73	31	13	+127
July	194.5	73	32	13	+ 76
August	109.5	73	29	12	- 4
September	67.8	73	19	8	- 32
Total	949.1	876	165	75	-167,000

a/ 30 percent storage.
All figures are 1000's of second-foot months.

b/ Sufficient diversion for irrigation for 2 million acres.

c/ River flow to generate pumping power assumed to pass through all Phase C-2 plants downstream and including Grand Coulee.

The same information given in tables VIII and IX is shown graphically in figures XII and XIII. Figure XII is a graphic representation of the flow of the Columbia River at Grand Coulee under average water conditions. The figures are for the average flows from 1913 to 1948, as shown in table VII.

Referring to figure XII, it will be noted that there is a deficiency in river flow in the period from October into the month of April, and again in the latter part of September. It has been assumed that the peak flows of May, June, and July are stored to replace the deficiency of the previous winter. Additional storage is shown in an amount required to furnish necessary water and pumping power for irrigation from April through September. In some of these months the natural flow of the stream is not sufficient to furnish 73,000 second-feet for power purposes, plus the requirements for irrigation. It will be noted that there is a surplus of water equivalent to about 10 million acre-feet for the year's operation.

The distribution of water requirements for a critical water year is shown in figure XIII. This picture is entirely different from the one shown in the previous chart. Perhaps it should be noted at this time that the values used for storage represent 100 percent effective use of the river flows. In the Review 308 Report the Army Engineers show actual performance in storing and utilizing water to be about 92 to 93 percent effective.

Referring to figure XIII, 20.1 million acre-feet of stored water is required to maintain the 73,000 cubic feet per second minimum regulated flow. At 92 percent effectiveness, this becomes 21.9 million acre-feet, which is very close to the storage determined from figure XI. After storing 20.1 million acre-feet of water to replace that used in the previous winter months there remains, over and above the total flow of the river through the summer months, only 3.8 million acre-feet for irrigation purposes. This means that there is a shortage

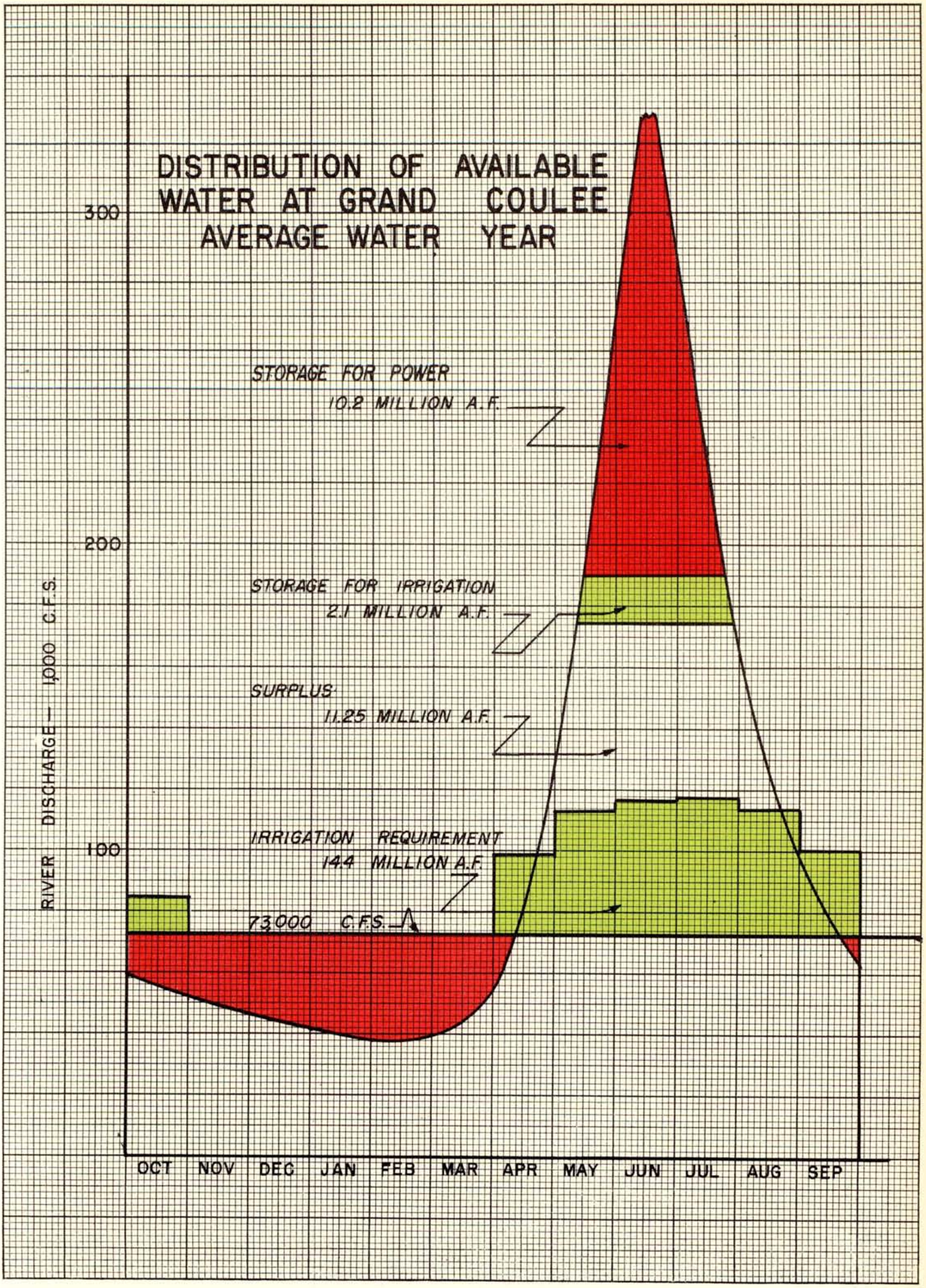

DISTRIBUTION OF AVAILABLE WATER AT GRAND COULEE AVERAGE WATER YEAR
STORAGE FOR POWER
10.2 MILLION A.F.
STORAGE FOR IRRIGATION
2.1 MILLION A.F.
SURPLUS
11.25 MILLION A.F.
IRRIGATION REQUIREMENT
14.4 MILLION A.F.
73,000 C.F.S.
300
200
100
RIVER DISCHARGE— 1,000 C.F.S.
OCT
NOV
DEC
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP

FIG. XII

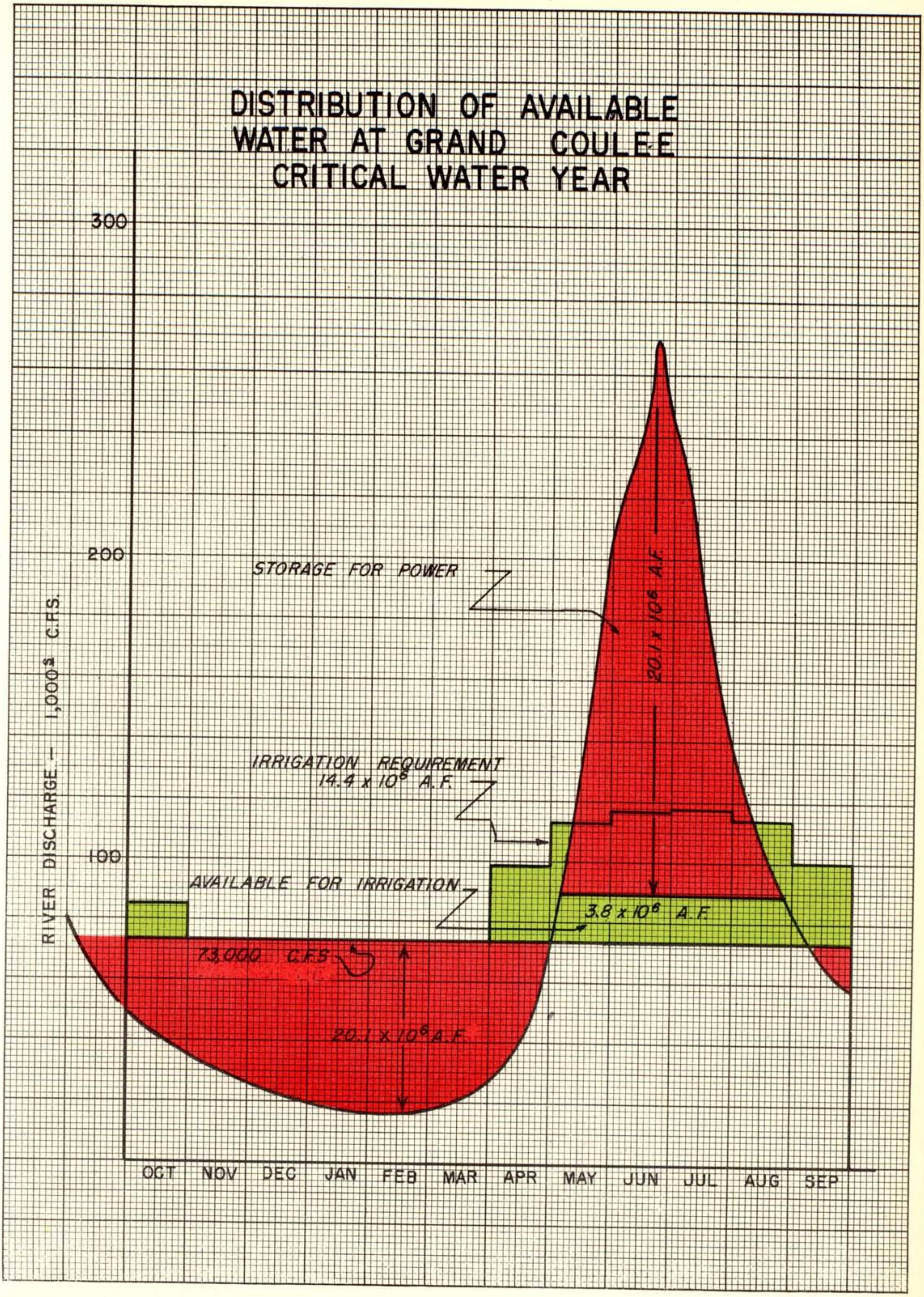

DISTRIBUTION OF AVAILABLE
WATER AT GRAND COULEE
CRITICAL WATER YEAR
300
200
100
RIVER DISCHARGE – 1,000$ C.F.S.
STORAGE FOR POWER
20.1 x 10^6 A.F.
IRRIGATION REQUIREMENT
14.4 x 10^6 A.F.
AVAILABLE FOR IRRIGATION
3.8 x 10^6 A.F.
73,000 C.F.S.
20.1 x 10^6 A.F.
OCT
NOV
DEC
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP

FIG. XIII

of approximately 10 million acre-feet in the requirement for the irrigation of the 2 million acres assumed at the start of this discussion. This agrees very closely with the net figure shown in table IX, which was 167,000 second-foot months, equivalent to slightly more than 10 million acre-feet.

There is an alternate method of operation, which would be to supply irrigation requirements of 14.4 million acre-feet and leave storage reservoirs on the river partially empty. This would mean less power available for the coming year unless far greater than average flow conditions existed during the succeeding six winter months.

It appears that the balance between surplus and deficiency occurs under the conditions of a modified-critical water year. Earlier in the report the conditions surrounding a modified-critical water year were defined. By definition, modified-critical water may be expected once in each 4-year period. Under the conditions of modified-critical water there would be just sufficient water to justify 30 percent storage and have sufficient flood flow during the summer months to supply the requirements of storage and irrigation.

There are those who would give consideration to diverting a portion of the Columbia River flow to California. Such a diversion, if taken from the upper reaches of the river, can only result in a higher cost of electric power generated from the projects on the Columbia River and the necessity of supplementing hydro generation by steam generating projects at a much earlier date to make up for the deficiency created by the diversion. It is important to remember that diversion from the upper reaches of the Columbia would normally drop through an effective head of about 1,500 feet in passing through the projects contained in the program of Phase C-2 of the Army Engineers' report. As previously mentioned, a careful study of the projected program through Phase C-2 definitely indicates the probability of a continued energy shortage in the Pacific Northwest through

1965. Any diversion of water can only aggravate this situation.

There have been several studies made which purport to show a very considerable saving by the replacement of steam-generated power on the load curve of northern California by surplus energy generated in the water-power plants in the Pacific Northwest. To obtain a sufficiently accurate answer, such a study must be based on ultimate storage on the upper reaches of the main stem of the Columbia River and its tributaries, as dictated by figure XI. A study based on a partial development of the Columbia and its tributaries is bound to show large blocks of surplus energy. These, however, are transient in nature and will largely disappear with further development of storage on the upper reaches of the river and the development of the irrigation projects in the Columbia Basin and its tributaries.

COORDINATION OF THE PRESENT RESOURCES AND PHASE C-2

Before leaving the discussion of the Army's Review Report, it is important to consider whether or not the projects recommended in Phase C-2 fit satisfactorily with the present resources now operating in the area served by the Northwest Power Pool.

Table V lists the power data of the Phase C-2 system. Under the heading of "Nominal prime capability, kilowatts," a total of 7,834,000 kilowatts is shown. The installed capacity in kilowatts is shown as 11,712,000 kilowatts. In the Army Engineers' report, Appendix O, page 212, nominal prime capability is defined as follows: "Nominal prime capability refers to one plant of an integrated system, and it is the average power available at the plant over the same period of time which determines the prime capability of the system." In short, nominal prime capability is the average energy available from the plant during the period of controlled flows. If we take the ratio of nominal prime capability to installed capacity, we obtain the figure which represents the average plant factor of the projects during the controlled-flow period. It is also the load factor of the additional load which can be served by the plants included in table V during the period of controlled flows of the system. This ratio for the totals given in table V is 66.9 percent.

In discussing the present electric-power resources and loads in the Pacific Northwest in section IV, it was pointed out that the monthly load factor for January 1950, as reported in the Northwest Power Pool operating program, was 70.6 percent. The figure for the monthly load factor in January is influenced quite materially by weather conditions throughout the area of the Pool. This figure varies from 70 to 72 percent. In the months preceding and following this peak month the system load factors are higher. It should be noted that the plant factor shown in table V of 66.9 percent is considerably below the monthly load factors of the controlled-flow months of September through March.

There are other adjustments which must be made before direct comparison can be made between the plant factor of the new projects included in table V and the projected load of the Northwest Power Pool. The Northwest Power Pool program for the water year of 1949-1950 includes the Bonneville project and twelve units of the Grand Coulee project. In the Army Engineers' report, Phase A, included in this report as table III, is approximately equal to this Bonneville-Grand Coulee combination, except that Phase A includes only nine Grand Coulee units. The following adjustment has been made, subtracting Phase A from Phase C-2, and adjusting for the three additional units at Grand Coulee:

Item	Average energy	Installed capacity
Phase C-2	7,834,000	11,712,000
Less: Phase A	1,399,000	1,490,400
Less: 3 units at Grand Coulee	106,000	360,000
Net additions	6,329,000	9,861,600

The plant factor of the net additions is 64.2 percent as shown below:

$$\frac{6,329,000}{9,861,600} = 64.2 \text{ percent plant factor during controlled-flow period}$$

More recently in the compromise program agreed to between the Army Engineers and the Bureau of Reclamation, the Glacier View project was eliminated from the program because the storage reservoir would be in Glacier National Park. As included in the Review Report, Glacier View would have a storage capacity of 3.16 million acre-feet, approximately two-thirds of which is hold-over storage. The nominal prime capability (average energy) of this project is 96,000 kilowatts. The installed capacity was to have been 210,000 kilowatts.

According to Appendix O, table XVIII, this storage would contribute about 3,187 c.f.s. to the minimum regulated flow of the main stem of the Columbia below the Canadian border during the controlled-flow period. The loss in nominal prime capability in the projects listed in Phase C-2 and located on the Columbia River below the Canadian border is as follows:

$$P_{100} = 0.0746 \times 1,005 \times 3,187 = 239,000 \text{ kilowatts}$$

The increment of nominal prime capability which will be added to the present system by completion of Phase C-2 without Glacier View is as follows:

Nominal prime with Glacier View		6,329,000
Less: Nominal prime of Glacier View	96,000	
Less: Nominal prime lost in down-stream plants	239,000	
	335,000	
Nominal prime capability without Glacier View		5,994,000

The installed capacity of Glacier View was to have been 210,000 kilowatts. If this is subtracted from the increment of installed capacity in Phase C-2, the resulting net addition becomes:

$$9,861,600 - 210,000 = 9,651,000 \text{ kilowatts}$$

and the plant factor of the net additions becomes:

$$\frac{5,994,000}{9,651,000} = 62.2 \text{ percent}$$

The resulting nominal prime capability and peaking capability of the present Northwest Power Pool system with the addition of Phase C-2 becomes:

Nominal prime of present system 1949-1950 water year	3,090,000
Net increment of Phase C-2	5,994,000
Total nominal prime capability	9,084,000

Similarly, the net peaking capability of Phase C-2 after adjustments can be added to that of the present system:

Peaking capability of present system under critical water conditions (See table II.)	4,615,000
Increment of installed capacity in Phase C-2	9,651,000
Total peaking capability of the combined system	14,266,000

The plant factor during the controlled-flow period becomes:

$$\frac{9,084,000}{14,266,000} = 63.7 \text{ percent}$$

Viewed from the standpoint of the requirements of the winter peak load, the peaking capability appears excessive when compared with the nominal prime capability of the combined systems. The peaking capability corresponding to 9,084,000 nominal prime capability and 72 percent load factor is:

$$\frac{9,084,000}{.72} = 12,620,000 \text{ kilowatts}$$

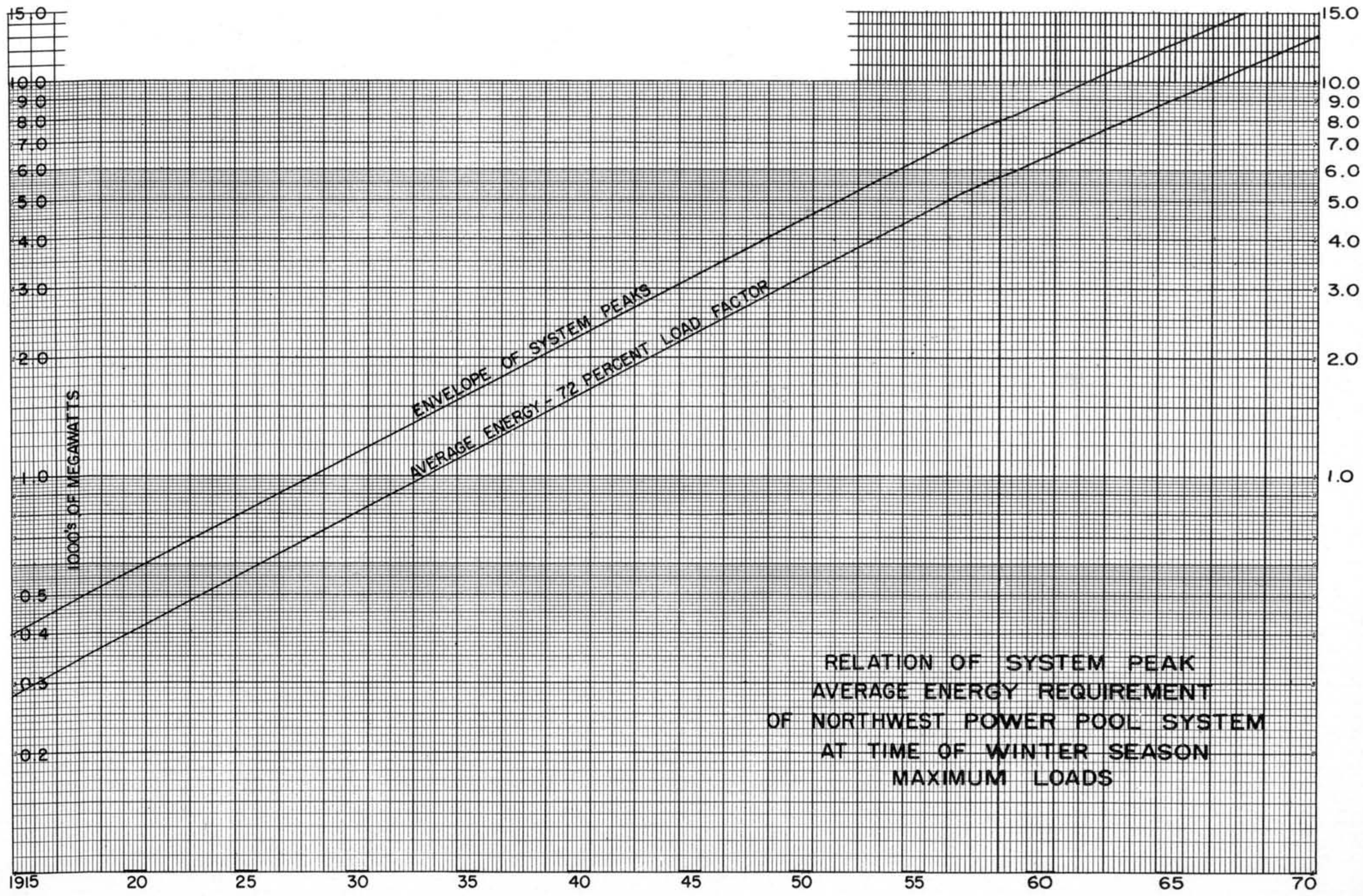
The operators of the Northwest Power Pool, after considerable study on the part of the operating committee, decided that a system reserve capacity of 6.7 percent is reasonable for such a system. On completion of Phase C-2 this would mean that the combined system should have a reserve of approximately 845,000 kilowatts. This would mean that the total plant capability should be

13,465,000. On this basis the system would have an excess peaking capability of approximately 800,000 kilowatts.

The foregoing calculation has been based on the power requirements of the winter system peak load. In discussion with the Army Engineers, it was pointed out to the writer that this method does not correctly determine the plant capability at the end of the drawdown period and does not allow a loss of peaking capability during the flood-flow season of the year. Their calculations showed that it was necessary to give consideration to these latter two factors in determining the total installed capacity of the plants in Phase C-2.

It is difficult to see how a program of new projects, which is itself deficient in energy, can be added to the present resources already deficient in energy without creating the possibility of an even greater energy deficiency under adverse water conditions.

The correlation between the present load and the generating resources of the Northwest Power Pool with the proposed additional projects included in Phase C-2 can be seen by reference to figure XIV. Referring to figure XIV, the top line is the envelope of system peaks extrapolated to 1968. It is identical with the top line of figure IV. The lower line in figure XIV differs from that on figure IV. The average energy line on figure IV is based on the average annual energy which, of course, varies from month to month. The lower line on figure XIV represents the average energy in the months of December and January at 72 percent load factor. The peak load on the Northwest Power Pool system, if it continues to grow at the rate of 6.8 percent per annum, will reach 12.5 million kilowatts by 1965. The corresponding average energy requirement in the peak months of the year will be nine million kilowatts. Nine million kilowatts represents the total average energy available from the present resources, together with the new resources of Phase C-2, and hence determines the date on



15.0
10.0
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.5
0.4
0.3
0.2
1000's OF MEGAWATTS
ENVELOPE OF SYSTEM PEAKS
AVERAGE ENERGY - 72 PERCENT LOAD FACTOR
RELATION OF SYSTEM PEAK
AVERAGE ENERGY REQUIREMENT
OF NORTHWEST POWER POOL SYSTEM
AT TIME OF WINTER SEASON
MAXIMUM LOADS
1915
20
25
30
35
40
45
50
55
60
65
70

FIG XIV

which Phase C-2 must be completed.

ANALYSIS OF THE LOAD DATA IN THE ARMY REPORT

Further study of the load data in Appendix O and Appendix N of the Army Engineers' report discloses other factors which must be given careful consideration. Perhaps the most important of these factors is that the load data on which the performance of the plants included in Phase C-2 have been based is entirely different from the present load characteristics of the area. To be sure, it is pointed out that the load characteristics which have been included in Appendix O are the characteristics of an assumed Federal system and are not the characteristics of the total electric load in the area presently served by the Northwest Power Pool. However, by the time the plants included in Phase C-2 are completed and in operation, the plants other than those of the Federal system will comprise only about 20 percent of the total installed capability of the area. This means that the shape of the load curve of the Federal system will be very near to that of the total area load.

Figure XV shows a comparison between the monthly peak loads of the Federal system for 1960 and the present Northwest Power Pool system. Peak loads for each month are expressed in percent of the January peak load. It is interesting to note that the peaks of the Power Pool system drop off rapidly after the middle of January. By April, the end of the controlled-flow period, it has decreased 12.5 percent. The June peak is 15 percent below the January peak.

The curve of the Federal system for 1960 shows an increase of 6 percent in June over the January peak. The growth factor has been taken out of both curves.

The total difference between the two system curves is 21 percent. This is equivalent at the end of Phase C-2 to 3 million kilowatts. It would appear that the distribution of load represented by the Federal system curve will be much more expensive to serve because of the need of additional generating units at most of the projects.

The drop in the system peak requirements of the present system allows the following things to be accomplished:

(1) Take units out of service for maintenance.

(2) Lower reservoir level for flood control.

(3) Draw additional water from the reservoirs in the latter months of a critical water period.

(4) Allow for heavy pumping to fill the equalizing reservoir of the Grand Coulee Basin project without required additional generating resources.

(5) Reduce the danger of a power shortage during the flood-flow period of the river.

The following tabulation taken directly from Appendix N, part I, page 12 of the Army Engineers' report, shows the estimated distribution of electric load in 1960:

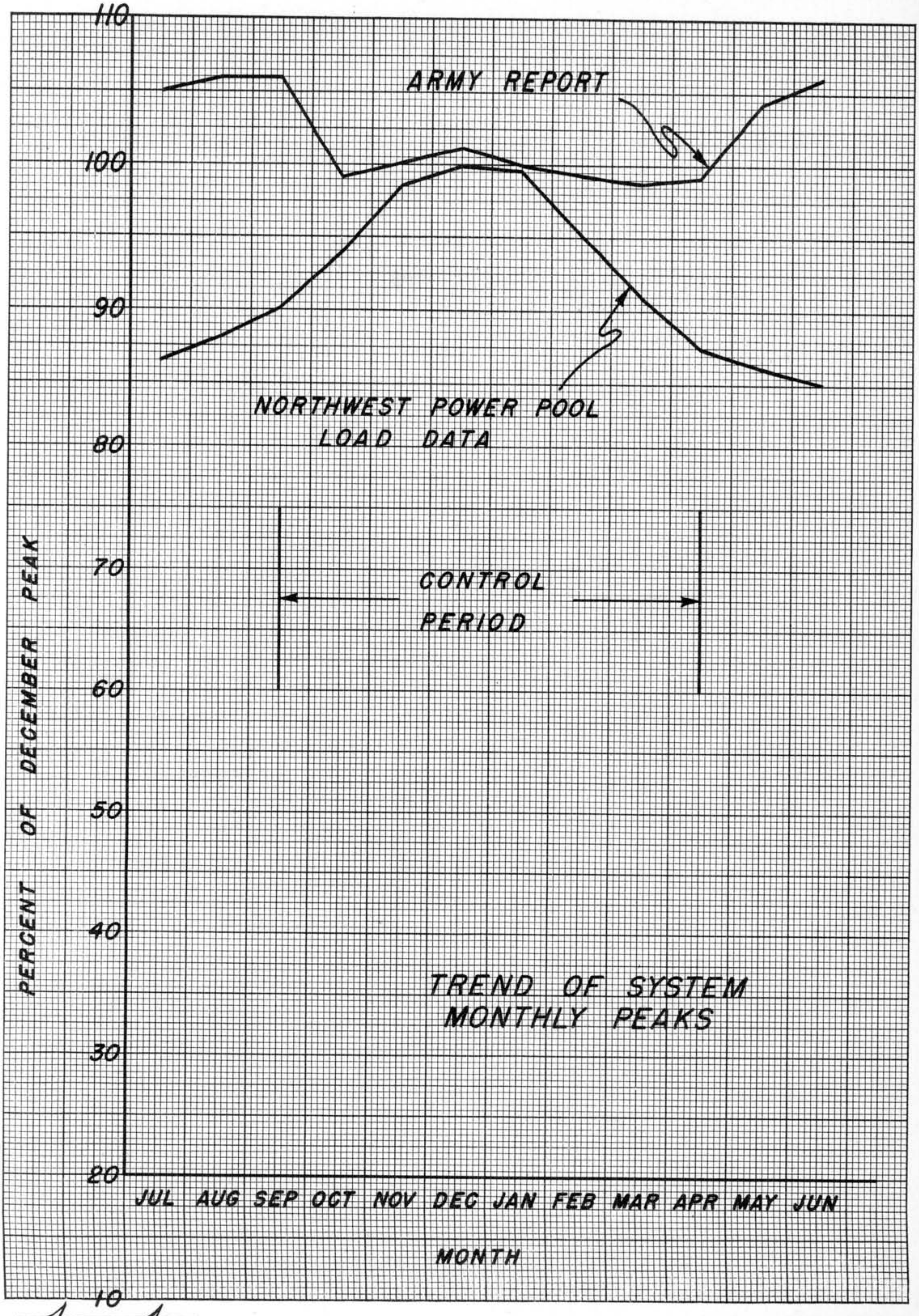

ARMY REPORT
NORTHWEST POWER POOL
LOAD DATA
CONTROL
PERIOD
TREND OF SYSTEM
MONTHLY PEAKS
PERCENT OF DECEMBER PEAK
110
100
90
80
70
60
50
40
30
20
10
0
JUL AUG SEP OCT NOV DEC JAN FEB MAR APR MAY JUN
MONTH

FIG. XV

Class of consumer	Annual energy consumption (millions of kilowatt-hours)	Contribution to coincidental peak power requirements (thousands of kilowatts)
Urban domestic	5,003	
Rural nonfarm	2,131	
Farm	1,920	
Subtotal	9,054	
Commercial	7,200	
Small industrial:		
Food processing	530	
Other	3,469	
Subtotal	3,999	
Subtotal	20,253	4,315
Large industrial:		
Forest products	3,038	454
Aluminum	29,300	3,500
Other	9,794	1,408
Subtotal	42,132	5,362
Railway electrification	720	160
Space heating	667	370
Irrigation	2,286	----
Street lighting	226	65
Miscellaneous	800	114
Total sales	67,084	10,386
Transmission and distribution losses	9,392	1,454
Total sales and losses	76,476	11,840

Particular attention is called to the fact that 38.4 percent of the energy and 30 percent of the peak load of the entire Northwest system is shown as aluminum-plant load. The effect of this on the over-all economy of the area is shown by the comparison on a percentage basis of the energy consumption by classes of consumers:

	Pacific Coast 1949	Northwest 1960	Total United States 1949
Residential and rural	33.2	14.5	26.4
Commercial	16.6	16.8	18.6
Industrial	45.4	63.8	48.5
Other	4.8	4.9	6.5
Total	100.0	100.0	100.0

Presently, residential and rural energy consumption in the Pacific Coast States is 33.2 percent of total consumption. In the 1960 distribution, as shown in the Army report, residential and rural consumption would be only 14.5 percent. A similar comparison can be made with the figures for energy consumption in the United States.

The conclusion to be drawn from this comparison is either that little labor is required for the industrial development planned for this area, represented by the distribution of energy shown in the above tabulation, or that the standard of living of labor as represented by the low residential electric-energy consumption will be below the average of the United States.

The following tabulation lists the approximate kilowatt-hours of electric energy consumed in various industries in the Northwest per man-years of employment in the industry.

Industry	Kilowatt-hours per man-year
Aluminum reduction	1,125,000
Paper products	85,900
Flouring mills and feed	30,700
Building materials	20,200
Lumbering and wood products	10,800
Textiles	6,100
Food products	5,560
Metals	5,083
Furniture	4,040

One of the principal reasons for considering the possibility of constructing steam-electric generating facilities in this area is the need of additional electric power to maintain full employment. Assuming 72 percent plant-factor operation of such facilities, it would require the following installed capacity per worker in the various industries:

Industry	Kilowatts per man-year
Aluminum reduction	180.0
Paper products	13.6
Flouring mills and feed	4.9
Building materials	3.2
Lumbering and wood products	1.7
Textiles	1.0
Food products	0.9
Metals	0.8
Furniture	0.6

The use of power transmission lines to transmit power from the Pacific Northwest to other areas in the south and east may not be to the advantage of the economy of this area. The amount of harm, however, that can be accomplished with transmission lines of limited capacity is relatively small. There are still technical limits beyond which power can not be reasonably transmitted. In the production of aluminum ingots this limit entirely disappears. Each pound of aluminum pig produced from alumina by the most modern of pot lines will absorb 10 kilowatt-hours of electric energy. As aluminum pig, it can be shipped anywhere in the world, extracting from the Pacific Northwest the energy required for its purification. The bringing of additional aluminum pot lines into an already energy-deficient area will have an adverse effect on the economy of the area. To the extent that the operation of these pot lines absorbs the available supply of low-cost water-power energy, high-cost steam-electric generating units must be operated to make up the energy deficiency.

ANALYSIS OF THE COST OF COLUMBIA RIVER HYDRO PROJECTS

In making a comparison between cost of steam and hydroelectric generating plants, it is first necessary to determine that the particular hydro plant and steam plant used in the comparison are comparable. A steam plant is available at 100 percent of its capacity at all times except for maintenance outages and emergency breakdowns. The reliability of a modern steam-electric generating plant is such that emergency outages have become rare.

The availability of a hydro plant will vary with stream flow conditions. If the capacity of a hydro plant is just equal to the minimum regulated flow of a stream, its availability is equal to that of a steam plant. If additional units are installed in a hydro plant and the stream flow is not sufficient for continuous operation, the additional units must be operated higher on the load duration curve for the system. Under these conditions, the unit cost of the additional units is not comparable with steam generating capacity. Additional upstream storage to increase the minimum regulated flow of the stream might be added to an extent that the additional hydro capacity would become available 100 percent of the time. Under these conditions this capacity is comparable with steam.

A major portion of the cost of one of the large hydro projects on the Columbia River is in the dam, spillway, and other portions of the project which are largely independent of the number of units installed in the power-house. Considerable variation in the per-kilowatt cost of capacity, installed within the limit of the prime flow of the river, may result from the assumption of different values of minimum regulated flow of the river.

Inspection of "Surface water supply of the United States, 1937, pt. 12, Pacific slope basins in Washington and upper Columbia River Basin": U. S. Geol. Survey Water-Supply Paper 832, 1938, shows a minimum natural flow of the Columbia River at Grand Coulee in this critical water year of approximately 18,200 cubic feet per second. At the present time there is approximately 7.2 million acre-feet of storage at and above the Grand Coulee project. This gives a minimum regulated flow of the stream under critical water conditions of about 44,100 cubic feet per second. Previously in this report the value of upstream storage at the Grand Coulee project was discussed. It was shown that the development of 22.5 million acre-feet of storage at and above this project would result in a minimum regulated flow of about 73,000 cubic feet per second.

The Chief Joseph project, located on the main stem of the Columbia River, approximately 50 miles below Grand Coulee, is under construction at the present time. It is typical of the more feasible moderate-head projects on the river. Flow characteristics of the Columbia at the Chief Joseph project are about the same as the flow characteristics at Grand Coulee.

The formula for the amount of power which can be developed from the prime flow of a stream is as follows:

$$P_{100} = 0.0746\ Q_{100}\ H_m$$

where

P_{100} = prime power in kilowatts at Chief Joseph

Q_{100} = net continuous flow in c.f.s. during the critical period (after deductions for irrigation, if any) and

H_m = mean gross head (feet) = headwater elevation at mean usable storage level minus tail-water elevation corresponding to Q_{100}.

Applying this formula to the three values of prime flow outlined in the previous paragraphs we have the following results:

Prime flow (c.f.s.)	Electric power from prime flow (kilowatts)	Number of units
18,200	228,000	3.5
44,100	554,000	8.6
73,000	905,000	14.1

Figure XVI is a graphic presentation of the cost of construction of the Chief Joseph project. The lower line marked "1940 Construction Cost" was taken directly from the Army report on this project, dated August 15, 1945. The upper line marked "1949 Construction Cost" was derived by multiplying the 1940 cost by 1.95.

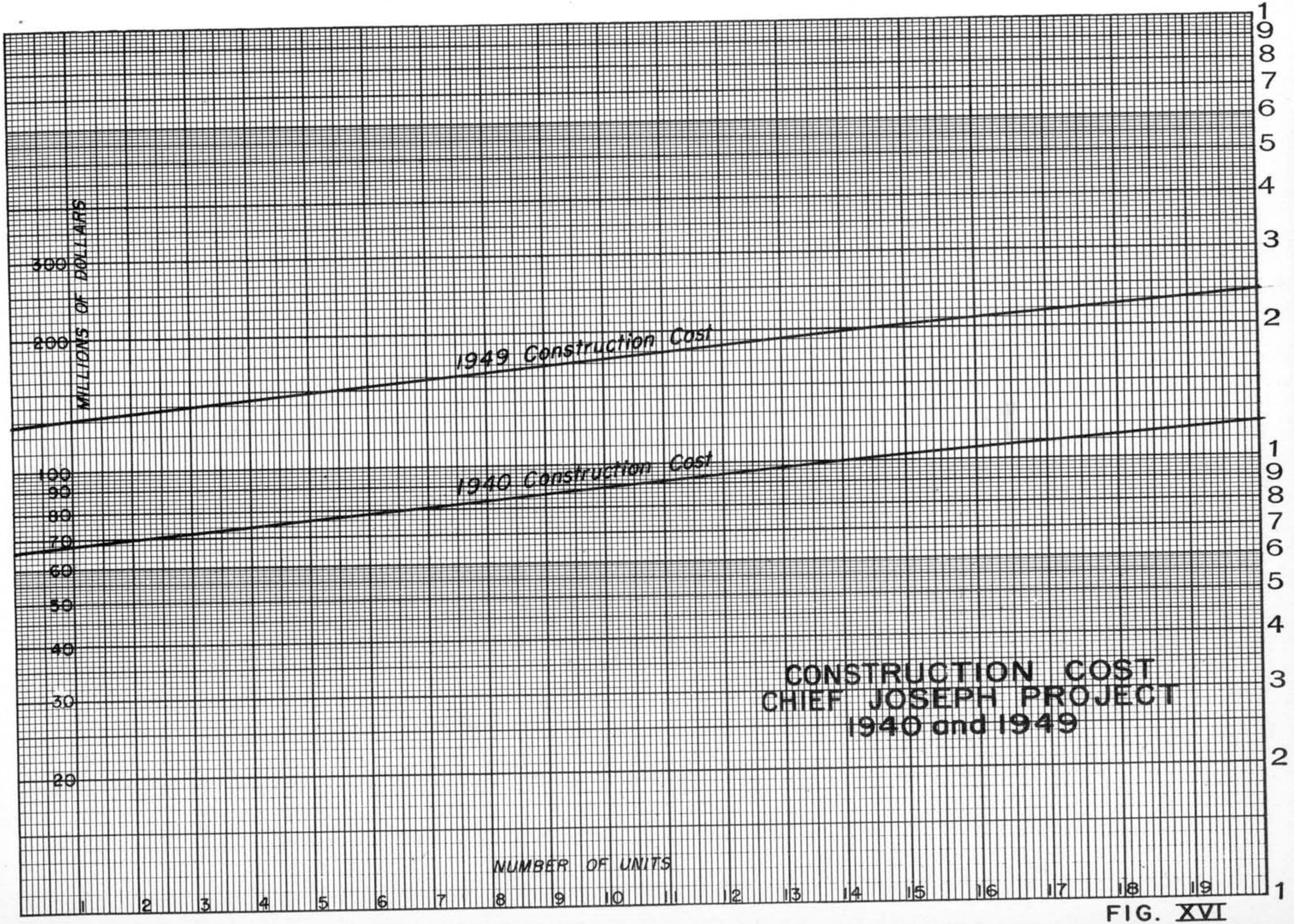
Referring to figure XVI, the total construction cost is given for one through sixteen units, inclusive. It is interesting to note that the cost of this project with no units installed is 128 million dollars. This is determined by following the 1949 construction cost curve to the left until it intersects the zero unit line.

The design of the Chief Joseph project calls for 64,000-kilowatt generators on each of the main units. If we divide the total power from prime flow by 64,000, we obtain the number of units required to pass the prime flow as indicated in the above tabulation. On page 99 the last column in the tabulation, headed "Number of units," is the number of units required to pass the prime flow as indicated in the tabulation.

Referring to the construction-cost curve for 1949 in figure XVI, the total construction cost corresponding to the number of units shown in the tabulation on page 99 can be read directly from the curve, giving the data shown by the tabulation below:

Storage	Number of units	Total construction cost (millions of dollars)	Cost per kilowatt at project (dollars)	Cost per kilowatt at load center (dollars)
Natural flow	3.5	141	618	720
Present storage	8.6	167	302	404
30 percent	14.1	198	219	321

Project costs of hydro plants and steam plants are not directly comparable. The hydro must be located on a stream where suitable potential head and river flow are available. On the other hand, a steam plant can usually be located adjacent to a principal load center. To make the hydro plant investment costs comparable with that of a steam plant, the cost of transmission from



MILLIONS OF DOLLARS
300
200
100
90
80
70
60
50
40
30
20
1949 Construction Cost
1940 Construction Cost
CONSTRUCTION COST
CHIEF JOSEPH PROJECT
1940 and 1949
NUMBER OF UNITS
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19

FIG. XVI

the project to the load center must be added.

The Army Engineers' Review 308 Report, Appendix O, page 123, gives an average transmission line cost of $102 per kilowatt delivered at the load center. This figure is determined from the transmission line net work required to deliver the power represented by Phase C-2 of the Review Report. If we add $102 per kilowatt to the hydro project cost in the third column in the above tabulation, we obtain the figures shown in the last column of the tabulation, which is entitled "Cost per kilowatt at load center."

THE ANNUAL COST OF HYDROELECTRIC PROJECTS

The fixed costs, including interest, taxes, insurance, and depreciation, are the most important elements of cost of a power-supply system deriving its energy from hydroelectric projects. Presently, there is a wide difference in the methods of bookkeeping of private and public systems with regard to the amount of these fixed costs. The following tabulation gives a comparison of the average figures used by the two groups:

	Percent of capital investment		Probable
	Public systems	Private systems	future charges
Interest	2.5	6.0	3.0
Taxes	-	2.0	2.0
Insurance	-	1.0	-
Depreciation	1.34	0.56	1.34
	3.84	9.56	6.34

As also mentioned in section VIII in the description of fixed costs for steam-electric generating plants, public systems, in most instances, have not been contributing materially to the revenue of Federal, state, county, and municipal governments. There is a definite tendency toward the increase in taxes on public systems for the purpose of supporting local divisions of government. Since this report looks to future development of the power system, it seems reasonable to use figures of 6.34 percent as the total fixed cost for the hydroelectric project costs and 8 percent of investment in transmission required to transmit the power from the project to the load center.

There is considerable discussion in technical literature as to the length of life of the concrete structure comprising a large portion of the cost of a modern hydroelectric project. The permanence of these structures is given as a reason for the use of an extremely low amortization cost. There is, however, one factor which must be considered before the calculated life of one of these projects is unduly extended. This factor is siltation. Relating to this subject, there are very few empirical data immediately available for the Columbia River and its tributaries. It is known, however, that the main stem of the Columbia carries a burden of silt which will be deposited in the large reservoirs formed by the various project dams. This is particularly important on a stream like the Columbia, where a large portion of the value of the projects depends upon the increase of the minimum natural flow of the streams to furnish the energy required during the peak load of the winter months. Referring to figure IX, the total potential power of the Columbia River Basin, without the benefit of storage, is only 10 million kilowatts. The ultimate capability, at 75 percent load factor, is 32 million kilowatts. The difference between these two figures is the benefit derived from storage.

The production expense, including both operation and maintenance, is much less in a hydroelectric project than it is in a steam-electric project. A reasonable figure for operation and maintenance expense of hydroelectric-power projects is about 1.0 percent of investment.

Operation and maintenance costs for transmission have been taken at $300.00 per mile-year. The average length of circuit from principal generating projects to the load centers is approximately 200 miles. Transmission lines which form a part of the 230-kw transmission grid have capacities varying from 160,000 to 200,000 kilowatts. On this basis the operating and maintenance cost of transmission becomes about 30 cents per kilowatt-year.

A figure of 40 cents per kilowatt-year has been used for the operation and maintenance costs of the principal substations which form a part of the transmission system.

A SUMMARY OF PROJECT COSTS IN PHASE C-2

The purpose of this subsection is to establish the costs of hydroelectric plant construction on a basis permitting a reasonable comparison with the cost of a modern steam-electric generating plant. Phase C-2 has been defined by the Army Engineers as the system which will be in existence after the completion of the projects recommended in the main control plan, plus those in Phase A and Phase B.

It has been suggested that a comparison should be made including the plants in Phase A, which of course are the Bonneville and Grand Coulee projects. Reference to figure XXII, which shows the electric construction cost index, shows the futility of attempting to compare 1950 construction costs with those of 1936 to 1938.

The construction of additional upstream storage at the projects included in the main control plan and Phase B will increase in amount the nominal prime capability at the Bonneville and Grand Coulee projects. The benefit of this additional energy has been taken into consideration in determining the cost of hydroelectric power. At the same time it was felt that the incremental cost of generating units and substructures should be included in plant costs. This incremental cost is approximately $75.00 per kilowatt.

The following tabulation lists all of the projects included in Phase C-2 with the exception of the Bonneville and Grand Coulee projects. This schedule provides space permitting the tabulation of plant investment costs, nominal prime capability of each plant in kilowatts, and the total installed capacity of the units in each plant based on the name-plate rating.

Project	Plant investment (millions of dollars)	Nominal prime capability (kilowatts)	Installed capacity (kilowatts)
Hungry Horse	110	120,000	300,000
Chief Joseph	250	876,000	1,280,000
McNary	300	635,000	910,000
Lower Snake	390	647,000	980,000
Glacier View	102	96,000	210,000
Libby	259	244,000	588,000
Albeni Falls	33	26,000	42,000
Priest Rapids	367	774,000	1,219,000
John Day	420	735,000	1,105,000
The Dalles	313	701,000	980,000
Hell's Canyon	372	602,000	980,000
Total	2,916	5,456,000	8,294,000

In establishing the cost of power from these projects it has been assumed that all costs of the project not directly chargeable to navigation or flood control are chargeable to power. The above tabulation includes all costs, so that it will be necessary to make certain adjustments to exclude navigation and flood control costs. The following tabulation summarizes the adjustments which should be made for items chargeable directly to navigation and flood control:

Project	Cost of additional facilities (millions of dollars) Navigation	Flood control	Total
Hungry Horse	none	none	-
Chief Joseph	"	"	-
McNary	15.0	"	15.0
Lower Snake	58.0	"	58.0
Glacier View	none	"	-
Libby	"	"	-
Albeni Falls	"	"	-
Priest Rapids	9.5	65.0	74.5
John Day	17.6	65.0	82.6
The Dalles	14.4	none	14.4
Hell's Canyon	none	"	-
Total			244.5

To allow for the increase in the nominal prime capability of the Bonneville and Grand Coulee projects, the following adjustments have been made:

	Bonneville	Grand Coulee
Phase C-2 nominal prime	482,000	1,677,000
Phase A " "	391,000	1,008,000
Increase in nominal prime	91,000	669,000
Total increase in nominal prime capability		760,000

The calculation of the incremental cost of substructures and units to absorb the increase in nominal prime at the Bonneville and Grand Coulee projects is given below:

760,000 @ 72 percent plant factor = 1,050,000 kilowatts of additional capacity required at Grand Coulee and Bonneville to use the increase in prime flow of the river.

1,050,000 @ $75.00 per kilowatt = 78.7 million dollars

In determining the useful energy available from these projects, it is assumed that all of the energy generated from the prime flow of the river at the projects is usable. No allowance in this calculation has been made for additional generation from the secondary flow of the stream. The nominal prime capability of the 11 projects in the above list supplemented by the increase in nominal prime capability of the Bonneville and Grand Coulee projects totals 6,216,000 kilowatts. At 100 percent plant factor, the average energy equivalent to this nominal prime capability is 54.5 billion kilowatt-hours. The plant investment figure of $2,916,000,000 must be increased by the amount of incremental costs of additional capacity at Bonneville and Grand Coulee and decreased by the amount of the adjustments for navigation and flood control. The net of this calculation is $2,995,000,000.

As previously explained, the annual fixed costs of these projects will be determined as 6.34 percent of project investment costs. This is equal to $190,000,000. To the above fixed costs must be added the production expense, which as previously discussed is taken as one percent of plant investment. This is equivalent to $30,000,000. The total cost becomes $220,000,000. If we divide this by the total energy from these projects, we obtain the unit cost of 4.03 mills per kilowatt-hour. Because the installed capacity at these projects is sufficient to allow the prime energy to be developed on a 72 percent load-factor basis, this load factor is considered in the future comparison with steam.

To make the comparison valid, with steam-electric generation it is of course necessary to add the cost of transmitting power from the various hydroelectric projects to the principal load centers of Puget Sound and the lower

Columbia River. By some, the costs of transmission as used in this report may be considered high. The principal loads in the area are west of the Cascades in the Puget Sound and lower Columbia River areas. The hydroelectric projects such as Chief Joseph, Priest Rapids, and McNary are located just east of the Cascade Mountains. For the greater part of their length, transmission circuits must traverse the rocky terrain of the mountain area. Just west of the mountains the transmission lines pass through forest areas. Adjacent to the principal load centers the costs of rights-of-way increase rapidly. The cost of operation and maintenance, including the problems of sleet, tends to increase the costs above normal.

In determining the cost of transmission, a calculation must be made to determine the average length of transmission from a sufficient number of the projects nearest the coast so that the energy equals approximately two-thirds of the annual output of the generating resources of the area on completion of Phase C-2. This average distance was figured to be about 150 miles.

Mr. S. B. Crary, of the General Electric Company, presented a technical paper for the American Institute of Electrical Engineers before the summer general meeting in Montreal, Canada, in June 1947. This paper was entitled "The economics of long-distance A-C power transmission." The costs presented in this paper are based on 1945 price levels. Adjusting the figures included in this paper to 1949 price levels, it is figured that the cost of transmission to the load centers on the Pacific Coast is approximately 2 mills per kilowatt-hour. In the Review 308 Report, Appendix O, page O-123, the average cost of transmission on the completion of Phase C-2 is $8.69 per kilowatt of firm-power peak load. This is equivalent to approximately 1.6 mills per kilowatt-hour at 50 percent load factor. In the load assumed for this transmission-line study, 30 percent of the entire load in the Pacific Northwest was assumed to be aluminum-plant load with its extremely high load factor characteristics. This characteristic of the study tends to give too low a figure for the cost of transmission. After careful consideration of all factors, the writer believes that the use of 2 mills per kilowatt-hour as a cost of transmission is entirely reasonable.

Adding the project cost and cost of transmission gives a total of 6.03 mills per kilowatt-hour as the cost of power delivered in the principal load centers west of the Cascade Mountains. The cost of 6.03 mills per kilowatt-hour, of course, includes the entire cost of the 11 projects except the portions directly chargeable to navigation, flood control, or irrigation. It is probable, with more upstream storage than has been included in Phase C-2, that downstream installations could be made on a more economical basis. With additional storage, it is probable that additional units could be installed in all the downstream projects at an incremental cost of less than $75.00 per kilowatt, as compared with unit costs that range from $250.00 to $700.00 per kilowatt in the present program.

VII. FUELS AVAILABLE FOR USE IN FUEL-BURNING ELECTRIC PLANTS IN THE PACIFIC NORTHWEST

TYPES OF FUELS

There are presently three fuels in use in the fuel-burning electric plants of the Pacific Northwest. These are, in the order of their importance, fuel oil, hogged fuel, and coal. Suitable methods of burning have been developed for all these fuels. In the final analysis the choice of fuel is dependent to a large degree upon two factors, its cost and its availability.

Fuel oil has always been readily available in seacoast ports of the Pacific Northwest except for a short period during the second World War. During this short period two large oil-distributing companies refused to deliver fuel oil in this area. The difficulty was primarily an economic problem, rather than one of the availability of oil. For a number of years prior to the second World War oil was sold in tanker lots for 90 cents a barrel, or less. The greatly increased demands for fuel oil during the second World War made it more profitable to sell the available supply elsewhere at much higher prices. Near the end of the war period oil was selling for $2.85 a barrel in this area. The present-day price in tanker lots is about $1.60 a barrel.

Fuel oil is an end product in the fractionization of crude oil. Present-day methods of cracking give considerable flexibility in the determination of the quantities of gasoline, diesel oil, and other fractions. To some extent the amount of the end products is controllable by the process of hydrogenation and other of the more modern processes of cracking.

In past years the supply of hogged fuel in the Pacific Northwest was sufficient to furnish the greater part of the fuel requirements for many large industrial plants. However, in recent years this supply of hogged fuel has gradually diminished. There are many factors contributing to this trend. Not the least of these factors is the cost of logs. In the early 1930's logs could be purchased on Puget Sound for as low as $6.00 a thousand, and the scaling was quite liberal. Presently, the same logs are being sold at prices ranging from $25.00 to $35.00 a thousand, and the scaling is much closer. As a result of this trend in the price of logs new methods of sawing and barking the logs have been developed to a point where very little mill refuse remains. Band mills have been substituted for circular saws. Hydraulic barkers replace slabbing on the head rigging. The cleaned slabs from the lumber shift, which at one time constituted a major supply of slab wood, are now made into chips and used as a source of fiber in pulp mills making kraft paper. The present supply of hogged fuel has diminished to a point where existing boiler installations in certain industrial plants and small central-station installations consume the entire available supply. Hogged fuel has ceased to be a consideration in future central-station development.

The third form of fuel available for fuel-burning electric-generating plants in the State of Washington is coal. Not too much is known of the coal reserves within the state. According to the estimate of the United States Geological Survey made in 1913 and revised in 1925, the original coal resources of the State of Washington were 63,877,000,000 tons. The distribution, according to rank, was given as follows:

Anthracite and semianthracite	23,000,000
Bituminous	11,412,000,000
Subbituminous	52,442,000,000
Total	63,877,000,000

As indicated in the above summary of reserves, 82 percent of the total reserves in the State of Washington is subbituminous coal.

A Report of Investigations entitled "Coal and coal mining in

Washington," by Stephen H. Green, was published in 1947 by the Division of Mines and Geology. This publication sets forth in splendid fashion a survey of the coal-mining operations in the state at the present time. Details are given in this bulletin for properties operating in 1946. Summaries are included covering longer periods of operation.

Table X, which was taken directly from the report by Stephen Green, shows indicative analyses of Washington coals. The analyses for Thurston, Lewis, and Cowlitz Counties are typical for subbituminous coals. These coals are characterized by unusually high percentages of moisture and volatile matter, and a correspondingly lower value of fixed carbon. In estimating the value of these coals for power generation, consideration must be given to the effect of these characteristics upon the efficiency of boiler operation of steam-electric generating plants. Subbituminous coal is difficult to store.

Table XI is taken from the "Annual report of coal mines for the year ending December 31, 1948." This report is published by the Department of Labor and Industries, State of Washington. It gives details of current operations for the year 1948. The total coal production for the year 1948 was 1,222,035 tons. It is interesting to note that, if the total coal production for that year had been burned in a modern fuel-burning electric-generating station, the electric-energy production would have been approximately equivalent to the annual energy production from 1.8 units of the Grand Coulee project.

COST OF FUELS

In the final analysis, the choice of a fuel for a fuel-burning electric-generating station is an economic problem. In each instance there is the cost of the fuel f.o.b. plant. To this first cost must be added the cost of storing. The type of fuel, to some extent, influences the capital cost of

TABLE X

INDICATIVE ANALYSES OF WASHINGTON COALS, BY COUNTIES OR PRINCIPAL COAL PRODUCING AREAS WITHIN COUNTIES

County and area	Moisture %	Volatile matter, %	Fixed carbon, %	Ash %	Sulphur %	British thermal units
Whatcom County						
Bellingham area	5.0-13.4	35.2-40.2	41.8-48.7	13.9-22.7	0.3-0.6	10,390-11,820
Glacier field	4.3- 5.8	7.8- 9.4	79.4-82.2	7.8-10.2	0.96-1.01	12,920-13,960
King County						
Renton-Black River area	8.9-18.0	36.2-45.4	43.2-52.4	6.8-17.4	0.6-1.8	10,920-12,730
May Creek-Cedar Mountain area	14.2-23.0	37.1-39.9	47.2-48.8	12.0-14.1	0.3-0.8	9,740-11,710
Newcastle-Issaquah area	12.3-18.2	37.2-42.2	42.6-52.2	11.2-18.5	0.4-0.7	10,600-11,990
Ravensdale-Black Diamond area	4.9-13.4	38.6-44.7	46.3-53.1	3.7-15.2	0.4-0.8	11,090-13,290
Cumberland-Palmer area	3.9- 7.2	24.9-38.6	38.7-51.2	11.1-23.1	0.5-1.2	10,120-12,880
Danville area	10.5-18.1	38.4-39.3	47.4-50.9	9.8-13.3	0.4-0.6	11,950-12,110
Pierce County						
Ashford area	4.1- 5.8	16.2-25.4	37.5-58.1	25.7-39.6	0.4-0.7	10,740-11,050
Wilkeson area	1.5- 5.5	19.1-38.5	51.4-60.8	8.5-16.7	0.4-1.02	11,380-13,850
Carbonado area	2.5- 5.3	21.4-38.4	46.8-58.2	8.4-20.8	0.4-1.01	11,800-13,920
Thurston County	16.0-22.5	32.9-44.4	34.5-44.7	11.5-20.6	0.4-1.6	8,970-11,160
Lewis County						
Centralia-Chehalis area	22.4-33.5	43.2-49.3	40.0-47.2	9.6-16.2	0.5-2.3	10,390-11,770
Morton area	4.1- 8.6	32.7-43.0	39.0-57.9	17.5-25.1	0.7-1.1	10,650-11,580
Cowlitz County	15.2-22.2	42.8-43.4	34.8-35.9	15.7-23.0	1.2-5.5	7,500- 9,750
Kittitas County						
Cle Elum area	3.1- 5.8	34.4-39.4	47.0-52.0	11.4-14.5	0.3-0.5	12,240-13,250

TABLE XI

COAL MINE STATISTICS FOR THE YEAR 1948

Name of company	Name of mine	Town	Total coal production (tons)	Av. yearly output per man shift (tons)	Coal value at mine (per ton)
KING COUNTY					
Anderson Coal Co.	Strip	Ravensdale	4,108	1,369	$ 4.87
B.P.D. Coal Co.	No. 1	Issaquah	4,378	952	7.80
B. & R. Coal Co.	Issaquah	Issaquah	13,909	740	6.85
B. & R. Coal Co.	Newcastle	Newcastle	18,310	826	7.32
Bianco Coal Co.	Queen No.1	Issaquah	33,927	632	6.94
Big Four Coal Co.	Elk	Palmer	14,586	815	6.31
C. & M. Coal Co.	No. 1	Issaquah	1,206	157	7.99
Carbon Fuel Co.	Bayne	Bayne	20,283	970	6.49
Fireking Coal Co.	No. 1	Renton	233	97	6.50
Franklin Gem Coal Co.	No. 1	Black Diamond	4,881	1,038	6.44
Johnson Coal Co.	No. 1	Black Diamond	1,942	405	6.20
Kummer Coal Co.	No. 1	Black Diamond	4,223	1,030	5.21
New Lake Young Coal Co.	No. 1	Renton	2,402	400	6.00
N.W. Improvement Co.	McKay	Ravensdale	24,474	298	9.04
N.W. Improvement Co.	Strip	Ravensdale	101,722	2,831	4.91
Olson Coal Co.		Cumberland	7,982	676	8.30
Palmer Coking Coal Co.	Nos. 10, 11, 12,	Black Diamond	34,242	1,062	7.01
Palmer Coking Coal Co.	Danville	Landsburg	18,201	1,005	5.93
Palmer Coking Coal Co.	Palmer	Durham	1,492	426	6.03
Renton Mining Co.	No. 1	Renton	9,248	402	7.16
Springbrook Mining Co.	No. 3	Renton	8,931	726	7.40
Spring Glen Coal Co.	No. 1	Renton	7,774	829	7.58
Strain Coal Co.	Newcastle	Newcastle	17,051	708	6.35
Totals for county			355,505	Av. 840	Av. $ 6.40
KITTITAS COUNTY					
Jonesville Coal Co.	No. 4	Ronald	3,680	177	$ 5.30
N.W. Improvement Co.	No. 3	Ronald	227,628	993	6.63
N.W. Improvement Co.	No. 9	Roslyn	182,821	961	6.63
N.W. Improvement Co.	Strip	Roslyn	77,444	1,906	6.62
Roslyn Cascade Coal Co.	No. 4	Ronald	106,328	721	7.06
Sun Ray Coal Co.	No. 1	Roslyn	77	77	8.08
Totals for county			597,978	Av. 949	Av. $ 6.70
LEWIS COUNTY					
Black Prince Coal Co.	No. 3	Centralia	4,004	1,250	$ 5.00
Bucoda Coal Co.	Bucoda	Centralia	1,273	255	4.92
Columbia Coal Co.	No. 1	Centralia	3,267	591	5.10
Golden Glow Coal Co.	No. 1	Centralia	430	331	5.70
Monarch Coal Co.	Monarch	Centralia	36,670	1,091	5.00
Stoker Coal Co.	Martin	Centralia	6,489	756	5.54
T & T Coal Co.	No. 1	Centralia	62	62	5.10
Totals for county			52,195	Av. 895	Av. $ 5.14

TABLE XI (continued)

COAL MINE STATISTICS FOR THE YEAR 1948

Name of company	Name of mine	Town	Total coal production (tons)	Av. yearly output per man shift (tons)	Coal value at mine (per ton)
PIERCE COUNTY					
Carbonado Coal Co.	No. 1	Carbonado	5,804	841	$ 7.05
Carbon Wingate Coal Co.	No. 1	Wilkeson	442	116	7.54
Champion Coal Co.	Champion	Wilkeson	175	175	7.30
Gale Cr. Coal Co.	Gale Creek	Wilkeson	2,557	511	7.32
Sparton Coal Co.	No. 1	Wilkeson	226	65	7.33
Wilkeson-Wingate Coal Company	Wilkeson-Wingate	Wilkeson	9,836	887	6.91
Totals for county			19,040	Av. 608	Av. $ 7.03
THURSTON COUNTY					
Strain Coal Co.	Tono	Tono	61,077	1,289	$ 4.63
WHATCOM COUNTY					
Bellingham Coal Co.	No. 1	Bellingham	136,240	843	$ 7.29
Grand totals for 1948			1,222,035	Av. 905	Av. $ 6.51

the plant. In an oil-burning plant the fuel oil is stored in tanks and pumped to the burners at the proper temperature.

As mentioned above, fuel oil prices in the Pacific Northwest have varied from 90 cents a barrel to $2.85 a barrel in the past few years. The present price in tanker lots is approximately $1.60 a barrel. For the purpose of this report, it would appear that the figure of $1.60 a barrel is a reasonable average cost.

In coal-burning plants provision must be made to unload the coal and store it. This is usually done by placing the coal in large piles in an area adjacent to the plant. When certain types of subbituminous coal are used, storage must be provided such that the coal can be submerged or otherwise handled to prevent loss of volatile matter and to safeguard against spontaneous combustion. Depending upon whether the coal is burned in stokers or as powdered coal, the coal must be variously prepared for use. If the fuel is coal, boiler foundations and setting must be so arranged as to facilitate ash handling. Provision must be made for the disposing of ash. The flues must be equipped with precipitators to control fly ash.

Referring to table XI, a reasonable mouth-of-mine value for Kittitas County bituminous coal is $6.50 per ton. Carload-lot freight to the Puget Sound area is $2.80 a ton. This gives a delivered price alongside a fuel-burning plant, located on Puget Sound, of $9.30 per ton.

A somewhat lower price can be used for Lewis and Thurston County subbituminous coal. An average mouth-of-mine value for this coal is $5.00 a ton, and the freight to the Sound is about $1.70, making a total cost of $6.70 per ton delivered alongside a fuel-burning plant on Puget Sound.

A discussion with men in the industry indicates that subbituminous coal in a mechanized mine operating continuously could be produced for $3.50

per ton at the mouth of the mine. This would reduce the cost of this coal alongside a plant on Puget Sound to $5.20 per ton.

The cost of a good grade of Utah bituminous coal, delivered in the Puget Sound area, in recent months has been $10.85 a ton. It would seem reasonable to use this figure as representing the cost of Utah coal. The Utah coal is a good grade of bituminous coal, with low moisture content and relatively high heat value.

It is usual to design a fuel-burning electric-generating plant so that the various fuels available in the area can be burned interchangeably. In this region a plant should be designed with the setting sufficiently high to permit the handling of ashes. Burners should be provided suitable for powdered coal, oil, or natural gas. The site for such a plant should be so chosen as to be convenient for tanker shipment of oil, and barge or rail shipment of coal. Of course, location relative to a supply of good condensing water and location with respect to centers of load are also prime considerations.

A summary of the cost of fuels available for steam-electric generating plant use is given in table XII. Costs are given in dollars per unit of fuel and in cents per million B.t.u., as received, and as fired.

Referring to table XII, fuel oil at 26.8 cents per million B.t.u., as fired, is the lowest cost fuel available for a steam-electric generating plant in the area at the present time. Oil is easy to store, and plant operation on fuel oil does not have the problem of ash handling and disposal. For the purpose of comparison of fuel-burning generating plants with hydroelectric generating plants, fuel oil will be assumed to be the fuel burned.

Table XIII is a tabulation of fuel costs in steam-electric generating stations in other parts of the United States. The data are for the year 1947. The fuel cost as listed in table XIII for nine of the stations is materially

TABLE XII

SUMMARY OF FUEL COSTS

Type of fuel	Unit	Cost per unit (dollars)	Cost per million B.t.u. (cents) As rec'd	Cost per million B.t.u. (cents) As fired
Fuel oil	Bbl.	$ 1.60	25.5	26.8
Bituminous coal:				
Utah	Ton	10.85	41.2	45.4
Washington	Ton	9.30	35.2	38.8
Utah (in Salt Lake City)	Ton	6.23	24.6	26.0
Subbituminous coal:				
Intermittent operation	Ton	6.70	40.0	44.0
Base-load operation	Ton	5.20	31.0	34.10

TABLE XIII

COST OF FUEL AS FIRED IN STEAM-ELECTRIC GENERATING STATIONS IN OTHER PARTS OF THE UNITED STATES

State	Company	Name of plant	1947 data cost per million B.t.u (cents)	Type of fuel
Alabama	Alabama Power Co.	Gorgas No. 2	20.42	Coal
California	San Diego Gas & Electric Co.	Silver Gate	28.50	Oil
Florida	Florida P. & L. Co.	Lauderdale	32.0	Oil
Georgia	Georgia Power Co.	Arkwright	15.8	Gas
Illinois	Commonwealth Edison Co.	Powerton	17.05	Coal
Maryland	Con. Gas & Elec. of Baltimore	Riverside	27.49	Coal
Massachusetts	Boston Edison Co.	Mystic	33.05	Coal
Michigan	Detroit Edison Co.	Trenton Channel	27.80	Coal
New Jersey	Pub. Serv. Elec. & Gas	Essex	31.90	Coal
New York	Con. Edison Co. of N. Y.	Hell Gate	30.05	Coal
North Carolina	Duke Power Co.	Riverbend	28.75	Coal
Ohio	Ohio Power Co.	Tidd	11.22	Coal
Oklahoma	Oklahoma Gas & Elec. Co.	Arthur S. Huey	8.59	Gas
Pennsylvania	Philadelphia Elec. Co.	Richmond	27.8	Coal
Rhode Island	Narragansett Elec. Co.	South Street	32.55	Coal
Texas	Dallas Power & Light Co.	Dallas	7.8	Gas
Washington	Puget Sound P. & L. Co.	Shuffleton	26.3	Oil

greater than the present cost of oil in the Puget Sound area. In 1947 only four plants in table XIII had fuel costs less than the Shuffleton (Tacoma, Washington) steam plant.

It would seem that the reason hydroelectric power is being developed in the Pacific Northwest to the exclusion of steam-electric generating plants is that water power is cheaper than steam in this area, rather than that the cost of fuel for steam-plant operation is excessive. This is particularly true in view of the distribution of cost in Federal multiple-purpose hydroelectric projects in this area.

VIII. THE COST AND OPERATING CHARACTERISTICS OF FUEL-BURNING ELECTRIC-GENERATING PLANTS

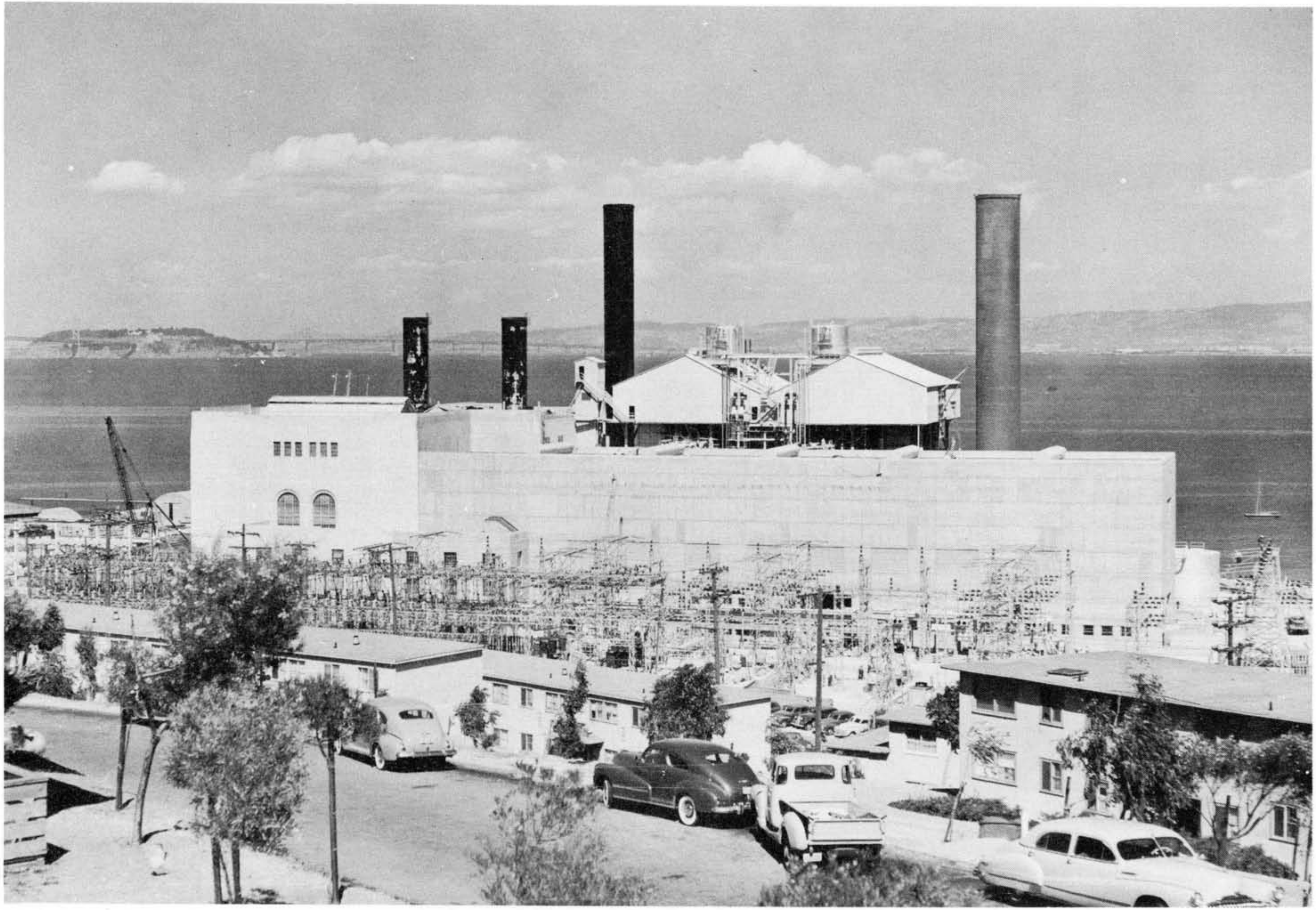
THE MODERN STEAM PLANT

As the prime purpose of this report is to discuss the role of modern steam-electric generating plants in the program of development of the electric-power resources of the Pacific Northwest, it seems important to describe such a plant in detail. The cost of equipment, labor, and fuel have all increased rapidly in recent years. Modern design has taken these factors into consideration, and the result is a highly efficient fuel-burning and electric-generating combination requiring a minimum of maintenance and operating labor.

In many of the modern plants constructed since the last war, equipment has been grouped so that the entire operation from fuel to outgoing electric energy is under the control of one operator at one point in the plant. The usual design is to group two large boilers and a large turbine together with necessary auxiliaries and controls to constitute approximately 100,000 kilowatts of plant capacity. As the plant is expanded, a second unit of the same size is added and the controls so located that one operator can still supervise the entire operation.

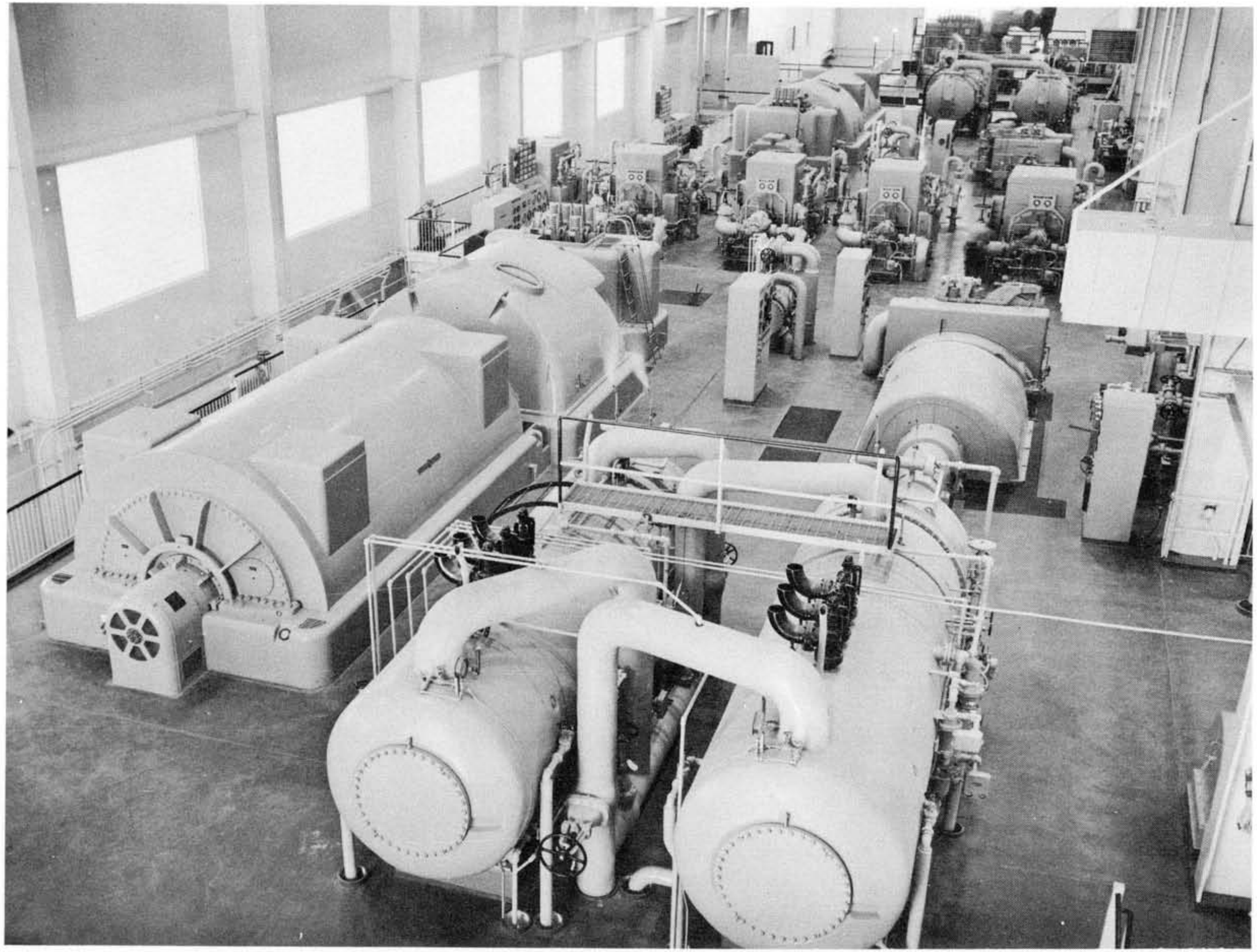
Figure XVII is an exterior view of one of the newest plants of the Pacific Gas and Electric Company. This plant, known as Station "P", is located on San Francisco Bay, a short distance south of East Bay Bridge. Figure XVII-A is a view of the turbine room of this station. One of the 100,000-kilowatt turbine-generator units is located in the left front. The second unit is in the back of the picture. Also located in the turbine room are the house turbines, boiler feed pump, and other station auxiliaries.

Figure XVIII shows a cross section through this plant. Two boilers are shown on the right-hand side of this section. The turbine is shown on the



Exterior view of Station "P" of Pacific Gas and Electric Co.,
San Francisco, California

FIG. XVII

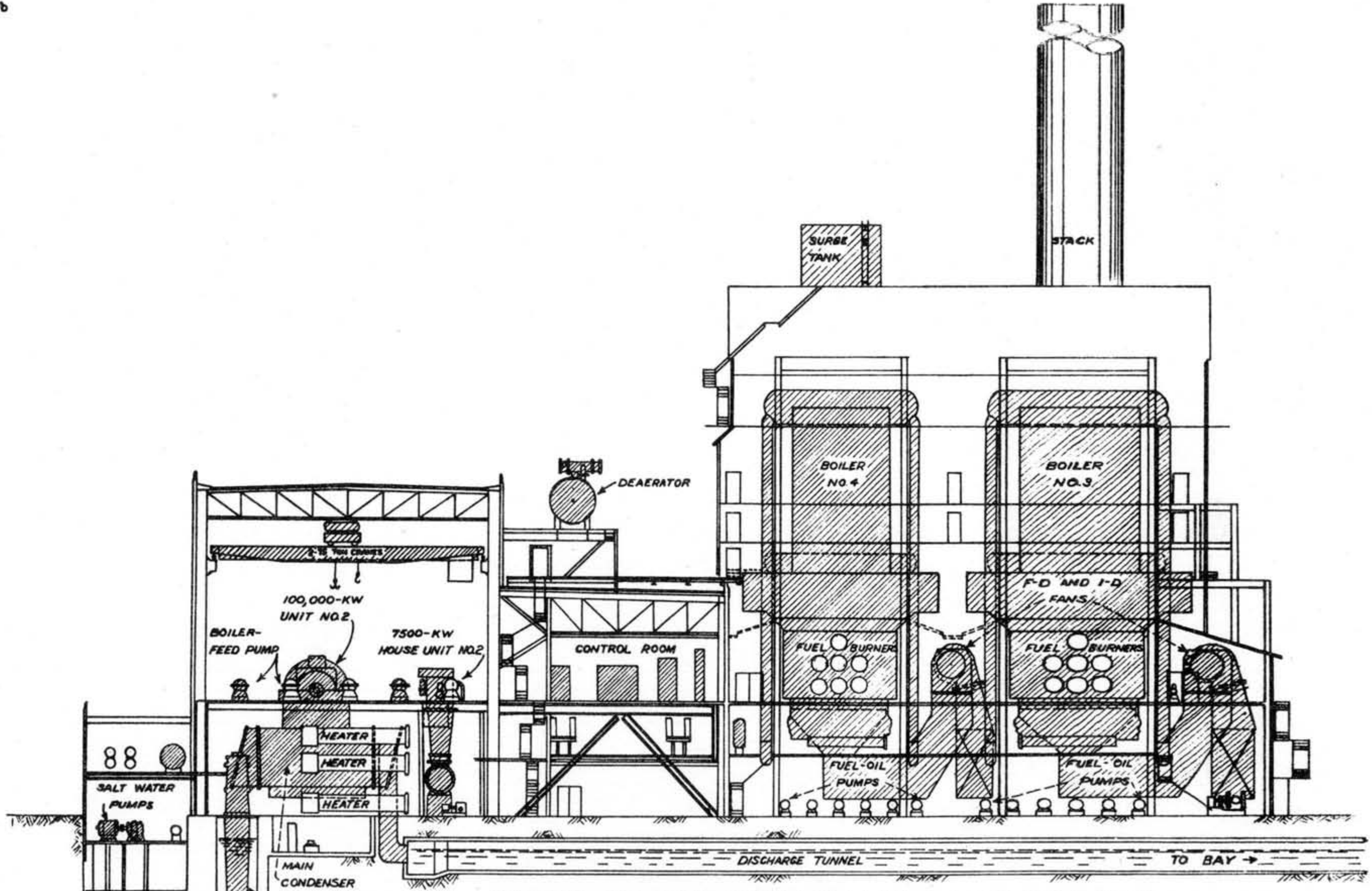


Interior of turbine room of Station "P".

Two 100,000-kilowatt turbine-generator units are adjacent to the left wall. Two house turbines are adjacent to the right wall. Evaporator condensers, boiler feed pumps and other station auxiliaries are also located in the turbine room.

FIG. XVII-A

3259b



CROSS SECTION VIEW OF NEW STATION "P"

PACIFIC GAS AND ELECTRIC CO. - SAN FRANCISCO, CALIFORNIA

NOTE:

ARRANGEMENT OF TURBO-GENERATORS, BOILERS AND AUXILIARY EQUIPMENT WITH RESPECT TO CONTROL ROOM

HLS 4-26-49

FIG. XVIII

left-hand side. The control room is located between the boiler house and turbine room. Steam passes from the boilers through the main steam headers to the turbine unit. Cooling water flows through water tunnels from the bay and enters the plant as shown in the lower left-hand corner. The main circulating pumps circulate the salt water for cooling purposes through the surface condensers attached to the under side of the turbine unit. From the condenser the circulating water passes through a discharge tunnel and back to the bay.

Figure XIX shows a cross section through one of the boilers in Station "P". Referring to figure XIX, natural gas and fuel oil enter the boiler on the left at the point marked "burners." To support combustion, a large quantity of preheated air is required. Air enters the boiler through the air heater located on the right-hand side of figure XIX, passes up through the tubes of the air heater and through ducts to the burners where it is mixed with fuel as it enters the combustion chamber. The primary combustion occurs in the combustion chamber of the boiler, surrounded on all sides by water walls. These water walls consist of a large number of tubes installed adjacent to one another to completely cover the area of the walls of the combustion chamber.

The products of combustion pass upward through the super-heater and economizer sections and then down through the air heater to the stack. Water enters the boiler at the main drum and is changed to steam as it circulates through the many tubes in the boiler. Saturated steam collects in the top of the main steam drum. The steam flows from the steam drum through the superheater tubes and then through the main steam headers to the turbine.

Figure XX is a photograph of an artist's sketch of a longitudinal section through a modern steam turbine. This section is of a General Electric Company 100,000-kilowatt tandem-compound steam turbine similar to those installed in Station "P".

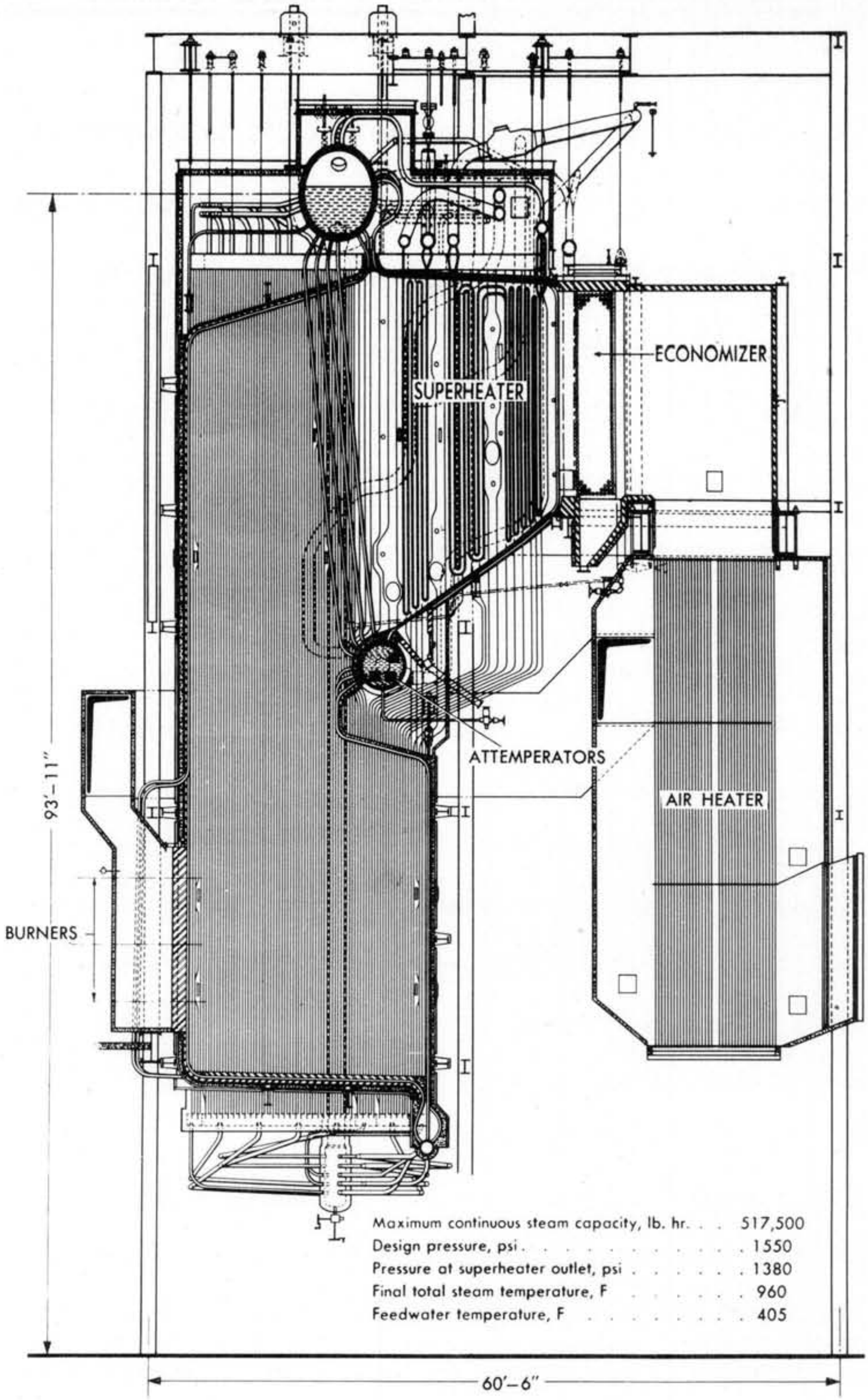
There is no piece of equipment in the electric industry which has had greater advance in design in recent years than the steam turbine-generator unit. As late as 1922 only the smaller turbine-generator units revolved at a speed of 3,600 revolutions per minute. The largest unit of this rotational velocity in 1922 was a 7,500-kilowatt unit. Improvement in the strength of materials, increase in throttle pressures, and development of the tandem-compound unit, with dual passages of low-pressure steam to the surface condenser, have all contributed their part to the increase in capacity of the 3,600-r.p.m. turbine unit. Similar increases in the capacity of the generators have been accomplished by the improvement in metals, the design of the rotating fields, and the application of hydrogen gas to the cooling of the units.

Paralleling the advancements in the design of the principal units have been improvements in auxiliary equipment, instrumentation of process, and development in combustion control. When we speak of a modern steam plant, we mean this assembly of modern equipment capable of producing large blocks of relatively low-cost electric energy.

PLANT INVESTMENT

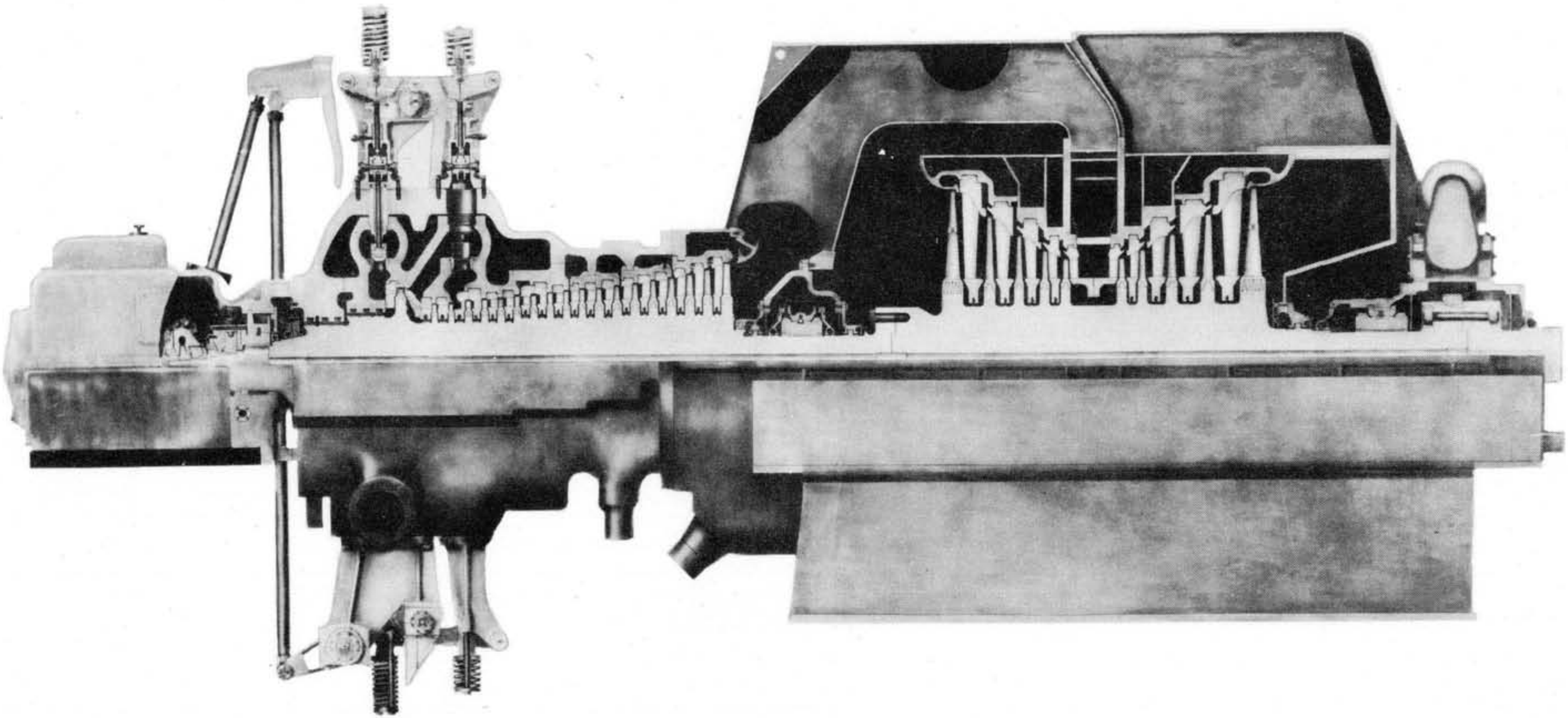
The "Statistical bulletin of the Edison Electric Institute for the year 1948" shows that approximately 71 percent of the total electric energy generated in the United States in the year 1948 was generated by fuel-burning plants. It is reasonable to assume that the reason for generating 71 percent of the energy by fuel-burning plants is that it is cheaper. In a sense, this figure of 71 percent summarizes the decisions of those in charge of the construction programs of all the power companies in the United States.

The choice between steam-electric and hydroelectric generation is not static. On existing systems a new plant is designed to fill a particular requirement of serving the increasing demands of a system. The choice must be



Cross section through a Babcock and Wilcox radiant-type boiler. Four of these boilers are installed in Station "P".

FIG. XIX



Photograph of an artist's sketch of a longitudinal section through a General Electric Company 100,000-kilowatt, 3,600 r.p.m., tandem-compound steam turbine.

Note the two passages for low pressure steam to the condensers. Units are now being built with four such passages.

FIG. XX

based on which type of generation can be added to the existing resources of the system to give the minimum production cost.

Theoretically, the minimum cost of operating a steam plant is obtained when the fixed costs and variable costs are equal. Such a condition can only be approached in actual operation because of the many variables entering into steam-plant operation. The annual load factor changes during the life of the plant. Fuel costs may increase or decrease. Bond interest and the cost of risk money vary. Construction costs of a plant vary with labor conditions, plant location, and variations in equipment cost.

In the early days the construction cost of steam-electric generating plants was relatively high. Small boilers were used to generate steam to operate Corliss steam engines which were used as the prime movers to drive electric generators. With the advancement of the engineering practice, plant costs decreased rapidly. There was a corresponding increase in the efficiency of plant operation. Tending to offset and erase these gains were increasing costs of labor and material entering into the completed plant. A survey of plant costs since 1900 shows costs as low as \$50.00 per kilowatt of plant capacity, and as high as \$250.00 per kilowatt.

The modern steam-electric generating plant consists of one or more groups of equipment, each group complete within itself. Each group consists of fuel storage and handling equipment, boilers, turbine generators, and necessary switching and control. Several of the newer plants constructed within the past two or three years have consisted of two boilers furnishing steam at approximately 1,500 pounds pressure and 950° F. total temperature to a 100,000-kilowatt, 3,600-r.p.m. turbine-generator unit. These major pieces of equipment are housed in modern buildings and supplemented by necessary auxiliaries and controls to produce a highly efficient source of electric power which can be operated and maintained at a minimum cost of labor and materials.

The investment in such a plant at present-day cost levels may vary from $120.00 to $160.00 per kilowatt. Variations in this investment cost will depend upon the type and unit cost of fuel, foundation conditions, and location of the plant with respect to a major metropolitan area. The availability of a good supply of circulating water will also affect the over-all cost. A figure of $150.00 per kilowatt will be used in this report.

FIXED COSTS

Certain of the costs of operating an electric utility have been classified as fixed costs. These include interest, taxes, insurance, and depreciation. The following tabulation lists approximate figures for these four components of fixed costs as they are applied in present-day accounting methods to privately and publicly operated utility systems.

FIXED COSTS OF STEAM-ELECTRIC PLANTS

	Percent of capital investment		Probable future charges
	Public systems	Private systems	
Interest	2.5	6.0	3.0
Taxes (property)	-	2.0	2.0
Insurance	-	1.0	-
Depreciation	2.93	1.82	2.75
Total	5.43	10.82	7.75

The interest component of public-system cost is stated as the cost of the bonds used to finance the project. In the case of the private system, interest includes not only interest on bonds, and dividends on risk capital, but also other costs of financing. A property tax of 2 percent of capital investment includes only the ad valorem tax on system projects. It does not include Federal, state, county, and city taxes other than property tax.

Depreciation has been figured on a 25-year life basis for both systems.

The fact that public systems do not contribute materially to the revenue of Federal, state, county, and municipal governments does not mean that the cost of electric energy will be less to the ultimate consumer; it simply means that additional sources of tax revenue must be found elsewhere to support schools and local governments.

There has been a definite tendency throughout the United States to recognize this factor and to correct it by assessing public systems to increase the revenue of local divisions of government. Since this report looks to the future operation of power systems in the area, a total figure of 7.75 percent has been chosen as realistic for the fixed costs of fuel-burning electric-generating plants.

PRODUCTION EXPENSE

The principal elements of production expense in a steam-electric generating plant are:

1. Fuel
2. Operating labor, supervision, and engineering
3. Operating supplies and expense
4. Maintenance (labor, materials, and expense)

In the modern steam-electric generating station operating at high plant factor, fuel is approximately 75 percent of the total production expense. Labor constitutes about 10 percent of production expense. Most of the remainder of production expense can be considered to be maintenance. This includes the labor of maintenance, together with the repair materials and other miscellaneous expenses relating directly to maintenance.

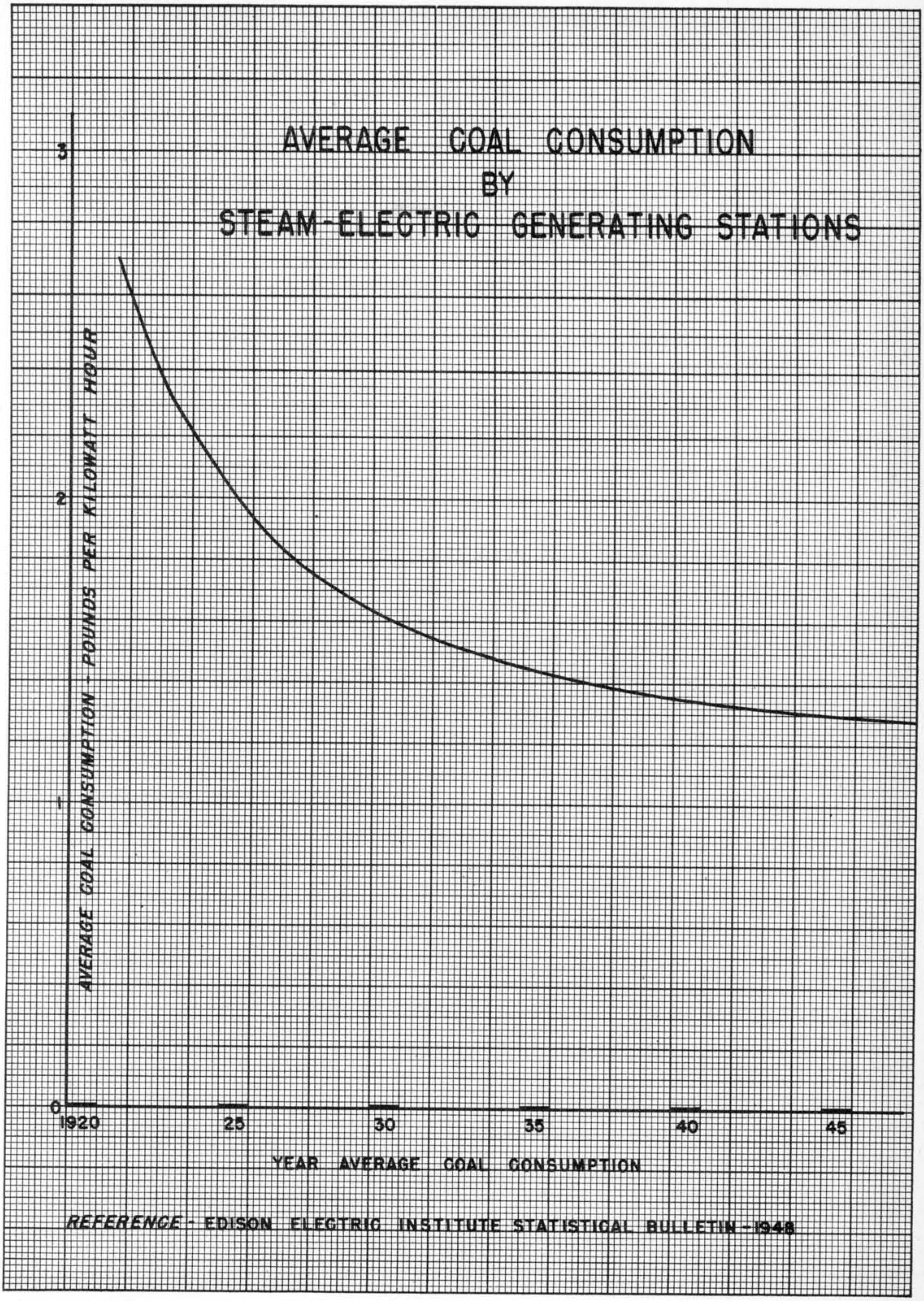
The efficiency of a steam-electric generating plant may be expressed in units of fuel consumed per kilowatt-hour of electric energy generated. If this method is used, the heat value of a unit of fuel must be given. Perhaps the simplest way of expressing the efficiency of a plant is to give the number of heat units (British thermal units) per net kilowatt generated. This is sometimes referred to as the B.t.u. requirement from "as fired" to "send out."

Also important in indicating the probable over-all cost of operation is a statement of the number of men required to operate a plant.

There is a very close relationship between the cost of fuel and proper plant investment. If the fuel cost is low there is little justification for expenditures of money to improve the efficiency of operation of a plant. As the cost of fuel increases there is justification for greater plant investment to obtain higher efficiency of operation.

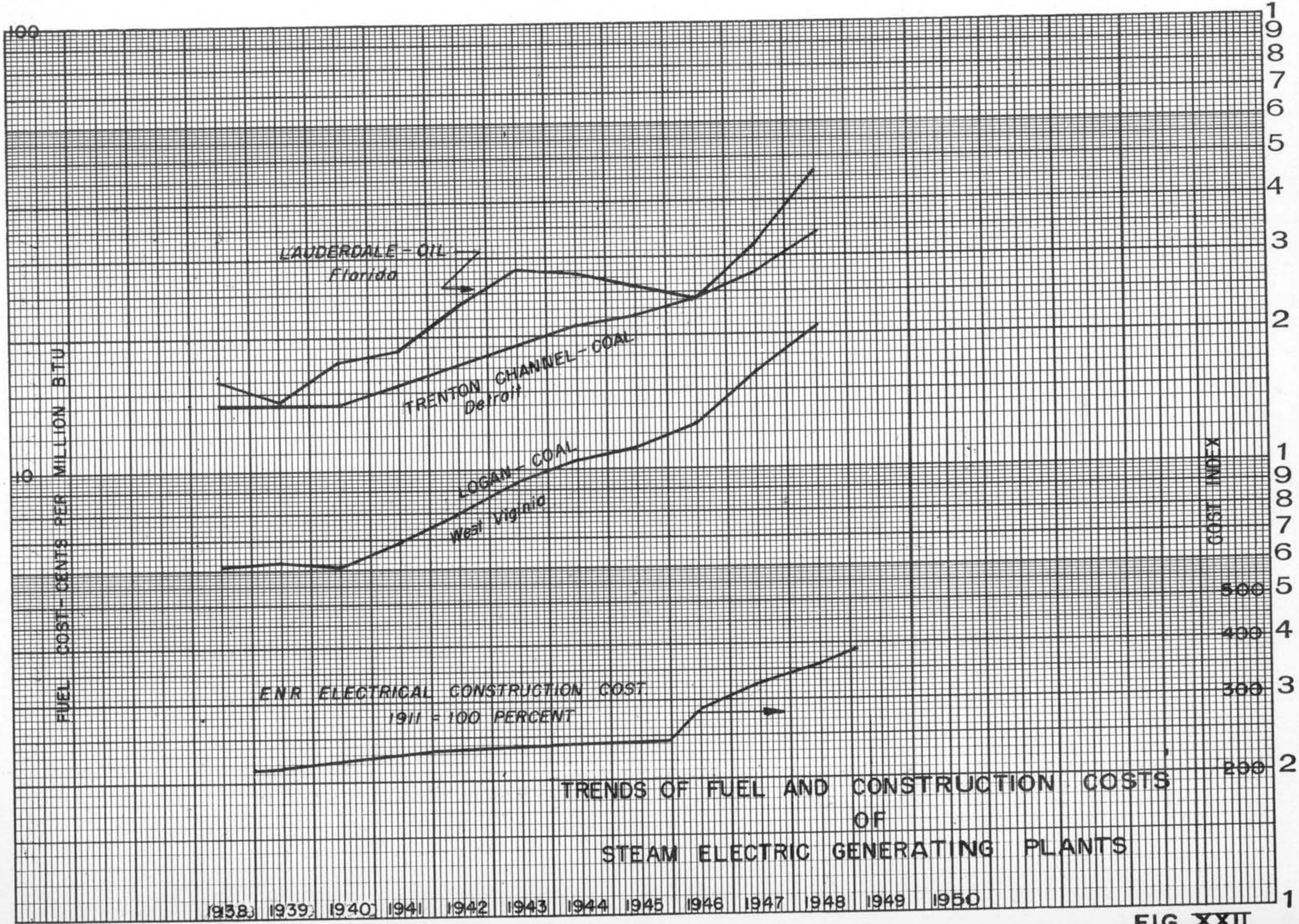
Figure XXI shows graphically the chronological improvement from 1921 to date in the average efficiency of all steam-electric plants dedicated to public use in the United States. This average efficiency is expressed in pounds of coal consumed in the production of a kilowatt-hour of electric energy. This average varies from 2.7 pounds per kilowatt in 1921 to 1.3 pounds in 1948. Because this average efficiency includes a large number of the older plants, it lags considerably behind the operating efficiency of some of the newer plants. Some of our modern plants require less than one pound of coal to produce a kilowatt-hour.

Since the beginning of the second World War there have been rather rapid changes in both construction and operating costs throughout the electrical industry. Figure XXII shows graphically the trend in fuel costs in three typical steam-electric generating plants in the United States. Also included in figure XXII is a curve showing the trend in the Engineering News Record index of electrical construction costs in recent years.



AVERAGE COAL CONSUMPTION
BY
STEAM-ELECTRIC GENERATING STATIONS
AVERAGE COAL CONSUMPTION - POUNDS PER KILOWATT HOUR
3
2
1
0
1920
25
30
35
40
45
YEAR AVERAGE COAL CONSUMPTION
REFERENCE - EDISON ELECTRIC INSTITUTE STATISTICAL BULLETIN - 1948

FIG. XXI



TRENDS OF FUEL AND CONSTRUCTION COSTS
OF
STEAM ELECTRIC GENERATING PLANTS

FIG. XXII

A SUMMARY OF STEAM PLANT COSTS

There are so many variables which may influence materially the cost of steam-plant operation that, no matter what refinements are calculated, it is impossible to more than approximate the total annual cost of operation. Usually, when a new plant is constructed it is more modern than its predecessors. Under these conditions it will be operated on base load, at high plant factor. As the years go by and newer and more efficient plants are constructed to serve the growing load of the system, it is normal to operate the older plants at lower plant factor, giving the base-load assignment to the most modern and efficient plants. Such changes effect fuel economies by reason of standby losses. Units on the line for spinning reserve tend to reduce the over-all fuel economy. For the purpose of this summary such factors have been neglected.

Plant investment is assumed to be $150.00 per kilowatt. Annual fixed costs are taken at 7.75 percent, or $11.62 per kilowatt-year.

Fuel cost is taken at $1.60 per barrel of oil, as received. This is equivalent to 25.5 cents per million B.t.u., as received, or 26.8 cents per million B.t.u., as fired. The over-all efficiency of the steam plant from "as fired" to "send out" is assumed to be 12,000 B.t.u. per kilowatt-hour. On this basis the kilowatt-hour production becomes 83.3 kilowatt-hours per million B.t.u. The fuel cost per kilowatt-hour is 3.22 mills. The following distribution of production expense is assumed at 80 percent plant factor: Fuel, 75 percent; labor, 10 percent; maintenance and supplies, 15 percent. On this basis labor and maintenance expense are 1.08 mills per kilowatt-hour.

Figure XXIII summarizes the fixed and variable costs of operation on the basis of the above assumptions. Total cost is stated in cents per kilowatt-hour as a function of the average monthly hours of operation. This curve assumes equal hours of operation for each month of the year. Two curves are shown on figure XXIII. The upper curve represents the costs as summarized above. The lower curve assumes lower production cost and represents the best operating practice which has been developed by some of our more recent high-pressure plants, similar to the Tidd plant of the Ohio Power Company and Station "P" of the Pacific Gas and Electric Company.

Referring to figure XXIII, if the plant were used for peaking purposes and operated only 100 hours per month or 1,200 hours per year, the cost in the average plant would be 19.2 mills per kilowatt-hour, or 1.92 cents per kilowatt-hour. If operated at 80 percent plant factor or 7,000 hours a year, or 585 hours per month, the cost of the average plant would be 6.3 mills per kilowatt-hour. Similar comparisons could be made with the somewhat more efficient operations of the modern plant.

A TABULATION OF PLANT COSTS

The Federal Power Commission in 1948 published a book entitled "Steam electric plant construction costs and annual production expenses, 1938-1947." The construction and operating costs of some 200 steam-electric generating plants are listed in the publication.

For such plants as the information is available, the Commission has listed, by years, production expense and fuel costs for the period 1938 through 1947. The trends in the cost of operating labor, fuel, and maintenance all showed decided upward trends.

Not much information is available for the newer plants constructed in the postwar period; however, such information as is available indicates a definite trend toward higher pressure steam, larger units, and a reduction in the number of men required to operate and maintain the plants. Table XIV is the tabulation for the Ohio Power Company's Tidd plant at Brilliant, Ohio. This tabulation is similar to the one in the Federal Power Commission's report,

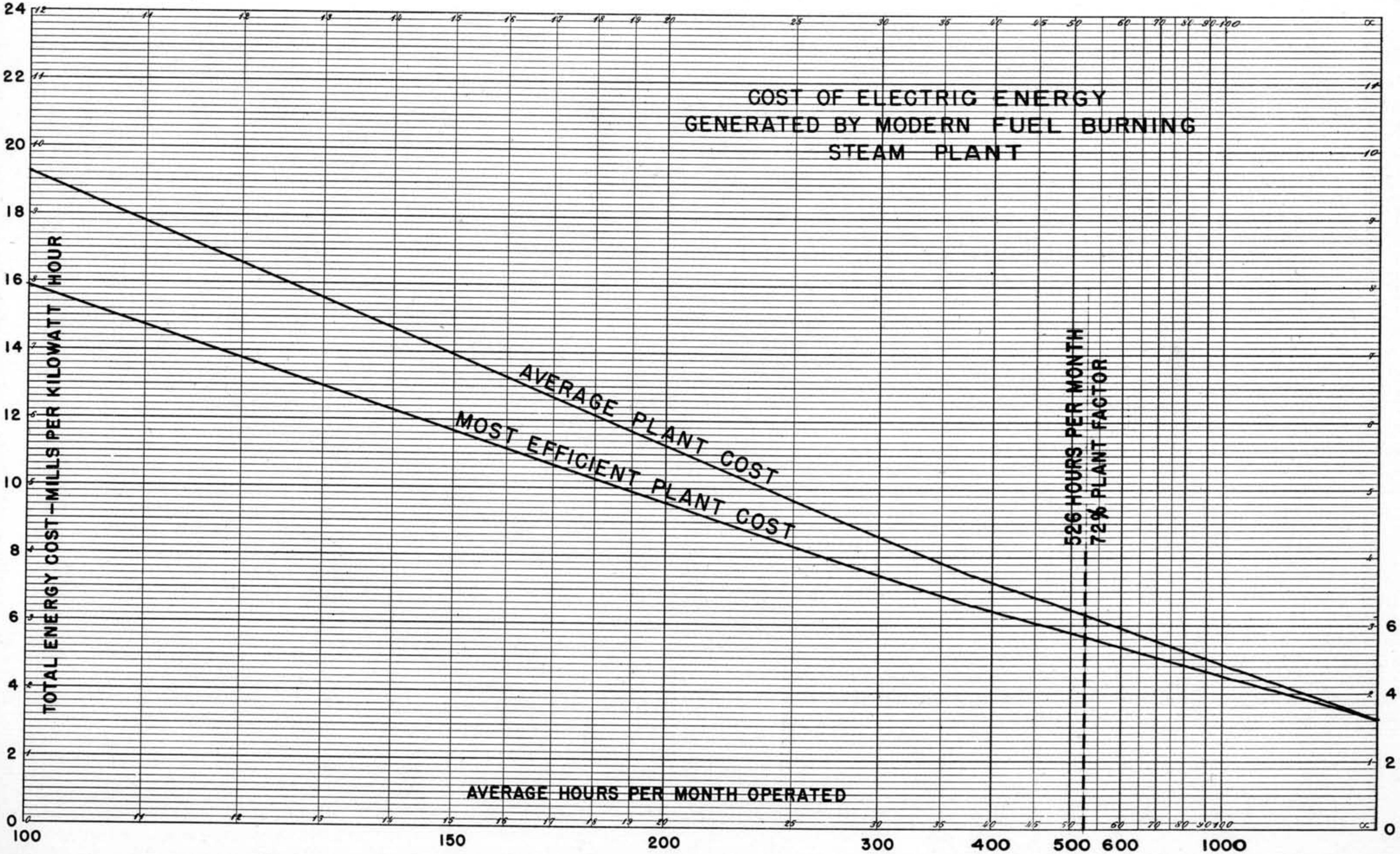

COST OF ELECTRIC ENERGY
GENERATED BY MODERN FUEL BURNING
STEAM PLANT
AVERAGE PLANT COST
MOST EFFICIENT PLANT COST
526 HOURS PER MONTH
72% PLANT FACTOR
TOTAL ENERGY COST-MILLS PER KILOWATT HOUR
AVERAGE HOURS PER MONTH OPERATED
24
22
20
18
16
14
12
10
8
6
4
2
0
100
150
200
300
400
500
600
1000

FIG. XXIII

TABLE XIV

PLANT INVESTMENT AND OPERATING COSTS
OF A MODERN STEAM-ELECTRIC STATION

Name of utility: Tidd Plant (The Ohio Power Company)

Line no.	YEAR 1948		
1	Installed generating capacity, megawatts (nameplate)	200	
2	Net generation, million kilowatt-hours	975	
3	Plant factor, percent	86	
4	Peak demand on plant, megawatts (60 minutes)	221	
5	Plant hours: Connected to load	8,669	
6	hot, not connected to load	11	
7	held in cold reserve	104	
8	COST OF PLANT: (thousands of dollars)		
9	Land and land rights	$ 116	
10	Structures and improvements	4,966	
11	Equipment	15,295	
12	Total cost	$20,377	
13	Cost per kilowatt of installed capacity	$ 101.88	Mills per Kwh
14	PRODUCTION EXPENSES:	$ 1,000	
15	Operation labor, supervision and engineering	$ 196	0.201
16	Water	18	0.018
17	Operation supplies and expenses	36	0.036
18	Maintenance (labor, material, and expenses)	246	0.253
19	Rents	-	-
20	Steam from other sources or steam transferred	-	-
21	Joint expenses	-	-
22	Total, exclusive of fuel	$ 496	0.508
23	Fuel	1,539	1.578
24	Total production expenses	$ 2,035	2.086
25	Production expenses (excluding fuel) per kw	$ 2.48	
26	FUEL USED:	Quantity	Cost
27	Coal, 1,000 tons of 2,000 lbs. and cost per ton	487	$ 3.15
28	B.t.u. per lb. and cost per million B.t.u.	11,405	14¢
29	Oil, 1,000 Bbls. of 42 gal. and cost per bbl.	-	-
30	B.t.u. per gal. and cost per million B.t.u.	-	-
31	Gas, million cu. ft. and cost per 1,000 cu. ft.	-	-
32	B.t.u. per cu. ft. and cost per million B.t.u.	-	-
33			
34			
35	Average B.t.u. per kilowatt-hour net generation	11,375	
36	Average number of employees	98	

but was obtained directly from the American Gas and Electric Corporation, New York City. Referring to table XIV, the first turbine generating unit and the first two boilers of this installation, together with land, structures, and improvements, represent contracts and construction costs of 1943-1945.

Referring to figure XXII, this represents a construction index average of approximately 241. The second turbine-generator unit and two additional boilers were added in 1948. The cost index for this construction is approximately 340.

Referring to table XIV, line 13, the average cost of construction of this plant was $101.88 per kilowatt. If constructed at the present level of cost, this plant would probably cost between $140.00 and $160.00 per kilowatt. The Tidd plant requires only 98 men for operation and maintenance, which is only a small fraction of the number required in some of the older plants. For example, the Philo plant of the same company has 434 men to operate a 415-megawatt plant. This is equivalent to approximately one man per thousand kilowatts of plant capacity for the Philo Plant, as compared with one-half man per thousand kilowatts at the Tidd plant. The original construction at the Philo plant was in 1924 with three additions in later years.

FUEL-BURNING CHARACTERISTICS OF A MODERN BOILER

Previously in this report, under section VII, an analysis was made of the availability of fuels for central-station operation in the Pacific Northwest. The comparison of cost between the several fuels was made on an "as fired" basis. Such a comparison is not entirely accurate because it does not take into consideration the differences in the efficiency of combustion of the fuels.

If this were a specific project study to determine the choice of fuels, it would not only be necessary to determine the relative efficiencies of combustion but also the deterioration in heat value of a fuel while stored, as well as the relative fixed cost and production expense involved in handling the fuel from alongside the plant to the point of firing. The present discussion will be limited to the differences in efficiency of combustion of the several fuels.

Table XV is a comparison of the heat losses in a boiler burning the several fuels considered in this report. For the purpose of the comparison it is assumed that these fuels are burned in a modern steam boiler designed with a maximum 24-hour rating of 650,000 pounds of steam per hour and operated at 500,000 pounds per hour. It is further assumed that these boilers are equipped with the necessary combustion control to give the maximum efficiency commensurate with normal industrial operation of the unit.

Referring to table XV, column 1 shows the estimated losses for a boiler operating with a good grade of bituminous coal with moisture not exceeding 3.7 percent. The total heat loss in this operation is estimated to be 12.8 percent. This is equivalent to a boiler efficiency of 87.2 percent.

The calculations in column 2 are for a local subbituminous coal with the following proximate analysis:

Moisture	26.8 %
Volatile matter	33.6
Fixed carbon	32.9
Ash	6.7
Total	100.0 %

It will be noted that this coal has relatively high moisture and volatile matter. The presence of moisture in the fuel increases the stack losses by the amount of heat energy required to evaporate the moisture. It is necessary to maintain a minimum flue-gas temperature of about 250° F. at the point where the flue gases leave the air heater. This is necessary to prevent a possible deposit of sulphuric acid on the walls of the air-heater tubes, or in the breaching between the air heater and the stack. If the temperature of the flue gas is allowed to drop below the dew point, deposits of moisture

TABLE XV

RELATIVE EFFICIENCY OF COMBUSTION OF FUELS

Heat losses	Good grade bituminous coal (1)	Sub-bituminous coal (2)	Oil (3)	Natural gas (4)
Dry gas	5.7%	6.6%	4.3%	4.4%
H_2 and H_2O in fuel	3.8	9.9	5.8	10.5
Moisture in air	0.2	0.2	0.1	0.1
Unburned combustible	1.2	1.5	-	-
Radiation	0.4	0.4	0.4	0.4
Unaccounted-for loss	1.5	1.5	1.5	1.5
Total loss	12.8%	20.1%	12.1%	16.9%
Unit efficiency	87.2%	79.9%	87.9%	83.1%

and acid will occur.

There are two ways in which flue gas may acquire an excessive burden of water vapor. Perhaps the easiest to understand is the case in which there are large amounts of water present in the unburned fuel. A second source of water vapor in the flue gas is the combustion of the fuel to form water. This is particularly true in the case of the burning of natural gas which contains large quantities of methane (CH_4) and hydrogen (H_2). In burning, methane and hydrogen combine with oxygen in the process of combustion to form water vapor. Each pound of water vapor passing up the stack carries with it 970 B.t.u. of heat plus some additional heat to superheat the moisture in the flue gas.

Table XVI shows the cost of fuel in cents per million B.t.u. of heat, both "as fired" and "as steam." The "as fired" cost is taken directly from table XII. The fuel costs in steam as shown in column 2 of table XVI are those of column 1 adjusted for the efficiency of combustion shown in table XV. It will be noted that oil, with its relatively high efficiency of combustion, has an even greater advantage over coal in the form of steam.

TABLE XVI

THE COST OF FUELS AS STEAM

Type of fuel	Cost per million B.t.u. (cents) As fired (1)	As steam (2)
Fuel oil	26.8	30.5
Bituminous coal:		
Utah	45.4	52.0
Washington	38.8	44.5
Utah (burned in Salt Lake City)	26.0	29.8
Subbituminous:		
Intermittent operation	44.0	55.0
Base-load operation	34.10	42.7

IX. THE ECONOMICS OF THE COMBINED OPERATION OF WATER-POWER AND STEAM PLANTS

A GENERAL COMPARISON OF WATER-POWER AND STEAM-POWER PROJECTS

Section VII of this report described the characteristics and availability of fuels for steam-electric generating plants in the Pacific Northwest. Section VIII discusses the economics of fuel-burning electric-generating stations. The results of this latter section are summarized on figure XXIII and indicate that, for an annual load factor of approximately 72 percent, the cost of electric energy generated from the fuel-burning electric-generating plants would cost about 6.0 mills per kilowatt-hour. Figure XXIII is plotted on average hours a month. A 72 percent load factor is equivalent to an average operation of 526 hours per month.

The cost of the present program for development of water power in the Pacific Northwest is discussed in section VI. The figures show that, if all the costs of this program are charged to power, power delivered to the load centers west of the Cascade Mountains will cost approximately 6.0 mills per kilowatt-hour, on the basis of the program set up in Phase C-2 of the Army Engineers' Review 308 Report. In short, if all the costs of the development of water power on the Columbia River are charged to power, the cost will be about the same for water power as for steam. In section VI, under the subheading "Coordination of present resources and Phase C-2," it is shown that the resources included in the Phase C-2 program will be required not later than 1965 if the secular trend of load growth continues at the present rate.

Viewed from the standpoint of collateral benefits accruing to the Pacific Northwest, if the costs are as shown one must certainly choose the program for development of the water-power resources as set forth in the Army

Engineers' report. The present study is concerned with the relative cost of electric energy generated by steam-electric and hydroelectric plants, hence no allocation has been made of hydroelectric plant costs as between power, irrigation, navigation, and flood control. It is enough to point out that the collateral benefits dictate the necessity of carrying out the development of water power on the Columbia before consideration can be given to any large program of development of steam-power projects for base-load operation in the Pacific Northwest. This last statement, however, does not mean that there is not a place in the immediate program for a limited amount of modern steam-generated electric energy to supplement the output of the water-power projects. However, before even additional supplemental steam can be considered, a method must be found of distributing the cost of the project so that this burden does not fall on one system or one group of customers.

COORDINATED OPERATION OF STEAM AND HYDRO PROJECTS

The water year of the Northwest Power Pool is from July 1 to the following June 30. This period was chosen because of the nature of the flow of the principal rivers in this area. Spring rains and water from the melting of snow normally fill all the storage reservoirs by July 1. The nature of the flow of the Columbia River in an average water year is shown in figure XII. Referring to figure XII, the months of January, February, and occasionally March, are periods of relatively low flow. This is also true of the months of October, November, and December. By April, thawing has begun in the river basins in the upper reaches of the principal streams, and increased flows of the rivers may be expected until the greater part of the snow and ice deposited in the winter months is melted. By August, on most rivers in this area, this flood flow has largely disappeared. On the main stem of the Columbia and the Kootenai, with drainage basins far to the north, this flood flow continues into

October. Figure XXIV shows graphically the distribution of flood flow on several important streams of the Northwest.

In discussing the cost of power, hydro power is known as power with a zero increment cost. The total cost of hydro power is independent of the amount of energy produced by the plant. Nearly all the costs are continuing costs and independent of station load.

Steam plants are said to have a fuel increment. A steam plant has continuing costs by reason of the investment, and where labor is held for continuous operation, the labor costs, as well as maintenance, can be considered as continuing costs. However, each time a steam plant is operated, a certain amount of fuel in the form of coal, oil, or natural gas is consumed. As shown in section VII, under the subheading "A summary of steam plant costs," the fuel increment of a modern steam plant burning fuel oil costing $1.60 as received is 3.22 mills per kilowatt-hour. It is obvious that zero increment hydro power will always be used, if available, before starting up a steam plant. The only exception to this rule is where the hydro power would be generated by draft from storage and the storage held for operation later in the current operating year.

With the more complete development of the Columbia River and tributaries and the addition of upstream storage to reduce the maximum floods on the rivers, it is doubtful if steam plants will be operated during the period of flood flow.

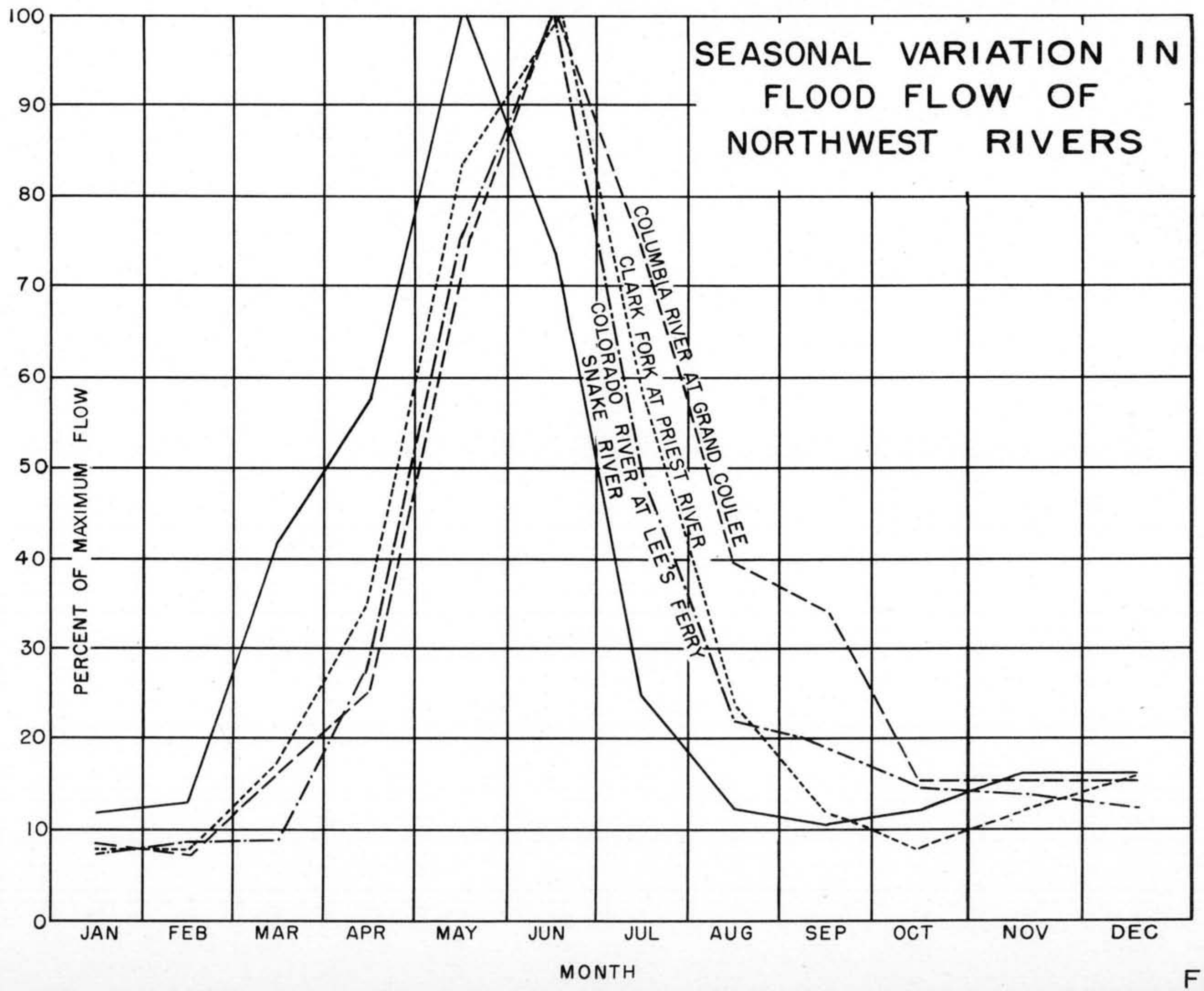
The flow of the stream during the flood season will be sufficient to serve the entire electric load requirement of the area and to fill all storage reservoirs. With flood flow into October, all storage reservoirs should be full as of the first of October.

The power supply from October 1 through March will depend upon the combination of power generated from the natural flow of the stream plus power generated from draft on storage. Figure XXV shows a plot of the mean and critical annual flows of the Columbia River at Grand Coulee. The difference in this natural flow is approximately 19,000 cubic feet per second. The natural flows from year to year will vary from the critical flow, as shown, to a maximum flow about the same distance above the mean flow as the critical flow is below mean flow. The modified-critical flow is the flow about halfway between mean flow and critical flow. As previously mentioned, critical flows can be expected about once in 20 years. Modified-critical flows can be expected about once in 4 years.

The difference between critical and mean flow, as shown on figure XXV, averages about 19,000 cubic feet per second throughout the controlled flow period. Assuming this flow to pass through all plants from the Grand Coulee project to the sea, this flow is equivalent to 1.5 million kilowatts, about 750,000 kilowatts of which would be between critical flow and modified-critical flow, and about 750,000 kilowatts between modified-critical and mean flow.

The electric deficiency resulting from low natural stream flows of the rivers on which hydroelectric plants are located in this area is an energy deficiency. To adjust for this deficiency, either the supply of available energy must be increased or the energy requirements of system load must be decreased. System energy can be increased by (1) additional upstream storage used only to supplement the natural stream flow during critical water years, (2) generation of electric energy in steam-electric plants.

The energy requirements of the system can be decreased by curtailing electric energy usage. This can be accomplished by the exercise of the provisions of interruptible power contracts. Under more severe energy deficiency it becomes necessary to resort to power-curtailment programs, in which all power customers must be requested to conserve electric energy.



SEASONAL VARIATION IN FLOOD FLOW OF NORTHWEST RIVERS
COLUMBIA RIVER AT GRAND COULEE
CLARK FORK AT PRIEST RIVER
COLORADO RIVER AT LEE'S FERRY
SNAKE RIVER
PERCENT OF MAXIMUM FLOW
100
90
80
70
60
50
40
30
20
10
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
MONTH

FIG. XXIV

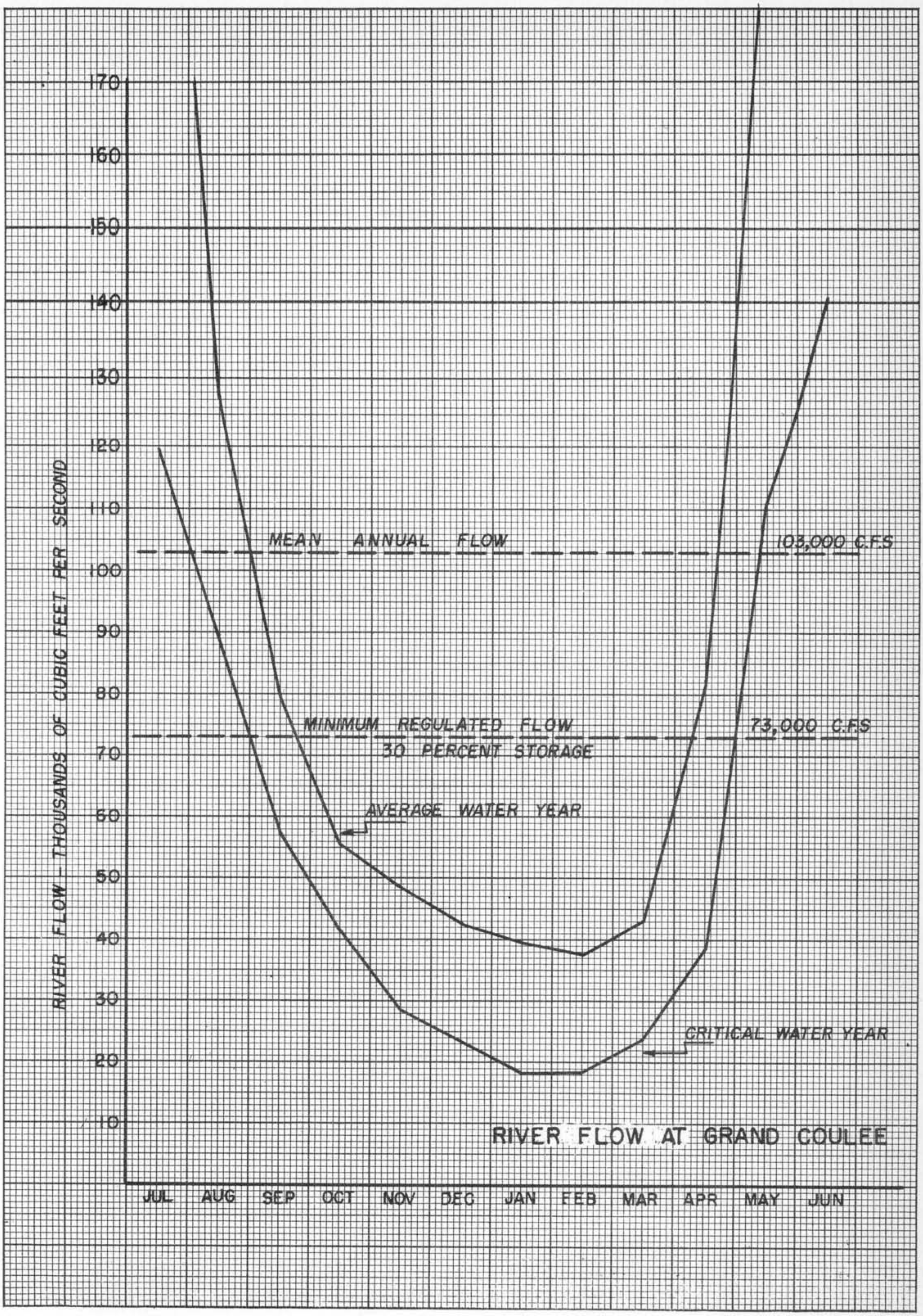

RIVER FLOW - THOUSANDS OF CUBIC FEET PER SECOND
170
160
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
JUL
AUG
SEP
OCT
NOV
DEC
JAN
FEB
MAR
APR
MAY
JUN
MEAN ANNUAL FLOW
103,000 C.F.S
MINIMUM REGULATED FLOW
30 PERCENT STORAGE
73,000 C.F.S
AVERAGE WATER YEAR
CRITICAL WATER YEAR
RIVER FLOW AT GRAND COULEE

FIG. XXV

Numerous upstream storage projects in addition to those included in Phase C-2 on tributaries of the Columbia River have been studied by the Army Engineers. Several of these projects show considerable promise. The choice between steam-electric plants and such projects must be made by comparison of the total annual cost of such projects with the total annual cost of a steam-electric generating station. Storage, when operated to supplement critical stream flows, would be kept at maximum storage level, except where the storage was also used for flood control. If used for flood control, the amount of draw-down of the storage each year would be dictated by the findings of the annual snow survey for the particular drainage basin.

Operating experience of electric power systems has shown that there are definite advantages in having a certain amount of steam-electric generation even though the major portion of the power requirements of the system are produced by water-power plants. At the present time, on the system of the Northwest Power Pool approximately 9 percent of the installed capacity is driven by steam prime movers. The present steam-electric generating resources in this area are about 375,000 kilowatts. This is equivalent to about 25 percent of the difference in average energy produced from the natural flow of the rivers for average and critical-flow conditions. Here in the Pacific Northwest it is difficult to find necessary capital to build steam-electric generating plants in competition with the multi-purpose projects of the Federal Government. If means could be found to distribute the cost of the steam-electric generation over the entire energy consumption of the area, it might be possible to introduce some steam generation as insurance against critical water conditions.

The use of interruptible power contracts is not always as simple as it might appear. In practically all instances the exercise of the interruptible feature of the contract means idleness to labor. If the customer is to receive power under an interruptible contract at the same time that all steam-electric generation is in full operation to produce additional energy, this creates a hardship for the owners of the steam-electric generating plants. In this particular area the existence of a large block of interruptible power contracts makes it very difficult to determine the hours of operation which would be required of any additional steam-electric generating projects. It should be possible to eliminate, in part at least, the effect of interruptible power contracts by inserting a clause in the contracts requiring the customer to pay an increased rate for power if supplied during the period in which steam-electric generating plants are operated.

COMPARISON OF COST BY TYPES OF LOAD

The characteristics of the daily load curve of an electric-power system were discussed in section III, under the subheading "The characteristics of electric loads." It was pointed out that the energy requirements of a load curve may be divided into the following classifications: base load, daytime energy, peaking energy. In addition, there is the capacity required for system standby reserve. In the following paragraphs a comparison will be made between the cost of capacity and electric energy in hydro and steam projects when assigned to serve the portion of the load curve represented by each of the above classifications.

Base-load units are required to operate continuously. In a hydro project this means that there must be water available 100 percent of the time for the operation of a base-load unit. The following tabulation lists the fixed costs and operating expenses of certain projects previously described in the report. The costs are expressed in mills per kilowatt-hour for energy delivered to the principal load centers west of the Cascade Mountains.

Project	Annual fixed cost	Transmission cost	Production expense Fuel	Production expense Other	Total
Steam	1.33	0.0	3.22	0.86	5.41
Chief Joseph (Present storage)	2.42	1.0		0.34	3.76
John Day (Phase C-2)	4.6	1.0		0.66	6.26

Referring to the tabulation for base-load steam operation, the fixed cost of 1.33 mills per kilowatt-hour represents an investment of $150.00 per kilowatt, with annual fixed costs of 7.75 percent distributed over 8,760 kilowatt-hours. The fuel and other production expenses are described in detail in section VIII and summarized on figure XXIII.

The cost for base-load operation of the Chief Joseph project is based on the present regulated stream flow of the river. Project cost is $302.00 per kilowatt of nominal prime capability. The fixed costs are taken as 6.34 percent, and production expense as 1 percent of investment. Transmission to the principal load centers is figured as 2 mills per kilowatt-hour at 50 percent load factor or 1 mill per kilowatt-hour at 100 percent load factor. An allowance of 10 percent is made for losses to load center.

The John Day project is figured on the basis of stream flow corresponding to the completion of Phase C-2. The investment is $575.00 per kilowatt of nominal prime capability, or 4.6 mills per kilowatt-hour. The average cost of transmission of 1 mill per kilowatt-hour is also used for 100 percent load factor operation of this project.

Referring to the above tabulation, the total cost of operation of the Chief Joseph project is less than either a steam plant or the John Day project. This is to be expected, as the Chief Joseph project, with a design head of 168 feet, is one of the finest hydroelectric sites in the Pacific Northwest. It is interesting to note the magnitude of the transmission cost as compared with the project cost. This is one of the factors that plays heavily in the favor of steam after the better hydro projects are in service and new projects must be found to carry the increasing load of the area.

The second classification of load listed above was daytime energy. This represents a load for about 16 hours a day, 5 days a week. This is approximately a 50 percent load-factor operation. The following tabulation lists the estimated costs of operation of the same projects over 50 percent load-factor conditions:

Project	Annual fixed cost	Transmission cost	Production expense Fuel	Production expense Other	Total
Steam	2.66	0.0	3.22	1.72	7.60
Chief Joseph (Present storage)	3.04	2.0		0.42	5.42
John Day (Phase C-2)	5.15	2.0		0.74	7.89

Referring to the cost of steam-plant operation at 50 percent load factor, it will be noted that the fixed costs are doubled per kilowatt-hour of energy produced. The fuel cost has remained the same. This is not strictly accurate, as there are greater standby and "peaking prepared for" losses under lower load-factor operations.

Referring to the 50 percent load-factor operation tabulation, the Chief Joseph project is still the most economical operation of the three examples shown. It will be noted that the fixed cost of this project is estimated to be only slightly over the fixed cost of the base-load operation.

The reason for this is that, under 50 percent load-factor operating conditions, the water which would go through one unit under 100 percent load-factor operation would be distributed between two units under 50 percent load-factor operation. The incremental cost of additional units at the project in excess of the number required to pass the prime flow of the river is approximately \$72.00 per kilowatt, even at the present-day price levels. This incremental cost is taken directly from the Review 308 Report.

In determining the hydro plant investment for 50 percent load-factor operation, it has been assumed that the cost of one base-load unit and one unit operating above prime flow of the river have been averaged as the per-kilowatt cost for 50 percent load operation. In short, one unit at \$302.00 per kilowatt and one unit at \$72.00 per kilowatt give an average plant investment of \$187.00 per kilowatt for 50 percent load-factor operation. Transmission costs are doubled to allow for the additional transmission and substation equipment required for 50 percent load-factor operation, particularly since the operation is for daytime energy and is continuous for the 16-hour period.

Similar calculations were made in determining the operations of the John Day project.

The determination of the cost of peaking resources cannot be made with the same degree of accuracy as may be used in determining the cost of resources for higher load-factor operation. Steam-plant investment for peaking operation remains about constant, even though the hours of operation decrease materially. Where operation of the plant is only for 2 or 3 months at time of system peak, there is the problem of how to handle seasonal labor. Standby and "peak prepared for" fuel costs become an appreciable proportion of total fuel cost.

Similar approximations must be made in determining the cost of hydro resources used for peaking purposes. The plant cost for peaking units approaches closely the incremental cost of additional units. The overload characteristics of plant and transmission equipment greatly influence cost, since peaking operations are of such short duration.

Under high load-factor operation transmission lines are designed so that the value of additional losses is about equal to the incremental cost of additional circuit conductors. For peaking purposes the stability limit of the circuit becomes the dictating factor.

From the standpoint of system reserves, a spare unit in a hydro plant can serve as effectively as a steam unit in the load center. In viewing this last statement, it is important to realize that the transmission network from the center of generation to the load areas along the Pacific Coast will be interconnected with some 30 to 40 circuits by 1965. The loss of one circuit will not materially affect the loading of the remaining circuits. With spare hydro units at the numerous projects, reserves will be entirely effective except from a standpoint of shortage of energy. This, of course, must be taken care of by steam reserves, additional upstream storage, or interruptible contracts, as previously outlined.

ELECTRIC ENERGY GENERATED IN INDUSTRIAL PLANTS USING PROCESS STEAM

There is one exception to the rather discouraging outlook for electric-power generation from fuel-burning plants in the immediate future. This exception relates to possibility of electric-power generation by industrial plants using large amounts of process steam.

The original construction of a number of such industrial plants in the State of Washington occurred at a time when large quantities of hogged fuel were available at a cost of about 7 cents per million B.t.u. With such low fuel cost there was no justification for capital expenditures to gain efficiency in these plants.

At about the time the supply of low-cost fuel began to disappear, the dream of an unlimited amount of low-cost power from Federal plants on the Columbia River began to affect the program of industrial power-plant construction. Power was supposed to become available in large blocks to industrial plants at 1 mill per kilowatt-hour. This program has not materialized, and there are reports of probable rate increases.

It would seem worthwhile to re-examine the possibility of electric-energy production as a by-product of the use of process steam. An efficiency of 520 kilowatt-hours per barrel of oil equivalent to 12,000 B.t.u. per kilowatt-hour "as fired" to "send out" represents good operation of a modern condensing turbine-generator unit. In a condensing operation about two-thirds of the heat input to the turbine throttle is carried away by the cooling water passing through the surface condenser attached to the turbine.

Where large amounts of low-pressure process steam are required for industrial process, it is possible to generate electric energy for about one-third the heat energy required by the condensing unit. The heat equivalent of a kilowatt-hour is 3,413 B.t.u. Allowing for gross boiler efficiency together with friction and windage and excitation losses of the turbine-generator unit, a kilowatt-hour can be produced for about 4,560 B.t.u. per kilowatt-hour. With a fuel cost of 26.8 cents per million B.t.u. "as fired," the fuel cost per kilowatt-hour is 1.22 mills.

The plant investment, including turbine-generator units and the incremental cost of boiler, piping, and higher-pressure auxiliaries should not exceed $100.00 per kilowatt. At 80 percent annual load factor and fixed cost at 10 percent, the fixed cost per kilowatt-hour is 1.44 mills.

The total cost per kilowatt-hour, including incremental maintenance and operating cost, would be less than 3.0 mills per kilowatt-hour, a very reasonable figure as compared with the cost of electric energy generated from water power or condensing steam-plant operation.

In existing plants the program as outlined above can only be accomplished over a period of a year as an integral part of maintenance, replacement, and/or expansion of the existing facilities.

State of Washington
Department of Conservation and Development
Division of Mines and Geology
Sheldon L. Glover, Supervisor