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ELECTRIC POWER RELIABILITY

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HEARINGS

BEFORE THE

COMMITTEE ON COMMERCE
UNITED STATES SENATE

NINETIETH CONGRESS

FIRST SESSION

ON

S. 1934

AMENDING THE FEDERAL POWER ACT
AND RELATED BILLS, S. 683, S. 1834, AND S. 2227

Part 2

DECEMBER 20 AND 21, 1967

Serial No. 90-30

Printed for the use of the Committee on Commerce

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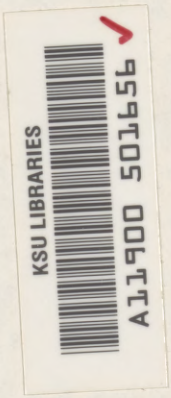



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ELECTRIC POWER RELIABILITY

WEDNESDAY, DECEMBER 20, 1967

U.S. SENATE,
COMMITTEE ON COMMERCE,
Washington, D.C.

The committee met at 10 a.m. in room 815, U.S. Court House, Seattle, Wash., Hon. Warren G. Magnuson (chairman of the committee) presiding.

OPENING STATEMENT BY THE CHAIRMAN

The CHAIRMAN. The committee will come to order. We are here today to open our first set of field hearings on S. 1934, the Electric Power Reliability Act, which was introduced in Congress this year.

The legislation—and I want to make this clear—was drafted by the Federal Power Commission at the President's request in an attempt to insure that major power blackouts, such as that which darkened the Northeast in 1965, can be eliminated or at least reduced to a bare minimum in the future. For all of us realize how important it is to the economy of the United States to keep a continuous supply of electrical energy in our power lines.

Our hearings on this legislation opened last August in Washington, when we heard extensive testimony from Lee White of the Federal Power Commission, and statements by Senator Metcalf of Montana and Senator Tydings of Maryland. Members of the Commerce Committee from the Northeast, particularly Senator Cotton of New Hampshire, the ranking minority member, and Senator Pastore of Rhode Island, are quite interested in this bill but did not make statements at that time because they are members of the committee and expect to reserve their comments until we have had these field hearings.

So the first hearing opened last August. The committee then decided to go into the field, because this is a complex piece of legislation, to hear how the proposed legislation would affect operations in different regions of the country. I'm particularly pleased that we could schedule these preliminary hearings on the bill here in the Northwest. We are extremely anxious to hear how the Commission's proposal has been received here.

As you realize, S. 1934 is one of the major bills before the 90th Congress. Although the Northeast blackout and extensive power failure in the PJM system fortunately did not result in much more than a great deal of inconvenience and some extra expense to the millions of people living in these areas, we all realize that such blackouts could, under certain circumstances, lead to disaster. It is for this

Staff counsel assigned to this hearing: Frederick J. Lordan and William G. Meserve.

reason that the President has consistently stressed the importance of this bill in discussing his legislative program.

The committee of course recognizes the great impact that this legislation may have on power operations throughout the United States. As a result, we have planned extensive hearings here and elsewhere in the country to make sure that all gradations of opinion can be fully expressed. Judging from the outstanding list of witnesses I see here, we are going to listen to some helpful and impressive testimony.

I want to make it particularly clear again—and here I speak for the other members of the committee as well as myself—that this bill is merely a working paper. It is the proposal of the Federal Power Commission, arrived at after many, many conferences, and it contains some ideas of Members of the Senate and of the House. As you will note, there are many cosponsors of the bill, both in the Senate, and in the House, but they regard this proposal as a working paper.

What we're here for is to get ideas, proposed modifications, and different viewpoints on the interpretation of language. We are interested in changes which will help achieve a general objective: minimizing the possibility of cascading power failures. I'm sure that everyone in this room agrees with this objective and wants to build the best possible system we can.

This is a bill that is complicated. It has a lot of features in it that I don't agree with, and I want to tell you frankly that some of them ought to be changed.

For we're trying to make this a practical bill—one that everyone can live with. You just don't pass a law to insure power reliability. Instead you try to have everybody agree that what you're doing is the best way to achieve this minimum objective. I hope you'll take these hearings in that spirit and tell us what you think about this bill.

I am pleased to have our distinguished Congressman, Brock Adams, with us today. He has been deeply interested in this matter, and he is one of the important members of our counterpart committee in the House of Representatives. Regardless of whether the bill goes through the Senate or the House first, he is going to have a great deal to do with its final consideration.

Brock, would you like to add something?

Mr. ADAMS. Just this, Senator; for those on the House side: there is a comparable House bill, and the House Members are interested in these hearings and will be awaiting the text of them.

I am extremely pleased that Senator Magnuson and the other members of the Senate committee have decided to hold field hearings because it will enable us, by the time the next session starts, to have some reliable information from various regions throughout the country. I'm pleased to be here this morning, and I regret that I won't be able to be here during all of the hearings; but we will be following them with a great deal of interest. I really appreciate the opportunity of being here, Senator.

The CHAIRMAN. Thank you. Now, for the record, I should mention the prospects for other regional hearings. The late adjournment of Congress has upset things, but probably Senator Cotton will hold some in the New England area and Senator Hollings down in the Southeast area. Others may be scheduled in the Southwest and in the Middle West. During January or early February we should know definitely.

I have listed here, as my first witness, Gordon Culp, representing the Corporate Services. You have a general statement on this matter.

Mr. CULP. Yes.

The CHAIRMAN. Do you represent also these other people who are testifying too?

Mr. CULP. They will testify also, Senator. There are six witnesses in our group.

The CHAIRMAN. Mr. Timme, Mr. Price, and Mr. Elmore. I see Howard here someplace, and Cliff Erdahl I know is here. Very well, Mr. Culp.

Mr. CULP. We would like to do this, however it would be the easiest for the committee. If you want to, we can bring our six witnesses up here so they will be readily available.

The CHAIRMAN. Yes, I feel kind of lonesome up here. And then we can ask any one of them questions or all of them questions.

Mr. CULP. First of all, Mr. Chairman, we want to thank you for the opportunity of being heard here today, and would like to make a few preliminary remarks. The composite statement that you have before you has been agreed to by 17 utilities in the Northwest. The first six witnesses listed on your witness list have been designated to present the statement on behalf of all 17. They will also try, as individuals of course, to answer an questions that you may have. I am sure that a representative of each of the 17 utilities is also present in the room, in the event that you want to question any of them.

In preparing this testimony, we have tried to summarize a rather wide scope of material as best we could; so, with your permission, we would prefer to present it orally without substantial further summarization.

The CHAIRMAN. We'll put this in the record in full. If you have any exhibits, we shall add them, for I think they are very important.

STATEMENT OF GORDON C. CULP, FIRM OF CULP, DWYER, GUTERSON & GRADER, REPRESENTING CORPORATE SERVICES

Mr. CULP. Reliability of electric service, how it is achieved and how it may be improved, is a broad and complex subject. Technical information and other material has already been submitted to the committee with relation to the bills now being heard, and much more will, no doubt, be forthcoming in the other regional hearings. The best interest of the public will certainly be served by such full and fair investigation and discussion of the many factors, decisions, and procedures which have led to the present high quality of electric service in the United States and which can maintain and improve that quality in the future.

We want to express our thanks to the committee for providing this hearing in the Northwest. Our testimony will be directed to the power situation in the Northwest. We do not presume to speak for other regions of the country—their problems and procedures may be different from ours. However, we believe that the Northwest's long experience of successful, voluntary, cooperative action among all segments of the industry will be of value to the committee in making its analysis as to whether a bill such as S. 1934 is necessary or desirable.

Because of the complexity of the subject matter, a group of electric utilities in the Pacific Northwest proposes, with the committee's per-

mission, to proceed as follows: the next six witnesses will each present testimony relating to only one part of the total presentation. Thus, we hope to minimize redundancy in our testimony and save the committee's time by telling one story in several statements.

The Pacific Northwest utilities that have agreed to this presentation are as follows:

Public Utility District No. 1 of Chelan County, Wash.
Public Utility District No. 1 of Cowlitz County, Wash.
Public Utility District No. 1 of Douglas County, Wash.
Eugene Water & Electric Board, Eugene, Oreg.
Public Utility District No. 2 of Grant County, Wash.
Public Utility District No. 1 of Grays Harbor County, Wash.
Idaho Power Co.
The Montana Power Co.
Pacific Power & Light Co.
Public Utility District No. 1 of Pend Oreille County, Wash.
Portland General Electric Co.
Puget Sound Power & Light Co.
City of Seattle, Wash., Department of Lighting
Public Utility District No. 1 of Snohomish County, Wash.
City of Tacoma, Wash., Department of Public Utilities
Utah Power & Light Co.
The Washington Water Power Co.

The stated purpose of the bills before the committee is to enhance the reliability of electric service. Since electric service can never be perfect as long as it is provided by human beings from equipment manufactured by human beings, "reliability" means a degree of dependability of service to customers short of perfection, but acceptable to the customers served. "Reliability" is, thus, an indefinite concept limited by the present state of technical knowledge and the cost of providing service. Obviously, these variable factors constantly interact, and a useful definition entails balanced judgment among them.

For instance, no one contends that every light bulb can be kept burning at all times—that is clearly impossible at any price. A driver running into a light pole or a ditchdigger plowing up an underground cable may turn out the lights in a neighborhood, and the spoiled roasts and stopped clocks are understood as an annoying fact of life that cannot be prevented by any practical means. Certain industrial power users may be happy to accept service which under normal circumstances may be interrupted from time to time in exchange for a lower cost of electric service; whereas hospitals are encourged to and often will install standby electric equipment, far beyond the economic reach of the general public, in order to reduce the possibility of interruption to its scientific minimum. Thus, for purposes of this discussion, not every outage is a failure of reliability that should be cured. One must consider the frequency of service interruption, the number of people affected, the speed with which service is restored, the purposes for which electric power is being used, and the cost of preventing a particular type of outage.

The Federal Power Commission, recognizing the impossibility and impropriety of curing every type of electric failure, has directed our attention to the large, cascading type of power failure like the North-

east power failure of November 9, 1965—faults that occur on one syste mand the effects of which spread or cascade, causing extensive outages on several other systems. This scope of inquiry is realistic and is consistent with the advice which was given to the Commission by its industry advisory committees. We will concentrate our attention on the cascading type of failure—one involving more than one system.

The main purpose of our discussion will be to describe how reliability is achieved in practice, how it may be maintained and improved, and why S. 1934 will not achieve those objectives.

The degree of reliability desired by the consuming public can be achieved only through the proper operation of electric systems which have been properly planned and properly and timely built. Thus, reliability is not an incidental detail of the power industry; it is a broad and continuous test of the general success of the industry in meeting its public obligations.

How successful has the U.S. electric power industry been to date? In answer to a question from Senator Brewster about allocation of markets during the August 22 hearing on these bills, Mr. Lee White, the Chairman of the Federal Power Commission, stated: "We have the best power system in the world; let there be no mistake about that." And as noted by the Federal Power Commission's Advisory Committee on Reliability of Electric Bulk Power Supply, "the pattern of reliability has been 99.99 percent plus and the public takes for granted that electricity is readily available at all times at the flick of a switch." This remarkable degree of reliability has been attained even though the requirements placed upon the electric power industry are far more stringent than those applicable in any other industry. As aptly described by the Advisory Committee, "An airline limits an aircraft's passengers to the seating capacity, and a telephone system prevents overloading of its circuits by busy signals." There are no such busy signals or traffic limitations in the electric power industry—exactly the right amount of electric energy, neither too much nor too little, must be instantly available to meet all demands.

Though the accomplishments of the industry to date have been monumental, increasing electric demands and growing technical possibilities of economic generation and transmission through large-scale equipment are increasing both the importance and the difficulty of providing reliable service. The objectives of the industry and the general public are the same: the maintenance and improvement of service reliability in spite of the increasing difficulty of that task. The industry is, we believe, accepting its responsibility to meet these objectives. The question now posed is whether Federal action can aid and accelerate progress; and if so, how.

That concludes my portion of the statement, Senator.

The CHAIRMAN. Your next witness is Mr. Timme. I see he has a statement on a very practical side of this: the definition of systems and pools.

Mr. TIMME. My part in the presentation by this panel of witnesses this morning is to review the interconnected and coordinated electric systems of the Pacific Northwest.

Before leading into the testimony itself, I would like to explain the charts here on your right. The first two are included as exhibits——

The CHAIRMAN. Why don't you first answer for the record what the Northwest power pool is? What is it composed of? Who's in it?

Mr. TIMME. This is covered a little bit later.

The CHAIRMAN. Thank you. Just so I know.

Mr. TIMME. I just wanted to point out the charts on the wall, and the first two are exhibits in the testimony. The one closest to you is a geographic map with a one-line diagram of the transmission system in the Pacific Northwest as relayed on the map. These will be referred to from time to time in the later testimony.

STATEMENT OF E. F. TIMME, DIRECTOR OF COORDINATION, NORTHWEST POWER POOL; SECRETARY, NORTH AMERICAN POWER SYSTEMS INTERCONNECTION COMMITTEE

DEFINITION OF SYSTEMS AND POOLS

Mr. TIMME. Power people refer to "systems" and "pools" as though everybody understood those terms with precision. However, a brief description of systems and pools may be helpful for our purposes in this discussion.

An electric system must be considered the basic and indivisible unit of the power industry within which the responsibility for electric power reliability exists. A proper definition of an electric system in this sense might be "the composite of electric facilities integrated in a service area under one utility ownership." A system is made up of thousands of pieces of equipment which were acquired at different times and at different stages in the development of technology and manufacturing arts. The physical equipment was ordered to serve a system purpose that was then foreseeable. There is no such thing as a standard system; each one is custom built to serve specific needs.

Additionally, however well conceived and built, an electric system will not serve those needs unless it is operated properly.

Power pooling and interconnected operation has been the vehicle for transition from thousands of isolated individual systems in the early 1900's to the transmission grid linking 94 percent of all the generating capacity in the United States in 1967. In the Northwest, interconnected operations began to emerge as early as 1918.

The Federal Power Commission defines a power pool as "two or more electric systems which are interconnected and operated on a coordinated basis, to achieve economies in supplying their combined loads." A pool may exist by virtue of a single interconnection and be based on formal or informal arrangements. Most, however, are formally organized and tend toward multiple interconnections. Some power pools perform both operating and planning functions.

The term "coordination" may be used in connection with systems, areas, or pools to indicate a joint cooperative effort in one or more of the many aspects of operation and planning to achieve an economic and reliable power supply. Coordinated operation or planning implies that systems have adopted the concept of a single system in approaching operating or planning objectives. Full or complete coordinated operation may necessitate heavy interconnections to permit utilization of large units, the sharing of reserve requirements, and the realization of various diversity benefits; and it requires uniform oper-

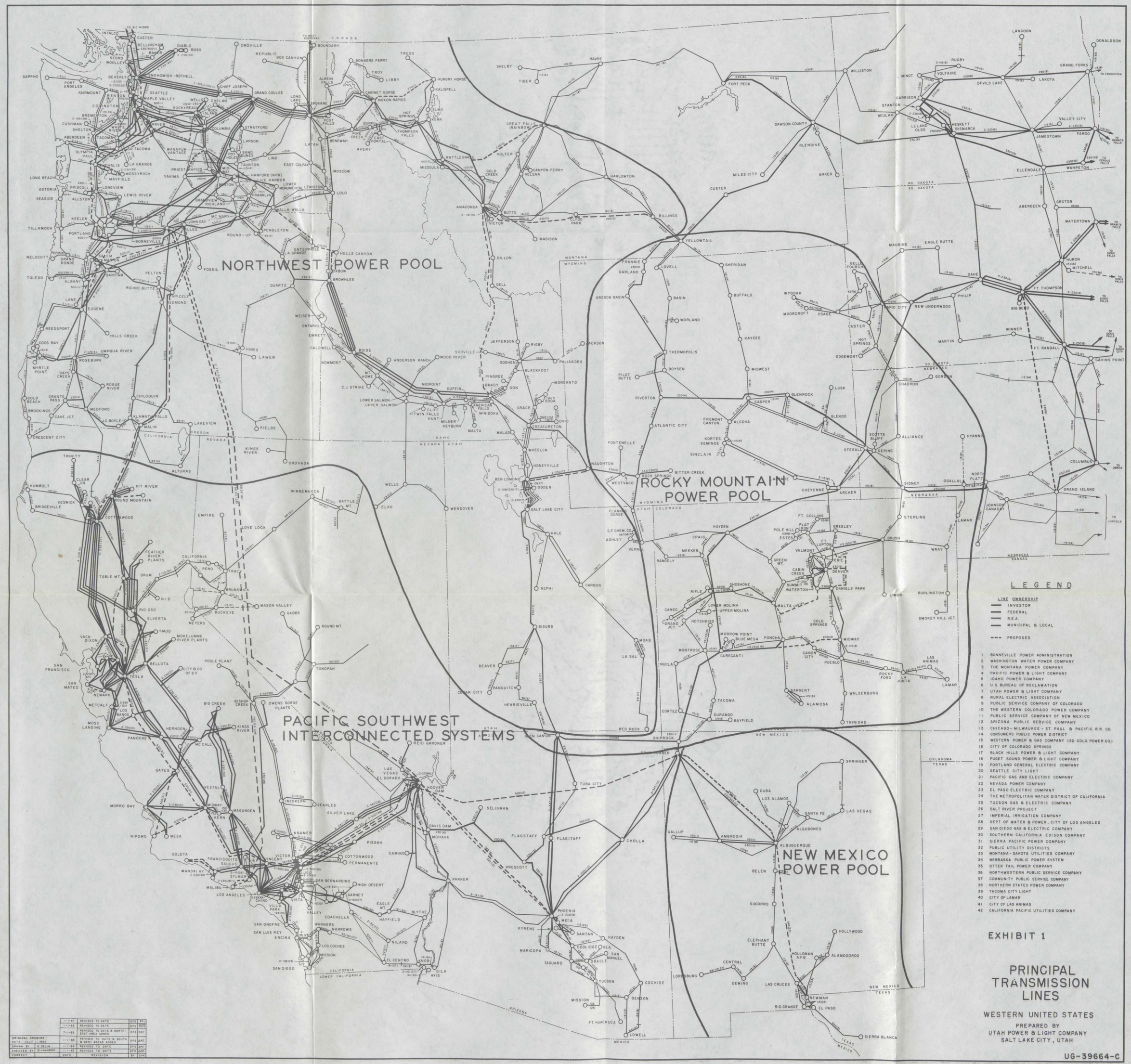

EXHIBIT 1

PRINCIPAL TRANSMISSION LINES

WESTERN UNITED STATES

PREPARED BY
UTAH POWER & LIGHT COMPANY
SALT LAKE CITY, UTAH

UG-39664-C

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	1-1-66	REVISED TO DATE	DFS	DAS
	7-1-65	REVISED TO DATE & NORTH-EAST AREA ADDED	DFS	DPC
ORIGINAL DRAWING DATE JULY 1, 1962	1-1-65	REVISED TO DATE & SOUTH & WEST AREAS ADDED	DFS	APC
DRAWN BY D. SELIN	1-1-64	REVISED TO DATE	DFS	APC
CHECKED BY D. CHAMBERS	1-1-63	REVISED TO DATE	DFS	DAC
CORRECT	DATE	REVISION	BY	CHK

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ating procedures. Full or complete coordinated planning calls for joint planning for construction of new generating facilities and backbone transmission.

GEOGRAPHY OF THE NORTHWEST

All of the interconnected electric systems in a geographic area covering all of the States of Washington, Oregon, and Idaho, and parts of Montana, Utah, Wyoming, Nevada, California, and the Province of British Columbia are included in the area served by the Northwest Power Pool. We still sometimes refer to this area as the Northwest or Pacific Northwest. The geographic area in the United States is shown on exhibit 1.

The total area is approximately 630,000 square miles, and it contains a population of about 9 million. Much of the area is sparsely settled, and great distances separate many small electric load and population centers. The major population centers are located in the Pacific coastal belt stretching from Vancouver, B.C., to Portland, Oreg.

ELECTRIC LOADS AND GENERATION

This year the estimated maximum peak electric load for the Northwest Power Pool is 19,670,000 kilowatts, representing the combined demands of some 3,430,000 domestic, commercial, and industrial customers. Unlike most major regions of the United States, which rely on thermal powerplants, the Northwest loads are supplied predominantly from hydroelectric powerplants. Only two Northwest systems normally utilize conventional thermal plants as part of their power supply. One nuclear plant is now in service, that being the 800,000-kilowatt plant owned by Washington Public Power Supply System and operated in conjunction with the new production reactor at Hanford. However, the U.S. portion of the Pacific Northwest is fast running out of economic hydroelectric power sites, and large thermal plants, both conventional and nuclear, will soon be built.

As of January 1968 the total peak generating capability with critical or minimum water supply will be 22,056,000 kilowatts. Approximately 86.8 percent, or 19,311,000 kilowatts, will be available from hydrogenerating capability with the balance available from thermal and miscellaneous resources. About 36.6 percent of the total generating capability will be available from Federal plants, and the remaining 63.4 percent will be available from non-Federal resources.

When speaking about matters bearing on reliability, we will often refer to a generating unit. By that term we mean an individual generator together with its associated turbine. Because of the predominance and characteristics of hydro generation, the average size of generating units in the Pacific Northwest is relatively small. At the present time, the capability of the largest hydro unit in operation is 159,000 kilowatts. Future hydro units presently scheduled do not exceed 253,000 kilowatts with the exception of the proposed 600,000-kilowatt units at Grand Coulee. The largest conventional thermal units in operation at the present time are 150,000 kilowatts, but a 700,000-kilowatt unit is now scheduled to be in service in 1971. At the one nuclear plant, the new production reactor powers two 400,000-

kilowatt units. As nuclear and conventional thermal plants are added to the system, many of the larger units are to be expected.

THE TRANSMISSION NETWORK

A vast network of transmission curcuits link generating plants to load centers in the Northwest. Transmission circuit voltages range from 69 kilovolts to 500 kilovolts. In some areas, circuits at the lower voltage levels may be considered transmission circuits, but circuits the same size in other areas and serving other loads are considered to be subtransmission or even distribution circuits. In general at the present time, circuits at the 115-kilovolt level and higher are considered to be transmission circuits. It should be noted, however, that 230 kilovolts and even higher voltages are coming into common use for intrasystem subtransmission and distribution networks.

A recent survey of the major pool systems indicates a total of 26,055 miles of transmission circuits in service in 1967. These are broken down into voltage levels as follows:

	Miles
115 kilovolts to 161 kilovolts	14,075
230 kilovolts to 345 kilovolts	11,155
500 kilovolts and higher	825

The same survey also indicates that between now and 1970, systems have scheduled the construction of 4,610 miles of additional transmission. Nearly 80 percent, or 3,656 miles, of this new transmission will be at the extra high voltage levels.

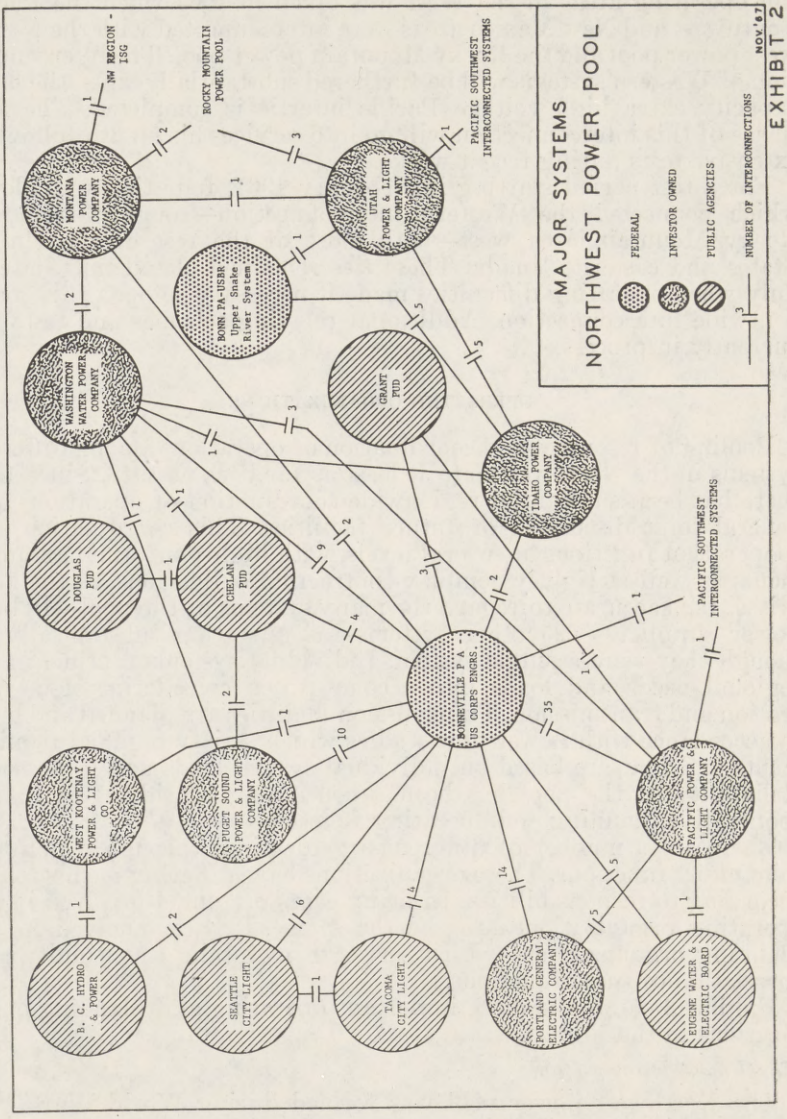
It is estimated that 38,000 relays are in service in the Northwest to provide protection for generating facilities and transmission circuits.

Major transmission lines in service and proposed are shown on exhibit 1. You will notice that a large part of the present, long-distance transmission, particularly at the higher voltages, is owned by Bonneville and connects the Federal hydro projects on the Columbia River with the major load centers. Since a Bonneville witness will appear later in the hearing, we will make no further comments on the Bonneville grid system.

SYSTEM INTERCONNECTIONS WITHIN THE NORTHWEST AND INTERCONNECTIONS WITH OTHER REGIONS

The electric power industry in the Northwest operates substantially as a single system with planning and operations resolved primarily through the coordinated activities of several voluntary organizations.

The location and characteristics of the hydropower supply, the necessity for electrical coordination to achieve hydraulic coordination, and the many transactions between the systems in the form of sales, purchases, and exchanges have resulted in a total of 136 interconnections between the major generating systems as shown on exhibit 2. These interconnections have been made at practically every transmission and subtransmission voltage level. A few that are still in service were built in the 1920's. In addition to these interconnections between the major systems, there are dozens of interconnections between the major systems (especially the Bonneville Power Administration system) and the smaller Northwest systems. These are utilized primarily


MAJOR SYSTEMS
NORTHWEST POWER POOL
FEDERAL
INVESTOR OWNED
PUBLIC AGENCIES
NUMBER OF INTERCONNECTIONS
NOV '67
EXHIBIT 2
SW REGION - ISG
ROCKY MOUNTAIN POWER POOL
PACIFIC SOUTHWEST INTERCONNECTED SYSTEMS
MONTANA POWER COMPANY
UTAH POWER & LIGHT COMPANY
BONN. PA-USBR Upper Snake River System
WASHINGTON WATER POWER COMPANY
GRANT PUD
IDAHO POWER COMPANY
DOUGLAS PUD
CHELAN PUD
BONNEVILLE P A - US CORPS ENGRS.
WEST KOOTENAY POWER & LIGHT CO.
PUGET SOUND POWER & LIGHT COMPANY
PACIFIC POWER & LIGHT COMPANY
B. C. HYDRO & POWER
SEATTLE CITY LIGHT
TACOMA CITY LIGHT
PORTLAND GENERAL ELECTRIC COMPANY
EUGENE WATER & ELECTRIC BOARD
PACIFIC SOUTHWEST INTERCONNECTED SYSTEMS

for distribution. Such additional interconnections are made at all voltage levels but generally at or below 115 kilovolts.

In addition to these many system interconnections within the Northwest, there are some interconnections with other operating areas outside the region. In 1958, the Northwest power pool was interconnected with the Rocky Mountain power pool. A further step in interconnecting operating areas in the West was taken in 1964 when the Pacific Southwest and New Mexico areas were interconnected with the Northwest power pool and the Rocky Mountain power pool. The interconnection of Western systems will be furthered substantially when the large capacity extra high voltage Pacific intertie is completed. The first phase of this interconnection will go into service this month following extensive tests during recent weeks.

For a test period starting in February 1967, four ties were closed which connected the Western interconnection—roughly from the Rocky Mountain area west—with most of the rest of the United States and eastern Canada. These ties remained closed until late in July when operating difficulties made it necessary to open this continentwide interconnection. Additional relaying schemes and tests are currently in process.

OPERATING ORGANIZATIONS

Pooling of resources and coordination of operations among different systems in the Northwest date at least as far back as 1918. Since 1942 there has been substantial regionwide coordination of operations and general joint discussion of future facilities. This coordination and cooperation functions at several levels, with highly informal arrangements as well as tightly complex contractual obligations, as the need arises. It is accurate to regard the many systems of the pool—18 bulk power suppliers—225 other systems—as operating substantially as though they were a single system. Individual systems routinely take regional needs and loads into account when considering new generation and transmission. Transmission facilities are planned and built in accordance with power flow studies which satisfy regional requirements and that are based on individual system loads and generation. Reliability of the pool has been a continuing consideration in the cooperative planning and operating functions.

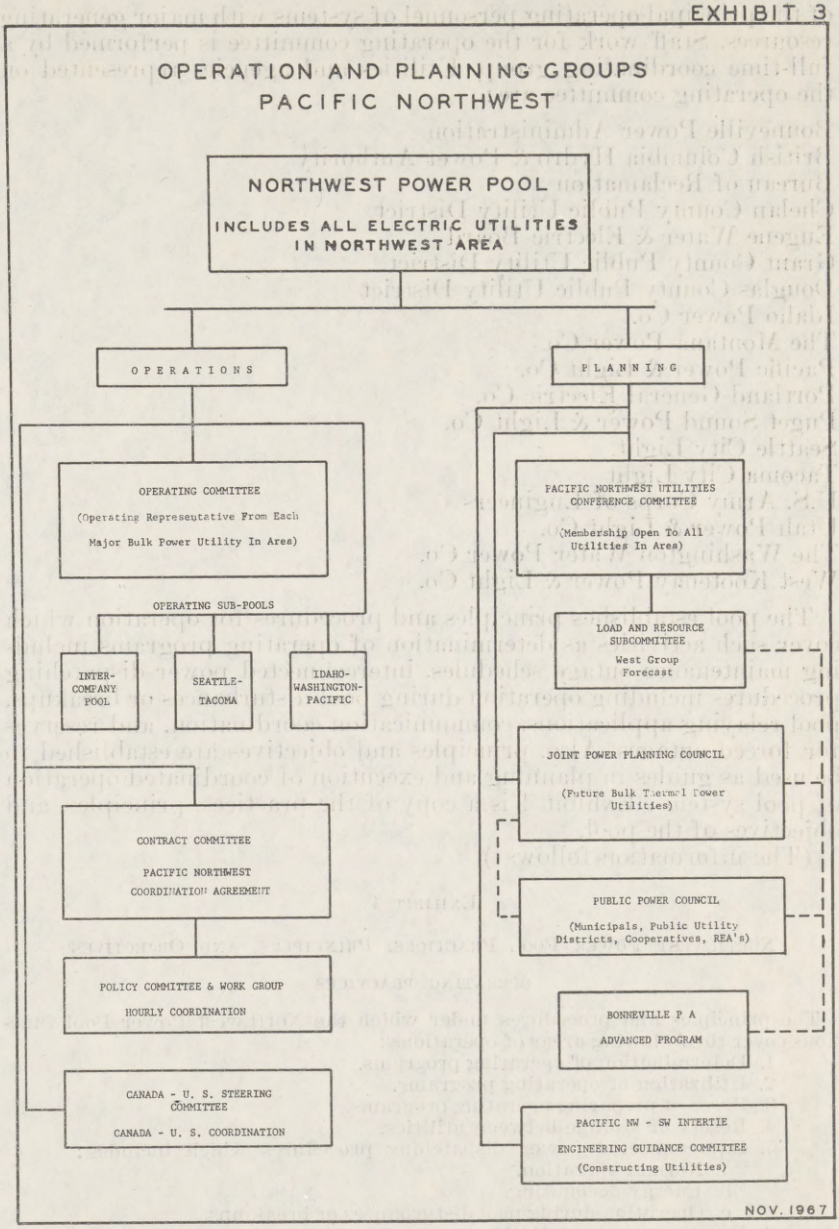
There are a number of different organizations through which this joint effort functions. These organizations have differing memberships according to responsibilities. In many cases personnel involved in the operating organizations may be the same as those involved in the planning organizations—which serves to maintain a continuity and correlation of these functions.

Exhibit 3 shows the more important operating and planning organizations in the Northwest.

Northwest Power Pool

The Northwest power pool was formed during World War II to assure maximum availability and use of electric power facilities in the Northwest in the national war effort. The pool has continued since that time as a voluntary organization of utilities and agencies in the area for the purpose of planning the operation of electric power systems for optimum power and energy production and for the greatest

EXHIBIT 3



benefits, within practical limitations, for each of the members and the Pacific Northwest region as a whole. The pool is an international organization comprising the electric systems in the Pacific Northwest geographic area described previously.

All interconnected electric power systems in the Pacific Northwest are members of the pool. The pool operating committee is made up

of the principal operating personnel of systems with major generating resources. Staff work for the operating committee is performed by a full-time coordinating group. Utilities and agencies represented on the operating committee are:

Bonneville Power Administration
British Columbia Hydro & Power Authority
Bureau of Reclamation
Chelan County Public Utility District
Eugene Water & Electric Board
Grant County Public Utility District
Douglas County Public Utility District
Idaho Power Co.
The Montana Power Co.
Pacific Power & Light Co.
Portland General Electric Co.
Puget Sound Power & Light Co.
Seattle City Light.
Tacoma City Light
U.S. Army Corps of Engineers
Utah Power & Light Co.
The Washington Water Power Co.
West Kootenay Power & Light Co.

The pool establishes principles and procedures for operation which cover such activities as determination of operating programs including maintenance outage schedules, interconnected power dispatching procedures including operation during pool disturbances or breakups, pool relaying applications, communication coordination, and reserves for forced outages. Also, principles and objectives are established to be used as guides in planning and execution of coordinated operation of pool systems. Exhibit 4 is a copy of the practices, principles, and objectives of the pool.

(The information follows:)

EXHIBIT 4

NORTHWEST POWER POOL PRACTICES, PRINCIPLES, AND OBJECTIVES

OPERATING PRACTICES

The principles and procedures under which the Northwest Power Pool functions cover the following areas of operations:

1. Determination of operating programs.
2. Utilization of operating programs.
3. Bases of preparing operating programs.
4. Reservoir storage between utilities.
5. Interconnected power dispatching procedures which includes:
   a. Normal operation.
   b. Energy accounting.
   c. Operation during pool disturbances or break-ups.
6. Reactive supply and voltage control.
7. Pool relaying application.
8. Carrier current communication coordination.
9. Reserves for turbine-generator breakdown.

The general principles and objectives that are used as guides in the planning and execution of coordinated operation in the Northwest Power Pool are as follows:

PRINCIPLES

1. Each utility has complete control of its own system operation; however, every effort shall be made to coordinate individual system operation for the best over-all operation of the Northwest Power Pool.
2. Each utility is entitled to utilize its own generation, transmission and associated facilities to supply its own requirements and any contractual obligations.
3. Each utility shall provide sufficient resources to supply its expected load requirements at 60 cps with provision for adequate reserves.
4. Each control area shall provide the power necessary to supply its load requirements in such a manner as not to impose its regulating burden on the interconnected systems.
5. Utilities will cooperate to provide voltage levels for best over-all customer service, and will make provision to supply their own reactive load.
6. Scheduled interchange transactions shall be made in accordance with agreements or contracts which are in effect.
7. Transfers of energy between utilities will be made in accordance with prearranged schedules set up for such transfers, independent of individual metered quantities on direct interconnections between utilities. The algebraic sum of all metered interchange of a utility with all other utilities represents the actual net interchange of that utility of any given period.
8. The scheduled net interchange between two utilities shall not exceed the total capability of the transmission facilities between those two utilities.
9. Each utility shall balance out inadvertent interchange energy accounts as soon as possible.

OBJECTIVES

1. To provide the best possible service to the customer in the most economical manner.
2. To realize the optimum firm load carrying capability for each system and for the Pool as a whole, and consistent with these objectives, to realize the optimum production of usable energy for each system.
3. To conserve resources and achieve the most economical operation for individual systems and the Pool.
4. To utilize resources to the extent possible within requirements to operate for non-power purposes.
5. To plan and make interchanges between utilities which will improve operation, effect more economical operation, or increase resources to the extent possible under existing contracts.
6. To give consideration to the probability of future streamflows when planning the operation and during the actual operation.

Maintenance outages on generating equipment are planned and coordinated by the Operating Committee. The Committee has approved operating guides adopted by the North American Power System Interconnection Committee (NAPSIC), and has approved the operating recommendations formulated by the Western Operations Subcommittee of NAPSIC.

To help insure against prolonged power interruptions, the pool has adopted schedules for the progressive shedding of load as frequency decays during disturbances. This program, which has been greatly expanded and improved during the 15 years of its existence, has been effective in helping to prevent any lengthy outage of a serious nature in recent years. Automatic underfrequency relays are now in service to drop those load increments which must be dropped first, and manual load shedding is used for later increments. The latest load shedding schedule for the pool is submitted for the record. This schedule is revised periodically. The practice of load shedding allows the systems in the Northwest to remain solidly tied together insofar as possible, with each dependent on the others, in the event of serious trouble. The main objective is to keep generation and transmission ties intact, resulting in quicker restoration to normal service following an emergency. This

is particularly important where, as in the Northwest, the major sources of generation are generally remotely located from the principal load areas.

POOLING ORGANIZATIONS OPERATING WITHIN THE FRAMEWORK OF THE NORTHWEST POWER POOL

Seattle-Tacoma Agreement. Since 1922 the cities of Seattle and Tacoma have operated their municipal electric systems on a coordinated basis under a contractual agreement. This agreement in its present form covers sale of surplus energy, use of reservoir storage, joint planning for use of generating resources, charges for thermal energy, and sharing of costs on interconnection facilities.

Intercompany pool. Since 1947, Puget Sound Power & Light Co., the Washington Water Power Co., Pacific Power & Light Co., and Portland General Electric Co., have operated under an intercompany pool agreement providing for a joint facility operation and the pooling of certain power resources of the companies.

Idaho-Washington-Pacific Agreement. Commencing in the late 1950's, the Washington Water Power Co., Idaho Power Co., and Pacific Power & Light Co., have coordinated certain operations under a separate agreement.

Pacific Northwest Coordination Agreement

The coordination agreement contractually assures that 16 utilities and agencies in the Northwest will coordinate the operation of their power facilities on a firm basis in order to increase the capability of the area to market firm power. It also assures each party that its contribution to such increased capability will be recognized in terms of benefits from coordination. Operations are jointly planned and are conducted by each party according to the agreement so as to take advantage of load and resource diversity, thus obtaining optimum usage of the generation, transmission, and storage facilities of the area. The coordination contract committee is established to implement the provisions of the agreement. Mr. Elmore will discuss this agreement more fully later in the testimony.

INTERNATIONAL ARRANGEMENTS RELATED TO THE COORDINATION AGREEMENT

The Pacific Northwest Coordination Agreement has international aspects now being effectuated.

Part of section 22 of the coordination agreement reads as follows:

> (a) The U.S. entity shall use its best efforts to develop and implement operating plans for Canadian storage with the Canadian entity in order to obtain optimum power generation downstream in the United States consistent with the provisions of this agreement and the treaty. To this end the U.S. entity will consult with the other parties hereto as provided in this agreement.
>
> (c) Prior to an agreement on such operating plans between the United States and Canadian entities, in accordance with the treaty, studies shall be made on a timely basis and consistent with the provisions of the treaty for the coordinated system assuming utilization of available Canadian storage to provide guidance to

> the U.S. entity in regards to the optimum generation desired by systems in the United States. The U.S. entity, consistent with its obligations under the treaty, shall use its best efforts to achieve such utilization in the operating plan finally determined and agreed to with the Canadian entity.

This provision is being carried out by the coordination contract committee and the treaty entities.

Mr. TIMME. That concludes my part of this presentation.

The CHAIRMAN. I don't know if I should interrupt these hearings—this able presentation of these witnesses. I think we could put this in better perspective, however, if I did ask one or two questions.

You go into a very good description of the number of pools in the area. Now, I suppose the first question that somebody would ask is: Although you have these pools and some of these agreements, how effective are they? Are the companies required to live up to them? With the different sections involved, if they have an agreement, they live up to it. But there isn't a binding agreement for the whole thing, is there?

Mr. TIMME. The Northwest Power Pool is a voluntary power pool, and the others that were mentioned, the subpools operating within the framework of the Northwest Power Pool are contractual.

The CHAIRMAN. I think the record shows that there are some which are contractual. The Tacoma-Seattle arrangement is an example. There are others that are contractual. But the whole pool is, as you say, voluntary.

Mr. TIMME. The Northwest Power Pool is a voluntary organization.

The CHAIRMAN. Has it been your experience that you can call upon these people in times of emergency, so that there is no question of their living up to the voluntary agreement?

Mr. TIMME. It should be recognized that the Northwest Power Pool has functioned at the operating level on a voluntary basis since 1942, and over these years we have developed guidelines relating to normal operating procedures, emergency operating procedures, and dispatching procedures. I think our record is very good as far as the ability of the systems in the Northwest to cooperate during cases of emergency.

The CHAIRMAN. In other words, you don't know of any particular instance where a power company would not help when it could do so?

Mr. TIMME. I have no recollection of such a case.

The CHAIRMAN. There may come a time, of course, when they could not help. In some cases they might have a problem of their own.

Mr. TIMME. In any case of trouble, one or more systems are in trouble and may need help from the balance of the interconnected systems.

Mr. CHAIRMAN. They might have to say: "Look, we have problems of our own. We'd be glad to help you, but we have to get our own thing solved first." How is agreement on plans reached within the organization? You said it's voluntary, I know that; but how is the voluntary agreement reached?

Mr. TIMME. The voluntary agreement is reached through the Operating Committee of the Northwest Power Pool. This committee is composed of representations from major systems in the Northwest; but the smaller systems can be represented, if they so desire, through the larger system with whom they are interconnected. Guidelines and

procedures are developed through many hours of argument and discussion with representatives, sitting around the table. Finally a procedure is developed that can be accepted by all of the representatives of the Operating Committee.

The CHAIRMAN. Now, I just want the record to be clear, for these questions are not meant critically. Is a unanimous vote required? Do some say, "We don't like it, we're not obligated, we're not bound by it?"

Mr. TIMME. Since it is a voluntary effort, it has to be unanimous. Exhibit 4 is an example of the guidelines that have been developed on a voluntary basis with unanimous approval of all of the systems.

The CHAIRMAN. We talk a lot about the regional power plans. Do you have any meetings with any of the other regions around the Pacific Northwest to discuss reliability problems?

Mr. TIMME. I would limit my answer to that question to the operating phase. Some of the later witnesses will cover the planning phase. We are becoming strongly interconnected throughout the western half of the country. In the past year the western and eastern parts of the country were interconnected. Foreseeing these interconnections, we have set up operating groups to look at the regional operation instead of just the operation in the Northwest Power Pool area.

The CHAIRMAN. Would this be a fair statement to make? The Northwest Power Pool that you talk about is a voluntary group where one member agrees to help the other in case of trouble and where the members coordinate the distribution of power in the best way they know how. But if everybody is in trouble at the same time they would want to take care of their own distibution system first. Is that correct?

Mr. TIMME. This is the first concern of every system.

The CHAIRMAN. I'm not critical of it. No; I don't blame them.

Mr. TIMME. This is the first concern of every system, to maintain its own integrity.

The CHAIRMAN. But if something happened to one group in an area, the rest of them would pitch in and do what they could to help out. Isn't that what it amounts to?

Mr. TIMME. They do it automatically in many cases.

The CHAIRMAN. I don't know whether technically it could be done automatically or not, but we can get into that later. They are trying to do it automatically, let's put it that way.

Mr. TIMME. To clarify—the assistance that other systems automatically provide to an interconnected system that has lost either a block of load or generating capability is through energy absorbed or delivered, based on the characteristic response of the other systems to an increase or decrease in the interconnected system's frequency caused by the load or generation loss. In such a situation the energy transfers are controlled by the laws of physics—human decisions only make adjustments to them where required.

In the Northwest, the conditions for energy transfers, under both normal and emergency conditions are covered by the Pacific Northwest Coordination Agreement and other contracts. Therefore, they are contractually binding and mandatory on all of the major bulk power suppliers in the Northwest.

The CHAIRMAN. Who makes the decisions on dropping loads and tripping interties in your pool?

Mr. TIMME. As indicated in the testimony, during the past 15 years we have developed a very comprehensive program for automatically shedding loads in case of emergency in the Northwest area. That program was initiated following a rather widespread disturbance in the western half of the Northwest Power Pool in 1950. The program was developed through the cooperative effort of the members of the Operating Committee of the Northwest Power Pool.

The CHAIRMAN. In other words, it's my understanding that right now—today—there is a prearranged plan in existence. Is that correct?

Mr. TIMME. That is correct.

The CHAIRMAN. And normally, unless there is some unusual reason for one member or one group or one distribution system not to adhere to it, they would carry out that plan. Is that correct?

Mr. TIMME. That is correct.

The CHAIRMAN. And that plan, as you pointed out, is periodically revised as you change the system.

Mr. TIMME. As the load increases and the relationship between the load and generation in an area changes, continual updating of the emergency load-shedding program is required.

The CHAIRMAN. Then it's like anything else. You prepare for emergencies, if you can, by having a prearranged plan, and you hope that it works all right. But you do have to meet and revise it periodically.

Mr. TIMME. That is correct.

The CHAIRMAN. I suppose you have to do so because there are changes in the system all the time.

Mr. TIMME. That is correct.

The CHAIRMAN. Now when we talk about the Northwest service area, we're talking about 9 million people, aren't we? Are all the systems serving those 9 million people interconnected and under this plan?

Mr. TIMME. The entire area that was described, the Northwest area or the Pacific Northwest, or the Northwest Power Pool, is interconnected throughout the entire area.

The CHAIRMAN. So as far as you know, engineeringwise, they're all connected.

Mr. TIMME. Engineeringwise, they're all interconnected, with the possible exception of a few hamlets, say, in northern British Columbia that may not be tied into the grid as yet.

The CHAIRMAN. Is that why you say that the Northwest Power Pool, or the operation here, is pretty much a single system?

Mr. TIMME. The complete interconnection together with the uniform operating practices that are followed by all of the systems in the Northwest.

The CHAIRMAN. I don't want to be too modest about my own area, but I'm sure some of those Senators holding hearings in the next few months are not going to find that exists in their regions.

Mr. TIMME. They're not going to find a comparable situation to what we have in the Northwest. I think this stems from the fact that we have worked together on a cooperative basis for so many years.

The CHAIRMAN. Now, once you agree upon a regional plan, is there any one person who puts it into effect? Say there is a real emergency.

Is there a man who pushes the button, or does everybody call everybody else?

Mr. TIMME. On the assumption that the Northwest experiences a severe disturbance, the dispatchers, sitting in the central dispatch office of each of the systems making up the Northwest Power Pool, are the key men as far as a case of trouble is concerned. He has been assisted prior to the disturbance by the automatic load-shedding program that we've just discussed. To the extent that this program corrects any imbalance between generation and load in an area, then no further manual shedding of customer load would be required and the dispatchers would proceed to restore their systems to normal operation.

The CHAIRMAN. Has he a single definite location?

Mr. TIMME. There are 14 load control areas throughout the Northwest with dispatching offices for each one of these control areas. Each dispatching office is connected with neighboring dispatching offices or even, possibly, remote systems.

The CHAIRMAN. But there's no one person?

Mr. TIMME. There's no one person or system, no.

The CHAIRMAN. Would it be advisable to have one central control system? It may not be practical.

Mr. TIMME. My answer to that is, first of all, no one person or system would have the capability to perform this operation.

The CHAIRMAN. Suppose all 14 fed into one person to make the decision.

Mr. TIMME. No one person or system has the capability to perform all of the functions performed by the existing dispatcher and control centers.

The CHAIRMAN. But as it is now you have no central control. It's a voluntary, coordinated effort? Everybody talks to one another and hopes they work it out; and they usually do?

Mr. TIMME. They usually do, that's right.

The CHAIRMAN. Now, for the record, how much of our power load in this area is industrial as against domestic? What percentage?

Mr. TIMME. I do not have a breakdown of that.

The CHAIRMAN. Would somebody get those figures for us? Get it for the record. How much of the load is industrial, and how much is pure domestic. Tell us how much is interruptible, too, if we can get those figures. How much can you automatically shed?

(In answer to this question, the following tabulation has been prepared:)

These data are based on the Federal Power Commission's bulletin on Electric Power Statistics for January 1967 and the electric utilities' estimated energy load for January 1968 in the United States portion of the Northwest Power Pool.

	Estimated energy load (Average kilowatts)	Percent
Residential	4,459,000	36.0
Commercial	1,895,000	15.3
Industrial	5,883,000	47.5
Other	148,000	1.2
Total	12,385,000	100.0

Mr. TIMME. At the present time it varies from area to area. The average percentage that every system can shed is in the same general order except in certain areas, areas like east of the Cascades, where we have a group of hydro plants up and down the river. This area does not require as much emergency protection, as it is practically assured of having one or more generating plants operating in the area. In the last load shedding program, which was compiled in July of this year, the total amount of load scheduled to be shed if the frequency of the system dropped to 57 cycles, is 7,744 megawatts. This is the total for the Northwest Power Pool, and that compares to the total estimated peakload in January 1968 of 19,670 megawatts.

The CHAIRMAN. 7,000 out out of 19,000—a little over a third that you can automatically shed if the frequency drops.

Mr. TIMME. Yes. This would be further augmented by manual shedding in those areas if it was necessary.

The CHAIRMAN. I think we can go on now. One more thing, though, for the record, how quickly can this load be shed?

Mr. TIMME. These relays operate in a matter of seconds, practically instantaneously.

The CHAIRMAN. All right, Byron. You have a statement on the organization.

Mr. PRICE. Yes, Senator. I would like to proceed by discussing the planning organization and how over the years many cooperative projects have been completed.

The CHAIRMAN. You're discussing in more detail what Mr. Timme's been talking about—the whole coordinated effort?

Mr. PRICE. Yes, and extending it just a little bit more. He's talking about the operating end, and I'll talk about the planning organization.

The CHAIRMAN. You don't have a definite corporation to deal with this, but all the utilities in the area are involved.

Mr. PRICE. That is right. Many of our projects have been completed as though this region were a single utility, if you will, on areawide efforts, organized through voluntary local and regional organizations. Additional joint efforts are in process both within the region and with other regions.

STATEMENT OF BYRON PRICE, GENERAL MANAGER, EUGENE WATER & ELECTRIC BOARD

We'll start with the Pacific Northwest Utilities Conference Committee. I'm presently chairman and have been for the past 10 years, and Mr. C. A. Erdahl of Tacoma was chairman for the preceding 10 years. For almost 20 years, then, we have found that the coordination of power planning by the Pacific Northwest Utilities has been handled principally through the conference committee. Membership is open to all Northwest utilities. At the present time, 27 utilities are are members.

The CHAIRMAN. Again, this functions primarily within this geographical area.

Mr. PRICE. It's the area of Oregon, Washington, Idaho, and Montana. We make estimates of loads and resources annually, and this

is done on a group basis for the ensuing 10 years. Special studies for longer periods. Power deficiencies are disclosed by these forecasts and are subject to extended analysis and discussion by the committee. A copy of the most recent forecast, entitled "West Group Forecast," is submitted for the record.

The conference committee has provided a forum where the plans of Federal agencies, municipalities, PUD's, and private utilities can be presented on an areawide basis. In the case of Federal projects, a spokesman for the committee has appeared regularly before congressional appropriations committees in support of needed projects. The timing of Federal projects has been coordinated with schedules for projects planned by individual non-Federal utilities.

Joint Power Planning Council

The Joint Power Planning Council was formed in November 1966, to encourage the cooperative development of thermal generation which will be needed by the mid-1970's to supply the increasing energy requirements of the Northwest region. Matters to be presented to the council include proposals for the construction of thermal plants and factors affecting plant siting, such as transmission requirements, environmental effects, and cooling water problems. The council has organized task groups to work in the various areas of planning required for development of nuclear powerplants. Represented on these task groups are all interested electric utilities and agencies, including the Bonneville Power Administration, concerned with finding a future energy supply for their system and for the region. Separate task groups are working in the areas of plant proposals, marketing arrangements, technical aspects of generating plants, transmission analyses and general plant site considerations, water standards, legal and licensing matters, power operations, and public information.

The CHAIRMAN. I know about this group. You've had a lot of meetings, and I've talked with many of you. We try to correlate these things so we have a good joint effort.

Is that a good statement?

Mr. PRICE. That is correct.

The CHAIRMAN. One doesn't precede the other so we try to put it all together.

Mr. PRICE. The Joint Planning Council is Federal, non-Federal, and Government agencies all together.

The CHAIRMAN. If we don't plan together, we're going to be in trouble.

Mr. PRICE. Yes, sir. That is correct.

Public Power Council

On December 15, 1966, the Public Power Council was formed to provide an informal organization through which all interested consumer-owned and public systems in the Bonneville Power Administration service area in the Northwest could plan together to meet their future power needs and also to plan with others to meet the future power needs of the region. The 18-member executive committee has established task groups to work on planning and investigations in connection with nuclear powerplant development.

Bonneville Regional Advisory Council

During most of the history of its operation, the Bonneville Power Administration has utilized a group of the region's leaders in business, industry, education, and labor to review periodically its plans and programs for meeting its portion of the responsibility for the region's electric power needs. This organization is called the Bonneville Regional Advisory Council. Members are appointed by the Bonneville Power Administrator for 2-year terms. Presentations and discussions with the council make possible a broad regional understanding of power planning needs for the region and provide Bonneville with an important source of constructive evaluation of its plans.

RESULTING COOPERATIVE PROJECTS IN THE NORTHWEST

The planning efforts of the various voluntary organizations in the Northwest have resulted in the success of many cooperative construction projects. Some of the more important ones are:

Central Columbia Dams

Four large hydro projects on the central Columbia River were financed and built through the cooperative efforts of several non-Federal public agencies and investor-owned utilities in the Northwest. The projects are Priest Rapids, Wanapum, Rocky Reach, and Wells. The first project, Priest Rapids, was begun in the early 1950's, and others have been added as needed to satisfy regional power needs. Their combined installed capacity is close to 3 million kilowatts.

Columbia Storage Power Exchange

Entitlement to 1.4 million kilowatts of firm power, belonging to Canada under the treaty with Canada for development of the upper Columbia River, was sold for 30 years to Columbia Storage Power Exchange, a nonprofit corporation, which in turn, through exchange agreements with BPA, sold the Canadian entitlement to 41 public and private utilities in the Northwest. CSPE issued $314 million in revenue bonds in September 1964 to make the purchase from Canada. These utilities have assigned most of their entitlement power to utilities in California subject to recall as needed in the Northwest. This was a cooperative effort of public and privately owned electric utilities in the Northwest working with U.S. Federal agencies, the Province of British Columbia, and the Government of Canada. The purchase from Canada and the $314 million advance payment made possible the construction of the three large treaty dams—Mica, Arrow Lakes, and Duncan Lake—which will provide 2,800,000 kilowatts of firm power in the United States, additional power benefits in Canada, and large flood control benefits in both countries.

Other non-Federal projects

Cooperative planning has resulted in construction scheduling for other non-Federal hydro projects being worked out so regional power demands could reliably be met. They include Boundary, Mayfield-Mossy Rock, Cabinet Gorge, Noxon, Upper Baker, Swift, Round Butte, Pelton, and others. Negotiations are now in process among many

public agencies and investor-owned utilities and BPA to determine useful cooperative undertakings in order to build and operate a large coal-fired thermal plant near Centralia, Wash., and the large hydro project long planned for the middle Snake River.

INTERREGIONAL ORGANIZATIONS

Pacific Northwest systems participate in several voluntary interregional organizations which are involved in planning for reliable service. The most important include:

Western Systems Coordinating Council

This is a very important group concerned with the planning and operations necessary for reliability in the western part of the United States and parts of western Canada. Mr. Floyd Goss, Chairman of the Council, will describe this organization at a later point in the hearing; so it will not be necessary for us to describe it further at this point.

Federal Power Commission Regional Advisory Committee

Less than 2 years ago, the FPC created the Western Regional Advisory Committee as part of the industry advisory committee system to update the national power survey, looking ahead to 1990, and to evaluate physical and organizational needs in the electric utility industry to improve electric bulk power supply. Some very hard work was undertaken by this voluntary committee and much of value has resulted from wholehearted cooperation and consultation, the only procedure through which this group functions.

The CHAIRMAN. How long has this group been in existence?

Mr. PRICE. Two years.

The CHAIRMAN. The Federal Power Commission makes the appointments?

Mr. PRICE. Yes.

The CHAIRMAN. Well, aren't there a lot of people who serve on the other committees who are on this one too?

Mr. PRICE. That is why some of us have several hats.

The CHAIRMAN. You have an interlocking directorate, so to speak, haven't you?

Mr. PRICE. I don't want to use those words, but yes, sir.

Pacific Northwest-Pacific Southwest EHV intertie

Another example of coordinated planning has been the successful negotiation of the many complex contracts required for the Pacific Northwest-Pacific Southwest EHV intertie and support of Federal appropirations for the federally constructed portions of the intertie. Four major transmission lines between the Northwest and the Southwest will make up the completed facility. Three lines will run from the vicinity of the Dalles and John Day Dams to Los Angeles and the fourth to Hoover Dam. Bonneville Power Administration is building the entire Oregon portion of one 500,000-volt AC line. The southernmost 178-mile section of the second 500,000-volt line in Oregon is being built by Portland General Electric Co. Pacific Power & Light Co. has completed a 47-mile section of the first 500,000-volt line in northern California. The remaining sections of the four lines in California, Nevada, and Arizona are being constructed by Pacific Gas & Electric Co., Southern California Edison Co., city of Los Angeles, the Bureau

of Reclamation, and Arizona Public Service Co. When completed, the intertie will permit the exchange and sale of surplus Northwest secondary energy and peaking capacity, the purchase of Southwest thermal energy to firm up Northwest secondary hydro energy, and seasonal diversity exchanges between the two regions.

The Pacific Intertie Systems Technical Studies Task Force has been engaged during the past several years in a series of analytical stability studies relating to reliable operation of the various interconnected systems after the intertie 500-kilovolt AC and 750-kilovolt DC lines are completed.

NATIONAL ORGANIZATIONS

North American Power Systems Interconnection Committee

As interconnected systems have developed in the United States and Canada, the need has been recognized to assure a general orderliness within the complex of systems. Various geographical area groups have organized for that purpose. In 1963 a nationwide committee was organized for the purpose of coordinating those factors necessary for the operation of all the interconnected systems. This organization is the North American Power Systems Interconnection Committee (NAPSIC). It is a voluntary and informal organization which functions from coast to coast including parts of Canada. Its areas of concern are frequency standards, time error standards, time error correction procedures, tieline schedules, actions in emergencies, and matters of reliability in general. Operating guides for these matters have been formulated by the committee. Ten regions or interconnected systems groups are represented in NAPSIC. These are:

1. Canada-United States Eastern Interconnection (CANUSE).
2. Pennsylvania, New Jersey, Maryland Interconnection (PJM).
3. Northeast Region of the Interconnected Systems Group (ISG).
4. Southeast Region of the Interconnected Systems.
5. Northwest Region of the Interconnected Systems.
6. Southwest Region of the Interconnected Systems.
7. Rocky Mountain Power Pool.
8. New Mexico Power Pool.
9. Pacific Southwest Interconnected Systems.
10. Northwest Power Pool.

National trade associations

The American Public Power Association, a national trade organization for publicly owned electric utility systems, sponsors committees and does staff work that promotes the efficiency and reliability of the member ssytems. Committee and staff work involves planning, engineering, and operations, as well as administrative, accounting, and personnel matters. The Edison Electric Institute, a national trade organization of the investor-owned electric utility systems, and the National Rural Electric Cooperative Association, a trade organization for cooperatively owned electric systems, both perform similar functions for their member systems as does the American Public Power Association for its members.

One of the most important functions of the national trade associations is in the fields of research relating to reliability and environmental qualities. Many research projects have been fun ded and carried

out by these organizations for many years. More recently, the national trade associations also are jointly financing and participating in the Electric Research Council. The council is involved in various important and expensive research projects, including the proposed high energy test center to be built at Grand Coulee and used for the benefit of the whole country.

It is through these organizations that we cooperate.

The CHAIRMAN. Before you finish, it would be good to discuss for the benefit of the large number of people who have been deeply interested in this possible High Energy Test Center—I think pretty nearly everybody in this room—what its prospects are. When we met to discuss the Interior appropriations, there was a proposal for the Federal Government to guarantee x number of dollars—I forget the exact amount—to help create this center. That was turned down by the committee for good and obvious reasons. But we did say—and I hope everybody will understand this because we get a lot of criticism about this from people—we did say in the report on the appropriation that if and when this was clearly supported by the other people—not necessarily guaranteed, but when there was some definite showing that they were going to participate—that we would then entertain and consider the participation of Bonneville in this program. And I want to say here that I don't think there is any doubt that we would be able to get the money appropriated for adequate Federal participation, but it has become a little bit like the chicken and the egg deal. Who is going to act first? With the fiscal condition where it is now, the Federal Government is not about to do things first in this particular field.

I think the establishment of the Test Center is one of the most important programs suggested to deal with what we're talking about right here: the reliability of electrical system. I think it's got to get underway. So I want you to know that we didn't turn it down altogether. We just said that when all the other contributors who are going to participate have gotten together, then the Federal Government will participate to the extent necessary.

Mr. PRICE. The Senator's always been helpful out here in setting these guidelines. If it's local participation you want, I am certain we will give it every consideration and get it going.

The CHAIRMAN. It started out with local participation, but we have a big stake in it; and I think we ought to be in it. Some people thought we had turned it down. We didn't turn it down at all. We were very interested.

Now, that concludes your statement, and I think you've covered all these organizations quite thoroughly. I have some questions here that are not necessarily in line, but they ought to go in the record.

What types of procedures have you currently developed to keep the Federal Power Commission informed about this planning you talk about?

Mr. PRICE. The Federal Power Commission representatives are often and generally in attendance at these various meetings we have with these organizations as observers or even participants. So I would say the FPC has this opportunity—and they avail themselves of the opportunity—of being informed right on the spot.

The CHAIRMAN. We've tried to encourage them to go in at least an observer status; for they may know of some techniques that would

be helpful. They have a big staff and they have a lot of things going on, so they ought to be there and be able to participate. We encourage them to do so.

Mr. PRICE. We feel we enjoy good communications with FPC.

The CHAIRMAN. Thank you very much.

Now, Howard, you have a statement about the increasing problems associated with interconnecting systems?

Mr. ELMORE. Yes, Senator. I would like to address my remarks to the increasing problems of interconnecting systems. First I would like to discuss some of the advantages and disadvantages of these types of interconnections.

STATEMENT OF HOWARD C. ELMORE, ASSISTANT MANAGER, CHELAN COUNTY PUBLIC UTILITY DISTRICT; PRESIDENT, COLUMBIA STORAGE POWER EXCHANGE; MEMBER, JOINT CANADA-UNITED STATES STEERING COMMITTEE; MEMBER, FPC WEST REGIONAL ADVISORY COMMITTEE, AND CHAIRMAN, TRANSMISSION SUBCOMMITTEE; MEMBER, POWER SUPPLY PLANNING COMMITTEE, POWER POLICY COMMITTEE AND SUBCOMMITTEE ON RELIABILITY STANDARDS, AMERICAN PUBLIC POWER ASSOCIATION

ADVANTAGES AND DISADVANTAGES OF INTERCONNECTING SYSTEMS

Systems are usually interconnected primarily for economic reasons, and reliability may thereby either increase or decrease; however, interconnections always increase the complexity of reliability problems and create the possibility of cascading failures.

The principal advantages that may be gained through power pooling and system coordination are primarily economic, but certain reliability gains or losses may also result. The advantages show up in many ways, such as the ability to realize economies of scale by construction of large generating units, sharing of backup reserve requirements, the reduction of spinning reserve requirements, reduction of load fluctuations on individual generating stations, staggering of maintenance schedules on generating units, taking advantage of load diversities, and increasing reliability by multiple interconnections and loops providing alternate transmission routes. The disadvantages include the high cost of transmission interconnections, the problem of cascading effects of a transmission line outage which extends a service interruption beyond its immediate locale, conditions created by inadvertent power flows in the interconnected transmission lines, and introduction of transmission line stability problems.

Contrary to some overgeneralizations that are heard rather commonly, pooling and coordination arrangements do not automatically result in net benefits. Careful decisions and value judgments must be made at the planning stage in each case by those most familiar with the circumstances in order to realize net benefits, particularly any benefits which improve reliability.

One thing is crystal clear. An expanding scope of interconnections results in a dramatic and cumulative increase in the complexity of

reliability problems. As explained earlier, the individual electric system must be considered the basic element for dealing with reliability. Within an electric system, under one ownership, with no interconnection with other systems, reliability is dependent upon the practices of that utility in its internal operation. Reliability, in such a case, is the sole responsibility of the one system. If that system interconnects with another system, reliability on each system becomes related to reliability of the other system and to reliability of the interconnection between the two. As additional interconnections are made between systems, either directly or indirectly, this interdependent relationship extends to all systems, with reliability on each system being affected by reliability of each of the other systems tied to the interconnected transmission grid and with the reliability of the grid itself.

Transmission interties between two or more power pools further extend the interdependence of system networks and compound the complexity of the reliability problem. To an even greater extent than interconnections within pools, these types of interties are established to provide a more economic power supply for the interconnected systems serving more widely separated geographic areas. To function properly these types of interties must be subject to the same planning and operating disciplines as those controlling the interties within well-organized pools.

High-capacity ties between pools are being utilized more and more (with strong encouragement from the Federal Power Commission and other Federal agencies, incidentally) in order to realize economies of large scale. But in so doing, greater complexity is added to the problems of electric service reliability.

It is obvious that a high degree of reliability of a large aggregation of electric systems cannot be maintained unless the integrity of the constituent systems and pools is maintained. The advent of extra-high-voltage transmission permits the exportation of trouble as well as the importation of assistance. Also, larger and larger concentrations of generating capacity add another and most difficult aspect to the problems of reliability. The larger the capacity of the transmission line or generating plant, the greater the impact can be if a forced outage on either should occur.

The joining of more and more systems together with interties tends to reduce the frequency with which small service outages will occur at the price of increasing the extent of those outages that do occur. It tends to trade many small failures for a few whoppers. The Northeast power failure was a classic example of this problem.

A DANGER TO BE AVOIDED

There is a danger of risking reliability if the headlong pursuit of economies of large scale is not tempered with an orderly evolution of practices and technology which can control the unintended effects of extra large equipment on the systems.

Present problems of reliability and future ones must be solved through an orderly evolution of operating and planning practices and manufacturing technology. The job cannot be done overnight in any event. It probably cannot be done at all, without intervening major, cascading outages, if the utility industry continues to be pressed toward huge physical equipment in order to produce cheap power without

the opportunity and encouragement to solve the corollary problems of reliability. On the other hand, the power system cannot be shut down while solutions are awaited. Additional electric demands must continously be served without going backward, at least, on reliability. We must avoid compounding unsolved complexities, and avoid all unnecessary delay in decisionmaking processes, or such a backward step is a real possibility.

MUTUAL AGREEMENTS WHICH SUPPORT RELIABILITY

Constant work by many highly trained people is necessary to negotiate the array of mutual agreements that must support the coordinated planning and operation necessary for reliability; and similar but intensified efforts will solve the more complex reliability problems of the future.

The Northwest Power Pool and other pooling and coordinated arrangements in the Pacific Northwest are backed up by a large array of interutility contracts of many kinds. These contractual interrelationships have a long history of development involving, in the case of some individual agreements, negotiations extending over many years. The Pacific Northwest Coordination Agreement is a good example. A copy is submitted for the record. Negotiations toward this agreement were first started in 1954, and the first short-term contract was finally developed in 1961. The long-term agreement which is now in effect was not completed until 1964. Between 1960 and 1964 concentrated negotiations on this agreement alone required a major portion of the time of more than 50 engineers and lawyers.

Sixteen utilities and agencies in the Pacific Northwest are parties to this agreement which extends to June 30, 2003. It requires the parties to coordinate the operation of their power facilities on a firm basis in order to increase the capability of the area to market firm power. Detailed provisions are specified with respect to planning and operation, reserve requirements, and rates and charges. The agreement also includes complex provisions for payment by downstream plans for coordinated storage releases and assurances of in-lieu energy in the event storage water is not released.

We know the committee is aware that the coordination agreement was an important factor in development of the Northwest bulk power supply and one of the key steps in the successful conclusion of the treaty with Canada. We are very grateful to the chairman for the many examples of his help and advice along the way, and his part in bringing the treaty into being. We are now trying both to expand the geographic scope of contractual coordination and to extend the agreement to include coordination of hourly peaking operations as hydro facilities increasingly become used for peaking purposes.

On September 27, 1966, representatives of 13 public and privately owned electric utility systems met with representatives of British Columbia Hydro and Power Authority and the British Columbia Provincial Government to discuss and evaluate the potential benefits of expanding coordinated operation between the British Columbia hydro system and the United States systems in the Pacific Northwest. Responsibility for making and implementing studies has been placed with the Joint Canada-United States Steering Committee composed of

three representatives from British Columbia Hydro and Power Authority, four representatives from U.S. public and privately owned utility systems and representatives from the U.S. Army Corps of Engineers and the Bonneville Power Administration. Work is progressing, and there is indication that mutual advantages can be obtained from expanding certain coordinated operation relationships between Canadian and United States systems.

Consideration and studies are also underway to extend the coverage of the Pacific Northwest Coordination Agreement to hour-to-hour control of operations and operating plans. Three task forces are now at work analyzing the load and resources information, and investigating data management and control procedures and equipment, necessary for such precise coordination. The following may illustrate the difficulties of attaining such precision. Last year, Autonetics Division, North American Rockwell, Inc., was retained by Bonneville Power Administration for preliminary advice on the data management and control procedures and equipment that would be required to carry out some planning functions and a considerably automated type of hour-to-hour coordination of electric systems. Among other things, North American reported as follows:

> The Apollo (space project) automatic checkout requires information rates up to 204,800 bits per second. Although the Apollo checkout system may be considered complex, automated large interconnected electric power systems are even more complex and phenomena can occur in shorter times than those of space activities.

In addition to the example of the coordination agreement, there are more than 150 other agreements, including transmission agreements, transfer agreements, and interutility contracts, that relate to pooling and coordinated operation in the Northwest. This does not include numerous power sales contracts. There are between 30 and 40 separate systems involved as parties to the agreements necessary to carry out this type of operation in the Northwest.

A contract provision has been developed over a period of time by which each contracting party will accept responsibility to design, construct, operate, and maintain its system to minimize the possibilities of cascading electrical disturbances. This provision is being included in most interutility contracts that are now being put into effect, including contracts with BPA.

It has taken many years and employed the best efforts of many highly trained people to understand the developing problems and negotiate appropriate solutions so the Northwest power system, with its diverse ownerships, could attain and maintain its present levels of reliability and cost. We are confident that similar but intensified cooperative efforts by the industry and various branches and levels of government will solve the increasingly complex reliability problems of the future.

The CHAIRMAN. What type of contracts are being made with Bonneville Power which bear on reliability? You say the contracting parties design and construct a system to minimize cascading electrical disturbance, and this provision is included in most utility contracts. Is that contained in a contract to deliver power?

Mr. ELMORE. These provisions are included in transmission contracts and also power sales contracts.

The CHAIRMAN. Each individual company writes its own provisions?

Mr. ELMORE. Well, this is the type of provision that I understand that is being included in the contract that Bonneville makes.

The CHAIRMAN. Does Bonneville require these provisions in its contracts?

Mr. ELMORE. They are including them in their general contract provisions, which are required.

The CHAIRMAN. Which deal with reliability?

Mr. ELMORE. Yes.

The CHAIRMAN. I think we ought to ask Bonneville what kind of provisions they have in there—how vigorously they are seeking reliability. They'll be here tomorrow, so we'll ask them about it because they can be very effective in coordinating these problems when they make contracts.

Well, all right. I was interested in part of your statement which was of particular interest to the committee. You indicated that the bigger the system, the bigger might be the blackout. We had one Senator who said he lived in a community that had its own completely independent system. If the next town went out, that was their business; they still had their own power—or vice versa. I think it's pretty hard to see, however, with these modern, complex systems how we could keep everybody separate. I guess it isn't possible.

Mr. ELMORE. Technology just isn't moving in that direction, to keep electric systems isolated.

The CHAIRMAN. We haven't had much talk about the bill yet. Everybody's been telling us what they're doing, but I'm here on a piece of legislation. I know a little bit of what you've been doing, but I would like to know what's wrong and what's right with the bill. Let's start with a question here. Would you care to comment on the provision of the bill which authorizes the Federal Power Commission to require an interconnection when the Commission finds it would be necessary to insure reliability?

Mr. ELMORE. The idea that a particular interconnection might be required to assure reliability, I think, may be the point of difference of opinion here.

The CHAIRMAN. There's no question that there might be a difference of opinion.

Mr. ELMORE. Transmission interconnections historically, of course, have been made when the economics justified their being made. In certain instances I think perhaps some interconnections could be described primarily as needed for reliability. However, I think there would probably be very few. It would seem to me, to visualize the situation, where some regulatory authority could tell utilities that they had to build a particular interconnection for reliability purposes would be, you might say, an unjust way to settle the question of where the burden of responsibility for payment lies. This sort of thing can be worked out, if it's a needed and justified type of transmission line, a voluntary basis.

I think our experience, at least here in the Northwest, has proved that this is the way to do it. This is the best answer that I can give.

The CHAIRMAN. I think what you're trying to say is that everybody will do it anyway. There's no point in granting this authority. But suppose somebody doesn't have the power to direct it? Who's going to say you should interconnect? There might be some cases where they say we need to have this done—it looks like it should be done, and all the evidence supports this judgment, but it isn't done. Should somebody have the authority to say you should?

Mr. ELMORE. I would say they should not.

The CHAIRMAN. There are plenty of procedural safeguards provided. Don't worry about a bill that wouldn't give everybody their say. That won't pass.

Mr. ELMORE. There's another point in this connection. There are other ways to resolve reliability questions other than building transmission interconnections.

The CHAIRMAN. Maybe that was the wrong type of question. Suppose that they directed certain types of planning, whatever it might be—maybe the construction of something—it might be necessary to achieve reliability. But they would say you had to do it. This is what I am talking about. Somebody would say, or somebody—in this case the Federal Power Commission—would make a decision. I suppose your whole point is that if you can do it voluntarily, there is no need for this authority. In addition, the solutions must be practical. I mean, it's like you said. I suppose you could spend billions of dollars and make everything completely reliable, but we have to reduce it to a minimum.

I just got through passing a bill on automobile safety. I suppose you could build a car that would be perfectly safe if you spent enough money—put a padded cell on wheels and no one would get hurt. But that isn't practical. We're talking about serving the people and allowing the people in private enterprise to make their own way. How can they do it without too many people directing them? I think this is what we're trying to find out. This is, I suppose, one of the basic arguments about this type of legislation.

Now, you people here have given us some good evidence of what we are doing in the Northwest—how we are trying to move rapidly to insure reliability. But there are some differences of opinion about that. You point out that whether you have a great big system or a bunch of little ones, or whether you have a central control or 14 guys calling one another on a given afternoon, may affect this question.

Mr. ELMORE. From our experience, I think it is fair to say that if we were organized the way we have been here in the Northwest, maybe establishing our planning on a somewhat more formal basis, that in the development of plans if it is evident that an interconnection is needed for reliability purposes there would be a way found to build it without someone ordering it to be built.

The CHAIRMAN. I think an order would be called for only when it was obvious there should be something done and nobody would do it, or when they neglected to do it, or maybe when they couldn't do it for some reason. But you have no disagreement that the Federal Power Commission ought to have its finger in this in an advisory way to meet with you, help you, work with you, and also to have some little authority to insure proper coordination.

Mr. ELMORE. It should continue to be concerned in such matters on an advisory basis, that's right.

The CHAIRMAN. I think it has to have a little bit of authority. Well, I didn't mean to get into this. I did want to hear a little bit about the bill here.

All right. Thank you, Howard. I didn't mean to make you chief answerer. Now we have Mr. Porter. We'll be glad to hear from you.

Mr. PORTER. My remarks will be directed toward achieving reliability in practice.

The CHAIRMAN. That's pretty important. You think you can do it. You will discuss whether it is practical to do it, how much you should do, and who pays for it—the consumer or the stockholders. We can't make everything perfect, but I think we have one of the finest systems in the world right now. That doesn't mean we can't make it better, however.

Mr. PORTER. I think there's a hundred percent agreement on that.

STATEMENT OF A. J. PORTER, VICE PRESIDENT, PORTLAND GENERAL ELECTRIC CO.; SECRETARY AND TRUSTEE, COLUMBIA STORAGE POWER EXCHANGE; MEMBER, JOINT CANADA-UNITED STATES STEERING COMMITTEE; DIRECTOR, PACIFIC NORTHWEST POWER CO.; MEMBER, COORDINATION CONTRACT COMMITTEE

Mr. PORTER. Reliability can be achieved only through proper overall system planning and operation.

One cannot narrowly define the actions through which reliability can be achieved in practice. It does not result from a single transmission line or relay setting; it involves the total processes of the industry. The two basic elements which together establish the reliability of a bulk power supply system are (1) the physical facilities of the system and (2) the manner in which those physical facilities are operated. A reliable system must be timely and properly planned, designed, and constructed but, of equal importance, it must be properly operated. We will first direct our attention to planning considerations.

PLANNING FOR PROPER RESERVES

Reserve facilities are a major defense against service failures, and each system must determine how to provide the correct type and amount at the lowest cost to its customers.

Electric energy cannot be stored. It must be generated and instantly used. Therefore, a system will not work properly if it is generating either more or less than the customers' instantaneous demands. Furthermore, there is no way to know with precision how much the customers will demand at any point in time. Demands vary with climatic conditions, general business conditions, the movement of people into or out of an area, and almost anything that affects the level and type of human activity. Accordingly, loads must be estimated, and estimated far enough in advance to permit the planning, financing, and construction of enough facilities of the right types to meet demands. Leadtimes to perform these functions may be as long as 10 years in the case of some major projects.

Since advance estimates and the actual demands that occur will never be exactly the same, and since a shortage of facilities to meet

all demands results in a failure of service, some facilities are provided and kept in reserve against unexpected demands.

No machine is perfect, and it will occasionally fail. Likewise, even the best machine will fail if a human error in operation occurs. Such equipment failures and human failures may also result in the system being unable to provide continuous service. Therefore, some amount of electric facilities are provided and kept in reserve to compensate for such outages of machinery. Such reserves are provided both to maintain generation and to maintain the ability to deliver energy to the loads through transmission, transformation, and other equipment needed for the delivery.

All physical equipment needs periodic maintenance, and this is especially true of extremely large electrical equipment used by power suppliers which must operate constantly with precision similar to the most delicate of instruments. Equipment must be shut down to provide such maintenance, and reserves must be provided so the system may function during such period of shutdown.

There is some possible overlapping of these three examples of reserve requirements, but, in general, they must be added together. There are also several other types of reserves which we have not mentioned.

It is obvious, but sometimes overlooked, that reserve facilities must remain available for use in the event of contingencies and cannot be depended upon to perform other functions such as carrying normal parts of the load. Thus, if a transmission line is built in order to transmit power during one of these contingencies and is later used to deliver energy which is being routinely depended upon, it is no longer part of the reserve, and more reserves must be provided.

The proper amount and type of all kinds of reserves is a very important test of the reliability of the physical plant that makes up a system, a pool, or an interconnected collection of pools. All reserves cost money which must be added to the other costs of the system and paid by that segment of the public which is served by the system, whether or not a kilowatt-hour is ever generated or transmitted by such facilities. Therefore, a substantial part of the time and ingenuity of the electric power industry is expended in a continuous and continuously changing search for methods to reduce the cost that must be expended on reserves without adversely affecting the ability of a system to meet contingencies.

There are endless possible combinations in planning and design that have an effect in this example of balancing cost and quality. The best combination of actions will vary from time to time, region to region, and system to system.

Mr. J. B. Tice of General Electric Co., writing about generation reserves in the November 20, 1967, issue of Electrical World, states:

> Individual utility systems have widely diverse generation reserve requirements. When they pool together, new requirements appear and some of the old ones disappear. When large pools interconnect effectively with neighboring pools, the combined reserve needs take on still a new complexion. Such reserve requirements are dependent upon relationships involving generating types, sizes, interconnection capacity, and load characteristics—and these are ever-changing variables.

PLANNING TO MEET ANTICIPATED LOADS

Planning for an increased bulk power supply to reliably satisfy increasing loads requires that many value judgments be made by responsible system managers familiar with all local conditions.

We mentioned, in connection with reserve requirements, that electric systems must constantly plan facilities in order to meet the demands of estimated future loads. Perhaps a more general treatment of that subject will illustrate that planning is essentially a continuous process of judging among various alternatives, each of which has a price tag.

Assume that a pool of several systems has a certain load, sufficient generation, transmission, and other facilities to serve the load, and sufficient reserves to meet contingencies which have any reasonable probability of occurrence. A new load estimate indicates that in 5 years the load will have grown by 1 million kilowatts, unequally divided among systems in the pool. Thus, a new power supply is required. What must the affected systems consider in planning for it?

(a) Build a steamplant—

(1) Close to the load centers to save transmission costs or landscape disfigurement?

(2) Far from the load centers to avoid air or water pollution or general community opposition?

(3) With one large generating unit to save unit costs of generation, or more but smaller units to save costs of reserves?

(4) Nuclear fueled to minimize air pollution or fuel delivery difficulties, or fossil fueled to permit more flexible operation or avoid community apprehension of nuclear contamination?

(b) Install additional hydrogenerating units in an existing dam, or build a new dam if a site is available?

(c) Buy power from someone outside the pool and provide transmission to bring it in?

(1) What additional transmission within the pool will that require?

(2) Will reserves also be purchased outside?

(3) How much transmission must be built outside the pool to protect against loss of the lines over which the deliveries are to be made?

(4) Can a load shedding system help protect against loss of the transmission over which the power is delivered?

(d) Use some combination of these and other alternatives?

In practice, the proper answer would probably involve some combination of most or all of these, and answers to many complicated questions which we have not mentioned. Each alternative has a cost, and none of the costs are the same. Each answer has an effect on reliability which must be calculated through complex analyses of the systems, the pool, and any outside systems with which the pool may be interconnected directly or indirectly. As to transmission, a correct resolution may involve more transmission within or outside the pool, less transmission outside the pool, or more transmission outside the pool with safety relays to open the circuits upon certain contingencies.

Each of these determinations depends on the electrical characteristics of each system and interconnected collection of systems at a particular time and in a particular area. A proper decision will also depend, in some instances, on a balance between the cost and availability of borrowed capital which may be required for one set of alternatives and an increase or decrease in operating costs that might result from another set.

DIVERSITIES IN SYSTEM CHARACTERISTICS

Due to the wide diversities in physical, and therefore electrical, characteristics of systems, broad physical standards for equipment are inapplicable—only performance criteria applicable to a system as a whole can have practical value in enhancing reliability.

Another important aspect of planning is the relationship of such planning to the particular system, pool, or interconnected region. The physical property, the "hardware" of electrical systems, is not static. Rather, it is constantly changing due to load growth and to technological advances producing new and improved equipment. The rate of growth in the electric industry as stated by the Federal Power Commission National Power Survey in 1964 is in excess of 6 percent per year. This means that the total capability of the industry on this date must be doubled within 11 years. The characteristics of the growth of individual systems, areas or regions are all different. Accordingly, there is a great difference between the physical plant within the industry. This, in turn, results in differences in the electrical characteristics of various systems. Further, the electrical characteristics of the individual systems, areas and regions are constantly changing as physical properties are added to serve load growth and as generation is installed at various locations within the system's transmission grid. A perfect example is the difference in physical and electrical characteristics between our generally hydro-based operations in the Northwest and the steam operations in other parts of the country. The differences between hydro and steam facilities result in different decisions as to the proper types and amounts of reserves and differences in many other factors that relate to reliability.

Because of these diverse characteristics, the physical plant of the industry does not lend itself to broad physical standards of national application. The type or amount of equipment that may be proper in one place may be totaly inadequate or unnecessary expensive in another. Moreover, since every system is custom built, new facilities must be chosen to fit with those that already exist. The only criteria that can have practical value are those which may help to describe the end product in terms of the ability of a system as a whole to perform its service function; there can be no standard approach as to how to arrive at a desired quality of service.

THE CONTINUOUS AND CHANGEABLE NATURE OF PLANNING

Plans do not remain fixed, but must constantly be revised in order to protect the reliability of the system, and therefore administrative delays would defeat the purposes of proper planning.

Although most planning is done on a long-range basis, the planning process must be sufficiently flexible to allow for immediate revision, modification or addition. There are many decisions that must be

made by power system managers which involve a combination of planning for construction, planning for correct operating procedures, and actual operations. For instance, fast changes in the size or location of load requirements may require that plans be changed in order to cope with the threat of immediate instability. In the 1967 budget of the Bonneville Power Administration, approval was given for the construction of a 500-kilovolt line between the Vantage Substation and the Covington Substation, both in the State of Washington. Within a year circumstances required that the line be shifted from Vantage to Rocky Reach Substation. As another example, because of a failure of a 500-kilovolt transformer for the line between Hanford and Covington, Wash., it became necessary to shift 345-kilovolt transformation, as well as to make physical line changes, so the Hanford powerplant could operate at 345 kilovolts in order to avoid restriction of the area power supply.

The loss of the Lower Baker plant, due to a completely destructive landslide in the spring of 1965, resulted in a necessary change in operating procedures as well as strengthening the transmission interconnection between the Puget Sound Power & Light system and the BPA system.

Such outages and changes cannot be anticipated. When they do occur, the operating personnel and management of the affected systems must have the ability not only to make immediate operating changes but also to make compensating changes in plans for physical plant. The best planning is that which can be made final as close as possible to the time that construction schedules preclude further change. Unnecessary freezing of plans, or delays in planning changes, tend to inhibit reliability.

Somewhat related is a general class of outages that will further illustrate the need for fast and flexible planning action by the responsible power managers. It is known as a second contingency outage. In practically all instances, the electric industry provides sufficient generating, transformation, and transmission reserves to compensate for emergency outages that may have any reasonable probability of occurrence. However, if such an outage occurs and persists for longer than a few hours, physical changes and operating changes must be made as rapidly as possible so that, in the event a second contingency occurs, reliability of the system is not lost. These essential, rapid changes cannot await administrative review and delay or reliability will be destroyed.

Proper planning for a physical system capable of providing reliable service is a continuous, flexible, and localized process requiring innumerable value judgments among possible alternatives. Any substantial delays that are imposed on the industry's planning processes will tend to destroy planning effectiveness. Also, any restrictions on planning flexibility in developing a reliable overall system or pool will tend to prevent development of the most reliable plan to meet local circumstances.

OPERATIONS

It takes a large number of highly skilled men exercising good and independent judgment to operate a modern electric system, however well planned, so that service reliability will be maintained—autonomy and flexibility of operations must therefore be protected.

The second basic element in establishing a reliable bulk power supply system is the operation of that system. Although the industry constantly strives to plan and install physical plant that will provide the optimum in reliability and economy of service, it is constantly confronted with load growth and load patterns and with mechanical and human failures that could not reasonably have been foreseen. Thus, the operation of the physical plant which is in existence, however well designed that physical plant might be, is frequently more important in maintaining reliability than the plant itself.

For years the Northwest has had an extremely strong network of transmission lines, and great effort has been put forth to operate the pool in a manner to maintain the maximum reliability that the physical plant was able to provide. We are submitting for the record a sampling of agenda, minutes and reports of the Northwest Power Pool prepared in the past several years. They clearly indicate that the attention of the committee has been primarily focused upon reliability of service. The voltage and reactive study prepared semiannually by the Northwest Power Pool, and referred to in the agenda, is a good example of the constant effort that the operating people are putting forth to maintain reliability.

A great many men are needed to plan and execute the desired operations. They are highly trained and knowledgeable and must be intimately familiar with the characteristics of their systems. Their qualifications include years of experience as well as excellent technical training and knowledge.

Of the many unexpected things that can happen in the operation of the complex of men and machines which makes up an electric power system, some happen at the speed of light. Space age science can reduce the number of surprises somewhat and can help to gather information necessary to deal with emergency situations. The technological problems involved in this part of operations are, as indicated by the previously mentioned report of North American Rockwell, Inc., roughly equivalent to those encountered in the exploration of outer space. However, no scientific method presently known or foreseeable can remove the major, decisionmaking responsibility from the shoulders of the operating man on the spot. It is obvious that operations must remain highly flexible and that operating people must retain a maximum of autonomy. Proper operation results from good experience and careful training and from the ability of operators to make sound and deliberate, but very rapid, judgments.

Thank you.

The CHAIRMAN. Thank you, Mr. Porter. There doesn't seem to be any common denominator with your people, is there?

Mr. PORTER. With this business?

The CHAIRMAN. You point out that each system is different and has different problems.

Mr. PORTER. That is correct.

The CHAIRMAN. Have there been any technological advances in the past few years which will help make systems more reliable than they were, say, 10 years or 15 years ago?

Mr. PORTER. I think we are continuing to improve our reliability of service. I can think back a few years when I started in this business. Of course, we didn't have very many electric plants or appliances in those days, so if the frequency wasn't at precisely 60 cycles, it didn't

make too much difference. But now with the greater use of electric service, we have to.

The CHAIRMAN. I was thinking in mechanical terms. I was thinking that if you had put this Northwest Power Pool together 20 years ago, there was certain harware that you would have been able to use. Is it better now than it was then—more reliable?

Mr. PORTER. Yes, we have much more sophisticated equipment than we had 20 years ago. That's part of the improvement that we've been able to realize.

The CHAIRMAN. Do you have any position on the Federal Power Commission certification of EHV transmission lines?

Mr. PORTER. We would be against that particular proposal. We think that would only tend to delay construction of needed lines.

The CHAIRMAN. The bill says there might be a 2-year period for commission review of the construction of lines of 200 kilovolts and above. Could you give us your opinion of its provisions.

Mr. PORTER. In my opinion, as I mentioned, I think that could only delay the construction of needed lines. Regardless of where you construct a line, it's difficult not to find some opposition to it. I think utilities have been very conscious of the problems of transmission construction. Sometimes it's necessary to build the line in a particular region, and probably somebody has a valid objection to it. But it's almost impossible to satisfy everybody all the time.

The CHAIRMAN. Would arguments arise generally from differences of opinion concerning proper land use in an area?

Mr. PORTER. Yes.

The CHAIRMAN. Has there been progress in the industry or even under local ordinances in increasing the proportion of underground lines?

Mr. PORTER. There's a lot of effort and research.

The CHAIRMAN. I mean underground lines.

Mr. PORTER. There is effort being developed to perfecting underground transmission. At the present time these higher voltage lines must remain overhead because in most cases it would be almost prohibitively expensive to put the lines of 230 kilovolts and higher underground except under special circumstances.

The CHAIRMAN. If you could put them underground, would the maintenance be cheaper over a period of time?

Mr. PORTER. I think the maintenance would probably be somewhat reduced. On the other hand, if you do have trouble, you are probably going to have a longer outage in making the necessary repairs than you would have if it were overhead.

The CHAIRMAN. Does your company, for example, think about other land uses when they put a line in and take some property.

Mr. PORTER. We certainly try to recognize other uses of a particular right-of-way and in selecting a given route we will try to select one that will have a minimum of impact on other uses of that land.

The CHAIRMAN. I think most of the opposition to this comes because you take up space that could be used for other purposes.

Mr. PORTER. We have some places where they raise Christmas trees on the rights-of-way.

The CHAIRMAN. Does the city have public hearings, where everybody comes in and has a say, before it puts a line through? I realize

you can't give people power without putting lines up, but we hope you do this in the best possible way to give them the power and still make maximum use of the land's potential. I'm just trying to suggest something. Isn't there more and more concern about proper land use with the power people?

Mr. PORTER. I think there's a growing awareness to environmental effect.

The CHAIRMAN. The whole environmental situation. That's the way it should be.

Mr. PORTER. We certainly wouldn't disagree with that.

The CHAIRMAN. Especially since land is getting a little scarce in many areas.

We'll recess here until 9 o'clock tomorrow morning.

(Hearing recessed at 12:30 o'clock.)

ELECTRIC POWER RELIABILITY

THURSDAY, DECEMBER 21, 1967

U.S. SENATE,
COMMITTEE ON COMMERCE,
Washington, D.C.

The committee met at 9 a.m., pursuant to recess, in room 815, U.S. courthouse, Seattle, Wash., Hon. Warren G. Magnuson (chairman of the committee) presiding.

The CHAIRMAN. Will the meeting come to order? I would like to welcome all you hearties who made it here in the snow today. Cliff, you're our first witness. For the record, Mr. Erdahl is the director of utilities for the city of Tacoma. What will you talk about?

Mr. ERDAHL. Senator, I'm going to try to draw some conclusions from the other speakers and tell you the best we can what we as a group think the situation is.

STATEMENT OF C. A. ERDAHL, DIRECTOR OF UTILITIES, CITY OF TACOMA

Mr. ERDAHL. By the foregoing testimony we hope we have illustrated that the optimum degree of reliability results from proper operation and proper planning. Both require continuous work, rapid adjustment, case-by-case analysis and judgment, and an army of highly skilled and responsible people. In short, decisions must be fast and they cannot be standardized.

We do not believe that S. 1934 would lead to enhanced reliability because much of the proposed type of governmental action is inappropriate for the desired objective. The administrative procedures through which the FPC acts are not adaptable to the fast and flexible decisions required for proper planning and operation. The provisions of S. 1934 affecting transmission lines pose one excellent example. Transmission lines are very often required on short notice in order to maintain reliable service in the face of ever-changing power demands. The procedures in S. 1934 for approving regional coordination plans, taken together with the transmission certification provisions, would in most cases permit anyone who might oppose a transmission line, for any reason, to delay the line through an adversary hearing and subsequent court review.

It presently takes a minimum of 2 years to plan and build a transmission line. S. 1934 would increase the time required by a minimum of 6 months and prudent management would undoubtedly feel that it would have to allow several years for the administrative process. When the time to commence construction arrives, conditions may have changed so as to indicate the desirability of a different arrangement

than was indicated at the time the original application was filed. The greater the leadtime required, the less likely it is that the best answer will be forthcoming. This coupled with the tremendous number of applications to be processed, which we estimate to be 300 per year, the requirement for a hearing where transmission lines cross public lands, and the probability of a hearing where there is any opposition will, in our opinion——

The CHAIRMAN. When you say 300 per year, that figure is nationwide?

Mr. ERDAHL. Yes.

This will swamp the FPC and do much to prevent reasonable solutions to the problems faced by the industry.

Our fear of delays is also raised by the provisions of S. 1934 that affect generating facilities. While it is true that S. 1934 does not give the Commission direct jurisdiction over thermal power production facilities, no such facility is useful without transmission. The complete authority over transmission provided in S. 1934 would give the FPC de facto control over new generating facilities. A particular commission may or may not so use its authority, but the authority is there if they desire to use it.

The provisions of the bill giving FPC authority to require interconnections between unwilling parties and requiring suppliers of power on short-term contracts to secure approval of the Commission to discontinue the service after the contract has expired are highly controversial. There are those who want this type of legislation. Others feel that the certification of transmission lines coupled with these additional powers could be used by FPC to take over the actual management of all utilities. So far as the Northwest is concerned, we have no problems for which these would provide a constructive solution, and at least some feel that they could be detrimental to our efforts to achieve reliability at the lowest possible cost.

The quality of electric service can be maintained and improved through cooperation and communication between the industry, the public, and all levels of government. Certainly there are several fields in which such cooperative efforts could be usefully employed or increased.

One field would be to attack the basic question of what constitutes an acceptable degree of reliable service. It will be a difficult task at best, and an absolute definition is probably neither possible nor desirable. General guidelines might prove a genuine aid to management judgment, as well as a measure of whether the industry and individual utilities are properly discharging their obligation. Such guidelines should deal primarily with preventing the cascading of failures from one system or pool to another. They should be prepared at the regional level and published for the information and use of anyone interested.

Improvement in service reliability or its maintenance at reasonable costs will require solutions to difficult engineering problems, and cooperative efforts to solve such problems should be increased. Intense use of all technical and managerial skills will be necessary to carry out this work. The needed experts are in very short supply and presently heavily employed. Therefore unstinting contributions of talent from all parts of industry and all levels of government are necessary and should be requested and encouraged.

The search for increased technical knowledge should be organized and pursued on the national level through a committee composed of recognized experts fairly representing the various segments of the power industry, including the Federal Power Commission.

In addition to the preparation of guidelines for system performance which will constitute on acceptable degree of reliability, voluntary regional organizations fairly representative of all segments of the industry within the region should undertake the duty of coordinating planning within the region and publishing plans that are developed.

Additionally, a present legal impediment should be removed in order to encourage the cooperative efforts described above and the many other cooperative undertakings by various groups that can lead to improved service and lowest costs to the public. A strict application of the antitrust laws might preclude, and therefore will impede, such cooperative efforts. We refer to the hearings on S. 683 held earlier this year for our views on a legislative method to remove this impediment and fully protect the overall public interest. We believe that the antitrust provisions of S. 1934 are inadequate and could in fact place the industry in a dilemma.

We agree there is a public interest in reliable electric service. However, it is a very difficult problem to determine whether that public interest is being properly served from time to time. Our suggestions are designed to establish, through the adoption of reasonable guidelines or criteria, a level of reliability which the public is willing to afford and intends to demand. Such criteria will thus define the public interest. An organized attack on the problem of criteria as we have suggested, carried on in the full glare of public scrutiny, will produce proper criteria faster and more efficiently than could be expected under administrative proceedings.

Our suggestions do not include any direct Federal enforcement authority. Based on our experience in the Northwest, we do not believe it is necessary. We will sit down together and solve our reliability problems without anyone standing over us with a stick. We all know that our customer will promptly inform us if the lights go out, and they will carefully explain the reasons why we should have been working even harder to avoid as many failures as possible.

The electric power industry in the United States has grown to the world's largest and finest system. Though operation of the power system is a very intricate matter, the scientific and managerial problems have been calmly resolved so successfully that the American public has reasonably come to expect that sufficient electric power will, as a matter of course, be available at the flick of a switch almost without exception. And it will be.

The present ability to manufacture larger equipment with cheaper unit costs of power output intensifies the problems of providing reliable service. But these problems will not prove to be insurmountable any more than were the problems entailed in the growing pains of the past. Government and industry should now be cooperating in every way to assure that improvements will continue in an already highly successful industry. It is not a place where proven methods should be abandoned or superseded.

Those who have the ability and the responsibility to operate the electric power industry and to secure the funds necessary for its de-

velopment must retain the authority to enable them to carry out their responsibilitites. The public is clearly entitled to demand and receive results that are necessary to protect the public interest, but the industry must retain both the ability and the responsibility to determine the way to get those results.

The CHAIRMAN. You speak of legal impediments in your statement. You are talking about the hearings, we held on S. 683 in Vancouver; [1] is that correct?

Mr. ERDAHL. That is correct, Senator.

The CHAIRMAN. It seems to me that in order to achieve even a voluntary arrangement for reliability, we would have to give the Federal Power Commission the authority to approve these pooling arrangements. We're not talking about mergers. It seems to me that some immunity comes first, doesn't it? Do you agree with me?

Mr. ERDAHL. Not being an attorney, I wouldn't want to comment.

The CHAIRMAN. Suppose you had an agreement with City Light and another agreement with Puget Sound Power & Light. The Federal Power Commission should be able to review the agreement, and say this looks all right because it is going to give us the efficiency and reliability we're talking about.

Mr. ERDAHL. It may be so. The question is——

The CHAIRMAN. Occasionally somebody might stand up and say there is an antitrust problem. The Power Commission should be the best agency to pass on this question, not the Attorney General.

I hadn't thought of that. But S. 683 sort of ties into this whole business. Don't you think so Gordy?

Mr. CULP. Yes; in our previous hearings on S. 683, we described why it is important to get one single decision from the U.S. Government as to whether or not a voluntary contract is consistent with the overall public interest. If it is decided to be in the public interest, participants in it should be exempt from the operation of all antitrust laws. The negotiation of voluntary agreements will be impeded unless there is a mechanism to secure such dependable governmental decisions.

The CHAIRMAN. What you're trying to say is we should give you a legal umbrella to enable you to achieve what we're talking about.

Mr. CULP. To permit it to be done voluntarily.

The CHAIRMAN. Yes, it would be permissive. It's not a matter of right. It's permissive.

Mr. ERDAHL. I think as long as you approach it on the basis that it's permissive, it is fine. We are able to work with the Federal agencies, as we stated, on a voluntary basis. Just to be clear, Senator, none of us has any feelings that the Federal Power Commission is not cooperative. They are very capable, and we work with them very well; and we have a lot of respect for the people in the Federal Power Commission. We just feel that we could do a better job on a voluntary basis. We have accomplished many things in the Northwest on a voluntary basis.

During World War II, in 1942, the Federal Government suggested or nudged us and said, "You form a power pool voluntarily, or we will set up one." We organized the Northwest Power Pool and it has worked most successfully. We have a feeling if that kind of nudging or suggesting could be said to others, the results might prove equally productive. I feel that the introduction of this bill that was submitted by the executive branch to the Congress has already accom-

[1] Serial No. 90–38, Senate Committee on Commerce.

plished something in that direction by reminding people that they do have that responsibility. We believe that the area's individual utilities feel that such responsibility is primarily ours and we would like to have the help of FPC; but we'd like to have it on a voluntary basis.

The CHAIRMAN. What we're trying to do in S. 683 is to give you the right to be exempt from private antitrust suits in cases where you might achieve this objective voluntarily. I think maybe the two bills should be considered together.

Mr. CULP. We agree; and I would like to add one thing, Senator. S. 683 would provide that, where an agreement was found to be in the overall public interest, after balancing all of the various aspects of the public interest, it would be exempt not only from State or private antitrust suits but from antitrust prosecution or civil action by the Department of Justice. One of the main problems with regard to the antitrust provisions of S. 1934 is that they would not give any protection against State suits or civil or criminal actions by the Department of Justice.

The CHAIRMAN. As Cliff Erdahl points out, you lawyers raise these problems. But there is a problem there, and we should look carefully at it.

Now, I think this record ought to show a discussion of your statement that needed experts are in short supply in this field.

Mr. ERDAHL. With all the meetings that we have in the Northwest Power Pool, the Western States Coordinating Council, and so forth, in connection with power operations and power supply, we can honestly say it requires so many of our top experts to be traveling here and there to the meetings to coordinate these efforts that finding people that are qualified in the field is a continuing and expanding problem. It's a real problem, not only for our utilities but utilities all over the country.

The CHAIRMAN. I think we heard testimony in Washington to that effect. The availability of people that are familiar with the subject is limited.

I happen to wear two hats in this matter. I handle the appropriations for the Federal Power Commission in the Senate, and I suspect that if this bill passed, they could come around to me and ask to raise salaries so they can snatch people you now employ to do the work.

Mr. ERDAHL. It would appear to me that with the number of people that are qualified in this field——

The CHAIRMAN. That's exactly what would happen.

Mr. ERDAHL. Yes; that's exactly what would happen if they raised the price. We would lose some people, and we don't have any too many people that are qualified to deal with the problem.

The CHAIRMAN. If they don't have the experts there, they might have to do that.

Mr. ERDAHL. If they're going to take on this problem, they cannot build——

The CHAIRMAN. They've got an awful lot of lawyers down there. But I think it ought to be pointed out to the public that this is a complex thing, and the number of people who are available that understand it are in short supply.

Mr. ERDAHL. I think we could set a pattern in this kind of an operation that would do well for many operations, to have the Federal

Government cooperating and working with us in the general public interest. We believe that many times when Federal agencies sit in our meetings feeling that they have special authority, we don't get the best results because their determinations are made before you get to the point—the ultimate or best results.

The CHAIRMAN. Gordy, you can sum up here as quickly as possible because we have some other witnesses.

Mr. CULP. Very well.

SUMMARY BY GORDON C. CULP

Based on our experience in the Northwest, we have gathered the following thoughts to be studied during the various hearings to be used as appropriate patterns of action to continue to improve reliability of electric service:

A. Regional councils

1. Voluntary regional councils on reliability should be organized in each region with appropriate representation from each electric system operating facilities that could have a substantial effect on the reliability of regional bulk power supply. The FPC and each affected State regulatory body could designate an observer or nonvoting member of each regional council.

2. Regional councils should perform the following functions: (*a*) Develop minimum performance guidelines for maintaining reliability of bulk power supply within the region, and (*b*) coordinate plans for regional bulk power reliability.

3. A full report on progress with regard to regional plans and reliability guidelines would be submitted annually to the FPC, the appropriate committees of the Congress, each affected State regulatory body, and the National Advisory Committee on Reliability. Such plans and guidelines should be subject to change by agreement of the regional councils at any time and reports of such changes should be submitted as soon as possible.

B. National Advisory Committee on Reliability

1. A National Advisory Committee on Reliability should be organized with appropriate relationship to regions, the number of customers served, and readily definable types of utility ownership. It should also include representation from the Federal Power Commission and experts in the field from the scientific community at large.

2. The committee should be authorized and encouraged to proceed, in cooperation with the industry, all branches and levels of government, and equipment manufacturers, to study all technical matters that will lead to enhance reliability. The committee could conduct such studies directly or through educational or research institutions; for example, the Electric Research Council or private contractors. Some permanent staff would be needed.

3. The committee should consult with and advise the regional councils in the preparation of performance guidelines for the region. It should also prepare minimum performance guidelines calculated to minimize the cascading of service failures from one region to another insofar as practicable with present technology and within acceptable economic limits.

4. All proceedings of the committee should be published.

The CHAIRMAN. And the Federal Power Commission should have a large part to play in this?

Mr. CULP. Yes, Senator; they should take an active and systematic part in the work of the National Advisory Committee and should advise and assist the regional councils in their planning work and preparation of reliability guidelines.

These suggestions provide for reliability guidelines to be devised by the industry with the help and advice from the best experts that can be found. We believe this method will be the most efficient due to the local nature of solutions to reliability problems and the common desire to find solutions. There is precedent for this method of developing effective criteria. The National Electrical Code and the National Electrical Safety Code are good examples of rules devised primarily by industry. However, we want to emphasize that these rules constitute detailed physical standards—a type of criteria that, as described previously, would not be applicable to electric service reliability. Exhibit 5 briefly explains how these codes are prepared.

(The information follows:)

EXHIBIT 5

INFORMATION RELATING TO THE NATIONAL ELECTRICAL SAFETY CODE AND THE NATIONAL ELECTRICAL CODE

NATIONAL ELECTRICAL SAFETY CODE

The National Electrical Safety Code is published by the National Bureau of Standards of the United States Department of Commerce, and provides safety standards for materials and installation in the electrical industry. Originally the National Bureau of Standards invited the recommendations of the electric industry but reserved the final decision on all standards incorporated in the Code. Now, however, the standards themselves are promulgated by committees of private individuals within the industry and in related fields and are adopted by the Bureau as its official rules. The reasoning of the Bureau was summarized by its then director, E. U. Condon, as follows:

> The Bureau, as sponsor for the work under this procedure, has given up its prerogative of determining details in return for the implied understanding that the many parties concerned will accept such a code as they can agree upon among themselves. All such codes of practice necessarily include compromises between conflicting aims. The Bureau has felt that decisions made by practically unanimous agreement among the interests affected would, in general, be wiser than those at which it might arrive after weighing the arguments of advocates for different views. It has, therefore, welcomed this procedure in spite of the fact that this involves the acceptance of some details of which it might not itself approve.

NATIONAL ELECTRICAL CODE

The National Electrical Code is sponsored and published by the National Fire Protection Association, an organization which promotes fire protection and prevention and whose membership includes over two hundred national and regional associations and over twenty thousand individuals, corporations and organizations. First published in 1897, the Code is offered by the Association in an advisory capacity "for use in law and for legal regulatory purposes in the interest of life and property protection." Many state statutes provide that compliance with the Code shall be admissable as prima facie evidence of compliance with state law relating to electrical safety. The standards appearing in the Code relate primarily to materials, equipment and installation procedures used in the construction of houses and buildings, and are promulgated by the National Electrical Code Committee, a group of individuals representing the electrical and casualty insurance industries and related fields.

In considering our suggestions, it is important, we believe, to note that legislative action to enhance reliability of electric service would

not be a "safety" measure in the usual sense of that term. At least it would not be reasonably comparable to other recent legislation on which this committee has taken action, such as the pipeline safety bill of the Motor Vehicle Safety Act. The aspects of the electric power industry similar to the matters covered by such safety measures are presently covered by the National Electrical Safety Code of the U.S. Bureau of Standards and by various State codes and statutes, all of which are now observed by the electric power industry. Any action on reliability must have as its central purpose the encouragement of an increasing amount and quality of the total service provided by electric systems. This is very different from safety measures intended to preclude bodily injury to citizens which may incidentally result from improper actions taken by companies in the prosecution of their main business. The provision of reliable electric service is the main business of the electric industry—the very result for which electric systems are formed.

The CHAIRMAN. Suppose someone in Congress suggests a national electric safety code. Do you think this would be different from insuring reliability?

Mr. CULP. Yes, Senator. There is a National Electric Safety Code in existence; it covers matters of personal safety similar to those covered by safety measures existing or proposed for other industries. The National Electrical Safety Code is followed today.

The CHAIRMAN. But you're saying that's a different thing?

Mr. CULP. That's different from what we were talking about.

The CHAIRMAN. I just don't know about that. It raises technical problems, but I suspect that this Congress is going to hear some suggestion for a National Electric Safety Code, maybe only for exposed wires. I don't know whether it's needed or not, but it may be part of the whole picture, like the pipeline safety bill and the auto safety bill.

Mr. CULP. That is a different question than we have before us now, Mr. Chairman.

The CHAIRMAN. It might involve, for example, some kind of guidelines for people who build lines, maybe limited to new lines. I'm sure new lines are better than the ones you built 10 or 20 years ago. But I'm glad you pointed out that this is a different subject altogether. In order to conserve time, the staff has some questions on all of this testimony which they will submit to you, folks in writing. We will leave the record open so you can give careful consideration in answering them. We want to make the record as good as we can, and we can keep it open till the first of February, if you want. The staff will submit some questions to you shortly.

Thank you very much.

Mr. CULP. Thank you again, Senator, for listening so patiently to all of our testimony.

(The questions referred to and the answers supplied by Mr. Culp follow:)

Hon. WARREN G. MAGNUSON,
Chairman, Senate Commerce Committee,
Washington, D.C.

MY DEAR MR. CHAIRMAN: The following are our answers to questions submitted to us by the staff following the hearings held on December 20 and 21, 1967, in Seattle, on S. 1934 and related bills. These answers have been prepared by the following witnesses: Messrs. Timme, Price, Elmore, Porter, Erdahl and

Culp. Time has not permitted us to pursue agreement with these answers by the seventeen utilities on behalf of which these witnesses presented the agreed statement.

Sincerely yours,

CORPORATE SERVICES,
GORDON C. CULP.

Question 1: In discussing the antitrust provisions of the bill, which would exempt any utility participating in an approved regional plan from private antitrust suits, Chairman Lee White made the following statement:

"We believe that this will adequately protect the regional councils and their plans from suits brought primarily for the purpose of stalling a plan, adopted after proper consideration by the council and approved by the Commission, but for some reason unsatisfactory to a single party. On the other hand, the chance of really harmful anticompetitive behavior—a chance we believe is very slight—will continue to be guarded against by the power of the Attorney General to bring suit at the instance of the Antitrust Division. Since the regional council itself would be open to every utility in the region, it is most probable that any possibly restrictive provisions in a regional plan would be fully exposed and corrected before the plan was adopted. For this reason, the immunity would extend only to actions taken pursuant to the regional plans; that is, to arrangements which the regional council had in fact sanctioned. A broader immunity might have the unfortunate effect of making it equally possible to achieve security from antitrust suits without going through the regional council's procedures, a course we believe is fundamentally inconsistent with the purpose of the Reliability Act."

Would you care to comment in more detail on this statement?

Answer: In our opinion, the partial antitrust immunity proposed in S. 1934 is worse than no mention of the subject at all. It does not provide the protection necessary to encourage the cooperative actions that reliability requires. Under section 404(d) the Commission could find that an action under an approved plan has a restraining effect on competition but that such effect is outweighed by other public interest considerations. However, at any time thereafter, the Department of Justice could bring suit, basing its action on the very finding of the FPC that there was a restraint, and neither the Department of Justice nor any court would be required to consider the various elements of the public interest evaluated by the Commission.

This is not an academic point. Antitrust questions are among the most difficult to be found in the law, and reasonable people with different outlooks and different backgrounds can, and often do, disagree. For example, in the El Paso case the FPC and the Attorney General, who was later supported by the courts, came to exactly opposite conclusions under the same state of facts. The bank merger cases and the protracted legislative action that followed pose another illustration of how the Attorney General and another agency of the United States can see the same facts in a different light and press their separate views.

Where, as in the case of electric service reliability, broad and dependable agreements for cooperative action are needed, we cannot see how the public interest can be served by codifying this legal state of limbo. The industry and the public is entitled to have a definitive decision, as is suggested in S. 683, from the United States Government, as such, as to whether or not a proposed cooperative action is in the over-all public interest; so the industry can dependably proceed with such action or be informed that it must embark on some other course which will be in the over-all public interest.

S. 683 provides a practical way that questions involving competition can be considered and decided by the FPC with full participation by the Department of Justice and any other interested party. As described in our previous testimony on S. 683, we believe that it would provide a reasonable and efficient vehicle through which all elements of the public interest can be protected while encouraging the cooperative actions required to provide reliable service at the lowest possible cost to the public.

Question 2: When power companies construct transmission lines across non-Federal lands, are there currently public hearings to determine land use questions?

Answer: This is something that varies from state to state and locality to locality. The problems in this connection would seem to be no different than any other zoning problems which state and local governments presently handle. Whether a manufacturing plant should go in at a particular locality or whether lands should be restricted to particular types of uses or particular designs,

would seem to be primarily a local question whether a utility company of some other industry is proposing to use the land.

Question 3(a): What are the conditions on which non-Federal utilities can secure transmission line rights-of-way across Federal land?

Answer:

1. The Secretary of Interior must find that the transmission line does not conflict with an undefined power-marketing program of the United States.

2. The permittee must accept the right-of-way grant subject to the following conditions:

(a) If the United States acquires the facility, it will not be required to pay any value for the right-of-way.

(b) The permittee must allow the Department of the Interior to use surplus transmission facility capacity of the permittee in excess of its needs as determined by the Department or by arbitration.

(c) The permittee cannot regain such excess capacity taken by the Department except on three years' notice.

(d) The permittee must allow the Department of the Interior to increase the capacity of the transmission line on an incremental cost basis, which increased capacity can be used exclusively and only by the Department of the Interior.

Question 3(b): Do the Northwest utilities favor continuation of the right-of-way regulations of the Interior and Agriculture Departments, including the wheeling conditions?

Answer: The Northwest utilities may not have identical positions on each of the regulations adopted by the Interior and Agriculture Departments. To date in the Northwest the regulations have had a varying impact on various utilities serving the area. Some utilities have been seriously delayed in constructing important transmission lines while problems presented by the regulations have been thrashed out, and these delays have created some reliability problems. It would be desirable to have the authority over land use of United States lands placed in a single and separate department so that any conflicts of interest could be eliminated. This is a broad subject under review by the Public Land Law Review Commission and should be considered separately from the more narrow problems of reliability.

Question 3(c): Do you understand that the Department regulations would be dropped if the legislation as passed includes FPC certification of EHV transmision lines?

Answer: We are not aware of the intentions of the departments as to whether or not the departmental regulations would be dropped if legislation included FPC certification of extra high voltage transmission lines. However, under the bill, the various departments have an absolute veto right which is tied in with aesthetic or historical values; and it is difficult to conceive a situation where a department might not be able to justify a veto on one of these bases under almost any circumstances.

Question 4: How would your proposal differ from the regional planning currently undertaken by the Pacific Northwest Utilities Conference Committee and the Northwest Power Pool?

Answer: Our proposal would make at least four substantial changes in the Northwest regional planning methods in order to adapt to the increasing complexities of regional power systems. It would:

(a) Consolidate the presently diverse planning activities into a more efficient body.

(b) Publicly assign to that body the specific responsibility of planning for reliability of regional bulk power supply.

(c) Require us to devise and publish reliability guidelines which all bulk power suppliers in the Northwest region would observe.

(d) Institute systematic, advance consultation with the FPC, the state regulatory agencies, and an objective, national body of experts, with regard to reliability guidelines and planning.

The question relates to the Northwest region, and we have restricted our answer to that region without trying to describe any effects that our proposal might have on inter-regional methods such as those that were described by Mr. Goss with relation to the Western Systems Coordinating Council.

Question 5: Under your proposal, would the guidelines adopted by the regional councils be mandatory upon its members? Would the guidelines be adopted by majority vote, or would unanimity be required?

Answer: Our decisions always have been adopted by unanimous consent. That method has worked very well for us, and our proposal would not change it. The problem is to *find* the right answer—when it has been found, we have had no trouble with any utility organization refusing to cooperate. Moreover, when unanimous consent is reached, contractual implementation will usually follow. The Pacific Northwest Coordination Agreement is a good example. Many aspects of that agreement were worked out in an informal way and were voluntarily observed for some time until the technical knowledge and the need for more formal arrangements developed. They were then incorporated in a firm, 39-year contract, and are now mandatory on all parties. We would expect that the reliability guidelines developed under our proposal would be contractually adopted as soon as practicable, and therefore they would be mandatory.

Question 6: Under your proposal, how would you make sure that a company's actual plans and construction complied with the guidelines?

Answer: Our proposal contemplates continued individual utility responsibility. The State Commissions and the Federal Power Commission already have very substantial authority to require reasonable and adequate service at reasonable rates. However, the main force that requires such reliable performance by utility companies is the demand and pressure from their customers and local governmental agencies. Also, our proposed Regional Councils would be charged with the duty of coordinating plans for regional bulk power reliability; therefore, the plans of a company or agency would be available to them for comparison with the guidelines.

Question 7: Under your proposal, would anyone evaluate the regional guidelines and plans to insure that they are adequate and in the public interest?

Answer: They would be evaluated at every stage by the FPC and state regulatory agency representatives who would participate, in an advisory capacity, in the preparation of guidelines and coordination of planning. They would also be evaluated by other governmental bodies in the region and by the general public that is affected by the reliability of regional bulk power supply. However, we do not believe that any group or authority removed from the region should have its judgment substituted for the judgment of a Regional Council composed of those that are closest to the situation and most competent to analyze the many and material local conditions.

Question 8: Under your proposal, how could we be sure that the guidelines developed by the Regional Councils would represent more than the lowest common denominator of the member facilities views on reliability?

Answer: This question seems to assume that it is in the self-interest of utilities to provide unreliable service; and such an assumption would be incorrect. It is in the self-interest of utilities to provide reliable electric service. The fact remains that reliability and cost have to be balanced off against each other. It is our hope that Regional Councils could help in defining where that balance best lies. We assume that utilities will be grateful to have a forum in which this decision can be made or these factors discussed. We feel very strongly that the operations of the councils through exchange of information, discussion and voluntarily action by the members would be far more effective in achieving a reasonable balance between reliability and cost than would an administrative proceeding.

Experience shows that the industry in the Northwest strives for the highest practicable levels of reliability. There are good reasons why the pressures, within the industry itself, for increased reliability must continue. Since all systems in the Northwest are firmly tied together with each dependent upon the other, each system must adhere to standards of reliability that are acceptable to the customers of all systems. Therefore, system 1 is impelled to insist that systems 2, 3, and 4 maintain reliability at a level that is acceptable to the customers of system 1.

Question 9: In your regional planning proposal, you state that membership would be open to facilities having a ". . . substantial effect on the reliability of regional bulk power supply." Under this criterion would the small PUD's be excluded?

Answer: We in the Northwest have never thought in terms of excluding anyone. However, as a practical matter, meaningful participation requires attendance of someone technically trained in the problems of bulk power supply. Under our proposal we would welcome any utility organization in the region that could make a contribution toward solving the reliability problems of regional bulk power supply.

Question 10: How could we make sure that in a regional planning procedure the interests of the smaller utilities would be adequately represented, and that the Council would not act in large part merely to preserve the status quo?

Answer: The problems of reliability, particularly the cascading type of power failure which we assume to be the main subject of this bill, do not differentiate between small and large utilities. Cascading failures affect everybody the same way, and all utilities have an identical interest in preventing them. Our preceding answer describes our views on participation in the planning procedure.

Additionally, FPC representatives would be present at all proceedings and able to speak on behalf of any smaller utilities not otherwise attending. If anti-competitive actions, as suggested in your question, were to develop in spite of the inevitable warnings, the FPC or the smaller utilities could challenge them in their proper context—under S. 683.

The CHAIRMAN. Mr. Goss? Just go right ahead.

Mr. Goss. Good morning, Senator.

STATEMENT OF FLOYD L. GOSS, CHIEF ELECTRICAL ENGINEER AND ASSISTANT MANAGER, LOS ANGELES DEPARTMENT OF WATER & POWER

Mr. Goss. My name is Floyd L. Goss. I am chief electrical engineer and assistant manager of the Los Angeles Department of Water & Power. I appear here today as chairman of the Western Systems Coordinating Council, and I appreciate this opportunity to discuss with you the history and purpose and future plans of this council and its relationship to the general subject of electric power system reliability.

The Western System Coordinating Council is a council of the representatives of 40 utilities which either generate or transmit to points of distribution electrical energy in the 13 Western States and southwestern Canada.

Included in the membership of the council are 19 investor-owned utilities and 21 public agencies, including municipalities, public utility districts, generating and transmission associations, the Bureau of Reclamation, the Bonneville Power Administration, and the Department of the Army. The present membership represents substantially all of the bulk power systems in the area. However, membership in the council is voluntary and open to all bulk power systems. It can be anticipated, therefore, that additional utilities will join the council when, as the result of progress of interconnection and the evolution of their systems, it becomes evident to them there is a need to participate in the regional coordination.

The primary purpose of WSCC is to promote the reliable operation of interconnected bulk power systems by the coordination of planning and operation of generating and interconnected transmission facilities. The council provides a formal means for exchanging information and system data and for making necessary regional studies and recommendations designed to increase reliability of the interconnected bulk power systems. In order to accomplish its objectives the council will—

1. Prepare and keep up to date a forecast of the future electrical needs of the western region;

2. Accumulate data supplied by the member systems relating to their plans for generating and transmisison facilities necessary to meet these future demands;

3. Perform regional studies based on the above for the purpose of assuring the reliable operation of the western regional bulk power network;

4. Develop criteria for elements of system design and for operating procedures which affect the reliability of operation of the interconnected systems; and

5. Provide the means for coordination of the operation of the western regional network with that of interconnected systems outside the region.

Reporting to the council are two standing committees made up of representatives from each of the member systems. The first of these, the Planning Coordination Committee, will accumulate necessary system data, perform regional studies, and formulate reports and recommendations to the council. The second, the Operations Committee, will review and analyze day-to-day, as well as future, operation of the interconnected systems and operating procedures, and recommend to the council new or modified operating procedures as they may be required from time to time to assure reliability. The council as a whole will constitute a forum at which the results of the studies and recommendations of these two committees will be presented and discussed and new or modified criteria and procedures reviewed and approved.

Throughout the foregoing description of WSCC and its activities two terms have been used which require some explanation. The first of these is "reliability" which is a very broad term, some of the implications of which involve consideration of continuity of service to individual customers or small groups of customers. This is obviously not the proper concern of the council, but rather the responsibility of individual power suppliers. Therefore, as used in this statement, "reliability" is the degree of assurance of a bulk power supply system in the delivery of electricity to major points of distribution. The term "bulk power system" embraces generating plants, transmission lines, and substations which collectively furnish power to these major points of distribution.

Cooperative planning and coordination of the development and operation of electric utility systems is not a new concept in the West. The establishment of this council was merely the next logical step in the orderly development of cooperative effort and was brought about by two significant events during the early part of this decade.

The first event was the approval of the Pacific intertie project which will provide for the first time a strong interconnection between the Pacific Northwest and the Pacific Southwest areas of this western region. The second was the so-called Glen Canyon closure which effected an interconnection between the Northwest, Rocky Mountains, and Southwest portions of the region by means of transmission lines.

The impact of these events can, I believe, be best illustrated by reference to exhibit Nos. 1 and 2. Exhibit No. 1 shows transmission lines operating at 230 kilovolts and above, which existed in the western area in 1960. As you can see, these transmission lines formed one network which interconnected the systems in the general area of California and Arizona and parts of Utah, Colorado, and New Mexico.

At the top of the map there was another network of transmission lines which interconnected systems in Washington, Oregon, Idaho, and parts of Montana, Wyoming, and Colorado. Interconnections between these two areas were at this time either nonexistent or of such low capacity that there was no need for coordination of planning and operation for the total region. Rather, at that time this responsibility was carried on by organizations in the separate areas. In the case of the Northwest, coordination was carried on primarily by the Northwest Power Pool; for the Rocky Mountain area, by the Rocky Mountain Power Pool and the New Mexico Power Pool; and for the Pacific Southwest area, the Pacific Southwest Power Interchange Committee. There are in each of these areas other organizations such as, for example, the California Power Pool, which coordinate the planning and operations for individual groups of interconnected utilities.

Exhibit No. 2 is a pictorial representation of the extra-high-voltage transmission network covering the same west region as it will exist in 1970 after completion of various elements of the Pacific intertie and certain other interconnections in the Rocky Mountain area. This illustrates the fact that by this time the western region will be solidly interconnected by a ring of transmission which has been named "The Big Donut." As a result of these interconnections, the bulk power systems of the region will effectively operate as one system.

If I may digress for a moment, looking at one of the exhibits on the left, which is a drawing of transmission lines, the principal transmission lines of Western United States; and this "Big Donut," if you can visualize it, is this network of lines making a circle covering the eastern portion, the Rocky Mountain area here, the Pacific coast here, connections across the bottom and across the top. There are no connections across the center of the Great Desert area, because there are very few people there. And this is what we call The Big Donut, virtually by its shape and the fact that it has a hole in the middle—although some people think of it more as a pretzel. But it has been given the name of "The Big Donut."

Recognizing this new set of system conditions which would be created by the establishment of the "Big Donut," a number of organizations initiated studies of its operation. The first of these, the Pacific Intertie Engineering Guidance Committee, had the responsibility of conducting load flow and stability studies and developing operating criteria and procedures in connection with the interconnected system after the completion of the elements of the Pacific intertie.

Now, I would like to digress again in view of some of the questions you asked yesterday. The planning for the operation of electric systems during emergencies has to be done long in advance because the things that take place during an emergency on an electric system happen so fast that no machine such as a computer, or no human being, certainly, could anticipate and control them. So the plans are made a long time in advance so that under the emergency conditions the system will automatically operate in a certain way. The operator's or dispatcher's function, then, is to recognize these conditions and

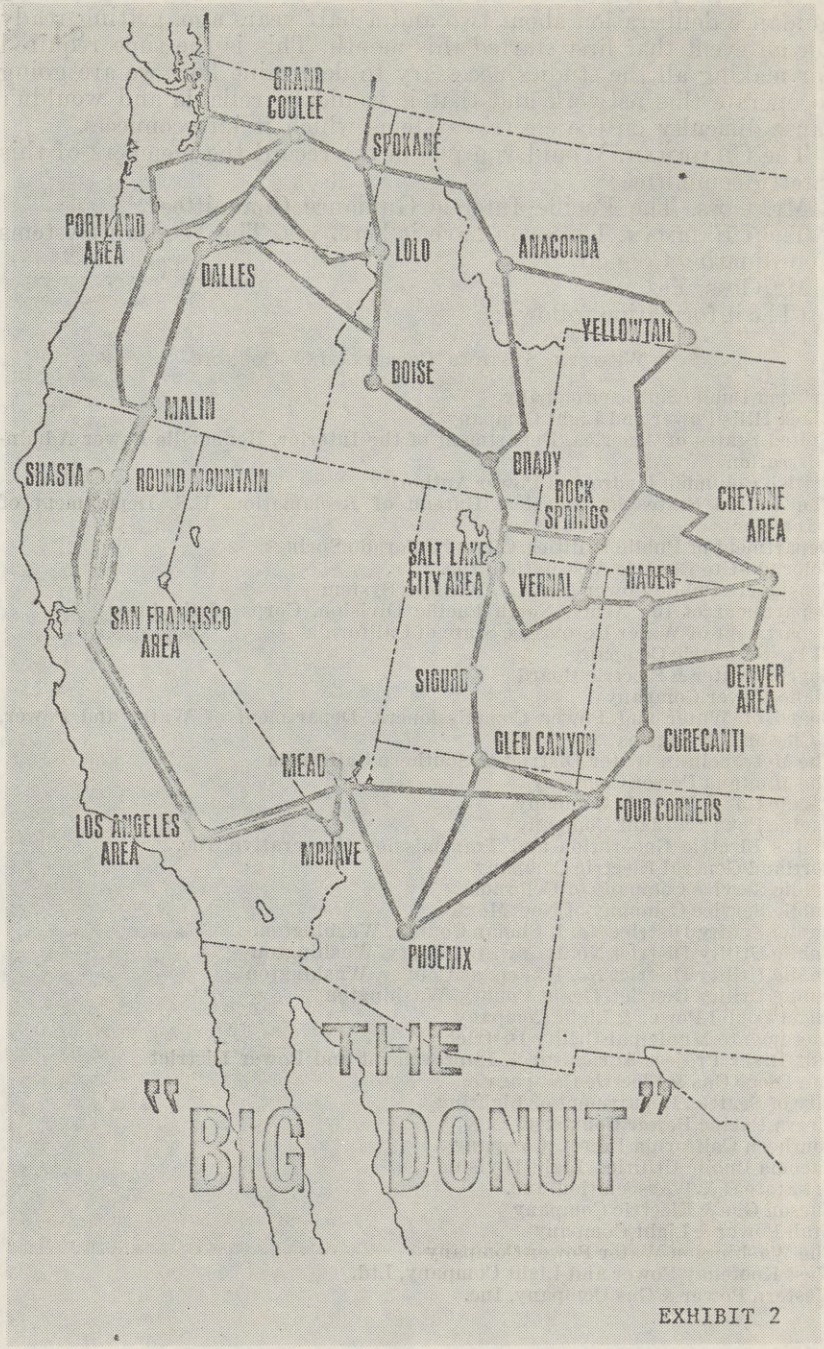

GRAND COULEE
SPOKANE
PORTLAND AREA
DALLES
LOLO
ANACONDA
YELLOWTAIL
BOISE
MALIN
SHASTA
ROUND MOUNTAIN
BRADY
ROCK SPRINGS
CHEYENNE AREA
SALT LAKE CITY AREA
VERNAL
HADEN
SAN FRANCISCO AREA
SIGURD
DENVER AREA
GLEN CANYON
CURECANTI
MEAD
FOUR CORNERS
LOS ANGELES AREA
MOHAVE
PHOENIX
THE "BIG DONUT"

EXHIBIT 2

take the steps that set up the operation to take care of the emergency if it occurs. That's the reason this committee started its engineering guidance deliberation about two and a half years ago, getting ready for an event that first started this month. This is the time required for making all the studies necessary to determine how we are going to operate this network and that it would be reliable and wouldn't cause difficulty on the electric systems which it interconnects.

The CHAIRMAN. Would you put in the record the members of this intertie committee?

Mr. Goss. The Pacific Intertie Guidance Committee?

The CHAIRMAN. I see you have it here, yes. The Western Systems Coordinating Council.

Mr. Goss. Yes.

(The information follows:)

WESTERN SYSTEMS COORDINATING COUNCIL

Arizona Public Service Company
Black Hills Power and Light Company
United States of America, Department of the Interior, Bonneville Power Administration
British Columbia Hydro and Power Authority
The United States of America, Bureau of Reclamation, U.S. Department of Interior
Department of Public Utilities, City of Colorado Springs
Colorado-Ute Electric Association, Inc.
Consumers Public Power District, Western System
Department of the Army, North Pacific Division, Corps of Engineers
Department of Water Resources, State of California
El Paso Electric Company
Eugene Water & Electric Board
Idaho Power Company
Board of Water and Power Commissioners, Department of Water and Power, City of Los Angeles
The Metropolitan Water District of Southern California
The Montana Power Company
Pacific Gas & Electric Company
Pacific Power & Light Company
Plains Electric Generation and Transmission Cooperative, Inc.
Portland General Electric Company
Public Service Company of Colorado
Public Service Company of New Mexico
Public Utility District No. 1, Chelan County, Washington
Public Utility District No. 1, Cowlitz County, Washington
Public Utility District No. 1, Douglas County, Washington
Public Utility District, Grant County, Washington
Puget Sound Power & Light Company
Sacramento Municipal Utility District
Salt River Project Agricultural, Improvement and Power District
San Diego Gas & Electric Company
City of Seattle, Department of Lighting
Sierra Pacific Power Company
Southern California Edison Company
Tacoma Public Utilities, Light Division
Tri-State G & T Association, Inc.
Tucson Gas & Electric Company
Utah Power & Light Company
The Washington Water Power Company
West Kootenay Power and Light Company, Ltd.
Western Power & Gas Company, Inc.

The second, the Western Operations Committee, a subcommittee of the North American Power Systems Interconnection Committee which was organized to coordinate the operations of systems in the western region in connection with the Glen Canyon closure and the later closing of certain East-West ties.

Other organizations as well as individual utilities were also concerned with certain phases of the operation of these interconnected systems. One of these, WEST Associates, which was formed in 1964 for the purpose of regional planning of generation and transmission facilities in Arizona, southern California, Colorado, Idaho, Nevada, New Mexico, Utah, Texas, and Wyoming, found it necessary to expand the scope of their load flow and stability studies to include the whole western region.

Studies performed by these various organizations demonstrated the need for one organization to coordinate the planning and analysis of the operation of the total interconnected systems in order to eliminate duplication of effort and to assure that opportunity was provided for participation by all the utilities in the region.

The initial step leading to the formation of such an organization covering all the 13 Western States was taken in 1966, when the Pacific Intertie Engineering Guidance Committee appointed an ad hoc committee to investigate the feasibility of, and to develop basic guidelines for, a regional council. In early 1967, the committee completed a report which recommended that such a council be formed. The first organization meeting of the new Western Systems Coordinating Council was held in Los Angeles in March 1967. Widespread interest in the formation of such a council was indicated by the attendance of 68 representatives from 40 agencies throughout the Western States and Canada. These representatives unanimously agreed to form the Western Systems Coordinating Council. Subsequent meetings developed the basic principles of organization, aims, and objectives which have heretofore been stated. An invitation was extended to all the utilities operating bulk power systems in the Western United States and southwest Canada to join and participate in the activities of the council. At the time of the first formal meeting of the council on November 13, 1967, 40 utilities had joined. Exhibit No. 3 lists these members.

The foregoing indicates that Western Systems Coordinating Council is an extension of the high degree of cooperation and coordination which has been going on in separate areas of the western region for many years.

The attainment of the objectives of reliability requires careful consideration of many separate and distinct aspects of power system planning, operation, and maintenance. The following is a list of some of the more important of these:

1. Carefully prepared estimates of future load requirements, both short term and long term.

2. Development of transmission network and generating resources sufficient to meet these future demands.

3. Provision for adequate and properly distributed spinning reserves.

4. Adequate and reliable communications systems.

5. Adequate instrumentation of critical elements of the bulk power system, including dispatching, central plants, and substations.

6. A coordinated and continuously reviewed system of protective relaying.

7. Established operating procedures to cover emergency conditions.

8. Auxiliary provisions for restoration of service, including sources of power for safe shutdown as well as rapid restarting of generation facilities.

9. Careful consideration of creditible contingencies upon which both system planning and operation must be based.

It is the responsibility of each utility in the first instance to plan the design, development, and operation of its system in a manner that will provide reliable service to its customers. It is also necessary that existing pools and similar associations concerned with the development of resources to meet constantly growing demands for electricity continue to carry out coordination of planning and development within their own respective areas.

Beyond this, however, broader regional coordination must be provided. We believe that WSCC, based on the firm and proven foundation of cooperation among all segments of the industry in the West and imbued with the primary objective of maintaining and improving reliability of electrical service, provides the necessary vehicle for carrying out the required regional studies and for exposing to all participants the needs of the region. It also provides the means to implement the actions required to fulfill the objective of achieving reliability.

I hope that this description of Western Systems Coordinating Council and the brief discussion of the history of cooperation and coordination in the planning and operation of bulk power systems in the West will be of assistance to your committee in its evaluation of the need for additional legislation such as that proposed by the Electric Power Reliability Act of 1967.

The CHAIRMAN. Well, I don't like to say this, but this is your answer to the bill?

Mr. Goss. As a Council, we didn't feel it was our purpose to go into the various aspects of the bill because we were sure that that was going to be covered.

The CHAIRMAN. You feel there is no need for the bill?

Mr. Goss. We don't feel there is a need for a law.

The CHAIRMAN. You formulated all this finally in March, didn't you? After the bill was introduced?

Mr. Goss. I think so.

The CHAIRMAN. Well, I think that's good. I'm not criticizing you. Now I notice that the bill was introduced in June. You beat us by a couple of months. [General laughter.]

Anyway, I'm not critical of this. This is the whole idea. We're trying to deal with a problem, and this may be part of the answer. Now, I think for the laymen, you ought to tell us a little bit about the

Donut. Let's go way over to the Denver area, which is part of the Donut, and then let's come back to this State. How would there be coordination between the power availability in the State of Washington and power that they needed in Denver?

Mr. Goss. That's a very good question, and I appreciate the opportunity to comment on it. I'm sure there are others in the room who would like to have the same opportunity. That's the reason we established this Council; consideration of that very question led to its formation.

The incident, the loss of the transmission line, for example, in the State of Colorado, would have a great effect on the flow of power in this network of transmission form of the Big Donut. Let's take, for example, a loss of transmission from Glen Canyon to the Salt Lake area. Since there will be transmission either from the north to the south or from south to north, in connection with the Pacific Intertie, this loss of transmission would result in a redistribution of loads on this transmission line. [Indicating on exhibit 2 transmission from Four Corners to Haden.] We need to know, are those transmission lines strong enough to stand that additional load. If they're not, obviously something has to be done.

The CHAIRMAN. Can all of you predict pretty well generally what the load is going to be at one point as against another?

Mr. Goss. Yes, sir.

The CHAIRMAN. And that's involved in working out your plans for transmission, isn't it?

Mr. Goss. That is correct. Two things that have to be watched on the Big Donut are, one, as you say just steady state conditions—no troubles at all. But as transfer of load is made over this system it reaches the point where if the load is increased in certain ways the system will become unstable and it might come apart. So the load flow studies have to be made to make sure that certain elements are not overloaded and to make sure the whole network does not become unstable; two, studies must be made of the dynamic stability of the network. What happens when a fault occurs?

The CHAIRMAN. What about the differences in transmitting capacity? This could affect the whole reliability, question couldn't it?

Mr. Goss. Yes, it's part of each of these systems.

The CHAIRMAN. Then, would you suggest we work toward the uniformity of transmission capacity?

Mr. Goss. I think that would destroy the very economics which makes interconnection desirable. It would not be practical.

The CHAIRMAN. Supposing the transmission lines themselves blockade this Donut. What do we do?

Mr. Goss. Obviously we'd have to increase the transmission capacity in that element of the network.

The CHAIRMAN. Doesn't that happen every day, to some extent, when people try to build transmission lines to coordinate their system with the next one?

Mr. Goss. One of the purposes of this Council is to study all this, and it is a continuous process. As you say, Senator, everyone is mak-

ing plans and construction is going on, so this has to be studied continuously.

The CHAIRMAN. Now, on the eastern side of the Donut, those lines are pretty weak lines, aren't they—comparatively speaking?

Mr. GOSS. Compared to the western side, they might be; but as compared to the development of the network, as I say, other connections are going to be made over there as well.

Mr. LORDAN. I think the weak point is there until we get the whole intertie finished; then we have better transmission, don't we?

Mr. GOSS. We have stronger transmission, and also the load flow will be much greater over here on the west side. The network will be coordinated with the load flow requirements in the various parts of the Donut.

The CHAIRMAN. Now, for my friends over here, and myself, could you explain some things we don't understand.

Supposing there's a problem in Boise, or Denver, on one end. Does a kilowatt from Skagit get over there, and how does it get over there? Does it go directly, or does it move through the entire Donut? I think we all ought to understand this.

Mr. GOSS. It doesn't go by displacement as such. Electricity is a continuous process, and it travels at the speed of light. So that Skagit and Boise, as far as electricity is concerned, are right together.

The CHAIRMAN. It's boosted as it goes along?

Mr. GOSS. The loads are taken off and additional power is put on as it goes along.

The CHAIRMAN. Now, you've got this organization, and your Donut exists, and it's going to be improved. I know that. Who's going to make the decisions?

Mr. GOSS. I think the first element in the decisionmaking process is the makeup of the committees, the study committees. Each utility having a part of the system will be represented. The representative participates in the studies, and in setting up the contingencies studied.

The CHAIRMAN. In other words, you would have a plan, and all the members of this group or all the people participating in it would know what it is.

Mr. GOSS. They help make it up.

The CHAIRMAN. They would help make it up, so it would exist if they need to carry out the plan.

Mr. GOSS. That's right.

The CHAIRMAN. No matter what the plan is, you suggest they would voluntarily follow it.

Mr. GOSS. I'm sure they would. They have the very best reason for doing it because it's in their own self-interest. Because if this whole system gets in trouble, their system is down; and no utility wants that.

The CHAIRMAN. In other words, their objective is to furnish the best service they can.

Mr. GOSS. That's right. And keep the meters turning.

The CHAIRMAN. I suppose the people that are really behind this sort of a bill would ask the question, "Are you doing the best you can?"

Mr. Goss. That's a good question. Are we? No, I don't think you ever do the best you can, Senator. I think we're trying to do the best we can.

The CHAIRMAN. You did pretty well. You formed your group 2 months before we introduced the bill, so you're way ahead of us there.

Mr. Goss. We do operate efficiently.

The CHAIRMAN. Thank you very much.

Mr. Goss. Thank you, Senator.

The CHAIRMAN. I understand Mr. Richmond of Bonneville is ill, but Mr. Klein is going to make the statement for him.

Mr. KLEIN. Mr. Chairman, I'm Assistant Administrator for Engineering and Chief Engineer. Today I'm representing Mr. Henry R. Richmond, Administrator, who is confined to his home by his doctor. He regrets that he cannot be present for these hearings. At this time I would like to introduce members of the staff that are with me.

On my right is Ed Grant from the Regional Solicitor's Office; Mr. Bosshart, System Operations Officer; Mr. Ralph Gens, next to me. He is the Chief of the Branch of System Engineering, Division of Engineering. On my left is Mr. Ray Foleen, Assistant to the Administrator; next to him, Mr. Marvin Harris, Assistant to the Chief Engineer. On the extreme left is Mr. Eugene C. Starr, Consulting Engineer, Division of Engineering.

We are submitting a written statement and exhibits to the committee. In our presentation I will read our prepared statement and then to acquaint the committee with the methods and procedures used by BPA in the fields of planning, construction, advanced techniques of control and of operations, I will call upon staff members.

STATEMENT OF HENRY R. RICHMOND, ADMINISTRATOR OF THE BONNEVILLE POWER ADMINISTRATION, PRESENTED BY KENNETH M. KLEIN, ASSISTANT ADMINISTRATOR FOR ENGINEERING, BONNEVILLE POWER ADMINISTRATION

I. INTRODUCTION

I appreciate the opportunity to present our views on the Federal Power Commission's proposed Electric Power Reliability Act of 1967.

The Bonneville Power Administration, a Bureau of the Department of the Interior, was created by Congress in 1937 to act as the marketing agent for power from Bonneville Dam. It since has been designated to market the power from 30 Federal dams in the region, eight of which are under construction. It also provides the region's backbone transmission grid which interconnects all major Pacific Northwest utilities and wheels power from numerous non-Federal generating sources.

BPA's marketing area consists of the States of Washington, Oregon, Idaho, and Montana west of the Continental Divide, plus small adjacent areas of California, Nevada, Utah, and Wyoming. Essentially, this marketing area is the Columbia River Basin in the United States

and the coastal areas of Washington and Oregon. It covers 290,000 square miles and has a population of 5.5 million. The Cascade Mountains running north and south divide the region. Most of the Federal power is generated east of the Cascades, whereas the greatest load points are west of the Cascades. The extensive grid system moves the power essentially from east to west.

BPA has in existence today over 10,000 miles of transmission line, of which over 6,000 miles is 230,000 volts or higher. We have almost 300 substations with a transformer capacity of 20,916,000 kilowatts. The transmission grid is connected at approximately 450 locations with other utilities. A map of the BPA transmission grid is submitted as exhibit 1.

BPA is building the Nation's largest 500,000-volt grid to overlay its present system. We will need about 2,000 miles of 500,000-volt lines in operation by 1970 exclusive of the Northwest-Southwest intertie. Nearly 700 miles of 500,000-volt lines are now in operation including the first 500,000-volt Northwest-Southwest intertie line, our portion of which is 270 miles in length. BPA has under construction 1,800 miles of 500,000-volt line. Also, as part of the intertie, 540 miles of 750,000-volt direct-current transmission lines are being constructed. A map of the principal transmission lines of the Western United States, including the intertie lines, is submitted as exhibit 2.

The 22 existing Federal dams for which Bonneville markets the power have a generating capacity of 6,700,000 kilowatts. In addition, BPA wheels or exchanges over its grid an additional 2,700,000 kilowatts for non-Federal utilities. In total, BPA supplies about 50 percent of the power generated in the region and has the high-voltage capacity to transmit about 80 percent of the region's power. A map of the electric powerplants in the Pacific Northwest and adjacent areas is submitted as exhibit 3. A description of the projects is submitted as exhibit 4.

BPA wholesales the electric power from the Federal projects, delivering it to 145 customers. This consists of 32 municipalities, 27 public utility districts, 45 cooperatives, eight private utilities, 10 Federal agences, and 23 industrial firms. A map of the location of BPA customers and points of delivery is submitted as exhibit 5. A map of the approximate service areas of the operating public and private utilities is submitted as exhibit 6.

The BPA's transmission system is subject to many different types of disturbances, due in part to the extensive area which it covers. For example, in 1966, on our 230-kilovolt or above system, we had 254 cases of automatic line interruptions of which 184 were caused by lightning. Other examples of causes of interruptions are equipment failure, malicious damage, storm trouble, and customer trouble. A comparative summary of automatic line outages for each year since 1961 is submitted as exhibit 7——

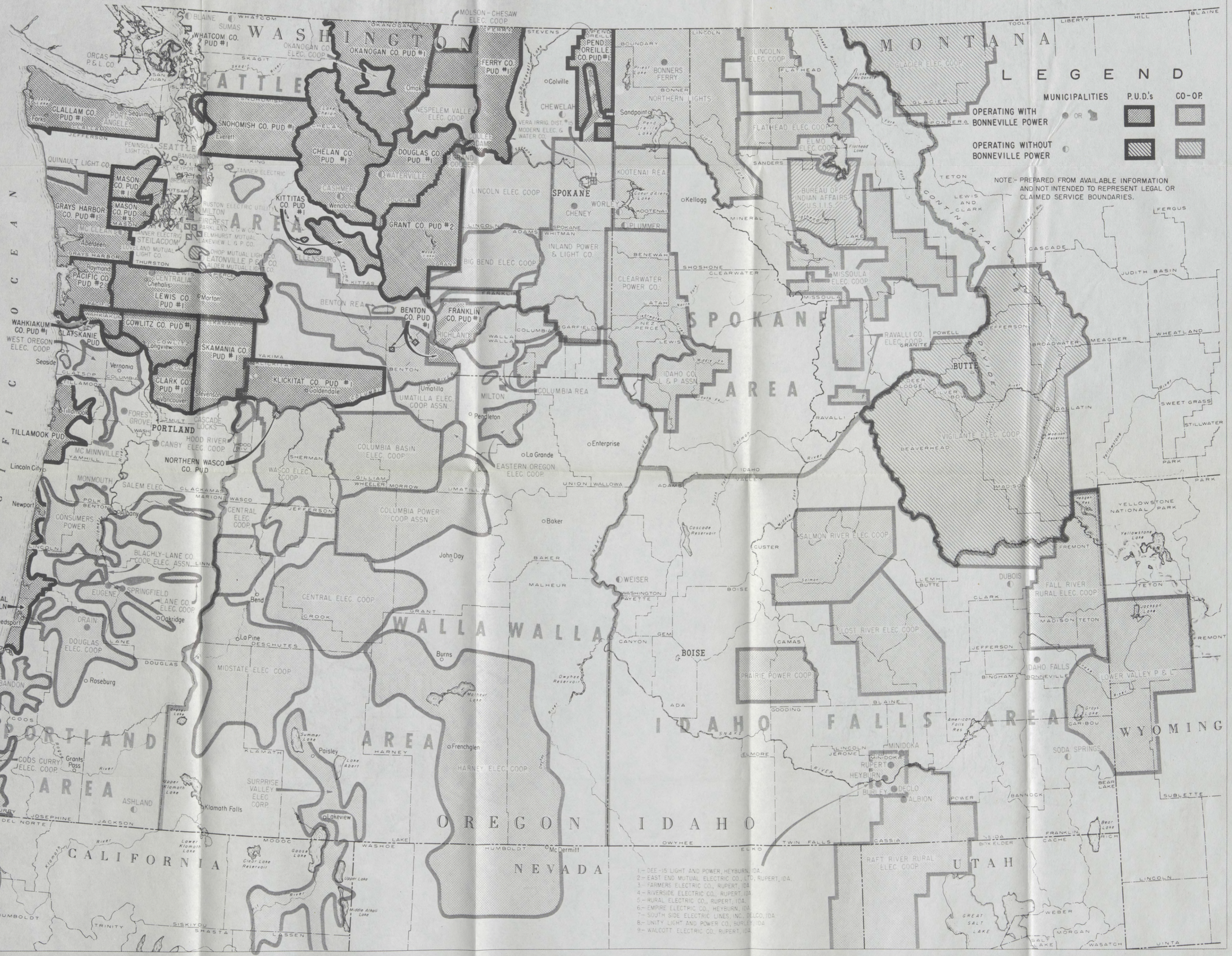
The CHAIRMAN. We want to put seven in the record. We'll put it in right at this point.

(The information follows:)

U.S. DEPARTMENT OF THE INTERIOR

BONNEVILLE POWER ADMINISTRATION

SERVICE AREAS - OPERATING PUBLIC AGENCIES AND COOPERATIVES



Revised 1-15-65 42502

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EXHIBIT 7.—*Comparative summary of automatic line outages*

	1961			1962			1963			1964			1965			1966		
	No.	Hr.	Min.	No.	Hr.	Min.	No.	Hr.	Min.	No.	Hr.	Min.	No.	Hr.	Min.	No.	Hr.	Min.
500 kilovolts:																		
Terminal equipment failure																4	69	1
Miles of line in service Dec. 31																	146.4	
287/345 kilovolts:																		
Lightning	7	0	0	10	0	18	21	0	32	10	2	58	8	0	11	16	6	8
Storm trouble													1	8	30			
Snow and ice							5	3	21	1	0	0						
Birds in line																1	0	0
Line material failure	1	0	6															
Terminal equipment failure										2	1	27	1	0	20			
Improper relaying							1	10	43	1	0	0	1	0	7	2	0	1
Accidental tripping							1	0	0	3	0	5	3	0	14			
Improper switching				4	0	2	1	0	6	2	2	12						
Customer trouble																1	0	15
Unknown				4	2	3				3	0	0	1	0	0	1	1	37
Total	8	0	6	18	2	23	29	14	42	22	6	42	15	9	22	21	8	1
Miles of line in service Dec. 31	570.2			570.2			570.2			570.2			800.4			800.5		
230 kilovolts:																		
Tree in line	2	0	3										3	4	22			
Lightning	172	3	29	94	32	51	175	27	1	87	45	53	116	30	20	168	31	16
Storm trouble	11	0	35	13	1,562	21							3	57	38	2	0	30
Snow and ice				1	0	1	8	0	43	2	0	44	2	0	3	2	4	49
Birds in line				6	0	2	2	0	5				1	0	0			
Fire	4	40	32	1	0	1				2	38	7	3	41	55	1	15	46
Line material failure	1	30	54	2	14	30	3	30	55	2	25	22	3	35	3	1	11	12
Terminal equipment failure	6	5	26	8	4	56	11	1,170	34	8	436	29	9	5	47	14	48	34
Overload							1	14	35									
Improper relaying	6	0	27	5	0	0	5	1	5	4	0	4	5	0	0	6	0	32
Accidental tripping	12	3	22	12	0	54	4	0	1	2	0	15	10	1	9	12	0	17
Improper switching				2	0	25	4	0	17	2	0	1				3	0	0
Malicious damage													1	8	51	3	30	40
Accidental damage	1	0	6				2	57	35	1	10	28	4	32	34	2	2	44
Customer trouble	7	1	10	7	0	6	4	0	7	5	0	25	4	6	58	9	4	38
Supervisory misoperation	4	0	29							2	0	2						
Unknown	7	0	3	12	2	28	12	0	5	8	0	13	10	3	20	6	0	11
Total	234	101	11	163	1,618	35	230	1,331	27	125	558	3	174	228	0	229	151	9
Trouble originating elsewhere, BPA	(9	10	34)				(8	10	43)	(2	0	4)	(1	0	8)	(3	0	25)
Miles of line in service Dec. 31	4,511.8			4,512.3			4,545.4			4,794.3			4,681.8			4,736.1		

EXHIBIT 7.—*Comparative summary of automatic line outages.*—Continued

	1961			1962			1963			1964			1965			1966		
	No.	Hr.	Min.	No.	Hr.	Min.	No.	Hr.	Min.	No.	Hr.	Min.	No.	Hr.	Min.	No.	Hr.	Min.
115 kilovolts:																		
Tree in line	5	44	15	3	17	10	3	11	41	7	36	37	14	86	34	5	22	53
Lightning	102	2	47	66	102	35	159	42	53	78	4	49	66	32	8	126	28	29
Storm trouble	25	52	12	101	1,725	7	35	31	46	5	5	47	6	15	58	7	15	25
Snow and ice	3	0	2	-----	-----	-----	9	12	15	13	19	19	38	9	57	8	0	0
Birds in line	3	0	5	2	0	0	2	0	0	-----	-----	-----	5	0	0	7	11	14
Animals or humans in line	1	0	0	1	0	0	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
Fire	1	0	0	-----	-----	-----	-----	-----	-----	3	22	23	-----	-----	-----	3	46	29
Line material failure	-----	-----	-----	-----	-----	-----	-----	-----	-----	2	21	11	1	65	57	2	9	17
Terminal equipment failure	6	6	35	5	11	32	7	0	34	6	2	11	7	110	7	10	12	37
Overload	-----	-----	-----	-----	-----	-----	6	0	20	1	0	0	3	0	12	-----	-----	-----
Improper relaying	4	0	17	2	0	40	4	0	3	7	0	0	6	3	37	3	0	10
Accidental tripping	5	0	6	9	0	7	7	0	25	3	0	10	4	0	32	3	0	8
Improper switching	3	0	38	2	0	1	1	0	1	3	0	22	2	0	0	-----	-----	-----
Malicious damage	5	44	6	2	15	7	5	8	54	3	23	59	4	22	49	3	19	58
Accidental damage	5	0	7	1	17	50	2	6	11	4	20	20	6	122	15	7	16	4
Customer trouble	25	95	42	11	25	16	15	12	58	10	69	51	16	6	27	19	113	6
Supervisory misoperation	1	0	2	3	1	36	5	4	7	-----	-----	-----	-----	-----	-----	-----	-----	-----
Unknown	6	0	9	9	0	7	12	0	1	11	0	36	10	3	43	11	0	3
Arc while switching	1	0	0	2	0	0	1	0	0	3	0	14	2	0	0	9	0	0
Total	201	247	3	219	1,917	8	273	132	9	159	227	49	190	480	16	223	295	53
Trouble originating elsewhere, BPA	(10	0	57)	-----	-----	-----	(5	0	3)	(5	0	1)	(9	7	30)	(17	0	17)
Miles of line in service Dec. 31	3,261.9			3,304.8			3,363.4			3,593.9			3,656.4			3,755.4		
69 kilovolts and below:																		
Tree in line	2	5	36	-----	-----	-----	-----	-----	-----	2	4	27	2	6	37	-----	-----	-----
Lightning	4	0	31	2	0	0	22	0	2	13	0	22	8	6	22	5	0	0
Storm trouble	7	15	3	3	29	34	-----	-----	-----	1	0	0	1	0	1	11	0	2
Snow and ice	2	0	0	-----	-----	-----	7	12	20	8	0	0	7	13	46	10	0	10
Birds in line	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	2	0	48	1	1	1
Fire	-----	-----	-----	-----	-----	-----	-----	-----	-----	5	4	5	2	228	28	-----	-----	-----
Line material failure	-----	-----	-----	-----	-----	-----	1	6	39	3	11	11	3	1	39	1	5	9
Terminal equipment failure	1	7	55	1	2	24	-----	-----	-----	1	1	29	-----	-----	-----	-----	-----	-----
Overload	2	0	50	-----	-----	-----	-----	-----	-----	1	0	5	-----	-----	-----	1	0	46
Improper relaying	-----	-----	-----	-----	-----	-----	-----	-----	-----	1	0	2	1	0	26	1	0	1
Improper switching	-----	-----	-----	-----	-----	-----	-----	-----	-----	1	0	0	-----	-----	-----	-----	-----	-----
Malicious damage	-----	-----	-----	1	20	50	-----	-----	-----	-----	-----	-----	2	1	25	-----	-----	-----
Accidental damage	-----	-----	-----	-----	-----	-----	-----	-----	-----	3	514	6	19	4	20	3	0	12
Customer trouble	11	5	2	10	28	33	15	4	40	16	5	55	19	0	21	18	10	43
Supervisory misoperation	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	11	0	5	-----	-----	-----
Unknown	-----	-----	-----	1	0	0	2	0	0	8	1	35	-----	-----	-----	4	0	18
Total	29	34	57	18	81	21	36	19	40	63	543	8	77	264	18	55	18	22
Trouble originating elsewhere, BPA	(2	0	0)	(2	0	6)	(2	0	0)	(3	0	17)	(2	0	6)	(3	0	13)
Miles of line in service Dec. 31	256.2			259.1			238.6			350.7			387.4			401.9		

Mr. KLEIN. It tabulates the causes, total outage time, and voltage class.

Fortunately, the integrated transmission system in the Northwest has been planned, designed, and constructed to provide a high degree of reliability. Only once in almost 20 years have we had a major system breakup and this occurred on June 6, 1950, when almost 800,000 kilowatts of load were lost. This breakup occurred when protection equipment at Grand Coulee Dam failed to operate. The prolonged short circuit which had to be cleared manually caused general instability in the Northwest power system. The system was separated into essentially four areas: (1) Utah-Idaho-Montana; (2) Grand Coulee-Spokane; (3) Portland-Willamette Valley; and (4) Puget Sound. There were several subareas such as the Astoria area and the Longview Chehalis-Aberdeen area that were isolated to permit matching of loads and resources. All loads were picked up and electric service normal in 63 minutes.

Since July 12, 1949, we have had 47 instances of outages which would be reportable to the Federal Power Commission under the present FPC order. This order requires that any loss of service of 15 minutes or more to aggregate loads in excess of 25,000 kilowatts must be reported except when the interruption affects only a single customer, such as an industrial plant. A tabulation of these disturbances is attached as exhibit 8.

Recent increases in power demands, technological advances in the electric power industry, and the advantages of extra-high-voltage interties have resulted in a tremendous increase in the size of areas embraced by interconnected facilities and an even greater proportionate increase in quantities of electric energy carried by such facilities. At the same time, increased demands on our land resources have rasied new problems of transmission line routing and of sufficient rights-of-way to transmit these increased quantities of power. These problems underscore the need for utility coordination to assure all users and distributors a reliable, abundant, and economical electric power supply.

S. 1934 is intended to meet this need. The objective of the bill, in the enchancement of reliability, strengthening of coordination, comprehensive development of power resources, with due regard for conservation, access for all utilities to the benefits of coordination, and the use of extra-high-voltage transmission, respect, so far as the public interest allows, for territorial integrity of service areas, and cooperation by all sectors of the industry, has our wholehearted support. It is in our interest to plan, construct, and operate a power system to meet the needs of reliability, efficiency, and conservation. Moreover, during the past decade we have come to realize the increased interdependence of one utility upon another or one region upon another region. Power system reliability becomes more difficult to analyze. Operations become more complex. Efficiency is difficult to measure. Conservation aspects have a wider application and play a more important role in planning.

The electric utility industry is moving into a new era of high capacity EHV interties, of massive generating units many times greater than those used in the past, and of power system operating complexities hardly visualized 10 years ago. We know this is the case in the Pacific Northwest. This bill directs its attention to a solution of the problem

of bulk power system reliability which has been brought about by this new era. It is esentially the same problem the electric utility industry has successfully faced in the past on a smaller scale. The problem now has a new dimension. It requires new methods of solution.

The FPC does not recommend the extreme of nationalizing the electric utility industry, neither does it adopt the other extreme of doing nothing. Instead it recognizes what we consider to be the most important aspect of power system reliability; that is, the achievement of reliability by cooperation among all persons engaged in bulk power supply as stated in section 403 of the bill. We in the Northwest have been very fortunate in this regard, as I discuss elsewhere in this statement.

We support the proposed Electric Power Reliability Act of 1967. This support is based upon our understanding of the intent and objective of this bill which meet the needs of a new and expanding electric utility service era. It is clear that a tremendous amount of study and work has gone into the drafting of this bill, and the members and staff of the FPC are to be commended for presenting bold new ideas to challenge the mounting problems. The desirability of the basic principle of achieving reliability by cooperation cannot be disputed.

The CHAIRMAN. Now, let me ask you: Section 403 says:

> The purposes of this part should be achieved as far as possible by cooperation among all persons engaged in bulk power supply, whatever their nature.

How do you interpret "bulk power supply"?

Mr. KLEIN. I'll ask Mr. Starr to answer that.

The CHAIRMAN. I think for the record we ought to clear up what we mean by "bulk power."

Mr. STARR. The bill defines this, I believe, as "power supplied to a point of distribution." I think it's broadly defined in the bill.

The CHAIRMAN. The bill says "facilities for generation and transmission." How far do you go in transmission before you leave bulk power supply and start serving the end needs of a customer?

Mr. STARR. We think of generation, transmission, control, and coordination with other power suppliers as a single factor in bulk power supply. Bulk power transmission extends to a major point of distribution; that is, a point where we are serving more than one industry and more than one customer such as a major receiving station in the Portland or Seattle area.

The CHAIRMAN. It's a pretty broad interpretation.

Mr. STARR. Yes. It can't be a narrow interpretation. In different parts of the country the definition has to be interpreted differently because of the size of loads involved and the nature of the system.

The CHAIRMAN. I think we ought to clear up another thing. They talked a great deal about generation of power. The Federal Power Commission has got to give anyone who wants to generate power a license, don't they?

Mr. STARR. Yes.

The CHAIRMAN. They have authority, do they not, to put in the license any condition they want?

Mr. KLEIN. I would say yes.

The CHAIRMAN. Yes, except thermal. They haven't got authority in that yet; but they could put in nearly any condition they want on the original license or the renewal of a license, could they not?

Mr. STARR. For hydro development, I believe.

The CHAIRMAN. The bill could be considered as an extension of FPC authority beyond generation to apply to everything that goes on after you generate the power and start sending it out over EHV lines. Is the problem of reliability one of generation? I thought we were talking more about the problem of inadequate transmission capacity.

Mr. STARR. Shall I address myself to that?

The CHAIRMAN. Yes.

Mr. STARR. This bill, I believe, came about primarily as the result of comments made rather meaningfully and sincerely following the famous Northeast blackout to the effect that interconnections were responsible for the cascading of this failure and therefore should not be encouraged; whereas, the 1964 report, the National Power Survey report of the Federal Power Commission, throughout its entire context encouraged interconnection, installation of very large generating units to effect economy of size and paid rather little attention to the general subject of reliability. And so in order to reinforce the statements made in 1964 and to take the onus off the alleged fault of interconnections, they are saying interconnection must be powerful, it must be carefully studied in order to make sure that cascading failure will not occur. In my opinion, the bill addresses itself mainly to the cascading type of outage and not to the outage of a particular substation in a particular part of a city or of an area. This is inferred in the bill, and I'm sure the main aim is to assure that there will not be the cascading type of outage that we saw in the Northeast.

The CHAIRMAN. We talk a lot about the lack of enough power being generated as a cause of this type of failure. Could you elaborate?

Mr. STARR. We have a very unfortunate technical situation. When the frequency of a system sinks beyond a certain point the steam generation must be taken off the line or it damages itself permanently. So the critical thing is to avoid the sag in frequency, the frequency where—the point where generation is lost. The most important thing in emergencies is to keep all the generation on to prevent a sag in frequency to the point where you have to reject generate. This is the critical thing.

The CHAIRMAN. And it becomes part of the whole complex problem.

Mr. STARR. This is part of the load shedding problem which you heard about yesterday.

The CHAIRMAN. I don't think we can deal with generation and transmission separately. I think all the testimony makes clear that these processes are interwoven and intertwined parts of the whole problem.

Mr. STARR. The reserve problem is another. The location and distribution of reserves and the immediately available reserves as contrasted to the eventually available reserves. It's an extremely important item.

The CHAIRMAN. This has little to do with the bill, but we'd better start getting some more generation around here, don't you think so?

Mr. STARR. We're doing our best.

The CHAIRMAN. I know you're doing your best, but it's the people east of the Mississippi River I'm troubled with. I think we'd better get moving faster.

Mr. STARR. There's no doubt about it.

The CHAIRMAN. Would you continue, then?

Mr. KLEIN. I will now commence the remaining portion of our prepared statement.

FURTHER STATEMENT OF HENRY R. RICHMOND, ADMINISTRATOR, BONNEVILLE POWER ADMINISTRATION, PRESENTED BY KENNETH M. KLEIN

II. COMPARISON OF BPA PROCEDURES WITH PORTIONS OF THE BILL

Mr. RICHMOND. I should like to point out and discuss some relevant procedures now employed by BPA in its operation. In so doing, I shall note and comment on portions of the bill pertaining to these matters.

Regional councils

The Commission's concept in section 404 of regional organizations which direct their attention to cooperation, planning, construction, operation, and other matters on a regional scale is essential as a first step in attaining improved reliability. Such an organization provides a forum——

The CHAIRMAN. Could you tell us what Bonneville has been doing up to now, what it plans to do to insure reliability?

Mr. KLEIN. At this point in my statement? At this point we've been describing what we have been doing.

The CHAIRMAN. Now you're going to talk about what can be done—what planning should be done. Is that right?

Mr. KLEIN. We're relating them now to different parts of the bill.

Mr. CHAIRMAN. I don't think we ought to look back. I think we ought to look ahead. Go ahead.

Mr. KLEIN. Such an organization provides a forum for exchanging ideas, presenting problems, understanding problems, and determining solutions. A regional council should, to the extent possible, determine its own course of action. It should be open to membership of all utilities whether they are one of the constructors of transmission facilities or one whose system is affected by the existence of other transmission facilities, and it should promote the spirit of cooperation among utilities with a free exchange of information and data.

The Pacific Northwest has been very fortunate in obtaining successful cooperation among its utilities. There has been disagreement among utilities, but more important is that we have been able to solve these disagreements through cooperation and better understanding of everyone's problem. Utilities continue to plan together and continue to operate in harmony. The result is a strong transmission grid using EHV technology and far-reaching planning, culminating in such programs as the Columbia River Treaty with Canada and the Northwest-Southwest Intertie. Another example of multiutility planning is our recently published advance program for the 20-year period 1967–87. Included in this program is the construction of fourteen 1-million-kilowatt nuclear plants built by Northwest utilities with diverse ownership, even greater diverse participation, and using the Federal transmission system for wheeling. Our estimate of the total investment in this joint endeavor is $14.3 billion of which $9.3 billion is non-

Federal and $5 billion Federal. The advance program is submitted as exhibit 9.

The CHAIRMAN. You talk about your advance program which calls for the construction of 14 nucear plants.

Mr. KLEIN. This is in addition to hydro developments.

The CHAIRMAN. You say we need fourteen 1-million-kilowatt plants?

Mr. KLEIN. That's the estimate we arrived at, sir, nuclear or thermal.

The CHAIRMAN. Does the program make a suggestion as to which—or as to what type of combination?

Mr. KLEIN. It is mostly nuclear. The only thermal plant on the horizon is the one at Centralia, which will be built by the Washington Water Power and the Pacific Power & Light Co.

The CHAIRMAN. You might have a mix in there—steam and nuclear?

Mr. KLEIN. That is possible.

The CHAIRMAN. When you say 14, you're talking about 14 million kilowatts?

Mr. KLEIN. Yes.

The CHAIRMAN. Do we have a copy of that plan?

Mr. KLEIN. It's on table 7 titled "Tentative Installation Schedule Potential Projects."

(The information follows:)

TABLE 7.—TENTATIVE INSTALLATION SCHEDULE, POTENTIAL PROJECTS

Project	Unit No.	Cumulative unit size (megawatts)	Date
Centralia steam	1	700.0	September 1971.
	2	1,400.0	July 1974.
Nuclear No. 1	1	1,000.0	Do.
Nuclear No. 2	1	1,000.0	May 1975.
Nuclear No. 3	1	1,000.0	May 1976.
Nuclear No. 4	1	1,000.0	April 1977.
Guffey	1, 2, 3, and 4	85.0	Do.
Lynn Crandall	1	60.0	Do.
	2	120.0	June 1977.
	3	180.0	October 1977.
	4	240.0	December 1977.
Palisades		135.0	April 1977.
Nuclear No. 5	1	1,000.0	April 1978.
Upper Scriver	1	37.5	June 1978.
Lower Scriver	1	30.0	Do.
	2 and 3	90.0	June 1979.
	4	120.0	June 1980.
Lucky Peak	1 and 2	35.0	June 1978.
North Fork-Snoqualmie		60.0	July 1978.
Muddy-Meadows		135.0	Do.
Eden Ridge		177.0	Do.
Kootenai Falls	1	60.0	Do.
	2	120.0	September 1978.
	3	180.0	November 1978.
High Mountain Sheep	1 and 2	600.0	March 1979.
	3	900.0	May 1979.
	4	1,200.0	November 1982.
	5	1,500.0	January 1983.
Ben Franklin	1, 2, and 3	103.2	March 1979.
	4	137.6	May 1969.
	5	172.0	July 1979.
	6	206.4	September 1979.
	7	240.8	November 1979.
	8	275.2	January 1980.
	9	309.6	March 1980.
	10	344.0	May 1980.
China Gardens	1, 2, and 3	180.0	June 1979.
Klamath River additions		118.0	July 1979.
		282.0	July 1980.
Grand Coulee P–T	P9 and P10	97.0	April 1980.
	P11 and P12	194.0	April 1986.
Nuclear No. 6	1	1,000.0	May 1980.
Garden Valley	1 and 2	87.5	June 1980.
	3 and 4	175.0	June 1981.

TABLE 7.—TENTATIVE INSTALLATION SCHEDULE, POTENTIAL PROJECTS—Continued

Project	Unit No.	Cumulative unit size (megawatts)	Date
Garden Valley reregulating	1 and 2	18.0	June 1980.
	3 and 4	36.0	June 1981.
Lower Flathead River	1 to 6	340.0	June 1980.
Little Goose	4, 5, and 6	405.0	December 1980.
Nuclear No. 7	1	1,000.0	April 1981.
Lenore	1 and 2	100.0	June 1981.
	3	150.0	August 1981.
	4	200.0	October 1981.
Sullivan Creek	1	6.8	September 1981.
	2	13.6	October 1981.
Lower Granite additions	4, 5, and 6	405.0	December 1981.
Dworshak additions	4	220.0	Do.
	5	440.0	October 1982.
	6	660.0	December 1982.
Nuclear No. 8	1	1,000.0	July 1982.
Wenatchee River		150.0	Do.
		300.0	July 1983.
Spruce Park	1 and 2	120.0	September 1982.
Smoky Range	1 and 2	190.0	Do.
Twin Springs	1 and 2	69.0	June 1983.
Nuclear No. 9	1	1,000.0	July 1983.
Strube	1	4.5	Do.
Wanapum additions	11	83.1	September 1983.
	12	166.3	November 1983.
	13	249.4	January 1984.
	14	352.5	September 1984.
	15	415.6	November 1984.
	16	498.8	January 1985.
John Day additions	17	135.0	October 1983.
	18	270.0	December 1983.
	19	405.0	October 1984.
	20	540.0	December 1984.
Yale additions	1	54.0	November 1983.
	2	108.0	January 1984.
Rock Island additions	1 to 7	231.0	Do.
Merwin additions	4	45.0	Do.
Cougar additions	3	35.0	Do.
Nuclear No. 10	1	1,000.0	February 1984.
Priest Rapids additions	11	78.9	September 1984.
	12	157.7	November 1984.
	13	236.6	January 1985.
	14	315.4	September 1985.
	15	394.3	November 1985.
	16	473.1	January 1986.
Nuclear No. 11	1	1,000.0	September 1984.
Libby additions	5 and 6	210.0	April 1985.
	7	315.0	June 1985.
	8	420.0	August 1985.
Buzzard's Roost	1	100.0	July 1985.
	2	200.0	September 1985.
Nuclear No. 12	1	1,000.0	July 1985.
Penny Cliffs	1 to 6	470.0	August 1985.
Boundary additions	5	137.8	November 1985.
	6	275.5	January 1986.
Asotin additions	3	135.0	December 1985.
	4	270.0	December 1986.
Libby reregulating	1 and 2	61.0	December 1985.
Mayfield additions	4	40.5	January 1986.
Mossyrock additions	3	150.0	Do.
Nuclear No. 13	1	1,000.0	April 1986.
Nuclear No. 14	1	1,000.0	July 1986.
Grand Coulee 3d powerplant	25	600.0	December 1986.
Chief Joseph additions	28 to 31	256.0	Do.

The CHAIRMAN. I want to know about that because in about 2 months Bonneville will be up for its appropriation again.

MR. KLEIN. Table 7 lists the installation of these plants by years and by capacity. I think we want to make it clear, Mr. Chairman, that it's not proposed that Bonneville will build these plants. These are plants that are needed in the Northwest as a total group.

The CHAIRMAN. That's good too. I'm glad to hear that. What you're saying, then, is you need this.

Mr. KLEIN. The Northwest needs it.

The CHAIRMAN. The Northwest needs it, and somebody had better start building them. Is that correct?

Mr. KLEIN. That is correct.

The CHAIRMAN. Bonneville can participate; but if it can't, you're telling us what's needed from an engineering standpoint.

Mr. KLEIN. It is our intent in the work we're doing with the utilities that we'll probably participate.

The CHAIRMAN. I think this is important. It doesn't have too much to do with the bill. The joint endeavor is going to involve $14 billion?

Mr. KLEIN. That is correct.

The CHAIRMAN. That is spread over a 20-year period?

Mr. KLEIN. That is correct. Including distribution, of course—that would give us 14-million kilowatts to the user.

The CHAIRMAN. We can do this year by year. We can keep moving as we have in the past. This plan will involve $5 billion of Federal money? Is that your estimate?

Mr. KLEIN. That is correct.

The CHAIRMAN. Would you go ahead with your statement?

Mr. KLEIN. An example of multiutility operation is the Pacific Northwest coordination agreement executed on September 15, 1964, by 16 different organizations. This agreement provides for the coordinated operation of over 100 hydroelectric, thermal, and miscellaneous resources in the Pacific Northwest with a firm peaking capability of over 15,700,000 kilowatts and takes into consideration nonpower uses for water resources.

Negotiation of a coordination agreement commenced in 1961 and a 1-year agreement was signed in the fall of that year. A similar 1-year contract was signed in 1962 followed by a 10-year agreement in 1963, and then in August 1964 a 39-year coordination contract was signed between the Government and 14 of the area's generating utilities.

Under the coordination agreement, the various public and private utilites and the Federal Government agree to operate their projects much as if all were owned by a single entity. For example, water releases from storage projects are carefully timed so they will result in the maximum firm load carrying capability by all downstream dams through which they flow. Thus, the owner of an upstream reservoir who might otherwise release stored water to produce power to meet his own loads at a time when the owners of downstream dams could not use the additional water, agrees to hold his storage for later releases at such time as it will result in the maximum firm load carrying capability of all plants. In the meantime, the owner of the upstream reservoir is supplied power from a downstream dam which has a surplus. Owners of downstream dams agree to pay owners of upstream storage for the benefits they get from the storage. Non-Federal owners pay each other and BPA in cash. BPA makes its payment in kilowatt-hours.

Most important, the power consumers of the region are assured that all of the region's utilities are cooperating to produce their firm load carrying capability at the lowest cost possible.

The coordination agreement is submitted as exhibit 10.

In many instances studies made by BPA or for BPA are also of use to other utilities in the Northwest and sometimes throughout the country. Where possible these studies are made available. An example is

a recent report made for BPA by Battelle-Northwest on nuclear powerplant siting in the Pacific Northwest. We desired information on future nuclear plant locations so we could develop a long-range transmission system plan. This required considering nuclear costs in addition to locations so the transmission plan could encompass the proper sequence of construction. The information developed was of value to other utilities. Information on siting and cost were of value but also important factors such as regulatory, geology, hydrology, meteorology, heat dissipation, biological effects, and public acceptance were discussed in detail. A summary of the siting report is submitted as exhibit 11.

Voluntary membership in planning and operational organizations in the Northwest is the rule, not the exception. In many cases there are no formal written rules or regulations. The utilities should be commended for this voluntary cooperation. Such organizations are:

1. *Power planning council.*—Top level representatives of the public and private utilities meet five or six times annually to discuss long-range resource planning.

2. *Northwest Power Pool.*—Representatives of the operating committee of the public and private utilities meet regularly and have weekly conference calls to discuss short-range operating plans.

3. *Pacific Northwest Utility Conference Committee.*—An organization of major Northwest power generating utilities. It annually prepares a summary of power loads and assured resources for the Pacific Northwest for the ensuing 10-year period. BPA does the power capability studies after assembly of basic data by the utilities.

4. *Coordination Policy Group.*—Representatives of major Northwest utilities meet to discuss and coordinate subjects of current interest and affecting long-range planning. Typical subjects are Canadian planning, future hydraulic coordination, and power system automation.

The CHAIRMAN. Let me ask you about this: If a private utility or a city were going to build a transmission line between two points, would they consult with you? Do you meet? Do they give you notice? How does this happen?

Mr. KLEIN. Normally, we know of their intentions through the meetings of our planning staff. This has been particularly so the last 10 or 15 years. In some instances we have altered our plans or the utility theirs. In a recent case, joint construction was the resolution.

The CHAIRMAN. Do you run into any difficulties over differences of opinion in line location? Supposing you're in disagreement. You say, "Well, Mr. A, you shouldn't be doing this" or "Mr. C Utility, we think the line ought to be over there." How do you resolve those things?

Mr. KLEIN. Once the decision is made who will build the line, then the decision of where it goes is pretty much up to the utility who accepts the responsibility to build the line, and I do not believe that we are much in disagreement on that point.

The CHAIRMAN. Where Federal lands are involved, you would meet with the people in the Forest Service who are responsible for line management. But suppose it's non-Federal. You have no authority to tell private utilities what to do. How do you coordinate the building of transmission lines with them?

Mr. KLEIN. We have to arrive at that with the utility itself.

The CHAIRMAN. What I'm trying to get at, is whether Bonneville usually just sits down, talks about it, and works it out so that the private line will be coordinated with yours?

Mr. KLEIN. Yes, if we're going to use adjacent rights-of-way, as on the intertie to California. We have a joint right-of-way with the Portland General Electric Co. We sat down with them and jointly planned the two lines. I believe we went out and did most of the basic survey, actually made some land negotiations in coordination with the Portland General Electric Co., so we only had one group of people in the field.

The CHAIRMAN. Supposing it's a line over which you have no authority at all. It's going to be a private line or a non-Federal line, but it's going to have to connect up with the whole Bonneville system someplace. How do you coordinate those efforts? On land use and things of that kind—do you sit down with them and talk about it?

Mr. KLEIN. Mr. Gens?

Mr. GENS. We study the requirements 5 or 10 years ahead of time. We do that generally by asking the utilities to tell us what plant facilities they are building. When we get the necessary information, we put it in the studies and we make these studies available to the utilities. Then the answers will tell whether the line will work or won't work. If there should be some problem that this line is not built strong enough or is going in the wrong direction, the engineers will discuss it and come up with a better plan. I think most of these things are resolved at the engineering level.

The CHAIRMAN. The point I'm trying to make is that you do have liaison with these people. Nobody just wakes up and says, tomorrow morning I'm going to build a line. Instead all you people sit down and talk about it. Would that be a fair statement?

Mr. GENS. Yes.

Mr. KLEIN. Mr. Gens, in his presentations will go into this in more detail.

The CHAIRMAN. The power pool helps this situation, doesn't it?

Mr. KLEIN. Mr. Gens will cover this a little later.

The CHAIRMAN. But everybody doesn't just put plants willy-nilly all over the area. Everybody gets together first.

Mr. KLEIN. I think we do this very well.

The CHAIRMAN. You may have your arguments and disputes.

Mr. KLEIN. In addition, there is the recently formed Western Systems Coordinating Council which has representation from 40 utilities and agencies throughout 13 Western States and western Canada.

Cooperation extends into the details of transmission planning. The normal procedure for solving a joint problem starts with the designation of task forces from the interested parties. Load data, resource data, and future construction plans are assembled. With this information available, the task force makes assumptions, outlines the objectives, and limits the studies. Power flow and cost studies are made and the results reviewed. Jointly agreed conclusions are prepared and submitted to the management level of the participating agencies.

From our experience in voluntary regional planning, we are convinced of the desirability of its greater use as proposed in this legislation.

RELIABILITY CRITERIA AND STANDARDS

Volume II on the Prevention of Power Failures, which is the Advisory Committee report to the Federal Power Commission, emphasized that a wide range of contingencies should be considered and investigated in terms of steady state and transient stability implications.

We embrace the concept of regional planning, using reasonable criteria for reliability purposes as proposed in section 408.

The difficulty of establishing planning criteria applicable in all regions or service areas must be recognized. A proper and complete definition of the terms used is required. For example, a transmission planning criterion might state that, "With one major line to a load area out of service a fault followed by an unsuccessful reclosure on another line to the same load area shall not cause regional disruption or area separation." What is a major line? What is a load area? What is regional disruption? Certain assumptions are required. What are the system load levels? What are the water conditions?

Standards are not new to the electric utility industry. At BPA the standards for system operation consist of a series of documents, the main ones of which are: Dispatcher's standing orders, operating bulletins, individual substation standing orders and station instructions, emergency procedures, and special instructions.

The dispatcher's standing orders are in two parts. The first part is of a permanent or semipermanent nature. A few examples of this class of orders are: Callout and notification of maintenance personnel during system trouble, use of customer maintenance crews, switching during peakload periods, relief for abnormal voltage conditions, load dropping in case of system emergency, bus differential relays—removal from service, and procedure to be followed in the energization of new facilities.

The second part is of a temporary nature to cover a specific situation that will change in the near future. Examples of this class of orders are: Puget Sound area load drop scheme (to provide area protection in the event of loss of certain transmission lines), Willamette Valley peakload problem (control of local generation to correct peakload voltage problems), interim operation of 500-kilovolt California intertie, operating plan for the Gorge-Ingledow 230-kilovolt line (temporary interconnection with the city of Seattle). We presently have 34 of the permanent and 13 of the temporary orders in effect. There are continuing changes being made in these orders as conditions on the system change. A copy of the dispatcher's standing orders is submitted as exhibit 12.

Operating bulletins are issued to cover those operating instructions which are common to the entire system. These include such bulletins as: General operating and dispatching procedure, general switching procedure, operators' and dispatchers' responsibility regarding relay settings, operation records and reports, customer billing meters, operation of supervisory controlled substations, operation of storage batteries, inspection of transformers, testing communication facilities, use of radio equipment, and availability log of maintenance personnel.

At the present time there are 28 of these operating bulletins in effect. A copy of the operating bulletin is submitted as exhibit 13.

In addition, standing operating orders are prepared for each substation. These orders are considered dispatchers' instructions and provide for restoration of service under emergency conditions when the substation is unable to contact the dispatcher. It also includes routine tests and inspections that the operator would make in even of trouble before calling the dispatcher.

The station instructions cover the routine work, identify peculiarities at the station, assignment of housekeeping duties, detail steps of such items as starting up a synchronous condenser, switch on and off of static capacitors, etc.

In addition to these operating standards, there are two operation studies made each year—one for the August load condition and one for the January condition. The peak load, and in some cases minimum load, conditions are studied with the system normal. After these base cases are established, additional cases are run with various facilities and combinations of facilities out of service to determine their effect upon system operation. Analysis of these conditions outlines the steps necessary to be taken when these outage conditions occur. If corrective measures need to be taken, such as automatic load dropping, emergency capacitor installations, or emergency interconnections, the necessary steps are taken to provide the required facilities. When reconfiguration of the transmission system or rearrangement of plant generation is required as a result of outages, emergency procedures are prepared to cover the situation. A copy of our January 1967 operations study is submitted as exhibit 14. A copy of our August 1967 operations study is submitted as exhibit 15.

Maintenance standards or performance level guides are also common. The FPC recognized the need for preventive maintenance rather than remedial maintenance in its recommendation No. 24 in its "Report on Prevention of Power Failures." BPA has performance level guides for transmission, substation, meter and relay, power system control, and nonelectric plant equipment. This preventive maintenance program has been in existence since 1952. A copy of our fiscal year 1970 performance level guide is submitted as exhibit 16.

ADVANCE NOTICE OF CONSTRUCTION

We support the concept of the need for increased leadtime in construction of facilities to allow for unexpected delays. However, planning precise routings of transmission lines far in advance of construction has long been a difficult problem. Long-range planning with general line routings is much simpler.

It is much more difficult to estimate loads on subregional or individual substation basis than it is to estimate total regional loads. We may be reasonably sure as a result of industrial studies that the pulp and paper industries, for example, will expand within the region, but the specific plant location is almost impossible to predict until after a company has purchased a site and announced its plans. Similar examples may be cited for almost any manufacturing indus-

try. Electric furnaces, steel, lumber, fertilizer, chemicals, light metals are all examples.

The location of large-scale private irrigation projects are also extremely difficult to anticipate in planning for orderly and adequate electrical service. The developers attempt to maintain a secrecy about their projects until all elements of the developmental package have been put together. Details of land, financing, operation, engineering studies, and water withdrawals are kept as confidential as possible. Once announced, project development proceeds rapidly.

Weather, business conditions, population movements, unanticipated industrial expansions, and technological change all contribute to the uncertainties of load forecasts.

In many cases, detailed BPA transmission planning is accomplished as much as 7 years ahead of energizing the line. This is made necessary because of our need to submit our budget about a year in advance of obtaining funds. Changing conditions such as previously outlined frequently force changes in our plans even after appropriations have been received. Certainly, investment decisions today, based on requirements 5 to 7 years in the future.

LAND USE

We believe the formation of regional plans by regional councils and increasing leadtime in construction of transmission lines will assist in the solution of delays caused by land acquisition difficulties. We also support the concept of thorough coordination of power transmission right-of-way use with other uses or considerations such as esthetic values.

BPA has developed good working arrangements for the use of Federal lands administered by the Bureau of Land Management and the U.S. Forest Service. BPA gives full recognition to the need to minimize its impact on Federal lands and BPA provides information as far in advance as possible regarding its planning to facilitate coordination in planning. Memorandums of understanding have been executed with both parties. A copy of the memorandum of understanding with the Bureau of Land Management is submitted as exhibit 17. A copy of the memorandum of understanding with the U.S. Forest Service is submitted as exhibit 18.

The effect of transmission lines and substations on the surroundings is taking a more important role in planning. Recognizing this fact and in an attempt to assist us in finding better ways to improve appearances, we engaged an architectural firm to conduct a study on appearance planning. A copy of this report is submitted as exhibit 19.

III. ADDITIONAL SUBJECTS ON RELIABILITY

Some matters affecting power system reliability directly or indirectly are worthy of further comment in some detail. These subjects concern (1) power system automation, (2) load estimating, (3) land acquisition methods, and (4) load shedding schemes. From this discussion, it will be apparent that BPA has for a long time been concerned with the problems of reliability and that it has done a great deal toward meeting those problems.

POWER SYSTEM AUTOMATION

The Federal Power Commission has recognized the advanced uses of the computer in the electric utility industry. Its recommendation No. 14 states:

> Utilities should intensify the pursuit of all opportunities to expand the effective use of computers in power system planning and operation.

BPA was one of the first to use computers for system planning purposes. We are intensifying our pursuit of their use and are now in the process of forming a systematic step-by-step plan that will utilize automation to its fullest extent consistent with economic and service reliability constraints. There are cost restrictions and computers do not replace people's judgment or assume full control at all times.

The plan that we are developing is one under which an interconnected system of utilities can operate on a coordinated basis so as to maximize, for their mutual benefit, the economies of scale and diversification between loads and resources.

It is a plan to apply to the management and direction of a utility system the unique expertise of the aerospace industry and the experiences of other industries in the fields of automated data collection and processing, advance scheduling, computer direction and control of system operations, advanced mathematical techniques, and other newly developed technologies.

Consider the circumstances under which the plan was conceived to meet BPA needs:

(1) The Canadian dams and the new U.S. storage dams give us for the first time the power to truly control the flow of the Columbia River;

(2) The high-capacity Northwest-Southwest intertie gives us for the first time a market for power surplus to regional needs;

(3) The new capability of BPA to schedule release of water from storage dams and to operate run-of-the-river reservoirs not only to satisfy regional load requirements but to maximize sales, on a surplus basis, outside the region;

(4) The new problems associated with this responsibility under the limitations imposed by navigation, flood control, recreation, wildlife, and other nonpower program requirements;

(5) The need to prepare precise weekly, daily, and hourly estimates of loads and resources in the Northwest and to make short-term commitments on an hourly basis to purchasers outside the region for surplus energy and capacity;

(6) The size and complexity of the Bonneville system, growing to such an extent that conventional utility control and dispatch methods became inadequate; and finally,

(7) The first priority requirement that the vast Northwest utility system recently interconnected with the even larger Southwest steam system be operated with a degree of precision and coordination never before attempted so that regional or west coast blackout catastrophes will not occur.

It is a plan that must cope continuously with a vast input of variables including weather information, streamflow information, reservoir elevation information, resource availability information, and de-

velop a continuous and concurrent balance of resources against an equally vast continuous data input reflecting the ever-changing loads within and without the region.

It is a plan that envisions such new concepts as a multiutility data information bank. The bank could provide system load, operating, and other data to many utilities operating within a regional area. The information could be provided instantaneously and continuously.

It is a plan that envisions, for example, computerized reaction to system emergencies so that on a preprogramed basis the system reacts instantaneously to emergency conditions to drop load, drop generator, switch transmission lines, or operate other facilities such as capacitors so as to maintain continuity of service.

The first priority requirement in the development of the power system automation program is the need to maintain a reliable power system, thus preventing blackout catastrophes.

The Federal "backbone" power transmission system in the Pacific Northwest is well engineered, but it is not immune to outages. High-speed control can prevent outages that would be experienced if only slow-speed control existed. Major outages can be reduced to minor interruptions with adequate control systems.

With the continued growth of the power system, expansion of the 500 kilovolt main grid and construction of 500-kilovolt alternating current and 750-kilovolt direct current interregional tielines, the power system will be too complex to use slow control techniques. Widespread system conditions must be continuously monitored, collected, and analyzed to execute the proper control action. Automatic computer techniques offer the most promise for replacing existing manual and semiautomatic methods. These modern control techniques are required to provide a power system of high reliability.

We believe it will require at least 10 or more years to fully develop this power system automation program. Assistance of consultants and industry is required to solve the complex problems involved.

The CHAIRMAN. You're way ahead of me. You say: "We believe it will require at least 10 or more years to fully develop this power system automation program." Why should it take 10 years?

Mr. KLEIN. The field of computer science and computer application, is one of extreme complexity and it's advancing at a very rapid rate. At the present time we feel there are techniques available to do this. It will require time to put them all together and get them into operation on a completely automated basis, we estimate 10 years. But I feel we will have, say, partial automation in a few years, it will come by steps.

The CHAIRMAN. In other words, you're saying that you can't do this overnight.

Mr. KLEIN. It's too tremendous a job.

The CHAIRMAN. But you hope that in 10 years you'll have this developed so that it would reduce the possibility of a cascading failure to a minimum.

Mr. KLEIN. I would say yes. Mr. Harris is going to address himself to this subject a little later on in our presentation.

The CHAIRMAN. Very well.

LOAD ESTIMATING

Mr. KLEIN. The FPC in its report on "Prevention of Power Failures" recognized the importance of load estimating in its recommendation No. 6:

> In estimating future loads, full attention should be given to economic trends, potential weather extremes, and growth in special uses of electricity in each load area.

In order to determine economic trends, BPA is making economic base studies for power requirements. These studies have been or will be made on the following subjects:

- Population
- Labor Force
- Employment
- Personal Income
- Agriculture and
  - Food Processing
- Forest Industries
- Minerals
  - Abrasives
  - Aluminum
  - Copper-Lead-Zinc
  - Ferroalloys
  - Magnesium
  - Steel
  - Titanium
- Fisheries
- Recreation
- Water
- Fuels
  - Coal
  - Natural Gas
  - Petroleum
- Defense Industries
- Chemicals
  - Ammonia
  - Calcium Carbide
  - Chlorine
  - Petrochemicals
  - Phosphorus
  - Sulfur
  - Other Chemicals

The purpose of the studies is to determine the time, amount, and location of regional electric power requirements. These studies are designed to furnish necessary information for our long-range planning by providing forecasts of the growth in employment, population, and electric energy use by Pacific Northwest.

Industries selected for intensive study include those which are important to the economy of the Northwest because of their effect upon employment and thus population. Examples of these are the reports on the agriculture, forest products, and defense industries. Those studies whose primary impact is on employment and population growth in the Northwest are used primarily to determine the overall economic growth of the region. From these studies the residential, commercial, and small industrial power loads and their location within the region are derived.

The power-intensive industries were studied because of their importance to BPA as potential large markets for electric energy. Examples of these are the aluminum, magnesium, titanium, sulfur, and chlorine industries. The base study also includes reports on the energy industries—coal, natural gas, and petroleum—in order to evaluate the long-term competitive position of these fuels in the total Pacific Northwest energy market. Twenty reports have been published to date and another three are currently in process.

A copy of the aluminum economic base study is submitted as exhibit 20. A copy of the forest industries study is submitted as exhibit 21.

The effect on the loads in the Northwest of potential weather extremes is very significant because of the large amounts of electric heating. For that reason, and because accurate load estimates are one

of the basic ingredients of a reliable power system, we believe a statement on our procedures would be beneficial to the committee.

PURPOSE OF LOAD FORECASTING

The Bonneville Power Administration, like most electric utilities, requires load estimates for both operational and planning purposes. Load estimates are used, for example on a short-term basis, as a guide in coordinating the operation of storage reservoirs or for the interregional marketing of short-term seasonal power peak and energy surpluses. Longer term forecasts are used for rate and revenue analysis and for the long-term planning of transmission, generation, and customer service facilities. The load forecasting function in BPA is centered within one department which is responsible for the preparation of all load estimates. This centralization of the load-forecasting function makes it possible to assign responsibility for load forecasting to specialists. The use of one load estimate has the advantage of eliminated duplication of work and preventing the discrepancies that inevitably occur when load estimates are simultaneously and independently prepared by various groups for their individual purposes. In addition, the repetitive use of one basic estimate for all purposes makes it advantageous to use machine methods of tabulating loads. Estimated loads are keypunched for every month for 10 years and coded to show type of customer, rate schedule, substation, power supply area, and State.

Having established one basic estimate, it can be adapted to suit any particular purpose. For example, when the loads are converted to dollars for revenue forecasts, the revenue forecast, in terms of dollars, can be reduced if a conservative bias is desired. On the other hand, in scheduling customer service facilities, the transformer capacity indicated by the load forecast can be increased by a given percentage. In one case revenues are reduced; in the other, transformer capacity is increased, but the basic load estimate is the same.

BPA has over 10,000 circuit miles of transmission lines in its marketing area from which the utility customers are served at several hundred different points of delivery. In order to schedule and provide the required transmission and substation facilities, load estimates are needed for each distributor at every point of delivery. When the distributor is served at more than one substation, separate estimates must be prepared. The sum of separate estimates by delivery points equals the distributors' total load. Two or more distributors may be served from the same substation and generally several distributors are served from the same main system transmission line. The sum of all utility estimates comprises the total regional load which must be matched against available generation.

HOW LOAD FORECASTS ARE MADE

Because the load estimates of so many distributors must be combined to determine required substation transmission and generation facilities, all the estimates should be prepared in accordance with the same basic procedures. All distributors in the BPA area have therefore been provided with a "Load Estimating Manual" which describes uniform methods and procedures and contains basic work sheets to be

used as a guide in the preparation of load forecasts. A copy of this manual is submitted as exhibit 22. All nongenerating public agency customers of BPA (PUD's, rural cooperatives and municipalities) cooperate with BPA economists in the preparation of peak and energy load forecasts by months for 10 years. The sum of these estimates along with estimates of BPA industrial power sales comprises the BPA "system load." This does not include loads of generating utilities purchasing part of their requirements from Federal generation. The loads of the generating utilities plus the BPA "system load" comprise the total Pacific Northwest regional load which the interconnected transmission grid is designed to serve. Basic assumptions considered in making load forecasts include the resource base of the area, employment opportunities, population growth based on this employment, the economic climate, the competitive position of electricity with other fuels, and new concepts in electric power use.

COMPARISON OF ACTUAL AND ESTIMATED LOADS

The Pacific Northwest Utilities Conference Committee, a voluntary organization of all generating utilities including BPA, makes a 10-year load-resource analysis each year for planning purposes. BPA prepares the estimates of all nongenerating utilities included in this forecast, as well as the estimates of BPA industrial loads. The generating utilities prepare their own estimates. These are the estimates which BPA uses for its advance program and other planning purposes. A comparison of PNUCC long-range estimates with the actual peakloads experienced is submitted as exhibit 23. The percent deviation of estimated versus actual loads is submitted as exhibit 24. A graph of the estimated versus actual loads is submitted as exhibit 25. In general, the peakload estimates are slightly higher than the actual loads experienced except for extremely cold weather experienced in 1964–65.

The forecasted total load every year includes BPA interruptible industrial loads of about 600,000 kilowatt. These are loads that BPA can curtail under adverse streamflow conditions, lack of generating capability, or lack of transmission capacity. The presence of these interruptible loads provides an element of additional reliability to the system since extremely cold weather conditions, which cause streamflows to diminish, also create high demands on the system because of heating loads.

Industry also finds it advantageous to contract for a portion of its load on an interruptible basis since these loads can be curtailed without penalty. This enables industry to adjust production schedules to market conditions. During the period January 1958 through January 1962, when there was a surplus aluminum reduction capacity, the BPA industrial customers chose to curtail between 350 and 500 megawatts of interruptible power. Except for these curtailments the deviations of the actual from the estimated loads would have been even less.

The single most important factor affecting deviations for the total regional peakloads is temperature because of the very high use of electric space heating. Total regional load at present responds approximately 100,000 kilowatts or seven-tenths of 1 percent of total load per degree change of temperature during the winter months. Exhibit 26 shows winter peak and energy loads and weekly average temperatures for the 1964–65 season illustrating the sensitive response of loads

to temperature changes. (Note that temperature is inversely plotted to that lower temperatures and higher loads move in the same direction on the plot.) During the week of December 17, 1964, area temperatures departed 31° from normal. The probability of this temperature deviation is approximately 1 in 100 on the basis of 60 years of record. In response to this temperature change, peakloads increased nearly 2 million kilowatts over the preceding week.

Area temperatures are grouped by the Weather Bureau according to probability of occurrence as follows:

	Percent of time
Much above normal	12.5
Above normal	25.0
Normal	25.0
Below normal	25.0
Much below normal	12.5

The BPA load forecasts provide for below normal temperatures with a probability of occurrence of approximately one in four.

LAND ACQUISITION METHODS

The time involved in land acquisition for power transmission construction is an important part of the total construction time, and the bill treats this subject in detail. We believe a statement concerning the procedures followed by BPA in planning, locating, and acquiring rights-of-way is pertinent.

The procedure will vary somewhat on individual lines depending upon the area to be traversed and the problems that are anticipated. The following procedure applies primarily to rights-of-way of considerable length since most of the lines we construct are in this category.

Approximately 4 to 6 years prior to energization, a tentative determination is made by our Branch of System Engineering as to the need for a transmission line and the terminal points to be connected. Prior to the time when funds will be requested of Congress for a specific transmission line, we use money appropriated for preliminary engineering work on future lines.

Six to 12 months prior to the beginning of the actual engineering surveys on the ground to finalize the location, studies of the proposed route are made. A number of tentative routes are usually selected at this time by studying topographic maps, geological reports, soil classification data, land use maps, and other available information. Some of the tentative routes may be altered or eliminated by observation flights over the area. No contact is made with anyone outside the Administration at this time, and ownership of the land involved is generally unknown except in a very general way.

Six to 9 months prior to commencement of the engineering surveys and usually after studies are well along, the field reconnaissance begins. The various alternate routes are checked by observations from automobiles and helicopters and supplemented by detailed ground studies of critical areas. Those found to be undesirable from a cost of maintenance standpoint are eliminated.

It is usually at this stage that we make contact with the Forest Service, the Bureau of Land Management, and the large timber owners whose lands are being crossed. We also at this time will, where appropriate, consult with local groups such as planning commissions.

Further, we will contact telephone and railroad companies having facilities in the vicinity of a proposed route to advise them of our intentions. Tours over the route may be arranged if specific problems are expected.

Where it is obvious that the Forest Service or the Bureau of Land Management may wish to make timber sales on this right-of-way, we attempt to consult them before this stage so that their sales may be planned. In some areas these timber sales require considerable planning, so we attempt to give the agencies as much leadtime as possible. Likewise, occasionally a timber company may wish to log the land itself prior to our entry.

All the location work for a transmission line is accomplished by our Civil Engineering Unit in consultation with our Branch of Land. Route selection and field marking of a route immediately follow field reconnaissance. This usually takes place some 3 to 6 months prior to the beginning of engineering surveys. We check public records to determine all ownerships on the line.

During this period, we begin to contact individual landowners to obtain entry permits for the surveys, and BPA location personnel talk to property owners while working out the details of the route. We discuss with each individual landowner the proposed general route location. A brochure explaining the purpose of the line and the right-of-way acquisition process is furnished the landowner. A copy of a brochure on the 500,000-volt Keeler-Allston transmission line is submitted as exhibit 27. Specific comments made by individual landowners are given to the surveyor in charge.

During the engineering surveys, which usually require some 6 to 12 months, the surveyor in charge maintains close contact with the resident landowners and also with nonresident owners, to the extent possible. In order to accommodate the desires of a landowner, minor revisions in line location occasionally may be made during the field survey, provided they do not impose excessive costs or impair the maintenance of the line. On a very few occasions, we have drastically revised line locations where costs and maintenance were not seriously affected.

Small-scale maps showing the entire line are prepared, and these so-called strip maps are furnished to the larger companies, the public agencies involved, and other affected parties for their comments and for permission to survey. Also, various railroad and communication companies are contacted in order to determine if there will be inductive problems with their facilities.

Following surveys, maps are prepared on a scale of 200 feet to the inch with 1 mile of right-of-way on each map. These maps also show details such as tower locations, property boundaries, names of landowners involved, and other pertinent information. Copies of these maps are furnished our Branch of Land approximately 9 to 12 months before the start of clearing.

At this time, valuation appraisals of the rights-of-way are started. As appraisals on sections of the line are completed, they are turned over to our Acquisition Section together with the necessary option documents. Contracts with individual landowners are started for acquisition of the easement rights necessary for the clearing and construction work that will follow.

Inevitably, there will be some controversy with individual landowners over the valuation that has been established by our staff ap-

praisers. When this occurs, new appraisals are obtained from independent appraisers in order to insure that just compensation is being offered. Although in most instances there is no great difference between the values of the independent appraisal and our staff appraisal, many of the landowners now become satisfied and will settle. Any transaction that cannot be concluded after this stage is turned over to the Office of the Regional Solicitor and ultimately to the Department of Justice for institution of condemnation procedure. Of those cases which are filed, most eventually are settled short of an actual condemnation trial. Generally, the percentage of cases filed is quite low, although at times it has risen drastically, depending upon the areas traversed.

LOAD-SHEDDING SCHEMES

BPA has for a long time had a load-shedding program based on dropping selected loads when the system frequency dropped to predetermined levels. However, it has been necessary recently to provide load-dropping schemes to drop noncritical loads in certain critical areas in case a line outage makes it impossible to carry the full load on the remaining lines. This temporary expedient has been caused by a combination of the inability of the transmission system to keep up with the unprecedented growth in electric power loads and the shortages of materials, long delivery schedules, equipment failures, and manpower limitations.

The load-dropping schemes resulting from a line outage are used primarily to increase system reliability during periods of heavy power transfers and until added transmission capacity is available.

I. UNDERFREQUENCY LOAD SHEDDING

BPA has, since 1951, had a load-shedding program based on system frequency. This scheme can minimize the effects of major disturbances and speed up the restoration of service. Experience has proven this form of protection to be an effective means of improving system reliability.

The primary purpose of the scheme is to prevent the further decay of frequency in a part of the system which has become isolated from the main system, so that the isolated portion can be resynchronized to the main system more rapidly and thus minimize the prospects of a complete system blackout. Also, the scheme operates for the loss of large blocks of generation even though an area breakup is not imminent.

The original underfrequency load-shedding scheme automatically shed large industrial loads consisting primarily of aluminum potline load. Further load reductions, if necessary, were accomplished by manual means. The scheme would not operate until the system or area frequency had been reduced to relatively low levels. Three levels of frequency were used: 58, 57.5, and 57 cycles per second. All manual load shedding occurred below 57 cycles per second as directed from the system control center. These low-frequency levels could be tolerated because the generating capacity of the area was almost exclusively hydro and hydro units are not adversely affected when operated at these frequency levels.

There was no attempt made to coordinate individual utility plans other than to analyze the composite on a pool basis. Arbitrary area boundaries were assumed by the Operating Committee of the Northwest Power Pool so that each load area could be analyzed with reference to load and resources should that area be separated.

Interregional ties to areas which have a predominance of steam generation and the realities of interregional breakups indicated that the underfrequency load shedding scheme needed to be updated and coordinated with other utilities and areas. Bonneville is now in the process of revising the old scheme to conform to the newly adopted standards. When completed, our underfrequency load shedding relays will automatically drop load at four frequency levels: 59, 58.5, 58, and 57.5 cycles per second. The magnitude of the load to be shed automatically will vary among the various assumed areas of the Northwest Power Pool. The Bonneville system load which will be set up for automatic load shedding is in the order of 60 percent. Approximately 64 percent of the load scheduled to be automatically dropped will be industrial loads made up primarily of aluminum potline load. The remaining load is customer load which will be automatically shed at Bonneville delivery substations or shed by customer underfrequency relay installations. The choice as to which method is used is given to the customers.

An attempt is made to equalize the load shed at each of the four frequency steps. However, the aluminum potline load is readily adaptable to short outages and Bonneville has weighted its load shedding program to take advantage of this condition by shedding all of the aluminum load in the first two frequency steps (59 and 58.5 c.p.s.). The last two steps are reserved for customer load. The result of this policy is that the percentage of load shed at each step, instead of being approximately equal in magnitude, is weighed heavily on the first two steps. As projected for January 1968 estimated peakloads, the new stepped program will shed:

29 percent at 59 cycles per second.
18 percent at 58.5 cycles per second.
7 percent at 58 cycles per second.
6 percent at 57.5 cycles per second.

Even though the percentages for the first two steps are large in proportion to the last two steps, the effect on the total area population is relatively small since approximately 83 percent of this load is industrial.

During the 1967–68 winter, we are prepared to shed by underfrequency relaying 3,503,000 kilowatts of load. This consists of 1,216,000 kilowatts in the Portland-Willamette Valley area, 1,080,000 kilowatts in the Puget Sound area, 490,000 kilowatts in the eastern Washington-northern Idaho area, 427,000 kilowatts in the central Washington-Oregon area, and 290,000 kilowatts in the central and western Montana area.

The Bonneville load shedding program has been updated annually. This policy will continue. The program has been coordinated with the other utilities and areas through the Northwest Power Pool since its inception. The amount of load dropped by the public and private utilities is approximately equal.

II. LOAD DROPPING FOR LACK OF TRANSMISSION CAPACITY

In addition to the underfrequency load shedding program, Bonneville has installed a number of schemes to trip load to relieve transmission line overloads during emergency conditions.

The propose of these schemes is to prevent the possible cascade tripping effects, during extremely heavy load conditions, due to the relaying of certain transmission lines. Transmission lines now being constructed and planned for the future will eventually remove the necessity for most of these schemes. In essence, the schemes are used as a stopgap measure to allow transmission line construction to catch up to the demands on the system.

There are four load areas which already have or will have transmission line load tripping protection. They are the Bellingham area, the Seattle area, the Portland area, and the Spokane-Montana area. In each area the schemes were installed as a temporary expedient, pending construction of adequate transmission facilities.

In each application, transmission line load levels are monitored. When the load levels reach critical values, the tripping devices are cut in service to trip aluminum potline feeders in the event key transmission lines relay out of service. The result is the unloading of the remaining overloaded facilities and lessening the risk of area isolation and blackout by the cascade tripping of the transmission lines involved.

The magnitude of aluminum potline load set to trip for each scheme is:

Bellingham: 130 megawatts.

Seattle: 215 megawatts or 345 megawatts (depends on line load).

Portland: 200 megawatts.

Spokane: 420 megawatts.

Montana: 0–210 megawatts (depends on generation).

The critical load period for the Portland and Seattle areas is the winter peakload months of December, January, or February. Bellingham is a high load-factor load area and is a continuing problem. The Spokane and Montana areas are critical in the late summer months when water storage manipulations require low levels of generation in that area.

IV. DELAYS

Today our main concern pertaining to electric power reliability is the matter of delays. The bill provides some relief in promoting cooperation, regional planning, advanced notice prior to construction and greater emphasis to land use. However, delays caused by nondelivery of equipment, new equipment failure, personnel limitations, and management action or inaction still give us concern.

Equipment failure or nondelivery is of particular importance because spare equipment is not always available. The difficulty is even greater when equipment is from a foreign manufacturer and many months can pass before equipment is sent to the manufacturer, repaired, returned, and reinstalled. A transformer of foreign manufacture that was to be installed on our 500,000-volt system failed in December 1966 and was just returned to service in November 1967, a period of 11 months. New technology results in higher voltage and

greater capacity equipment which is untried in service. This adds to the problem.

All utilities face the problem of obtaining adequate numbers of personnel. System designers, planners, test engineers, computer programers, and others, are in short supply. Exotic subjects like electronics and space technology seem more attractive than power engineering. A shortage of trained personnel is only a part of the problem. Regional planning, greater coordination among utilities, and the ever-increasing construction program compound the personnel problem.

When plans have been made they are then submitted to management for approval. Sometimes the decision process is slow, or if negotiation is required with others it takes time. This in itself can use time that could otherwise be used in construction. I don't want to imply that management decisions should be hurried and without thought, but they should be made without delay.

V. SUMMARY

I support the proposed Electric Power Reliability Act of 1967 as introduced in S. 1934 and related bill.

I believe this proposed legislation will improve the reliability of electric service. It effectively directs its attention to the reliability problems we face today. This proposed act lays out a plan, under FPC leadership, for electric utilities to follow so they in turn can plan together and cooperate in other ways to minimize the possibility of massive power failures.

Adapting to the provisions of the proposed act will require BPA to reevaluate many of its present budget, planning, land acquisition, construction, and operating procedures. This cannot be determined in any detail at this time until the FPC determines more precisely how it will proceed to administer its responsibilities under the proposed act.

The proposed act will place a great administrative burden on the Federal Power Commission. It must make many decision in a timely manner so as to expedite the utility planning-decisionmaking process. The whole thrust of FPC administrative procedures should be directed at speedy implementation of plans and programs; delay resulting from lengthy review, hearing, appeal procedures could, indeed, cause future blackouts.

Our experience with utilities in the Northwest leads me to believe that integrated planning on a regional and national scale is a goal that can and must be achieved. Some public entity must be designated to be responsible for the leadership role if the overall objective is to be met. I believe the FPC can successfully assume that role.

At this time I would like to call on staff members to make presentations on planning, construction scheduling, advanced techniques of control, and operation. To discuss BPA planning within the Northwest area, which includes British Columbia as it relates to the northwest and western region. I call on Mr. Ralph Gens, Chief, Branch of Systems Engineering. Mr. Gens.

The CHAIRMAN. In your summary, you suggest that the role of the Federal Power Commission should be one of leadership and planning.

Mr. KLEIN. That is correct.

STATEMENT OF RALPH GENS, CHIEF, BRANCH OF SYSTEM ENGINEERING, BONNEVILLE POWER ADMINISTRATION

Mr. GENS. Mr. Chairman, I have been asked to describe briefly BPA's effort in the field of planning and the planning activities of the Branch of Systems Engineering. It is the planning of the BPA's transmission facilities. In the following remarks we will try to emphasize planning activities as related to reliability, or more precisely, that planning, operating, and reliability are interdependent. Let me make a distinction at this point. There are basically two types of planning studies, long-range study and short-range study. The short-range study will cover the immediate construction program efforts of which you are well familiar; it is generally translated into our budget program. However, we do make considerable long-range studies, up to 20 years, which are identified particularly with exhibit 9.

There are basically three ingredients for planning studies, particularly as they're related to transmission. These ingredients are the loads, the resources to serve those loads, and the desired objective. First, keep in mind that the desired objective has to be defined precisely. It cannot be such a broad definition as to "increase reliability." The desired objective may be the plan of integrating a new hydro development, a new thermal plant, or a new load, but the objective has to be specific. Let me briefly describe the necessary preparation of the ingredients.

LOADS

Loads are probably the most easy one to define. Utility load increases can be estimated, taking into consideration such things as population increase, use rate, temperature factor, and load building programs. We in the Northwest have forecast our load for the next 20-year period as a joint endeavor by all of the participating utilities.

The second part of the load increase is the industrial expansion, and there again, in the terms of the regional forecast, this may be quite easily done. However, when it comes to the identification of the specific location and timing of this industrial expansion, a greater degree of uncertainty will result.

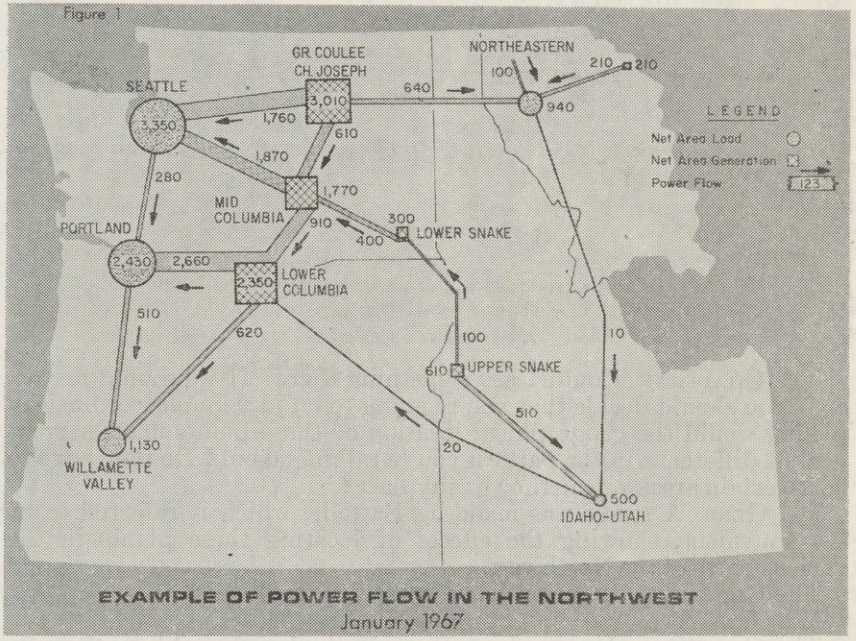
Another factor that we have to consider in our load forecasting is the effect of new methods of irrigation which may alter the landscape and also alter the electrical system requirements. You'll find this all well detailed in exhibit 9, which you have available.

The second important or necessary group of data which have to go into the planning study are the resources. Here we enter a great area of uncertainty, because we are talking about resource commitments within the next 10 to 20 years. While again, we may be able to identify the regional needs for resources, to pinpoint those locations is certainly not feasible at this time. However, one has to recognize in order to make planning studies assumptions will have to be made; therefore, these studies, no matter how precise, are no better than their assumptions. Up to now we have been able to locate our resources, our hydro resources, where the sites have been readily identified, and therefore long-range planning was quite readily done.

In terms of the specific resource requirements that we mentioned, as for reliability, let us talk about margins. Thus, we have to serve a

load, we have to overinstall the generation to take care of such things as unexpected load growth, forced outages, maintenance reserves, river level fluctuation limitations, hydro or waterflow levels, flood control restrictions and pollution control restrictions and all of these things have to be reduced to some criteria to add the necessary generation to serve the load. And you will notice in this advanced program that this is basically only one of the many possibilities of assumption of resources that would be feasible in the 20-year period. All of these things have to be agreed to before any studies can be made.

Now, I have some exhibits here which you will also find in your advanced program, Mr. Chairman, and I will go to the board here. This will give you some picture of the power flow that has to be studied or to be looked into in the future. We have here a power flow, for example, that would be typical of last January and that would not be too different this year. We have identified here in color circles and squares the points of generation, points of load—major load—and the transmission flow, the amount of kilowatts that are being transferred to these various points. Notice that our generation is concentrated on the east side of the Cascade Mountains [indicates with pointer].

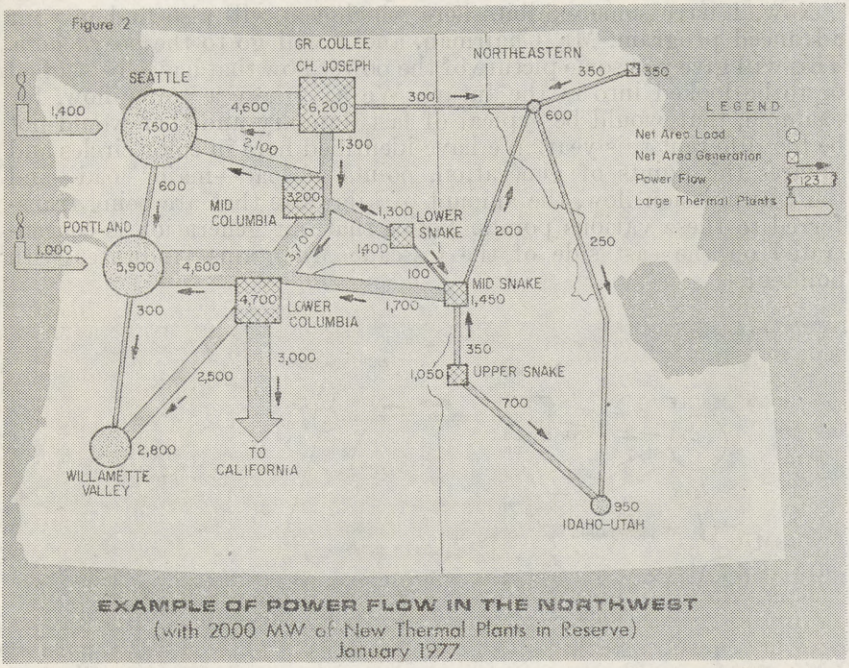


The necessity to shift this power over limited passes to the load centers—definitely has an influence on reliability because the pass certainly is subject to snowslides and similar disturbances. Now, to give you some idea as to how this will change in time and how our reliability becomes important, we have here first a minor variation. [Turns to new chart.]

Now, this shows a new condition—the summer condition when some dams are storing, and the power flows east instead of west, but in

planning you have to look at the daily pattern and the seasonal pattern and their variations. [Turns chart.]

Now, here's the system developing 10 years from now which recognizes the enlargement in the Grand Coulee power house and the amount of power now that has to be transferred, and the concentration of power, and the effect on reliability. We have here also shown the installation of two nuclear plants, and one of the things that we have to provide for in reliability is to consider the outage of these plants.



EXAMPLE OF POWER FLOW IN THE NORTHWEST
(with 2000 MW of New Thermal Plants in Reserve)
January 1977

The CHAIRMAN. Could I ask something there? If we should decide, or if you should decide that you're going to build x number of nuclear plants, would the geographical location of those plants make a great deal of difference in the pattern you're talking about? Do they have to be in certain areas, or can they be anyplace?

Mr. GENS. A study was made by Battelle, which is referred to in the statement, showing the effects of locating these plants in the various parts of the Northwest.

The CHAIRMAN. Location has a great deal to do with it.

Mr. GENS. Yes.

The CHAIRMAN. Do you have them in the best possible places?

Mr. GENS. What?

The CHAIRMAN. Would they be on the west side, or the east side?

Mr. GENS. This is what we assumed, that they are on the west side. One minimizes the transmission requirements.

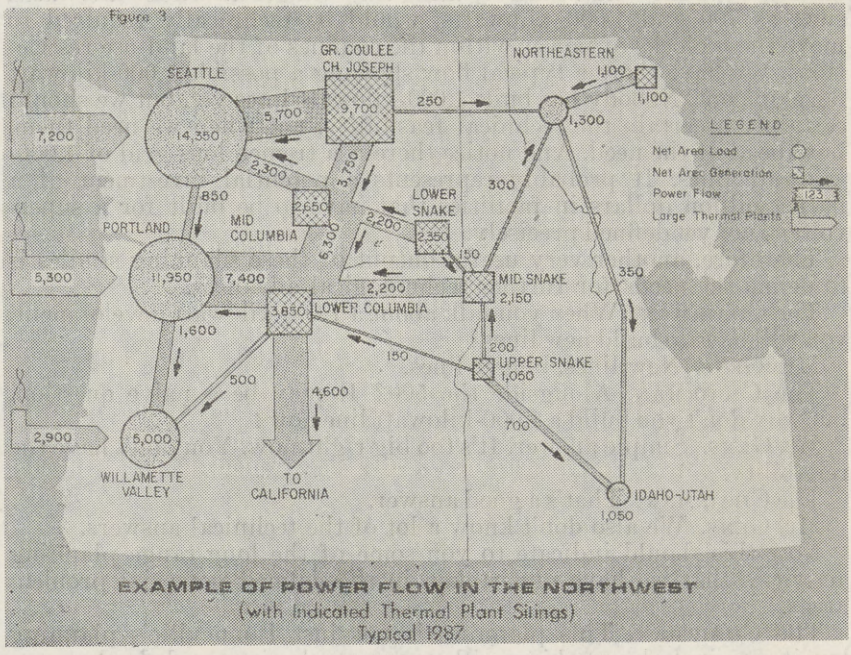
The CHAIRMAN. That's what I wanted to bring out. In other words, you can adjust some of your transmission problems with the location of the steam or nuclear plants—whichever you're going to supple-

ment your present generation with. You don't have to put those where the dam has to go.

Mr. GENS. That brings in another degree of uncertainty.

The CHAIRMAN. I think that's important to the whole question.

Mr. GENS. I have here another chart showing the tremendous load that these plants are supplying. We must anticipate nonscheduled outages. There has to be reliability enough to support the flow of power. Yet we are not satisfied as to the adequacy of our planning studies. So we have this chart here not only 10 but 20 years ahead, and it gives an estimate as to the concentration of power and the growth of load and the impact on the right-of-way and land use that we can foresee within the next 20 years.



EXAMPLE OF POWER FLOW IN THE NORTHWEST
(with Indicated Thermal Plant Sitings)
Typical 1987

It is interesting to note here—it even shows on the previous chart—that our generation site locations are so large that no one particular load area can actually absorb it. This was particularly true of the early years. Now, this resulted into a unique development in the Northwest, that we're not just an interconnected system here, but have created an integrated system where the lines will cross each other. We have achieved this by the very necessity of having these large plants. This type of integration may not be followed in other parts of the country. These are basically——

The CHAIRMAN. Don't we have a better chance to create an improved system than other places in the country that are more settled?

Mr. GENS. I think we have a better chance.

The CHAIRMAN. If we plan and do the right thing we have a better chance. In other parts of the country you have to tear things up and

change them and move everything around. We really have a chance to do something.

Mr. GENS. That is correct.

The CHAIRMAN. It kind of scares you, but I think we can do it. We 've done other things before.

Mr. GENS. These studies are all supported by technical load flows, even though they are broad outlines. I have another exhibit here which shows a possible development. Now, in order to move these large blocks of power, when we look far enough in the future, we are considering transmission voltages higher than we have right now. We are just developing our 500-kilowatt system, and undoubtedly we have to look at the next step beyond. And so we look in the 1985 area. We can show that possibly using the voltages above 500 kilowatts, such as 700 and 1,000 kilowatts, would be technically required to move these blocks of power within the confines of the land-use restrictions. We have there a typical flow showing a possible 1,000-kilowatt development. Nobody has built 1,000-kilowatt lines yet, but we should certainly ascertain the technical feasibility, not when we need them, but ahead of the need. And notice there is a tremendous grid of 1,000-kilowatt lines. It probably represents a potential investment of a half a billion dollars in facilities that have to be built for a supervoltage not yet defined precisely.

Therefore, another very useful output of these planning studies is to define the needs for further technological advances.

The CHAIRMAN. When you talk about a 1,000-kilowatt development, you will have to build new lines?

Mr. GENS. New lines, bigger lines.

The CHAIRMAN. Alongside the 500? It may be a naive question, but why don't you build a 1,000-kilowatt line now?

Mr. GENS. Simple answer. It's too big right now. You don't have the reliability.

The CHAIRMAN. That's a good answer.

Mr. GENS. We also don't know a lot of the technical answers.

Now this should indicate to you some of the long-range planning activities that we have undertaken in the defined potential problem areas.

The CHAIRMAN. This planning is not just Bonneville's planning but it also includes working with everyone else involved. Is that correct?

Mr. GENS. Yes, that is correct.

Now, we cannot ignore our immediate planning problems also, the ones related to our construction budget preparation. Here of course we can talk about more identifiable loads. In other words, the uncertainty factor is certainly reduced. We also talk about identifiable resources because if you look into your advance program the resource additions up to the next 5 years are pretty well defined, and they're committed. We know where they will be. To do these studies we need all the technical expertise and competence that we can gather. We use computers, and I might mention here with great pride that some of the largest awards by the Department were made to two engineers in our branch for the pioneering of the use of computers for load studies. We studied alternate developments. Every one of these load flows——

The CHAIRMAN. You know why I'm smiling? Every time a Bonneville Administrator comes in touch with a computer, he says it will reduce employment, but it never has happened. Would you go ahead.

Mr. GENS. We have to look at alternate developments. We have to look at normal system conditions, abnormal system conditions; and this is where the computer comes in. We can look at so many more alternatives to find the optimum. We must make stability studies, we must make cost studies, and all these require the technical expertise to come up with a plan of service which would provide the desirable grade of service. We have pioneered technical innovation such as the use of series capacitors, and Mr. Starr is one of the basic inventors of that. The use of high voltage, some of the new concepts that we have developed which are used all over the country and the world. And certainly the members of the BPA technical staff are recognized internationally.

We would like to mention here one important thing—that reliability is planned. And once one has a system planned, the limits of operation have been established. If one operates beyond those limits, reliability is impaired. Now, we think we know all the answers, but certainly even in only a 5-year prediction load levels wil change. Undoubtedly you are familiar with the Northwest aluminum plant location problem, where this plant was located at five different places in the Northwest before it finally settled down, and yet we had to be able to have a transmission system designed to accept its location and requirements wherever the plant's location would be. It might be of interest also to mention that the 747 development here at Boeing and the SST certainly resulted in increase of load that were not predicted 5 years ago. As such we have to have changes made into our plans to accept this change in the region's economy.

We would like to mention in a lot of these activities we not only have joint planning but also joint construction. We are jointly building with Puget Sound Power and with the Portland General Electric Co. double circuit lines where the land use requires us to have shared facilities; and these decisions are all based on engineering studies. We have made interregional planning studies. However, all of these interregional planning studies have been based on known resource assumptions. That's why we classified them as an operation-type study. One of the outcomes of these interregional studies is the need for a data bank, a need to centrally maintain the characteristics of the various transmission facilities.

In summary, I would like to say that planning studies, irrespective of whether they are for the immediate future or long range, have factored into them a reliability consideration. To be meaningful, these studies must be made by competent transmission engineers employing the latest computer simulation techniques. The results, however, can only reflect the merits of the input assumptions. These planning studies cannot ignore tomorrow's problems, and the engineers in the Northwest and at Bonneville are identifying and eliminating tomorrow's uncertainties.

The CHAIRMAN. Let me ask you this question. How can the Federal Power Commission help you do what you're talking about? Can they do more? Are they not doing enough? How can they do it?

Mr. KLEIN. The Federal Power Commission has sat in on some of our coordination activities in a very general way. However, they at the present time do not give us any direct assistance.

The CHAIRMAN. Could they do more?

Mr. KLEIN. Mr. Starr states that in the past the assistance has gone from us to them. He is referring to participation of Bonneville and other utilities in the preparation of the FPC reports on the blackout studies made recently, which he served on; and assistance was given to the FPC in the power survey of a few years ago.

The CHAIRMAN. It seems to me that they have such a great concern with this matter—whether we have a bill or not—that they ought to be more involved.

Mr. KLEIN. I'd have to concur.

The CHAIRMAN. Well, we thank you all very much. Oh, you're not through?

Mr. KLEIN. We have three more quite short presentations.

The CHAIRMAN. The hour is getting a little late here, so I hope we can speed up.

Mr. KLEIN. Mr. Chairman, I would like to briefly discuss transmission line construction scheduling as adequate leadtime is essential to building a reliable system. We must avoid the hazard of delay.

The CHAIRMAN. Now, this is Bonneville only you're talking about; is that right?

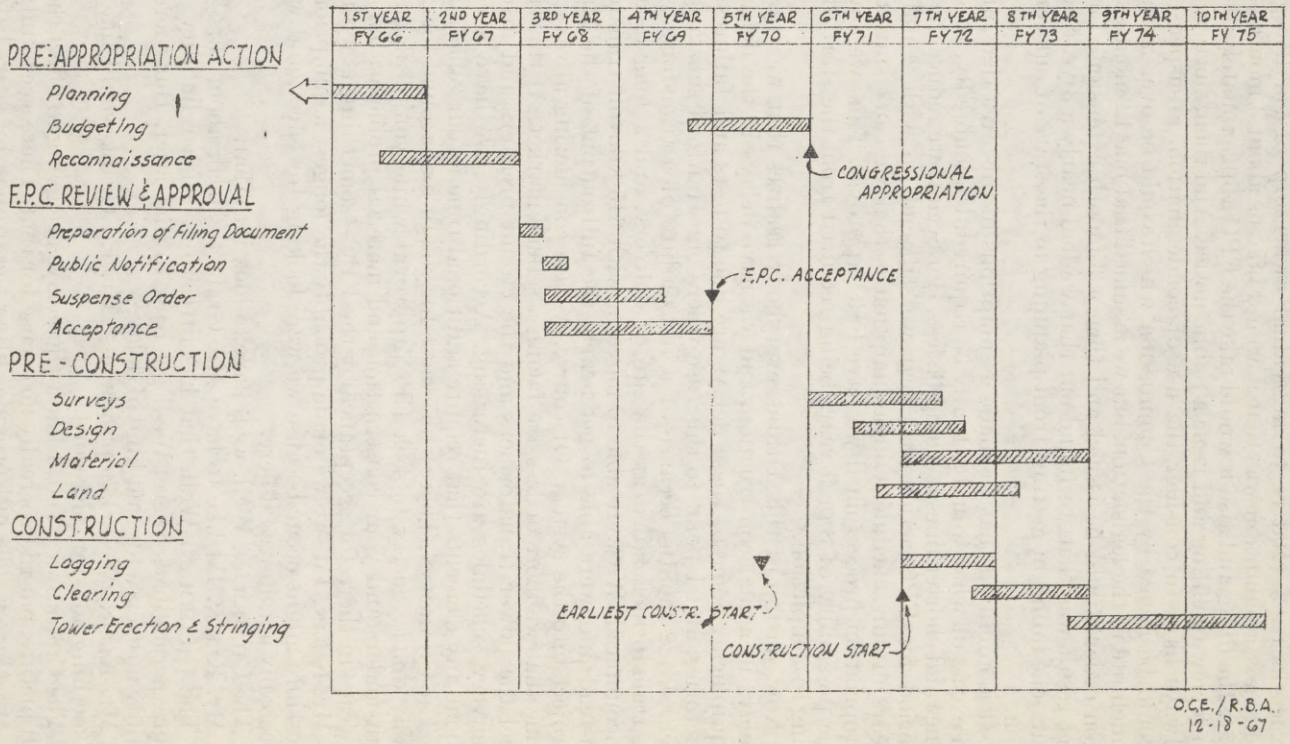
Mr. KLEIN. Yes. We're talking about the Bonneville scheduling, the importance of adequate leadtime was emphasized in the FPC committee report, and we concur.

I've indicated here on this chart activities involving the total time of constructing a transmission line. The time required is from the start of planning to the energization of the line. The line represented here is a long EHV line over the mountains. It's probably not typical of all the lines we build, but it's typical of many major lines. The leadtime from the start of planning to energization under our present method of scheduling is 6 to 7 years. This breaks down about 2 years for planning and budgeting and 4 to 5 for construction. Under our present procedure we have our budgeting going on coincidental with our planning and reconnaissance work. This is what we call preappropriation work. We do this before we request money to build a line, and then we move directly into postappropriation activities after we get a congressional appropriation. This includes surveys, design, the ordering of material, the acquisition of right-of-way, which takes us through the preconstruction activity. We have defined the start of construction as the start of logging or clearing as private owners, or the Forest Service might make timber sales. In other words, this is the point where we enter the field to build something.

Since we were having trouble holding our leadtime to 6 or 7 years under our present mode of operation, we were quite concerned with anything in the bill that might delay this action. So I have inserted a segment covering the FPC review and approval. Now in this area we had to make some assumptions. We made the first assumption that we would have to move our appropriation budgeting process out to follow the approval by FPC of our plan. We also made the assumption that we could make a filing with the FPC using the reconnaissance map where the line is shown as a line on a photo mosaic.

84-381—68—pt. 2——7

TYPICAL SCHEDULE - LONG LENGTH TRANSMISSION LINE



Now, this gives a good determination of the location of the line in respect to large areas like forests or lakes and recreational areas, and other areas of major land use; but it does not show in all cases, the exact location relative to individual ownership of small segments. The next assumption was that it would take us about 3 months to prepare the filing and also it would take the FPC approximately 3 months to review the filing and issue a public notice. And then, since we would always have to consider the use of condemnation, a suspense order would be issued by the Commission which could be over a year. It's indefinite in the legislation, but we assumed that one 12-month suspension order would be issued and then a 3-month extension. The total net result was that we found out that we had nearly a 3-year delay in our scheduling in getting from planning to the start of our construction.

It is admitted that we made assumptions in this area that might be in excess of what would actually be required. Undoubtedly, on smaller lines and shorter lines it would be less. But even if we reduce the 2-year period for FPC action to 1 year we still end up with 2 additional years in our schedule. Our assumption is that we can't start the appropriation process until we have FPC approval. Thus we now have the possibility of 8 or 9 years being required from the start of planning to completion.

Now, on top of this I think everybody realizes that we are facing delays in actual construction, and we have delays in the delivery of equipment. Some of these delays are due to tests and failures at the factories, and I point to this case where our Hanford substation was delayed 22 months because of a test failure of a transformer bank. A transformer failed at the site of delivery, and a long delay was encountered. We were able to move in with 345-kilovolt transformers instead and were able to get nearly the full output of the Hanford project into the system. Of course, we are considering always at this time that we more or less are facing a sellers' market. At this time we feel the power transformers and the circuit breakers and insulators delivery schedules are increasing. Accordingly, we have a concern about any elements that require additional time in our scheduling.

The CHAIRMAN. There's no excuse for you to fool around for 2 years. Why don't you try to seek FPC approval while you're planning? I can understand your construction and material problems, but to add 2 years in there for acceptance by the FPC—something is wrong.

Mr. KLEIN. I'd say we made probably the longest assumptions that possibly might occur because we were looking for effect, and we have probably maximized it here.

The CHAIRMAN. Well, we'll have to look into that.

Mr. KLEIN. I'd like to have Mr. Grant to speak about this.

The CHAIRMAN. Well, that has little to do with reliability. That's bureaucracy back there. We'll get back to that later. But there's certainly no excuse for that kind of delay.

Mr. KLEIN. Well, I hope it's less. Mr. Ed Grant would like to say something now for the record.

The CHAIRMAN. Well, I know the delays are going to affect the overall picture, but there's really no excuse for that. There's certainly none.

Mr. GRANT. The bill provides filing the proposal 2 years before the start of construction. In order to file a proposal, planning and recon-

naissance have to be accomplished. The way Mr. White interprets the bill——

The CHAIRMAN. I don't care how Mr. White interprets this—or anybody else. You can submit it, and it shouldn't take 2 years to decide it. That's just stupid when there is a transmission line that the country needs—a growing country.

Mr. KLEIN. To describe to the committee more fully our activities in the field of advanced techniques and power control with the use of computers, I am calling on Mr. Marvin Harris, assistant to the chief engineer.

STATEMENT OF MARVIN HARRIS, ASSISTANT TO THE CHIEF ENGINEER, BONNEVILLE POWER ADMINISTRATION

Mr. HARRIS. Mr. Chairman, the size and complexity of the Bonneville Power system is growing to such an extent that conventional utility control and dispatch methods are rapidly becoming inadequate. The complex power network has such a multiplicity of interdependent quantities that human decisions are no longer adequate and automatic control becomes essential.

The time-honored relay can handle local problems but not related or contingent abnormalities developing elsewhere, often in some remote location. In 1965 BPA considered the advancements of automation techniques and equipment sufficient to initiate a solid program for automation that could provide increased benefits and greater system security. Many of BPA's problems in developing this program are shared with other major utilities of the country as they face the problems of design and operation of an expanding interconnecting network.

"Automation" used here refers primarily to the use of modern data management techniques, computers, and high speed control devices. BPA's objectives for the automation program are first, to maintain our high level of power system reliability in the face of rapidly increasing growth and complexity; second, to make the most efficient use of our natural resources; and third, to optimize the use of our generation and transmission capacity.

Today I will limit my discussion to our first objective, system reliability. Perhaps the major justification for computer control of a power system is the potential improvement and security which it offers. This improvement means fewer interruptions in power service, less extensive interruptions when they do occur, and more rapid restoration of normal conditions afterwards.

In fact, computer control can eliminate the need for construction of entire transmission lines, which would otherwise be necessary for a secure system. Most of the details of a comprehensive automatic power system control program have not been developed. However, the present state of the art in control, communications, and computing enables us to establish the basic security functions of such a system with assurance that they can be achieved.

Automatic computer control would enhance system security in the following ways: First, in normal operation, computers could continuously check the current operation of the system to detect impending emergency conditions. When such conditions were detected, the

controller would determine the appropriate control action to avert the emergency. It could either indicate the action or perform the action directly.

Second, in the event of a sudden emergency resulting in system damage or service disruption, the computer would determine the control action which would minimize further degradation of service and system damage. It would initiate this action automatically and rapidly enough to make it effective. Such action would assist in the prevention of blackouts.

Third, in the period following an emergency resulting in load or generation dropping and opening of tielines, the computer would determine and direct the restoration of the system in the most expedient manner possible. This would minimize the duration of any customer service outages. It would also protect the system against the contingency of another emergency occurring while major facilities are out of service.

Whenever system trouble occurs, the dispatcher must quickly analyze system data displayed on more than 100 indicating devices and decide upon the correct actions. As a consequence, the dispatcher's actions are sometimes delayed, while the trouble may be growing to greater proportions. In the future, system, events will be more far reaching in their consequence, and such slow-speed information gathering and analysis cannot be tolerated. A display system is envisioned in which most of the analysis and actions are performed by computers. A computer-driven display system will automatically tell the dispatcher exactly and quickly what he needs to know. Eventually, many of the control actions will be made by the computer directly, and the display will inform the dispatcher that the action has occurred.

BPA's advanced control and dispatch program will require vast quantities of information, automatically gathered from all parts of the system. The data must be store in a way that it can be readily used by any of several computer programs, or displayed to the dispatchers, operators, engineers, and others.

Some of these data are also needed by other Federal agencies and other utilities. A number of Federal, State, and private organizations have expressed an interest in the development of a common data bank. This would be a bulk data-storage device and computer system, with data supplied by automatic and manual methods. Each organization would have direct access to the data bank.

Many other aspects of power system operation can be automated to advantage. The preliminary data gathering and processing for weather, streamflow, and load forecasts can be handled automatically. The control of generation, now handled semiautomatically, can be made more accurate and reliable by permitting computers and automatic equipment to make the many necessary adjustments and settings. Charts, graphs, and scratch pad computations now made by the dispatchers to maintain a feel for system performance can be performed automatically. Predictions of system performance with certain equipment and transmission lines out of service can be prepared quickly by computers in response to pushbutton requests. These are practical, justifiable, and in fact vitally needed improvements that are technically feasible. An active program has been initiated at BPA to implement

them. This is a long-range program to be developed over a period of 10 or more years. Contracts with consultants, universities, and industry, including North American Rockwell Corp., have been written to help solve the complex problems involved. Facilities included in this program are a highly reliable microwave communication system, a system-wide computer complex, computer-driven displays, and a new control center, all coordinated by a long-range development plan.

Control systems must work without interruption or power system trouble may develop. These control systems are dependent on telemetering and telecontrol circuits. For this reason, BPA relies almost entirely on dedicated microwave facilities owned and maintained by the Government. We have submitted as an exhibit a drawing of the BPA microwave system. BPA engineers have designed highly reliable communication systems suitable for meeting the requirements of the power system as it exists, and for the forthcoming automated power system.

To achieve even greater reliability, BPA microwave systems are being arranged in geographical loops to provide alternate paths for critical control circuits.

High-speed data management system must be built for automatic digital data acquisition and equipped with error-detecting features and computer interface capabilities. Information and measurements will be collected and processed automatically from about 30,000 data points located at up to 500 locations in the Pacific Northwest.

In the advanced control and dispatch program, we envision the use of a large number of relatively small digital computers for data storage and processing and power system control. These will be interphased with a large, multipurpose computer for power flow, optimization, and security programs. Our present plan includes about a dozen area control computers to be installed at major 500-kilovolt substations. They will interface with each other and with the central control computer through wide band data channels. Each area computer will supervise several subordinate or first-level substations. First level substations may also be equipped with digital or hybrid data processors and supervisory control equipment.

The new requirements for computer, communications equipment, and power dispatchers' displays will exceed the space limitations of the Portland Control Center. After extensive study of possible ways to expand the existing center, it was determined that a new center should be built.

This new power system control center, to be located at the J. D. Ross substation, will house the power dispatching facility, the central computer complex, power system control circuits and terminals, the Portland area substations supervisory control center, the substation operator training center, a visitors' viewing area, and the necessary office space and support facilities. It will be a semi-underground structure which will provide a high degree of protection from storms, earthquakes, fallout, and other potential hazards. This will help assure continuity of power system operations and control. Our target date for placing the control center in operation is July 1971.

The technical problems involved in this undertaking are extremely complex, and the consequences of adopting an unsound approach are

severe. Close coordination has been established between the planning of these facilities and the overall development of the advanced power control and dispatch system.

The staff at the Bonneville Power Administration is enthusiastic about the challenge of this project. We believe the results of our effort will be of significant value to BPA and the entire utility industry.

The CHAIRMAN. You anticipate that Bonneville would take the lead in this enterprise? Is that correct? Bonneville would have to do so because it's the largest of the systems involved in it. How would the other people participate in it and get the information out of this system? Would you charge them, or would they participate in the building under a joint enterprise?

Mr. HARRIS. First I should mention that within the Federal Government, the Corps of Engineers and the Bureau of Reclamation are participating directly with us in developing this plan. They have the generating facilities. Also we are coordinating with the Northwest utilities in this effort. In fact, a member of the Bonneville staff is chairman of the group, a task force working on some of the same problems and to develop data systems interface standards.

The CHAIRMAN. In other words, you render a service to the whole system?

Mr. HARRIS. To some extent the utility industry is working on this together. There is an exchange of technical papers, some coordination groups organized and many informal meetings. This is an industrywide problem. Efforts are being initiated by many utilities, particularly some of the major utilities in the United States, to develop advanced control techniques. We have direct contact with most of these utilities.

The CHAIRMAN. It would technically be run by Bonneville.

Mr. HARRIS. Our particular program, yes.

The CHAIRMAN. Would it be similar to the research laboratory we are talking about at Grand Coulee?

Mr. HARRIS. No, this is being done by ourselves. We have to develop this program especially for the Bonneville system. Because of its large size, and its unique problems. We can't wait for anyone else to develop it for us.

The CHAIRMAN. You have to go ahead because you have the responsibility for wide distribution of power. This would be sort of a central control to you, wouldn't it?

Mr. HARRIS. There would be some central control, area control and local control in a hierarchy of control levels.

The CHAIRMAN. I think it's very important when we're talking about reliability.

Mr. HARRIS. Very.

The CHAIRMAN. I wish it wouldn't take 10 years to get it started.

Mr. HARRIS. This program will not take years to get started; it will take 10 years for full implementation, maybe longer. We know that technically this program is feasible to accomplish.

The CHAIRMAN. Have you contracted for this study with the Rockwell people? Is it a private contract?

Mr. KLEIN. We have a contract with North American Rockwell.

The CHAIRMAN. They're now engaged in a study?

Mr. HARRIS. They're participating with us in this study. We're utilizing their aerospace experience.

The CHAIRMAN. Are they providing a plan? When will they come up with this plan? Do you have a target date?

Mr. HARRIS. Another year in the development.

The CHAIRMAN. Because you're going to have to get this underway to get an initial appropriation.

Mr. KLEIN. Oh, yes.

The CHAIRMAN. The plan is important so that we would know what we are doing.

Mr. HARRIS. Part of the program is already being implemented. We have enough of a concept that we can implement parts of it. It will be an evolutionary development. Parts implemented through this 10-year period.

The CHAIRMAN. It might provide some of the answers we're looking for.

Now, do you have another presentation?

Mr. KLEIN. Yes, a short one. To discuss the aspects of operations as they pertain to reliability, I am calling on Mr. William Bosshart, operating officer.

STATEMENT OF WILLIAM BOSSHART, SYSTEM OPERATIONS OFFICER, BONNEVILLE POWER ADMINISTRATION

Mr. BOSSHART. The physical system of BPA has grown since its inception in 1938 to a system that now consists of many interconnections in many locations throughout the Northwest. Along with this increase in physical growth we have increases in the regulating requirements of the units, and we had growth in the stability problems that have arisen as the system has grown. In the early days, the Bonneville system consisted of two dams, Bonneville and Grand Coulee, and just two lines connecting the two dams together. A major disturbance occurred anytime any one of those lines opened. Now it takes a little more to do that. Since about June of 1950, when we had our last major disturbance, the system has been strong enough to withstand all of the shocks that it has been subjected to. Any disturbances that have occurred have been area disturbances, affecting one portion of the system.

The CHAIRMAN. In other words, they've been limited to certain areas?

Mr. BOSSHART. Yes; and in size.

As we get more and more interconnections, the effect on Bonneville with its strong system is relatively less than the effect on other systems. There can be a disturbance occur in the Northwest, anywhere in the Northwest, and the effect upon Bonneville is relatively light; but the effect on other adjacent utilities may be rather severe.

Recognizing these problems, NAPSIC, as previously discussed, had organized the Western Operations Subcommittee to study the problems associated with interconnections in the Western United States.

The CHAIRMAN. Is this one of the organizations that we talked about previously?

Mr. BOSSHART. Yes; it was changed to be under the Western Systems Coordinating Council, but the functions are the same. The scope of

their functions is operational and relate to such things as emergency operating dispatching procedures, rates coordination, area control boundaries, central information centers, dispatcher training requirements, relaying practices, interconnection test closures, and current and anticipated operating programs and problems. We are looking to the Western Operations Committee for guidelines that are being and have been prepared for the coordinated operation of the various dispatchers throughout the system throughout the Northwest.

The dispatchers have a tremendous responsibility in this area. Their duties relate to the substation operators and the operation of generation day to day and hour to hour, and this is based on information that is given to them after it is obtained from computer studies of the scheduling requirements, forecasts, and estimates of streamflow and weather, and schedules with other utilities. Dispatchers have to adjust the generation to the proper magnitude and observe all the parameters that go with the day-to-day operation of the system. They also have to coordinate many day-to-day activities that happen on the system in relation to emergencies; and when the time comes that we have a disturbance, it comes down to the system power dispatcher to make the decision as to whether or not—or, rather, as to what he has to do to restore service as quickly as possible.

We can write, and we do write as many procedures as we possibly can and anticipate as many conditions as we possibly can that will enable him to function as well as possible in these emergencies. But it is physically impossible to cover every imaginable condition. The dispatcher, therefore, has to make vital decisions; it's essential that he be given the very latest equipment and the very best guidelines and the very best cooperation if he's going to do this. He can't operate a system with reliability if it isn't inherent in the system itself.

Thank you, Mr. Chairman.

Mr. KLEIN. Mr. Chairman, do you have any questions?

The CHAIRMAN. No; but we would like to ask some questions of all you people, which we will submit to you in writing. You will have a chance to put your answers down in much better form so we can make this a good record.

Mr. KLEIN. Yesterday, Mr. Chairman, you raised the question, or the question was raised about our contract provisions relative to electric disturbances with utilities. Mr. Foleen is prepared to speak on this, or we can make it a part of the record.

The CHAIRMAN. Would you make it a part of the record?

(The information follows:)

(The following provision, relating to electrical disturbances, is standard in Bonneville contracts.)

23. *Electric Disturbances.*

(a) Each party shall design, construct, operate and maintain its system.

(1) to minimize electric disturbances, such as the abnormal flow of power, which may damage or interfere with the system of the other party or systems connected with such other party's system, and

(2) to minimize the effect on its system of such electric disturbances from the other party's system.

To accomplish the foregoing all electric facilities installed by either party and connected with the other party's system shall conform to accepted modern practices and applicable state regulations, or, in the absence of applicable state regulations, to the specifications, rules, and regulations contained in the latest

editions of, and supplements to, the National Electrical Safety Code of the United States Bureau of Standards.

(b) A party to this contract shall not be liable to the other party for damage to the other party's system or facilities caused by an electric disturbance on the first party's system, whether or not such electric disturbance is the result of negligence by the first party, if the other party has failed to fulfill its obligations under subsection (a) (2) of this section.

A party to this contract shall hold harmless and indemnify the other party, its officers and employees, from any claims for any loss, injury, or damage suffered by the first party and those to whom it delivers power not for resale, which loss, injury or damage is caused by an electric disturbance on the other party's system, whether or not such electric disturbance results from the negligence of such other party, if such first party has failed to fulfill its obligations under said subsection (a) (2) of this section, and such failure contributed to the loss, injury or damage.

(c) Nothing in this section shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a party to this contract.

Mr. KLEIN. This concludes our testimony.

Thank you.

(The questions submitted by the Committee to BPA and the answers follow:)

Q. Do you feel that the engineering viewpoint is generally adequately represented and considered in management decision making?

A. Insofar as BPA is concerned, management gives proper review and consideration to all factors that are brought to its attention. Engineering is one factor. Economics is another. Environmental effects is still another.

Equally important from a management viewpoint is that it should receive the alternatives to the solution of a problem in order to make a proper management decision.

Q. Do you believe the establishment of regional reliability criteria is appropriate?

A. Yes, provided the criteria are flexible. Flexibility is necessary to meet the particular conditions or service requirements of the area. For example, criteria should consider high or low load density areas and areas served by multiple or radial lines.

Q. In what ways does the co-ordinated planning and operation of the facilities owned by separate systems differ from single-system operation?

A. Coordinated planning and operation activities are influenced by the needs and requirements imposed by a region or area regardless of the number of utilities involved. Decisions can only be reached by achieving agreement among the various utilities, each of which may have interests which are not best served by the best over-all plan.

In the case of single-system planning or operation, only one utility is required to make a decision.

Q. Do you feel that a central control center in the Northwest to coordinate the power output of all the generating facilities which are tied together in the region would enhance reliability by shortening the time required to meet sudden changes in demand within the system?

A. Yes. A central control center for bulk power supply would be helpful during troubles when a large change in generation or load occurred suddenly. The central controller could more efficiently coordinate the area response to the trouble. In addition, a central control center could be beneficial in the fast diagnosis and correction of system transmission troubles.

A control center would be particularly valuable if it also controlled the water in an entire river system or related systems. In this way the most efficient use of the water could be realized regardless of the demands of the individual systems. Nonpower uses of the river system would, of course, be recognized.

A central control center would be of no significant value during normal load changes because this response is automatic and predetermined. It should also be recognized that the workload associated with a central control center will be tremendous, and during times of trouble a great deal of confusion could ensue.

Q. Do you feel there is currently an adequate pre-planned scheme to deal with a regional system break-up or will the different utilities tend to respond individually?

A. It is not possible to have a detailed prepositioned regional plan for restoration of service which would cover all cases but, generally, we believe the present procedures will enable the utilities to deal promptly and effectively with regional system breakup.

In the event of a system breakup, each utility has a plan to restore its system frequency to 60 cycles. This is done by automatic load shedding, generator dropping or system sectionalizing. If then contacts its neighbor and if both systems are at 60 cycles they will interconnect. A utility short of capacity will inquire of its neighbor if additional capacity is avialable to aid in making up any deficiency.

In the case of the "donut" and other interconnections, it has been predetermined which ties will be the last closed.

Q. Do you favor voluntary or compulsory membership in regional councils?

A. The only means that this area or any area can be continually assured of regional planning and operation is through a regional entity whose membership or representation is open to all utilities, with compulsory membership of all utilities whose planning and operation affect the reliability of bulk electric service of the region. However, it should be recognized that voluntary membership in multi-utility Pacific Northwest organizations has so far been successful.

Q. Do you believe that reliability can be insured when planning is conducted in voluntary organizations where agreement on plans requires unanimous consent?

A. No. Requiring unanimous consent for adoption of a plan may result in a stalemate, or a plan that receives unanimous consent may be a compromise plan and therefore not the best regional plan.

Q. How do the differences in transmitting capacity of the principal EHV lines making up "the big doughnut" affect reliability?

A. The Pacific Northwest-Pacific Southwest Intertie on the west side of the "donut" in parallel with the presently constructed 230 kV lines on the east side of the "donut" will improve the over-all bulk power system reliability of the Western United States.

However, at the present time major disturbances on the intertie will cause transmission line outages on the east side. Also, the east side will experience transmission line overloads under some conditions of loading of the intertie. Simply stated, that is the "donut" problem.

Q. Do you believe the "doughnut" problem can be effectively and equitably resolved by voluntary regional planning?

A. Joint studies are now underway by many of the utilities in the Western United States, including BPA, to find the proper solution to this problem. It is therefore premature at this time to speculate whether the problem will be effectively and equitably resolved. The utilities involved in these studies are members of the Western Systems Coordinating Council, a voluntary organization.

Q. Would you care to comment on the provisions in the bill which would authorize the FPC to require an interconnection when the Commission finds that it would be neecssary in order to insure reliability?

A. We believe that Section 411 on compulsory interconnections is a desirable provision of the bill. We also believe the bill should clearly provide for compulsory wheeling including the protection of present wheeling rights to preference customers of the Federal Government.

Q. Are you a member of the Western Systems Coordinating Council?

A. Yes.

Q. How are guidelines or plans adopted by the WSCC?

A. A planning Coordination Committee recommends criteria for such elements of system design as affect the reliability of the interconnected bulk power systems, and the Operations Committee recommends such operating procedures as affect the reliability of operation of the interconnected bulk power systems.

Each member of the Council informs the Executive Committee of its plans or changes for generation or transmission additions and such operating procedures or changes in operating procedures which may significantly affect the reliability of operation of the interconnected bulk power systems.

The Council Chairman reports to the Council for its consideration any findings, conclusions and recommendations of the Committees, together with any recomconclusions and recommendations of the Committees, together with any recommendations of the Executive Committee, with respect to such additions, alterations or operating procedures.

Exhibit 1

U. S. DEPARTMENT OF THE INTERIOR

BPA AREAS AND TRANSMISSION FACILITIES

BONNEVILLE POWER ADMINISTRATION

LEGEND

- EXISTING TRANSMISSION SYSTEM (LINE RATINGS ARE SHOWN IN KV).
- TRANSMISSION FACILITIES APPROVED OR UNDER CONSTRUCTION (incl. F.Y. 1966 program)
- EXISTING DAM WITH HYDROELECTRIC POWER
- DAM AND POWER PLANT UNDER CONSTRUCTION
- NON-FEDERAL DAM AND POWER PLANT
- AREA OFFICE BOUNDARIES
- DISTRICT OFFICE BOUNDARIES
- AREA OFFICE
- DISTRICT OFFICE

INTERCONNECTIONS

1. Washington Water Power Co.
2. Pacific Power & Light Co.
3. Puget Sound Power & Light Co.
4. Portland General Electric Co.
5. Chelan County P.U.D.
6. Seattle City Light
7. Tacoma City Light
8. Pend Oreille County P.U.D.
9. Eugene Water & Electric Board
10. B.C. Hydro & Power Auth.
11. C.M. St. P. & P. R.R. Co.
12. West Kootenay Power & Light Co.
13. Inland Power & Light Co.
14. Idaho Power Co.
15. Utah Power & Light Co.
16. Montana Power Co.
17. Grant County P.U.D.
18. Wash. Pub. Pwr. Supply System
19. Raft River Rural Electric Coop. Inc.
20. Milton-Freewater Light & Power Co.
21. Snohomish Co. P.U.D. No. 1

SCALE IN MILES 25 0 25 50

WASHINGTON IDAHO MONTANA OREGON CALIFORNIA NEVADA UTAH

SEATTLE AREA · WENATCHEE DISTRICT · SPOKANE AREA · PORTLAND AREA · WALLA WALLA AREA · EUGENE DISTRICT · IDAHO FALLS AREA · KALISPELL DISTRICT

SEATTLE · SPOKANE · PORTLAND · WALLA WALLA · EUGENE · KALISPELL · BUTTE · IDAHO FALLS · BOISE

Blaine · Custer · Intalco · Bellingham · Fidalgo · Sappho · Port Angeles · Fairmount · Snohomish · Duckabush · Sno-King · Bangor · Bremerton · Monroe · Maple Valley · Kitsap · Belfair · Potlatch · Shelton · Mason · Aberdeen · Tacoma · S. Tacoma · Covington · P.J. Raver · S. Elma · Olympia · Cosmopolis · Raymond · Willapa River · Long Beach · Naselle · Svenson · Cathlamet · Tongue Pt · Astoria · Clatsop · Westport · Driscoll · Wauna · Longview · Lexington · Cowlitz · Cardwell · Clatskanie · Chehalis · Centralia · Holcomb · Silver Creek · Mossrock · Morton · Packwood Lake Dam · Mayfield Dam · Warren · Alcoa · J.D. Ross · Garibaldi · Mohler · Thatcher · Tillamook · Timber · Carborundum · St. Johns · Junction · Forest Grove · D.R. Keeler · Troutdale · Gresham · Beaver · Hebo · Mc Minnville · Walnut City · Carlton · Oregon City · Chemawa · Salem Alumina · Salem · Monmouth · Toledo · Burnt Woods · Wren · Albany · Lebanon · Harrisburg · Junction City · Florence · Walton · Mapleton · Fern Ridge · Lane · J.P. Alvey · Springfield · Gardiner · Tahkenitch · Reedsport · Drain · Dorena · Cottage Grove · Oakridge · Hauser · Coos · Fairview · Reston · Bandon · Norway · Looking glass · Langlois · Port Orford · Geisel Monument · Gold Beach · Hanna · Marcola · Blue River · Cougar Dam · Dexter Dam · Lookout Point Dam · Hills Creek Dam · Detroit Dam · Big Cliff Dam · Foster Dam · Green Peter Dam · Trail Bridge Dam · Pelton Dam · Round Butte Dam · Redmond · Carmen Dam · Grizzly · Fossil · Yamsay · Malin · U.S.B.R. · City of Los Angeles · Hampton · To Harney Elec. Cooperative, Inc.

Oroville · Tonasket · Okanogan · Gpose · Lake · Chief Joseph Dam · Grand Coulee Dam · Brewster · Foster Creek · Chief Joseph · Lone Pine · Nilles Corner · Orondo · St. Andrews · Rocky Reach Dam · Wenatchee · Eastmont · Keokuk · Columbia · Valhalla · Soap Lake · North Ephrata · Ephrata · Quincy · Burke · Coulee City · Rocky Ford · Larson · Odessa · Moses Lake · Pelican Horn · Sand Dunes · Warden · Potholes · Ritzville · Ellensburg · Jericho · Wanapum Dam · Royal · Vantage · Hanford · Eagle Lake · Roza Dam · (USBR) Roza · Priest Rapids Dam · Midway · Moxee · White Swan · Lower Monumental Dam · Jerita · Colfax · Riparia · Mayview · Chambers · Lower Granite Dam · Little Goose Dam · Dayton · Pomeroy · Dworshak Dam · Clarkston · Scooteney · Ringold · Baxter · Glade · Riverview · Franklin · Ice Harbor Dam · Burbank · Blackrock · Toppenish · Grandview · Prosser · Chandler Dam · Benton · 300 area · Stevens Dr. · Thayer Dr. · Richland · Benton City · Ledbetter · Highlands · Kennewick · Hedges · Stateline · N. McNary · McNary Dam · Freewater · Milton · Pendleton · Roundup · La Grande · Lone · John Day Dam · John Day · The Dalles Dam · Big Eddy · Tygh Valley · Horsey · Chenowith · Gilmer · Goldendale · Spearfish · Underwood · Jingo · North Bonneville · Bonneville Dam · Carson · N. John Day · Hood River · Boundary · Metaline Falls · Box Canyon Dam · Pend Oreille · Republic · Bonners Ferry · Samuels · Sandpoint · Albeni Falls · Newport · Troy · Yaak · Deer Park · Green Bluff · Trentwood · Athol · Prairie · Springhill · G.H. Bell · Vera · Valley Way · Four Lakes · Noxon Sw. Yd. (W.W.P.CO.) · Albeni Falls Dam · Libby Dam · Trego · (Anac. Alum. Co.) Conkelley · Hungry Horse Dam · La Salle · Columbia Falls · Kalispell · Elmo · Hot Springs · Kerr · Frenchtown · Stevensville · Sherryl · Anaconda · Silver Bow · Butte

Black Canyon Dam · Boise · Boise Diversion Dam · Anderson Ranch Dam · Dixie · Mountain Home · Minidoka Area Inset · Minidoka · Acequia · Hay Mill · Rupert · Paul · Budge · Heyburn · Newcomb · Minidoka Dam · Burley · Unity · Pella · Riverside · Declo · Weeks · Albion · All lines 34.5 kv · See Inset · Minidoka Dam · Idahome · American Falls Dam (power by Idaho Power Co.) · Idaho Falls · Goshen · Palisades Dam · Teton

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Exhibit 3

ELECTRIC POWER PLANTS

IN THE PACIFIC NORTHWEST AND ADJACENT AREAS

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Rosiyn F-4
Ross E-4
Round Butte G-4
Roza F-4
Ruddle D-3
Ruskin D-3
Russell G-7
Ryan F-6

Salem "H" G-3
Samoa G-3
Salt Caves I-3
Sammis I-11
Sanford D-7
Selby C-4
Seven Mile E-6
Shasta J-3
Show-Low A-11
Sheridan G-10
Shoshone H-9
Shoshone Falls H-7
Tr-Tetton F-3
Shawnigan Falls D-3
Sixth Water J-9
Skook Creek N-3
Smoky Range E-7
Snake Creek J-9
Snoqualmie Falls I F-4
Snoqualmie Falls 2 ..... F-4
Soda I-6
Soda Springs H-9
South J-3
South Slocan D-6
Spillimacheen C-6
Spokane F-6
Spray C-7
Spring Creek J-3
Springfield H-3
Spruce Park E-7
Starr J-8
Stamp River D-2
Steel Falls H-3
Strathcona D-2
Strawberry Creek J-9
Stroke I-6
Stubb H-1
Sullivan G-3
Sullivan Creek I-6
Sultan No.1 ..... E-4
Sultan No.2 ..... E-4
Sultan No.3 ..... E-4
Sunlight G-9
Swan Falls H-6
Swift No.1 ..... F-3
Swift No.2 ..... F-3
Syon J-9

Tacoma No.1 ..... F-3
Tacoma No.2 ..... F-3
Tellm H-6
Teton River H-8
The Dalles G-4
Thief Creek G-6
Thompson Falls F-7
Thousand Springs I-7
Three Sisters C-7
Thunder Creek E-4
Tillamook G-3
Timothy Meadows G-3
Tolma D-3
Tolvana H-3
Trail Bridge H-3
Trinity J-3
Trout Creek G-4
Troy E-6
Twin Falls H-7
Twin Springs H-6
Tyee Valley G-4

Umtah J-9
Upper Baker E-4
Upper Bonnington D-6
Upper Falls F-6
Upper Idaho Falls H-8
Upper Malad I-7
Upper Salmon I-7
Upper Scriver H-6

Vanderhoof A-3
Vermilion B-8
Volta J-3

Wahonsh B-7
Wahtash G-3
Walter Harding D-5
Walterville H-3
Wanapum F-4
Wanship J-9
Wapato Drop No.2 ..... F-4
Wapato Drop No.3 ..... F-4
Warm Springs I-3
Weiser J-4
Wells E-4
Wells (Nev.) J-5
Wenatchee G-5
Whatshan D-5
White River (Colo.) J-10
White River (Wash.) F-3
Williston E-10
Winnemucca J-5
Wynoochee F-3
Wyodak H-11

Yale F-3
Yellowtail F-10
Yelm F-3



LEGEND

FEDERAL PLANTS

P.H.	HYDRO	
■		EXISTING
□		UNDER CONSTRUCTION
□		AUTHORIZED
::		UNDER CONSIDERATION

NON-FEDERAL PLANTS

FUEL	HYDRO	
●	▬	EXISTING
⊕	▭	UNDER CONSTRUCTION
○	▭	LICENSED
∷	▭	UNDER CONSIDERATION

NOTE:

Nameplate ratings at plants of 1000 KW capacity or more.

_/Alternative Project, conflicts with another project shown.

N

SCALE IN MILES 0 10 50 100

UNITED STATES
DEPARTMENT OF THE INTERIOR
BONNEVILLE POWER ADMINISTRATION
DECEMBER 31, 1966

84-381 O - 68 - pt. 2 (Face p. 292) No. 2

U.S. DEPARTMENT OF THE INTERIOR

BONNEVILLE POWER ADMINISTRATION

SERVICE AREAS - PRIVATE UTILITIES

NOTE:- PREPARED FROM AVAILABLE INFORMATION AND NOT INTENDED TO REPRESENT LEGAL OR CLAIMED SERVICE BOUNDARIES.

PUGET SOUND POWER & LIGHT COMPANY

PACIFIC POWER & LIGHT CO.

WASHINGTON WATER POWER CO.

PACIFIC POWER & LIGHT CO.

PORTLAND GENERAL ELECTRIC CO.

PACIFIC POWER & LIGHT COMPANY

CALIFORNIA PACIFIC UTILITIES CO.

MONTANA POWER CO.

IDAHO POWER CO.

UTAH POWER & LIGHT COMPANY

SEATTLE AREA

SPOKANE AREA

PORTLAND AREA

WALLA WALLA AREA

IDAHO FALLS AREA

WASHINGTON

MONTANA

OREGON

IDAHO

CALIFORNIA

NEVADA

UTAH

WYOMING

PACIFIC OCEAN

Bellingham, Anacortes, Mt. Vernon, Port Townsend, Bremerton, Seattle, Bothell, Skykomish, Renton, Tacoma, Enumclaw, Cle Elum, Olympia, Yakima, Grandview, Othello, Ritzville, Davenport, Wilbur, Spokane, Deer Park, Colville, Sanpoint, Libby, Columbia Falls, Kalispell, Coeur d'Alene, Kellogg, Thompson Falls, Odessa, St. Maries, Superior, Missoula, Rosalia, Colfax, Moscow, Pullman, Lewiston, Clarkston, Dayton, Walla Walla, Asotin, Wallowa, Enterprise, Joseph, La Grande, Pendleton, Umatilla, Hermiston, Hood River, Arlington, The Dalles, Moro, Heppner, Condon, Fossil, Prineville, Redmond, Bend, Madras, Mt. Vernon, Long Creek, John Day, Prairie City, Baker, Drewsey, Burns, Ontario, Vale, Payette, Emmett, Caldwell, Nampa, Boise, Sun Valley, Twin Falls, Jerome, Mountain City, Pocatello, Blackfoot, Idaho Falls, St. Anthony, Jackson Lake, Yellowstone Lake, Anaconda, Butte, Darby, Salmon, Preston, Logan, Brigham, Ogden, Randolph, Astoria, Seaside, Rainer, Portland, Oregon City, Lincoln City, Albany, Corvallis, Sweet Home, Cottage Grove, Roseburg, North Bend, Powers, Grants Pass, Medford, Klamath Falls, Lakeview, Crescent City, Yreka, Tulelake, Alturas, Dunsmuir, Mt. Shasta, Lassen Peak, Klamath Lake, Upper Klamath Lake, Lower Klamath Lake, Clear Lake Reservoir, Goose Lake, Summer Lake, Lake Abert, Harney Lake, Malheur Lake, Owyhee Reservoir, Cascade Reservoir, Swan Lake, Flathead Lake, Yellowstone National Park, Grand Teton National Park, Great Salt Lake, Bear Lake, Hungry Horse Reservoir, Hebgen Reservoir, Madison Reservoir, Jackson Lake, Grays Lake, Palisades Reservoir, Island Park Reservoir, Henrys Lake, Mackay Reservoir, Magic Reservoir, Lake Walcott, Milner Dam, Anderson Ranch Reservoir, Arrowrock Reservoir, Lucky Peak Lake, Deadwood Reservoir, Payette Lake, Cascade Reservoir, Owyhee Reservoir, Malheur Lake, Harney Lake, Fern Ridge Reservoir, Detroit Reservoir, Lake Chelan, Diablo Lake, Ross Lake, Baker Lake, Priest Lake, Pend Oreille Lake, Coeur d'Alene Lake, Kootenai, Flathead Lake, Swan Lake, Lake McDonald, Missouri River, Yellowstone River, Snake River, Columbia River, Clearwater River, Salmon River, Bitterroot River, Clark Fork, Flathead River, Kootenai River, Pend Oreille River, Spokane River, Grande Ronde River, Wallowa River, Powder River, Malheur River, Owyhee River, Boise River, Payette River, Weiser River, Deschutes River, John Day River, Umatilla River, Willamette River, Rogue River, Klamath River, Trinity River, Sacramento River, Pit River, Madison River, Gallatin River, Yellowstone River, Missouri River, Marias River, Milk River, Musselshell River, Judith Basin, Continental Divide, Lewis and Clark, Glacier, Pondera, Teton, Chouteau, Fergus, Cascade, Meagher, Broadwater, Wheatland, Sweet Grass, Stillwater, Gallatin, Park, Madison, Beaverhead, Ravalli, Missoula, Granite, Powell, Lake, Flathead, Lincoln, Sanders, Mineral, Shoshone, Clearwater, Latah, Nez Perce, Lewis, Idaho, Valley, Custer, Lemhi, Clark, Fremont, Jefferson, Bingham, Bonneville, Butte, Blaine, Camas, Gooding, Lincoln, Jerome, Minidoka, Elmore, Ada, Canyon, Gem, Washington, Payette, Owyhee, Twin Falls, Cassia, Box Elder, Power, Bannock, Caribou, Oneida, Franklin, Cache, Rich, Bear Lake, Sublette, Lincoln, Uinta, Wasatch, Morgan, Weber, Salt Lake, Grant, Harney, Lake, Deschutes, Crook, Jefferson, Wasco, Sherman, Gilliam, Morrow, Umatilla, Union, Wallowa, Baker, Malheur, Grant, Wheeler, Klamath, Lake, Modoc, Siskiyou, Shasta, Trinity, Humboldt, Lassen, Washoe, Douglas, Lincoln, Linn, Benton, Polk, Marion, Clackamas, Yamhill, Tillamook, Clatsop, Columbia, Multnomah, Hood River, Wasco, Sherman, Gilliam, Morrow, Umatilla, Jefferson, Deschutes, Crook, Grant, Wheeler, Klamath, Lake, Harney, Malheur, Baker, Union, Wallowa, Curry, Josephine, Jackson, Del Norte, Coos, Douglas, Lane, Linn, Benton, Lincoln, Polk, Yamhill, Tillamook, Clatsop, Columbia, Multnomah, Clackamas, Marion, Wasco

Q. What does the WSCC do when a member disagrees with a proposed guideline or plan?

A. Presently there is no provision in the WSCC agreement for the resolution of disagreements.

Q. Do all major planning decisions of the WSCC require unanimous consent?

A. Presently there are no voting requirements or procedures in the WSCC agreement.

Q. Could one generalize to say that systems in which thermal rather than hydro generation is predominant, are apt to be more reliable because of the longer time required to bring additional generating capacity onto the line?

A. One could not generalize on whether a hydro or a thermal system is more reliable. It is true that steam units are more difficult to restart than hydro units. However, a steam unit can pick up a small increment of load faster than hydro units. Electric systems can be designed with the same degree of reliability whether the system has steam or hydro power.

Q. Do you foresee any difficulty in the FPC obtaining trained personnel to carry out its duties prescribed in this bill?

A. Yes. BPA and other utilities in the electric power industry have found the hiring of trained planning personnel very difficult.

The CHAIRMAN. Thank you all. I appreciate your coming to testify. Now we shall hear from Mr. Ken Billington, representing the Washington Public Utility Districts' Association.

Mr. BILLINGTON. Mr. Chairman, in deference to the time, I wish to submit my written statement for inclusion in the record.

The CHAIRMAN. We'll put it in the record in full.

Mr. BILLINGTON. I do want to emphasize several parts because we are a little different in some respects than that testimony which you have before you so far. If I might just read the summary so that you understand basically what's in the statement.

STATEMENT OF KENNETH BILLINGTON, EXECUTIVE SECRETARY OF THE WASHINGTON PUBLIC UTILITY DISTRICTS' ASSOCIATION

Mr. BILLINGTON. We would favor Federal legislation designed to assist in maintaining a good level of reliability of electric service in the various regions of our country. We favor the use of voluntary means to accomplish this to the greatest extent possible but would agree with a law to effectuate reliability needs where voluntary efforts fail or establish monopoly abuses affecting smaller electric systems. We recommend that the Federal bulk power supply facilties should not be included in the law as regards certification of extra high voltage lines. Extra high voltage line certification procedures should be specific to prevent third party "destroy by delay" tactics. We support the establishment and use of the National Electric Study Committee and the use of advisory boards. The grant of immunity from antitrust laws should be based on specific conditions and subject to review by the Federal Power Commission upon filed complaint or by its own motion.

Seven, the use of excess capacity and the right to increase——

The CHAIRMAN. Right there you said that the right of review by the Justice Department should never be abolished.

Mr. BILLINGTON. It's not so provided in the legislation, sir. I understand the legislation just eliminates third party harassment.

The CHAIRMAN. I think they always should have the right to move in. I think you'd agree, sir.

Mr. BILLINGTON. Yes. But then from the utilities standpoint, when you get into the necessary contracts to justify or finance these large

transmission lines, you border on the edge of, you might say, price fixing, monopoly, and so forth. So you do need to have means to prevent third party harassment in these instances.

The CHAIRMAN. This would eliminate some delays which we don't want. We have to rely on the fact that somebody's going to use their head at Justice and be sensible and act wisely. I don't think you're ever going to abolish the right of the Department of Justice to review certain cases if they deem fit.

Mr. BILLINGTON. The use of excess capacity or the right to increase the capacity in transmission lines should be allowed any utility provided it pays for such cost and does not adversely affect the owning utility. Finally, specific conditions should govern the grant of rights-of-way across public lands. Now, in my statement I have elaborated on each of these summarized statements. I would emphasize the fact to the committee that we have a Federal transmission grid in the Pacific Northwest which does set us apart from some of the problems of other regions; and our natural reaction to compulsory or mandatory legislation is to oppose it. I think if I might characterize what we envision in regard to this legislation, and I do not know whether it can be done—is some type of a watchdog procedure. A procedure which maintains the prerogatives of local management to the fullest extent and then provides means that if there is monopoly abuse or something that prevents full participation by all utilities, then the Federal Power Commission by receipt of a proper complaint and under investigation may take the necessary steps to require compliance with the purposes of the act. I might say, Senator, you might liken it to a shotgun colored "white" for a wedding. You may not intend to use the gun, but its presence will insure the wedding. The possibility of overloads of work in a regulatory commission which by virtue of its present requirements must practice slowness for the purpose of deliberation and the assurance of deliberation concerns us. Putting this transmission certification program into that arena could cause us considerably more problems.

(Mr. Billington's prepared statement follows:)

PREPARED BY KEN BILLINGTON, EXECUTIVE SECRETARY OF THE WASHINGTON PUBLIC UTILITY DISTRICTS' ASSOCIATION

Mr. Chairman, Members of the Senate Commerce Committee, I am Ken Billington, Executive Secretary of the Washington Public Uutility Districts' Association. Our address is 601 Tower Building, Seattle, Washington. The group I represent is an association of Public Uutility Districts operating electric facilities in the State of Washington. They serve approximately 300,000 electric customers in over 50 per cent of the land area in our State.

Nearly all of the power sold by these Districts is purchased from the Federal Power System through the Bonneville Power Administration. However, several of our member Districts own and operate a number of the large generating plants located on the Columbia River in the mid-part of our State. Additionally, the Districts, through their joint operating agency, The Washington Public Power Supply System, own and operate the large Hanford nuclear fired steam plant and the related extra high voltage transmission lines operated in conjunction therewith. Thus these Districts have a direct interest in this legislation which proposes a new section to the Federal Power Act involving the establishment of regional councils for utility planning and coordination, basic reliability standards, interconnection of utility systems, grants of immunity from anti-trust laws, the use of Federal eminent domain proceedings to secure rights-of-way and procedures to use public lands for such rights-of-way.

We recognize the desirability of increasing by any means the reliability of electric service. The establishing of reliability standards and practices becomes more important and yet more complex as we move in the electric industry to-

wards interconnection and related operation as between not only individual utility systems, but indeed, even regional systems of utilities. The tremendous blackouts which have occurred in certain parts of our Nation make it mandatory that the electric utilities institute higher standards of reliability which extend a good level of protection against re-occurrence of such outages.

However, we emphasize one fact. Reliability of service is a built-in goal of every utility. No utility, large or small, would knowingly adopt operating practices which foster blackouts. Thus there is a mutual goal in this legislation.

It is difficult for us who represent utility systems in the Pacific Northwest to see what contribution this legislation will make to our region. Also, it is very broad and gets into many policy factors other than those affecting reliability. We, as a region, have already accomplished on a voluntary basis many of the arrangements and procedures which are made mandatory by this legislation.

Here in the Pacific Northwest we have the large Federal "backbone" transmission grid with an established coordination agreement, northwest power pool and operating procedures existing between the operating utilities—Federal and non-Federal. Perhaps the presence of this Federal transmission grid sets us apart from the problems which prompt this legislation. We thus, at first glance, rebel against compulsory type legislation. This is not to say that we have an ironclad preventive guarantee arrangement to prevent substantial power outages in our region. It could happen here, although the nature of our service based on hydro plants and a joint regional transmission grid makes us less vulnerable to prolonged blackouts. However, no law can never prevent outages and we are coordinated and integrated to an extent that passage of this legislation would not necessarily enhance or improve our own Pacific Northwest regional situation. Our first reaction to this legislation is to favor a position of using voluntary methods for coordination and integration to the fullest extent before any mandatory enforcement methods take effect.

We have prepared this statement without referring to specific sections or paragraphs of the legislation. Rather we attempt to state those policy questions or cite those policy conditions which we would favor or oppose. In other words, our statement is more of a policy statement rather than a specific legislative analysis of S. 1934.

We feel that substantial re-wording of the legislation will be necessary but would leave such drafting to the Committee's technical and legal staff, hopefully to be based on our policy viewpoints as expressed here.

The establishment of regional councils for the purpose of coordination planning, comprised of all utilities in any defined region, either by direct or indirect representation, regardless of ownership, is indeed worthwhile. We have to a great effect accomplished this in the Pacific Northwest. However, the legislation makes this mandatory. It might be well to re-write the legislation to allow this to be done under a voluntary arrangement first. Then if it is not done, or if it is done in a manner with which one or more of the utilities located in such region do not agree or feel is inadequate, a specific complaint or request by such utility could be made to the Federal Power Commission and formation would become mandatory and accomplished under the formal procedure provided by the legislation. In other words, let us keep as much of the actions pertaining to coordination and planning as close as possible and within the prerogatives and controls of the local utilities without Federal bureau involvement, but be prepared to prevent any monopoly blocking of needed interconnections and construction of service facilities to provide reliability.

Underlying this entire legislation is the basic policy issue as to what degree should the mandatory decisions made by a Federal regulatory agency usurp or override the basic management prerogatives in utility operation. We would tend towards as little of this type of regulation as can be had, but still permitting a forum to correct defects or settle arguments as between different utility interests or eliminate monopoly abuses on power supply.

We are opposed to the inclusion in this legislation of the Federal agencies who directly construct and operate bulk power supply facilities as regards the certification requirement on extra high voltage transmission lines.

Participation by all Federal agencies in any regional council and its planning activities is a proper requirement, but the certification of Federal lines by the Federal Power Commission would be superfluous. For example, no bulk power facilities can be built by the Bonneville Power Administration until it has gone to Congress and secured authorization and appropriations for such lines. Does this certification of a Federal extra high voltage line by the Federal Power Commission as provided in this legislation assure Congressional authorization and

appropriations for such line? Is it a good policy to transfer evaluation of such Federal lines to any authority other than Congress? We do not think so. Further, how can a Federal agency, which is not self-financing and which uses Congressional appropriations, be certain that a line planned for construction at least two years hence will be possible of construction at that time? This certification of Federal lines could cause a lot of confusion and delay.

It is elementary that the guidelines and procedures in this legislation provide rapid and better means to expedite the adoption and carrying out of adequate plants and construction programs which will foster reliability.

Any red tape delays should be avoided wherever possible. Delay is an enemy of reliability. This will require a new approach from the standpoint of a regulatory body where slowness for the assurance of full deliberations has prompted very formal and lengthy procedures. Placing transmission lines in the same type of procedures might result in some very serious delays because of legal involvement in re-hearings and court appeals. It could make it impossible to meet needed construction schedules to answer needed power supply demands.

In fact, one major concern of ours relative to this legislation is that nowhere to date has there been any specific testimony as to just how the tremendous workload in the Federal Power Commission which will result from this legislation will be handled, staffed or expedited.

That portion of the legislation which provides for the establishing of a National Electric Study Committee, as well as the various Advisory Councils, appears very worthwhile. Wherever representatives of the industry and related groups can be used to promote reliability it should be done.

We have certain reservations relative to the provisions which grant immunity from anti-trust action provided the line or utility facility being constructed is in accordance with the approved regional coordinating plan.

Previously in testifying on another bill which concerned this same matter, we stated that we recognize the necessity of protecting utilities contracting together for the joint construction and use of a transmission line from third party harassment by means of the anti-trust laws.

To finance, construct and use an interconnecting utility facility it is necessary that the contractual arrangement be quite specific, both as to use and as to price. Therefore, such arrangements may border on the danger of restraint of trade and price fixing.

Our previous position, which is the one we state here, is that while provisions might be made, as is done in this legislation, to grant needed immunity, such grant should be based on specific conditions which would be reviewable by the Federal Power Commission upon complaint. Conditions on which immunity is granted today can change by virtue of a change in the service area needs or future operation of the utilities involved over a period of time. The right of review should be retained.

There is another way of avoiding or lessening this problem of unfair competition or restraint of trade by monopoly domination in any given utility transmission facility. This would be to provide the right of other utilities to use any excess capacty in a given transmission line at a proper cost to the using utility. In fact, increasing the capacity in any given line should be allowed if the using utility paid the cost and provided it did not disrupt or damage the use of the transmission facility by the original contracting and owning parties.

A new widespread practice of joint ownership of generating facilities is now entering the utility industry. Building large plants is essential to gain the economies of size. However, it creates the need, where immunity against anti-trust is to be granted, that procedures be specific to protect against smaller utilities being locked out of direct participation in large generating plants.

Adoption of standards governing reliability may prove difficult. We note that the legislation provides the adoption of either national or regional standards. While electric service is basically the same industry and nationwide, the divergencies in the types and ownerships of utility service, even within regions, will cause complex problems in adopting reliability standards which will fit the needed and proper management of a given utility. This complexity is going to be intensified by assignment of this responsibility to a central staff, coordinated in the service of a nationwide regulatory agency. Most certainly the regional councils will have to play a strong role in this work.

Care must be exercised in establishing any grant of use of public lands for transmission rights-of-way. The denial of such use has been an effective negotiating pressure in the past to protect regional development in several parts of our Nation.

We have had several instances in the Pacific Northwest where private power companies have proposed building particular transmission lines which were not compatible to regional planning. In one case, a proposed line would have overlaid the backbone Federal transmission grid and was designed specifically for the purposes of the individual company involved. From a regional planning standpoint it was completely wrong in direction and use. The only way construction of these transmission lines was blocked was when the Department of Interior refused rights-of-way across Federal lands which had to be traversed if the lines were to be built.

In another instance, a private power company proposed the construction of a line, but with very specific limitations on wheeling service over such line to some local publicly and cooperatively owned utilities by the Federal Power System. Here again, the only restraining or negotiating control over this arbitrary position was the denial of use of Federal lands for rights-of-way.

In that section which allows the Federal Power Commission in an emergency to grant an exemption to the requirements of the Act without notice, hearing or any other procedure, any grant of immunity from anti-trust should be withheld. Most certainly the grant of immunity against anti-trust action should only be allowed after full public disclosure, comments and hearings, if need be, on any facilities to be constructed.

Recent action of the Federal Power Commission has afforded the smaller utilities a forum through which to obtain fairness in rates and assurance as to availability of supply for purchased power. It is proper that the Federal Power Commission retain its authority of regulation in those areas where a utility has accepted a public utility responsibility on power supply to other utilities by virtue of its size and monopoly position. We are glad that specific provision has been placed in this legislation to maintain all present authority of the Federal Power Act. We would not like to see a change in this type of regulation based on this new reliability concept of regulation.

We summarize and conclude as follows:

1. We would favor Federal legislation designed to assist in maintaining a good level of reliability of electric service in the various regions of our Nation.

2. We favor the use of voluntary means to accomplish this to the greatest extent possible but would agree with a law to effectuate reliability needs where voluntary efforts fail or establish monopoly abuses affecting smaller electric systems.

3. Federal bulk power supply facilities should not be included in the law as regards certification of extra high voltage lines.

4. Extra high voltage line certification procedures should be specific to prevent third party "destroy by delay" tactics.

5. We support the establishment and use of the National Electric Study Committee and the use of Advisory Boards.

6. The grant of immunity from anti-trust laws should be based on specific conditions and subject to review by the Federal Power Commission upon filed complaint or by its own motion.

7. Use of excess capacity or the right to increase the capacity in transmission lines should be allowed any utility provided it pays for such use or cost and does not adversely affect the owning utility.

8. Specific conditions should govern the grant of rights-of-way across public lands.

We thank the Committee for holding hearings in the Pacific Northwest region and appreciate the Committee's courtesy in permitting us to testify on S. 1934.

Mr. BILLINGTON. I might refer back to the previous testimony of the Bonneville Power Administration. We raised this in our own statement here. We are not so sure that we like to see the Federal agencies go under this certification procedure. We like the Federal procedure where they go to Congress and are authorized, and money is appropriated for their facilities. We feel this is the forum where these matters should be considered; and this bill does provide a dilemma from the Federal agency standpoint. It is somewhat of a chicken and an egg process from their viewpoint.

What I'm saying is, this bill provides 2 years' notice on any transmission line that is going to be constructed; and even though, as you

say, redtape bureaucracy should not permit any delays on this, you also have in this procedure the right of other people coming in and challenging with petitions for rehearings and involvements and so forth. And if the FPC procedure is subject to court review, you can get into these delays.

Now, their question is, do they have to get FPC certification before they have to come to Congress? We feel the fact that they have to come to Congress is sufficient to evaluate whether or not the line should or shouldn't be built. They should participate in any regional council planning, without a question. This is very essential.

Our position on the regional council, I think, is important. We think that every utility, regardless of ownership, should participate either directly or indirectly in the regional council. Give the little utility as well as the large utility a chance to have something to say about future plans. Granting of this—and we stress this again, this refers to bulk power supply facilities which gets into generating plants as well as transmission pools. Now that we're moving toward the concept of joint ownership and joint participation, there's got to be a forum to be shared and which guarantees there automatic lockout of the smaller utilities.

Again, in closing, I think we in the Pacific Northwest by virtue of this large Federal transmission grid have a unique situation—and in that instance I might comment just very briefly on this grant of land use or public land use under this legislation. We think that great care should be exercised in determining the procedures or rights under this. We have had instances in the Pacific Northwest where powerlines were being proposed by individual utilities which were contrary to a regional planning or service concept, and the only negotiating pressure to protect this concept was the refusal of use of public lands by the Department of the Interior and the Forest Service. Sure, it's a pressure point, but if in this legislation you write in a procedure whereby you can just automatically get this land use, you have eliminated a possible way to make sure that all of us remain good people in regional transmission planning.

We appreciate the courtesy of the committee in coming here, especially at this time, for these hearings and your courtesy in letting us appear before you.

The CHAIRMAN. Thank you. If we have any further questions, we will submit them to you in writing.

Now Mr. Wickberg. We're glad to have you and Mr. Timm here, as well as Francis Pearson. Go right ahead.

STATEMENT OF RALPH H. WICKBERG, IDAHO PUBLIC UTILITIES COMMISSION

Mr. WICKBERG. Senator Magnuson, this is a personal evaluation of a bill, a very complex bill, and I assure you I don't appear here as an expert but as a State regulator. And that is a conflicting statement.

Electric reliability is undoubtedly the most important function of any organization or group of organizations that furnish electricity to consumers. Without reliability our modern computer-based economy would fall. Pricing, tax policy, ownership of facilities, and even

esthetic considerations must take a back seat when ultimate reliability would be seriously affected by any of these subsidiary questions.

S. 1934 is a unique proposal that would place regulatory personnel in line-management positions. This is a radical departure from the role of business regulation that has been developed in the United States for the last 100 years. Management functions have not been assumed by regulators on the theory that quasi-judicial agencies whose decisisons have legal status, subject to court review, must observe strict neutrality so as to be able to render fair and impartial decisions.

Management has had the responsibility under regulatory supervision to operate efficiently. Private utility managers must not only please the regulators, but they must also earn a fair return to those who have furnished the capital. The same general comments pertain to cooperatives, cities, and Federal agencies. In other words, cooperative managers are responsible to their members, municipal managers are responsible to mayors, and city councils and Federal agency managers are responsible to Cabinet officials and Congress. Should regulators assume management prerogatives then they will have to assume obligations that would conflict with their quasi-judicial duties. Regulators could not question the efficiency of management if, in fact, they themselves have been the managers.

Amongst the provisions of S. 1934 is the creation of regional councils. These regional councils would be composed of many divergent interests. I could visualize that a Pacific Northwest Regional Council could consist of representatives of Bonneville Power Administration, Department of Interior, Bureau of Reclamation, Army Engineers, Department of Agriculture, U.S. Forest Service, public utility districts, cities, cooperatives, investor-owned utilities, State regulatory commissions, fish and game interests, varied land-use advocates, and the Federal Power Commission. The makeup of the council would be determined by the Federal Power Commission. The operating rules of the council and any recommended decisions of this body would also be subject to Federal Power Commission approval. It is unrealistic to assume that such a divergent group could agree on any meaningful long-range solution. The Federal Power Commission would have to resolve the differences of the contending parties. Then in future formal proceedings before the Federal Power Commission they would, in fact, be adjudicating matters they had either approved or disapproved at the regional council level. It would seem that a conflict of interest would exist.

Accepting the proposition that electric reliability is not being fully attained under present procedures, what then is an alternative to S. 1934? I offer this suggestion. Each and every private utility, cooperative, municipality, public utility district, and all Federal agencies having responsibility for providing electric service should be directed to report to the Federal Power Commssion and all State regulatory bodies in the affected area on any apparent generation or transmission deficiencies that would affect the reliability of electric power. This would bring the alleged deficiencies into the open where State and Federal regulatory bodies would evaluate the reasons for the deficiencies, which electrical system could be at fault, and any generating and transmission construction that could be needed. Public disclosure of

these deficiencies would accelerate various plans or proposals by which these defiiciencies could be corrected. The regulatory bodies would now be in a position to exert their statutory responsibility in assuring that this country would have the most reliable nationwide electric system. This would also provide the vehicle for negotiations with interconnected systems within either Canada or Mexico as interconnections between nations can affect reliability as well as interconnections between regions in the United States. This can best be illustrated by the outage that occurred in the Northeastern United States and Canada. This method would make it unnecessary for regulatory personnel to assume management functions, and, in my opinion, would avoid the built-in delays of S. 1934.

In my opinion, adequate notice will be provided to those interested in esthetic values, land use problems and other public interest questions. Private conservation oriented associations are able to eloquently present their views in opposition to generating stations, transmission lines, or any other structure that displeases them. Their opposition to dam construction in the Grand Canyon and the pumped storage project on the Hudson River illustrate their power and influence.

This is not a States rights-Federal Government dispute. No regulator should be clothed with managerial authority and power unless he or she has the ultimate responsibility for the success or failure of the enterprise.

State and Federal regulators have ample statutory power. If a regulatory gap exists, it is caused from lack of cooperation and coordination. Voluntary joint Federal-State action taken in concert with all segments of the electric industry will accomplish the purposes of electric reliability much better and in a shorter period of time.

Thank you.

The CHAIRMAN. Thank you, Ralph, that's a good suggestion. I want to compliment you on what you have to say. We in politics sometimes say: "If you don't like what's going on, what are you going to do about it? What's your alternative?" At least here's a suggestion as to how we might accomplish some of these things. But I do feel, and perhaps you and Mr. Timm agree, that the Federal Power Commission should have some role to play—that they should have some responsibility, whether they act as a conduit for information, possess the power to correct it, or help out in providing some leadership. Maybe they could set minimum standards to insure reliability without dictating or telling everybody what to do.

Mr. WICKBERG. Senator, may I add one thing? What you've pointed out is so important. Regulators have many responsibilities and the public interest is served in many intangible areas, and if you start making each person a technician, I don't think you're going to get your statutory function completed.

The CHAIRMAN. Yes, that's true. It should be independent, but it should also be making regulations. They have a great deal of authority that could be used for the benefit of people. They should make some decisions.

All right, Mr. Timm. I'm glad to hear from you.

STATEMENT OF ROBERT D. TIMM, CHAIRMAN OF WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Mr. TIMM. My name is Robert D. Timm. I am chairman of the Washington Utilities and Transportation Commission, the agency within this State directed by statute to assume jurisdiction over service and rates for electric utilities, privately owned. With this direction by the legislature, we give special attention to the needs of the electrical customer, and our first concern is for the public we serve. Believing that strong companies are vital to our economy, one section of our commission deals exclusively with utility matters, and the ability of a company to serve well is a basic consideration for us.

It is my understanding from both reading about the legislation embodied in S. 1934, and discussing it with persons more knowledgeable specifically than I, that it was submitted as a basic document and proposal to serve as a legislative vehicle for the purpose of getting the facts on the subject before the Senate Commerce Committee. With this in mind, I will limit my discussion and statements to general attitudes about this type of legislation, and will not attempt to be specific on the content of S. 1934 itself. Later in my discourse I will suggest some logical points of departure that may be helpful to the committee, and I hope will be worthy of consideration.

I am aware that this legislation represents a departure as it now stands and virtually excludes State commission participation. At the last convention of the National Association of Regulatory Commissioners, the president of that body appointed an ad hoc committee on the Electric Reliability Act to represent the group, which is an association of all State regulatory bodies. It was their charge to determine if the States should play a role in such new law, and the alternatives form a State-oriented position on how to achieve what we all agree should be a goal, that of maximum reliability of electric service. Their work is only partially completed, and should be presented to your committee at later hearings. I suspect that every State commission in the Nation, in addition, is trying to reach conclusions on the advisability and scope of this type of legislation.

As chairman of the State agency directly charged with this matter of service and reliability for the customer, I am vitally concerned that the public has an advocate as it related to reliability of their electrical service, so that they will (1) not have to suffer economic loss as a result of outages; (2) not have to suffer inconvenience and delay; and (3) that their lives and properties will not be endangered. I raise the rhetorical question of who will fill that role if the decisionmaking process of management passes from management's hands to a governmental body far from home. We at the Washington Utilities and Transportation Commission pride ourselves on our intimate knowledge of the management process and personnel of the companies we regulate in this State, and we feel certain that given broad national guidelines as to reliability the companies in our region would cooperate and we could enforce those factors that would be considered in the best national and public interest. Such cooperation was very

much in evidence after the northeastern blackout when the Washington Utilities and Transportation Commission called together all of the electrical distributive entities in the State—private, public, municipal—and with the help of Bonneville authorities made a study at the request of Gov. Daniel J. Evans to determine our reliability posture. For the use of the committee, I hand you a copy of the report that was the result of the leadership of an enlightened group of electrical distributors and producers in the Northwest. I believe it points out the attention to the matter of reliability that exists here, and even more important, the exacting cooperation that was displayed in this effort. I bring to your attention pages 9 to 14.

Although I have a great appreciation for the purpose of this legislation, and a great respect for the Federal Power Commission, any proposals should take advantage of the closely held knowledge and relationships between State commissions and the companies they see almost every day. It would not be in the public interest, in my opinion, to lose this stockpile of integrity and expertise that has accrued at the State level. Therefore, it would be my position that the avowed purpose of the proposed Federal legislation might be accomplished without the heavy hand of government, either State or Federal, being placed too firmly at the helm of management.

I do believe that the legislation your committee is sponsoring, Mr. Chairman, should, as a starting point (1) set guidelines, on a national basis, on what the people of America should expect from their electrical companies as it concerns reliability of service, and insist the several State commissions enforce these guidelines on intrastate operations; (2) that in those matters where reliability depends on sophisticated interstate systems, that a joint board procedure with State cooperators be constituted to oversee these interstate procedures; and (3) the Federal authorities limit their initial moves to the establishment of reliability procedures, and force the States to react swiftly to exacting standards. We would then have served notice that the public has a strong advocate to act in its behalf on this important matter of reliable electrical service, and they can expect to be inconvenienced physically or economically to a very minimal degree. We would institute, at our level of government, a program of constant surveillance. We would employ any personnel necessary to accomplish the goals laid down, and we would cooperate with the Federal Power Commission on any programs they might develop on a regional basis. We would immediately submit a detailed plan on the reporting of outages and the actions taken, both by our agency and the companies and systems where the outages may have occurred.

In conclusion, on behalf of my colleagues at the Washington Utilities and Transportation Commission—Commissioners Francis Pearson and Dayton A. Witten—I thank you, Senator Magnuson, and your staff, for the courtesy in allowing me to extend my general views before your committee.

As a further statement, I have been asked by Commissioner Fred P. Morrissey, speaking for the California Commission, to urge your committee to have a similar hearing in the Pacific Southwest where the California Commission and others could be heard as to their attitudes and feelings regarding this legislation. They seem most anxious to get

the views of their region on the record, and I believe they have been in contact with Mr. Lordan.

Again, I thank you for coming to the Northwest to hear my colleague, Mr. Wickberg, and me add our views and thoughts to the record.

And I do subscribe specifically to Mr. Wickberg's views on this subject also.

The CHAIRMAN. I want to thank you both. I think you have made some interesting suggestions. We want to see that there is as reliable an electrical system as is practical and possible. The Commission dedicates itself to this, of course. I suppose there could be some guidelines—some general minimum guidelines—as you point out. This would help if there is a glaringly deep defect that might result in outages somewhere. But, as has been pointed out, whether public or private utilities are involved, I think they would go right ahead and try to do something about a problem without somebody issuing an order or something like that, because their objective is to serve the public. There may be a problem as to general surveillance and assistance, but the Power Commission could provide that. I suspect, if the Power Commission told somebody there was something wrong, the utilities would try to do something about it. They don't want to get in bad with the Power Commission.

Mr. TIMM. They seem to respond to us fairly well, too, and——

The CHAIRMAN. And the Power Commission doesn't want to get in trouble with me, so we have a balance here. I appreciate your suggestions. Francis, do you have anything to add to this? I know one thing that might be bothering you if the suggested delays in the bill are comparable to those I think we have with our gas problems.

Mr. PEARSON. As the second vice president of our national association, I wish to state that we will have a statement at a later date relative to this bill. However, I do want to remind you that I called on you a year or so ago relative to our natural gas problem. I am not blaming the Commission, per se, but the procedure under the Administrative Procedures Act. The case I spoke to you about over a year ago has not been concluded yet. Since the first of November the transmission line has been running at capacity. Since the 20th of November we have curtailed from 50 to 300 million cubic feet of gas per day in the Northwest. The Federal Power Commission has full control over interstate gas transmission lines. If the above practices prevail and we give them full control of our electric transmission lines, all we will do is rehabilitate the coal industry. Because of delays we won't have either enough gas or electricity for our needs in the Pacific Northwest.

The CHAIRMAN. We want to get away from that. I just want to state generally, for no one knows this better than you people at the public utilities commission, that we haven't got too much time on these things. We have things to do. Whenever you put bureaucracy in the middle of it, for some reason, results come too late. It's just as if we're sitting around. We've got a lot of things to do. We read the testimony here that we want expertise to expedite these things without too much delay. When you talked about a 2-year notice to an agency, you know that's the least it's going to be—2 years. They couldn't get it done in 14 months. It's 2 years or more. Thank you all very much. I appreciate your coming.

Now Jim Hoag wants to make a statement on behalf of the Confederated Tribes of the Yakima Reservations. He's been working for them since 1934. Glad to hear from you, Jim.

STATEMENT OF JAMES HOAG, CONFEDERATED TRIBES OF THE YAKIMA RESERVATIONS

Mr. HOAG. Thank you. I'm James Hoag and I'm here on behalf of the Confederated Tribes of the Yakima Indian Nations. We are principally concerned with the land use of the Yakima Nations but also with other Indian tribes in the country. Most of the reservations are contiguous to public lands. At the present time extra high voltage lines traverse these properties. As you know, the Yakima Nation holds over a million acres of land, and has excellent relationships with both Bonneville Power and Pacific Power—utilities that serve us in our area.

But we are concerned with the fact that this bill, in sections 409 and 410, completely ignores the Indian government. There is no consideration of the routing of EHV lines over reservations or for compensating the Indian governments. We are requesting that the committee consider amending sections 409 and 410, so as to require the consent of the Indian governmental bodies prior to construction of these high-voltage lines over their reservations.

At this time, we would request Mr. Chairman, that the statement you have before you be inserted in the record.

(The information follows:)

STATEMENT OF CONFEDERATED BANDS AND TRIBES OF YAKIMA INDIAN NATION ON S–1934 AT SEATTLE, WASHINGTON, DECEMBER 21, 1967

The Confederated Bands and Tribes of The Yakima Indian Nation does object to the passage of S. 1934 as written. We would request that the bill be amended to provide that no extra-high-voltage right-of-way be granted across any Indian Reservation without the consent of the tribal governing body having jurisdiction of the reservation. This position is also the position of the National Congress of American Indians. A copy of the resolution of National Congress of American Indians on this matter follows:

RESOLUTION 21

RIGHTS OF WAY FOR ELECTRIC POWER LINES—H.R. 12322

Whereas, sometime ago there was introduced in the Senate of the United States a Federal Power Commission Bill # S. 1934 known as the "Electric Power Reliability Act" which was designed mainly to help prevent future power blackout but which bill also provides generally for new Federal controls over the construction and operation of high-voltage transmission lines by privately-owned utilities. Similar bills were introduced in the House of Representatives by several Congressmen known as H.R. 10727, H.R. 10721, H.R. 10722, H.R. 10779, H.R. 10816, H.R. 10885, H.R. 10935, H.R. 10975, H.R. 11029 and H.R. 11069; and

Whereas, it has been brought to the attention of the National Congress of American Indians that the said bills do not mention Indian lands and thus are inadequate to protect Indian rights; and

Whereas, Congressman John E. Moss has introduced in the House of Representatives of the 90th Congress, H.R. 12322 which bill is a revised version of the Federal Power Commission Electric Power Reliability proposal; and

Whereas, Congressman Moss's bill provides that no extra-high-voltage right of way may be granted across any Indian reservation without the consent of the tribe having jurisdiction, whether or not the tribe is organized under the Wheeler-Howard Act; and

Whereas, H.R. 12322 further provides that a tribe may impose reasonable land use conditions upon power companies which seek rights-of-way across res-

ervation lands and also assures that Indian owners will receive just compensation for the use of their property: now, therefore, be it

Resolved by the National Congress of American Indians in convention assembled in Portland, Oregon, October 2–6, 1967. That it endorses and supports the existing amendments to the proposed Electric Power Reliability Act which have been incorporated in H.R. 12322 and if such bill is enacted the rights of Indian tribes and Indian land owners would be protected; and be it further

Resolved, That copies of this Resolution be sent to Congressman John E. Moss and copies to the House and Senate Committees on Interstate and Foreign Commerce and to the National Resources and Power Subcommittee of the House Committee on Government Operations.

Mr. CHAIRMAN. I understand that Congressman Moss has some amendments to the bill in the House which would take care of the matter, and we shall consider his amendment.

Mr. HOAG. We never question this.

Mr. CHAIRMAN. All right, Mr. Evans, we'll hear from you.

STATEMENT OF BROCK EVANS, NORTHWEST REPRESENTATIVE OF THE SIERRA CLUB AND THE FEDERATION OF WESTERN OUTDOOR CLUBS

Mr. EVANS. Thank you, Mr. Chairman. My name is Brock Evans. I am a Seattle attorney and am the Northwest representative of the Sierra Club and the Federation of Western Outdoor Clubs. These two organizations have a combined membership of nearly 70,000 individuals across the country. The federation itself is an organization of some 46 outdoor clubs in eight Western States. The Sierra Club was founded in 1892, and the federation in 1932; and, as you are aware, both organizations have had and continue to have a great concern for the wilderness, scenic beauty, and the general quality of our American environment. We are extremely interested in the legislation before us today because it contains provisions which could affect this quality of our environment.

It is our understanding that since 1934 the administration bill reflects an outgrowth of increasing public concern about the reliability of our electrical power generating and transmission facilities. As had been pointed out by many other speakers and writers, our present electrical systems are subjected to an increasing strain and are not always able to meet the demands made upon them. Prime examples of this, of course, are the famous blackout of the Northeastern States in November of 1965, and at least 20 other major power failures between that time and last summer. It has become increasingly apparrent to many that there is a great need for an adequate reserve generating capacity, regional coordination, and joint comprehensive planning of future facilities. We are not experts in this field, and would not presume to offer technical suggestions as to the method of solution of these increasingly dangerous problems. However, it does appear that S. 1934 offers a sound approach to the problem of reliability and adequacy of power supply. It could serve as a model for providing much needed controls on the heretofore somewhat unplanned construction and operation of power generating and transmission facilities.

As I have already noted, we have a deep and longstanding concern for the scenic and wilderness quality of our American environment.

Quite often in the past we have noted that the construction and location of various types of public utilities has disastrously and needlessly harmed this environment. We have been particularly concerned about the adverse effect of the location of such utilities in the national park system or the national wilderness system. Both the Sierra Club and the federation have gone formally on record as being in opposition to structural developments in dedicated areas, as being contrary to the principles governing the use of such areas. It opposes the condemnation of rights-of-way for highways and other utilities across parks. It has been and is our belief that such dedicated areas deserve the very highest degree of protection possible from any type of encroaching development.

We are, therefore, very pleased to note that S. 1934 recognizes that the construction and operation of high-voltage transmission lines will involve esthetic values and questions of land use. We are pleased that the bill would authorize the Federal Power Commission to appoint advisory coordination review boards to help in its resolution of questions of land use, and also the use of joint boards. However, we note that those particular sections, sections 410 and 406, make no specific provisions for membership on these joint review boards for persons interested in conversation and esthetic values to be appointed to them. We suggest that any final legislation incorporate such a provision in order that esthetic and wilderness values receive full recognition and consideration.

Section 409(E)(ii) permits the construction and operation of high-voltage transmission facilities located partly or wholly within the lands or reservations of the United States subject to "reasonable land use conditions" relating to nonpower matters as prescribed by the administrating agency. This section also permits the department or agency to have a period of 60 days to issue a protest to the terms of an order permitting such construction and operation; but it permits such a protest on the grounds only that the order would fail to give due regard to the preservation of identified esthetic or historic values. Again, we find this a commendable and necessary provision, but feel that it could be strengthened by permitting protests of the agencies affected not only on the grounds of failure to give due regard or protection to communities of flora or fauna. We think the addition of such a phrase would help to give protection to high quality or unique natural environments about which some question could possibly exist as to their "esthetic" or "historic" value.

S. 1934 seems to have no provision which expressly prohibits the grant of rights-of-way for extra-high-voltage powerlines in national parks, national monuments, or battlefields or historic sites administered by the Park Service. There also seems to be no provision which indicates that the restrictive provisions of the Wilderness Act, requiring Presidential permission for construction of transmission lines in wilderness areas, are not superseded by this act. Because of the exceptionally high cultural value to the Nation which is the purpose for the dedication of such lands, we suggest that the final legislation incorporate provisions prohibiting entirely the grants of rights-of-way for transmission facilities across all areas administered by the Park Service except for areas which may not have the preservation of the

natural or historical environment as their primary purpose, such as some national recreation areas. We would also suggest that the final legislation make it plain that it is not intended to supersede the Wilderness Act in any of its provisions.

We think it necessary that the Federal Power Commission be empowered to review and approve the location of high-voltage transmission lines before they are built. The bill seems to do this, and we believe that it will help very much to avoid long and costly controversies such as we have experienced in the past over transmission locations.

In summary, we feel that the provisions of S. 1934 contain many commendable features which go a long way toward providing the sort of comprehensive planning and regulation of our pluralistic electric system which can increase the total national power supply without the construction of excessive generating facilities. We think it most commendable that the act contains provisions for Federal Power Commission review of transmission line construction which could endanger esthetic and historical values, but we think that these provisions should be increased and strengthened, to provide firmer and more complete controls along the lines we have suggested. We particularly favor the language of S. 2227 in this regard, because it provides for publication in the Federal Register of a description of lands and waters adjacent to lands owned by the United States which have a historic, recreational, or scenic value, and it seems to forbid the construction of transmission lines or associated facilities across such lands. The incorporation of similar language into final legislation would protect not only dedicated areas and Federal lands having esthetical or historical values, but also those areas having recreation values—something which does not appear in S. 1934. Although it is not now a subject of consideration today, we would like to point out that H.R. 12322 on this same subject, does contain many of the features which we believe would strengthen the Electric Power Reliability Act.

We appreciate this committee's consideration of our views, and the opportunity to be heard. We are extremely interested in the impact on scenic and environmental values of the Electric Power Reliability Act. We think that the proposed legislation takes a long step in the right direction in this area, and hope that it can be strengthened still further.

Thank you.

Mr. CHAIRMAN. Thank you. I want to mention that there are several bills on this subject, but the one you pointed out, H.R. 12322, is quite pertinent. A member of the Commerce Committee wants us to include provisions of this bill as part of any final proposal, and I think he's going to be heard.

There is a member of the committee who comes from the State of Maryland. They are building a high voltage transmission line right through the battleground of Antietam. Right in the middle of it, and he doesn't like it. They don't like it in Maryland, but they don't have any way of getting out of it.

Now, does anyone else want to be heard? We will leave the record open for awhile so staff and myself can ask some questions of different people who testified and give them a chance to answer. I don't know

the exact dates when other Senators want to hold their regional hearings, but I presume it will not be until the first part of the year, when they get back. I have encouraged them to schedule hearings, however.

Mr. Timm is not here. He mentioned holding some hearings in the Southwestern part of the United States, and also in the Midwest, Northeast, and in the Southeast. I suspect we're also going to have another hearing in Washington to summarize this whole thing after we get all this material collected in the field.

This hearing has been very helpful. I state again that we are seeking all the ideas we can get to point out ways we can achieve our objective. It seems to me that there is no controversy at all about the fact that everyone wants to get power reliability and create the best system we can. We do have a system here that, I think, is more reliable than any other one. And soon we will almost be a part of operations with people in other parts of the country.

There seems to be a great deal of cooperation and coordination in this area to help insure reliability. But I think we pointed out that we also have a lot of things to do. We're going to have an energy problem in this area and we had better start making our plans and do the best we can to meet it.

So, again, I thank you for coming and take this opportunity to wish you a very happy holiday. Thank you so much.

(The hearing adjourned at 12:30 p.m.)

WRITTEN STATEMENTS

BOARD OF RAILROAD COMMISSIONERS OF THE STATE OF MONTANA,
EX-OFFICIO PUBLIC SERVICE COMMISSION OF MONTANA,
Helena, January 15, 1968.

Hon. WARREN G. MAGNUSON,
Chairman, Commerce Committee, U.S. Senate, Washington, D.C.

DEAR SENATOR MAGNUSON: The Montana Public Service Commission was unable to be present at the December hearing in regard to S. 1934 held in Seattle by your committee. However, the Commission would like to file this statement for the record with your committee.

The Montana Commission has authority under state law to demand and get reliability of service from the electric utilities operating within its jurisdiction. It also has authorty over all non-federal bulk power sales within its jurisdiction.

Shortly after the northeast blackout, this Commission met with representatives of the Montana electric utilities and reviewed the means taken and to be taken to assure the Montana public of reliability of electric service. A report of this review was furnished the Congressional Committee then considering the reliability of electric service.

Reliability of any utility service is something the public demands and is something the utility wants to assure the public it will furnish. The Montana Commission has always insisted upon all of its utilities furnishing reliable service.

This Commission has found the principle of cooperation between the utilties and with the Commisison to be most effective in establishing reliability of service. With this in mind, the Commission recommends that regional advisory planning councils be established consisting of members from federal agencies involved, state and local government agencies involved and industry representatives, including privately owned, publicly owned and cooperatively owned utilities. These regional councils would of necessity have to consult with one another to formulate advisory planning on a larger area basis.

It is the belief of this Commission that any recalcitrant utility could readily be brought to measure by the authority of the state commissions involved.

The Commission is of the opinion that any intertie, interconnection or pooling agreement used in improving the reliability of service is only as strong as its weakest utility's system. That is why we so strongly believe that it is through state and local regulation together with federal cooperation with state regulatory bodies that improvements in reliability of service can be accomplished best.

Another point arguing in favor of state and local regulation is the fact that no matter what construction is made by the direction or by the approval of a federal agency, the only thing that will improve the reliability of service is the method in which the construction is operated. This, of course, is again a matter in which only state and local regulation can prevail.

Another point that supports the desirability of state and local regulatory enforcement of reliability of service is the wide diversity of service conditions within the area proposed to be controlled by the Federal Power Commission. Montana has an area of 158,000 square miles, with a population of approximately 700,000. This equates to 4.5 people per square mile. New York City, on the other hand, according to the information available to the Commission, has 24,700 people pre square mile. Montana is divided by the Continental Divide and has areas in which the snow depth reaches 126 inches. We are of the definite opinion, that under service conditions as diverse as these, the more the regulatory control is pinpointed, the more reliable the service will be.

We also agree completely with our colleagues from the States of Washington and Idaho in the position taken by them that to substitute regulatory decision making for management decision making is not in the best interests of preserving the quasi-judicial role performed by regulatory bodies.

We also are of the opinion that the certification of transmission lines will have the effect in the long run of impeding construction and will, of course,

also impede the reaching of the goal for which we are all striving, 100 per cent reliability of service.

We do feel the federal government could perform an important part in establishing reliability of service by developing guidelines for the use of the state and local regulatory bodies and the industry.

W would also suggest that in the interest of more freedom of action between the parties involved in establishing and maintaining reliability of service, that every effort be expended to secure passage of S. 683.

Very truly yours,

ERNEST C. STEEL, *Chairman.*
PAUL T. SMITH, *Commissioner.*
LOUIS G. BOEDECKER, *Commissioner.*

POCATELLO, IDAHO.

HON. WARREN MAGNUSON,
U.S. Courthouse,
Seattle, Wash.:

The Shoshone-Bannock Tribes have been advised of hearings to be held by your committee at the courthouse in Seattle on December 20 and 21.

Inasmuch as we are unable to send a delegation to the subject hearings we wish to express our attitude regarding the various electric power reliability bills together with bills relating to establishment of regional councils for regional coordination of electric power.

Inasmuch as the Shoshone-Bannock Tribes have had their property rights violated numerous times by private power companies without any means of redress. We vigorously urge that any legislation relating to power development, specifically comprehend the unique property rights held by Indians on reserved land, in the same manner as Congressman Moss' H.R. 12322 provides.

Unless the legislation contains complete protection techniques for the respective Indians tribes their property rights and treaties will be subject to further trespasses and infractions of rights afforded them under their original treaties with the U.S. Congress.

Trusting that you will personally appreciate this problem, as you have heretofore appreciated the cause of the Indians, we remain,

Very truly yours,

SHOSHONE-BANNOCK TRIBES,
Fort Hall Business Council, Fort Hall, Idaho.

WASHINGTON STATE SPORTSMEN'S COUNCIL, INC.,
Vancouver, Wash., January 5, 1968.

HON. WARREN G. MAGNUSON,
Senior Senator from Washington State,
Old Senate Office Building,
Washington, D.C.
(Attention: W. M. Meserve, Staff Council, Commerce Committee).

DEAR SENATOR: Reference S. 1934, the Electric Power Reliability Act of 1967 and the hearing thereon in Seattle on December 20, 1967. At that hearing, you gave the Washington State Sportsmen's Council permission to submit a statement for the record if received by January 10, 1968. I wish to thank you for your cooperation in this matter.

I wish to remark on only that part of the bill dealing with resources other than power and plans not being in the public interest.

We, who have had experience with the F.P.C. in such issues as the Cowlitz River dams, feel that perhaps the statement "public interest" should be spelled out, as it relates to the powers of the Act. The statement in the Act might appear clear enough and perhaps is adequate to protect the public interest and other resources but at the moment, it does not appear adequate for the intent of the Act.

At present, under the Wilderness Preservation Act, transmission lines would not be permitted if the rule held that machinery is not allowed in a Wilderness. But again, speaking from our experience with dams, would an F.P.C. permit carry with it the implied right to transend other acts?

Would S. 1934, as presently written, deter an F.P.C. licensed transmission line from crossing a migratory waterfowl refuge? Would this be over overriding in the public interest to protect scarce or rare species of waterfowl, or any species where a refuge is involved?

If a transmission plan indicated the line were going through a delicate ecological area, would the present wording of S. 1934 protect the area in the "public interest"?

Senator, please be sure we are definitely in favor of a bill of the caliber of S. 1934; it could be long over-due for some areas, but probably that portion of the bill dealing with the "public interest" and "other resources" should be spelled out in more detail—detail that can be incorporated in such a bill. Daily, other resources are becoming more valuable and should be accorded protection in cases where they could be destroyed through an administrative error.

Thanks again, Senator Magnuson, for your usual fine cooperation with this Council.

Conservationally yours,

LEN H. MABBOTT,
President.

WASHINGTON, D.C.

Senator WARREN MAGNUSON,
Senate Commerce Committee,
U.S. Federal Courthouse,
Seattle, Wash.:

As a lifelong conservationist and property landowner involved in the Antietam powerline right-of-way battle I urge your committee to strongly support regulation by the Federal Power Commission of new transmission lines. FPC says that by 1975 some 44,815 miles of new powerlines will take one million acres of land. It is absolutely vital to the public interest in historic, scenic, and recreational values that the FPC be given adequate jurisdiction. It is simply unfair not to establish a public control over matters in which the public has such a vital interest. The Pacific Northwest is a region of unusual scenic beauties and would benefit greatly by the protection offered by S. 1934. Congratulations on your leadership in this important legislation and I hope this telegram can be incorporated in the record.

BERNARD F. HILLENBRAND

BETHESDA, MD.

APPENDIX

EXHIBIT 9

ADVANCE PROGRAM: 1967–1987

U.S. DEPARTMENT OF THE INTERIOR • BONNEVILLE POWER ADMINISTRATION

I INTRODUCTION

PURPOSE

This year, for the first time, Bonneville Power Administration's Advance Program presents data for 20 years into the future. In the past, Advance Programs have contained 10-year forecasts of the demand for electric energy in the Pacific Northwest and the schedule of generation and transmission facilities required to meet that demand. However, the Pacific Northwest will soon be required to meet part of its electric energy requirements from thermal generation. Because of the extensive coordinated planning required to fit large thermal plants into the existing generation and transmission system in the region, this Advance Program looks 20 years into the future rather than the usual 10 years.

In most areas of the United States thermal generation is the rule rather than the exception. In the Pacific Northwest, however, over 98 percent of the electric energy sold by electric utilities in 1966 came from hydro generation. The Pacific Northwest enters the period of thermal generation at a time when technological developments have made it possible to build large thermal generating units which can produce electric energy at much lower cost than units previously available, and when nuclear generating costs have decreased to the point where they are competitive with, or cheaper than, other fuels in many areas of the United States. This is particularly important in the Pacific Northwest where there are no indigenous oil or natural gas resources and only limited coal supplies.

These large generating units are capable of supplying more generating capacity than any single utility in the region can absorb in one year with its normal load growth. As a consequence, extensive coordinated planning is required so that these generating facilities can be constructed to meet the load growth patterns of the many utilities in the region. Backup generation is required in case these large generating units are shut down for refueling, maintenance work, or because of failure of a unit. Since they are most efficient when they operate continuously at full capacity, or as "base load" plants, they should be operated on a coordinated basis with peaking plants to meet the daily and seasonal peaks in electric power demand.

Bonneville Power Administration, although not engaged in thermal generation itself, can, through its region-wide high voltage transmission grid, supply the most economical transmission to carry electric power from these generating plants to all the utilities in the region. The federal hydroelectric projects can also supply economic backup and peaking capability for these plants. During many years when the Columbia River flows are above average the federal system may have surplus hydro energy that can be used to displace fuel generated energy. BPA and the utilities of the region have formed

the Joint Power Planning Council to look ahead to meet the power needs of the region at the lowest possible cost. A number of task forces have been appointed to study the various problems expected to arise in thermal generation development. The joint work of the task forces and the Planning Council has enabled the utilities in the region, through BPA, to prepare this 20-Year Advance Program.

THE LAST 30 YEARS

On August 20, 1937, the Bonneville Project Act creating the Bonneville Power Administration was signed into law by President Franklin D. Roosevelt. At that time the population of the Pacific Northwest (States of Idaho, Oregon, Washington, and Montana west of the Continental Divide) was 3,000,000. Population in the area today is about 6,000,000, or double what it was then. In 1937 the average residential consumer in the area used approximately 1200 kwh per year. Today average annual residential electric energy consumption has increased to over 12,000 kwh.

The Bonneville Power Administration started by marketing power from only one dam – Bonneville. Today it is the marketing agent for 22 federal dams in the Columbia River Basin. It is also marketing agent for 8 new federal dams under construction and authorized in the Pacific Northwest. The first transmission line built by BPA was a 3.4 mile long line from Bonneville Dam to the City of Cascade Locks which was energized at 13,800 volts in 1938. Today BPA has 10,035.7 circuit miles of transmission lines in operation at voltages as high as 500,000 a.c. Two d.c. lines at 750,000 volts are under construction.

BPA's revenues in its first fical year were $49,835. In fiscal year 1967 federal system revenues were almost $113,000,000. Cumulative revenues to date exceed $1-1/3 billion.

A number of significant developments in the coordination of resources and the transmission of electric energy have taken place in the Pacific Northwest since BPA began operating. The federal high-voltage transmission grid not only permits power to flow from federal hydroelectric projects to load centers but interconnects all of the generating facilities in the region, providing greater reliability of service to all and permitting excess energy in one area to be transmitted to another. The Northwest Power Pool, created during World War II, permits the maximum efficiency in the use of generating facilities, reduces the amount of reserves required, and enables all utilities to obtain power from the most economical sources. The Pool has set a pattern of cooperation on the part of public systems, private utilities and the federal power agencies. This pattern has been carried forward in many projects to the benefit of the region.

The Pacific Northwest-Pacific Southwest Intertie, consisting of two 500,000-volt alternating current and two 750,000-volt direct current transmission lines, will help tie together the electrical systems of twelve western states. It will permit the Northwest to sell surplus energy and peaking capacity in the Southwest, to take advantage of the seasonal diversity between the two areas, thereby requiring less generating capacity in each, and to exchange surplus Northwest capacity for off-peak steam energy from the Southwest.

The treaty with Canada, under which three dams will be built on the upper reaches of the Columbia River in British Columbia, will add 2,800,000 kilowatts of firm power at downstream dams in the United States as well as supply needed flood control. One of these dams has been completed and two are under construction. Initially half of the power, 1,400,000 kilowatts, goes to each nation. The Canadian share has temporarily been sold to utilities in the United States. In addition, Libby Dam in Montana will add 750,000 kilowatts of firm power at site and downstream in the United States.

In conjunction with the Canadian treaty, and necessary to the signing of the treaty, a 39-year coordination agreement was reached by the Department of the Interior, the Corps of Engineers, and 14 major generating utilities in the Pacific Northwest. This agreement was necessary since the Canadian share of the power benefits was calculated on the basis of maximum coordinated power output. While voluntary coordination has existed in the Northwest for many years, this agreement assures that coordination will be extended and facilities operated for maximum benefit to the region.

The Washington Public Power System operates the largest nuclear power electric generating facility in the world at Hanford, Washington, utilizing excess heat from the Atomic Energy Commission's new production reactor. Bonneville Power Administration supplies the reserves, peaking capacity and the necessary transmission facilities to market this power throughout the Pacific Northwest.

THE NEXT 20 YEARS

The demand for electric power in the Pacific Northwest will more than triple in the next 20 years. The power distributors in the Pacific Northwest are acquiring large power loads at a more rapid rate than in the past due to improvements in the region's economy. In southeastern Washington and northeastern Oregon, new private irrigation developments are expected to add substantial irrigation pumping loads within the next 10 years. The aerospace development in the Puget Sound area and pulp, paper, chemicals and metal processing plants in the Portland and lower Columbia River areas have increased loads of utilities not only for service to these and associated industrial development but for the new residential and commercial loads which will occur because of these developments. In total, these loads, most of which were not anticipated a year ago, amount to about 600,000 kw.

By the mid 1970's, loads in the Pacific Northwest will have increased to the point where there will not be sufficient new economical hydro capacity available to meet them. A thermal plant of 1,000,000 kw or more capacity will be needed each year to meet regional load growth. No single utility can absorb generation in this amount for several years. Combinations of public and private utilities are now planning such plants for the 1970's. BPA, by providing transmission, backup and peaking for these plants, is expected to receive a share of the output which can be used in combination with federal hydro generation to serve public agency and industrial loads.

Since the federal Columbia River Power System together with BPA's main grid transmission system can provide economical backup for the large thermal plants to be built in the region in the 1970's, it is essential that planning for these projects be coordinated among the utilities concerned and BPA. The main grid transmission system will have to be planned to provide the necessary backup for these thermal plants wherever they are located.

Obviously, the grid system has to provide a high degree of reliability of service. BPA's reliability of service has suffered recently because of the inability of the transmission system to keep up with the unprecedented growth in electric power loads. Shortages of materials, long delivery schedules, equipment failures and manpower limitations have also contributed to this inability. Load dropping plans are in effect in critical areas to drop noncritical loads in case a line outage makes it impossible to carry the full load on the remaining lines. These, however, are temporary expedients and not substitutes for adequate transmission facilities.

Reliability of service is an interregional as well as a regional problem and requires interregional joint planning. BPA has engaged in this type of planning in the case of the Pacific Northwest-Pacific Southwest Intertie, the first line of which was energized at 500,000 volts in September 1967.

The total program for Northwest electric service over the next 20 years, herein presented, involves expenditures on the part of all utilities in the area – for generation, transmission and distribution – amounting to about 14 billion dollars. Of this, about 5 billion dollars will be federal expenditures.

II GROWTH IN POWER REQUIREMENTS

RESIDENTIAL

Thirty years ago the average residential use of electric energy in the Pacific Northwest was only one-tenth of what it is today. When the Bonneville Project Act was signed in 1937, the average home in the Pacific Northwest purchased less than 1200 kwh per year with most of the energy used for lighting and a few minor appliances. Today with the intensive use of appliances and electric heating the average annual residential use is estimated at over 12,000 kwh. This is more than twice the average residential use in the United States. Average residential use in the United States in 1937 was a little more than half the average use in the Northwest, and while residential use throughout the nation has grown quite rapidly in the last 30 years, the rate of growth in the Northwest has been higher than the U.S. growth rate.

The number of residential consumers in the Northwest is now about two and one-half times what it was 30 years ago. Combined with a tenfold increase in the average use per residential consumer, the result is about a twenty-fivefold increase in total residential electric energy use in the region.

The cost of power to residential consumers averages about 1.1 cents per kilowatt-hour in the region today. This is one-third of the average cost 30 years ago.

Changes in living habits, combined with the low cost of electric power, have made it possible to achieve the high standard of electric living which the Northwest enjoys today. Almost one-quarter of the homes in the area are now heated electrically and in some areas the majority of new homes are using electric heat.

In the next 20 years the use per residential customer is expected to almost double. By 1987, average consumption is expected to reach 20,000 kwh per year. This will result from the increased use of electric space heating, a higher saturation of today's electric appliances and the use of new appliances.

Average KWH Use Per Domestic Consumer
1937-1987 – Pacific Northwest

1937	1947	1957	1967	1977	1987
1,200	3,606	8,154	12,200	16,000	20,000

COMMERCIAL AND INDUSTRIAL

Commercial power loads (which include many small industries) tend to grow as the economy of the region expands and its population grows. The number of commercial consumers is actually growing more rapidly than the population in the area. The amount of electric energy which each commercial consumer uses is also increasing. Competition forces the use of better lighting, air conditioning, and the modernization of office, production and warehouse facilities. Electric heat in commercial establishments and more automation in small industrial establishments add substantially to the average electric power consumption for this class of consumer.

The table below indicates how the average electric energy use per commercial consumer has grown in the Pacific Northwest and what is expected for the future.

Average KWH Use Per Commercial Consumer
1937-1987 – Pacific Northwest

1937	1947	1957	1967	1977	1987
6,400	13,317	23,219	41,500	65,000	85,000

LARGE INDUSTRIAL

The large industrial loads of BPA consist mainly of electroprocess industries. The first electroprocess plant served by BPA was the Alcoa Aluminum reduction plant at Vancouver, Washington, which went into operation in September 1940 with an initial load of 26,000 kw. By 1967, large industrial loads served by BPA had a total electric power demand of 2,300,000 kw, almost 90 times the size of the loads served in 1940.

Most of the industrial load now served is in the same industry as the first industrial load – aluminum reduction. Today 30 percent of the aluminum produced in the United States comes from plants to which BPA supplies electric power. Of the 2,300,000 kw of industrial load, 87 percent goes to the aluminum industry with the remaining amount going to industries producing silicon carbide, elemental phosphorus, calcium carbide, chlorine and caustic soda, ferro-silicon, ferro-manganese, and ferro-nickel. The last product is from the only nickel producing facility in the United States.

Power use by large electroprocess industries, primarily aluminum and magnesium, will almost quadruple by 1987 if power is available at approximately BPA's current rates. By 1987, thermal generation will provide nearly all the new firm capacity being installed in the Pacific Northwest. BPA expects that the energy it receives from these thermal plants in exchange for capacity, transmission and

reserves will enable it to continue to provide rates attractive to the electroprocess industries.

In addition to the large industrial loads normally served by BPA, public agency distributors have, in the last few years, developed existing and future industrial loads of great magnitude. The Boeing expansion in the Puget Sound area is adding to the Snohomish PUD load. The City of Centralia in southwestern Washington is serving an abrasives plant. The City of McMinnville in western Oregon expects to serve a new electric steel furnace plant. Clatskanie PUD, on the lower Columbia River in northwest Oregon, is serving a new pulp and paper plant. These loads total 239 mw and have developed in the past two years. There will also be additional residential and commercial loads as a result of the new industrial employment.

The private utilities have also been adding new irrigation and industrial loads at a rapid rate in the last few years. Among the new industrial loads added are a new pulp and paper plant and a titanium sponge plant in the Willamette Valley, a chemical plant on the lower Columbia River and a steel plant in the Portland area. In eastern Oregon, one private utility has had to call in extra line crews to provide service to the rapidly expanding irrigation loads. These and the attendant residential and commercial loads have substantially increased the private utility loads.

IRRIGATION

Since the days of first settlement, irrigation has been the key to agricultural production in much of the arid West. Most of the first areas were irrigated by small, privately-owned gravity flow systems. With the Bureau of Reclamation developing larger irrigation projects in the West, nearly six million acres of land in the region are now being irrigated.

We are now witnessing a revolution in irrigation agriculture. Technological developments in the irrigation industry, particularly sprinkler equipment, have made it economic to lift water 800 to 1,000 feet from wells or streams to irrigate lands never before considered feasible to irrigate because of distance from water source, low quality of the land, or roughness of the terrain. Single sprinkler systems rotating around a central pumped water source now make it possible to irrigate up to 160 acres on a continuous basis. Land which was covered with sagebrush this spring is now producing crops with fewer man-hours of labor than would have been possible under previous irrigation methods.

The new irrigation systems are not only making former waste lands productive but they are also changing the pattern of operations on large acreages of land previously producing crops in alternate years on the summer fallow system. These lands are being irrigated up to 10 months each year. The result is measured by the factor of "four;" double the yield and a crop each year.

These developments have a threefold effect on the consumption of electricity. Each gallon of water used for irrigation requires more energy to get it to the land because of the higher lifts involved. Second, more land is potentially irrigable than ever before. Third, as previously mentioned, the pumping season has been lengthened. Each of these factors add to the total energy requirements for irrigation. In southeast Washington and northeast Oregon, along the Columbia and Snake Rivers, new private irrigation developments of the type described above have gone into operation for the first time this year. It is estimated that the power requirements for new private irrigation projects in Walla Walla and Benton Counties in Washington and Umatilla and Morrow Counties in Oregon will be about 400,000 kw within the next 10 years. As a consequence, estimates of future irrigation loads have been raised considerably above those shown in the Advance Program for 1966-1976.

III GENERATION

For thirty years the Pacific Northwest has enjoyed the lowest cost electric power in the nation. This asset was obtained primarily by utilizing the Columbia River, North America's greatest power-producing stream.

At present, Pacific Northwest electric power is supplied almost entirely from hydroelectric generation. Federal power plants of the Corps of Engineers and the Bureau of Reclamation are linked by the BPA transmission grid which further interconnects with non-federal public and private sources. The hydroelectric system thus formed is one of the world's largest.

By 1980, nearly all the feasible large dams in the region will have been built and the trend will be to thermal generation to provide firm energy. As loads increase, the region will become more dependent on thermal generation for base loads and hydro will be used increasingly for peaking. Fortunately, the Northwest has potentially many millions of kilowatts of hydro peaking power available for development at relatively low per-unit cost. For example, over nine million kilowatts of capacity can be installed at hydroelectric projects at an average annual cost of about $5.60 per kilowatt year. This cost is about one-half the cost of adding peaking capacity by use of steam-electric plants, gas turbines or pump storage in other sections of the country.

By mixing hydro peak power, surplus energy and thermal generation from the largest economical sized plants, the Pacific Northwest should be able to maintain its position as the lowest cost power area in the nation.

HYDRO RESOURCES

By the mid 1970's, there will be insufficient hydro constructed to meet base energy load in the Pacific Northwest. Tables 5 and 6 are the generator installation schedules for federal and non-federal hydro projects, respectively.

Federal

Installed capacity of the 22 operating federal dams was 6,758,150 kilowatts on July 1, 1967. Additional generators are being installed at two existing dams, The Dalles (8 units) and Grand Coulee Third Powerhouse (6 units). There are eight dams under construction; Foster, John Day (16 units), Lower Monumental (3 units), Little Goose, Lower Granite, Lost Creek, Dworshak, and Libby. They will add 8,552,000 kilowatts of installed capacity by September 1978. Two new federal dams authorized are Teton and Asotin. General specifications of federal projects which are completed, under construction, and authorized are shown on Table 8.

Also, to meet the load growth by December 1978, this program proposes that additional generating units be installed at existing dams. This includes 704,000 kilowatts in 11 units at Chief Joseph; 324,000 kilowatts in six units in a second powerhouse at Bonneville Dam; 270,000 kilowatts in three units at Ice Harbor; and two pump-turbine units totaling 97,000 kilowatts to be added in the pumping plant at Grand Coulee.

Additional projects suggested for completion include Guffey, Palisades additions, China Gardens, Lynn Crandall, Upper and Lower Scriver, Garden Valley and Garden Valley Reregulating of the Garden Valley project, Ben Franklin, Smoky Range, Lenore, Lucky Peak, Twin Springs, Lower Flathead River, Kootenai Falls and others.

Projected new federal generation shown in Table 8 includes the proposed High Mountain Sheep Project which would add at least 1,500,000 kilowatts under the federal proposal and possibly more than 2 million kilowatts. The Department of the Interior is investigating an alternate above the Imnaha River at the Appaloosa site which would have approximately the same capacity. The Mountain Sheep Project has been proposed for construction by both the Washington Public Power Supply System and the Pacific Northwest Power Company. Originally, the Federal Power Commission granted the Pacific Northwest Power Company a license to build the project. On June 5, 1967, the Supreme Court revoked the license and ordered the Federal Power Commission to hold new hearings in which the benefits of federal development would be given thorough consideration.

Non-Federal

Nameplate rating of non-federal hydroelectric projects on June 30, 1967, was 7,366,228 kilowatts. Four new dams, Boundary, Wells, Hells Canyon, and Mossyrock, plus licensed additions to Rocky Reach and the three licensed Sultan plants will add 2,586,350 kilowatts of installed capacity by 1975. Puget Sound Power and Light Company's Lower Baker powerhouse was buried in a landslide in 1965. The company expects to have one 64,000-kilowatt unit operating by the fall of 1968. These additions will bring total non-federal hydro generation in the Pacific Northwest to 10,016,578 kilowatts as shown in Table 9.

THERMAL RESOURCES

Installed thermal generating capacity in the Pacific Northwest now totals some 1,249,954 kilowatts. This consists of 449,954 kilowatts in existing non-federal fossil-fueled steam plants and 800,000 kilowatts of nuclear-powered capacity at the recently completed Hanford Atomic Power Plant (NPR). Ownership of this capacity is shown in Table 9.

OTHER SOURCES

The Canadian share of the downstream benefits from the three dams built on the upper Columbia River in Canada (1,400,000 kilowatts) has been sold by the British Columbia Government to utilities in the Pacific Northwest for 30 years. The Northwest utilities resold most of their power to California utilities on a withdrawable basis with the exception of 300,000 kilowatts to the State of California. This Advance Program assumes that the withdrawable power will be withdrawn as soon as permitted under the contracts.

Imports

In addition to the treaty power, the possibility of other power from British Columbia to supply part of the needs of the Pacific Northwest for a period of years should not be overlooked. However, with the very rapid growth of power loads in British Columbia, it does not appear that these resources would be available before 1975 or that they could be depended on as a permanent power supply for the Northwest.

Coal resources in the Missouri Basin and Wyoming could be used to generate energy for importation in the Pacific Northwest. The first few nuclear plants in the Pacific Northwest, which would be located west of the Cascades near load centers, could provide power more economically due to the difference in transmission costs. There is, however, a possibility large coal-fired plants in the Missouri Basin and Wyoming may eventually be built with their output divided between the Missouri Basin and Wyoming and the Pacific Northwest.

This program already assumes exchanges with the Pacific Southwest to the extent permitted by present and planned transmission lines.

Fossil Fuels

Conventional fuel-fired generating plants will not be economic sources of power in the Pacific Northwest to meet the area loads which will develop after the mid 1970's. The Northwest has no indigenous sources of either petroleum or natural gas. Natural gas was first brought into the region in 1956 from the San Juan Basin in New Mexico. The cost of transmission is too high to make it a competitive fuel for the purpose of electric generation.

It appears that the only economic source of coal for power generation in the Pacific Northwest is a field near Centralia, Washington. It is believed that this field contains enough low-cost reserves to support a 2 million kilowatt steam generating plant. Plans call for a first unit of 700,000 kilowatts to be constructed by 1971 by the two private power companies owning the coal and possible participation by other private utilities and public agencies. These utilities have offered to build the plant three years in advance of their own needs in order to accommodate an intertie commitment permitting the Bureau of Reclamation's Central Valley Project in California to purchase up to 400 megawatts over the intertie facilities. BPA will buy the difference to make up slippage that has occurred at one of the generating plants and to meet load growth that has been largely unanticipated.

The multi-ownership plan being worked out for the Centralia plant is the first project to result from the joint thermal plant planning undertaken in 1967 by BPA and the region's publicly and privately owned utilities.

Nuclear Fuels

Because hydro, imports and fossil fuels cannot meet the future energy needs of the Pacific Northwest at an economical cost, large nuclear plants offer the best alternative. There are three reasons large nuclear plants are expected to serve most of the energy load growth of the region over the next 20 years. First, and most important is the fact that these plants produce power much more cheaply than smaller nuclear plants. Unit cost of power from large plants (1,000 mw and larger) is considerably less than for smaller plants. Indicative of the difference in unit costs of power from large and small nuclear generating units is the fact that manufacturers of generating equipment are not making units smaller than about 600,000 kilowatts as regular production items.

Second, large size nuclear plants can be absorbed into the load growth pattern in the Pacific Northwest. By the time the first nuclear plant is scheduled on the line in 1974-75 (Tables 2, 3 and 7) Pacific Northwest area loads are expected to grow by more than 1,000,000 kilowatts per year.

Third, nuclear plants do not face the same location restrictions as hydro plants. They require water for cooling but the problem of head for generation does not exist. This makes it possible to locate nuclear plants closer to the load centers. A considerable savings in transmission costs is thus possible for energy generated at nuclear plants compared to hydro plants.

Preliminary studies have been made of transmission and generation

costs. These costs, examined together with loads, indicate that the first new thermal plants should be located in the Portland, Puget Sound, lower Columbia River, upper Willamette River Valley and southern Oregon areas. Development of area loads will dictate the location of additional plants which could range from the coast to the inland areas in Idaho and Montana.

There are several conceivable methods by which nuclear power plants can be built to supply the future electric energy needs of the Northwest. The least desirable, from an economic standpoint, and also the least likely method would be for each individual utility, public or private, to build individual units to meet its own power requirements. This would mean small, relatively inefficient generating plants and high cost capacity, assuming each utility also provided its own. Because of the high costs involved no one advocates this plan.

Another possibility would be for the non-federal utilities in the region to build large nuclear power plants as a consortium, achieving lower cost than possible with small plants. If these utilities attempted to supply their own peaking capacity, reserves and transmission, however, they would lose much of the advantage gained by the large plants because of the high cost of these latter three items.

Another alternative would be for the federal government to undertake construction of necessary thermal generation. The federal government is not presently considering construction of steam plants. Through joint planning it now appears that large, economical plants can be built by the non-federal utilities in the region. These plants, together with additional peaking at existing hydro plants and the use of the regional transmission grid will continue to make power available in the region at low cost.

This plan, whereby the federal government would provide peaking capacity, reserves and transmission in exchange for off-peak energy from thermal plants in the most desirable locations and of the most economic size feasible, appears to be the arrangement that will be developed in the Pacific Northwest.

The share from the thermal plants that the federal government would receive as payment for its services would be used first as a reserve to meet unanticipated public and private utility load growth in the region and second to serve industrial loads. These industrial loads, to the extent to which they could be interrupted, could form a forced outage reserve. To this extent the forced outage reserves shown in Table 3 could be reduced and some generator installations, as shown in Table 8, could be delayed.

Since the federal system would provide most of the main grid transmission and add most of the hydro generating units to provide peaking capacity while non-federal entities would construct the thermal generation facilities, capital expenditures would be shared by federal and non-federal utilities.

A tenative proposal for BPA's sharing in the output of these thermal plants in exchange for providing reserves, peaking capacity and transmission has been incorporated with resources shown in Table 4. Since relationships of off-peak energy and peaking capacity and transmission may change in the future, BPA's suggested ratio of exchange applies only to the first six nuclear plants. Similar exchanges are expected for later plants but, since the exchange ratio may be modified, additional power from later plants is not included in this Advance Program. Presently contracted BPA industrial loads amount to 2,581 mw so that the additional industrial load which could be served under this proposal is 1,600 mw. Additional amounts would probably be available after 1980.

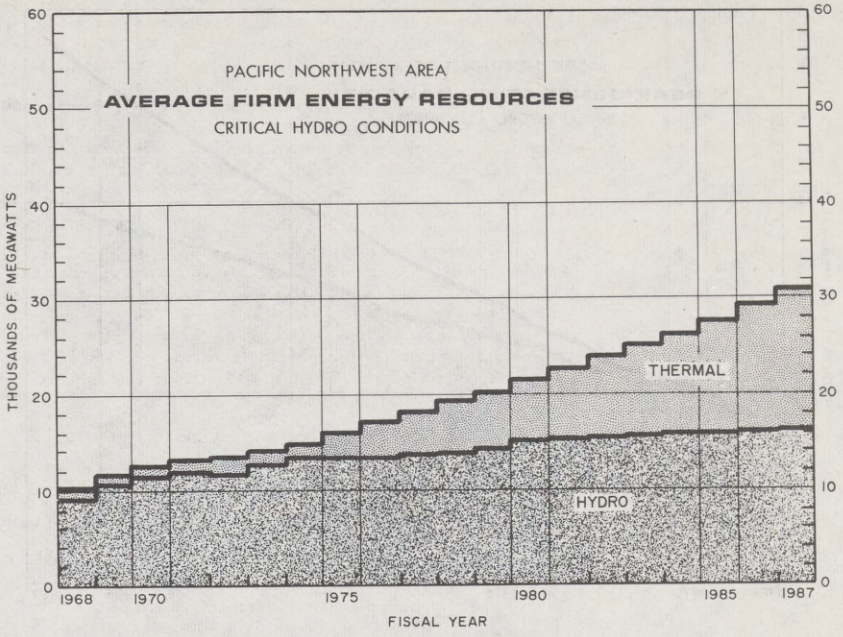
Potential electroprocess loads, however, exceed the amount shown as served in Table 4. Economic studies of electroprocess industries, prepared for BPA by outside consultants, indicate that another 3,367 average megawatts (last column, Table 1) of additional potential electroprocess industry load could develop in the Pacific Northwest area by 1987 assuming an adequate power supply at approximately BPA's present rates. These loads are primarily in the aluminum and magnesium industries.

COMPARISON OF LOADS AND RESOURCES

Pacific Northwest area firm energy loads (Table 2) are expected to almost double from about 10 million average kilowatts in 1967-68 to over 18 million kilowatts in 1977-78 and to almost 30 million kilowatts in 1986-87. These forecasts are based on present estimates of the most probable load growth. Loads may grow more slowly or more rapidly than forecast. Planning the future power supply of the region should take into account the possibility of rapid load growth. With the large amount of interruptible power sold to industry, surpluses, if they develop, can be used to improve the availability of interruptible power or exported to California.

Area peak loads, Table 3, are expected to increase from about 15 million kilowatts in 1967-68 to over 30 million kilowatts in 1977-78 and to 50 million kilowatts in 1986-87. As in the case of energy resources, generation schedules must be maintained if peak loads are to be met. There is the further problem of peak load response to temperature variations. In the Pacific Northwest this is about 6/10 of 1 percent per degree temperature change. Thus in 1970-71, when total reserves (1295 mw plus 556 mw) exceed additional resources needed (989 mw) by about 850 mw, a ten degree below normal temperature, which is quite possible, could increase the peak load from the 20,495 mw forecast in Table 3 to over 21,700 mw and completely erase the reserve. It appears, then, that while total reserves, including forced outage reserves, are sufficient to cover any deficit in resources, they could be wiped out by a short cold snap. Furthermore, system reliability deteriorates when forced outage reserves are used for other purposes. However, in contrast to the energy situation, arrangements have been made with industry to drop load as a part of forced outage reserves for peak loads, but not for the purpose of meeting unanticipated load growth.

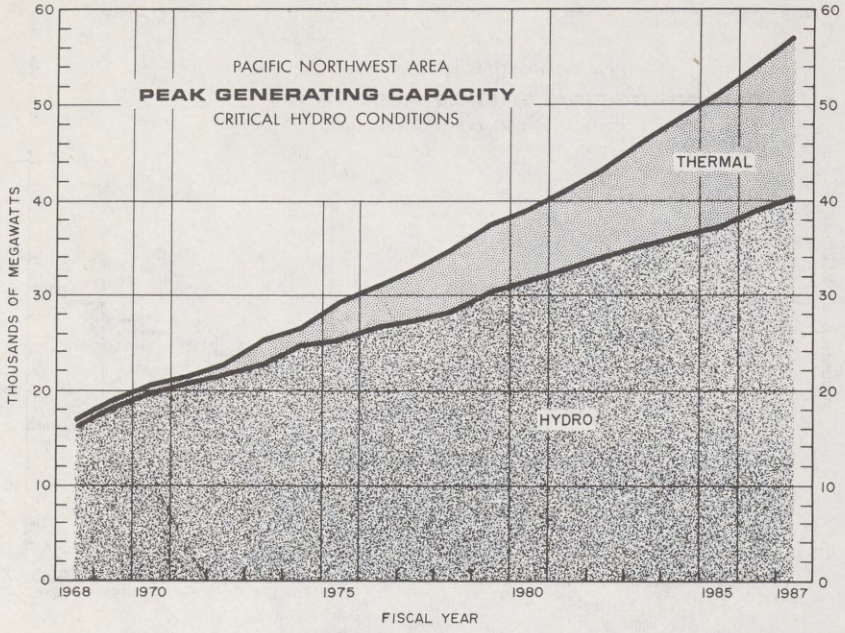
Chart 1



The difference between the situations which the Pacific Northwest faces in regard to future peak and energy resources is shown graphically in Charts 1 and 2. Chart 1 depicts the energy situation from now until 1987. It shows the hydro energy base leveling off in about 1980 with most of the growth in energy load from that point on being supplied by thermal generation. In contrast, Chart 2 shows hydro peaking capacity continuing to grow throughout the period. This results from the fact that additional generating units can be added at existing hydro plants which will increase the peaking capacity of the plants, and add some secondary, but very little firm energy.

Federal energy loads and resources, Table 4, show a pattern similar to that shown for the Pacific Northwest area. Resources available to BPA include, in addition to the federal projects existing, under construction and authorized, only the assumed 1600 mw share of the new thermal plants that would be sold to new industry. The table shows that BPA cannot continue to meet the load growth of its customers in the 1970's. Private utilities need additional resources beginning

Chart 2



in 1974-75. Public agency load growth cannot be met in 1978-79 and thereafter. This situation arises in spite of an increase in federal resources from 4,477 mw in 1967-68 to 8,495 mw in 1986-87. During this same period, public agency loads alone will increase by 6,390 average mw. During this period the public agencies expect to add less than 450 average mw of their own generation, which is only about 7 percent of the amount of their load increase of 6,390 average mw. Hence, to meet public agency load growth until 1978-79, BPA will have to withdraw power from the private utilities and limit sales to new industry to part of the energy it would secure from thermal generation. Most of the additional resources shown as required by the public and private utilities in Table 4 will be met by new non-federal thermal generation.

While large additional resources are required to meet loads both regionally and on the federal system, the additional resources required are not spread evenly among the utilities in the region. Most of the non-generating publicly owned utilities in the region would not require generation in addition to the federal power supply

to meet their requirements by 1984-85. The following table shows the loads, resources, and additional requirements of various classes of utilities in the region in 1984-85.

Energy Loads and Requirements of BPA Utility Customers[1]
1984-85

(Average Megawatts)

	System Loads	Own Resources	Estimated Allocation from BPA & Hanford Exchange	Additional Requirements
4 Private Utilities	10,485	3,620	498	6,367
6 Largest Preference Customers	5,327	1,184	2,766	1,377
26 Other Preference Customers with Additional Requirements	2,323	77	1,734	512
69 Other Preference Customers with No Additional Requirements	1,203	293	910	-
Totals	19,338	5,174	5,908	8,256

[1] The figures shown in this table are not comparable to those in Tables 1, 2, 3, and 4, since they are for different periods and different utilities.

The six largest preference customers consist of three large public utility districts serving heavy industrial areas and three large municipal systems. The 26 other preference customers with additional requirements are primarily public utility districts and municipalities plus a few cooperatives. The 69 other preference customers with no additional requirements are distributors with estimated system loads of less than 25,000 kilowatts in 1984-85. A list of utilities included in each of these four groups is shown in Table 12.

Almost 94 percent of the additional requirements of public and private agencies in 1984-85 are to serve the four private utilities and the six largest public agencies. Only one of the other 26 public agencies with additional requirements needs more than 50 mw. Thus it is the large, rather than the small utilities in the area that will require participation in the new thermal plants.

IV TRANSMISSION

The regional backbone high-voltage grid serving all the distributing utilities in the Pacific Northwest is operated by BPA. Expansion of this grid to integrate the new hydro and thermal generation necessary to meet load growth would avoid costly duplication of facilities and provide operational and engineering uniformity.

Load growth, of course, will occur in varying degrees at varying locations throughout the region. Transmission to accommodate this growth at widely separated points must be planned and constructed on a region-wide basis. This can only be done by the Federal system in cooperation with the individual distributing utilities.

The pattern that has developed in the Northwest involves, for the most part, BPA assuming responsibility for extra-high voltage

transmission from the major generating plants, with the other utilities responsible for lower voltage transmission and distribution within their individual service areas.

Under the direction of the Joint Power Planning Council, a study has been made of where the Northwest's first six nuclear plants (other than Hanford) should be located from the standpoint of the most efficient and economical transmission. The study showed that all six of these thermal plants should be located west of the Cascades and that the transmission to serve each should be constructed as an extension of the existing BPA system.

This would permit a further utilization of the transmission system on a displacement basis. Each utility participating in a generation project, for instance, need not take its share of the power at that particular plant but rather at a point on the high-voltage grid that would best suit its own needs.

Generating plants, whether thermal or hydro, are exposed to unscheduled outages. The sudden loss of a 1,000,000-kilowatt thermal plant causes a severe shock to the connected transmission system, and an alternate power source must be available to fill the gap caused by the plant outage. No single utility in the region has the necessary generation or transmission required to provide "backup" for the proposed thermal plants. Only the combined generating facilities of the Columbia River System and BPA's interconnected transmission system have the ability to provide this vital function.

For many years BPA has made excess capacity on its system available for power transfer by the utilities; however, it was not until the 1950's that the present policy of firm long-term wheeling agreements was initiated. Our objective is to cooperate with all utilities of the region in providing an efficient transmission system available for region-wide use.

The entry of thermal generation into the Northwest, as shown in greater detail in the chapter on Generation, makes it mandatory that cooperative use of BPA's system be continued and expanded. Continued cooperation will result in economic and operational advantages which will help maintain the low power rate structure.

We believe our main grid system, existing and planned, has enough flexibility to support the addition of large thermal plants with a minimum of grid reinforcement.

Figures 1, 2 and 3 illustrate the effect of load growth and changes in the location of generation on power flows. These power flow diagrams for January 1967 and 1977 and typical 1987 conditions provide a visual conception of the resource development and transmission construction required to meet projected load growth for the 20-year period.

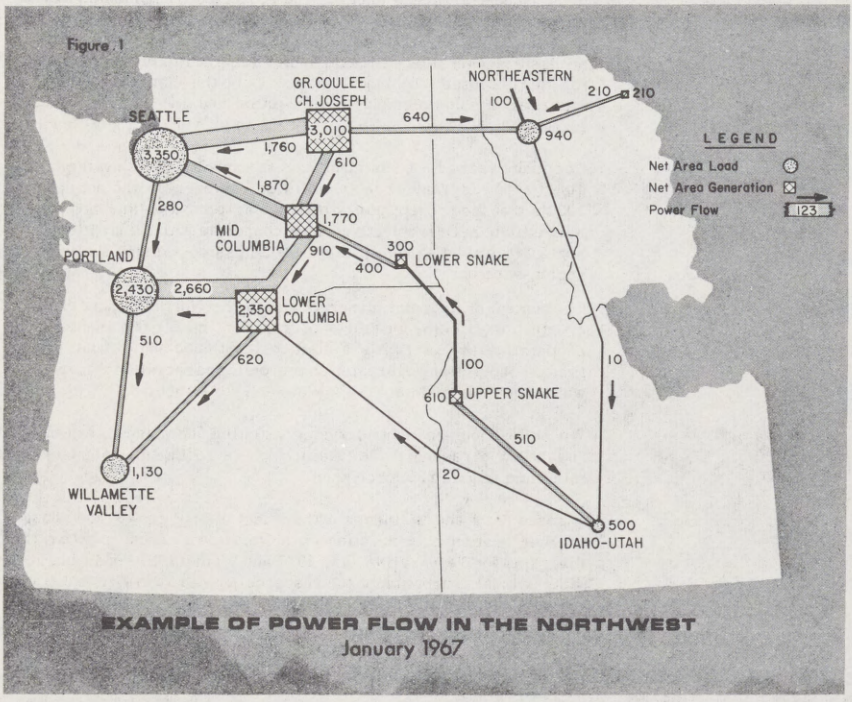
These diagrams should be considered only as representative examples, as any deviations in resource development schedules or load patterns will cause changes in the power flow diagrams.

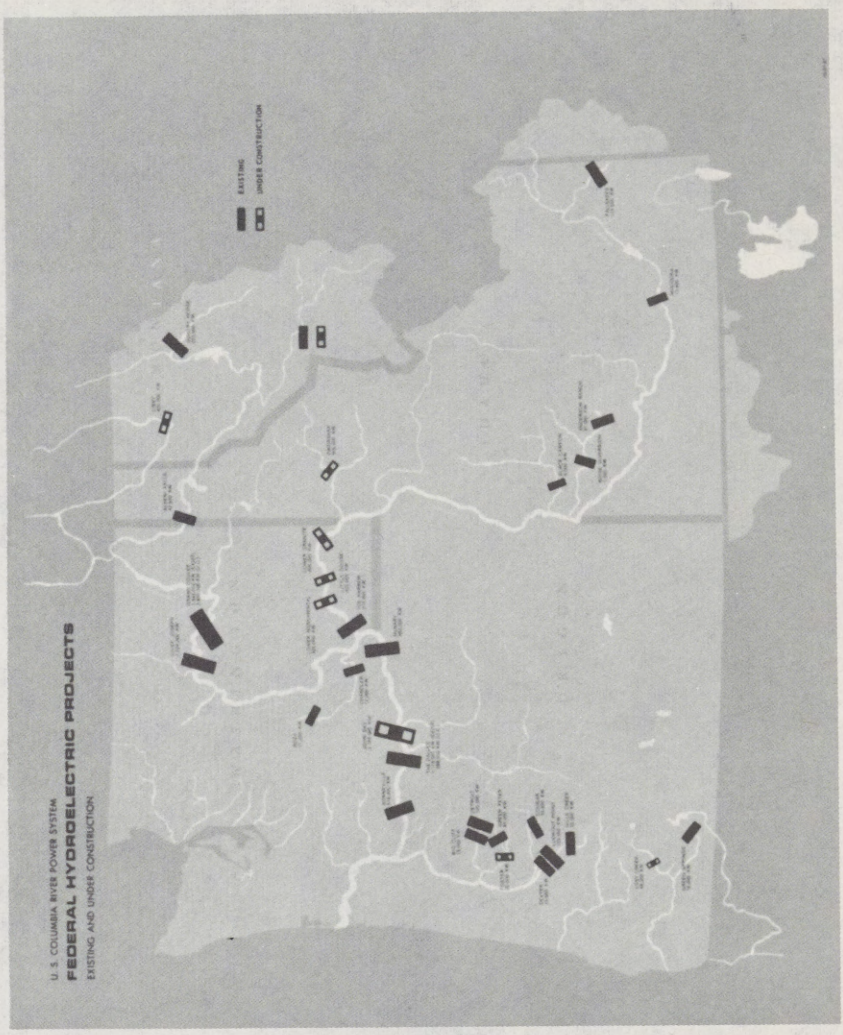
BPA has long been a pioneer in extra-high voltage research and utilization. The trend to higher transmission voltages is an inevitable result of the steadily increasing demand for power. Simply stated, "high voltage means high power transfer."

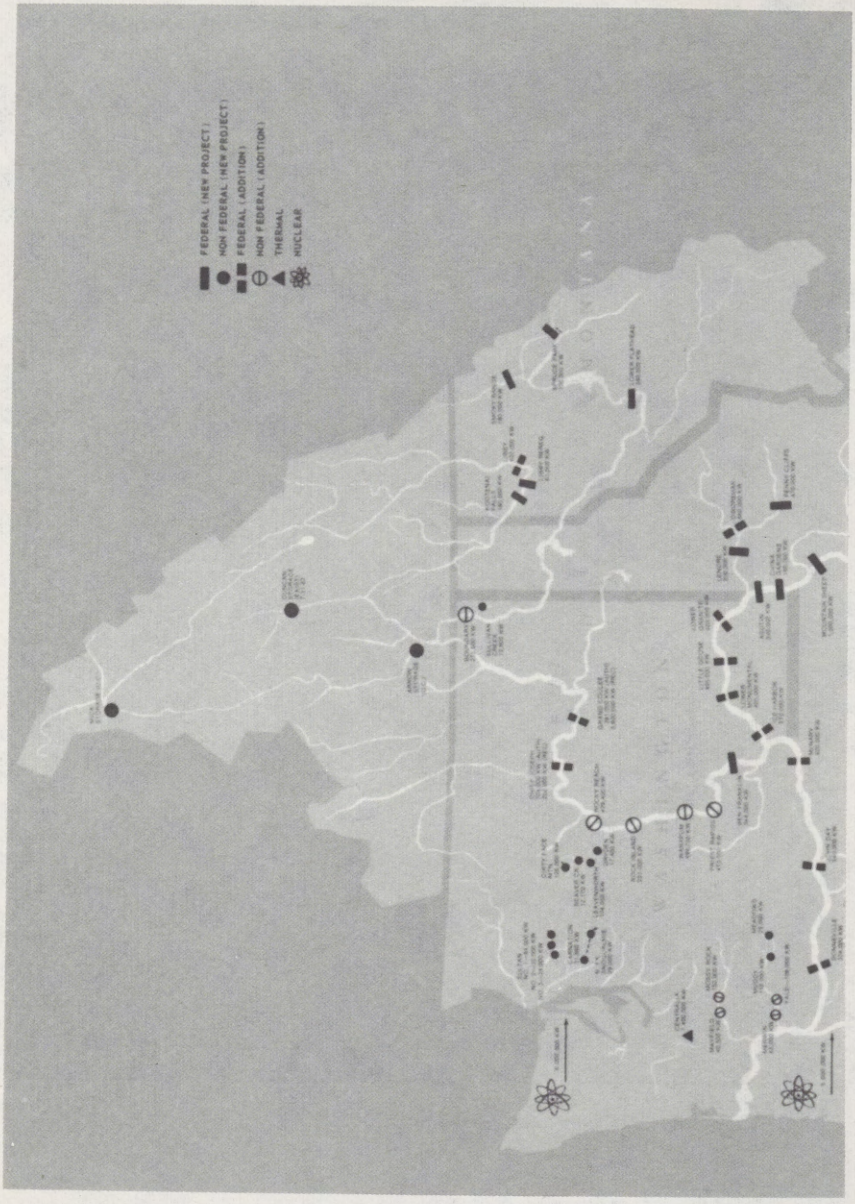
Studies are under way to determine the feasibility of utilizing transmission voltages in the 700 and 1000-kv class.

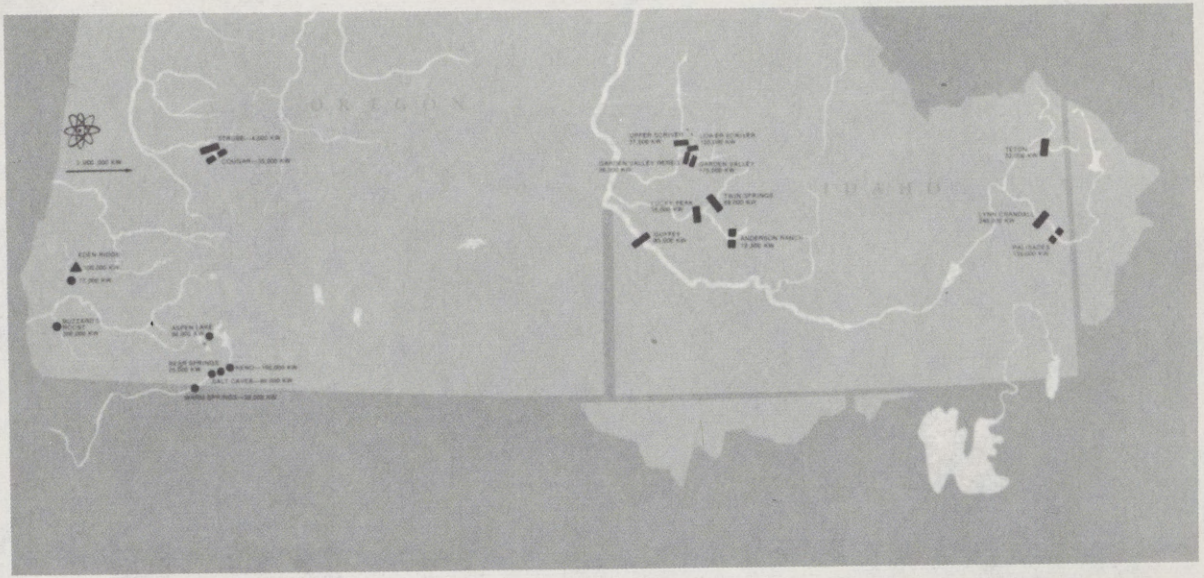
Our 500-kv grid overlay, which permits the transmission of large blocks of power at a low per-unit cost, is a major factor in maintaining BPA's low rate schedule in the face of rising material and labor costs. Hopefully, similar economies can be achieved through the use of still higher voltages, when the transmission system and the interconnected generating sources have been developed to the degree that the sudden loss of several thousand megawatts will not seriously affect system stability.

When we consider that projected peak loads will more than triple in the next 20 years, it is apparent that the most practical way to con-




U.S. COLUMBIA RIVER POWER SYSTEM
FEDERAL HYDROELECTRIC PROJECTS
EXISTING AND UNDER CONSTRUCTION
EXISTING
UNDER CONSTRUCTION

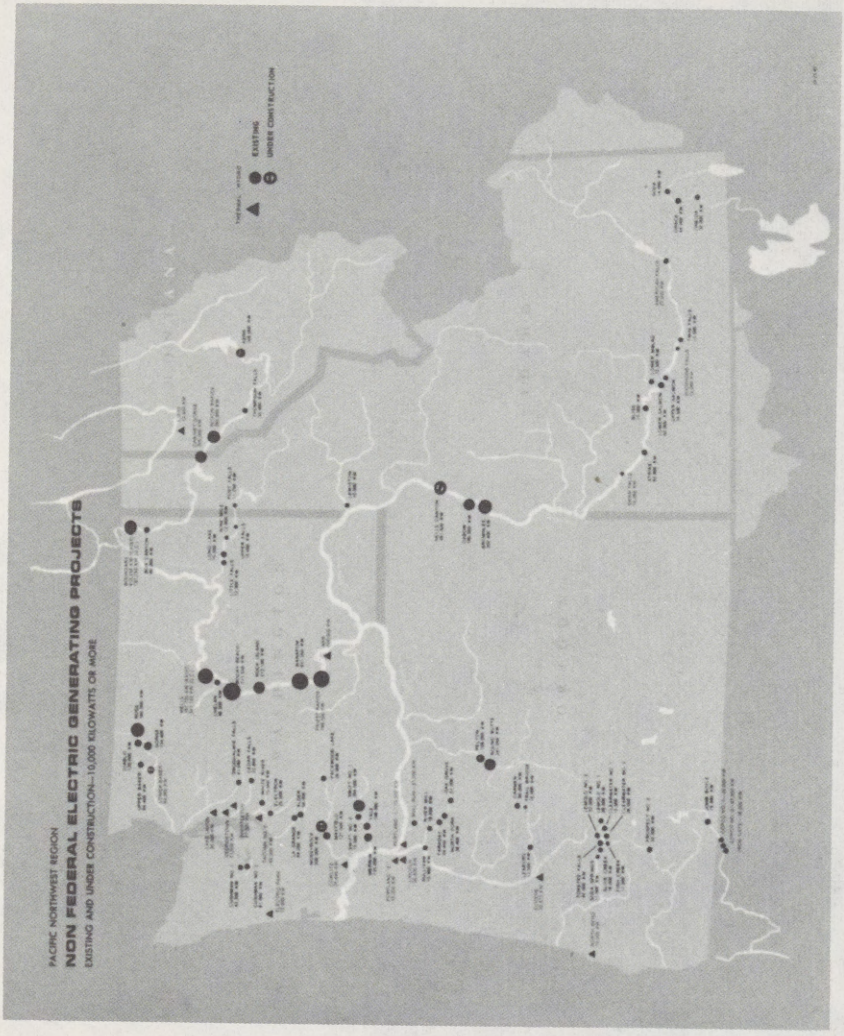

FEDERAL (NEW PROJECT)
NON FEDERAL (NEW PROJECT)
FEDERAL (ADDITION)
NON FEDERAL (ADDITION)
THERMAL
NUCLEAR



POTENTIAL DEVELOPMENT

PROJECTS AUTHORIZED, LICENSED OR UNDER ACTIVE

CONSIDERATION—AND POTENTIAL ADDITIONS


PACIFIC NORTHWEST REGION
NON FEDERAL ELECTRIC GENERATING PROJECTS
EXISTING AND UNDER CONSTRUCTION—10,000 KILOWATTS OR MORE
EXISTING
UNDER CONSTRUCTION

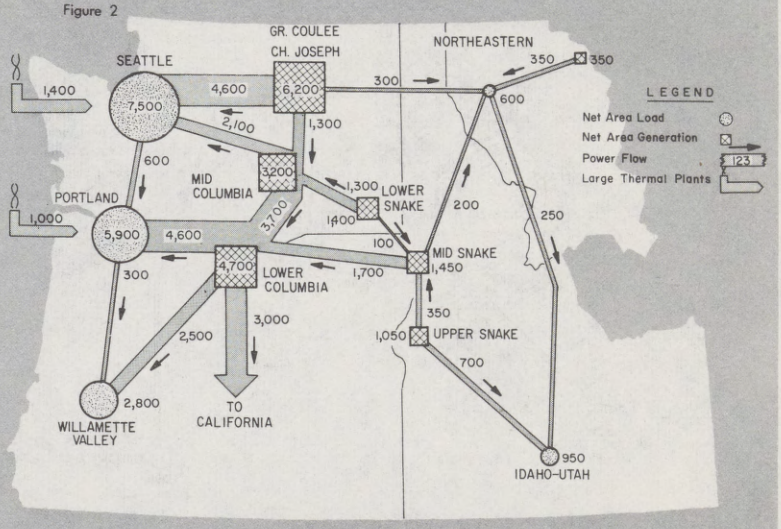
serve land – from both an esthetic and economic standpoint – is to go to higher voltage transmission using existing right of way whenever possible.

SYSTEM RELIABILITY

As a result of the massive blackouts in the East, the term "power system reliability" has taken on new meaning to the man in the street. Each region is involved in fresh examinations of its power generation and transmission facilities. Many questions are being asked regarding system vulnerability and the need for corrective measures.

BPA as a wholesaler is mainly concerned with bulk power system reliability. A utility may have the finest equipment and all the latest innovations to provide service reliability to its customers. But the service will be no better than the bulk power transmission system providing power to the area. Most of this bulk power system in the Northwest (approximately 80 percent of the high-voltage grid inte-

Figure 2



EXAMPLE OF POWER FLOW IN THE NORTHWEST
(with 2000 MW of New Thermal Plants in Reserve)
January 1977

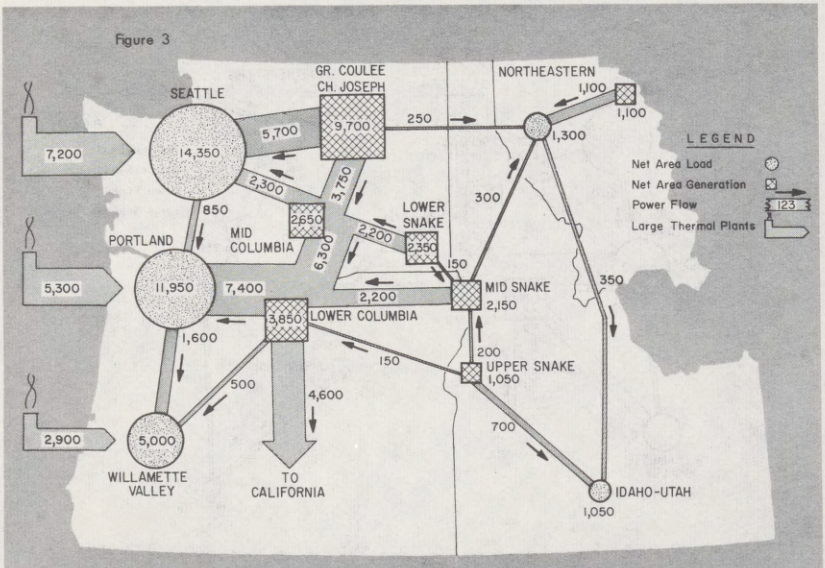
grating the Federal and non-Federal generating facilities) has been built and is owned and operated by BPA.

BPA's outlook on power reliability has undergone considerable change in recent years. Previously, our concern was providing reliable transmission for the Pacific Northwest with its predominately hydro system. Forced outages normally were of short duration because of the flexibility inherent in a hydro system. Now, the situation has changed largely as a result of the interties connecting the Northwest with thermal systems to the south.

While a system disturbance in the Northwest might have a small effect within the region, it could – because of a pyramiding effect – have much more severe consequences in neighboring areas. Therefore, this region must consider the reliability of its power supply in relation to effects on adjoining areas.

As defined by the FPC, "reliability means the ability of a utility system or group of systems to maintain the supply of power.

Figure 3



EXAMPLE OF POWER FLOW IN THE NORTHWEST
(with Indicated Thermal Plant Sitings)
Typical 1987

Reliability is gauged by the infrequency of interruption, the size of the area affected, and the quickness with which the bulk power supply is restored if interrupted".

The key to the solution of the reliability problem is adequate transmission.

Volume II of the FPC Report on "The Prevention of Power Failures" contains broad principles on bulk power supply planning. The BPA system reliability standards are in close agreement with these principles. But in recent years, BPA's construction program has been unable to keep pace with rapid load growth. This lag in meeting system reliability standards has necessitated emergency measures such as load-dropping under certain conditions. Factors contributing to the deficiency include late material deliveries and failures of some major equipment.

At present we are participating in studies relative to reliability over the 12 Western States. System studies are now under way, regional reliability standards are being prepared, and a 12-State utility organization – the Western Systems Coordinating Council – has been formed. Agreement on standards, development of solutions to operating problems and formulation of long-range plans remain to be accomplished. Once standards for planning have been agreed upon by all utilities, and cooperative long-range plans developed for a reliable integrated transmission network, it is important that each utility (including the Federal Goverhment) follow through with its commitment. Hopefully, this will set the requirements so that each utility, including BPA, can do its share in construction of a reliable and economical power network.

V MONETARY REQUIREMENTS

NON-FEDERAL

The total amount of new thermal generation which the region will require by 1986-87 as listed in Table 8 is 15,400,000 kilowatts. At today's average construction costs of $135 to $140 per kilowatt plus $30 to $40 per kilowatt for the initial nuclear fuel loading, the total investment cost for thermal generation would be in excess of $2,500,000,000 over the next 20 years.

New non-federal hydro generation expected to be installed over the next 20 years amounts to over 4,400,000 kilowatts. This hydro construction is estimated to cost about $1,100,000,000.

All of the distribution facilities to be constructed by 1987 will be non-federal. At an assumed cost of $175 per kilowatt, the non-federal utilities would invest approximately $5,200,000,000 in distribution facilities in the next 20 years.

While it is contemplated that most of the new EHV transmission capacity needed to carry new generation to load centers will be part of the BPA grid, it is expected that lines directly related to a utility's own system requirements and within that utility's service

area will be built by that utility. It is estimated that the non-federal utilities share of the required transmission lines will cost approximately $500,000,000.

FEDERAL

The federal government has eight new hydro projects under construction, two plants with additions being built, and six more authorized as shown on Table 5. In addition to the projects under construction and authorized, there are potential new projects and additional units at existing plants which will probably be in service by 1987. The total cost of all of these federal hydro projects is estimated to be $4,400,000,000 (Table 10) including costs allocated to purposes other than power. The costs allocated to power would approximate $3,000,000,000.

As previously mentioned, we anticipate that the bulk of the new transmission will be a part of the BPA transmission grid. Construction costs of the federal transmission grid over the next 20 years are estimated at $2,000,000,000. The cost of federal transmission lines under construction and requested for the 1969 program is estimated at $550,000,000. An additional $1,450,000,000 will be required for potential transmission lines. Construction funds required by BPA for EHV transmission facilities over the next ten years are shown in Table 11.

The following table summarizes the federal and non-federal construction expenditures for power facilities during the next 20 years.

Investment in Electric Facilities
in the Pacific Northwest in the Next 20 Years

	Federal	Non-Federal
Thermal Generation		$2,500,000,000
Hydro Capacity		
Under Construction and Authorized	$1,400,000,000)	
Potential projects and additional units not yet authorized at existing plants	1,600,000,000)	1,100,000,000
Transmission, Main Grid		
Under Construction and the 1969 Program	550,000,000)	500,000,000
Other	1,450,000,000)	
Low Voltage Transmission and Distribution		5,200,000,000
TOTAL	$5,000,000,000	$9,300,000,000

VI THE ROLE OF THE FEDERAL GOVERNMENT

As the Pacific Northwest shifts from a hydro to a combination thermal and hydro system, the responsibilities of the federal government are changing. The federal government does not propose to build any of the new thermal plants which will start to carry the base energy load in the mid 1970's. However, the most economic transmission, peaking capacity and reserves to go with the new thermal plants can be provided by additions to the federal system. In order to carry out their responsibilities, both the federal government and the non-federal utilities must participate in the joint planning for the thermal plants.

Both the federal and non-federal utilities have obligations to each other and to the region in this joint effort to provide power at a low cost. That of the federal government is to see that adequate bulk power transmission, peaking capacity and reserves are constructed as needed to make most effective and efficient use of the federal hydro plants when coordinated with the new thermal plants. The obligation of the non-federal utilities is to provide sufficient thermal generation to carry the area's firm loads and also to provide the local distribution systems for both hydro and thermal power.

The planning of new facilities must take into consideration not only serving the future power needs of the region but the conservation of resources and the maintenance of esthetic values. Higher voltage lines, such as BPA's 500 kv grid now under construction, require the use of less land per kilowatt transmitted for rights of way thus helping to preserve our forest lands and their attendant scenic and recreational values.

Coordinated planning among the federal government and the public and private utilities in the region is needed since each thermal plant will provide more generation than any single utility can absorb. Coordination is also necessary in order to schedule the thermal plants in logical sequence and at suitable locations. The transmission, peaking capacity and reserves must also be scheduled to fit into the pattern of development of area loads and thermal resources.

While the role of the non-federal utilities in the Pacific Northwest will be to construct the new thermal plants, add peaking at non-federal hydro plants and build the lower voltage transmission and a portion of the extra-high-voltage system, the federal government's role can be summarized as follows:

1. To add peaking capacity to existing hydro plants.
2. To build some additional multipurpose hydroelectric projects.
3. To supply surplus hydro energy.
4. To build most of the extra-high-voltage transmission system.
5. To provide leadership in the coordinated planning.

TABLES

PACIFIC NORTHWEST AREA FIRM LOADS 1967-87 TABLE 1

(Thousands of Kilowatts)

January Peak

Fiscal Year	Public Agencies	Private Utilities	BPA Industry Served	Federal Losses	Intertie Loads	Grand Coulee Pumping	Total Area Load	Additional Potential Industry Not Served
1967-68	5,975	7,096	1,833	366	–	–	15,270	–
68-69	6,293	7,572	2,194	369	633	–	17,061	–
69-70	6,710	8,068	2,269	366	1,758	–	19,171	–
70-71	7,101	8,593	2,419	391	1,991	–	20,495	–
71-72	7,528	9,149	2,024	358	2,016	–	21,075	–
1972-73	7,970	9,773	2,442	388	1,966	–	22,539	–
73-74	8,446	10,390	2,834	436	2,277	–	24,383	–
74-75	8,939	11,101	3,038	519	2,331	–	25,928	228
75-76	9,465	11,852	3,242	516	2,490	–	27,565	390
76-77	10,031	12,672	3,446	516	2,544	–	29,209	557
1977-78	10,631	13,535	3,650	522	2,550	–	30,888	724
79-79	11,347	14,455	3,854	554	2,605	–	32,815	772
79-80	12,021	15,455	4,059	587	2,579	–	34,701	939
80-81	12,739	16,527	4,263	622	2,529	–	36,680	1,115
81-82	13,492	17,678	4,263	658	2,429	–	38,520	1,495
1982-83	14,309	18,909	4,263	696	2,329	–	40,506	1,875
83-84	15,183	20,249	4,263	736	2,229	–	42,660	2,255
84-85	16,160	21,645	4,263	777	2,129	–	44,974	2,640
85-86	17,093	23,139	4,263	820	2,129	–	47,444	3,026
86-87	18,087	24,736	4,263	865	2,129	–	50,080	3,400

Average During the Critical Period

1967-68	3,827	4,337	1,781	246	7	33	10,231	–
68-69	3,975	4,667	2,075	248	136	24	11,125	–
69-70	4,159	4,888	2,220	243	543	70	12,123	–
70-71	4,385	5,192	2,372	260	572	19	12,800	–
71-72	4,640	5,516	2,003	238	572	48	13,017	–
1972-73	4,839	5,824	2,419	253	492	73	13,900	–
73-74	5,053	6,122	2,781	281	173	96	14,506	–
74-75	5,325	6,524	2,981	335	171	97	15,433	227
75-76	5,609	6,945	3,181	333	167	99	16,334	389
76-77	5,911	7,407	3,381	333	163	100	17,295	555
1977-78	6,227	7,896	3,581	336	142	101	18,283	721
78-79	6,669	8,422	3,781	356	76	103	19,407	770
79-80	7,031	8,964	3,981	377	58	104	20,515	937
80-81	7,405	9,584	4,181	399	–	105	21,674	1,112
81-82	7,814	10,234	4,181	423	–	106	22,758	1,487
1982-83	8,250	10,928	4,181	447	–	107	23,913	1,863
83-84	8,700	11,667	4,181	473	–	108	25,129	2,237
84-85	9,167	12,465	4,181	499	–	109	26,421	2,617
85-86	9,687	13,313	4,181	526	–	110	27,817	2,993
86-87	10,217	14,218	4,181	555	–	111	29,282	3,367

PACIFIC NORTHWEST AREA

TABLE 2

AVERAGE FIRM ENERGY LOADS AND RESOURCES
CRITICAL HYDRO CONDITIONS

(Thousands of Kilowatts)

	1967-68	1968-69	1969-70	1970-71	1971-72	1972-73	1973-74	1974-75	1975-76	1976-77
Total Area Load from Table 1	10,231	11,125	12,123	12,800	13,017	13,900	14,506	15,433	16,334	17,295
Resources										
Existing Hydro[1]	8,652	8,660	9,236	9,375	9,295	9,483	9,918	9,916	9,907	9,903
Existing Thermal and Misc.[2]	1,066	1,112	1,096	1,096	1,066	1,069	885	736	761	711
Hydro Under Const. and Auth.	874	1,843	1,993	2,243	2,229	2,921	3,206	3,207	3,262	3,425
Exchanges, Imports and Other	-261	-110	50	181	258	260	345	143	188	200
New Thermal[3]	–	–	–	–	365	247	247	1,903	2,803	3,765
Hydro Potential	–	–	–	–	–	–	–	–	–	24
Total Area Resources	10,331	11,505	12,375	12,895	13,243	13,971	14,601	15,905	16,921	18,028
Reserves – Unanticipated Load Growth	306	330	347	361	373	469	502	534	566	600
Net Area Resources	10,025	11,175	12,028	12,528	12,870	13,502	14,099	15,371	16,355	17,428
Surplus or (Deficit)	(206)	50	(95)	(272)	(147)	(398)	(407)	(62)	21	133

	1977-78	1978-79	1979-80	1980-81	1981-82	1982-83	1983-84	1984-85	1985-86	1986-87
Total Area Load from Table 1	18,283	19,407	20,515	21,674	22,758	23,913	25,129	26,421	27,817	29,282
Resources										
Existing Hydro[1]	9,895	9,915	9,916	9,917	9,918	9,919	9,920	9,921	9,922	9,923
Existing Thermal and Misc.[2]	736	711	736	761	711	736	711	736	761	711
Hydro Under Const. and Auth.	3,425	3,463	3,463	3,463	3,463	3,463	3,463	3,463	3,463	3,463
Exchanges, Imports and Other	208	210	276	400	400	400	400	400	400	400
New Thermal[3]	4,665	5,377	5,503	6,340	7,556	8,460	9,716	11,034	12,248	13,860
Hydro Potential	140	666	1,537	1,778	1,875	2,168	2,220	2,240	2,529	2,574
Total Area Resources	19,069	20,342	21,431	22,659	23,923	25,146	26,430	27,794	29,323	30,931
Reserves – Unanticipated Load Growth	726	773	818	867	910	1,196	1,256	1,321	1,391	1,464
Net Area Resources	18,343	19,569	20,613	21,792	23,013	23,850	25,174	26,473	27,832	29,467
Surplus or (Deficit)	60	162	98	118	255	37	45	52	115	185

[1] U.S. and Canadian downstream benefits from Treaty storage are included.

[2] Capability is reduced to reflect inability of projects to operate for a 43-month critical period. The projects which have been in operation in excess of the normal service life of thermal plants were considered available for peaking use only.

[3] Resources exclude CVP purchases of 383 average megawatts of Centralia Thermal plant capability until pulled back for use in the PNW on December 31, 1981.

PACIFIC NORTHWEST AREA TABLE 3

JANUARY FIRM PEAK LOAD AND PEAK GENERATING CAPACITY
CRITICAL HYDRO CONDITIONS

(Thousands of Kilowatts)

	1967-68	1968-69	1969-70	1970-71	1971-72	1972-73	1973-74	1974-75	1975-76	1976-77
Total Area Load from Table 1	15,270	17,061	19,171	20,495	21,075	22,539	24,383	25,928	27,565	29,209
Resources										
Existing Hydro	15,303	15,282	15,597	15,616	15,611	15,478	15,321	15,287	15,288	15,288
Existing Thermal and Misc.	548	548	548	548	548	1,385	1,385	1,385	1,385	1,385
Hydro Under Const. and Auth.	1,398	3,268	4,292	5,224	5,831	7,991	9,244	10,856	11,363	11,680
Exchanges, Imports and Other	-473	-122	-94	-31	58	194	225	76	89	107
New Thermal [1]	–	–	–	–	274	274	274	1,974	2,974	3,974
Hydro Potential	–	–	–	–	–	–	–	–	–	–
Total Area Resources	16,776	18,976	20,343	21,357	22,322	25,322	26,449	29,578	31,099	32,434
Reserves – Forced Outage	1,069	1,150	1,219	1,295	1,334	1,749	1,879	2,000	2,131	2,267
Reserves – Unanticipated Load Growth	458	493	523	556	572	720	773	826	878	933
Net Area Resources	15,249	17,333	18,601	19,506	20,416	22,753	23,797	26,746	28,090	29,234
Surplus or (Deficit)	(21)	272	(570)	(989)	(659)	214	(586)	818	525	25

	1977-78	1978-79	1979-80	1980-81	1981-82	1982-83	1983-84	1984-85	1985-86	1986-87
Total Area Load from Table 1	30,888	32,815	34,701	36,680	38,520	40,506	42,660	44,974	47,444	50,080
Resources										
Existing Hydro	15,269	15,123	15,123	15,123	15,123	15,123	15,123	15,123	15,123	15,123
Existing Thermal and Misc.	1,385	1,385	1,385	1,385	1,385	1,385	1,385	1 385	1,385	1,385
Hydro Under Const. and Auth.	12,691	13,860	13,860	14,408	15,094	15,534	15,844	16,155	16,526	17,615
Exchanges, Imports and Other	121	–	–	–	–	–	–	–	–	–
New Thermal [1]	4,974	5,974	5,974	6,974	8,400	9,400	10,400	12,400	13,400	15,400
Hydro Potential	310	973	2,574	3,252	3,570	4,499	5,616	6,101	7,407	7,407
Total Area Resources	34,750	37,315	38,916	41,142	43,572	45,941	48,368	51,164	53,841	56,930
Reserves – Forced Outage	2,550	2,719	2,891	3,074	3,248	3,436	3,639	3,856	4,078	4,316
Reserves – Unanticipated Load Growth	1,134	1,209	1,285	1,366	1,444	1,909	2,022	2,142	2,266	2,397
Net Area Resources	31,066	33,387	34,740	36,702	38,880	40,596	42,707	45,166	47,497	50,217
Surplus or (Deficit)	178	572	39	22	360	90	47	192	53	137

[1] Resources exclude CVP purchases of 426 megawatts of Centralia Thermal plant capacity until pulled back for use in the PNW on December 31, 1981. Intertie loads do not include CVP load.

ESTIMATED DISTRIBUTION OF FIRM ENERGY AVAILABLE TO BPA
AVERAGE ENERGY DURING THE CRITICAL PERIOD
WITH CRITICAL HYDRO CONDITIONS
(Thousands of Kilowatts)

TABLE 4

Fiscal Operating Year	1967-68	1968-69	1969-70	1970-71	1971-72	1972-73	1973-74	1974-75	1975-76	1976-77
Number of Months in the Critical Period	7-1/2	7-1/2	8-1/2	8-1/2	8-1/2	20	43	43	43	43
Net Resources Available to BPA[1]	4,477	5,129	5,532	5,983	6,264	6,622	6,971	7,093	7,292	7,605
DISTRIBUTION										
Public & Federal Agencies & Cooperatives										
Estimated Load	3,827	3,975	4,159	4,385	4,640	4,839	5,053	5,325	5,609	5,911
Own System Resources	1,605	1,790	1,759	1,745	1,748	1,898	2,084	2,114	2,169	2,082
Purchases from BPA	2,222	2,185	2,400	2,640	2,892	2,941	2,969	3,211	3,440	3,829
Total Resources	3,827	3,975	4,159	4,385	4,640	4,839	5,053	5,325	5,609	5,911
Additional Resources Required[2]	–	–	–	–	–	–	–	–	–	–
Industries										
Estimated Total Firm Potential Load	1,781	2,075	2,220	2,372	2,003	2,419	2,781	3,208	3,570	3,936
BPA Contracts and Commitments	1,781	2,075	2,220	2,372	2,003	2,419	2,581	2,581	2,581	2,581
Additional Industry Served[3]							200	400	600	800
Additional Resources Required	–	–	–	–	–	–	–	227	389	555
Private Utilities[4]										
Estimated Load	4,337	4,667	4,888	5,192	5,516	5,824	6,122	6,524	6,945	7,407
Own System Resources	3,999	4,143	4,266	4,349	4,414	4,694	4,901	5,119	5,154	5,303
Purchases from BPA	338	524	622	843	1,102	1,130	1,221	901	671	395
Total Resources	4,337	4,667	4,888	5,192	5,516	5,824	6,122	6,020	5,825	5,698
Additional Resources Required[2]		–	–	–	–	–	–	504	1,120	1,709
Total Estimated Distribution of Federal Resources	4,341	4,784	5,242	5,855	5,997	6,490	6,971	7,093	7,292	7,605
Reserve	136	345	290	128	267	132	–	–	–	–
Total Additional Resources Required	–	–	–	–	–	–	–	731	1,509	2,264

Fiscal Operating Year	1977-78	1978-79	1979-80	1980-81	1981-82	1982-83	1983-84	1984-85	1985-86	1986-87
Number of Months in the Critical Period	43	43	43	43	43	43	43	43	43	43
Net Resources Available to BPA[1]	7,833	8,009	8,269	8,599	8,539	8,547	8,510	8,524	8,539	8,495
DISTRIBUTION										
Public & Federal Agencies & Cooperatives										
Estimated Load	6,227	6,669	7,031	7,405	7,814	8,250	8,700	9,167	9,687	10,217
Own System Resources	2,082	2,104	2,099	2,114	2,101	2,094	2,082	2,072	2,060	2,051
Purchases from BPA	4,145	4,174	4,234	4,364	4,304	4,312	4,275	4,289	4,304	4,260
Total Resources	6,227	6,278	6,333	6,478	6,405	6,406	6,357	6,361	6,364	6,311
Additional Resources Required[2]	–	391	698	927	1,409	1,844	2,343	2,806	3,323	3,906
Industries										
Estimated Total Firm Potential Load	4,302	4,551	4,918	5,293	5,668	6,044	6,418	6,798	7,174	7,548
BPA Contracts and Commitments	2,581	2,581	2,581	2,581	2,581	2,581	2,581	2,581	2,581	2,581
Additional Industry Served[3]	1,000	1,200	1,400	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Additional Resources Required	721	770	937	1,112	1,487	1,863	2,237	2,617	2,993	3,367
Private Utilities[4]										
Estimated Load	7,896	8,422	8,964	9,584	10,234	10,928	11,667	12,465	13,313	14,218
Own System Resources	5,372	5,470	5,528	5,649	5,733	6,206	6,300	6,399	6,476	6,561
Purchases from BPA	107	54	54	54	54	54	54	54	54	54
Total Resources	5,479	5,524	5,582	5,703	5,787	6,260	6,354	6,453	6,530	6,615
Additional Resources Required[2]	2,417	2,898	3,382	3,881	4,447	4,668	5,313	6,012	6,783	7,603
Total Estimated Distribution of Federal Resources	7,833	8,009	8,269	8,599	8,539	8,547	8,510	8,524	8,539	8,495
Reserve	–	–	–	–	–	–	–	–	–	–
Total Additional Resources Required	3,138	4,059	5,017	5,920	7,343	8,375	9,893	11,435	13,099	14,876

[1] Net after adjustments for losses, Canadian Entitlement deliveries to PSW and Canada, exchange contracts with PNW and PSW utilities, restoration to non-Federal utilities due to Canadian Treaty, Federal storage payments, Centralia purchase and assumed BPA share of thermal generation from first six nuclear plants.
[2] Additional resources required to be met by utilities from new thermal generation and added hydro projects.
[3] Served from assumed BPA share of thermal generation from first six nuclear plants.
[4] Idaho Power Company, Montana Power Company west of the Continental Divide, Kalispell Division of Pacific Power and Light Company and Montana Light and Power Company have been included.

U. S. COLUMBIA RIVER POWER SYSTEM
SCHEDULE OF GENERATOR INSTALLATION[1]

TABLE 5

Project	Stream	Cumulative Nameplate Rating (thousand kw)[2]	Date Scheduled	Status[3]
Foster	S. Santiam R.			U.C.
Reregulation			October 1967	
Unit 1		10	March 1968	
2		20	May 1968	
John Day	Columbia R.			U.C.
Units 1, 2, & 3		405	June 1968	
4		540	July 1968	
5		675	September 1968	
6		810	November 1968	
7		945	January 1969	
8		1,080	March 1969	
9		1,215	May 1969	
10		1,350	July 1969	
11		1,485	December 1969	
12		1,620	February 1970	
13		1,755	April 1970	
14		1,890	June 1970	
15 & 16		2,160	November 1971	
Lower Monumental	Snake R.			U.C.
Unit 1		135	May 1969	
2		270	August 1969	
3		405	November 1969	
4, 5, & 6		810	December 1977	
Little Goose	Snake R.			U.C.
Units 1, 2, & 3		405	June 1970	
The Dalles	Columbia R.			U.C.
Units 15 & 16		172	August 1971	
17		258	November 1971	
18		344	February 1972	
19		430	May 1972	
20		516	August 1972	
21		602	November 1972	
22		688	February 1973	
Grand Coulee (Pumping Plant Additions)	Columbia R.			Auth.
Units P-7	(Pump Turbines)	48.5	March 1972	
P-8		97	June 1972	
Dworshak	N.Fk. Clearwater			U.C.
Commence Filling 2.0 Million A.F. Usable Storage[4]			June 1971	
			June 1972	
Units 1 & 2		180	June 1972	
3		400	June 1972	
Lower Granite	Snake R.			U.C.
Units 1, 2, & 3		405	June 1972	
Ice Harbor	Snake R.			Auth.
Unit 4		90	July 1972	
5		180	October 1972	
6		270	January 1973	
Lost Creek	Rogue R.			U.C.
Unit 1		24.5	April 1973	
2		49.0	July 1973	
Teton	Teton R.			Auth.
Units 1 & 2		22	April 1973	
Chief Joseph	Columbia R.			Auth.
Units 17 & 18		128	June 1973	
19		192	August 1973	
20		256	October 1973	
21		320	December 1973	
22		384	February 1974	
23		448	April 1974	
24		512	June 1974	
25		576	August 1974	
26		640	October 1974	
27		704	December 1974	
Libby	Kootenai R.			U.C.
Commence Filling 2.5 Million A.F. Usable Storage to 5.0 Million A.F.[4]			August 1971	
			August 1972	
Units 1 & 2		210	July 1973	
3		315	October 1973	
4		420	January 1974	
Grand Coulee (Third Powerhouse)	Columbia R.			U.C.
Unit 19		600	September 1973	
20		1,200	March 1974	
21		1,800	September 1974	
22		2,400	September 1977	
23		3,000	March 1978	
24		3,600	September 1978	
Bonneville (Second Powerhouse)	Columbia R.			Auth.
Unit 1		54	March 1975	
2		108	May 1975	
3		162	July 1975	
4		216	September 1975	
5		270	November 1975	
6		324	January 1976	
Asotin	Snake R.			Auth.
Units 1 & 2		270	June 1976	

[1] Unit installation schedules may be rearranged between projects to provide better hydraulic balance or more economical construction schedules.

[2] Manufacturer's rating and does not necessarily represent maximum capability.

[3] U.C. – Under Construction; Auth. – Authorized for Federal construction.

[4] Availability of storage subject to streamflow conditions.

NORTHWEST UTILITIES OTHER THAN U. S. COLUMBIA RIVER POWER SYSTEM TABLE 6
INSTALLATION SCHEDULE OF GENERATORS LICENSED OR UNDER CONSTRUCTION

Utility and Plant	Stream	Cumulative Nameplate Rating (thousand kw)	Date Scheduled	Status[1]
B.C. Hydro and Power Authority				
Canadian Storage (usable)	Columbia R.			U.C.
Arrow Lakes 7.1 million AF			1969[2]	
Mica 7.0 million AF			1973	
City of Seattle				
Boundary	Pend Oreille R.			U.C.
Unit 4		137.75	November 1967	
Douglas County PUD				
Wells	Columbia R.			U.C.
Unit 6		77.4	November 1967	
Unit 7		154.8	January 1968	
Unit 8		232.3	March 1968	
Unit 9		309.7	April 1968	
Unit 10		387.1	May 1968	
Idaho Power Company				
Hells Canyon	Snake R.			U.C.
Unit 1		130.5	November 1967	
Unit 2		261.0	February 1968	
Unit 3		391.5	March 1968	
City of Tacoma				
Mossyrock	Cowlitz R.			U.C.
Storage & Unit 1		150.0	March 1968	
Unit 2		300.0	June 1968	
Chelan County PUD				
Rocky Reach	Columbia R.			Lic.
Units 8-11		429.6	September 1972	
Snohomish Co. PUD & City of Everett, Washington[3]				
Sultan No. 1	Sultan R.			Lic.
Units 1 & 2		84.0	February 1975	
Sultan No. 2	Sultan R.			Lic.
Units 3 & 4		32.0	April 1975	
Sultan No. 3	Sultan R.			Lic.
Unit 5		24.0	June 1975	

[1] U.C. – Under Construction; Lic. – License granted by FPC.

[2] Dates established by the Canadian Treaty. Project may be in operation before this date.

[3] Construction agencies are requesting extension of time for installation of power facilities. Installation dates are tenative.

TENATIVE INSTALLATION SCHEDULE
POTENTIAL PROJECTS

TABLE 7

Project	Unit No.	Cumulative Unit Size MW	Date
Centralia Steam	1	700	Sept. 1971
	2	1,400	July 1974
Nuclear No. 1	1	1,000	July 1974
Nuclear No. 2	1	1,000	May 1975
Nuclear No. 3	1	1,000	May 1976
Nuclear No. 4	1	1,000	Apr. 1977
Guffey	1, 2, 3, & 4	85	Apr. 1977
Lynn Crandall	1	60	Apr. 1977
	2	120	June 1977
	3	180	Oct. 1977
	4	240	Dec. 1977
Palisades		135	Apr. 1977
Nuclear No. 5	1	1,000	Apr. 1978
Upper Scriver	1	37.5	June 1978
Lower Scriver	1	30	June 1978
	2 & 3	90	June 1979
	4	120	June 1980
Lucky Peak	1 & 2	35	June 1978
N. Fork Snoqualmie		60	July 1978
Muddy-Meadows		135	July 1978
Eden Ridge		177	July 1978
Kootenai Falls	1	60	July 1978
	2	120	Sept. 1978
	3	180	Nov. 1978
High Mountain Sheep	1 & 2	600	Mar. 1979
	3	900	May 1979
	4	1,200	Nov. 1982
	5	1,500	Jan. 1983
Ben Franklin	1, 2, & 3	103.2	Mar. 1979
	4	137.6	May 1979
	5	172.0	July 1979
	6	206.4	Sept. 1979
	7	240.8	Nov. 1979
	8	275.2	Jan. 1980
	9	309.6	Mar. 1980
	10	344.0	May 1980
China Gardens	1, 2, & 3	180.0	June 1979
Klamath River Additions		118	July 1979
		282	July 1980
Grand Coulee P-T	P9 & P10	97	Apr. 1980
	P11 & P12	194	Apr. 1986
Nuclear No. 6	1	1,000	May 1980
Garden Valley	1 & 2	87.5	June 1980
	3 & 4	175	June 1981
Garden Valley Reregulating	1 & 2	18	June 1980
	3 & 4	36	June 1981
Lower Flathead River	1-6	340	June 1980
Little Goose	4, 5, & 6	405	Dec. 1980
Nuclear No. 7	1	1,000	Apr. 1981
Lenore	1 & 2	100	June 1981
	3	150	Aug. 1981
	4	200	Oct. 1981
Sullivan Creek	1	6.8	Sept. 1981
	2	13.6	Oct. 1981
Lower Granite Additions	4, 5, & 6	405	Dec. 1981
Dworshak Additions	4	220	Dec. 1981
	5	440	Oct. 1982
	6	660	Dec. 1982
Nuclear No. 8	1	1,000	July 1982
Wenatchee River		150	July 1982
		300	July 1983
Spruce Park	1 & 2	120	Sept. 1982
Smoky Range	1 & 2	190	Sept. 1982
Twin Springs	1 & 2	69	June 1983
Nuclear No. 9	1	1,000	July 1983
Strube	1	4.5	July 1983
Wanapum Additions	11	83.1	Sept. 1983
	12	166.3	Nov. 1983
	13	249.4	Jan. 1984
	14	352.5	Sept. 1984
	15	415.6	Nov. 1984
	16	498.8	Jan. 1985
John Day Additions	17	135	Oct. 1983
	18	270	Dec. 1983
	19	405	Oct. 1984
	20	540	Dec. 1984
Yale Additions	1	54	Nov. 1983
	2	108	Jan. 1984
Rock Island Additions	1-7	231	Jan. 1984
Merwin Additions	4	45	Jan. 1984
Cougar Additions	3	35	Jan. 1984
Nuclear No. 10	1	1,000	Feb. 1984
Priest Rapids Additions	11	78.9	Sept. 1984
	12	157.70	Nov. 1984
	13	236.6	Jan. 1985
	14	315.40	Sept. 1985
	15	394.3	Nov. 1985
	16	473.10	Jan. 1986
Nuclear No. 11	1	1,000.0	Sept. 1984
Libby Additions	5 & 6	210	Apr. 1985
	7	315	June 1985
	8	420	Aug. 1985
Buzzard's Roost	1	100.0	July 1985
	2	200.0	Sept. 1985
Nuclear No. 12	1	1,000.0	July 1985
Penny Cliffs	1-6	470.0	Aug. 1985
Boundary Additions	5	137.8	Nov. 1985
	6	275.5	Jan. 1986
Asotin Additions	3	135	Dec. 1985
	4	270	Dec. 1986
Libby Reregulating	1 & 2	61	Dec. 1985
Mayfield Additions	4	40.5	Jan. 1986
Mossyrock Additions	3	150	Jan. 1986
Nuclear No. 13	1	1,000	Apr. 1986
Nuclear No. 14	1	1,000	July 1986
Grand Coulee 3rd Powerplant	25	600	Dec. 1986
Chief Joseph Additions	28-31	256	Dec. 1986

U. S. COLUMBIA RIVER POWER SYSTEM
GENERAL SPECIFICATIONS, PROJECTS EXISTING, UNDER CONSTRUCTION AND AUTHORIZED
INSTALLATIONS AS OF JUNE 30, 1967

TABLE 8

Project	Operating Agency[1]	Location	Stream	Existing			Under Construction		Authorized		Total	
				Initial Date in Service	Number of Units	Total Capacity Kilowatts[2]	Number of Units	Total Capacity Kilowatts[2]	Number of Units	Total Capacity Kilowatts[2]	Number of Units	Total Capacity Kilowatts[2]
Bonneville	CE	Ore.-Wash.	Columbia	June 1938	10	518,400	–	–	6	324,000	16	842,400
Grand Coulee	BR	Washington	Columbia	Sept. 1941	18	1,944,000	6	3,600,000	6	291,000	36	9,435,000[3]
Hungry Horse	BR	Montana	S. Fk. Flathead	Oct. 1952	4	285,000	–	–	–	–	4	285,000
Detroit	CE	Oregon	North Santiam	July 1953	2	100,000	–	–	–	–	2	100,000
McNary	CE	Ore.-Wash.	Columbia	Nov. 1953	14	980,000	–	–	6	420,000	20	1,400,000
Big Cliff	CE	Oregon	North Santiam	June 1954	1	18,000	–	–	–	–	1	18,000
Lookout Point	CE	Oregon	M. Fk. Willamette	Dec. 1954	3	120,000	–	–	–	–	3	120,000
Albeni Falls	CE	Idaho	Pend Oreille	Mar. 1955	3	42,600	–	–	–	–	3	42,600
Dexter	CE	Oregon	M. Fk. Willamette	May 1955	1	15,000	–	–	–	–	1	15,000
Chief Joseph	CE	Washington	Columbia	Aug. 1955	16	1,024,000	–	–	11	704,000	27	1,728,000
Chandler	BR	Washington	Yakima	Feb. 1956	2	12,000	–	–	–	–	2	12,000
The Dalles	CE	Ore.-Wash.	Columbia	May 1957	16	1,119,000	8	688,000	–	–	24	1,807,000
Roza	BR	Washington	Yakima	Aug. 1958	1	11,250	–	–	–	–	1	11,250
Ice Harbor	CE	Washington	Snake	Dec. 1961	3	270,000	–	–	3	270,000	6	540,000
Hills Creek	CE	Oregon	M. Fk. Willamette	May 1962	2	30,000	–	–	–	–	2	30,000
Minidoka	BR	Idaho	Snake	May 1909	7	13,400	–	–	–	–	7	13,400
Boise Diversion	BR	Idaho	Boise	May 1912	3	1,500	–	–	–	–	3	1,500
Black Canyon	BR	Idaho	Payette	Dec. 1925	2	8,000	–	–	–	–	2	8,000
Anderson Ranch	BR	Idaho	S. Fk. Boise	Dec. 1950	2	27,000	–	–	1	13,500	3	40,500
Palisades	BR	Idaho	Snake	Feb. 1957	4	114,000	–	–	–	–	4	114,000
Cougar	CE	Oregon	S. Fk. McKenzie	Feb. 1964	2	25,000	–	–	1	35,000	3	60,000
Green Peter	CE	Oregon	Middle Santiam	June, 1967	2	80,000	–	–	–	–	2	80,000
Foster	CE	Oregon	South Santiam		–	–	2	20,000	–	–	2	20,000
John Day	CE	Ore.-Wash.	Columbia		–	–	16	2,160,000	4	540,000	20	2,700,000
Lower Monumental	CE	Washington	Snake		–	–	3	405,000	3	405,000	6	810,000
Little Goose	CE	Washington	Snake		–	–	3	405,000	3	405,000	6	810,000
Lower Granite	CE	Washington	Snake		–	–	3	405,000	3	405,000	6	810,000
Teton	BR	Idaho	Teton		–	–	–	–	2	22,000	2	22,000
Lost Creek	CE	Oregon	Rogue		–	–	2	49,000	–	–	2	49,000
Dworshak	CE	Idaho	N. Fk. Clearwater		–	–	3	400,000	3	660,000	6	1,060,000
Strube	CE	Oregon	S. Fk. McKenzie		–	–	–	–	1	4,500	1	4,500
Libby	CE	Montana	Kootenai		–	–	4	420,000	4	420,000	8	840,000
Asotin	CE	Wash.-Ida.	Snake		–	–	–	–	4	540,000	4	540,000
Total number of projects and Installed Capacity					22	6,758,150	8	8,552,000	3	5,459,000	33	24,369,150

[1] CE – Corps of Engineers; BR – Bureau of Reclamation.
[2] Nameplate Rating.
[3] Includes a recommended 3,600,000 kw at the Third Powerhouse in addition to that under construction and 291,000 kw from 6 authorized pump-turbine units.

PACIFIC NORTHWEST NON-FEDERAL GENERATION

TABLE 9

NAMEPLATE RATING OF PLANTS EXISTING, UNDER CONSTRUCTION AND LICENSED

(Kilowatts)

June 30, 1967

Ownership	Existing		Under Construction		Licensed		Total	
	No. of Plants	Nameplate Rating	No. of Plants	Nameplate Rating	No. of Plants	Nameplate Rating	No. of Plants	Nameplate Rating
Public Agencies								
Hydro	42	3,885,636	4	1,625,450	3	569,400 [1]	49	6,080,486 [1]
Thermal	19	986,019	0	0	0	0	19	986,019
Total Public Agencies	61	4,871,655	4	1,625,450	3	569,400 [1]	68	7,066,505 [1]
Private Utilities								
Hydro	95	3,480,592	2	455,500	0	0	97	3,936,092
Thermal	13	263,935	0	5,500 [1]	0	0	13	269,435 [1]
Total Private Utilities	108	3,744,527	2	461,000 [1]	0	0	110	4,205,527 [1]
Non-Federal Utilities								
Hydro	137	7,366,228	6	2,080,950 [1]	3	569,400 [1]	146	10,016,578 [1]
Thermal	32	1,249,954	0	5,500 [1]	0	0	32	1,255,454 [1]
Total	169	8,616,182	6	2,086,450 [1]	3	569,400 [1]	178	11,272,032 [1]

[1] Includes additions to projects existing or under construction.

ESTIMATED CONSTRUCTION FUNDS REQUIRED FOR FEDERAL HYDROELECTRIC INSTALLATIONS[1]

TABLE 10

(Millions of Dollars)

Fiscal Year	Projects Under Const.[2]	Additions to Projects Existing and Under Const.[3]	Authorized Projects[4]	Potential Projects[5]	Total
1968	191	22	1	0	214
1969	272	56	1	0	329
1970	225	91	9	0	325
1971	171	95	13	1	280
1972	90	89	11	9	199
1973	42	81	30	39	192
1974	7	78	30	101	216
1975	–	71	32	212	315
1976	–	77	16	311	404
1977	–	55	4	327	386
1978	–	52	2	324	378
Subtotal 1968-1978	998	767	149	1,324	3,238
1979-1987	–	150	2	972	1,140
Total	998	917	151	2,296	4,378

[1] Projects included in U.S. Columbia River Power System Schedule of Generator Installations dated September 1, 1967, plus projects listed in Footnote 5, below.

[2] Costs of Foster, John Day (Units 1-16), Lower Monumental, Little Goose, Dworshak, Lower Granite, Lost Creek, and Libby.

[3] Projects included are The Dalles (Units 15-22), Grand Coulee Pump-Turbines (Units P7 & P8), Ice Harbor (Units 4-6), Chief Joseph (Units 17-27), Grand Coulee Third Powerhouse (Units 19-25), Bonneville Second Powerhouse, Lower Monumental (Units 4-6), Little Goose (Units 4-6), Dworshak (Units 4-6), Lower Granite (Units 4-6), John Day (Units 17-20), Cougar, Palisades, and Libby (Units 5-8).

[4] Includes Teton, Asotin, and Strube.

[5] Potential projects considered for installation include Lynn Crandall, Guffey, Upper Scriver Creek, Lower Scriver Creek, China Gardens, Kootenai Falls, Lucky Peak, Ben Franklin, Garden Valley, Garden Valley Reregulating, Lower Flathead River, Lenore, Spruce Park, Smoky Range, Twin Springs, Penny Cliffs, Libby Reregulating, High Mountain Sheep, and Snoqualmie No. Fork.

ESTIMATED CONSTRUCTION FUNDS REQUIRED BY BONNEVILLE POWER ADMINISTRATION FOR EHV TRANSMISSION FACILITIES

TABLE 11

(Millions of Dollars)

Fiscal Year	Project Under Construction,[1] Authorized Projects, and Additions to Existing Plants	Potential[2] Projects	Thermal[3] Plants	Total
1968	123	0	0	123
1969	164	0	4	168
1970	146	0	5	151
1971	110	0	16	126
1972	81	0	21	102
1973	92	2	30	124
1974	97	17	28	142
1975	68	31	25	124
1976	54	49	19	122
1977	44	63	16	123
TOTALS	979	162	164	1,305

[1] Includes transmission additions for Foster, John Day, Lower Monumental, Little Goose, Dworshak, Lower Granite, Lost Creek, Libby, The Dalles, Grand Coulee, Teton, Asotin, Ice Harbor, Chief Joseph, Bonneville and Palisades additions.

[2] Includes transmission additions for Guffey, Lynn Crandall, Upper Scriver, Lower Scriver, Kootenai Falls, Lucky Peak, High Mountain Sheep, China Gardens, Ben Franklin, Garden Valley, Garden Valley Reregulating, Lower Flathead, and wheeling for non-federal hydroelectric additions.

[3] Includes transmission additions for 7400 mw of steam to be installed by F. Y. 1980.

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NAMES OF BPA UTILITY CUSTOMERS INCLUDED IN ANALYSIS OF TABLE SHOWING LOADS, RESOURCES AND ADDITIONAL REQUIREMENTS ON PAGE AP-3-18 — TABLE 12

4 Privately Owned Utilities

Pacific Power & Light Co.
Portland General Electric Co.
Puget Sound Power & Light Co.
Washington Water Power Co.

6 Largest Preference Customers

Clark County PUD
Cowlitz County PUD
Eugene Water & Electric Board
Seattle City Light
Snohomish County PUD
Tacoma City Light

26 Other Preference Customers With Additional Requirements

Benton County PUD
Big Bend Electric Coop.
Central Lincoln PUD
Clallam County PUD
Clatskanie PUD
Columbia REA
Consumers Power, Inc.
Coos-Curry Electric Coop.
Ellensburg
Franklin County PUD
Grays Harbor County PUD
Idaho Falls
Inland Power & Light Co.
Lane County Electric Coop.
Lewis County PUD
Mason County PUD #3
McMinnville
Okanogan County PUD
Pacific County PUD
Pend Oreille County PUD
Port Angeles
Richland
Salem Electric
Springfield
Tillamook PUD
Umatilla Electric Coop.

69 Other Preference Customers With No Additional Requirements

Albion
Bandon
Blaine
Bonners Ferry
Burley
Canby
Cascade Locks
Centralia
Cheney
Coulee Dam
Declo
Drain
Forest Grove
Grand Coulee
Heyburn
McCleary
Milton-Freewater
Minidoka
Monmouth
Rupert
Vera Irrigation District
Chelan County PUD
Douglas County PUD
Ferry County PUD
Grant County PUD
Kittitas County PUD
Klickitat County PUD
Mason County PUD #1
Northern Wasco PUD
Skamania County PUD
Wahkiakum County PUD
Whatcom County PUD
Benton Co. REA
Blachly Lane Electric Coop.
Central Electric Coop.
Clearwater Power Co.
Columbia Basin Electric Coop.
Columbia Power Coop.
Douglas Electric Coop.
East End Mutual
Fall River Electric Coop.
Farmers Electric Co.
Flathead Electric Coop.
Harney Electric Coop.
Hood River Electric Coop.
Idaho Co. L&P Coop.
Kootenai Electric Coop.
Lincoln Electric Coop. (Mont.)
Lincoln Electric Coop. (Wash.)
Lost River Electric Coop.
Lower Valley Electric Coop.
Midstate Electric Coop.
Missoula Electric Coop.
Nespelem Valley Electric Coop.
Northern Lights, Inc.
Okanogan Co. Electric Coop.
Orcas Power & Light Co.
Prairie Power Coop.
Raft River Electric Coop.
Ravalli Electric Coop.
Riverside Electric Co.
Rural Electric Co.
Salmon River Electric Coop.
South Side Electric Lines
Surprise Valley Electric Corp.
Tanner Electric
Unity Light & Power Co.
Wasco Electric Coop.
West Oregon Electric Coop.

Agreement

for

Coordination of Operations

among

Power Systems of the Pacific Northwest

Contract No. 14-03-4822/ Conformed Copy September, 1964

PACIFIC NORTHWEST COORDINATION AGREEMENT

THIS AGREEMENT, executed as of September 15, 1964, by and between the UNITED STATES OF AMERICA, acting by and through the BONNEVILLE POWER ADMINISTRATOR of the DEPARTMENT OF THE INTERIOR (hereinafter called "the Administrator") and the DIVISION ENGINEER, North Pacific Division, Corps of Engineers, Department of the Army (hereinafter called "the Division Engineer"); THE UNITED STATES ENTITY designated pursuant to Article XIV of the Treaty; the CITY of EUGENE, OREGON, a municipal corporation of the State of Oregon; the CITY OF SEATTLE, WASHINGTON, a municipal corporation of the State of Washington; the CITY OF TACOMA, WASHINGTON, a municipal corporation of the State of Washington; PUBLIC UTILITY DISTRICT No. 2 of GRANT COUNTY, WASHINGTON, a municipal corporation of the State of Washington; PUBLIC UTILITY DISTRICT No. 1 of CHELAN COUNTY, WASHINGTON, a municipal corporation of the State of Washington; PUBLIC UTILITY DISTRICT No. 1 of PEND OREILLE COUNTY, WASHINGTON, a municipal corporation of the State of Washington; PUBLIC UTILITY DISTRICT No. 1 of DOUGLAS COUNTY, WASHINGTON, a municipal corporation of the State of Washington; PUBLIC UTILITY DISTRICT No. 1 of COWLITZ COUNTY, WASHINGTON, a municipal corporation of the State of Washington; PUGET SOUND POWER & LIGHT COMPANY, a corporation; PORTLAND GENERAL ELECTRIC COMPANY, a corporation; PACIFIC POWER & LIGHT COMPANY, a corporation; THE WASHINGTON WATER POWER COMPANY, a corporation; THE MONTANA POWER COMPANY, a corporation; and COLOCKUM TRANSMISSION COMPANY, INC., a corporation.

WITNESSETH:

Whereas, the parties hereto operate major electric plants and systems which serve the Pacific Northwest area and have in the past voluntarily cooperated in the coordinated operation of their facilities through the Northwest Power Pool and through various contracts and arrangements, including particularly the Pacific Northwest Coordination Agreements for the years 1961-62, 1962-63 and 1963-73, between certain parties, and have thereby achieved substantial economies and additional firm power resources for the Pacific Northwest; and

Whereas, coordination for the production of power must take into consideration non-power uses for water resources and must be achieved as a part of the comprehensive development and management of water resources for maximum sustained benefit for the public good; and

Whereas, THE UNITED STATES OF AMERICA and CANADA have entered into the "Treaty between Canada and the United States of America Relating to the Cooperative Development of the Water Resources of the Columbia River Basin" ("the Treaty") which Treaty assumes coordination among the producers of power in the Pacific Northwest and the Canadian facilities subject to the Treaty; and

Whereas, the Administrator and the Division Engineer have been designated the United States Entity pursuant to Article XIV of the Treaty; and

Whereas, the Administrator, the United States Entity, Public Utility District No. 2 of Grant County, Washington, Public Utility District No. 1 of Chelan County, Washington, and Public Utility District No. 1 of Douglas County, Washington, have entered into Canadian Entitlement Allocation Agreements, specifying for a term of years the portion of the power benefits to which Canada is entitled under the Treaty which is allocable to the generating plants owned by said public utility districts and which said public utility districts agree to deliver to the Administrator, which portion is based upon coordination among the producers of power in the Pacific Northwest and the Canadian facilities subject to the Treaty; and

Whereas, Columbia Storage Power Exchange, a Washington non-profit, non-stock corporation, has entered into an agreement with British Columbia Hydro and Power Authority, as the Canadian Entity provided for in Article XIV of the Treaty, providing for the purchase from Canada, for a term of years, of Canada's right to receive power and energy under the Treaty by Columbia Storage Power Exchange; and

Whereas, the Administrator, Columbia Storage Power Exchange, and certain participants have entered into Canadian Entitlement Exchange Agreements, which provide for the transfer by Columbia Storage Power Exchange to the participants of the benefits purchased by Columbia Storage Power Exchange from British Columbia Hydro and Power Authority and the exchange with the Administrator of such benefits in return for specified amounts of capacity and energy; and

Whereas, Columbia Storage Power Exchange has issued and sold Bonds secured by obligations of the participants set forth in the Canadian Entitlement Exchange Agreements referred to above to pay for such benefits purchased by the participants from Columbia Storage Power Exchange and exchanged with the Administrator for designated amounts of capacity and energy; and

Whereas, the parties desire to substitute a long term coordination agreement for the coordination agreement presently in effect; and

Whereas, the Administrator is authorized to transmit and dispose of electric power and energy generated at various federal hydroelectric projects in the Pacific Northwest in accordance with

the Bonneville Project Act, approved August 20, 1937, as amended, the Reclamation Project Act of August 4, 1939, the Flood Control Act of December 22, 1944, and pursuant to the following orders of the Secretary of the Interior: No. 2563 dated May 2, 1950, and No. 2860 dated January 19, 1962, as amended; and

Whereas, the Administrator is authorized by said Order No. 2860, as amended, to enter into such contracts, agreements, and arrangements, upon such terms and conditions and in such manner as he may deem necessary, as provided in said Bonneville Project Act, as amended; and

Whereas, the Secretary of the Army and the Chief of Engineers have delegated necessary and appropriate authority thereunder to the Division Engineer;

Now, Therefore, in consideration of the premises and of the mutual benefits from covenants hereinafter set forth, the parties do hereby agree as follows:

PART I

Introductory Provisions

Section 1. *Term of Agreement.*

(a) *Term of Agreement.* This agreement shall become effective on January 4, 1965, and shall remain in effect until June 30, 2003, provided that Part III and Part IV hereof shall not be operative until July 1, 1965.

(b) *Survival of Rights and Obligations.* Upon the expiration or other termination of this agreement the rights and obligations, then accrued or incurred, for the delivery of power or energy or the payment of monies shall survive.

(c) *Termination of Existing Agreement.* The Pacific Northwest Coordination Agreement executed as of September 1, 1963, by and between certain of the parties hereto is hereby terminated effective July 1, 1965, subject to the provisions of subsection 1(b) thereof.

Section 2. *Definitions.* The following terms used in this agreement shall have the following respective meanings:

(a) "*Actual Adjusted Energy Load*" and "*Actual Adjusted Peak Load*" of a System shall mean the actual System energy load and actual System Peak Load, respectively, adjusted by including the amount of firm commitments to sell from the System's Firm Resources to other utilities and by excluding the amount of firm rights to purchase from Firm Resources of other parties hereto. Actual Adjusted Energy Load and Actual Adjusted Peak Load of the Coordinated System shall mean the sums of the Actual Adjusted Energy Loads and Actual Adjusted Peak Loads, respectively, of the individual Systems. Actual Adjusted Energy Load and Actual Adjusted Peak Load shall be referred to collectively as the "*Actual Adjusted Load*" of a System or of the Coordinated System.

(b) "*Actual Energy Capability*" shall mean the energy (by Periods) that could have been generated or obtained from a System's Firm Resources after adjustments for entitlements and obligations determined pursuant to subsection 9(b). The Actual Energy Capability of the Coordinated System shall mean the sum of the Actual Energy Capabilities of the individual Systems.

(c) "*Actual Peaking Capability*" shall mean the Peaking Capability of all the Firm Resources of a System, except those scheduled for Maintenance Outage pursuant to subsection 8(a) and subparagraph 6(c)(1)(C), after deduction of Forced Outage Reserve and after appropriate adjustments for current delivery or receipt of Interchange Capacity under subsection 9(c).

(d) "*Canadian Storage*" shall mean the storage provided by Canada under Article II of the Treaty.

(e) "*Contract Year*" shall mean July 1 through June 30.

(f) "*Coordinated System*" shall mean the generating plants, reservoirs, transmission systems and associated facilities owned or controlled, and operated by the parties hereto on a coordinated basis under this agreement and shall be deemed to include Canadian Storage to the extent such inclusion is not inconsistent with the Treaty.

(g) "*Critical Peaking Period*" shall mean the Period or Periods (not necessarily consecutive) during a Contract Year in which the relationship of the computed Peaking Capability of the Coordinated System to the Estimated Adjusted Peak Load of the Coordinated System limits the Firm Peak Load Carrying Capability of the Coordinated System.

(h) "*Critical Period*" shall mean that multi-month period, determined for the Coordinated System under adverse stream flows of historical record adjusted for changes in consumptive uses, during which the least amount of Estimated Firm Energy Load can be served from the Firm Resources of the parties hereto.

(i) *"Critical Period Energy Capability"* of the Coordinated System or of a System shall mean the average energy which can be produced under the coordinated operation during the Critical Period by Firm Resources, excluding energy reserve pursuant to subsection 8(c) and also excluding those Firm Resources scheduled for Maintenance Outage pursuant to subsection 8(a) and subparagraph 6(c)(1)(C), based on full use of stored water available under the coordinated operation and which can be shaped to the Estimated Adjusted Energy Load of the Coordinated System during the Critical Period by the machine capacity, pondage, reservoirs, transmission and associated facilities of the Coordinated System.

(j) *"Critical Rule Curve"* shall mean a guide to the use of storage water from each reservoir when reservoirs of the Coordinated System are required to operate below their Energy Content Curves. The Critical Rule Curve for each reservoir shall consist of a graphic or tabular representation of one or more reservoir elevations at the end of each Period determined as specified in subsection 6(h) from the planning of operation for the Coordinated System to supply the Firm Energy Load Carrying Capability of the Coordinated System in the event that there should be a recurrence of the Critical Period streamflows.

(k) *"Drawdown Period"* shall mean that portion of each Contract Year commencing after July 1 when storage water is drafted from reservoirs resulting in a sustained decrease in total Storage Energy in the Coordinated System or when the Energy Content Curves of reservoirs indicate a sustained decrease in the total Storage Energy in the Coordinated System, whichever is earlier, and ending after January 1 when storage water is first retained in reservoirs resulting in a sustained increase in total Storage Energy in the Coordinated System or when a sustained decrease in thermal energy generation occurs to avoid an increase in such Storage Energy, whichever is earlier.

(m) *"Energy Content Curve"* shall mean a guide to the use of storage water from each reservoir used to define certain operating rights, entitlements, obligations and limitations. The Energy Content Curve for each reservoir shall consist of a graphic, tabular or other representation of reservoir elevations at the end of each Period determined as specified in section 7.

(n) *"Estimated Adjusted Energy Load"* and *"Estimated Adjusted Peak Load"* of a System shall mean energy load and Peak Load amounts equal to the System's Firm Energy Load Carrying Capability and Firm Peak Load Carrying Capability, respectively. Initially, for the preliminary regulation, a System will furnish preliminary Estimated Adjusted Peak Loads and Estimated Adjusted Energy Loads which shall be those that a System reasonably expects could be supplied from its anticipated Firm Load Carrying Capability, and this initial Estimated Adjusted Load shall be changed as provided herein as planning progresses so that a System's Estimated Adjusted Load is identical to its Firm Load Carrying Capability as determined by the final regulation. Estimated Adjusted Energy Load and Estimated Adjusted Peak Load of the Coordinated System shall mean the sums of the Estimated Adjusted Energy Loads and Estimated Adjusted Peak Loads, respectively, of the individual Systems. The Estimated Adjusted Energy Load and the Estimated Adjusted Peak Load shall be referred to collectively as the *"Estimated Adjusted Load"* of a System or of the Coordinated System.

(o) *"Estimated Firm Energy Load"* and *"Estimated Firm Peak Load"* of a System shall mean that System's estimate of the firm energy load and the firm Peak Load, excluding firm contracts to supply energy or power to other parties hereto, which such System expects to be obligated to supply from its Firm Resources and firm contracts to receive energy or power from other parties hereto. When such loads include firm obligations to supply energy or power outside the area defined in subsection 2(ii) such inclusions shall be specified at the time data is submitted under subsection 6(a). The Estimated Firm Energy Load and Estimated Firm Peak Load of the Coordinated System shall mean the sums of the Estimated

Firm Energy Loads and Estimated Firm Peak Loads, respectively, of the individual Systems. Estimated Firm Energy Load and Estimated Firm Peak Load shall be referred to collectively as the "*Estimated Firm Load*" of a System or of the Coordinated System.

(p) "*Firm Energy Load Carrying Capability*" and "*Firm Peak Load Carrying Capability*" of the Coordinated System shall mean the firm energy load and firm Peak Load, respectively, that the Coordinated System is able to supply in any Period from the Firm Resources of the Coordinated System after deducting the required energy reserve and Forced Outage Reserve. Firm Energy Load Carrying Capability and Firm Peak Load Carrying Capability of a System shall mean the energy load and Peak Load, respectively, that a System is entitled to supply in any Period on a firm basis under this agreement. Firm Energy Load Carrying Capability and Firm Peak Load Carrying Capability shall be referred to collectively as the "*Firm Load Carrying Capability*" of the Coordinated System or of a System.

(q) "*Firm Resources*" shall mean the facilities and firm arrangements available to a party to supply firm energy and firm capacity as follows:

(1) Projects owned, leased or otherwise controlled by a party from time to time during the term of this agreement located within the area described in subsection 2(ii), except resources committed to others under the type of agreement described in paragraph (2) of this subsection.

(2) All resources under an agreement or agreements which provide that a party's System obtains from time to time during the term of this agreement from a specific Project located within the area described in subsection 2(ii), all or a portion of all the various and several benefits available from such Project.

(3) All or any part of dependable thermal and miscellaneous resources available to a party and included in the Coordinated System at the option of such party. Miscellaneous resources may include, but shall not be limited to, contracts for the purchase of firm power or energy from resources not a part of the Coordinated System and arrangements by a party for a supply of firm power or energy from its own resources not otherwise included in its System. Firm power and energy from a generating facility located outside the area described in subsection 2(ii) may be included in a party's Firm Resources, but neither the generating facility nor the variable output thereof may be included.

(r) "*Forced Outage*" shall mean an outage due to any failure of the turbine, generator, or any of their auxiliaries or pertinent structures extending from, and including, the water passages or the boiler to the generator leads which requires the unit to be taken out of service. An outage to be considered forced must satisfy one of the following conditions:

(1) It is necessary to immediately take the unit out of service.

(2) It is not necessary to immediately take the unit out of service, but the eventual outage cannot be delayed until a normally scheduled maintenance period or light load period which is of sufficient length to make the necessary repairs.

(s) "*Forced Outage Reserve*" shall mean generating capacity which may be used to replace the loss of generation due to a Forced Outage which would result in a loss of load.

(t) "*Holding Interchange Energy*" shall mean energy transferred under certain conditions between Systems in order to delay for coordination purposes the draft of a reservoir which a Reservoir Party would otherwise draft. Schedules of Holding Interchange Energy transfers shall be prepared pursuant to paragraph 6(d)(3). Such transfers are made pursuant to subsection 9(d).

(u) "*In Lieu Energy*" shall mean the energy that is delivered by a Reservoir Party to the owner of a downstream Project in an amount equivalent to the energy that could have been pro-

duced at the downstream Project if water above the Energy Content Curve had been released from the reservoir of the Reservoir Party as requested by the owner of the downstream Project.

(v) "*Interchange Capacity*" shall mean capacity transferred between Systems on request to supply all or a part of any deficiency between a System's Actual Peaking Capability and its Firm Peak Load Carrying Capability.

(w) "*Interchange Energy*" shall mean energy transferred between Systems either to supply all or a part of any deficiency between a System's Actual Energy Capability and its Firm Energy Load Carrying Capability or to return such energy to the supplying System. Interchange Energy, as used herein, shall not include Holding Interchange Energy as defined in subsection 2(t).

(x) "*Maintenance Outage*" shall mean any outage of a Firm Resource for the purpose of routine or special maintenance work, and which is not a Forced Outage. An outage need not have been scheduled prior to the Critical Period as provided in subsection 8(a) to be considered a Maintenance Outage.

(y) "*Peaking Capability*" shall mean the maximum ability of a Firm Resource or of all Firm Resources of a System, to carry a Peak Load.

(z) "*Peak Load*" shall mean the highest of the loads, each integrated over one clock-hour, in a stated period.

(aa) "*Period*" shall mean a calendar month, except that when the beginning or end of the Critical Period falls within a calendar month, such month or months shall be divided into two Periods, the portion within the Critical Period and the portion not within the Critical Period.

(bb) "*Project*" shall mean any hydroelectric generating facility or reservoir in a party's System used for power purposes.

(cc) "*Provisional Energy*" shall mean energy generated from water released as permitted in subsection 9(n) by drafting a reservoir below the elevation which it would otherwise be required to maintain under this agreement.

(dd) "*Refill-hold Period*" shall mean that period beginning at the end of the Drawdown Period and ending at the beginning of the next subsequent Drawdown Period.

(ee) "*Reservoir Party*" shall mean any party who, by virtue of ownership or of a contract of the nature described in paragraph 2(q)(2), is entitled to determine operations of reservoir storage. The United States of America shall be deemed a Reservoir Party with respect to Canadian Storage. The reservoir of a Reservoir Party shall refer to the appropriate relationship between such party and such reservoir.

(ff) "*Spinning Reserve*" shall mean the unloaded generating capacity of a System's Firm Resources ready at all times to take load upon demand, together with any firm arrangements with another System or Systems for obtaining such capacity, and less any such firm arrangements for the supply of such capacity to another System or Systems. Only that portion of such capacity or firm arrangements which is capable of serving load on a sustained basis within five (5) minutes of the time of demand may be considered Spinning Reserve. Capacity being used to supply loads to which service can be interrupted upon five (5) minutes notice may be considered Spinning Reserve.

(gg) "*Spinning Reserve Requirement*" shall mean the minimum Spinning Reserve which a System is required to maintain at all times under this agreement.

(hh) "*Storage Energy*" shall mean the energy equivalent of water stored in a reservoir above normal bottom elevation, related to such water by using the total of the at site and downstream Projects' average conversion factors during the Critical Period.

(ii) "*System*" shall mean those Firm Resources and transmission facilities of a party, which are adequately interconnected and interconnected with the Systems of other parties hereto to accomplish the objectives hereof, and which are located within the states of Washington, Oregon, Idaho and that part of Montana lying west of the continental divide and, in the case of Pacific Power & Light Company, its System shall also include Firm Resources and transmission facilities of Pacific located in California within the Klamath River Basin and so interconnected that such resources and facilities are coordinated with other facilities of Pacific in the Columbia River Basin without this agreement. The System of the United States of America shall be deemed to include Canadian Storage to the extent such inclusion is not inconsistent with the Treaty.

(jj) "*Treaty*" shall mean the "Treaty between the United States of America and Canada Relating to the Cooperative Development of the Water Resources of the Columbia River Basin" signed at Washington, D. C., January 17, 1961, as finally supplemented by the exchange of notes between the governments of the United States and Canada at the time of the exchange of ratifications thereof.

SECTION 3. *Exhibits.* Exhibits attached hereto numbered 1 through 7 are by this reference incorporated herein as fully as though set forth verbatim in the body of this agreement.

SECTION 4. *Agreement to Coordinate.* The parties agree to coordinate the operation of their respective Systems as provided herein so as to make available to each System its optimum Firm Load Carrying Capability, to provide optimum Firm Load Carrying Capability for the Coordinated System, and, consistent with these objectives, to produce the optimum amount of usable secondary energy for each System.

SECTION 5. *Coordination Contract Committee.* Each party shall appoint a representative and an alternate to act for it in matters pertaining to coordinated operation in accordance with the provisions of this agreement; provided, however, that the United States shall appoint such a representative and alternate from each of the following agencies: the Corps of Engineers, Bonneville Power Administrator and the Bureau of Reclamation. The provisions of this section shall not apply to the United States Entity. Each party shall evidence such appointment by written notice to the other parties and, by similar notice, any party may at any time change its representative or alternate. For convenience of reference, the representatives so appointed are collectively referred to as the Coordination Contract Committee, or the "committee". The committee is delegated no authority under this agreement. It is understood that neither the committee nor any member thereof shall make administrative interpretatations of this agreement.

(a) *Studies and Plans.* The committee shall make such studies and plans as may be required from time to time for the coordinated operation for the advice and information of the parties and it shall meet upon request by one or more representatives.

(b) *Rules of Procedure.* The committee shall adopt such rules of procedure as may be necessary for its proper functioning.

(c) *Expenses.* Each party shall be responsible for the individual expenses and compensation of its representatives. Twenty-five per cent of the general overhead and staff expenses of the committee shall be paid equally by all parties hereto. The remaining seventy-five per cent of such expenses shall be divided equally among and paid by each of the parties hereto which has, for the current Contract Year, a Firm Energy Load Carrying Capability in excess of one per cent of the Firm Energy Load Carrying Capability of the Coordinated System for the current Contract Year. The expenses of the committee shall be subject to approval by the committee, and shall consist primarily of engineering, secretarial and clerical services and expenses, space, furniture and equipment rentals, utility services, supplies and miscellaneous office expenses. The chairman will submit to the parties itemized statements monthly, in triplicate, showing the total of such expense for the preceding month, and the allocation of such expense among the parties.

PART II

PLANNING

SECTION 6. *Determination of Firm Load Carrying Capability.* The Firm Load Carrying Capability of the Coordinated System, and of each individual System, shall be determined annually in accordance with the following procedures. In connection with such determination, the parties shall exchange all data pertinent to such determination.

(a) *Load and Resource Data.* Not later than February 1 of each year, the parties will exchange the following data:

(1) Load data for the Periods, commencing on the following July 1, pertinent to all determinations to be made under this agreement, including Estimated Firm Load, estimated secondary energy load and Peak Load, and Estimated Adjusted Load for their own Systems. Estimated Firm Load is a basic requirement for planning. Each System will make these estimates to the best of its ability.

(2) Hydro plant and thermal plant data, including changes thereto, unless exchanged in a previous Contract Year, consisting of Project natural flows for the historical period of record beginning July 1928, reservoir capacity, conversion factors and peaking capacities throughout the operating range, operating restrictions, minimum flow limitations, limitations required for nonpower uses, fuel conversion rates and any other data necessary for the determination of Firm Load Carrying Capability.

(3) Information and data relating to firm contracts or arrangements and concerning amounts of energy and capacity which a party expects to receive from outside or deliver outside the Coordinated System for the period of time pertinent to these determinations.

(4) Schedules of Maintenance Outages as required by subsection 8(a).

(5) Schedules of new or additional resources not previously exchanged setting forth the first full month that generating units and associated facilities are scheduled to be available for operation. These schedules shall cover the period of time pertinent to these determinations and commencing on the following July 1. Any other pertinent data associated with new or additional resources shall also be exchanged.

(6) Schedules of retirement of facilities affecting generating capability listed in Exhibit 1, provided that any retirement of a Project at which there is seasonal storage shall have been preceded by at least four years' notice to all parties, unless said retirement was a result of failure due to uncontrollable forces as defined in section 21.

New or additional resources scheduled for service under paragraph 6(a)(5) or resources scheduled for retirement under paragraph 6(a)(6) will be added to or removed from a party's Firm Resources and used as scheduled in the determination of Firm Load Carrying Capability. Adjustments in Firm Load Carrying Capability will be made for delays or advances in such schedules as set forth in subsection 9(p). There shall be set forth on Exhibit 1 Projects, thermal plants and miscellaneous resources included in the Firm Resources of the parties hereto, together with various items of characteristic data for each of the resources listed. The committee shall prepare and issue to all parties a modified Exhibit 1 upon change of any such characteristic data or the addition or retirement of any such resources.

(b) *Preliminary Coordinated System Regulation.* Not later than March 15, a preliminary Coordinated System regulation will be made to determine a preliminary maximum Critical Period Energy Capability for the Coordinated System, as follows:

(1) Except as set forth in subsection 8(a) and 8(c), such regulation shall be based on the utilization of all Firm Resources. Except as set forth in subparagraphs (A), (B) and (C) below, such regulation shall assume each reservoir to be at its normal top eleva-

tion at the beginning of the Critical Period, and shall draft each reservoir to its normal bottom elevation by the end of the Critical Period. The Period by Period release of Canadian Storage in such regulation shall be that set forth in the operating plan (including any revision thereof) agreed upon by the United States Entity and the Canadian Entity pursuant to the Treaty.

(A) When draft of a reservoir to its normal bottom elevation would result in a net loss of Critical Period Energy Capability to the Coordinated System, then draft of such reservoir shall be limited to the extent necessary to eliminate such loss.

(B) When non-power uses of a reservoir limit the full release of all storage water in the Critical Period, such regulation shall be based on the maximum use of storage water under such limitation.

(C) When a new reservoir is to be included in such regulation, the elevation at which such reservoir is expected to be on the following July 31 shall be estimated by the Reservoir Party for the July 31 preceding the Critical Period in such regulation. For the purposes of this subparagraph and paragraph 9(p)(2) a new reservoir shall be any reservoir which has not, since its inclusion as a Firm Resource under this agreement, attained the Energy Content Curve determined for it.

The output of all Projects, at site and downstream, shall not exceed an 85 per cent plant factor in any Period, unless a higher plant factor is necessary to make all storage water usable during the Critical Period. In multiple-year Critical Periods no reservoir shall be drafted by any April 1 below the elevations determined for it in paragraph 7(b)(2) unless all reservoirs have been drafted to such elevations and additional draft is required to meet the Estimated Adjusted Energy Load of the Coordinated System. If storage draft of each reservoir to the elevation determined for such reservoir pursuant to paragraph 7(b)(2) is not so required by any April 1, the amount of Storage Energy to be retained in reservoirs on April 1 above such elevation shall be allocated among the reservoirs for which such elevation is above normal bottom elevation in proportion to the Storage Energy represented by the draft to such elevations for such reservoirs. The preliminary Coordinated System regulation will be made to distribute energy capability during the Critical Period in the same pattern by Periods as the sum of the Estimated Adjusted Energy Loads submitted in paragraph 6(a)(1). Unless otherwise agreed and within the capability of hydro facilities to shape hydro energy capability, any energy surplus or deficiency between the Critical Period Energy Capability and the Coordinated System's Estimated Adjusted Energy Load will be shaped in a uniform amount during the Critical Period.

(2) A preliminary Critical Period Energy Capability for each System will be determined from the preliminary regulation by adjusting for restoration in accordance with subsection 6(f). Such preliminary Critical Period Energy Capability and the preliminary regulation will be made available to all parties by March 15.

(c) *Modified Coordinated System Regulation.*

(1) Prior to April 1, each party shall make necessary or desired changes and designations in accordance with and subject to subparagraphs (A) through (D) below:

(A) The amount of thermal energy and capacity to be included in a System's Firm Resources may be reduced to the extent such amount is surplus to that System's load requirements. In the Critical Period, such changes in thermal energy capability, unless required to support thermal peaking capacity, must either be reductions by the same amount in each Period or in such amounts in each Period that the remaining energy capability has the same shape as the System's Estimated Adjusted Energy Load.

(B) Adjustments or revisions may be made pursuant to existing or new firm contracts between a party hereto and others outside the Coordinated System.

(C) Adjustments or revisions may be made in the schedule of Maintenance Outages or in reductions of peak and energy capability resulting from such Maintenance Outages.

(D) Each party may revise its Estimated Adjusted Energy Load and Estimated Adjusted Peak Load for any reason, including changes in contracts between parties, and each party must revise its Estimated Adjusted Energy Load so that the average during the Periods in the Critical Period is equal to its expected Critical Period Energy Capability adjusted for restoration in accordance with subsection 6(f) and must revise its Estimated Adjusted Peak Load so that it does not exceed in any Period its anticipated Firm Peak Load Carrying Capability expected from the modified regulation in such Periods.

(2) Following April 1, a modified Coordinated System regulation will be made to determine a modified maximum Critical Period Energy Capability for the Coordinated System. Such modified regulation will utilize Firm Resources, as they were used in the preliminary regulation made in subsection 6(b), as modified in subparagraphs 6(c)(1)(A), (B) and (C). In the modified regulation the following objectives will be observed, within the capability of the resources of the Coordinated System to shape hydro energy capability and in the order of priority listed below:

(A) Shape the Critical Period Energy Capability of the Coordinated System to its Estimated Adjusted Energy Load.

(B) Limit the quantity of nonusable energy to no more than that which occurred in the preliminary regulation pursuant to subsection 6(b).

(C) Limit the draft of each reservoir by each April 1 in a multi-year Critical Period to that elevation determined for each reservoir pursuant to paragraph 7(b)(2) unless all reservoirs have been drafted to such elevations and additional draft of storage water is required to meet Coordinated System Estimated Adjusted Energy Load. If storage draft of each reservoir to the elevation determined for such reservoir pursuant to paragraph 7(b)(2) is not so required by any April 1, the amount of Storage Energy to be retained in reservoirs on April 1 above such elevation shall be allocated among the reservoirs for which such elevation is above normal bottom elevations in proportion to the Storage Energy represented by the draft to such elevations for such reservoirs.

(D) Limit the output of all Projects, at-site and downstream, in each Period to an 85 per cent plant factor, unless a higher plant factor is necessary to make all storage water usable during the Critical Period.

(E) Produce from each System's Firm Resources, in the portion of each Contract Year included in the Critical Period, average energy capability, after adjustments for energy reserve and restoration, equal to that System's Estimated Adjusted Energy Load.

(F) Minimize the loss in the Critical Period Energy Capability of the Coordinated System due to reduced head resulting from draft of storage water.

(3) Estimated Adjusted Energy Loads will be adjusted for nonusable energy during the Critical Period based on the modified regulation made pursuant to paragraph 6(c)(2) as follows: when the energy capability of the Coordinated System less energy reserve as provided in subsection 8(c) in any Period during the Critical Period exceeds the Estimated Adjusted Energy Load of the Coordinated System for such Period, the Estimated Adjusted Energy Load of the Coordinated System shall be increased for such Period

by the amount of such excess and the Estimated Adjusted Energy Load of the System or Systems which have energy capability, adjusted for restoration and energy reserve, in excess of its Estimated Adjusted Energy Load shall be similarly increased. If more than one System has such an excess, increases shall be made prorata among all Systems having excesses based on the amounts of such excesses. Any such increase in the Estimated Adjusted Energy Load of a System shall be offset by a compensating reduction in a later Period or Periods of the Critical Period.

(4) A Firm Load Carrying Capability for each System will be determined from the modified regulation made pursuant to paragraph 6 (c) (2) in accordance with (A) and (B) following:

(A) The Firm Energy Load Carrying Capability of each System for each Period shall be the product of that System's modified Critical Period Energy Capability, determined pursuant to paragraph 6(c)(2) after adjustment for restoration in accordance with subsection 6(f), and the ratio of that System's Estimated Adjusted Energy Load for that Period, adjusted for nonusable energy as provided in paragraph 6(c)(3), to its average Estimated Adjusted Energy Load during the Critical Period.

(B) The Firm Peak Load Carrying Capability of the Coordinated System in each Period of the Critical Peaking Period shall be the sum of the computed Peaking Capabilities of the individual Systems. The computed Peaking Capability of a System in each Period shall be based on values of Peaking Capability from the modified regulation and derived in the following manner:

(i) for the Period during which the highest of the Estimated Adjusted Peak Loads of the Coordinated System for the Contract Year occurs and for the two adjacent Periods thereto, and for the Period during which the lowest of the Estimated Adjusted Peak Loads of the Coordinated System occurs and for the two adjacent Periods thereto, the computed Peaking Capability shall be the average of the Peaking Capabilities computed for the beginning and the end of each such Period in the modified regulation, with consideration of Maintenance Outages as scheduled under subsection 8(a), and after deduction of Forced Outage Reserves.

(ii) for any Period not described in subdivision (i) preceding and for which the magnitude of the Estimated Adjusted Peak Load is between the magnitudes of the Estimated Adjusted Peak Loads of the preceding and subsequent Periods, the computed Peaking Capability shall be either the Peaking Capability computed in the modified regulation for the beginning of such Period, if the Estimated Adjusted Peak Load of the preceding Period is greater than that of such Period, or the Peaking Capability computed for the end of such Period, if the Estimated Adjusted Peak Load of the subsequent Period is greater than that of such Period, with consideration of Maintenance Outages as scheduled under subsection 8(a), and after deduction of Forced Outage Reserves.

(iii) for any other Period the computed Peaking Capability shall be the average of the Peaking Capabilities computed for the beginning and the end of such Period in the modified regulation, with consideration of Maintenance Outages as scheduled under subsection 8(a), and after deduction of Forced Outage Reserves.

The average Firm Peak Load Carrying Capability of each System for the Critical Peaking Period shall be the summation of the computed Peaking Capability of the System for the Periods of the Critical Peaking Period divided by the number of Periods in the Critical Peaking Period. In each Period of any Contract Year

the Firm Peak Load Carrying Capability of a System shall be equal to the Estimated Adjusted Peak Load of such System in such Period plus or minus the amount by which the average Firm Peak Load Carrying Capability of such System during the Critical Peaking Period is larger or smaller than the average of the Estimated Adjusted Peak Loads for such System for the Periods of the Critical Peaking Period; provided, however, that the Firm Peak Load Carrying Capability of a System in any Period not included in the Critical Peaking Period may not exceed the maximum computed Peaking Capability for that System in any Period of such Contract Year.

If it is determined that any Period is included in the Critical Peaking Period because of Maintenance Outages scheduled under subsection 8(a) and that such Period would not have been included in the Critical Peaking Period in the absence of such Maintenance Outages, and if it is possible to schedule such Maintenance Outages in any Period not currently included in the Critical Peaking Period without such Period then becoming part of the Critical Peaking Period, the owner of such facilities shall make every reasonable effort to reschedule in accordance with subsection 8(a) such Maintenance Outages in Periods not included in the Critical Peaking Period. If such Maintenance Outages are so rescheduled, the Critical Peaking Period and Firm Peak Load Carrying Capibility of all Systems shall be recomputed.

Any System which has Firm Peak Load Carrying Capability, as determined in this subparagraph 6(c)(4)(B), which is either less than its Estimated Adjusted Peak Load as revised pursuant to subparagraph 6(c)(1)(D) in any Period of the Critical Peaking Period, or greater than its computed Peaking Capability as determined in this subparagraph 6(c)(4)(B) in any other Period, shall be considered a peak deficient System for the purposes of subsection 6(d).

(d) *Changes in the Modified Regulation.* Not later than May 15, each Reservoir Party may, in order to obtain an optimum regulation for its System and within the limits of this subsection 6(d), make changes in the regulation of its reservoirs, determined in the modified regulation made pursuant to paragraph 6(c)(2). Such changes shall be made a Period at a time progressing from the start of the Critical Period to the end of the Contract Year in which the Critical Period ends.

(1) Adjustments in the regulation of reservoirs allowed in this paragraph 6(d)(1) shall be limited as follows:

(A) No adjustment shall be permitted which causes increased total spill of water in the Coordinated System during the Critical Period, or which results in uncontrollable Coordinated System energy capability less all energy reserves in excess of the Estimated Adjusted Energy Load of the Coordinated System in any Period during the Critical Period or which makes it impossible to draft all usable storage water to normal bottom elevations during the Critical Period;

(B) No adjustment shall be permitted which would cause any reservoir elevation as of April 1 of each year of the Critical Period to differ from that elevation determined in the modified regulation pursuant to subparagraph 6(c)(2)(C); and

(C) No adjustment shall be made by a System, which will increase the indicated import or export of energy of the System in any Period except as provided in paragraph 6(d)(3). No adjustment shall be made by a System which will reduce an indicated requirement to import or export energy in any Period in excess of the adjustment necessary to eliminate that requirement and a System may not reduce

an indicated export by reducing the storage draft from a reservoir designated as receiving Holding Interchange Energy which will be required to be scheduled from such reservoir as return of Holding Interchange Energy under paragraph 6(d)(3). An indicated import or export of energy by a System in any Period shall, for purposes of this subsection 6(d), mean the amount by which such System's Firm Energy Load Carrying Capability determined pursuant to subparagraph 6(c)(4)(A) is greater or less than the energy capability of its Firm Resources determined pursuant to paragraph 6(c)(2) for that Period adjusted for restoration determined pursuant to subsection 6(f), and energy reserve determined pursuant to subsection 8(c).

To the extent necessary to make the Coordinated System energy capability, less all energy reserves, equal to the Estimated Adjusted Energy Load of the Coordinated System in every Period, Reservoir Parties having reservoirs for which the regulation can be further adjusted within the limitations of this paragraph 6(d)(1) shall adjust the regulation of such reservoirs within such limits. When such adjustment can be made by more than one Reservoir Party, the adjustments shall be prorated among such parties in proportion to the indicated imports or exports of energy by the Systems of such parties. Any adjustment in the regulation of a reservoir made pursuant to this paragraph 6(d)(1) in any Period shall be offset by a compensating adjustment or adjustments for such reservoir in a later Period or Periods before the following April 1 or before the end of the Critical Period if such Critical Period ends in the Contract Year for which such adjustments apply.

Unless otherwise agreed, adjustments shall be allowed in the following order of priority: first, by peak deficient Systems, as described in subparagraph 6(c)(4)(B), to reduce their indicated exports of energy during the Period under consideration and to reduce toward zero their cumulative indicated exports of energy from the start of the Critical Period through the Period or Periods of their peaking deficiency; second, by any System to reduce its indicated import of energy during the Period under consideration; and third, by any System to reduce its indicated export of energy during the Period under consideration. When adjustments in the regulation of reservoirs are desired in any Period by more than one Reservoir Party, and the adjustments that can be made are limited by the provisions of this paragraph 6(d)(1), adjustments shall be made in the order of priority set forth above and any balance shall be prorated among the desired adjustments requested under the lowest priority affected. Such proration shall be made in proportion to the change in the indicated amounts of energy which would have been produced by the desired adjustment in reservoir regulation indicated under such priority.

(2) Following the adjustments in paragraph 6(d)(1), each Reservoir Party may reregulate its reservoirs, subject to the conditions imposed in this paragraph 6(d)(2), (a) to increase its Peaking Capability, if its System is a peak deficient System as described in subparagraph 6(c)(4)(B), or (b) to increase its average annual energy capability. If the reregulation results in less than total draft during the Critical Period, the Reservoir Party shall have given to all parties at least three (3) years' notice of the intended reregulation, provided that in no event shall such reregulation affect the planning or operation of the Coordinated System for the Critical Period computed in a prior Contract Year. Such notice shall identify the reservoir or reservoirs to be reregulated, specify the maximum draft from such reservoirs as so reregulated, and stipulate the purpose of such reregulation as to either (a) or (b) above. Except as otherwise provided in this paragraph 6(d)(2), the total draft of the reservoirs shall be reduced in accordance with such notice and may not be increased thereafter, during the term of this agreement, without the consent of all parties. Such reregulation shall not in any Period exceed the adjustment necessary to reduce to zero the cumulative indicated export of energy.

Section 6(d)(2)

(A) If the reregulation is for the purpose of increasing Peaking Capability designated under (a) above:

Any downstream party losing Critical Period Energy Capability as a result of a Reservoir Party either reducing reservoir draft in a Critical Period, or making such downstream party's Critical Period Energy Capability partially unusable, may elect to compute its Critical Period Energy Capability based on reservoir draft without such reregulation, provided that such downstream party shall supply to the Reservoir Party the downstream party's pro rata share of the Peaking Capability that the Reservoir Party would lose during the Periods in which the Reservoir Party is a peak deficient System without such reregulation. Such proration among parties downstream from the reregulated reservoir shall be in proportion to the conversion factors of their respective Projects during the Periods involved. Any downstream party not so electing shall compute its Critical Period Energy Capability based upon the reregulation desired by the Reservoir Party.

In computing section 13 payments by all downstream Project owners or operators for a reservoir reregulated pursuant to this subparagraph 6(d)(2)(A), the Critical Period energy components of the formula shall be based on the rule curve desired by the Reservoir Party whether or not any downstream party has elected to supply Peaking Capability.

(B) If the reregulation is for the purpose of increasing average annual energy capability designated under (b) above: Any downstream party losing Critical Period Energy Capability as a result of the reregulation may accept or reject such reregulation. The Critical Period Energy Capability and payments under section 13 shall be based on the reregulation for each downstream party accepting the reregulation, or on the reservoir draft without such reregulation for each downstream party rejecting the reregulation.

(C) Elections made by downstream parties pursuant to this paragraph 6(d)(2) shall be made concurrently with other adjustments in regulation of reservoirs allowed in this subsection 6(d), and, in the case of reregulation affecting a downstream Project which provides Firm Resources to more than one party the election shall be made by the owner of such downstream Project in accordance with arrangements between such owner and such parties.

(3) In the event that the limitations of paragraph 6(d)(1) prevent any Reservoir Party from making desired adjustments in regulation of its reservoirs to reduce or eliminate the indicated import of energy to its System in the first two Periods of the Critical Period, then such Reservoir Party may designate a part or all of the remaining required import to its System in said Periods as Holding Interchange Energy. Each exporting System may in turn decide that all or part of its indicated exports of energy in said Periods will be made available as Holding Interchange Energy.

A schedule of Holding Interchange Energy transfers between Systems will be prepared, showing the amounts of delivery in said Periods, the amounts of return, the Periods in which such return shall occur and the reservoirs designated by the importing System as involved in the transfers. Transfers of Holding Interchange Energy will first be scheduled to the extent that the two parties involved in such transaction agree. Otherwise, in the first Periods after the second Period of the Critical Period that the importing System has an indicated export, it shall schedule the return of Holding Interchange Energy in the amount available for return from the reservoir or reservoirs designated by the importing System as hereinabove provided, but not in excess of the System's indicated export. Such return shall be scheduled prior to making adjustments to reduce draft from

such reservoir or reservoirs. The importing System may further reregulate its reservoirs, and shall at the option of the exporting System reregulate the designated reservoir or reservoirs, within the limits of paragraph 6(d)(1) to increase the scheduled return to the extent that the exporting System can store or otherwise utilize such scheduled return on its own System. Schedules shall in any case provide for return of all Holding Interchange Energy before the end of the month of March following delivery. At the option of each exporting System, its remaining energy exports, if any, made available as Holding Interchange Energy will be scheduled to the unsatisfied energy imports designated as Holding Interchange Energy by the importing Systems by prorating these quantities.

If any exporting System decides that all or part of its indicated exports of energy in a Period will not be made available as Holding Interchange Energy, the Estimated Adjusted Energy Load of such System shall be increased by the same amount in such Period and decreased in a later Period or Periods designated by the exporting System, after the first two Periods of the Critical Period and before the end of the following March. Reservoirs of the importing Systems designating Holding Interchange Energy shall be reregulated to produce on the importing System the energy designated by it but not made available to it as Holding Interchange Energy, or to produce the energy so designated which cannot be delivered by the exporting System or Systems through use of facilities of the Coordinated System at such rate as to be usable, as determined by the importing System, in its Estimated Adjusted Energy Load.

(4) Following the changes in the regulation of reservoirs permitted in this subsection 6(d) the Estimated Adjusted Energy Load and Estimated Adjusted Peak Load of each System shall be finally increased or decreased by the increases or decreases in resources of such System due to changes in hydro plant heads.

(e) *Final Coordinated System Regulation.* Not later than July 1, a final Coordinated System regulation will be made incorporating all changes made in subsection 6(d). The resulting final Critical Period Energy Capability, after restoration adjustments for each System as set forth in subsection 6(f), will be used to determine each System's Firm Load Carrying Capability using the procedures set forth in paragraph 6(c)(4), provided that computed Peaking Capability of a party reregulating its reservoirs pursuant to paragraph 6(d)(2) shall be increased by the amount of Peaking Capability other parties have agreed to supply under said paragraph, and the computed Peaking Capability of each of such supplying parties shall be reduced by the amount of its share of the total Peaking Capability to be supplied. The Firm Load Carrying Capability so determined and the reservoir drafts from the final regulation will be utilized pursuant to subsections 6(i) and 6(h), respectively.

(f) *Determination of Restoration.* Each Project (Project in this subsection 6(f) shall mean a Project or group of Projects listed in Exhibits 2 or 3, or a portion of a Project described in paragraph 2(q)(2) and so listed) shall be entitled to carry at least the same firm energy load with development of Canadian Storage as without such development. Whenever such a Project's ability to carry firm energy load is reduced as a result of the addition of Canadian Storage, the owner of such Project shall be entitled to be restored by all owners of Projects having increases in ability to carry firm energy load with the addition of Canadian Storage. After the preliminary Coordinated System regulation under subsection 6(b) is completed, a Coordinated System regulation will be made similar to the preliminary regulation in all respects except that the Canadian Storage will be excluded and Estimated Firm Energy Load of the Coordinated System will be used. When the Critical Period duration is less than one year, such load shall include only firm load within the area defined in subsection 2(ii). In such regulation, the Estimated Firm Energy Load of the Coordinated System shall be increased or reduced in each month by the same percentage so that such loads as adjusted

and Critical Period Energy Capability of the Coordinated System without Canadian Storage are in balance. In the event the resulting Critical Period without Canadian Storage includes less than seven months in any Contract Year, a new regulation without Canadian Storage shall be made for the purposes of this section using a seven month Critical Period of September through March for such Contract Year.

(1) The amount of gain or loss for each Project shall be determined by the following formula:

$$Q = P_w - \frac{S_w}{S_{w/o}} P_{w/o}$$

in which,

Q = Project gain or loss. Gain is indicated by a positive value and loss by a negative value; provided, however, that for a negative amount greater in absolute value than that given in Exhibit 3 for the particular Project, the amount shown in Exhibit 3 shall be used instead.

P_w = Critical Period Energy Capability of each Project from the preliminary Coordinated System regulation made pursuant to subsection 6(b) with Canadian Storage after adjustment for tailwater encroachment.

$P_{w/o}$ = Critical Period Energy Capability of each Project from the regulation made under this subsection 6(f) without Canadian Storage after adjustment for tailwater encroachment.

S_w = Average Estimated Firm Energy Load of the System including the Project in its Firm Resources for those Periods included in the Critical Period with Canadian Storage.

$S_{w/o}$ = Average Estimated Firm Energy Load of the System including the Project in its Firm Resources for those Periods included in the Critical Period without Canadian Storage and all repetitions of such Periods that are included within the Critical Period with Canadian Storage.

(2) The amount of restoration to be supplied by each gaining Project shall be the amount determined for such Project under paragraph 6(f)(1) multiplied by the ratio of the absolute value of the sum of all losses determined under paragraph 6(f)(1) to the sum of all gains determined under paragraph 6(f)(1).

(3) The net amount of restoration to be supplied by or to each System shall be the algebraic sum of the losses computed under paragraph 6(f)(1) and amounts of restoration computed under paragraph 6(f)(2) for all of that System's Projects. Such net amount of restoration shall be used as a uniform monthly addition to or reduction of the energy capability of each System during the Critical Period in computations made pursuant to this section 6.

(4) Any Project existing or under construction on January 17, 1961 that, subsequent to the effective date of this agreement, is included as a Firm Resource of the System of any party shall be included in Exhibit 2 for restoration purposes pursuant to this agreement.

(g) *General Limitations on Estimated Adjusted Loads.* Nothwithstanding any other provision of this agreement, the average Estimated Adjusted Energy Load for any System during the Critical Period shall not be greater than that System's Critical Period Energy Capability, adjusted for restoration pursuant to subsection 6(f). To the extent possible consistent with such limitation, the Estimated Adjusted Energy Load and the Estimated Adjusted Peak Load in any Period during the Critical Period, shall not be less, except by the amount of the

capability of that System's planned new resources not included as Firm Resources, than the energy or the Peak Load which the System reasonably estimates it will be required by existing commitments or utility responsibilty to serve from its Firm Load Carrying Capability.

(h) *Determination of Critical Rule Curves and Entitlement Curves.* Not later than July 1, the reservoir drafts determined pursuant to subsection 6(e) will be utilized to determine Critical Rule Curves as follows: the reservoir drafts indicated for the Contract Year beginning on the current July 1 from all final Coordinated System regulations made pursuant to subsection 6(e) which included any part of said Contract Year in the Critical Period shall be the Critical Rule Curves for said Contract Year. Such Critical Rule Curves shall be ranked and known as the first, second, third, et cetera, Critical Rule Curves on the basis of most to least total Coordinated System Storage Energy indicated by such Critical Rule Curves at the beginning of said Contract Year. Critical Rule Curves shall be tabulated for each reservoir in feet of elevation at the end of each Period of said Contract Year.

Reservoirs which have been reregulated pursuant to paragraph 6(d)(2) shall have two entitlement curves for each Critical Rule Curve. One of the entitlement curves is the reservoir draft desired by the Reservoir Party as described in paragraph 6(d)(2), and the other is the reservoir draft established by the modified regulation in which all storage was fully drafted during the Critical Period. Such entitlement curves will be utilized pursuant to subsection 7(d) and paragraph 9(k)(3).

(i) *Establishment of Firm Load Carrying Capability.* Not later than July 1, the Firm Load Carrying Capability of each System for the current Contract Year will be established as that most recently determined pursuant to subsection 6(e). If however, the Storage Energy in reservoirs of the Coordinated System fails, during the month of July, to reach 98 per cent of the total Storage Energy, such Firm Load Carrying Capability of each System will be re-established retroactively using the following procedure:

(1) The total Storage Energy in reservoirs of the Coordinated System on the July 31 corresponding to the current year will be computed for the most recent final Coordinated System regulation and for every other final Coordinated System regulation which included the current July 31 in the Critical Period.

(2) The one or more amounts of total Storage Energy computed in paragraph (1) of this subsection will be compared with the actual Storage Energy in the reservoirs of the Coordinated System as of the current July 31. The Firm Load Carrying Capability of each System computed for the current Contract Year from the final Coordinated System regulation for which the computed Storage Energy is nearest said actual Storage Energy will be established as the Firm Load Carrying Capability of each System in the current Contract Year. When said actual Storage Energy is less than the lowest computed Storage Energy from applicable final Coordinated System regulations, the Firm Load Carrying Capability of each System computed for the current Contract Year from the final Coordinated System regulation with the lowest computed Storage Energy will be established as the Firm Load Carrying Capability of each System in the current Contract Year.

(3) Adjustments will be made in accordance with paragraph 9(b)(3) as necessary to conform with the Firm Load Carrying Capability of each System thus re-established.

(j) *Adjustments in Planned Firm Load Carrying Capability.* Not later than August 15, if the Firm Load Carrying Capabilities for Systems are re-established pursuant to subsection 6(i), the following adjustments in Firm Resources will be permitted. Firm Resources which a party plans to retire during the current Contract Year may be removed from the Coordinated System, Firm Resources not previously available to a party may be added to the Coordinated System and changes in a party's firm purchases from outside the Coordinated

System may be made, and a change shall be made in that party's Firm Load Carrying Capability in each Period of the Contract Year equal to the capability of that resource or change in purchase in each such Period.

SECTION 7. *Determination of Energy Content Curves.* Energy Content Curves shall, within the limits of this section, provide sufficient storage at all times so that the Coordinated System will be able to generate its Firm Energy Load Carrying Capability under a recurrence of any historical streamflow sequence. Energy Content Curves will be expressed as elevations in feet at the end of each Period for the 13 month period starting July 1. Energy Content Curves for each reservoir will be determined annually in accordance with the following procedures:

(a) *Critical Period One Year or Less.* When the Critical Period duration is one year or less the Energy Content Curve for each reservoir will be determined from the final Coordinated System regulation made in subsection 6(e) and from additional data, in accordance with the following procedures, subject to recalculation as provided in subsection 7(c).

(1) The amount of natural flow available for refill and other requirements at each reservoir shall be, unless otherwise agreed, the second lowest volume inflow from natural flow which occurred in the historical period of record beginning July 1928 during that portion of the year in which the Energy Content Curve would indicate that the reservoir would be filling. The available natural flow in each Period of such year will be reduced by deducting minimum discharge requirements, non-power requirements for water at site and upstream and water required for refill at upstream reservoirs.

(2) The Energy Content Curve for each reservoir that would have sufficient flow as determined in paragraph (1) of this subsection to permit refilling to normal top elevation during that portion of the year between the end of the Critical Period and the following July 31 will correspond to the Critical Rule Curve of such reservoir from July 31 through the last Period included in the Critical Period. The refill portion of the Energy Content Curve will be based on the distribution of water among Periods determined in paragraph (1) of this subsection.

(3) The excess of the Firm Energy Load Carrying Capability of the Coordinated System over Estimated Firm Energy Load of the Cordinated System for those Periods that would fall in the Critical Period beginning in the year following the Contract Year will be determined.

(4) Seventy-five percent of the excess determined in paragraph (3) of this subsection will be prorated among all reservoirs that would not have sufficient flow as determined in paragraph (1) of this subsection to permit refilling from normal bottom to normal top elevation during that portion of the year between the end of the Critical Period and the following July 31. Such proration shall be made on the basis of the Storage Energy not refilled with such flow.

(5) The Energy Content Curve for each reservoir to which paragraph (2) of this subsection does not apply will correspond to the Critical Rule Curve from July 31 until that point in time is reached when the amount of storage water draft as represented by the Critical Rule Curve corresponds to an amount of water which is the summation of the water in those months from such point in time through the following July, as determined in paragraph (1) of this subsection, and the water equivalent to the Storage Energy prorated to the reservoir under paragraph (4) of this subsection. From such point in time, the Energy Content Curve will be calculated to fill the reservoir to normal top elevation by the end of the following July. The water required to refill the reservoir shall be distributed among Periods in the same proportion as available water determined in paragraph (1) of this subsection occurred in such Periods.

(b) *Critical Period Longer Than One Year.* When the Critical Period duration is longer than one year, the Energy Content Curve for each reservoir at the end of each Period shall be the higher of the reservoir elevations determined under paragraphs (1) and (2) below, subject to recalculation as provided in subsection 7(c).

(1) The elevations corresponding to the reservoir drawdowns calculated in the final Coordinated System regulation made in subsection 6(e) for the first year of the Critical Period which begins during the year beginning on the current July 1.

(2) The elevations necessary to refill the reservoir by the following July 31 based on conservative estimates of the amount of inflow available. The amount of natural flow available for refill and other requirements from the beginning of the Period to the July 31 following such Period at each reservoir shall be, unless otherwise agreed, the second lowest volume inflow from natural flow which has occurred in any comparable period in the historical period of record beginning July 1928. Such available natural flow will be reduced by deducting minimum discharge requirements, non-power requirements for water at site and upstream and water required for refill at upstream reservoirs.

(c) *Variable Energy Content Curves.* For each reservoir which does not have all storage drafted to normal bottom elevation by its Energy Content Curve as determined in subsection 7(a) or 7(b), variable Energy Content Curves will be determined for the period January through July in accordance with the following procedures:

(1) Not later than August 1 of each year, each Reservoir Party shall supply to all other parties the basic method used for forecasting volume inflow into each of its reservoirs to which this subsection applies. The basic forecast methods shall include methods for determining the probable volume inflow to each such reservoir and the volume inflow for an agreed upon probability of occurrence for the periods from the first of each month, January through July, through July 31. The forecasts to be used in this subsection and in paragraph 9(o)(1) shall be, unless otherwise agreed, such that the actual volume inflow will equal or exceed the forecast with 95 per cent probability.

(2) Not later than August 1 of each year, each Reservoir Party shall supply to all other parties variable Energy Content Curves for each of its reservoirs to which this subsection applies. Such Energy Content Curves shall be in the form of either a table, equation, family of curves, or other form from which end-of-Period reservoir contents or feet of elevation for the period January through July can be determined from forecasts of volume inflow. The variable Energy Content Curves shall provide for drafts below the Energy Content Curve determined in subsection 7(a) or 7(b) by the amount the forecasted volume inflow is in excess of total requirements for refill of the reservoir, minimum discharge requirements, non-power requirements for water at site and upstream and water required to refill at upstream reservoirs. The variable Energy Content Curves shall be such that all reservoirs return to normal top elevations by the end of the following July.

(3) Not later than September 1 of each year, a Coordinated System regulation shall be made using stream flows of an agreed upon historical period starting from July 1928 or such other date as may be agreed upon. The historical flow period will be updated at least once each ten years. In these regulations, the Coordinated System's assumed reservoir elevations on August 1 of each of the historical years shall be the actual reservoir elevations as of August 1 of the current Contract Year. Each reservoir shall be regulated on the Energy Content Curve determined in subsection 7(a) or 7(b) or the variable Energy Content Curve submitted pursuant to paragraph 7(c)(2), whichever is lower, except that the reservoirs shall be regulated below Energy Content Curves as provided in subsection 9(h) if necessary to produce the Firm Energy Load Carrying Capability of the Coordinated System. In determining variable Energy Content Curves after Jan-

uary 1, the forecasted volume inflow for each reservoir for the applicable month shall be the actual historical flow data reduced by the forecasting error with the agreed upon probability referred to in paragraph 7(c)(1).

(4) The regulations made pursuant to paragraph 7(c)(3) shall be analyzed to determine the number of years that energy in excess of the Coordinated System's Estimated Adjusted Energy Load was produced in the January-July period and the Storage Energy in reservoirs of the Coordinated System failed to reach at least 98 per cent of the total Storage Energy on July 31, except that when the Critical Period is less than one year the total Storage Energy less seventy-five per cent of the excess energy determined pursuant to paragraph 7(a)(3) shall be substituted for the total Storage Energy in such analysis. If the number of such years exceeds 5 per cent of the years in the historical period, each Reservoir Party shall adjust the variable Energy Content Curves of its reservoirs that failed to refill to those higher elevations necessary to reduce the number of such years to be no more than 5 per cent of the years in the historical period. Such percentage shall be revised to reflect any change in the forecast probability referred to in paragraph 7(c)(1). Adjustments will first be made up to the elevations determined in subsection 7(a) or 7(b). If the above adjustments fail to reduce the number of such years as required above, then further adjustments shall be made to elevations higher than those determined pursuant to subsection 7(a) or 7(b). If adjustments can be made to such reservoirs of two or more Systems, the variable Energy Content Curves of the reservoirs of each such System with an indicated energy generation in excess of that System's Estimated Adjusted Energy Load during those Periods in which adjustments are required shall be adjusted to higher elevations in proportion to the amount of such excess generation. In the event such adjustments by such excess System or Systems fail to reduce the number of years as required in this paragraph, additional adjustments required to achieve such reduction shall then be made by each reservoir with a variable Energy Content Curve where such adjustment will reduce the number of years, such adjustment to be made in the same proportion on each reservoir as each reservoir's ability to adjust to reduce the number of years bears to the total adjustment that all such reservoirs can make for such purpose.

(5) Not later than October 1 of each year, the variable Energy Content Curves, as adjusted pursuant to paragraph (4) of this subsection, shall be tabulated as a function of forecasted volume inflow for each reservoir in feet of elevation for the end of each Period, January through July.

(d) *Entitlement Curves.* Each reservoir which as been reregulated pursuant to paragraph 6(d)(2) shall have, during that portion of the year in which its Energy Content Curve is equal to its Critical Rule Curve, two entitlement curves in addition to its Energy Content Curve determined in this section. These two entitlement curves define the rights and obligations of various parties as described in paragraph 9(k)(3). One of the entitlement curves is associated with the reregulation desired by the Reservoir Party as described in paragraph 6(d)(2) and the other is associated with the modified regulation in which all storage was fully drafted during the Critical Period.

SECTION 8. *Maintenance and Reserves.*

(a) *Maintenance.* Each party shall submit, at the time required in subsection 6(a), a schedule of planned maintenance work which might reduce the Peaking Capability or energy capability of its System during the period pertinent to the determinations of Firm Load Carrying Capability made pursuant to section 6 or the period of 24 months commencing on the following July 1, whichever is longer. The parties shall make every reasonable effort to schedule a minimum of Maintenance Outages in the Critical Peaking Period and in as many Periods

adjacent in time as possible and to coordinate outages to the end that a uniform peak surplus or peak deficit will result over all Periods. Such surplus or deficit shall be measured for each Period by subtracting from the Peaking Capability of the Coordinated System the sum of the Estimated Adjusted Peak Load of the Coordinated System, Forced Outage Reserves of the Coordinated System and the effect of total scheduled Maintenance Outages. Adjustments in schedules will be made as permitted in subparagraphs 6(c)(1)(C) and 6(c)(4)(B). The schedules submitted by each party will be prepared on the assumption of operation under the conditions which are to be used to determine the Firm Load Carrying Capability. While nothing in this agreement shall be construed as specifying the amount of any party's scheduled maintenance, each party shall be obligated to submit an adequate schedule of Maintenance Outages to protect its ability to actually produce the Firm Load Carrying Capability for that System computed pursuant to section 6.

(b) *Forced Outage Reserves.* The Coordinated System shall maintain reserve capacity at a level sufficient to protect against loss of load to the extent that the probability of load loss in a Contract Year shall be no greater than the equivalent of one day in twenty years. The determination of such probability shall be based upon characteristics of Peak Load variability and generating equipment Forced Outage rates.

(1) Not later than May 15 of each Contract Year, a reserve requirement study as described in this subsection 8(b) shall be made based on the modified regulation for use pursuant to subparagraph 6(c)(4)(B). Not later than July 1 of each Contract Year the study required to compute Forced Outage Reserve used in the determination of Firm Load Carrying Capability pursuant to subsection 6(e) shall be made.

(2) The Forced Outage Reserve for each System shall be determined for each period:

(A) The Peaking Capability of the Coordinated System shall be as determined in subdivisions 6(c)(4)(B)(i), (ii) and (iii) for each Period, except that Forced Outage Reserve shall not be deducted.

(B) A Peak Load which is uniformly greater or less than the Estimated Adjusted Peak Load for the Coordinated System in each Period shall be determined such that the probability of load loss for the Contract Year is equivalent to one day in twenty years.

(C) The Critical Peaking Period shall comprise those Periods for which the probability of load loss is greater than or equal to one hundredth of the highest probability of load loss in any Period of the Contract Year.

(D) For each Period in the Critical Peaking Period the Forced Outage Reserve of the Coordinated System shall be the difference between the Peaking Capability determined for such Period in subparagraph 8(b)(2)(A) and the Peak Load for such Period determined in subparagraph 8(b)(2)(B). For all other Periods the Forced Outage Reserve of the Coordinated System shall be deemed to be equal to the average of the Forced Outage Reserves of such System for the Periods of the Critical Peaking Period.

(E) For each Period of the Critical Peaking Period the Forced Outage Reserve of the Coordinated System shall be allocated to each party hereto by the method described in Exhibit 4, and the quantity so allocated to a party in a Period shall be such party's Forced Outage Reserve for such Period. For all other Periods the Forced Outage Reserve of any party shall be deemed to be equal to the average of the Forced Outage Reserves of such party for the Periods of the Critical Peaking Period.

(3) The load loss probability distribution shall be determined by convolving the capacity loss probability distribution with the Peak Load probability distribution in accordance with probability mathematics detailed in Exhibit 4:

(A) The capacity loss probability distribution shall be computed considering the following:

(i) The resources to be included in such computation for each System shall be the Firm Resources for such System as defined in paragraph 2(q)(1) and 2(q)(2), the thermal resources included pursuant to paragraph 2(q)(3) and generating facilities located outside the Coordinated System but which otherwise meet the requirements of subsection 2(q) for Firm Resources.

(ii) The Forced Outage probabilities (rates) used in such computation shall be as listed in Exhibit 4. Such probabilities shall be reviewed and revised by the parties every five years, or more often if necessary.

(iii) Where a major resource is shared by a number of parties on a pro rata basis, and where the resource is operated so that the sharing parties' loads are in some part served by such resource as if it were in fact within such parties' utility responsibility areas, the effect of such resource on the capacity loss probability distribution for such party shall be as described in Exhibit 4.

(iv) Capacity available to any System on a firm basis from major interties with other areas shall be represented as single sources of generation with appropriate Forced Outage rates assigned thereto.

(B) The characteristics of the Peak Load probability distribution applicable to each System shall be as given in Exhibit 4. Such characteristics shall be reviewed and revised every five years, or more often if necessary, by each party and approved by the parties.

(c) *Energy Reserve.* The energy reserve of a System shall be the product of the firm energy capability of thermal plants included in the Firm Resources of that System and the applicable Forced Outage rate shown in Exhibit 4.

(d) *Spinning Reserve.* Spinning Reserve Requirement is established to insure a degree of Spinning Reserve capability and diversity within the Coordinated System and it is recognized that tie line control requirements, transmission limitations, local standby reserves and prudent operating practices may result in greater Spinning Reserves for some parties than the Spinning Reserve Requirement hereafter specified.

The Spinning Reserve Requirement of each System shall be one per cent (1%) of the estimated Adjusted Peak Load of such System for the current Contract Year.

A party may arrange with another System to supply all or part of its Spinning Reserve Requirement.

PART III

OPERATIONS

SECTION 9. *Operating Procedures, Obligations and Entitlements.*

(a) *Use of Firm Load Carrying Capability and of Energy and Capacity in Excess of Firm Load Carrying Capability.* Each party may use its Firm Load Carrying Capability for any and all purposes. Each party may use its energy or capacity in excess of Firm Load Carrying Capability for any and all purposes to the extent that the Actual Energy Capability or Actual Peaking Capability, respectively, of the Coordinated System is in excess of that required to supply the Firm Load Carrying Capability of the Coordinated System. The amount of such energy on any individual System is the excess of such System's Actual Energy Capability over its Firm Energy Load Carrying Capability after adding Interchange Energy and Holding Interchange Energy to which the System is currently entitled and subtracting the Interchange Energy and Holding Interchange Energy that the System is currently obligated to supply to other parties. The amount of such capacity on any individual System is the excess of such System's Actual Peaking Capability over its Firm Peak Load Carrying Capability after adding Interchange Capacity to which the System is currently entitled and subtracting Interchange Capacity that the System is currently obligated to supply to other parties.

(b) *Actual Energy Capability.* The determination of Actual Energy Capability by each System shall be made as set forth in paragraph (1) of this subsection. Estimates of Actual Energy Capability shall be made and used by a System as set forth in paragraph (2) of this subsection.

(1) The Actual Energy Capability of a System for a Period shall be determined within 5 business days after the end of such Period. The determination of Actual Energy Capability shall be based on the energy actually received under firm contracts and arrangements with systems outside the Coordinated System and actual energy generated from a System's Firm Resources and then adjusted for any entitlements and obligations pursuant to this section, observing priorities for use of facilities set forth in subsection 9(i). Appropriate adjustments shall be made when applicable for Maintenance Outages, Forced Outages, energy capability of Firm Resources not used, In Lieu Energy, stored energy, flexibility account, Provisional Energy, Interchange Energy, Holding Interchange Energy, energy reserve and energy for secondary purposes. Such adjustments for entitlements and obligations shall observe the following procedures, when applicable: Forced Outages and Maintenance Outages not scheduled pursuant to subsection 8(a) and subparagraph 6(c)(1)(C) will not reduce the capability of a System's Firm Resources and will, therefore, neither increase a party's entitlement to Interchange Energy nor decrease such party's obligation to deliver Interchange Energy at any time from what such entitlement or obligation would have been without the outages; adjustment for a flexibility account shall be made only for positive balances in said account; appropriate adjustments for Interchange Energy and Holding Interchange Energy received, delivered or returned during the Period shall be made to determine any remaining obligation or entitlement; appropriate reductions will be made for storage water which has been drafted below the lowest elevation permitted under subsection 9(h); appropriate reductions will be made in a Period for energy generation utilized for secondary purposes, and not requested as Interchange Energy, which could not have been stored in the Coordinated System's reservoirs and which would have otherwise spilled; any adjustment involving the conversion of water to energy capability shall be determined by application of the same plant characteristic data submitted and used in the determination of Firm Energy Load Carrying Capability pursuant to section 6.

(2) Estimates of each System's Actual Energy Capability shall be used for operating pur-

poses during each Period whenever rights, duties or entitlements are to be determined currently based on Actual Energy Capability. Estimates for the current Period or the remaining part of the current Period shall be made by the party based on conservative forecasts from known conditions. Required adjustments on account of differences between Actual Energy Capability and such estimates for a Period will be made after the Period.

(3) A System which during a Period receives more energy under subsection 9(c), or takes the return of more energy under subsection 9(e) than the amount to which it is entitled, as determined within ten days after the end of the Period, shall upon notice from the supplying or returning System, given within three business days after such determination, return the excess amount to the supplying or returning System at such time during the current Period, or as soon thereafter as priorities established under subsection 9(i) will permit, as the supplying or returning System shall specify in such notice. If such notice is not given, such excess shall be deemed to have been Interchange Energy when it was delivered or returned, except that if the delivering party has a remaining obligation to return Holding Interchange Energy to the receiving party, the excess may, on agreement of such parties, be treated as return of Holding Interchange Energy.

(c) *Interchange Energy and Interchange Capacity.* Each party to this agreement shall be entitled at all times to energy and capacity equivalent to its Firm Load Carrying Capability.

(1) *Interchange Energy.* Subject to the provisions of subsections 9(d), (f) and (g), any party whose System's Actual Energy Capability is less than its Firm Energy Load Carrying Capability shall be entitled to request and take delivery of Interchange Energy to bring it up to its Firm Energy Load Carrying Capability. Any party whose System's Actual Energy Capability is less than its Actual Adjusted Energy Load shall request and take delivery of Interchange Energy (or otherwise procure energy from other parties or from outside the Coordinated System) to bring it up to its Actual Adjusted Energy Load or its Firm Energy Load Carrying Capability, whichever is less. Interchange Energy shall be supplied by any party whose System's Actual Energy Capability is in excess of its Firm Energy Load Carrying Capability, or may be supplied by any party from Firm Energy Load Carrying Capability in excess of its Actual Adjusted Energy Load. When the Actual Energy Capability of the supplying System includes both hydro-generated and thermally-generated energy, the receiving System shall be entitled to the hydro-generated energy, but only to the extent that the Actual Energy Capability of the supplying System, excluding use of thermally-generated energy, exceeds the Firm Energy Load Carrying Capability of the supplying System. A party may but shall not be obligated to deliver Interchange Energy during hours designated by it as peak load hours, but not in excess of a total of six hours per day, Mondays through Saturdays, except national holidays.

(2) *Interchange Capacity.*

(A) Any party whose Actual Peaking Capability is less than its Firm Peak Load Carrying Capability shall be entitled to request and take delivery of Interchange Capacity to bring it up to its Firm Peak Load Carrying Capability. Except as provided in subparagraph (B) below, Interchange Capacity shall be supplied by any party whose System's Actual Peaking Capability is in excess of its Firm Peak Load Carrying Capability, or may be supplied by any party from capacity in excess of its Actual Adjusted Peak Load.

(B) Interchange Capacity required by a Reservoir Party in those Periods in which it elected to reduce its peak deficiency by reregulating its reservoir or reservoirs pursuant to subparagraph 6(d)(2)(A) shall be first supplied by parties computing their Critical Period Energy Capability based on full draft pursuant to subpara-

graph 6(d)(2)(A), up to the amount of their obligation determined in subparagraph 6(d)(2)(A), and thereafter as provided in subparagraph (A) above.

(C) Interchange Capacity service shall be accounted for on the basis of a calendar week. The measurement therefor as between any two Systems shall be the maximum amount requested and delivered during any hour as Interchange Capacity; provided however, that if the supplying System is subsequently, during that calendar week, unable to deliver Interchange Capacity at a rate as great as Interchange Capacity which was previously delivered during that calendar week, such lesser amount shall be deemed to be the Interchange Capacity delivered during such calendar week. Interchange Capacity thus delivered shall be paid for as provided in subsection 14(c), except that no payment shall be made for Interchange Capacity delivered pursuant to subparagraph (B) above up to the amounts obligated under subparagraph 6(d)(2)(A).

(d) *Delivery and Return of Holding Interchange Energy.*

(1) Any System shall be entitled to request and receive in accordance with the schedules prepared under paragraph 6(d)(3) such Holding Interchange Energy as is necessary to keep such importing System's reservoirs on the Energy Content Curves, but not in excess of the amount shown for each Period on such schedule. Unless mutually agreed otherwise, Holding Interchange Energy shall be delivered in any one day in amounts up to but not in excess of one hundred twenty per cent of the average amount shown on such schedules for delivery in the applicable Period.

(2) The importing System will utilize its facilities, subject to the limitations of subsection 9(i), to the maximum extent to facilitate the receipt of Holding Interchange Energy in the shape the exporting System has such energy available. It shall be the obligation of the exporting System to arrange and pay for the use of facilities of a third party, if necessary, to make the balance of the scheduled Holding Interchange Energy usable to the importing System.

(3) To the extent that Holding Interchange Energy is about to be spilled from the reservoir into which it was imported, such energy shall be converted at no charge to energy stored under the provisions of subsection 9(j) and shall thereafter be subject to the provisions of subsections 9(j), 14(e) and 14(h). If Holding Interchange Energy has been imported into the reservoir from more than one exporting System, the importing System shall designate the Holding Interchange Energy to be converted under this paragraph.

The importing System's obligation to return Holding Interchange Energy shall be decreased by the amount of Holding Interchange Energy which has been converted to stored energy, but the exporting System's remaining obligation to deliver Holding Interchange Energy shall not be increased.

(4) The importing System shall return any remaining Holding Interchange Energy, upon request, to the extent that and as soon as there is generating capacity at the hydro facilities involved not being used by the importing System to supply its Firm Load Carrying Capability; provided that it need not return energy in advance of the Period during which such return was scheduled if such return would require draft below the Energy Content Curve of the reservoir involved. The importing System may return remaining Holding Interchange Energy upon request at any time and from other facilities. Energy returned shall be paid for in accordance with subsection 14(d).

(e) *Return of Interchange Energy.* Each System supplying Interchange Energy shall specify at the time of delivery whether such deliveries are to be classed as loaned Interchange Energy or as other than loaned Interchange Energy.

(1) The receiving System shall return either class of Interchange Energy to the supplying System on demand to the extent that the receiving System's Actual Energy Capability is in excess of the Firm Energy Load Carrying Capability. In addition, the receiving System shall return loaned Interchange Energy on demand, irrespective of its own energy requirements, whenever the supplying System's Actual Energy Capability, excluding the use of thermally generated energy, is less than its Firm Energy Load Carrying Capability, and shall return other than loaned Interchange Energy on demand, irrespective of its own energy requirements, whenever the supplying System's Actual Energy Capability is less than its Firm Energy Load Carrying Capability; except that the receiving System need not so return either class of Interchange Energy received after June 30 in any Refill-hold Period, during which a settlement of Interchange Energy imbalances has been made pursuant to paragraph (3) below, prior to November 1 and thereafter in quantities greater than 20 per cent of such energy monthly during the November through March period except that such quantities shall be increased cumulatively in the subsequent month by the amount of any such energy not returned in the previous month of such period.

Obligations to return either class of Interchange Energy on demand pursuant to this paragraph 9(e)(1) shall be limited in rate to the amount by which the receiving System's Peaking Capability exceeds the capacity such System is using for purposes of higher priority under subsection 9(i). A party may but shall not be obligated to return Interchange Energy during hours designated by it as peak load hours, but not in excess of a total of six hours per day, Mondays through Saturdays, except on national holidays.

(2) If no demand is made, the receiving System shall nevertheless have the right to return other than loaned Interchange Energy to replace current thermal generation in excess of minimum generation being operated on the supplying System for any purpose, provided that, whenever the supplied energy originated from thermal generation of higher cost than that replaced by the returned energy, the energy credit shall be the energy returned multiplied by the ratio of the incremental cost of said current thermal generation to the incremental cost of said original thermal generation. When two or more parties desire to return such Interchange Energy at a rate greater than the amount current thermal generation on the supplying System is in excess of minimum generation, then the supplying System shall have the right to determine which party or parties shall return such energy.

(3) At the end of any Refill-hold Period during which the Coordinated System's reservoirs have filled to at least 98 per cent of the total Storage Energy, any imbalance as of the previous June 30 between other than loaned Interchange Energy received and other than loaned Interchange Energy returned shall be paid for as provided in subsection 14(a). Upon such payment, all obligations to return other than loaned Interchange Energy imbalances pursuant to paragraph (1) of this subsection shall terminate. At the end of any Refill-hold Period during which the Coordinated System's reservoirs have filled to at least 98 per cent of the total Storage Energy all outstanding obligations as of the previous June 30 to return loaned Interchange Energy shall terminate.

(4) It shall be the obligation of the party supplying the Interchange Energy to keep the receiving party currently informed as to the imbalance of Interchange Energy and the charges associated with such imbalance. Return of Interchange Energy pursuant to paragraph (1) of this subsection shall reduce the Interchange Energy imbalance, kilowatt hour for kilowatt hour or by the energy credit provided for in paragraph (2) of this subsection whichever is applicable, and shall reduce the charges for such imbalance by eliminating the charges per kilowatt hour associated with the energy designated at the time of such return by the supplying System.

(5) Any Interchange Energy returned between the previous June 30 and the end of the Refill-hold Period during which the Coordinated System's reservoirs have filled to at least 98 per cent of the total Storage Energy shall be deemed an initial delivery of Interchange Energy.

(6) Interim cash advances on account shall be made when requested from a party having a net debit in its account with the requesting party.

(7) Energy received with the delivery of Interchange Capacity will, at the option of the supplying System, either be returned by the receiving System within seven days of such delivery during such relatively light load hours as required by the supplying System and unless otherwise agreed, at a rate not to exceed that of the delivery of such Interchange Capacity, or be purchased at the rate specified in subsection 14(a).

(f) *Priorities on Deliveries of Hydro Interchange Energy.* Priorities on deliveries of hydro Interchange Energy shall be as follows:

(1) Each System which includes in its Firm Resources one or more of the Hungry Horse, Kerr, Thompson Falls, Noxon Rapids, Cabinet Gorge, Albeni Falls, and Box Canyon Projects shall have priority on hydro Interchange Energy to which it is entitled under subsection 9(c), from those Systems making net restorations pursuant to subsection 6(f), up to one-half the total annual restoration for such Projects owned by it and at a monthly rate not to exceed the uniform monthly restoration for such Projects owned by it, as determined in subsection 6(f); provided that such priorities shall be exercised on current Interchange Energy imports until such priorities have been exhausted. If more than one System has hydro energy available for Interchange Energy, deliveries subject to priority under this paragraph 9(f)(1) shall be supplied in accordance with paragraph 9(f)(2) below, but all priorities under this paragraph shall be satisfied before any delivery of Interchange Energy not subject to priority hereunder.

(2) The supplier may supply the quantity of Interchange Energy requested but if there is more hydro energy available for Interchange Energy in the Coordinated System than is requested, the supplier is obligated to supply only the pro rata amount of hydro energy that it has with respect to the total hydro energy available. If the supplier is supplying all of its hydro energy actually available as Interchange Energy, it may deliver to the party or parties of its choice. Otherwise it must deliver the hydro energy it makes available for Interchange Energy to the parties requesting such energy in proportion to such requests.

(3) Except for the return of Interchange Energy and the delivery and return of Holding Interchange Energy, no party will supply hydro available for the supply of Interchange Energy to another party for secondary uses until all parties are receiving their requested amounts of Interchange Energy from hydro necessary to make up their respective Firm Energy Load Carrying Capabilities.

(g) *Priorities on Deliveries of Thermal Interchange Energy.* Priorities on deliveries of thermal Interchange Energy shall be as follows:

(1) Each System which is unable under paragraph 9(f)(1) above to receive hydro Interchange Energy to the extent of its priority, shall be entitled to fulfill such priority from the lowest cost thermal Interchange Energy available from Systems supplying such priority under such paragraph. If more than one System has a priority on such thermal Interchange Energy, deliveries shall be supplied in accordance with paragraphs 9(g)(2) and 9(g)(3) below, but all priorities under this paragraph shall be satisfied before any delivery of thermal Interchange Energy not subject to a priority hereunder.

(2) When thermal Interchange Energy is requested in amounts greater than are available from a given facility of a supplier, such supplier shall have the right to select a party

or parties to whom it will deliver such thermal Interchange Energy.

(3) If a supplier has more thermal energy available for Interchange Energy than is requested, it shall supply all requests with the lowest cost thermal energy it has available for Interchange Energy.

(h) *Operation of Reservoirs Below Energy Content Curves and Critical Rule Curves.*

(1) Subject to the provisions of subsection 9(n), and except as may otherwise be agreed upon by all parties, no reservoir in the Coordinated System shall be drafted below its Energy Content Curve unless

(a) all reservoirs have been drafted to their respective Energy Content Curves, except a reservoir which cannot be drafted to its Energy Content Curve because of physical limits, and

(b) all Firm Resources of the Coordinated System are in full operation to the extent such resources were committed in the determination of Firm Load Carrying Capability established for use in the current Contract Year pursuant to subsection 6(i), and

(c) further draft is necessary to produce the Firm Energy Load Carrying Capability of the Coordinated System;

provided that a Reservoir Party may exchange storage water, which such party can reasonably demonstrate is equivalent in usable energy and probability of refill, among the reservoirs of such Reservoir Party for the purpose of balancing such party's reservoirs; and provided further that a Reservoir Party may draft its reservoirs below their respective Energy Content Curves, but not below the elevation established in subparagraph 6(c)(2)(C), to store, pursuant to subsection 9(j), the resultant energy together with any head losses incident to the transaction, in a reservoir of another party from which it can subsequently be returned with no greater risk of its being spilled during the time it was so stored than if such storage had remained in the original reservoir from which it was withdrawn, and where such draft of water affects downstream Projects, arrangements shall be made with such Projects similar in every respect to the provisions for Provisional Energy as specified under subparagraphs 9(n)(1)(B) and 9(n)(1)(C).

(2) Any party having a Firm Resource required to be placed in operation under the terms of paragraph 9(h)(1) above may substitue for such resource an equivalent amount of energy obtained from outside the Coordinated System, or from the Firm Energy Load Carrying Capability of its own or of another System in excess of the Actual Adjusted Energy Load of such System.

(3) When all reservoirs of the Coordinated System are to be operated below Energy Content Curves in accordance with (c) of paragraph 9(h)(1) above, each such reservoir shall be operated so that its elevation is proportionately the same distance, expressed in feet of elevation, between the Energy Content Curve and the first Critical Rule Curve tabulated and identified pursuant to subsection 6(h), then when the first Critical Rule Curve is passed on all reservoirs, between the first and second Critical Rule Curves, and when the second Critical Rule Curve is passed, between the second and third, et cetera. When it is necessary to operate the Coordinated System reservoirs below their lowest Critical Rule Curves, then each reservoir shall be operated proportionately between the lowest Critical Rule Curve and normal bottom elevation. If the Energy Content Curve for any Period for a reservoir has been adjusted pursuant to subsection 9(o) to an elevation below one or more of its Critical Rule Curve elevations, then for the purposes of this subsection 9(h) the elevations of all such Critical Rule Curves for such Period which are above the adjusted Energy Content Curve elevations shall be deemed

to be the same as such adjusted Energy Content Curve elevations. If a reservoir is unable to reach the elevation required in accordance with this paragraph 9(h)(3) without spilling water which reasonably is expected to be used within the Critical Period, or because of outlet restrictions, discharge requirements, or operation for non-power requirements, then that reservoir shall be operated to the maximum extent possible within such limitations to achieve the elevation required, and the operation of each of the other reservoirs of the Coordinated System will be adjusted ratably as required to produce the Firm Energy Load Carrying Capability of the Coordinated System. Notwithstanding the foregoing provisions of this paragraph (3), a Reservoir Party may exchange storage water, which results in no adverse effect on any downstream Project not owned or operated by the Reservoir Party and which such party can reasonably demonstrate is equivalent in usable energy and probability of refill, among the reservoirs of such Reservoir Party for the purpose of balancing such party's reservoirs.

(i) *Priorities on Use of Facilities.* No party shall be required to exceed the capabilities of physical facilities available for its use. In the event that a party reasonably determines that operation to meet demands made pursuant to this agreement, when combined with the requirements of such party in supplying its own Firm Load Carrying Capability and in performing its contracts for transmission of power and energy, would cause such party to exceed such capabilities, priority on the use of facilities (including machine capacity, reservoir capacity and transmission capacity) of such party shall be in the following order:

(1) Supply of the party's own Firm Load Carrying Capability from its own hydro Firm Resources; use of the party's transmission capacity for its own Firm Load Carrying Capability and to fulfill contracts for transmission of power or energy.

(2) Supply of the party's own Firm Load Carrying Capability from its other Firm Resources.

(3) Delivery of Interchange Capacity undersubsection 9(c).

(4) Delivery and return of In Lieu Energy, delivery of replacement energy under subparagraph 9(n)(1)(B) and delivery of energy under the refusal option pursuant to paragraphs 13(c)(2) and 13(c)(3) when required to maintain Firm Energy Load Carrying Capability.

(5) Return of energy stored in reservoirs under subsection 9(j) when such return is required to supply Firm Energy Load Carrying Capability except to the extent that such return is being used by the party receiving such return for a purpose other than to serve its firm System load or other firm commitments.

(6) Delivery and return of Interchange Energy and of Holding Interchange Energy under subsections 9(c), 9(d) and 9(e), except to the extent that such delivery or return is being used by the party receiving such delivery or return for a purpose other than to serve its firm System load or other firm commitments.

(7) Supply of any requirements of the party owning the facilities for any purpose other than maintaining the Firm Load Carrying Capability of such party's System.

(8) Delivery and return of energy under paragraphs (5) and (6) above to the extent that such delivery or return is being used by the party receiving such delivery or return for a purpose other than to serve its firm System load or other firm commitments.

(9) Delivery and return of In Lieu Energy, delivery of replacement energy under subparagraph 9(n)(1)(B) and delivery of energy under the refusal option pursuant to paragraphs 13(c)(2) and 13(c)(3) for any purpose other than maintaining Firm Energy Load Carrying Capability.

(10) Return of energy stored in reservoirs under subsection 9(j) when such return is required for any purpose other than maintaining Firm Energy Load Carrying Capability.

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(11) Delivery of energy produced from the release of water for the production of Provisional Energy under subdivision 9(n)(1)(B)(i).

(12) Delivery and receipt of energy for other purposes, priority among such purposes to be at the option of the party owning the facilities.

(j) *Storage of Energy in Reservoirs.*

(1) Any party having energy which it has determined is available for storage may store such energy with any Reservoir Party, and the Reservoir Party shall accept such energy for storage to the extent such energy can be stored in a reservoir of the Reservoir Party. The Reservoir Party shall have the right to determine the use for all or any part of the storage space in its reservoir to store energy for its own account or the account of others, and if necessary for any purpose, to displace stored energy previously received. The Reservoir Party shall have the right to determine which request can be met between conflicting requests for storage space or for return of stored energy and, in the event of any spill, which energy was spilled. When the Reservoir Party desires to displace any party's stored energy, it shall notify that party and shall make reasonable efforts to conserve the stored energy which will be displaced.

All energy stored, spilled, or returned shall be accounted for in kilowatt hours. The energy in kilowatt hours equivalent to the amount of stored water spilled at the reservoir shall be computed by using the average conversion factor (kw/sf) during the time when the water was spilled.

The Reservoir Party shall return any or all stored energy which has not been purchased or spilled to the supplying System on demand, kilowatt hour for kilowatt hour, except as provided below, whenever there is hydro-generating capacity available at the reservoir in excess of that required for higher priority purposes under subsection 9(i); provided that a party may but shall not be obligated to make such return during hours designated by it as peak load hours, but not in excess of a total of six hours per day, Mondays through Saturdays, except on national holidays. If the releases of water to return the stored energy results in spill at downstream Projects of In Lieu Energy to which the Reservoir Party would have been entitled in the absence of spill at such Projects, or results in spill at the Reservoir Party's own downstream plants, the number of kilowatt hours of energy so spilled shall be deemed to have been returned, but no charges shall be made therefor.

Excess energy generated to keep from spilling shall not be considered energy spilled unless equivalent water is spilled at some other plant of the Reservoir Party, or an equal amount of energy is supplied to another party for immediate spill.

Stored energy remaining in a reservoir at the end of a Refill-hold Period during which the reservoirs of the Coordinated System have filled to at least 98 per cent of their total Storage Energy, may be purchased by the Reservoir Party at the rate for Interchange Energy imbalances in subsection 14(a).

(2) Parties may enter into agreements which provide special terms and conditions for the retention and return of, and charges for, storage of energy in reservoirs.

(k) *Release of Water From Storage and In Lieu Energy Deliveries.*

(1) At the request of the owner of any downstream Project, the Reservoir Party shall release water from storage accumulated in the reservoir above the Energy Content Curve, or, at the option of the Reservoir Party, supply to the owner of such downstream Project energy in lieu of the energy that could have been generated at the downstream Project had the requested releases been made; except that under no circumstances in any Contract Year beginning prior to April 1, 1973 will water be released from storage below reservoir elevation 1208 feet at Grand Coulee at the request of a downstream Proj-

ect owner or energy supplied in lieu thereof. The downstream Project shall be entitled to receive such In Lieu Energy on a schedule neither more nor less favorable than if equivalent storage had been released. The receipt by the downstream Project owner of any In Lieu Energy shall constitute an assignment to the Reservoir Party of the downstream Project owner's right to water in an amount equal to the In Lieu Energy accepted.

(2) The owner of the downstream Project shall make reasonable efforts to direct requests for water so as to minimize spillage as a result of the requested releases. No release of water shall be required which would exceed the generating capability of the Project at the site of the reservoir except that such limitation shall not apply to the extent that reasonable forecasts by the Reservoir Party indicate that the reservoir would otherwise be above its Energy Content Curve at the end of the Drawdown Period.

(3) During that portion of the year when Energy Content Curves are determined from the Critical Rule Curves any party electing to compute its Critical Period Energy Capability based on full storage releases during the Critical Period from reservoirs reregulated pursuant to paragraph 6(d)(2) shall be entitled to actual water releases or energy in lieu thereof based on the entitlement curve established under subsection 6(h) from the modified regulation for the reservoirs involved. During the same portion of the year, any party electing to compute its Critical Period Energy Capability based on the reservoir draft desired by the Reservoir Party from reservoirs reregulated pursuant to paragraph 6(d)(2) shall be entitled to actual water releases or energy in lieu thereof based on the entitlement curve established under subsection 6(h) from the regulation desired by the Reservoir Party.

Any party electing to compute its Critical Period Energy Capability based on the reservoir draft desired by the Reservoir Party from reservoirs reregulated pursuant to paragraph 6(d)(2) shall return to the Reservoir Party all energy generated at such downstream party's facilities from storage releases occurring below the downstream party's entitlement curve established under subsection 6(h) from the regulation desired by the Reservoir Party approximately concurrently with the receipt of water at such facility.

In the case of reregulation affecting a downstream Project which provides Firm Resources to more than one party, entitlements to water releases or energy in lieu thereof, and obligations to return energy generated at such downstream Project shall inure to the owner thereof for the account of such parties.

(4) At any time water is released from a reservoir at a rate in excess of the rate indicated by its Energy Content Curve, and the entitlement of any downstream Project to all water above the Energy Content Curve has been satisfied, such downstream Project shall make available to the Reservoir Party, to the extent of any remaining assignment on account of In Lieu Energy deliveries, all energy which can be generated at the downstream Project from such excess water releases which are above minimum releases at the reservoir approximately concurrently with the receipt of the water at the downstream Project; provided however that if the Energy Content Curve of a reservoir is adjusted as provided for in paragraph 9(o)(3) each downstream Project shall make available to the Reservoir Party, in each of the five weeks following such adjustment, twenty (20) per cent of the energy represented by any assignment, remaining at the time such adjustment was made, of the downstream Project owner's right to water in such reservoir. In addition and not in limitation of the foregoing obligations, during that portion of the year when the Energy Content Curve indicates an upstream reservoir would be refilling, a downstream Project owner may terminate its right to request further release of water from such reservoir until the end of the current Refill-hold Period and may thereafter during such period of time designate any or all water released

from such upstream reservoir, in excess of minimum releases, as assigned water releases and thereby reduce the assignment remaining in the reservoir. If he so designates he shall make available to the Reservoir Party the energy which can be generated from such assigned water releases. If the Reservoir Party adjusts the Energy Content Curve as provided in paragraph 9(o)(1), the downstream Project shall again have the right to request further release of water starting at the time the adjusted Energy Content Curve deviates from the previously designated Energy Content Curve. Unless another date is agreed upon, on June 1 of each year when the Critical Period is less than one year, any assigned rights to water remaining in a reservoir with sufficient flow to refill as described in paragraph 7(a)(2) shall be canceled and the right of a downstream Project to request release of water from such reservoir shall terminate until the beginning of the succeeding Drawdown Period as indicated by the Energy Content Curve of such reservoir.

(5) Any Project downstream from a reservoir may at any time during the last Contract Year of this agreement terminate its right to request any further release of water from such reservoir and thereafter may generate and make available to the Reservoir Party all or part of any additional energy which can be generated at such Project from any releases of water in excess of minimum releases made by the Reservoir Party.

(6) Unless otherwise agreed, if any water the right to which is assigned to a Reservoir Party remains in the reservoir on the termination of this agreement, it shall be assumed to have been used for generation through the assigning downstream Project at the average incremental conversion factor applicable to stored water releases experienced by such Project during the Drawdown Period preceding the termination of this agreement and each such Project owner shall compensate the Reservoir Party for the computed kilowatt hours applicable to its Project through a credit to any exchange account between the parties or, if there be no exchange account, by payment at the rate provided under paragraph 14(a)(1).

(7) The Reservoir Party shall be responsible for an accounting to each downstream Project not more often than once a day of entitlements to water and of deliveries and returns of In Lieu Energy, water released, and In Lieu Energy equivalent to water releases.

(8) For the purposes of this subsection 9(k), except under the conditions described in section 21 of this agreement, all generating units at site of the reservoirs and at downstream Projects shall be assumed to be operable whether or not in fact operable and water which could under such assumption be utilized shall be considered to be usable whether in fact it is usable or would be spilled. As used in this subsection 9(k), energy which could have been generated shall be deemed to be the amount which could have been generated increased by rights to receive energy from and reduced by obligations to deliver energy to an adjacent Project arising out of a settlement for tailwater encroachment.

(m) *Adjustments in Firm Energy Load Carrying Capability During Contract Year.*

A party may change its Firm Energy Load Carrying Capability in any month of the Contract Year subject to the following limitations:

(1) The algebraic sum of all such changes in the party's Firm Energy Load Carrying Capability shall be zero at the end of the Contract Year and shall be zero at the end of the Critical Period associated with the Firm Load Carrying Capability established pursuant to subsection 6(i) for the current Contract Year if such Critical Period ends in the current Contract Year.

(2) The accumulation of such changed monthly Firm Energy Load Carrying Capability shall not exceed the accumulation of the System's monthly Firm Energy Load Carrying Capabilities developed in accordance with subsection 6(i) by more than 5 per cent of the

remaining Firm Energy Load Carrying Capability between the date of such change and the date on which the System's changes in Firm Energy Load Carrying Capabilities must be zero pursuant to paragraph (1) above.

(3) Except for the use of Firm Energy Load Carrying Capability previously retained under paragraph (4) below, the amount of change in any month of the Contract Year shall not exceed the sum of the following amounts:

(A) the difference between the party's Actual Adjusted Energy Load and that party's Estimated Adjusted Energy Load for such month;

(B) the amount of energy capability resulting from the difference between the actual Maintenance Outages and Forced Outages and the Maintenance Outages finally scheduled pursuant to subsection 8(a) and subparagraph 6(c)(1)(C);

(C) changes for specific other purposes which may be approved by all the parties.

(4) Any change which increases a party's Firm Energy Load Carrying Capability during the remaining months of the Contract Year above that which was established in accordance with subsection 6(i) shall be accompanied by an increase in the contents of that party's reservoirs over their Critical Rule Curves, entitlements under this agreement, or other arrangements for increasing the party's Actual Energy Capability equivalent to such increase in Firm Energy Load Carrying Capability. The party which makes a change in its Firm Energy Load Carrying Capability shall demonstrate to any party requesting such demonstration the ability of the party's Firm Resources, or entitlements under this agreement, or other arrangements for providing increased Actual Energy Capability, to produce the claimed increase in the Firm Energy Load Carrying Capability of the Coordinated System during the remaining months of the Contract Year with the adverse streamflows of historical record which were used to establish Firm Energy Load Carrying Capability in accordance with subsection 6(i).

Each time a party makes a change in its Firm Energy Load Carrying Capability, a concurrent entry equivalent in energy to such change shall be made in an account of such party, with reductions in Firm Energy Load Carrying Capability treated as positive quantities, such account to be known as the flexibility account. The balance in a party's flexibility account shall be appropriately accounted for in such party's Actual Energy Capability pursuant to subsection 9(b). Any party making a change in its Firm Energy Load Carrying Capability in accordance with the provisions of this subsection 9(m) shall notify all the parties of the estimated amount of such change in Firm Energy Load Carrying Capability and the means of providing capability to effect such change within 10 days after the end of the month to which such change applies. The party making such change may adjust such change by not more than the amount by which such party's Actual Adjusted Energy Load differs from the estimate of the Actual Adjusted Energy Load on which such change was based.

(n) *Provisional Energy.*

(1) A Reservoir Party may draft its reservoir below the elevation which it would otherwise be required to maintain under subsection 9(h), for the production of Provisional Energy, subject to the following conditions:

(A) Provisional Energy may be generated and sold or otherwise disposed of or utilized only when the party selling or disposing of or utilizing such energy can provide assurance that the energy plus any generating losses incident to the transaction can be recovered, either from the purchaser under contractual commitments for its return or from generating resources available to such party on a firm basis for such purpose but not committed for Firm Energy Load Carrying Capability under this agreement, at such time as the storage drafted to produce such energy would otherwise have been released assuming that such storage increment would be the last

drafted power storage from the reservoir, provided that such commitments need not extend more than two years beyond the end of the Critical Period associated with the Firm Load Carrying Capability established pursuant to subsection 6(i) for the current Contract Year.

(B) At such time as a Reservoir Party makes a determination that it will release water for the production of Provisional Energy, it shall notify downstream Project owners of its schedule of provisional releases. Each downstream Project owner shall, on receipt of such notice, advise the Reservoir Party that it will either:

(i) deliver the energy which it can produce from the provisional release to the interconnected system for the account of the Reservoir Party for disposition under the conditions stated in this subsection 9(n); or

(ii) retain the energy which it can produce from the provisional release for disposition by it as Provisional Energy under the conditions stated in this subsection 9(n).

If the downstream Project owner elects option (i) above, then at such time as the water used to produce Provisional Energy would have been released in the absence of Provisional Energy deliveries, the Reservoir Party shall deliver replacement energy to the downstream Project owner in the amounts which could have been generated at the downstream plant with such release. No charge shall be applied either to the original delivery of energy by the downstream Project owner or to the replacement of such energy by the Reservoir Party. If the downstream Project owner elects to retain the energy under option (ii) the Reservoir Party shall have no obligation to the downstream Project owner to supply water or its energy equivalent except in accordance with the schedule of provisional releases.

(C) In computations involving the actual elevation of the reservoir, the actual elevation shall be deemed to be the elevation corresponding to the sum of the water in storage at any time and the water equivalent to the energy in the "reservoir Provisional Energy account" at the same time, except that such elevation shall not exceed normal top elevation.

(2) Each party selling or otherwise disposing of or utilizing Provisional Energy in accordance with paragraph 9(n)(1) shall maintain a full accounting of the transaction involved. Further, each Reservoir Party shall separately maintain, for each of its reservoirs, an accounting of the Provisional Energy produced by drafting storage from each such reservoir and sold or otherwise disposed of or utilized by it together with the amount of Provisional Energy produced from the same storage draft by downstream parties and retained by them under option (ii) of subparagraph 9(n)(1)(B), such account to be known as the "reservoir Provisional Energy account". The amounts of energy returned to the Reservoir Party under option (i) of subparagraph 9(n)(1)(B) shall be separately accounted for.

(o) *Adjustment of Energy Content Curves.*

(1) At the beginning of each month, January through July, or as soon thereafter as is practical, each Reservoir Party shall notify all other parties of the Energy Content Curve elevation for the end of each Period during the remainder of the Contract Year for each reservoir for which a variable Energy Content Curve has been determined pursuant to subsection 7(c). The Reservoir Party shall also supply to all other parties the inflow forecast and the data necessary to determine the forecast of inflow to such reservoir. In determining such Energy Content Curve elevations the Reservoir Party shall use the forecast method submitted pursuant to paragraph 7(c)(1) and the variable Energy Con-

tent Curve specified in paragraph 7(c)(5), except that when the Reservoir Party reasonably determines that the elevations so determined do not represent the planned operation as described in subsection 7(c), then the Reservoir Party may deviate, to the extent necessary to achieve such operation, from the forecast method or the variable Energy Content Curves or both in his determination of the Energy Content Curve elevations. If the Reservoir Party deviates from the procedures of paragraphs 7(c)(1) and 7(c)(5), then the Reservoir Party shall also advise all other parties of the reasons for such deviation.

(2) When a reservoir is required to operate below the Energy Content Curve to satisfy nonpower requirements, then the actual elevations of such reservoir shall be deemed to be the Energy Content Curve for such reservoir.

(3) When the outflow of a reservoir is being limited by a natural restriction and the Project controlling such reservoir is discharging water with the full use of facilities including facilities for spilling at such Project and the actual elevation is above the Energy Content Curve for such reservoir, then the actual elevations shall be deemed to be the Energy Content Curve for such reservoir.

(p) *Adjustments for Changes in Schedules of Resource Availability.*

(1) Adjustments in the Firm Load Carrying Capability of each affected System will be made for delays or advances in the availability of generating facilities from the schedule of availability exchanged pursuant to paragraph 6(a)(5) and used for the determination of Firm Load Carrying Capability in section 6 as follows:

(A) If the availability of a generating facility is delayed, the Firm Load Carrying Capability of each affected System shall be reduced during the period of such delay by the amount of capacity and energy that the delayed resource was assumed to be capable of providing to each such System as indicated in the final regulation used to establish Firm Load Carrying Capability under subsection 6(i).

(B) If the availability of a generating facility is advanced, the Firm Load Carrying Capability of each affected System may be increased at the option of each affected System during the period of such advance by the amount of capacity and energy that such resource would have provided to each such System had such resource been assumed to be in service according to its actual availability in the final regulation used to establish Firm Load Carrying Capability under subsection 6(i).

(2) Adjustments in the Firm Load Carrying Capability of each affected System shall be made for the actual elevation on July 31 in those reservoirs described in subparagraph 6(b)(1)(C) as new reservoirs if the actual elevation is different from that assumed and used for the determination of Firm Load Carrying Capability in section 6 as follows:

(A) If the actual elevation on July 31 in each such reservoir is less than that assumed for such reservoir on July 31 of the year corresponding to the current year in the regulation used to establish Firm Load Carrying Capability under subsection 6(i), then the Firm Energy Load Carrying Capability of each affected System shall be reduced by the amount which absence of such amount of storage would have reduced each System's Firm Energy Load Carrying Capability in such regulation. Such reduction shall be made for each affected System between the date of the beginning of the Critical Period and March 31 of the current Contract Year in those Periods desired by each such System.

(B) If the actual elevation on July 31 in each such reservoir is greater than that assumed for such reservoir on July 31 of the year corresponding to the current year

in the regulation used to establish Firm Load Carrying Capability under subsection 6(i), then the Firm Energy Load Carrying Capability of each affected System may be increased at the option of each affected System by the amount of energy which the greater amount of such storage would have increased each such System's Firm Energy Load Carrying Capability in such regulation. Such increases will be made for each affected System between the date of the beginning of the Critical Period and March 31 of the current Contract Year in those Periods desired by each such System.

(q) *Tranfers Due to Forced Outage.*

(1) Any party having a portion of its thermal capability out of service due to Forced Outage shall have the right to receive energy from any other party hereto having thermal capability currently available for service, but not being used to produce energy, to the extent of such available energy or the amount of energy lost due to such Forced Outage, whichever is less. In no case shall the delivery of such energy permit the delivering party to operate its reservoirs below those elevations which would be permitted under subsection 9(h) in the absence of such delivery. Such energy shall be paid for by the receiving party at the rate provided for thermal Interchange Energy imbalances in paragraph 14(a)(2).

(2) Each party hereto shall have the right to request and receive from each of the other parties hereto emergency capacity to the extent required to protect against a loss of load due to Forced Outage; provided however, that such emergency capacity shall be limited to that amount of Forced Outage which is in excess of the requesting party's Forced Outage Reserve and further limited by each of the other party's Forced Outage Reserve which is in excess of the sum of any then existing Forced Outages on such other party's System and emergency capacity being supplied to other Systems. Energy associated with the capacity obtained shall be returned within one week or purchased at the option of the supplying party. If purchased such energy shall be paid for by the receiving party at the rate provided for Interchange Energy imbalances in subsection 14(a).

(r) *Operating Data and Deviations.* Each party, in cooperation with the other parties, shall prepare in advance hourly schedules of power and energy transfers for each day, with simultaneous deliveries of power under various arrangements being identified and accounted for each hour. Such scheduled power and energy transfers shall be deemed to have been made at the point of delivery when delivered through the supplying System's interconnections. Operating deviations from schedule shall be held to a minimum and properly accounted for. Operating data shall be promptly exchanged between the parties as necessary for determinations under this agreement.

In the event it is necessary to reduce or interrupt operations hereunder to repair, maintain or replace facilities, such reductions or interruptions will be arranged as far in advance as feasible by mutual agreement of the parties. When such reduction or interruption or emergency or accidental interruption restricts or interrupts the delivery or receipt of scheduled power and energy, compensation shall be made for such reductions or interruptions by adjusting future schedules of deliveries under similar conditions of water supply and load.

SECTION 10. *Transmission Lines and Associated Facilities.*

(a) *Coordinated System Transmission.* Subject to the other provisions of this agreement, capacity available in transmission lines and associated facilities owned, leased or otherwise controlled as part of the Systems of the parties may be used by other parties without charge for the delivery of Interchange Capacity, Interchange Energy, Holding Interchange Energy, In Lieu Energy, energy transferred to or from storage under subsection 9(j) and for the delivery or replacement of Provisional Energy pursuant to subdivision 9(n)(1)(B)(i); provided

that, where such capacity is provided by a party acting solely as a transferor, and the use of such capacity has not otherwise been provided for, a transmission charge shall be applied as provided in subsection 14(f); and provided further, that except for transfers of Interchange Capacity such transferor shall not be obligated to make such capacity available during hours designated by it as peak load hours, but not in excess of a total of six hours per day, Mondays through Saturdays except on national holidays.

(b) *System Transmission.* It shall be the obligation of each party to provide adequate firm transmission capacity through ownership, lease or other firm arrangements to make usable its Firm Load Carrying Capability. The parties shall, at the request of any party, review compliance with the transmission requirements established by this section and shall prepare such studies as may be required to assist in the determination of such matter. All data necessary for such studies will be exchanged between the parties. If it is determined that a party has not provided adequate transmission capacity as required hereunder, its Firm Load Carrying Capability shall be appropriately reduced unless arrangements are made to overcome such deficiency.

(c) *Transmission Scheduling.* Power and energy to be delivered hereunder shall be scheduled to a directly interconnected System but in such amounts that the difference between the quantities scheduled in opposite directions shall not exceed the available capacity of the interconnecting transmission lines and associated facilities. When such power and energy is to be delivered through such interconnected System to other Systems, it shall be so designated at the time of scheduling.

SECTION 11. *Reactive.* The parties shall coordinate their operations so that the flow of reactive power will not adversely affect the Coordinated System or the directly interconnected Systems.

SECTION 12. *Loads in Excess of Capabilities.* Any System having a load in excess of the sum of its Firm Load Carrying Capability and the secondary energy to which it is entitled under section 9 shall supply that excess load from power and energy sources other than its Firm Resources, and shall not be entitled to power or energy for such excess load from the Coordinated System.

PART IV

Rates and Charges

Section 13. *Payment for Coordinated Storage Releases from Reservoirs Located in the United States.*

(a) *Computation of Payments.* The parties owning or operating downstream Projects entitled under this agreement to coordinated storage releases from upstream reservoirs controlled by dams located in the United States shall make annual payments to the owners or operators of such reservoirs. The payments for all years shall be computed as follows:

(1) The annual costs to be borne by power arising from ownership and operation of the dam and reservoir furnishing the benefits shall include, but not be limited to, that part of the interest, maintenance, and depreciation (or similar charges) to be borne by power under applicable law, and that part of the operation expenses (including land rentals and similar charges), administrative and general costs, and taxes other than net income taxes to be borne by power. The capital and such annual costs for each Project for which headwater payments are to be made under this section are illustrated by Exhibit 5 hereto. This Exhibit shows the cost for the 1963-64 year and will be revised as appropriate. Such annual costs shall be apportioned between the storage and head functions.

(2) The cost to be apportioned to the storage function shall be determined by the following formula:

$$C_s = C_p \frac{P_s + A_s}{P_s + A_s + P_h + A_h}$$

in which,

C_s = Annual power cost of the dam and reservoir apportioned to storage.

C_p = Annual cost of the dam and reservoir to be borne by power both at-site and downstream.

A_s = Average annual usable energy, at-site and downstream from at-site storage after adjustment reflecting the relative values of average annual and Critical Period energy all as determined pursuant to paragraph 13(a)(3).

A_h = Average annual usable energy, at-site from natural flow and from at-site and upstream storage after adjustments reflecting the relative values of average annual and Critical Period energy all as determined pursuant to paragraph 13(a)(3).

P_s = Critical Period energy, at-site and downstream from at-site storage as determined pursuant to paragraph 13(a)(4).

P_h = Critical Period energy, at-site from natural flow and from at-site and upstream storage as determined pursuant to paragraph 13(a)(4).

(3) The reservoir regulations made pursuant to paragraph 7(c)(3) and adjusted for changes in Energy Content Curves made pursuant to paragraph 7(c)(4) shall be used to determine the average annual usable energy to be adjusted as hereinafter provided in this paragraph 13(a)(3).

The average annual energy gains from storage before adjustments for tailwater encroachment and usability shall be determined for each Project for each Period by computing the energy capability with and without storage. The resulting increment of energy from storage for each Period shall be adjusted by the obligation to deliver energy or right to receive energy from an adjacent Project arising out of a settlement for tailwater encroachment. The amount of such obligation assigned to storage shall in each

Period bear the same ratio to the total obligation in the Period as storage use bears to total plant discharge in the Period. The Coordinated System's total increment of energy gained or lost due to storage shall be reduced to the amount usable in the Coordinated System's estimated load after use of energy from natural flow and such gain or loss shall be prorated to each Project in each Period in proportion to that Project's increment of energy due to storage.

The increments of average annual usable energy gain or loss at each Project from storage shall be assigned to each upstream reservoir in proportion to the storage change at each reservoir.

The A_s for each storage Project shall be the algebraic sum of these increments in megawatt months for that Project's storage at-site and downstream divided by the number of months in the study and multiplied by the applicable j factor hereafter provided.

The A_h for each storage Project shall be the algebraic sum of the usable energy at-site from natural flow and the usable energy from at-site and upstream storage, divided by the number of months in the study and multiplied by the applicable j factor hereafter provided.

The A_h and A_s values determined above shall be adjusted to reflect entitlements and obligations pursuant to paragraph 6(d)(2).

For the purpose of this agreement, j will be zero initially and will increase, effective in each case at the beginning of the Contract Year in which the conditions causing such increase occur, in accordance with the following schedule as the secondary market and average annual replaceable thermal energy included in the secondary market, as derived from the data submitted pursuant to subsection 6(a), reach the indicated levels:

j = 0.5 with 2,000 Mw secondary market

j = 1.0 with 4,000 Mw secondary market which includes 2,000 Mw or more of replaceable thermal
or with 6,000 Mw secondary market which includes less than 2,000 Mw of replaceable thermal

j = 2.0 with 6,000 Mw secondary market which includes 4,000 Mw or more of replaceable thermal or
with 10,000 Mw secondary market which includes less than 4,000 Mw of replaceable thermal

j = 3.0 with 8,000 Mw secondary market which includes 6,000 Mw or more of replaceable thermal;

provided that in the event the Coordinated System's Critical Period is extended to include parts of 4 historical flow years before the secondary market reaches 4,000 Mw, j will be increased, effective at the beginning of the Contract Year in which the conditions causing such extension occur, to 1.0 and will not thereafter be reduced.

For this purpose "secondary market" shall include but not be limited to the average annual replaceable thermal energy in the Coordinated System, interruptible load available in the Coordinated System and the indicated available market for export of secondary energy from the Coordinated System.

(4) The final regulation made pursuant to subsection 6(e) shall be used to determine P_s and P_h to be used in the formula set forth in paragraph 13(a)(2).

The Critical Period energy gains from storage before adjustment for tailwater encroachment shall be determined for each Project for each Period by computing the energy capability with and without storage. The resulting increment of energy from storage for each Period shall be adjusted if applicable for the tailwater encroachment assigned to

storage for that same Period as set forth in paragraph 13(a)(3) and shall be further adjusted for any restoration received from Projects which gain from Canadian Storage as determined in paragraph 6(f)(1). After such adjustments the increments from storage shall be assigned to all upstream reservoirs in proportion to each reservoir's storage release during the Critical Period. The P_s for each reservoir shall be the sum of these increments in megawatt months computed for such reservoir, including the increment computed at the reservoir Project itself, divided by the number of months in the Critical Period. The P_h for each reservoir Project shall be the sum of the megawatt months of energy over the Critical Period from natural flow and from releases from at-site and upstream storage, divided by the number of months in the Critical Period.

(5) The costs so apportioned to the storage function of each reservoir Project shall be distributed among the Projects, at-site and downstream in proportion to each Project's increment of the quantity $(P_s + A_s)$ from the applicable reservoir. The annual costs thus apportioned to each downstream Project shall be the annual payment to be made by the owner or operator of that Project to the owner or operator of that reservoir subject to the limit hereinafter provided.

(b) *Limit of Payment*

The payment under paragraph 13(a)(5) will be limited so as not to exceed the value of the benefits received from each storage Project. For the purposes of this agreement initially and continuing until the end of the Contract Year in which j, as determined by paragraph 13(a)(3) becomes greater than zero, the value of benefits received from storage shall be computed as 0.55 mills per kilowatt hour for energy available from storage during the Critical Period, and after j is determined to be greater than zero, the value of benefits received from storage shall be computed as $4.38 multiplied by the total kilowatts represented by each downstream Project's increment of the quantity $(P_s + A_s)$ as described in subsection 13(a).

(c) *Refusal Option*

(1) Parties owning a Project or Projects downstream from any dam and reservoir hereafter constructed in the United States shall be entitled, not less than 60 days prior to the receipt at such Project or Projects of the initial storage releases from any such dam and reservoir, to reasonably accurate estimates of the data required to make the computations provided for in subsection 13(a), including, without limitation, the date when such releases will be made, and shall, within 30 days after receipt of such estimate, elect, as to any such Project or Projects, one of the following options:

(a) to make available for return to the reservoir owner or operator all energy which can be generated at such Project or Projects from storage releases from such dam and reservoir for a period of 10 years from the estimated date when such initial releases will be made, which period shall terminate at the end of a Contract Year, and to accept such energy thereafter throughout the remainder of the term hereof, provided that prior to 5 years before the 10-year period terminates the downstream party or parties may elect to make available for return such energy to the reservoir owner or operator throughout the remainder of the term hereof, or

(b) to make available for return such energy to the reservoir owner or operator throughout the remainder of the term hereof, or

(c) to accept such energy throughout the remainder of the term hereof;

provided, that a downstream party accepting energy from such dam and reservoir, within 60 days after notice of any increase in the annual payment to be made to the owner or operator of such dam and reservoir in respect thereto, shall again have the option to elect one of the options, (a), (b), or (c) of this paragraph.

(2) Energy to be returned by the owner of a downstream Project or Projects pursuant to

this subsection shall be made available to the reservoir owner or operator approximately concurrently with the receipt of the storage releases from the reservoir at the downstream Project or Projects, subject to the priorities on the use of machine capacity set forth in subsection 9(i) hereof. Such energy shall be made available at the high voltage side of the switchyard of the affected downstream Project, or an equivalent amount of water shall be spilled if so directed by the reservoir owner or operator.

(3) During the time that the reservoir owner or operator is storing water to refill its reservoir, the reservoir owner or operator shall make available to the downstream party or parties who returned the energy generated from storage releases under options (a) or (b) in paragraph 13(c)(1), the energy which would otherwise have been usable at the downstream Project. The return of such energy shall be approximately concurrent with the storing of such water for reservoir refill, subject to the priorities on the use of machine capacity set forth in subsection 9(i) hereof. Such energy shall be made available at the high voltage side of the switchyard of the affected downstream Project.

(4) During such time as a downstream Project is making energy available for the return to a reservoir owner or operator pursuant to this subsection 13(c), the owner of such downstream Project shall be relieved of the obligaton to pay to the reservoir owner or operator on account of such downstream Project any amounts in excess of those required to be paid by Section 10(f) of the Federal Power Act and such reservoir owner or operator shall pay to the owner of such downstream Project an amount equal to the 10(f) payments so required to be made.

(5) The party or parties which are receiving energy from another party due to the release or withholding of storage under this subsection 13(c) shall make a payment of one mill per kilowatt hour as compensation for the generation of the energy actually so returned.

(d) *Procedure on Payments.*

All payments for each Contract Year to be made pursuant to this section except payments pursuant to paragraph 13(c)(5) shall be made in twelve (12) equal monthly payments due and payable on or before the fifteenth day of each month beginning September 1965 and continuing each month through August 2003. Payments to be made to the United States pursuant to this section by a downstream Project owner shall be paid to the Bonneville Power Administrator to be held in suspense for the credit of such owner pending annual determination by the Federal Power Commission of the amount due from such owner to satisfy the requirements of Section 10(f) of the Federal Power Act as applied to Projects owned by the United States within this agreement. Within thirty days after such determination by the Federal Power Commission, or prior to delinquency, whichever is sooner, the Bonneville Power Administrator shall transfer to the Federal Power Commission from such funds to the extent available the amount so determined necessary to satisfy the requirements of Section 10(f) as between such owner and such Projects of the United States. Payments to be made by the United States shall be converted into kilowatt hours in the manner hereafter specified, and such kilowatt hours shall be appropriately entered in the exchange account established under contract between the Administrator and such party. The dollar charges shall be converted to kilowatt hours by dividing such charges by the rate currently employed by the Administrator for settlement of such exchange account. At the request of any party, payments shall be appropriately adjusted to reflect any delay or advance from the schedule assumed for a new Firm Resource coming into service.

(e) *Provision Relating to Grand Coulee Dam.*

Notwithstanding the foregoing provisions of this section 13, because of the special restrictions on reservoir draft below elevation 1208 feet at Grand Coulee Dam, and because of the special provision relating to such excess draft in paragraph 9(k)(1), the payments by downstream Project owners to the United States of America, pursuant to this Section 13, on account of

such headwater improvements shall be determined based on draft of such reservoir to an elevation no lower than 1208 feet.

(f) *Provision Relating to the Lewis River Basin.*

Payments for coordinated storage releases from reservoirs located in the United States as computed pursuant to the provisions of this section 13 shall not be applicable to Projects located on the Lewis River, Washington, since Pacific Power & Light Company and Public Utility District No. 1 of Cowlitz County, Washington have entered into a power contract dated June 4, 1957 and certain other agreements which provide for the settlement for headwater benefits for existing and potential Projects on the Lewis River in a different manner.

(g) *Effect of Payments.*

It is the intention of the parties that the payments provided for in this section shall, among other things, constitute full satisfaction as between the parties of all obligations under Section 10(f) of the Federal Power Act for the period covered by this agreement. The parties hereto agree to submit this agreement promptly to the Federal Power Commission. The non-federal parties will file this agreement with the Commission pursuant to Section 13.1 of the Regulations under the Federal Power Act.

(h) *Provision Relating to Payments by the United States.*

No payments, offsets, or credits shall be required to be made by the United States under this section 13 for benefits received by federal Projects from coordinated storage releases from an upstream reservoir Project completed after July 1, 1965 where the license for such reservoir Project requires such reservoir Project owner to provide such benefits without payments, offsets, or credits by the United States.

SECTION 14. *Other Charges.* The charges listed in this section shall be applicable to exchanges, transfers and services performed under this agreement.

(a) *Interchange Energy Imbalances.*

Interchange Energy imbalances between Systems referred to in paragraph 9(e)(3) shall be paid for at the following rates:

(1) When supplied from hydroelectric sources, two and one-half (2.5) mills per kilowatt hour.

(2) When supplied from thermal electric sources or miscellaneous purchases, one-fourth (0.25) mill per kilowatt hour plus incremental costs. Incremental costs shall include but not be limited to fuel costs, special maintenance costs and starting and shutdown costs of thermal electric plants, but shall not include fixed charges or other costs which would have been incurred by the supplying System if the transfer had not been made.

(b) *Interchange Energy Service Charge.*

Any party returning Interchange Energy under subsection 9(e) shall pay to the original supplying party a service charge at the following rates:

(1) No charge for energy returned during the hours between 8:00 a.m. and 10:00 p.m., Mondays through Saturdays, except national holidays.

(2) One-half (0.5) mill per kilowatt hour when returned at other hours, unless such energy was supplied during such other hours, or its return during such other hours was requested, in either of which events there shall be no charge.

(c) *Interchange Capacity Imbalances.*

Except for Interchange Capacity delivered under subparagraph 9(c)(2)(B), which shall be at no cost, Interchange Capacity imbalances between Systems resulting from Capacity Interchanges provided for in paragraph 9(c)(2) shall be paid for at the end of each Contract Year at the rate of twenty cents ($0.20) per kilowatt week.

(d) *Holding Interchange Energy Service Charge.*

Any party accepting the return of Holding Interchange Energy under paragraph 9(d)(4) shall pay to the importing party a service charge of one (1.0) mill per kilowatt hour.

When Holding Interchange Energy is delivered by a third party during the hours between 8:00 a.m. and 10:00 p.m., Mondays through Saturdays, except national holidays, and said energy was delivered to the third party at other hours, the original exporting party shall pay to the third party a service charge of one-half (0.5) mill per kilowatt hour whenever such service is required for the original delivery or subsequent return of Holding Interchange Energy.

(e) *Stored Energy Service Charge.*

Energy returned from storage pursuant to paragraph 9(j)(1) shall be paid for by the party requesting the return of such energy at the rate of one (1.0) mill per kilowatt hour.

(f) *Transmission Service Charges.*

Transmission capacity provided pursuant to subsection 10(a) by a party for transactions where it acts solely as a transferor shall in the absence of a separate agreement for such transmission between the parties involved, be paid for in accordance with the following rates and by the following parties:

(1) Interchange Energy—one-fourth (0.25) mill per kilowatt hour, paid by the receiving System.

(2) Holding Interchange Energy returned pursuant to subsection 9(d) and stored energy returned pursuant to subsection 9(j)—one-half (0.5) mill per kilowatt hour, determined at the time of such return and on the basis of the number of kilowatt hours of Holding Interchange Energy or stored energy returned, paid by the party requesting such return.

(3) In Lieu Energy—no charge, except when the priorities of subsection 9(i) are invoked by the supplying or receiving System to require the transferor to provide such transmission, in which case the party invoking the priority shall pay one-fourth (0.25) mill per kilowatt hour.

(4) Provisional Energy delivered or replaced pursuant to subparagraph 9(n)(1)(B)—one-fourth (0.25) mill per kilowatt hour paid by the Reservoir Party.

(5) Interchange Capacity delivered pursuant to paragraph 9(c)(2)—five cents ($0.05) per kilowatt week, paid by the receiving System.

(6) Return of energy received with the delivery of Interchange Capacity—one-fourth (0.25) mill per kilowatt hour, paid by the party requesting such return.

(g) *Special Storage Arrangements.* Unless otherwise agreed to by the parties to the storage arrangement, energy returned from storage pursuant to paragraph 9(j)(2) shall be paid for by the party requesting the return of such energy at the following rates:

(1) One (1.0) mill per kilowatt hour when returned during the hours between 8:00 a.m. and 10:00 p.m., Mondays through Saturdays, except national holidays.

(2) One-half (0.5) mill per kilowatt hour when returned at other hours.

(h) *Transfers to Avoid Spill.* Notwithstanding the foregoing subsections of this section there shall be no charge for the transfer of stored energy from the reservoir of one party to the reservoir of another party in order to avoid probable spill; provided, however, that if such energy is returned to the original supplying System and if it is determined at the end of the Drawdown Period, on the basis of such System's actual reservoir contents, that a part or all of such energy has been used by such supplying System, the energy so used shall be paid for by such supplying System to the party returning such energy at the rate of one (1.0) mill per kilowatt hour.

(i) *Billing.* Other than as provided in paragraph 9(e)(6) and in subsection 13(d), parties shall be billed monthly and shall make payment within 10 days after billing; provided, however, that charges other than charges under subsection 13(d) accruing under this agreement between the Administrator and any party hereto shall be converted into kilowatt hours of energy in the manner hereafter specified, and such energy shall be entered as appropriate debits or credits to the Administrator and such party in the exchange account established under contract between the Administrator and such party. The charges shall be converted into kilowatt hours of energy by dividing such charges by the rate currently employed by the Administrator for settlement of such exchange account.

(j) *Changes in Charges.* Commencing on July 1, 1969 and each fifth year thereafter, the parties shall, upon notice given by any party prior to each such July 1 specifying desired changes, review the charges in effect under this section. If the parties fail to agree on revised charges, the parties hereto who are subject to the jurisdiction of the Federal Power Commission with respect to such charges shall submit the matter on or before the following January 1 to the Commission for determination of charges to be made by such parties; and the other parties hereto agree, insofar as they may lawfully do so, that the charges to be made by them shall not be in excess of the charges so fixed by the Commission, provided that any of such other parties may, but shall not be obligated to, reduce any charge in effect at the time of such submission. Each party hereby gives its irrevocable consent to the intervention by all other parties in such proceeding before the Commission. The charges agreed upon or as finally determined by the Commission shall become effective at the beginning of the Contract Year following such agreement or determination.

PART V

General Provisions

Section 15. *Nonpower Uses.* Nothing in this agreement shall require a party to operate a Project in a manner inconsistent with its requirements for nonpower uses or functions, and no party shall be considered in violation of this agreement or suffer any penalty thereunder because of any Project operation undertaken in good faith for the purpose of preserving priority to such nonpower uses or functions, or of protecting against harm to human life or property.

Section 16. *Regulatory Authorities.* This agreement is subject to the regulatory powers of any federal or state agency having jurisdiction.

Section 17. *Miscellaneous Provisions.*

(a) *Work Hours.* This agreement, to the extent, if any, that it is of a character specified in the Work Hours Act of 1962 (Public Law 87-581, 76 Stat. 357-360) and is not covered by the Walsh-Healey Public Contracts Act (41 U.S.C. 35-45), is subject to the provisions contained in Exhibit 6, attached hereto, relating to said Work Hours Act of 1962, and to all other provisions and exceptions of said Work Hours Act of 1962, and the parties shall have the obligations of "contractors" thereunder.

(b) *Prison Labor.* A party hereto shall not employ any person undergoing sentence of imprisonment at hard labor.

(c) *Members of Congress.* No Member of, or Delegate to Congress, or Resident Commissioner shall be admitted to any share or part of this contract or to any benefit that may arise therefrom. Nothing, however, herein contained shall be construed to extend to such contract if made with a corporation for its general benefit.

(d) *Nondiscrimination.* The parties agree to comply with the provisions relating to the obligations of "contractors" contained in the nondiscrimination provisions of Executive Order No. 11114, dated June 22, 1963, which provisions are attached hereto as Exhibit 7.

Section 18. *Preservation of Rights of Public Bodies and Cooperatives.* Nothing contained in this agreement shall be construed to abrogate, modify, limit or otherwise change in any respect the right of any public body or cooperative to exercise preference and priority as provided by law or of the United States to accord such preference and priority.

Section 19. *Preservation of Contractual Rights and Obligations.* It is recognized that many of the parties hereto have existing contracts which may in some degree conflict with provisions herein. Nothing in this agreement will be construed to abrogate, modify, limit or otherwise change in any respect any existing contract of a party hereto, or to prevent the renewal or extension of the term thereof, or to prevent the continuing operation of the provisions of such contract in any replacement contract by the same parties or their successors in interest. All rights and obligations of the parties under this agreement shall be subordinate to and limited by the rights and obligations of the parties contained in such contracts; provided, however, that in the event any party to this agreement requests any service to which it would otherwise have been entitled hereunder from any other party hereto and the latter party is unable to provide such service because of conflicting terms and conditions of any such existing contract, the party requesting the service may offset the value of the service so denied to it, to the extent it is unable to obtain such service from other parties to this agreement, by refusing to perform an equivalent amount of the same service at the time or times that such service is first thereafter demanded by the party which originally denied such service.

Section 20. *Preservation of Water Rights.* Nothing contained in this agreement shall be construed to abrogate, modify, limit or otherwise change, in any respect, any water rights held by any party.

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SECTION 21. *Uncontrollable Forces.* A party shall not be considered to be in default in respect to any obligation hereunder if prevented from fulfilling such obligation by reason of uncontrollable forces, the term "uncontrollable forces" being deemed for the purpose of this agreement to mean any cause beyond the control of the party affected, including but not limited to flood, earthquake, storm, lightning, fire, epidemic, war, riot, civil disturbance, labor disturbance, sabotage, proceeding by court or public authority, or act or failure to act by court or public authority, which uncontrollable forces, by exercise of due diligence and foresight, such party could not reasonably have been expected to avoid. A party rendered unable to fulfill any obligation by reason of uncontrollable forces shall exercise due diligence to remove such inability with all reasonable dispatch.

SECTION 22. *Provision Relating to Canadian Storage.*

(a) The United States Entity shall use its best efforts to develop and implement operating plans for Canadian Storage with the Canadian Entity in order to obtain optimum power generation downstream in the United States consistent with the provisions of this agreement and the Treaty. To this end the United States Entity will consult with the other parties hereto as provided in this agreement.

(b) The United States of America shall assume the rights and obligations of a Reservoir Party in this agreement relative to Canadian Storage as if such storage were a part of the System of the United States of America, except to the extent that the operating plan (including any revision thereof) agreed upon by the United States Entity and the Canadian Entity does not permit implementation of such obligations.

(c) In accordance with the Treaty, before the first storage water from Canadian Storage becomes available for operation, the United States Entity and the Canadian Entity will agree on operating plans for each year until the total storage water is expected to become available; and in addition, commencing five years before the total storage water from Canadian Storage is expected to become available, operating plans will be agreed to annually for the sixth succeeding year of operation. Such operating plans will be designed to achieve optimum power generation in the United States until such time as generation facilities are installed at the dam described in Article II(2)(a) of the Treaty or at sites in Canada downstream therefrom, after which such operating plans shall be designed to achieve optimum power generation in both the United States and Canada or in either country as provided in the Treaty.

Prior to an agreement on such operating plans between the United States and Canadian entities, in accordance with the Treaty, studies shall be made on a timely basis and consistent with the provisions of the Treaty for the Coordinated System assuming utilization of available Canadian Storage to provide guidance to the United States Entity in regards to the optimum generation desired by Systems in the United States. The United States Entity, consistent with its obligations under the Treaty, shall use its best efforts to achieve such utilization in the operating plan finally determined and agreed to with the Canadian Entity.

Unless mutually agreed otherwise and consistent with the provisions of the Treaty, studies for the Coordinated System shall be conducted in accordance with the provisions and procedures set forth in section 6, section 7 and section 8.

(d) Nothing in this agreement shall be construed to be a delegation by the United States Entity of its rights and powers under the Treaty to any party hereto, nor shall this agreement impose upon the United States of America any liability for damages with respect to the operation of Canadian Storage beyond the liability of Canada under Article XVIII of the Treaty.

SECTION 23. *Provision Relating to Federal Reclamation Project Requirements.* Nothing contained in this agreement shall be construed to abrogate, modify, limit or otherwise change in any respect the right or the obligation of the United States of America to furnish power and energy to its present or future Federal Reclamation Project requirements.

SECTION 24. *Re-negotiation.* It is the intention of this agreement that all parties will obtain a net positive benefit from coordination of their facilities with the other parties over the term hereof. It is recognized however that the positions of the parties will change, and that the characteristics of the Coordinated System will change as the result of addition of thermal generation or may change as the result of changes in load shape or periods of peak load demands or other causes, and the parties agree that if the provisions of this agreement do not adequately accommodate such changes to provide optimum generation to Systems and to the Coordinated System, the parties will modify this agreement as required for such purpose. In the event that the continued participation in this agreement by any party without modification of its terms will cause for any reason under this agreement detriment to such party, in that such party is materially less able to provide from its Firm Resources economic utility service to its customers during the balance of the term hereof than it would be if this agreement were not in effect, such party may at any time give written notice to all other parties that it requests re-negotiation of all or any part of this agreement. Each party shall upon such notice, forthwith commence and pursue, without any unnecessary delay and for a reasonable time, good faith negotiations with all of the other parties for modification of this agreement as required to eliminate such detriment. If such negotiations shall fail to result in such modifications, then such party may upon notice to take effect at the beginning of the fifth Contract Year following the Contract Year in which the notice is given, irrevocably withdraw from this agreement such Firm Resources as are hereinafter permitted to be withdrawn. If any party or parties within one year after such notice shall file suit contesting the existence of such detriment, then such withdrawal shall not be effective unless there be a determination of such suit in favor of the withdrawing party. In such case such withdrawal shall be effective at the end of the Contract Year in which determination of the suit in favor of the withdrawing party becomes final or the beginning of the fifth Contract Year after notice, whichever is later. A withdrawing party which has in its Firm Resources any Project or share of output of a Project which is upstream from the tailrace of Bonneville Dam shall continue fully to coordinate all such Firm Resources and such Projects, either as a party hereto or through the owner of such Projects, under this agreement, but provided that such party shall withdraw all its other Firm Resources. Upon withdrawal settlement for accrued obligations and entitlements shall be made by the parties hereto by payment at appropriate rates for any energy accounts outstanding, and for other payments or charges due.

SECTION 25. *Notices.* Any notice to be given in accordance with the terms of this agreement shall be deemed properly given to the respective parties if mailed, postage prepaid, and addressed to each party's representative or representatives designated pursuant to section 5 at the principal offices of the party. Any notice to be given by the United States may be given by either the Administrator or the Division Engineer.

SECTION 26. *Additional Parties.*

(a) Additional parties may join in this agreement at any time that all existing parties agree to such joinder. Such joinder shall be evidenced by the execution of an addendum entitled "Agreement Joining Additional Party" which shall be signed by such additional party and all existing parties. The addendum shall bear the date of execution and shall bind such additional party to all of the covenants, terms and conditions of this agreement and such other provisions as may be agreed upon and included in the addendum, as of the date of such addendum or such other date as may be agreed to in such addendum. All such addenda shall be attached to and incorporated in this agreement.

(b) In the event that the High Mountain Sheep Project is finally licensed for non-federal construction, the licensee of the High Mountain Sheep Project, at such time as all appeals are resolved or time for appeals has expired, may become a party by subscription hereto, subject to the provision of subsection 13(h) of this agreement, and provided further that, to the extent of any inconsistency between the provisions of this agreement and the terms of the license granted for such Project, the terms of the license shall prevail.

IN WITNESS WHEREOF, the parties have executed this agreement in several counterparts.

UNITED STATES OF AMERICA
By DEPARTMENT OF THE INTERIOR

By CHARLES F. LUCE
Administrator, Bonneville Power Administration

By DIVISION ENGINEER, NORTH PACIFIC DIVISION,
CORPS OF ENGINEERS, DEPARTMENT OF THE ARMY

By W. W. LAPSLEY

THE UNITED STATES ENTITY

By CHARLES F. LUCE
Administrator of the Bonneville Power
Administration, Department of the Interior

By W. W. LAPSLEY
Division Engineer, North Pacific Division, Corps
of Engineers, Department of the Army

CITY OF EUGENE, OREGON By and Through
The Eugene Water & Electric Board

(SEAL)

Attest: BYRON PRICE
Supt Secy

By CALVIN R. SMITH
Pres.

(SEAL)

CITY OF SEATTLE, WASHINGTON

Attest: C. G. ERLANDSON
City Comptroller

By J. D. BRAMAN

(SEAL)

Attest: M. A. RUFFCORN
Deputy City Clerk

CITY OF TACOMA, WASHINGTON

By H. M. TOLLEFSON
Mayor

(SEAL)

Attest: PAUL NEIHART

PUBLIC UTILITY DISTRICT NO. 2 OF GRANT COUNTY, WASHINGTON

By WM. SCHEMPP

(SEAL)

Attest: L. J. RICHARDSON
Sec.

PUBLIC UTILITY DISTRICT NO. 1 OF CHELAN COUNTY, WASHINGTON

By IVAN J. COMPTON
Pres.

(SEAL)

Attest: F. W. SCHWAB

PUBLIC UTILITY DISTRICT NO. 1 OF PEND OREILLE COUNTY, WASHINGTON

By F. R. JORDAN

(SEAL)

Attest: HOWARD PREY
Sec.

PUBLIC UTILITY DISTRICT NO. 1 OF DOUGLAS COUNTY, WASHINGTON

By LLOYD McLEAN

(SEAL)

Attest: FRED C. HUSON
Act. Sec.

PUBLIC UTILITY DISTRICT NO. 1 OF COWLITZ COUNTY, WASHINGTON

By W. E. SAILORS
Pres.

(SEAL)

Attest: C. B. SCHOEGGL
Secy

PUGET SOUND POWER & LIGHT COMPANY

By L. E. KARRER
Vice-President

(SEAL)

Attest: CLARENCE D. PHILLIPS
Secretary

PORTLAND GENERAL ELECTRIC COMPANY

By FRANK M. WARREN
President

(SEAL)

Attest: M. E. THOMPSON
Assistant Secretary

PACIFIC POWER & LIGHT COMPANY

By E. ROBT. de LUCCIA
Vice President

(SEAL)

Attest: R. D. YEOMANS
Secretary

THE WASHINGTON WATER POWER COMPANY

By M. L. BLAIR
Vice President

MFH
APO

(SEAL)

Attest: JOHN C. HAUCK
Assistant Secretary

THE MONTANA POWER COMPANY

By R. M. BALL
Vice President

(SEAL)

Attest: JOHN W. CARLSON, JR.
Asst. Sec'y.

COLOCKUM TRANSMISSION COMPANY, INC.

By W. N. FARQUHAR
Vice President

COORDINATED SYSTEM FIRM RESOURCES EXISTING SEPTEMBER 15, 1964

HYDRO PROJECTS

Project	Location River	Type [1]	Normal Full El. - Ft.	Normal Bottom El. - Ft.	Usable Storage Capacity MSFD	Usable Storage Capacity MSFM	Peak Cap. Full Resv. MW	Minimum Discharge CFS [2]	Remarks
THE MONTANA POWER COMPANY									
Kerr	Flathead	1	2893.0	2883.0	614.080	20.200	185.0		
Thompson Falls	Clark Fork	2	2396.0	2380.0			40.0		
PACIFIC POWER & LIGHT COMPANY									
Swift #1	Lewis	1	1000.0	878.0	225.400	7.414	268.0	0	
Swift #2	Lewis	4					77.0	0	Entire output of Swift #2 Contracted to Pacific
Yale	Lewis	1	490.0	430.0	95.400	3.138	134.0	0	
Merwin	Lewis	1	239.6	190.0	91.700	3.016	150.0	650	
East Side	Klamath	4					3.3		
West Side	Klamath	4					0.8		
John C. Boyle	Klamath	2					88.0		
Copco #1	Klamath	2					26.5		
Copco #2	Klamath	4					30.0		
Iron Gate	Klamath	2					20.0		
Fall Creek	Fall Creek	5					2.3		
Upper Klamath Lake	—	1	4143.3	4137.0	234.600	7.717	—	Variable	
Prospect #1	Rogue	5					4.6		
Prospect #2	Rogue	3					36.8		
Prospect #3	So. Fk. Rogue	5					7.8		
Prospect #4	Rogue	5					1.3		
Gold Ray	Rogue	5					1.3		
Eagle Point	So. Fk. Big Butte Cr.	5					3.2		
Lemolo #1	No. Umpqua	1	4148.5	4095.5	6.370	0.210	30.0		
Lemolo #2	No. Umpqua	2					35.1		
Clearwater #1	Clearwater	2					18.7		
Clearwater #2	Clearwater	2					32.0		
Toketee Falls	No. Umpqua	2					44.5		
Fish Creek	Fish Creek	2					12.4		
Slide Creek	No. Umpqua	4					19.0		
Soda Springs	No. Umpqua	2					12.0		
Winchester	No. Umpqua	4					0.5		
Condit	White Salmon	3					15.0		
Minor Hydro	Oregon & Washington	5					18.6		Minor Hydro includes Albany, Bend, Naches Drop, Lebanon, Powerdale, Naches, Tygh Valley, Stayton, Cline Falls, Wallowa Falls.

[1] Type: 1 Seasonal Storage Project
2 Pondage Project Downstream from Seasonal Storage
3 Pondage Project
4 Run-of-river Project Downstream from Seasonal Storage
5 Run-of-river Project

[2] Cyclical Reservoirs.

Exhibit 1
Sheet 1

Exhibit 1
Sheet 2

COORDINATED SYSTEM FIRM RESOURCES EXISTING SEPTEMBER 15, 1964

HYDRO PROJECTS

Project	Location River	Type[1/]	Normal Full El. - Ft.	Normal Bottom El. - Ft.	Usable Storage Capacity MSFD	Usable Storage Capacity MSFM	Peak Cap. Full Resv. MW	Minimum Discharge CFS[2/]	Remarks
PORTLAND GENERAL ELECTRIC COMPANY									
Round Butte	Deschutes	1	1945.0	1860.0	138.260	4.548	300.0		3,000 cfs (3500 cfs March through June) average monthly minimum discharge or inflow, whichever is less.
Pelton	Deschutes	2	1580.0	1573.0			124.0		
Timothy Lake	Oak Grove Fork	1	3190.0	3125.0	31.130	1.027	—	10	
Oak Grove	Oak Grove Fork	2	1990.0	1958.0			49.0		
North Fork	Clackamas	2	665.0	646.0			54.0		
Faraday	Clackamas	4					44.0		
River Mill	Clackamas	2	388.8	381.0			23.0		
Bull Run	Sandy	3	655.0	648.0			22.0		
T. W. Sullivan	Willamette	4					15.0		
PUGET SOUND POWER & LIGHT COMPANY									
Upper Baker	Baker	1	724.0	674.0	93.116	3.063	103.0		
Lower Baker	Baker	1	438.6	355.0	71.776	2.361	110.4		
White River	White	1	543.0	515.0	23.522	0.774	63.8		
Snoqualmie Falls	Snoqualmie	3					44.0		
Electron	Puyallup	3					26.4		
Nooksack	Nooksack	3					1.7		
THE WASHINGTON WATER POWER COMPANY									
Post Falls (C. d'Alene)	Spokane	1	2128.0	2120.5	112.500	3.700	15.0		
Upper Falls	Spokane	2	1870.5	1864.3			10.2		
Monroe St.	Spokane	4					7.2		
Nine Mile	Spokane	2	1606.6	1590.0			18.0		
Long Lake	Spokane	1	1536.0	1512.0	52.540	1.730	72.5		
Little Falls	Spokane	2	1362.0	1351.0			36.0		
Noxon	Clark Fork	1	2331.0	2295.0	116.300	3.830	430.0		
Cabinet Gorge	Clark Fork	2	2175.0	2160.0			230.0		
Lewiston	Clearwater	3	764.0	761.0			10.4		
Meyers Falls	Colville	3					1.4		
Priest Lake Storage	Priest Lake, Idaho	1	3.0*	0*	36.480	1.200			

[1/] Type: 1 Seasonal Storage Project
2 Pondage Project Downstream from Seasonal Storage
3 Pondage Project
4 Run-of-river Project Downstream from Seasonal Storage
5 Run-of-river Project

[2/] Cyclical Reservoirs.

* Gage heights.

COORDINATED SYSTEM FIRM RESOURCES EXISTING SEPTEMBER 15, 1964

HYDRO PROJECTS

Project	Location River	Type[1/]	Normal Full El. - Ft.	Normal Bottom El. - Ft.	Usable Storage Capacity MSFD	Usable Storage Capacity MSFM	Peak Cap. Full Resv. MW	Minimum Discharge CFS[2/]	Remarks
PUBLIC UTILITY DISTRICT NO. 1 OF CHELAN COUNTY									
Chelan	Chelan Falls	1	1100.0	1079.0	341.500	11.230	53.0		
Rocky Reach[3/]	Columbia	2	707.0	703.0			815.0		
Rock Island	Columbia	4	606.4	602.9			249.0		Peaking capacity before Wanapum encroachment.
PUBLIC UTILITY DISTRICT NO. 2 OF GRANT COUNTY									
Priest Rapids[3/]	Columbia	2	488.0	481.5			912.0		
Wanapum[3/]	Columbia	2	571.5	560.0			983.0		
PUBLIC UTILITY DISTRICT NO. 1 OF PEND OREILLE COUNTY									
Box Canyon	Pend Oreille	2	2031.3	2012.5			82.0		3 hr. peaking capability 77.2 Mw under lowest flows.
Calispel Creek	Near Dalkena	5	2425.0	2404.6			0.6		
Sullivan Lake	Nr Metaline Falls	1	2588.7	2564.0	15.640	0.514	—		

[1/] Type: 1 Seasonal Storage Project
2 Pondage Project Downstream from Seasonal Storage
3 Pondage Project
4 Run-of-river Project Downstream from Seasonal Storage
5 Run-of-river Project

[2/] Cyclical Reservoirs.

[3/] Project outputs after encroachment presently allocated to other Systems on a percentage basis, as follows:

	Rocky Reach	Wanapum	Priest Rapids
Pacific Power & Light Co.	7.1	36.44825	30.04825
Portland General Electric Co.	16.0	31.44825	26.34825
Puget Sound Power & Light Co.	50.0	17.18750	14.78750
The Washington Water Power Co.	3.9	13.09100	10.99100
Colockum Transmission Company, Inc.	23.0	—	—
Public Utility District #2 of Grant County	—	1.82500	1.82500
City of Seattle	—	—	8.00000
City of Tacoma	—	—	8.00000
	100.0	100.0	100.0

Exhibit 1
Sheet 4

COORDINATED SYSTEM FIRM RESOURCES EXISTING SEPTEMBER 15, 1964

HYDRO PROJECTS

Project	Location River	Type[1/]	Normal Full El. - Ft.	Normal Bottom El. - Ft.	Usable Storage Capacity MSFD	Usable Storage Capacity MSFM	Peak Cap. Full Resv. MW	Minimum Discharge CFS[2/]	Remarks
CITY OF SEATTLE									
Ross	Skagit	1	1600.0	1475.0	515.686	17.000	446.0		Amount required to maintain 1000 cfs average discharge at Gorge.
Diablo	Skagit	2	1205.0	1195.0			159.0		
Gorge	Skagit	2	880.0	870.0			175.0		
Newhalem	Newhalem Creek	5					2.0		
Cedar Falls	Cedar	5					30.0		
CITY OF TACOMA									
Cushman #1	Skokomish	1	738.0	615.0	187.600	6.171	47.0	0	
Cushman #2	Skokomish	2	480.0	400.0			96.0		
Alder	Nisqually	1	1207.0	1114.0	90.600	2.980	52.0	250-500	Variable, depending on requirements of City of Centralia.
La Grande	Nisqually	2	935.0	910.0			67.0		
Mayfield	Cowlitz	3	425.0	415.0			135.0[3/]		
EUGENE WATER AND ELECTRIC BOARD									
Leaburg	McKenzie	4					14.8		
Walterville	McKenzie	4					9.4		
Carmen	McKenzie	3	2605.0	2525.0			101.6		
Trail Bridge	McKenzie	3	2092.0	2045.0			11.5		

[1/] Type: 1 Seasonal Storage Project
2 Pondage Project Downstream from Seasonal Storage
3 Pondage Project
4 Run-of-river Project Downstream from Seasonal Storage
5 Run-of-river Project

[2/] Cyclical Reservoirs.

[3/] Estimated.

COORDINATED SYSTEM FIRM RESOURCES EXISTING SEPTEMBER 15, 1964

HYDRO PROJECTS

Project	Location River	Type[1/]	Normal Full El. - Ft.	Normal Bottom El. - Ft.	Usable Storage Capacity MSFD	Usable Storage Capacity MSFM	Peak Cap. Full Resv. MW	Minimum Discharge CFS[2/]	Remarks
UNITED STATES COLUMBIA RIVER SYSTEM									
Hungry Horse	S. Fk. Flathead	1	3560.0	3336.0	1593.600	52.421	328.0	145	Hungry Horse minimum discharge is 145 cfs or more when required for load protection or voltage control. Average monthly minimum discharge is estimated to be 400 cfs.
Albeni Falls	Pend Oreille	1	2062.5	2049.7	582.400	19.158	49.0		
Grand Coulee	Columbia	1	1290.0	1208.0	2638.000	86.776	2292.0		
Chief Joseph	Columbia	2	946.0	930.0			1178.0		
McNary	Columbia	2	340.5	335.0			1127.0		
The Dalles	Columbia	2	160.0	155.0			1283.0		
Bonneville	Columbia	2	74.0	70.0			558.0		
Ice Harbor	Snake	2	440.0	437.0			310.0		
Hills Creek	M. Fk. Willamette	1	1541.0	1414.0	122.800	4.039	34.0	100-100	Willamette basin minimum outflows vary seasonally. The first figure applies to July-Nov., the second figure to Feb.-June. Minimum outflow during December and January is inflow.
Lookout Point	M. Fk. Willamette	1	926.0	819.0	169.700	5.582	138.0	1000-1200	
Dexter	M. Fk. Willamette	2					17.0		
Cougar	S. Fk. Willamette	1	1690.0	1516.0	77.600	2.553	28.8	200-300	
Detroit	N. Santiam	1	1563.5	1425.0	162.000	5.329	115.0	750-1000	
Big Cliff	N. Santiam	2					21.0		
Roza	Yakima	5					13.0		
Chandler	Yakima	5					13.5		

[1/] Type: 1 Seasonal Storage Project
2 Pondage Project Downstream from Seasonal Storage
3 Pondage Project
4 Run-of-river Project Downstream from Seasonal Storage
5 Run-of-river Project

[2/] Cyclical Reservoirs.

Exhibit 1
Sheet 5

Exhibit 1
Sheet 6

COORDINATED SYSTEM FIRM RESOURCES EXISTING SEPTEMBER 15, 1964

THERMAL & MISCELLANEOUS RESOURCES

Plant or Source	Location	Type	Peak Capacity MW
PACIFIC POWER & LIGHT COMPANY			
Lincoln	Portland	Steam	47.0
Pittock	Portland	"	4.0
Springfield	Springfield	"	5.0
Astoria	Astoria	"	7.0
North Bend	North Bend	"	15.0
Trinity Center	Trinity Center	Diesel	0.3
Tillamook	Tillamook	Steam	6.5
Tillamook	Tillamook	Diesel	1.8
Wyoming Division	Wyoming	Transfer	100.0
Miscellaneous Resources			
Weyerhaeuser Timber Co. (Coos Bay)[1/]		Contract	4.0
Brooks Scanlon Inc.		"	2.5
Ochoco Lumber Co.		"	1.0
Warm Springs Lumber Co.		"	0.3
Georgia-Pacific Corp.		"	3.0
Weyerhaeuser Timber Co. (Cottage Grove)		"	3.0
Willamette National Lumber Co.		"	1.5
Cascade Lumber Co.		"	1.5
International Paper Co.		"	2.0
Cascade Plywood Corp.		"	2.0
Santiam Lumber Co.		"	2.1
Montana Light & Power Company		"	2.5
U.S.B.R. Green Springs		"	18.3
Idaho Power Company		Contract	53.0
Idaho Power Company		"	60.0

[1/] Through December 1964, nothing thereafter.

COORDINATED SYSTEM FIRM RESOURCES EXISTING SEPTEMBER 15, 1964

THERMAL & MISCELLANEOUS RESOURCES

Plant or Source	Location	Type	Peak Capacity MW
PORTLAND GENERAL ELECTRIC COMPANY			
Station L	Portland	Steam	82.0
Station E	Portland	Steam	9.0
Station H	Salem	Steam	3.0
Miscellaneous Resources			
U. S. Plywood Corp. Lake Oswego Corp. Dwyer Lumber Co.		Contract	1.0
PUGET SOUND POWER & LIGHT COMPANY			
Shuffleton	Renton	Steam	86.0
Miscellaneous Resources			
Weyerhaeuser Timber Co. Weyerhaeuser Timber Co.	Snoqualmie White River	Contract	10.0
Pope and Talbot Inc.	Port Gamble	Contract	1.0
THE WASHINGTON WATER POWER COMPANY			
Miscellaneous Resources	City of Spokane	Hydro	1.0
Idaho Power Company		Contract	22.0

Exhibit 1
Sheet 7

Exhibit 1
Sheet 8

COORDINATED SYSTEM FIRM RESOURCES EXISTING SEPTEMBER 15, 1964
THERMAL & MISCELLANEOUS RESOURCES

Plant or Source	Location	Type	Peak Capacity MW
CITY OF SEATTLE			
Lake Union	Seattle	Steam	40.0
Georgetown	Seattle	Steam	21.0
CITY OF TACOMA			
Tacoma #2	Tacoma	Steam	56.0
Tacoma #1	Tacoma	Steam	9.0
EUGENE WATER AND ELECTRIC BOARD			
Steam Plant	Eugene	Steam	32.1
Miscellaneous Resources			
University of Oregon	Eugene	Contract	1.6
Weyerhaeuser Timber Co.	Springfield	Contract	5.0

HYDROELECTRIC PROJECTS

Project	Nameplate Rating Kilowatts
Columbia River Power System	
Albeni Falls	42,600
Big Cliff	18,000
Bonneville	518,400
Chandler	12,000
Chief Joseph	1,024,000
Cougar	25,000
Detroit	100,000
Dexter	15,000
Foster	20,000
Grand Coulee	1,944,000
Green Peter	80,000
Hills Creek	30,000
Hungry Horse	285,000
Ice Harbor	270,000
John Day	1,350,000
Lookout Point	120,000
Lower Monumental	405,000
McNary	980,000
Roza	11,250
The Dalles	1,119,000
Public Agencies	
Chelan County PUD	
Chelan	48,000
Rock Island	212,100
Rocky Reach	711,550
Cowlitz County PUD	
Swift #2	70,000
Eugene, City of	
Carmen	80,000
Leaburg	13,500
Trail Bridge	10,000
Walterville	8,000
Douglas County PUD	
Wells	542,000
Grant County PUD	
Priest Rapids	788,500
Wanapum	831,250
Pend Oreille County PUD	
Box Canyon	60,000
Sullivan Lake	13,600
Seattle, City of	
Cedar Falls	22,860
Diablo	120,000
Gorge	134,400
Newhalem	2,000
Ross	360,000
Tacoma, City of	
Alder	50,000
Cushman #1	43,200
Cushman #2	81,000
La Grande	64,000
Mayfield	120,000
Mossyrock	300,000
Private	
Montana Power Company (Columbia Basin)	
Kerr	168,000
Thompson Falls	30,000
Pacific Power & Light Co. (Excl. Wyoming Plants)	
Albany	800
Bend	1,110
Big Fork	4,150
Clearwater #1	15,000
Clearwater #2	26,000
Cline Falls	1,000
Condit	9,600
Eagle Point	2,813
Copco #1	20,000
Copco #2	27,000
Iron Gate	18,000
Fall Creek	2,200

Exhibit 2
Sheet 1

HYDROELECTRIC PROJECTS

Project	Nameplate Rating Kilowatts
Pacific Power & Light Co. (Cont.)	
East Side	3,200
Fish Creek	11,000
Gold Ray	1,500
John Boyle	79,990
Lebanon	144
Lemolo #1	29,000
Lemolo #2	33,000
Merwin	136,000
Naches	6,370
Naches Drop	1,400
Powerdale	6,000
Prospect #1	3,760
Prospect #2	32,000
Prospect #3	7,200
Prospect #4	1,000
Slide Creek	18,000
Soda Springs	11,000
Stayton	600
Swift #1	204,000
Toketee	42,500
Tygh Valley	2,250
Wallowa Falls	800
West Side	600
Winchester	500
Yale	108,000
Portland General Electric Co.	
Bull Run	21,000
Faraday	34,450
North Fork	38,400
Oak Grove	51,000
Pelton	108,000
River Mill	19,050
Round Butte	247,050
Sullivan	15,400
Puget Sound Power and Light Co.	
Electron	25,500
Lower Baker	103,500
Nooksack	1,500
Snoqualmie Falls #1	11,600
Snoqualmie Falls #2	30,090
Upper Baker	94,400
White River	70,000
Washington Water Power Co.	
Cabinet Gorge	200,000
Lewiston	10,000
Little Falls	32,000
Long Lake	70,000
Meyers Falls	1,200
Monroe Street	7,200
Nine Mile	12,000
Noxon Rapids	282,880
Post Falls	11,250
Upper Falls	10,000

Exhibit 2
Sheet 2

LIMITS OF RIGHTS TO RESTORATION

Project	Restoration Limit Megawatts: Coordinated System Critical Period 24 Months or less [1]	more than 24 months [2]
Columbia River Power System		
Albeni Falls	2	0
Big Cliff	1	1
Chandler	3	2
Cougar	3	0
Detroit	1	0
Dexter	2	1
Foster	0	3
Green Peter	5	2
Hills Creek	1	0
Hungry Horse	103	29
Lookout Point	2	1
Public Agencies		
Chelan County PUD		
Chelan	10	11
Cowlitz County PUD		
Swift #2	5	4
Eugene, City of		
Leaburg	0	1
Pend Oreille County PUD		
Box Canyon	12	11
Sullivan Lake	2	1
Seattle, City of		
Skagit River	18	33
Tacoma, City of		
Alder	3	3
Cushman #1	7	2
Cushman #2	15	7
La Grande	4	4
Mayfield	19	10
Mossyrock	24	14

Exhibit 3
Sheet 1

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Project	Restoration Limit Megawatts: Coordinated System 24 Months or less [1]	Restoration Limit Megawatts: Critical Period more than 24 months [2]
Private		
Montana Power Company (Columbia Basin)		
Kerr	50	6
Thompson Falls	6	0
Pacific Power & Light Company		
Condit	0	1
Merwin	11	10
Swift #1	7	10
Yale	9	11
Klamath River	10	2
Portland General Electric Company		
Oak Grove	1	0
Pelton	2	0
Sullivan	2	0
Puget Sound Power and Light Company		
Baker River	2	5
Washington Water Power Company		
Cabinet Gorge	19	11
Lewiston	1	1
Spokane River	4	0
Noxon Rapids	22	6

Any Project or group of Projects not listed on this Exhibit at the date of execution of this agreement shall have a restoration limit of zero, except Brownlee, Oxbow and Hells Canyon, for which the restoration limits have been determined to be 8 and 18, 3 and 13, and 6 and 23 megawatts, respectively.

[1] Limits apply whenever the Critical Period of the Coordinated System including Canadian Storage is 24 consecutive months or less.

[2] Limits apply whenever the Critical Period of the Coordinated System including Canadian Storage is more than 24 consecutive months.

Exhibit 3
Sheet 2

RESERVES

1. Probability Mathematics

(a) Capacity Loss Probabilities

(1) The capacity loss probability distribution will be determined considering all possible combinations of simultaneous generating unit Forced Outages. An example of such determination follows:

(A) System has two generating plants with a total of five units:

Plant	Unit	MW	Outage Rate
A	1	1	0.01
A	2	2	0.01
B	1	1	0.01
B	2	3	0.01
B	3	5	0.01

(B) For each possible outage magnitude, or state, all possible combinations are considered which will result in exactly such state. For example, the combinations of outages which will result in a loss of three (3) megawatts for this System are the following:

(i) A1, A2 out; B1, B2, B3 not out

(ii) A2, B1 out; A1, B2, B3 not out

(iii) B2 out; A1, A2, B1, B3 not out

(C) The probability of any combination existing, such as shown in 1(a)(1)(B)(i) above, is the product of the probabilities of the various single events making up such combination. For 1(a)(1)(B)(i) above, then, the probability is:

$$\Pr[\text{A1, A2 out; B1, B2, B3 not out}] = (0.01)^2(0.99)^3$$

(D) The probability of any state existing, or exactly such amount of capacity loss, is the sum of the probabilities of all the various combinations resulting in such state. Thus, for a capacity loss of three megawatts the probability is:

$$\Pr[3\text{ mw}] = (0.01)^2(0.99)^3 + (0.01)^3(0.99)^2 + (0.01)(0.99)^4$$

(E) If all units are the same size and have the same outage rate, this procedure reduces to the binomial formula

$$\Pr[\text{r-fold outage}] = \frac{n!}{r!(n-r)!} p^{r} (1.0-p)^{n-r}$$

where

n = number of units
r = number of units within such group on simultaneous Forced Outage
p = Forced Outage rate of the units

(F) The cumulative capacity loss probability distribution is generated from the capacity loss probability distribution as follows:

$$\Pr[\text{capacity loss} \geq m] = \Pr[m] + \Pr[m+1] + \ldots \Pr[n]$$

where

m = any given magnitude of Forced Outage
n = total Peaking Capability of System

This results in

$$\Pr[\text{capacity loss} \geq 0] = 1.0$$

Exhibit 4
Sheet 1

(2) The effect on the capacity loss probability distribution of any resource described in subdivision 8(b)(3)(A)(iii) shall be computed in accordance with the following:

(A) The probability of capacity loss for each of the participants shall be determined with all such resources excluded.

(B) The probability of capacity loss for the participants, as a group, shall be determined both with and without each such resource, and with the participants' shares of other such resources being included.

(C) For each such resource the difference in capacity loss calculated in (B) above for each given probability shall be divided among the participating parties according to their share of the output of such resource, and such quantity of capacity loss for each given probability shall be added to the amount of capacity loss for the same probability as determined in (A) above. Such procedure shall be repeated for a sufficiently large number of probabilities to result in an accurate probability distribution.

(b) Peak Load Probabilities

The Peak Load probability distribution for the weekday Peak Loads in any Period shall be assumed to be a normal, or Gaussian, distribution. Weekend Peak Loads shall not be considered. The Peak Load for any Period shall be assumed to have been estimated on the basis that the probability of a higher (or lower) Peak Load is one-half; that is, it will be assumed that the Peak Loads for the various Periods are estimated such that the estimate will be too high in half the Periods and too low in half the Periods. With these assumptions, and given the standard deviation of such distribution, the characteristics of a System's Peak Load probability distribution for any quantity of forecasted Peak Load may be determined. The number, R, of standard deviations above the mean of a normal probability distribution at which the expected value of the highest observation of various likely sample sizes occurs is given as follows:

Observations in sample	R
16	1.76
17	1.79
18	1.82
19	1.84
20	1.87
21	1.89
22	1.91
23	1.93
24	1.95
25	1.97

Thus, if the standard deviation, σ, of the Peak Load probability distribution (expressed in per unit of the mean) and the number of weekdays, w, in a given Period are known, the mean, $\bar{x}$, of the Peak Load probability distribution may be found from the forecasted Peak Load, P, of the Period by

$$\bar{x} = \frac{P}{1.0 + R_{w\sigma}}$$

and the standard deviation (expressed in terms of power) is obtained by multiplying $\bar{x}$ by σ. These two parameters describe fully the Peak Load probability distribution. With forecasted reserve defined as the difference between available Peaking Capability, C, and forecasted Peak Load, a Peak Load probability distribution may then be con-

structed for any assumed value of forecasted reserve:

$$\bar{x} = \frac{C - \text{forecasted reserve}}{1.0 + R_w\sigma}$$

(c) Load Loss Probabilities

The load loss probability distribution defines the probability of load loss for any value of forecasted reserve. The actual amount of reserve, or margin, at any time is

$$\underline{M} = C - \underline{L} - \underline{O}$$
$$= C - (\underline{L} + \underline{O})$$

where

$\underline{M}$ = margin (a probability distribution)
C = available Peaking Capability (a constant)
$\underline{O}$ = Forced Outage (a probability distribution)
$\underline{L}$ = Peak Load (a probability distribution)

The probability of load loss for any given forecasted reserve, which defines $\underline{L}$, is the probability of margin being less than zero; that is, it is the area of $\underline{M}$ to the left of zero. The method described herein for this determination is to find the probability of $(\underline{L} + \underline{O})$ being greater than C by convolving the Capacity Loss distribution and the Peak Load distribution, as follows:

(1) The capacity loss probability distribution is determined and, from it, the cumulative capacity loss probability distribution.

(2) A Peak Load probability distribution is determined for each of the assumed values of forecasted reserve (selected at frequent intervals in the range likely to be significant; for example, one percent intervals in the range zero to fifty percent).

(3) Each such Peak Load probability distribution is divided into intervals (of, say, 0.1 standard deviations from —5.0 to +5.0 standard deviations) defining assumed discrete Peak Loads such that the Peak Load representing each interval is assumed to have a value equal to the center of area of such interval and a probability equal to the area of such interval.

(4) For each of the discrete Peak Loads, L_i, computed for each value of forecasted reserve, the amount of capacity loss, O_i, which would result in load loss is determined. The sum of the products of the probability associated with each L_i and the cumulative probability associated with the corresponding O_i, then, is the probability of load loss for such value of forecasted reserve.

(5) By computing such a sum of cross products for each value of forecasted reserve, the load loss probability distribution is determined.

2. Allocation of Forced Outage Reserve

(a) The allocation of a given Coordinated System Forced Outage Reserve in a Period to the various Systems shall be as follows:

(1) A load loss probability distribution shall be determined for each System for such Period.

(2) The amount of forecasted reserve for each System shall be determined such that:

(A) The sum of such forecasted reserves for all Systems equals the given Coordinated System Forced Outage Reserve.

(B) The quantity of forecasted reserve selected for each System corresponds to the same probability of load loss (hence, the "isoprobability method") for all Systems.

(3) Such amount determined for each System shall be that System's Forced Outage Reserve for such Period, if such Period is within the Critical Peaking Period.

(b) Any party whose System, although fully integrated, is not entirely within the Coordinated System shall be included as follows:

(1) The Coordinated System Forced Outage Reserve in any Period shall be initially determined as if the entire system of such party were included therein.

(2) The load loss probability distribution for such party, as described in 2(a) above, shall be computed as if the entire system of such party were included.

(3) The Forced Outage Reserve for such party in such Period shall bear the same proportion to the quantity of forecasted reserve allocated to such system in 2(a)(2)(B) above as the Peaking Capability of that part of such system included in the Coordinated System bears to the total Peaking Capability of such entire system. The remainder of such forecasted reserve shall be assumed to be available on the portion of such system not included in the Coordinated System.

(4) The Forced Outage Reserve of the Coordinated System initially determined in 2(b)(1) shall be reduced by such remainder.

If such party elects, on notice to all other parties hereto, to include such portion of its system not included in the Coordinated System for the sole purpose of contributing to and benefiting from the provisions of this agreement pertaining to Forced Outage Reserve, the remainder of forecasted reserve as determined in paragraph 2(b)(4) above shall be added to the Forced Outage Reserve of such party and the Coordinated System. Notwithstanding the provisions of subsection 6(c), such party may, at the time of such determination, increase an indicated import of firm capacity from the portion of its system outside the Coordinated System by the amount of such remainder, and such increase shall be considered a Firm Resource for the purpose of determining Firm Peak Load Carrying Capability. The provisions of subsection 9(q) shall be extended, upon such election and subsequent adjustments, to include all of such party's system.

3. Forced Outage Rates

(a)	Existing and new hydro	0.0073
(b)	Existing thermal (1964)	0.0101
(c)	New thermal	
	(1) NPR (Dual Purpose)	
	Turbine-Generator:	0.0078
	Reactor:	0.0300
	(2) Fossil and Nuclear (Single Purpose)	
	(A) 0-100 MW	0.015
	(B) 101-300 MW	0.035
	(C) 301-500 MW	0.050
	(D) above 500 MW	0.055

4. Peak Load Characteristics

The standard deviations of the Peak Load probability distributions are assumed to be as follows:

System	Months	Standard Deviation
Coordinated	All	0.020
Federal	"	0.025
All others	"	0.030

Exhibit 4
Sheet 4

PACIFIC NORTHWEST COORDINATION AGREEMENT

COMPUTATION OF PAYMENTS UNDER SUBSECTION 13a
1963-64 CONTRACT YEAR
Capital and Annual Costs—Storage Reservoir—Joint Use Facilities Allocated to Power

	Hungry Horse	Albeni Falls	Grand Coulee	Kerr	Noxon Rapids	Sullivan Lake	Coeur d'Alene Lake	Long Lake	Lake Chelan	Priest Lake
Capital Costs										
Joint Use Facilities Allocated to Power										
Land	$ 4,019,006	$ 2,758,024	$ 6,450,250	$ 797,422	$30,912,214	$ 47,244	$1,029,170	$1,425,554	$2,559,855	$ —
Land Excluded	54,260,802	8,342,973	67,165,924	3,733,689	24,740,303	136,400	498,395	2,713,206	3,209,782	127,989
Total	58,279,808	11,100,997	73,616,174	4,531,111	55,652,517	183,644	1,527,565	4,138,760	5,769,637	127,989 [3]
Other		764,000 [1]	43,859,227 [2]							
	58,279,808	11,864,997	117,475,401	4,531,111	55,652,517	183,644	1,527,565	4,138,760	5,769,637	127,989
Annual Costs										
Operation (Incl. Rents & Overflow)	11,911	18,117	151,496	222,646	2,693	—	61,138	8,011	960	1,185
Maintenance	27,268	55,306	345,932	1,186	304	6,141	605	261	17,669	—
Admin. & General	19,966	22,027	131,167	1,358	899	1,842	10,218	2,482	5,588	356
Taxes	—	—	—	101,497	1,246,616	863	34,217	92,708	27,117	—
Interest	1,748,394	296,625	2,208,485	271,867	3,339,151	8,066	91,654	248,326	187,513	7,679
Depreciation or Amortization	516,650	121,711	652,607	2,871	19,025	1,308	383	2,086	10,422	440
Insurance	58,280	11,865	117,475	4,531	55,653	184	1,528	4,139	5,770	128
Interim Replacements	11,656	18,984	82,233	—	—	—	—	—	—	—
Depreciation — Irrigation			877,185							
Total	$ 2,394,125	$ 544,635	$ 4,566,580	$ 605,956	$ 4,664,341	$ 18,404	$ 199,743	$ 358,013	$ 255,039	$ 9,788
Basic Factors Used in Determining Annual Costs										
Taxes %	—	—	—	2.24	2.24	0.47	2.24	2.24	0.47	—
Interest—Power Allocation %	3.00	2.50	3.00	6.00	6.00	4.392	6.00	6.00	3.25	6.00
Assumed Life of Facilities or Amortization Period Years	50	50	50	75	75	40	75	75	75	50
Depreciation or Amortization Factor—Power %	0.8865	1.0258	0.8865	0.0769	0.0769	0.9588	0.0769	0.0769	0.3247	0.344
Irrigation %			2.0							
Insurance %	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Interim Replacements %	0.02	0.16	0.07	—	—	—	—	—	—	—

[1] Estimated costs of earthfill dam in lieu of powerhouse.

[2] Costs of joint use facilities allocated to irrigation.

[3] $127,989 is the cost incurred by The Washington Water Power Company for providing storage from facilities owned by the State of Idaho. These facilities are operated under a continuing agreement between the State and Northern Lights, Inc., which Northern Lights has assigned to The Washington Water Power Company. This cost is included in this computation in consideration of The Washington Water Power Company's commitment to make this storage available pursuant to the terms of this agreement for the duration thereof subject to the terms of the Idaho-Northern Lights agreement and Northern Lights-The Washington Water Power Company assignment.

Exhibit #5

PROVISIONS RELATING TO WORK HOURS

(a) No contractor or subcontractor contracting for any part of the contract work shall require or permit any laborer or mechanic to be employed on such work in excess of eight hours in any calendar day or in excess of forty hours in any workweek unless such laborer or mechanic receives compensation at a rate not less than one and one-half times his basic rate of pay for all hours worked in excess of eight hours in any calendar day or in excess of forty hours in such workweek, whichever is the greater number of overtime hours.

(b) In the event of any violation of the provisions of paragraph (a), the contractor and any subcontractor responsible for such violation shall be liable to any affected employee for his unpaid wages. In addition, such contractor or subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed, with respect to each individual laborer or mechanic employed in violation of the provisions of paragraph (a), in the sum of $10 for each calendar day on which such employee was required or permitted to work in excess of eight hours or in excess of forty hours in a workweek without payment of the required overtime wages.

(c) The Contracting Officer may withhold, or cause to be withheld, from any moneys payable on account of work performed by the contractor or subcontractor, the full amount of wages required by this contract and such sums as may administratively be determined to be necessary to satisfy any liabilities of such contractor or subcontractor for liquidated damages as provided in paragraph (b).

Exhibit 6

PROVISIONS RELATING TO DISCRIMINATION

During the performance of this contract, the contractor agrees as follows:

(1) The contractor will not discriminate against any employee or applicant for employment because of race, creed, color or national origin. The contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, creed, color, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion, or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by the contracting officer setting forth the provisions of this non-discrimination clause.

(2) The contractor will, in all solicitations or advertisements for employees placed by or on behalf of the contractor, state that all qualified applicants will receive consideration for employment without regard to race, creed, color, or national origin.

(3) The contractor will send to each labor union or representative of workers with which he has a collective bargaining agreement or other contract or understanding, a notice, to be provided by the agency contracting officer, advising the said labor union or workers' representative of the contractor's commitments under this section, and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(4) The contractor will comply with all provisions of Executive Order No. 10925 of March 6, 1961, as amended, and of the rules, regulations and relevant orders of the President's Committee on Equal Employment Opportunity created thereby.

(5) The contractor will furnish all information and reports required by Executive Order No. 10925 of March 6, 1961, as amended, and by the rules, regulations, and orders of the said Committee, or pursuant thereto, and will permit access to his books, records, and accounts by the contracting agency and the Committee for purposes of investigation to ascertain compliance with such rules, regulations, and orders.

(6) In the event of the contractor's noncompliance with the non-discrimination clauses of this contract or with any of the said rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 10925 of March 6, 1961, as amended, and such other sanctions may be imposed and remedies invoked as provided in the said Executive Order or by rule, regulation, or order of the President's Committee on Equal Employment Opportunity, or as otherwise provided by law.

(7) The contractor will include the provisions of paragraphs (1) through (7) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the President's Committee on Equal Employment Opportunity issued pursuant to section 303 of Executive Order No. 10925 of March 6, 1961, as amended; so that such provisions will be binding upon each subcontractor or vendor. The contractor will take such action with respect to any subcontract or purchase order as the contracting agency may direct as a means of enforcing such provisions, including sanctions for noncompliance; *Provided, however*, that in the event the contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by the contracting agency, the contractor may request the United States to enter into such litigation to protect the interests of the United States.

Exhibit 7

STABILITY OF ELECTRIC POWER SERVICE
IN
THE STATE OF WASHINGTON

* * *

A Report Prepared
For
Governor Daniel J. Evans
Of
The State of Washington

By
Washington Utilities and Transportation
Commission

February 14, 1966

STATE OF WASHINGTON
DANIEL J. EVANS, Governor

COMMISSIONERS:
FRANCIS PEARSON, CHAIRMAN
PATRICK D. SUTHERLAND
DAYTON A. WITTEN

ROBERT D. TIMM
SECRETARY AND ADMINISTRATIVE OFFICER

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION
OLYMPIA
98502

February 14, 1966

Honorable Daniel J. Evans
Governor of the State of Washington
Legislative Building
Olympia, Washington 98501

Dear Governor Evans:

Pursuant to your letter of November 12, 1965, we have studied the possibility of an extensive electric power outage occurring in this state and are pleased to submit this report on our findings.

As a result of our investigation, it is our opinion as well as the consensus of qualified engineers from the various local generating utilities and the Bonneville Power Administration, that it is highly unlikely there could be any extensive or serious power outage in the State of Washington or to the Northwest Power Pool. The conditions and factors that led to the November power blackout in the northeast part of the United States do not exist in this area's power network, primarily because of dissimilar sources of power as well as greater technical experience by our engineers in the design and operation of extensive power networks.

It is our sincere hope this report will allay any fears the general public may have that this state or the Northwest Power Pool could be subject to a widespread power outage, with the resulting inconvenience and possible danger to life and property, comparable to that which occurred in the Northeast on November 9th and 10th. We wouldn't be so naive as to claim there will be no future electric outages

in some areas of our state, since any mechanical device is subject to failure and there will always be unforeseen and uncontrollable forces of nature that could seriously damage transmission or generating facilities. However, our investigation shows that electric utilities in this area, recognizing the possibility of damage to facilities, have plans and procedures for restricting the extent and duration of any power failure. We have also found that a large number of activities with a critical need for continuous electric service, have emergency generating equipment available to tide them over any temporary restriction in their normal source of electric utility service.

The Commission is pleased to report it has had the full cooperation of all the electric utilities, both private and public, as well as the Bonneville Power Administration, with its investigation. Many public service activities that require a continuing source of electric power were also helpful in advising the Commission of their plans for operating in case of a power outage.

Very truly yours,

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

FRANCIS PEARSON, Chairman

PATRICK D. SUTHERLAND, Commissioner

DAYTON A. WITTEN, Commissioner

ROBERT D. TIMM
Secretary

INTRODUCTION

Starting late in the afternoon of November 9, 1965 and continuing into the morning of November 10th, a large section of northeast United States and the Province of Ontario, Canada, were subject to a total interruption of electric service. It was probably the largest and most extensive power failure in the history of the electric industry. The outage lasted from a few minutes in some locations to more than a half a day in others, which included most of the City of New York. The power interruption started about 5:16 p.m., when there is usually the greatest demand for electric power, and over 30 million people living in the area were more or less affected and inconvenienced by the blackout. This unprecedented power blackout directly focused the attention of President Lyndon B. Johnson and others on the importance of an uninterrupted source of electric power to the health, safety and well being of the public as well as the defense of the country. President Johnson immediately directed Chairman Swidler of the Federal Power Commission to make a thorough study of the cause of the power failure and determine what could or should be done to prevent a recurrence of such an outage. Committees from both houses of Congress also planned to investigate this Northeast power blackout.

Following the wide publicity given to the November 9-10, 1965 interruption of electric service throughout the northeast section of the United States, Governor Evans requested the Utilities and Transportation Commission to make a study to determine if "Washington's power distribution network could be subject to a similar failure and what steps we ought to take, if any, to prevent such a disastrous event in the State of Washington." With the highest per capita use of electricity in the nation, there is no question about the importance of reliable and dependable electric service to the citizens of Washington and the Pacific Northwest area.

Officials of all utilities in this area, both private and public, who operate electric generating plants, as well as the Bonneville Power Administration, were immediately contacted by the Commission and agreed to fully cooperate in any study that might be undertaken. It was decided to hold a meeting with qualified technical representatives from these utilities and obtain the benefits of their experience and

knowledge on the possibility of a complete or extensive electric power outage occurring in this area, an outage which might follow any accident to the area's power network or generating plants. It was also important to determine if the utilities had plans and procedures for limiting the extent or duration of any power outage to their customers. Arrangements were made to hold the meeting on December 17, 1965, in the Commission's office at Olympia. This late date was selected because several engineers who had a comprehensive knowledge of this area's electric transmission network and generating facilities had been requested by, and were assisting, the Federal Power Commission with its investigation of the cause of the northeast United States power blackout and would not be available for an earlier meeting.

Prior to the December meeting, the FPC had issued a preliminary report covering its investigation of the Northeast power failure. The report not only detailed the primary cause of the power outage, but located its starting point and the reason for it spreading to other utilities, even those that were many miles away. The report also pointed out the deficiencies and problems of certain utilities that led to unusual delays in restoring normal electric service to their customers. No doubt it was this inability to restore service in a reasonable length of time that created the greatest inconvenience and danger to the public, especially in the large cities and metropolitan areas. With full knowledge of the cause and effect of the Northeast power blackout, the Commission's investigation was also directed to determining if comparable conditions with their latent danger existed in the Pacific Northwest power systems. A review of the FPC report on the Northeast blackout is included as Appendix A of this report.

At the December 17, 1965 meeting, well qualified technical representatives from some fifteen generating utilities, as well as the Bonneville Power Administration and Mr. E. F. Timme, chief engineer of the Northwest Power Pool Coordinating Committee, were present. A complete list of all those who participated or were present at the meeting will be found in Appendix B. Everyone of this group of technical experts has spent many years working with the problems of providing adequate and dependable sources of power to his utility's customers and as a group have a complete and unequaled know-

ledge and understanding of all the facilities and operations of the Northwest power network. At the meeting, Mr. Timme, who had participated in the FPC's investigation of the Northeast power outage, reviewed the FPC's preliminary report on the cause of that trouble. He also compared the characteristics of the Northeast area's power network with the Pacific Northwest network and pointed out why it was unlikely this area would be exposed to any extensive or long duration blackout as had occurred in the Northeast. Mr. Kenneth Klein, assistant chief engineer of the Bonneville Power Administration which not only generates approximately 50% of the Northwest Power Pool's power, but through its extensive transmission lines, which form the backbone of this area's power transmission line grid, transmits or wheels a great deal of electric power for other members of the pool, explained in detail the extent and capabilities of the power grid. He also explained operating procedures that had been set up to prevent any local power outage from cascading into a serious or complete power blackout of any substantial part of the Pacific Northwest. The cascading effect was one of the primary factors in contributing to the widespread extent of the Northeast power interruption. Following these two men, representatives from each generating utility explained in detail their plans for operating under any emergency conditions that might arise from either trouble on the Pacific Northwest power grid or in a local generating plant. It appears that all the generating utilities have special operting programs designed to restrict the cascading effect of any power outage from expanding into a complete or extensive area-wide power interruption. Section I of the report is a compilation of the Northwest Power Pool's operating procedures. The Section also includes a list of the Federal Power Commission's recommendations to improve the stability of the Northeast (CANUSE) power network and related comments on the Northwest Power Pool procedures.

While the general public can be assured the State of Washington will probably never be faced with a complete or serious statewide electric outage, or even to a substantial part of the state, we must be realistic and realize there will always be natural disasters - floods, snow or ice storms, abnormal winds, etc., - that could cause electric service outages. While the outage may be of short duration, it could create problems for certain classes of electric users. Among

these users are hospitals, certain state institutions, communication companies, airports, gas utilities, water and sewer plants, and other vital public service activities. Recognizing the need for emergency power facilities by the above, this report has been expanded to include a general study of the present emergency power policy of hospitals, institutions, airports, gas distribution utilities, communication companies, water and sewer utilities. It seems that most of these activities are aware of the danger to their operations of even an electric outage of short duration and have available auxiliary power sources.

A number of cities were contacted regarding availability of auxiliary power to operate necessary public services in case of a general power outage. The cities' replies to the Commission's inquiry are contained in the Miscellaneous Section of the report.

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SECTION I

THE NORTHWEST POWER POOL

A. Transmission System and Generating Capability

The area served by the 17 utilities and agencies comprising the Northwest Power Pool involves nearly 500 plants having a capacity in excess of 1,000 kilowatts or more, with a total generating capacity of nearly 20,000,000 kilowatts. It was formed in 1942 by War Production Board Order No. L-94. The capacity gained by pooling during the War was in excess of 125,000 kw. Following the War, the members decided that the gains of pooling should be retained.

The transmission system of the State of Washington and northern Oregon is designed to serve the load areas which are predominantly west of the mountains from generating plants which are for the most part east of the Cascades. For this area 20 lines, 230-kv or higher, cross the mountains. This is part of a total network mileage of approximately 18,000 miles of 115-kv or higher voltage lines. By the close of calendar year 1969, 1,800 miles of 500-kv line will be added to the network, together with additional 230-kv lines to strengthen the transmission system.

With the beginning of the power pool operation in 1942, the Bonneville Power Administration made studies and experiments to determine the maximum stability limits of the system in order to maximize its transmission capability. These studies resulted in an increased loading on some lines up to 50% more than their designed capacity. Following these studies, studies were instigated to develop faster breaker and relay operation and the use of transfer trip relaying schemes. Series compensation was installed on long transmission lines to reduce the reactance. New power plants were equipped with generators of lower impedance and faster excitation, and generator dropping schemes developed. All of these actions maximized transmission capability still within the limits of system stability.

In studies to further the technical knowledge of system stability, BPA is studying and experimenting with the following:

a. Switches series compensation
b. Shunt reactor dropping
c. Dynamic load breaking

B. Load Shedding Program During Emergencies

Prior to a major outage in the Northwest on June 6, 1950, it had been the policy of the utilities to hang on-to all loads to the bitter end. After this outage the pool members considered and adopted the principle of automatically shedding or disconnecting certain loads during cases of low frequency. It should be realized that load shedding on reduced frequency cannot prevent a system breakup, but is a major aid to rapid restoration of service and can prevent damage to electric equipment of both the utilities and their customers.

The load shedding plan for the pool is reviewed annually and revised as required. The Northwest Power Pool area is arbitrarily divided into 11 load areas. In each of these load areas the total area load is matched against the internal generating capability, arriving at a required import. Excluded from the internal area generation is the generation served by either long transmission lines or the mid-Columbia plants which, during a system breakup, may or may not remain connected to any particular load area. For example, the Coulee and Chief Joseph generation may be fed into the Seattle-Tacoma area, Central Washington-Oregon area, or Eastern Washington and Northern Idaho load area, but these resources are not included in the resources of any of those three load areas. This determination is arbitrary, but does consider the probabilities. For example, the Seattle-Tacoma area is interconnected with the Portland area, the Central Washington-Oregon area and the Western British Columbia area, together with the mid-Columbia and Grand Coulee-Chief Joseph generation. It is improbable that all three sources of power into the area would be eliminated during any case of trouble. The dropping schedule in each area is related to the required input into an isolated area. This is still an area load concept rather than an individual system concept. In any breakup, it is expected that a segregated load area would not affect just a single company's system, but portions of several systems would be left in the isolated area.

For an expected peak load of 17,790 mw, 5,332 mw can be shed by automatic means, and 4,913 mw by manual means. On the BPA system, the 1,669 mw of automatic load shedding consists entirely of electrometalurgic loads. Most other

systems include dropping of area load feeders as well as industrial loads. It is never expected that in a system break-up all the manual shedding would be required. In any isolated area it may be necessary in addition to the automatic shedding to shed additional load manually to permit restoration of the frequency in that isolated area to be returned to 60 cycles. This permits resynchronization with the rest of the system. As soon as frequency has been restored to 58 cycles and is rising, load is either automatically restored or restored by direction of the dispatcher. In most cases, load which can be controlled by manned substations is restored by order of the dispatcher, while in automatic substations not under the direct control of the dispatcher load is restored by relay action.

C. Forced Outage Reserve and Spinning Reserve

In September 1964, all major generating utilities in the State of Washington became parties to the Pacific Northwest Coordination Agreement. This Agreement specifies that each party participate in providing reserve generating capacity to protect the Coordinated System from loss of load due to the breakdown of generating facilities. This Forced Outage Reserve is calculated by probability methods, utilizing outage factors obtained from experience records in the Northwest Power Pool. The total reserve requirement for the Coordinated System is based on the criteria of no loss of load, due to generating facility breakdown, in excess of an average of one day in twenty years. There is provision for interchange of capacity in case of breakdown of generating equipment on a System. For 1965-66, the Forced Outage Reserve amounts to 566 mw. An analysis to determine the amount of reserve required is made each year.

For those utilities having thermal capability, the Agreement required that energy reserve equivalent to the product of the thermal capability and outage factor be maintained. Energy reserve for hydro capability is not required, since the majority of hydro installations have either reservoir capacity to conserve energy, or spare hydro machine capacity to prevent energy loss.

The Agreement also provides that each generating utility provide a minimum spinning reserve of one per cent

of its generating capability less Forced Outage Reserve, at the time of the System's peak load. Each utility is responsible for locating the spinning reserve on its System.

D. Emergency Operating Procedures

Emergency operating procedures have been set up by individual Systems, as well as practices to train operating personnel under normal and emergency operating conditions. In the Northwest Power Pool, emergency procedures for coordinated operation have been developed over the years by the Operating Committee.

These procedures had been scheduled for general revision, in view of the changed operating conditions which have developed since interconnection with the Pacific Southwest. Following the November 9th disturbance in the Northeast, a subcommittee under the Operating Committee was set up, and a general revision is underway.

Communication channels in the Pool are quite extensive and alternate channels are generally available to important stations and between utility dispatching centers. Facilities utilized to provide communication channels include microwave, carrier current, private telephone lines, leased circuits from the telephone companies and toll circuits of the telephone companies.

Conference Calls are utilized to review operating procedures and conditions where a number of utilities are involved. Continuous communication is maintained between directly interconnected Systems at the dispatcher level, under both normal and emergency operating conditions.

E. Expected Performance of Northwest Power Pool Systems During Major Disturbances

Representatives of utilities in the Northwest Power Pool are of the opinion that a major disturbance comparable to that occurring in the Northeast on November 9, 1965, is unlikely to occur in the Northwest with the present generating and transmission facilities and under the present operating conditions. However, it should be recognized that smaller disturbances affecting local areas have occurred and will con-

tinue to occur from time to time. Many of these local disturbances result from adverse weather conditions.

In the event of a major disturbance affecting a widespread area, it is felt that the severity and duration of any outages will be considerably reduced from that occurring in the Northeast. This opinion is based on the following characteristics of the systems and emergency operating procedures which have been developed:

1. Generating plants in the Northwest are predominantly hydro, and have much more stable operating characteristics during system disturbances than do thermal generating units.

2. In the event that a hydro plant is isolated from the system, the time required to restart units is considerably less than for thermal units; and in practically all cases, no outside power source is required for startup.

3. The Northwest has an extensive network-type of high voltage transmission system. A majority of the breakers on high voltage lines are equipped with automatic reclosing, which will tend to keep the transmission system intact.

4. A coordinated load shedding program has been developed over the years in the Northwest Power Pool, that will automatically shed up to 1/3 of the estimated load in a major disturbance, supplemented by additional manual shedding, to enable the rapid restoration of normal service.

F. Federal Power Commission Recommendations and Related Comments on Northwest Power Pool Procedures

Nineteen recommendations were made by the Federal Power Commission in its preliminary report on the Northeast power failure of November 9, 1965. Thirteen of these recommendations were directed to the utilities in the Northeast (CANUSE) interconnection. These recommendations are set forth below, and comments on practices and procedures in the Northwest Power Pool are made in conjunction with the recommendations.

Recommendation:	All utilities, individually and collectively, should re-examine the overall design and operation of their power systems.
Northwest Power Pool:	The overall design and operation of individual systems is the responsibility of each system. Many of the separately owned lines within the Pool were designed and built for the best overall network operation by voluntary agreement. Sometimes in cooperative studies the affected utilities almost continuously review overall design, stability, reliability, and load balancing because no one utility's system can be studied in isolation from the rest of the Pool. The coordinated operation achieved on a voluntary basis in the Northwest Power Pool is directed by the Operating Committee. Operating procedures are continually reviewed and modified by this group.
Recommendation:	Closer working relationships between United States' and Canadian utilities.
Northwest Power Pool:	The two interconnected Canadian utilities are members of and have full representation on the Operating Committee, and participate fully in the Pool's coordinated operation.
Recommendation:	Accelerate construction of stronger internal transmission networks, and stronger interconnections between systems.
Northwest Power Pool:	The Pool is characterized by an extensive network-type transmission system, particularly in the western part. There

	are 125 interconnections between the sixteen Pool utilities, and additional transmission capacity is programmed as required.
Recommendation:	Coordinating groups for planning and operation should be established.
Northwest Power Pool:	A coordinating group for assisting in the coordination of operation has been established since the Pool was formed. Coordination of planning in the area is carried on through Pacific Northwest Utilities Conference Committee, CBIAC, Pacific Intertie Engineering Guidance Committee, and by groups of utilities interested in joint projects or transmission facilities.
Recommendation:	Additional system stability studies should be made.
Northwest Power Pool:	Data has been exchanged among systems desiring to make stability studies. Studies of maximum conceivable emergencies such as outages of all lines in a given mountain pass are being made and means are being sought to utilize high-speed communications to limit the effects of such outages to the dropping of pre-selected loads. At the present time, stability studies are being run in connection with the Pacific EHV interties under the Engineering Guidance Committee.
Recommendation:	Frequent checking and review of relay settings should be made.
Northwest Power Pool:	Each system has the responsibility of calibrating and reviewing its own relay settings. On interconnections and major internal transmission lines, utilities cooperate in the coordina-

tion of relay settings. Close liaison between relay, communication and operating departments of utilities has been recommended. At the Pool level, the Operating Committee sponsors meetings of relay engineers to facilitate any necessary coordination.

Recommendation: Review reserve margins in transmission system and generating capability.

Northwest Power Pool: Comments concerning reserves in the Pool are covered in an earlier section of this report.

Recommendation: It is desirable to give heavy weighting to service reliability.

Northwest Power Pool: The determination of economic and reliability factors in the construction of new facilities is a difficult problem. It is the responsibility of the constructing utility to make this determination.

Recommendation: Rate of response of generating capability should be considered in deciding between alternate projects.

Northwest Power Pool: In general, this is not a problem in the Northwest where hydro generating capability predominates. Hydro units have the ability to make sustained load changes throughout their operating range.

Recommendation: Study the adequacy of automatic equipment, communication facilities, intrumentation and operating procedures during emergencies.

Northwest Power Pool: The Pool utilities will cooperate in any industry-wide study to improve equipment performance during emergency.

Emergency operating procedures are currently under review by individual systems, and by the Pool's Operating Committee.

Recommendation: Load shedding should be considered as part of emergency procedures.

Northwest Power Pool: Since 1950, the Pool has developed a coordinated program for the emergency shedding of load, automatically supplemented by manual shedding, if necessary. In 1965-66, nearly 1/3 of the estimated peak load is equipped with underfrequency relays set to drop load between 59 cps and 55 cps.

Recommendation: A review of training procedures for emergencies should be made.

Northwest Power Pool: The training of operating personnel is the responsibility of each individual utility. Training procedures will no doubt vary among the utilities.

Recommendation: Auxiliary power supply should be maintained for instrumentation, communication facilities and startup of generating units.

Northwest Power Pool: Utilities in the Pool have auxiliary and backup power supply. In general, startup power requirements for hydro plants are small compared to those of a thermal station.

SECTION II

AIRPORTS

The Department of Aeronautics reports that among the airports serving commercial airlines there are some deficiencies in emergency power generating equipment. Even so the capability to maintain normal air traffic operations during an electrical power outage is good.

Airports having standby equipment for control tower operation, in-flight communications and for the operation of runway lights are:

Seattle-Tacoma	Spokane International
Renton Municipal	Yakima Municipal

Boeing (King County) has standby equipment for the tower and in-flight messages, but lacks equipment to operate its runway lights.

The F.A.A. Air Traffic Control Center in Auburn has emergency power equipment for the four long-range (200 mile) radar systems.

The Seattle-Tacoma airport will soon have standby equipment for the approach lighting systems.

Airports having emergency power generating equipment for in-flight communications, and in most cases for runway lights as well, are:

Hoquiam	Wenatchee
Ephrata	Felts Field (Spokane)
Walla Walla	

SECTION III

GAS DISTRIBUTION UTILITIES

A major electrical power failure would not only affect the customers of a gas transmission or distribution utility, but would also affect the gas utility. A large segment of business and industry might be shut down as a result of the power outage and the use of fuel gas might also be reduced proportionately.

1. The natural gas pumping stations owned by El Paso Natural Gas Company and Pacific Gas Transmission Company normally use commercial electrical energy for illumination, instrumentation, radio communications, cooling fans, pumps, and so forth. This load will be supplied by emergency power equipment at these stations during a power outage. A major power outage might leave some of El Paso Natural Gas Company's remotely located radio transmitter stations inoperative. If this were to happen, mobile units would be used as relay stations. The main compressor-driving engines are fueled with natural gas, therefore the supply of gas to the distributing companies would not be reduced during an electrical power failure.

2. Washington Natural Gas Company. This company serves the area on the east side of Puget Sound from Marysville to Olympia and south of there to Toledo. Everett, Seattle, Tacoma and the east side of Lake Washington are large population areas served.

A gas fueled generator at the main office in Seattle will operate some lights, one elevator, the office machines in the Customer Accounting section, and will provide power for radio communications. The telemetering circuits would not operate during a power outage.

Company radio communication centers in Tacoma, Everett and Olympia have standby generators, Other operation centers would depend on mobile radio for communications.

3. Northwest Natural Gas Company. This company operates principally in Oregon, but does supply gas in Washington to some towns and industries along the Columbia River as far east as White Salmon.

At the company's service center in Portland, Oregon, there is an emergency generator that will supply power for illumination and radio operation. There are several truck-mounted generators which could operate instrument circuits, a gasoline pump, or be used for other requirements.

4. Cascade Natural Gas Corporation. This distribution company serves several cities and towns in Washington including Bellingham, Bremerton, Longview, Mount Vernon, Pasco, Snohomish, Yakima and Wenatchee, as well as some towns in Oregon.

The Yakima office has emergency equipment for all its needs. At Mount Vernon, the emergency equipment will handle a part of the office load. No other centers have emergency power generating equipment, and there is none provided for radio communications anywhere. The mobile units would provide all communications.

5. Columbia Gas Company which serves Ritzville, Warden and Goldendale reported it would expect to lose approximately 90% of its gas load during a major electric power outage.

6. Olympic Gas Company serving Port Townsend with a mixture of propane and air, would not be affected immediately by a power outage since the only power used in the plant, other than lights, is provided by batteries.

7. Natural Gas Corporation of Washington which serves Port Angeles with propane-air gas has an emergency electric power unit which will and has supplied power for operation of the pressure boosting pump, the only critical part of the plant.

SECTION IV

HOSPITALS

The following summary of emergency power facilities in hospitals is based on a list prepared by the State Department of Health, which agency licenses hospitals operating within the State. Excluded are state-operated hospitals, military hospitals, and those operated by the federal government.

Of 119 hospitals having beds for 11,359 patients, 96 having beds for 10,501 patients have emergency power generating equipment. Information on two other hospitals is incomplete.

Listed below is information on hospitals located in the major cities:

Hospitals

City	Emergency Power	No Emergency Power	Beds
Seattle	17		3,639
"		6	274
Tacoma	6		1,034
"		2	87
Spokane	6		1,366
"		2	22
Yakima	3		346

Among the several codes adopted by the State Department of Health is one entitled "Construction Regulations for Hospitals" which was adopted January 24, 1962.

The rule (18.770 sec. 17) on Emergency Power requires that there be "adequate electrical generating equipment (or equivalent)" for, among other purposes, operation of fire alarm systems, X-ray machines, elevators, the heating plant and emergency lighting of exits, stairs, patients' corridors, operating rooms, and emergency rooms.

In the case of a federal grant being used for modernization of a hospital, adherence to the U. S. Public Health Service Regulations - Part 53 is required. This code requires emergency lighting in operating rooms, stairs, patients' corridors, and other areas.

SECTION V

RADIO BROADCASTING STATIONS

Following the Northeast power outage, widespread publicity was given to the cause and effect of the blackout, but little if any credit was given to the part the local radio stations played in preventing the general public from panicing. Many of the local radio stations had available a source of auxiliary power and continued operating during the power outage. With their news gathering facilities, the stations were able to broadcast the cause of the power outage and what was being done to correct the problem. This ability to continue operating plus the extensive use and availability of the transistorized radio receivers, made it possible to keep the public fully informed of what had happened. There is no doubt this broadcasting of the real facts about the blackout had a tremendous effect on preventing the spread of wild or terrifying rumors. One can only guess what might have happened in New York or other large cities, where thousands of people were attempting to get home, if someone had started a rumor the power outage had resulted from a nuclear attack by some foreign country or even an attack by creatures from another planet.

An investigation of the availability of standby power for radio stations in this state shows some 31 stations out of approximately 127 have a source of auxiliary power. The 31 stations are located in the cities listed below:

Seattle	Spokane	Bellingham
Tacoma	Yakima	Pasco
Mount Vernon	Everett	Wenatchee
Aberdeen	Pullman	Ellensburg
Puyallup	Longview	Bremerton
Centralia	Port Angeles	Grand Coulee

As will be noted, the radio stations with auxiliary power facilities are scattered throughout the state. This means there should be very few areas in the state that would be without radio coverage during any kind of an electric power outage.

It is highly recommended that in case of any kind of a disaster the public should tune in on a radio station

and not attempt to contact the local police or fire departments for information. Such action by the public generally creates an overload on the departments' communication facilities and prevents necessary calls from getting through. Being well aware of the various radio stations' actions of promptly investigating and informing the public of newsworthy events, there is no doubt if commercial power to a radio station was discontinued, its news reporters would immediately investigate that matter and promptly broadcast their findings. Likewise information on local disasters are quickly broadcast by radio stations. Small and efficient transistor radio receivers are available at very reasonable prices and every household should have at least one available for emergencies.

SECTION VI

RAILROADS

Railroads, like the telephone utilities, energize their telephone circuits with batteries. These batteries derive their charging energy from commercial power sources, and in the case of a power failure, the batteries would operate the telephone circuits for a period of eight hours at normal load. With the exception of the Union Pacific, all major railroads in the State are so equipped.

1. The Chicago, Milwaukee, St. Paul, and Pacific Railroad has no equipment for use during a power outage other than the telephone batteries.

2. The Northern Pacific Railway has auxiliary power at Pasco for operation of the classification yard only. A Centralized Train Control system in Spokane is, like their telephone circuits, battery operated. These also would provide power for a period of eight hours after failure of commercial power for charging. Most of the crossing and block signals are likewise battery operated. Block signals use considerable current and in order to not run down the batteries, they would be made inoperative in sections where there was no, or no anticipated, train movement.

Swing bridges can be manually operated, and those having lift spans can be closed manually.

The railway has a microwave system between Seattle and Portland for which standby equipment is planned.

3. The Union Pacific Railroad has no emergency power generating equipment in Washington. The reason is that all Union Pacific operations in Washington are considered branch-line movements.

4. The Great Northern Railroad has standby power equipment at the Cascade Tunnel for operation of the ventilation system and lights at the nearby stations. This diesel-driven unit has a twenty-four hour supply of fuel and will operate unattended for that period.

There is a Centralized Train Control system which, like the railroad's telephone system, is battery powered and so will operate eight hours after failure of the charging current. This control system, located in Seattle, controls all train movement between there and the Cascade Tunnel.

84-381 O—68—pt. 2——18

SECTION VII

STATE INSTITUTIONS

1. There is no fixed emergency power generating equipment on the Capitol Grounds in Olympia, except for that serving the State Patrol radio and a unit that will provide power in the boiler plant for operation of lights, pumps, and other equipment. There is no provision for providing power for general illumination or other purposes in any of the buildings.

2. The State Patrol has an oil burning auxiliary generator in the General Administration Building in Olympia that will operate the radio equipment and lights at that location. The Patrol also has sufficient auxiliary equipment at other fixed radio stations so that between these and the mobile units, complete radio coverage of the State will be possible during any electric outage.

Present plans are to install auxiliary power units in Walla Walla, Kennewick, Bremerton, Hoquiam, Kelso and at some transmitters located on mountain tops. The Patrol has also six portable generators for use as necessary.

3. The Department of Highways has fifty fixed radio stations throughout the State. Bellingham, Seattle, Spokane, Yakima and Vancouver have a combined total of thirteen stations with nine of these equipped with emergency power generating equipment. The stations in Olympia and Wenatchee also have emergency equipment. The five stations in Everett, Pasco, Tacoma and Walla Walla do not have emergency generating equipment. Of the remaining thirty stations, eight have standby equipment.

4. The Fire Control Division of the Department of Natural Resources has no emergency power generating equipment for its radio station on the Capitol Grounds, but does have at its Martin Way station east of Olympia, and at remotely located repeater stations, such as Capitol Peak.

5. Nine of the hospitals, schools and other institutions operated by the State have emergency power equipment for use in boiler plants, hospital surgical areas, kitchens and farm buildings. Emergency lighting can also be provided in such places as security and administration buildings.

This type of equipment is in the Penitentiary, Reformatory, Correction Center, and in the hospitals at Steilacoom, Sedro Woolley and Medical Lake.

Of the other seventeen institutions, those not having emergency power for any purpose are: School for the Blind, School for the Deaf, Yakima Valley, Fircrest and Maple Valley schools, the Woodinville Group Home, and the Cedar Creek, Capitol Forest and Mission Creek camps.

6. The Department of Fisheries has thirty-one mobile units that operate on the State Patrol radio network, but has no fixed radio stations. The department therefore has no need for standby equipment for communications.

Some of the fish hatcheries are supplied water by gravity flow, while for others the water must be pumped. Those hatcheries depending on pumps for their water supply have emergency power equipment for operation of these pumps only.

7. The Superintendent of Public Instruction reports that the University of Washington has emergency generating equipment for the hospital and plans to add sufficient standby equipment to handle the power requirements of research centers, auditoriums and other buildings.

Washington State University has standby power equipment for the hospital, for food services, and other needs.

8. The Puget Sound ferries can operate their own docking facilities if commercial power fails.

Bridges operated by the Toll Bridge Authority and having emergency power generating equipment for operation of the toll-collecting devices and lighting in the toll plazas are as follows: Vancouver Interstate, Hood Canal, Evergreen (crosses Lake Washington), Port Washington Narrows (Bremerton), Maple Street (Spokane), and the Vernita (crosses the Columbia River). No standby power is provided for the operation of draw spans or lift spans in the bridges; however, if a power failure occurs while a bridge is open, it can be closed manually.

SECTION VIII

TELECOMMUNICATIONS

The public has accepted the telephone as a necessary part of its daily life and it is not only greatly inconvenienced by any disturbance to that means of communication, but it could result in the loss of property or even a human life by the failure to obtain prompt medical aid for a sick or injured person. An investigation of the telephone and telegraph companies operating in Washington shows they are in a good position to continue operating during a major or extended commercial electric power outage. It should be noted that all telephone and telegraph equipment, generally speaking, operates from power supplied from batteries; the commercial power being used primarily to operate equipment which keep the batteries properly charged. The reserve battery supply is in most cases engineered to a minimum of eight hours at peak load. This means that in the event of a commercial power failure, switching equipment will continue to operate for a minimum of eight hours even though emergency power equipment is not readily available. This should allow ample time to bring portable generating equipment to locations not normally equipped with a fixed source of emergency power. Adequate supplies of fuel for emergency generating equipment are also maintained at all exchanges having fixed standby equipment. However, it must be pointed out that irrespective of the emergency generating equipment, delays in completing telephone calls during a complete electric outage might result if a large number of people attempted to simultaneously place calls and overloaded the central office switching facilities. This condition would not be caused by a lack of power, but from inability of the equipment to handle the abnormal number of calls.

Telephone Companies Emergency Power Facilities

Pacific Northwest Bell Telephone Company

The service area of the Pacific Northwest Bell Telephone Company is general throughout Washington State with a total of 102 exchanges, serving about 1,183,000 telephones. Approximately 85% of all these telephones are protected by fixed emergency power generating equipment. Some 72 exchanges do not have permanently installed emergency power plants.

However, Pacific has 46 portable generating units located at strategic locations throughout Washington with others available from Bell operating companies in other parts of the nation. The company has no immediate plans for installing fixed emergency generating equipment in those exchanges not now equipped.

West Coast Telephone Company

West Coast Telephone Company operates generally in the area north from Seattle to Burlington with five exchanges in southwestern Washington. West Coast has thirty-seven exchanges in Washington serving approximately 140,000 telephones. Fifteen of the thirty-seven exchanges do not have emergency power plants, however, seven of these fifteen will have such plants installed in 1966 and the remaining eight in 1967.

General Telephone Company of the Northwest

General Telephone Company operates in the eastern part of the state serving about 60,000 telephones from forty-three exchanges. Twenty-three of these exchanges do not have emergency power at this time. Nine plants are to be installed in 1966, two in 1967, five in 1968 and the remaining seven in 1969.

United Telephone Company of the Northwest

United Telephone operates in part of the Yakima Valley and along the Columbia River serving about 25,000 telephones from twenty exchanges. Twelve of these do not have emergency power equipment at this time. United presently has two portable generating units in reserve and possibly could obtain other units from other United companies outside of Washington.

Skagit Valley Telephone Co.

Skagit serves approximately 10,000 telephones in Skagit County outside Mount Vernon, Burlington and Sedro Woolley. Skagit has eleven exchanges, seven of which do not have standby generating equipment, however, the company does have three portable units in reserve. Each of the seven exchanges without emergency power is small, none serve more than 1,000 telephones.

Washington Telephone Co.

Washington Telephone Co. serves approximately 10,000 telephones in Whatcom County in the area mostly north of Bellingham and between that city and the Canadian border. Washington has ten exchanges, six of which do not have emergency generating equipment. The company has three portable generating units in reserve and available in an emergency.

Ellensburg Telephone Company

Ellensburg Telephone serves an area in and around Ellensburg, Kittitas and Vantage with about 6,000 telephones and is 100% protected by emergency generating equipment having power plants ranging in size from 125 KVA for the main office to 1 KVA for Wanapum. All subscriber carrier, mobile radio, as well as the main switching center, are protected with standby power equipment.

All Other Operating Telephone Companies

All other companies have reported on their emergency operating capabilities. These companies serve areas throughout Washington with a total of ninety-four exchanges, ranging in size from fifty telephones to 3,000 telephones. These companies have a total of nineteen fixed emergency generators (those dedicated to one location) and thirty-two portable generators. Seven companies do not have either fixed or portable generating equipment. No doubt in an emergency they could make arrangements to obtain portable generating equipment from other companies.

Telegraph Company

The Western Union Telegraph Company

Western Union operates from twenty-two locations throughout Washington State. At present Western Union does not have any fixed generating equipment but does have two portables, one located in Seattle, one in Yakima. The 1966 construction program calls for the installation of three fixed emergency power plants, one in Seattle, one in Spokane and one in Tacoma and the retention of the portable units.

SECTION IX

MISCELLANEOUS

1. Reports from various cities on their plans for providing necessary public services in case of the discontinuance of their normal source of electric power.

2. Capability of certain water utilities to function during a power failure as compiled by the Office of Emergency Resource Management for Water.

ALFRED B. LOOP
COMPTROLLER
EX-OFFICIO CITY CLERK

U. H. WOLKEN
CHIEF DEPUTY COMPTROLLER

CITY OF BELLINGHAM
OFFICE OF THE COMPTROLLER
BELLINGHAM, WASHINGTON 98225

January 19, 1966

Robert D. Timm, Secretary
Washington Utilities & Transportation Commission
Olympia, Washington 98502

File No. UT-6444

Dear Sir:

In reply to your letter of January 4, 1966, there are no requirements in the Bellingham Building Code, Electrical Code or Elevator Code that would require auxiliary power for at least one elevator in a multiple story building in case of emergency.

In respect to the other questions you asked, I am enclosing a report from the Chief of Police, the Fire Chief and the Water and Sewer Superintendent for the City of Bellingham.

If any further information is needed, please feel free to write.

Sincerely,

Alfred B. Loop

ALFRED B. LOOP
City Comptroller

ABL:s
Enclo.

CITY OF BELLINGHAM
WASHINGTON

Water Department

OFFICE OF THE SUPERINTENDENT

January 17, 1966

MEMORANDUM

From: Water Superintendent
To: City Comptroller

Subject: Emergency power for water and sewage flow, report of

Reference: (a) State of Washington Utilities and Transportation Commission ltr UT-6444 dated January 4, 1966

1. Reference (a) requested information concerning the availability of emergency power for maintaining water flow and pumping sewerage in the event of electrical power failure. The tabulation below provides this information for the Water and Sewer Departments.

(a) Water Department. The City of Bellingham depends on gravity flow of water for a major portion of its water distribution system. There are however, four high-rise areas where pumping is required. The emergency facilities available for these areas are as follows:

1. Sehome reservoir and Sunset Heights reservoir: emergency power available by a diesel engine driving a 1350 gallon per minute pump. This pump is adequate to handle normal water distribution requirements for the area. Pump is located in the Maple Street pump house.

2. Dakin Street reservoir: emergency power available in the Whatcom Falls screenhouse and pumping station in the form of a 500 gallon per minute gasoline engine driven pump. This pump will meet all normal water distribution requirements for the area serviced by this reservoir.

3. Yew Street reservoirs (2): no permanently installed emergency pump available.

4. Fortieth Street reservoir: no permanently installed emergency pump available.

5. The Water Department does have one (1) portable gasoline engine driven pump capable of pumping 500 gallons per minute. This pump could be used for pumping water to item 3 or item 4 listed above but not to both at the same time.

6. Sewage Disposal Plant: there is no emergency pump available in the disposal plant. Sewage would have to be discharged into the bay by gravity in the event of an electrical power failure vice pumping it through the disposal plant for treatment.

Respectfully,

Charles C. Gold
Superintendent



January 5, 1966

Mr. Al Loop, City Comptroller

Dear Mr. Loop:

In regard to the letter, file UT-6444, from the Washington Utilities and Transportation Commission seeking information on emergency power for essential services.

The Fire Department is equipped with automatic emergency generators at the Prospect Street station, in conjunction with a battery bank, that will allow communications to be maintained under all conditions. At the Sehome Hill site of the main radio transmitter we are equipped with an auxilliary generator that will automatically start and provide uninterrupted service in radio communication. We have a sufficient number of mobile radio units that communications could be maintained even should these emergency generators fail.

We maintain a 35 K.V.H. mobile generator that can be placed in service at once to handle any power supply demanded by any function of the fire service.

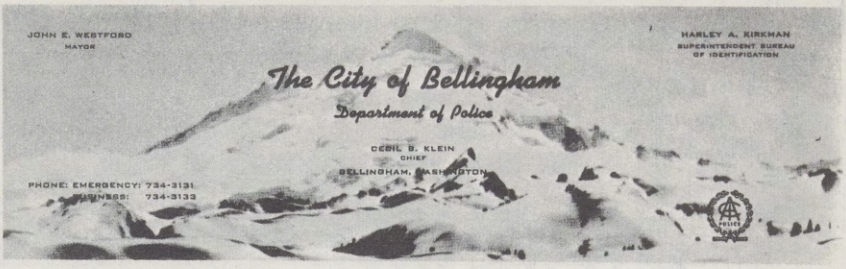
In addition to the above we have alternators on all first line apparatus that are capable of providing emergency lighting that may be needed at a fire scene.

I trust that this information will be of service in compiling the data required.

Very truly yours,

Wesley E. Baker

Wesley E. Baker, Chief
Bellingham Fire Department



January 5, 1966

City Clerk
City Hall
Bellingham, Washington

Dear Sir:

As per your request for emergency power within the Police Department, we have emergency power equipment for our communications system and some lights within the jail area.

Sincerely,

Chief
C. B. Klein

gic

CITY OF EVERETT
CITY HALL, EVERETT, WASHINGTON 98201

ENGINEERING DEPARTMENT
A. C. "JERRY" KREKOW
COMMISSIONER
RODNEY V. COLVIN
CITY ENGINEER

January 21, 1966

Robert D. Timm, Secretary
Washington Utilities and Transportation Commission
Olympia, Washington 98502

File #UT-6444

WIDESPREAD ELECTRIC POWER FAILURE

A widespread electric power failure effecting Everett would not jeopardize the sewer system of the City and would not cause a health or sanitation problem. The sewer system is mainly a gravity system with seventeen lift stations. Five of the lift stations have auxiliary gas engine power. These stations are located in predominantly residential areas with no available river or bay to which sewage could be discharged, so an auxiliary power supply was mandatory.

The remaining twelve lift stations are located adjacent to the bay, river, or creek to which sewage can be diverted in case of a rare prolonged power failure, and without a health or sanitation problem.

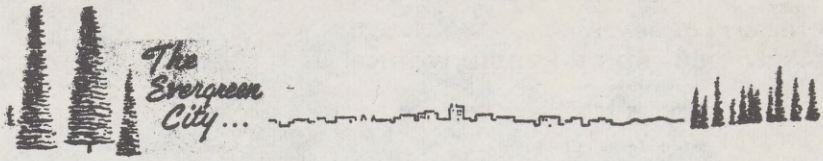
The maintenance vehicles of the Sewer Department are radio equipped so that emergency communications can be maintained between vehicles and contact with base stations maintained by reason of emergency power plant installations of the Communications Department.

The Sewer Department has a small, portable gas engine electric generator for furnishing lights and operating small tools in times of emergencies.

Sincerely
Rodney V. Colvin

RODNEY V. COLVIN
City Engineer

RVC:mt



CITY OF EVERETT

COMMUNICATIONS DEPARTMENT

L. H. MACHIN, SUPERINTENDENT

2811 OAKES AVENUE · EVERETT, WASHINGTON

January 14, 1966

Robert D. Timm, Secretary
Washington Utilities and
Transportation Commission
Olympia, Washington 98501

File No. UT-6444

Dear Mr. Timm:

Speaking for the Communications Dept. of the City of Everett, Washington, we have fixed automatic emergency power plant installations at the following listed locations:

10 KVA 115-230 VAC 60 cycle at our municipal radio stations, which house the base station radio equipment for the City Police, City Fire, County Fire and Local Government radio systems - all of which are located at 601 - 38th Street, Everett, Washington.

30 KVA 115-230 VAC 60 cycle unit located at 2811 Oakes Avenue, which is the Communications Dispatching Headquarters. It provides emergency lights and power for the remote radio control consoles on city and county radio systems, and power to operate all fire alarm and telephone systems. This unit also provides emergency lighting in our headquarters fire station located at 2801 Oakes Avenue, Everett, Washington.

3 KVA 115-230 VAC 60 cycle plant located at Police Headquarters, 3006 Wetmore Avenue. This plant provides emergency power for remote radio control for City Police dispatching and bank holdup alarm systems; also lights in the dispatching room only.

10 KVA 115-230 VAC 60 cycle plant located at Panther Creek water filter and control station. This plant provides emergency for the 2-way radio stations, water pump and heat in chlorination room, and emergency lighting for the entire filter plant.

5 KVA 115-230 VAC 60 cycle plant located at Lake Chaplain headworks water storage and control station. This plant provides emergency power for the radio station; also heat and lights in control station operator's building.

2 only 10 KVA 115-230 VAC 60 cycle portable plants mounted on licensed two-wheeled trailers. These plants are equipped to back up any of the above listed fixed plants and/or provide lights and power at location of any emergency in the City.

If further clarification is required, please advise.

Sincerely yours,

L. H. Machin

L. H. Machin, Supt.
Communications Dept.

THE CITY OF SEATTLE J. D. BRAMAN, MAYOR

BOARD OF PUBLIC WORKS

E. G. HENRY, SECRETARY

404 Seattle Municipal Building • Seattle, Washington 98104 • JUniper 3-2040

BOARD OF PUBLIC WORKS
ROY W. MORSE, CITY ENGINEER, CHAIRMAN
J. RAY HEATH, SUPT. OF WATER
FRED B. McCOY, SUPT. OF BUILDINGS
JOHN M. NELSON, SUPT. OF LIGHTING

Re: File No. UT-6444
Request for Information Pertaining to
Emergency Power Sources for the
City of Seattle

January 31, 1966

Mr. Robert D. Timm, Secretary
Washington Utilities and Transportation
Commission
Olympia, Washington 98502

Dear Sir:

Your communication of January 4, 1966 directed to the City Clerk was forwarded to the office of the Board of Public Works to gather the necessary information regarding emergency power sources in the public agencies servicing the residents of our City.

After circulating the four departments of the Board, namely, Light Department, Water Department, City Engineer and the Building Department, I am enclosing copies of their letters summing up the major standby equipment available for the residents of our City enabling them to carry on operations during the power failure periods.

Our Superintendent of Buildings, Mr. Fred B. McCoy, has sent his reply directly to you on January 17 and, therefore, I am enclosing a carbon copy of his report.

This report covers the facilities under the Board of Public Works and therefore we cannot account for the other departments such as; Health, Police, Civil Defense, and I recommend any report relative to the facilities under the control of the other departments be secured directly.

I trust this combined report will give you the information that you require for your study.

Yours very truly,

BOARD OF PUBLIC WORKS

E. G. Henry
Secretary

EGH:fh

Enc.
cc: C. Erlandson

CITY OF SEATTLE
DEPARTMENT OF BUILDINGS
FRED B. McCOY, *Superintendent*
MEMBER, BOARD OF PUBLIC WORKS

J. D. Braman, Mayor

IN RE:

January 17, 1966

Mr. Robert D. Timm, Secretary
Washington Utilities and
Transportation Commission
3695 East Marginal Way South
Seattle, Washington

Dear Sir:

We are replying to your inquiry of January 4 addressed to the City Clerk and relative to Building Code requirements for emergency power.

The Building Code requires buildings of certain occupant loads to have pathway lighting and egress signs. In such cases, the Electric Code requires that the egress circuits be taken off ahead of the main switch. There are other alternatives such as battery power or auxiliary generators.

We do not, however, require auxiliary power to operate elevators. The State Fire Marshall's Office does have certain requirements for hospitals in addition to our code requirements.

We would be glad to discuss the question of auxiliary power requirements with you or your commission.

Very truly yours,

FRED B. MCCOY
Superintendent of Buildings

FBM:rj

cc: Mr. E. G. Henry

WATER DEPARTMENT
CITY OF SEATTLE
OFFICE OF SUPERINTENDENT

January 12, 1966

Mr. Everett G. Henry
Secretary
Board of Public Works
City of Seattle

Dear Mr. Henry:

Replying to the questions asked in the January 4th letter from Mr. Robert D. Timm, the Seattle Water Department has automatic auxiliary power at our intake at Landsburg, and at our controlling works southeast of Renton.

The Water Department furnishes its own power at the Tolt River development. However, we do have two sources at the Tolt, one being a very small hydroelectric generator, and the other being an auxiliary gasoline powered unit.

Water supply for the City of Seattle is furnished by gravity flow from the 29 reservoirs, tanks, and standpipes located throughout the distribution system. Supply to the City is also by gravity flow from our intake at both Cedar River and Tolt River. Only the tops of the hills require pumping. However, as long as there is water in the standpipes and tanks on the tops of these hills, it will flow by gravity to the consumers in the same manner as our water flows by gravity from the reservoirs to the consumers.

The Water Department has three gasoline powered pumping units which are mobile and can be located at points where it is felt they might be needed. These three auxiliary powered pumping units have capacities of 1800 gpm, 1500 gpm, and 900 gpm, respectively.

For many years the State Civil Defense program has carried water pumping as the highest priority for restoration of electric power.

Very truly yours,

J. Ray Heath,- Superintendent of Water

EJA:ed

MEMORANDUM

Seattle Engineering Department
Seattle, Washington

January 18, 1966

TO: Board of Public Works

BY: P. M. Buswell

SUBJECT: Emergency Power for Essential Municipal Service

Emergency generators are in service and cut in automatically any time the line power fails at either our north or south radio transmitter sites.

A total of eight portable electric generators of 1,500 or 2,000 watt capacity are available at the various street maintenance headquarters and four additional such portable generators are in use by the Sewer Utility.

In case of electrical power failure, the seven City operated bascule bridges (4 City owned and 3 State owned) are equipped to operate with emergency gas engines and can also be hand operated.

WCS:tj

CITY OF SPOKANE

SPOKANE, WASHINGTON
DEPARTMENT OF PUBLIC WORKS & UTILITIES
GLEN A. YAKE
DIRECTOR

January 27, 1966

Mr. Robert D. Timm, Secretary
Washington Utilities and Transportation Commission
Olympia, Washington 98502

Dear Mr. Timm: Re: Your File - Ut-6444

In answer to your letter of January 4th, requesting a statement from us as to whether or not we have emergency power for communications, etc., we give you the following:

WATER

1. The hydro-electric plant can operate independently of the power pool.
   a. We can furnish water directly from the hydro-electric plant location to approximately 80% of the City area.
   b. Other systems have sufficient storage with a conservative use of water for some period of time.
2. We have no auxiliary power to boost into any of our higher systems.

SEWERAGE

1. The Sewage Treatment Plant has no emergency power, but a total flow can be by-passed to the river.
2. Clark Avenue, Elm Street, Francis & Assembly Lift Stations automatically by-passed to the river on power failure.
3. Francis & Cannon Lift Station has automatic standby emergency power.
4. 35th & Helena Lift Station can be connected to a portable compressor to operate.

5. 36th & Bernard and 46th & Cook Lift Stations can be handled by Sewer Division pumpers and tanks.

6. The Great Northern Hillyard Lift Station could pose a problem. With power off, the Safeway Store's processing would probably cease.

COMMUNICATIONS -

WATER: There is a small auxiliary power supply that could be connected to the Water Department main station. As the rest of the stations are mobile, this does not pose a problem. Water communications could be taken up by a mobile unit until the portable is connected. Also, Civil Defense has a water unit at City Hall that has an emergency unit connected.

There is a problem in that AC is required to operate the telephone in the Maintenance Building area. Said equipment could eventually be connected to the portable emergency power supply.

SEWER & STREET: The transmitter is located at City Hall. It has an emergency power unit available for its use. Also, there are units in Civil Defense in City Hall which are connected to emergency power. Here again, as the greatest number of units are mobile (battery operated), a unit could be set up to operate as a base station.

In regard to building code requirements as to auxiliary power for at least one elevator in multi-story buildings, our present Building Code does not require this.

We do hope the foregoing information is that which you wished, and we are sorry for the tardiness in our response.

Very truly yours,

Glen A. Yake
Director

gay:msr

DIVISIONS
Light
Water
Belt Line

City of Tacoma
WASHINGTON

DEPARTMENT OF PUBLIC UTILITIES
C. A. Erdahl, Director

Please address reply to:
City of Tacoma
Department of Public Utilities
P. O. Box 11007
Tacoma, Washington 98411

Attention:

January 11, 1966

Washington Utilities and Transportation Commission
Olympia,
Washington 98502

ATTENTION: Mr. Robert D. Timm, Secretary

Subject: Electric Power Failure ---
Emergency Equipment

Dear Mr. Timm:

Your inquiry dated January 4, 1966 concerning emergency power for certain uses during periods of widespread electric power failure, has been referred to this office for reply. Our comments follow.

Communications. The City's water and electric utilities, communications, and the City's police, fire and civil defense departmental communications, all have suitable emergency fuel operated power generating facilities to maintain effective interim operations in the event there is a widespread interruption in the normal supply of electric power.

Water flow. Tacoma's water supply is normally gravity fed from its Green River System, with electric driven pumped well water supply for auxiliary or supplemental use in the event of failure of, or turbidity in, the gravity supply. With considerable storage available, the City's water needs are adequately protected without resorting to fuel or electric driven auxiliary pumping.

Sewerage pumping. The sewer utility has emergency diesel driven equipment which cuts in automatically in the event of an electric power failure.

Elevator (Building Code) requirements. The City's Building Code does not require auxiliary power for at least one elevator in multi-story buildings. Insofar as is known, no such auxiliary power supply has been installed in Tacoma's multi-story buildings.

Hospitals. Tacoma's major hospitals maintain auxiliary power generating facilities which can be cut-in in the event of a power failure.

The City's electric utility, Tacoma City Light, is participating in the preparation of a comprehensive report on electric service capabilities, following the eastern and Texas blackouts, which report will be presented directly to the Commission by the Committee currently engaged in the study.

Yours very truly,

C. A. Erdahl

C. A. Erdahl,
Director of Utilities

CITY OF VANCOUVER

CITY CLERK

WASHINGTON

January 12, 1966

Mr. Robert D. Timm, Secretary
Washington Utilities and
Transportation Commission
Capitol Building
Olympia, Washington 98502

RE: UT-6444

Dear Mr. Timm:

In regards to your inquiry of January 4, 1966 asking us what operations our City would be able to carry on during a power failure.

Our Department of Public Works Director Mr. H. R. Nunn states that, we do have power for maintaining our communication system, our water distribution system and other services. In addition, where we do not have by-passes for our pumping stations, we do have emergency power to keep them in operation..

Very truly yours,

George E. Carson

George E. Carson
City Clerk

GEC/lnr

City of Yakima
State of Washington

OFFICE OF CITY MANAGER

January 28, 1966

Mr. Robert D. Timm
Secretary and Administrative Officer
Washington Utilities and Transportation Commission
Olympia, Washington 98502

Re: UT-6444

Dear Mr. Timm:

This will acknowledge your letter of January 4, 1966, requesting certain information concerning emergency power for various municipal operations in Yakima.

With respect to our water system and water supply, the City of Yakima receives its main source of water from a watershed at Oak Flats which is approximately 15 miles northwest of the city. This water is transmitted by gravity flow to our main reservoirs. Water from these reservoirs, which have a combined capacity of 25 million gallons, flows by gravity to approximately 98.5% of the water users in the city. We have but one small are in our city involving some 150 customers which does not receive its water supply by gravity flow. The only effect of a power blackout would be in serving this one area. Since this represents only approximately 150 customers out of some 12,500 water users, we do not feel that a major power failure would pose any serious problem to our city's water users.

Should a major blackout occur during the fruit processing season, we would, of course, have to call on water users to be extremely conservative in order to meet the peak demands of the canneries as well as serving water to all of the areas of our city.

With respect to our Sewage Treatment Plant, we are dependent on power for pumping. We have no emergency source of power at the Treatment Plant. In the event of a major curtailment of power, we would have to direct the sewage through the Plant primary clarifiers and chlorinate the effluent as heavy as possible in order to provide some bacterial control

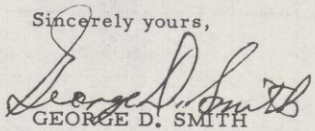
before the discharge into the Yakima River.

The City of Yakima has adopted by reference the Uniform Building Code. This Code does not cover any requirements for auxiliary power for elevators in multi-story buildings.

The city has standby power available for two weeks' continuous run for the Police and Fire Departments and all radio communications within the city. We also have a limited emergency power source for lights in the City Hall building. The city, through our Civil Defense Department, also has a mobil power plant on a trailer with three heavy flood lights to light any area necessary or to furnish power to gasoline pumps for filling of emergency vehicles. The Yakima County Civil Defense Department does have a 100 kw standby unit which is powered by diesel which also could be available to the City in event of an emergency.

I hope the foregoing may be of assistance in providing the information requested in your recent letter. If there is any additional information desired, kindly let me know and it will be promptly provided.

Sincerely yours,



GEORGE D. SMITH
City Manager

GDS:mh

STATE OF WASHINGTON
OFFICE OF EMERGENCY RESOURCE MANAGEMENT FOR WATER

WATER UTILITY CAPABILITY TO FUNCTION DURING A POWER FAILURE

UTILITY REPORTING	POPU. SERVED	GRAVITY YES	GRAVITY NO	GRAVITY %	WELLS YES	WELLS NO	WELLS %	EMER. POWER FOR WELLS YES	EMER. POWER FOR WELLS %	EMER. POWER FOR WELLS NO	HOURS FROM STORAGE NORM.	HOURS FROM STORAGE NO INDUST.	% OF POPULATION OUT OF WATER AT END OF FOLLOWING HOURS: 1 HR.	12 HR.	24 HR.	72 HR.	168 HR.	POPULATION OUT OF WATER AT THE END OF THE FOLLOWING HOURS: 1 HR.	12 HR.	24 HR.	72 HR.	168 HR.	REMARKS
CITY OF SEATTLE WATER DEPARTMENT	885,000	X	-	90	-	X	-	X*	25	-	24	-	0	0	0	0	0	0	0	0	0	0	* EMERGENCY POWER FOR BOOSTER PUMPING. SOME WATER DISTRICTS MAY HAVE PROBLEMS AFTER 72 HOURS.
CITY OF TACOMA WATER DIVISION	160,000	X	-	98	X	-	97*	-	-	X	96	240+	0	0	0	0	0	0	0	0	0	0	* THE WELLS SERVE AS AN AUXILIARY AND SUPPLEMENTARY SUPPLY.
PORT ANGELES WATER DEPARTMENT	17,000	X	-	100	-	X	-	-	-	-	100	100*	5	5	5	5	5	850	850	850	850	850	FIVE (5) BOOSTER PUMPS WITHOUT STANDBY POWER SERVE APPROXIMATELY 5% OF THE TOTAL POPULATION. * INDEPENDENT INDUSTRIAL GRAVITY SUPPLY.
ABERDEEN DEPARTMENT OF UTILITIES, WATER DIV.	25,000	X	-	95	-	X	-	-	-	-	192	192*	5	5	5	5	5	1,250	1,250	1,250	1,250	1,250	* INDEPENDENT INDUSTRIAL GRAVITY SUPPLY.
CITY OF PASCO PASCO, WASHINGTON	17,000	-	X	0	-	X	-	-	-	X	48	48-72	0	0	0	100	100	0	0	0	17,000	17,000	WATER PUMPED FROM THE COLUMBIA RIVER.
CITY OF WENATCHEE WATER-SEWER DEPARTMENT	17,700	-	X	-	-	X	-	-	-	-	24	48	0	0	10	100	100	0	0	1,770	17,700	17,700	WATER IS PUMPED FROM THE COLUMBIA RIVER TO STORAGE AT A HIGHER ELEVATION FROM WHICH THEIR SYSTEM IS FED.
CITY OF HOQUIAM WATER DEPARTMENT	11,000	-	X	-	-	X	-	-	-	X	72	144	0	0	0	5	100	0	0	0	550	11,000	PRIMARY WATER SUPPLY PUMPED FROM CREEKS. EMERGENCY STANDBY WATER AVAILABLE FROM ABERDEEN, WASHINGTON.
CITY OF CHEHALIS WATER DEPARTMENT	6,750	X	-	100	-	X	-	-	-	X	48	300	0	0	0	0	0	0	0	0	0	0	
CITY OF CENTRALIA WATER DEPARTMENT	10,000	X	-	100	X	-	100	-	-	X	120	130	0	0	0	0	0	0	0	0	0	0	WELLS SERVE AS ALTERNATE AND AUXILIARY SUPPLY.
CITY OF PORT TOWNSEND WATER DEPARTMENT	10,000	X	-	100	-	X	-	-	-	-	100	100	0	0	0	0	0	0	0	0	0	0	
EVERETT WATER DEPARTMENT	51,000	X	-	99	X	-	1	-	-	X	12	96	0	0	0	0	1	0	0	0	0	510	
LONGVIEW WATER DEPARTMENT	32,000	-	X	-	-	X	-	-	-	X	72	132	0	0	0	0	100	0	0	0	0	32,000	WATER IS PUMPED FROM COWLITZ RIVER.
RICHLAND WATER AND SEWER DEPARTMENT	25,900	-	X	-	X	-	10	X	11	-	24	24	0	0	0	100	100	0	0	0	25,900	25,900	PRIMARY WATER SUPPLY FROM COLUMBIA RIVER FILTERED AND PUMPED TO STORAGE. 1-1/2 MGD. WELL & 3 MGD BOOSTER PUMPS WITH AUXILIARY POWER.
CITY OF YAKIMA WATER DEPARTMENT	45,000	X	-	97	X	-	100	-	-	X	30/84	50/100	0	0	0	3	3	0	0	0	1,350	1,350	WELLS SERVE AS ALTERNATE & AUXILIARY SUPPLY.
CITY OF BELLINGHAM WATER DEPARTMENT	40,000	X	-	65	-	-	-	X*	-	-	8	8	0	0	15	20	35	0	0	6,000	8,000	14,000	* SUPPLY TO INDUSTRY ALL GRAVITY.
CITY OF WALLA WALLA WATER DEPARTMENT	25,825	X	-	100	X	-	20	X	25	-	24	48	0	0	0	0	0	0	0	0	0	0	WELLS SERVE AS SUPPLEMENTARY SUPPLY.
CITY OF VANCOUVER WATER DEPARTMENT	50,000	-	X	-	X	-	100	X	30	-	10	12	0	0	0	5	25	0	0	0	2,500	12,500	
CITY OF SPOKANE WATER DEPARTMENT	187,000	-	X	-	X	-	100	X	70*	-	8	16	0	0	15	25	25	0	0	28,000	46,700	46,700	* SPOKANE CITY WATER HAS THEIR OWN WATER POWER GENERATION PLANT.
TOTAL	1616,175																TOTAL	2,100	2,100	37,870	121,800	180,760	
																	CALCULATED TOTAL PERCENTAGE OF POPULATION OUT OF WATER:	0.13	0.13	2.3	7.5	11.2	

A. J. BENEDETTI, DIRECTOR
1/25/66
HSB:LG

SECTION X

CONCLUSION

Based on our investigation we believe it is highly unlikely that there could be any extensive or serious electric power outage in the State of Washington. This is also the opinion of well-qualified and experienced engineers who are most familiar with the characteristics and operating procedures of the Northwest Power Pool. All of the generating utilities in Washington, as well as the Bonneville Power Administration and utilities in adjoining states, are members of the Northwest Power Pool and are continually in contact with each other.

The Northwest Power Pool was organized in 1942 and has continued to operate as an interconnected power pool since that date. From its beginning all the members have fully cooperated not only with common operating procedures, but in planning and constructing separately-owned transmission facilities that were compatible with the best overall operation of the Pool network. The technical people employed by the members of the Pool have acquired, through years of actual experience, a comprehensive knowledge regarding the design and operation of extensive power networks. It is also interesting to note that most of the Federal Power Commission's recommendations for avoiding the recurrence of major power failures, as detailed in the Commission's preliminary report on the Northeast power outage, had previously been adopted by the Northwest Power Pool.

Besides the knowledge and experience of the Northwest Power Pool members in successfully operating an extensive and dependable power network, there are characteristics of the pool that could also limit the extent or duration of any power outage. These characteristics are covered in Section I - The Northwest Power Pool - and will not be repeated here. Special operating programs have been set up by all members of the Pool to prevent the cascading of any trouble to other members' facilities. Also a load shedding program to assist in limiting the duration of any outage that may occur.

The operating practices of the Northwest Power Pool are continually being reviewed by the Pool's Operating Commit-

tee. There is also an agreement between the members regarding the reserve capabilities required to protect the Pool against loss of load due to the breakdown of generating facilities. All of this activity has been planned with a desire to provide adequate and reliable power service to the electric users in this area.

It must be realized that local power outages have occurred and will continue to occur from time to time, resulting from extreme weather conditions or accidents to some equipment. However, our investigation shows that many public service activities that require a continuous source of electric power have available auxiliary generating equipment capable of tiding them over any interruption to their primary power source.

We believe all the members of the Northwest Power Pool have been and are still cognizant of the need for providing continuous electric service to their customers and that all members of the Pool will continue to cooperate as they have in the past in preventing any extensive power outage in this area. Certainly there appears no chance of any power blackout comparable to that which occurred in the Northeast.

APPENDIX A

REVIEW OF THE NORTHEAST POWER OUTAGE NOVEMBER 9-10, 1965

Since November 9, 1965, a large amount of information has appeared in the press, trade and technical journals concerning the power disturbance occurring in the Northeastern part of the United States and adjoining areas of Canada which make up the CANUSE Interconnection.

In addition, the Federal Power Commission made a preliminary report, "Northeast Power Failure, November 9 and 10, 1965", to the President. This report was made on December 6, 1965 and contains pertinent detail of the disturbance. Anyone desiring a detailed discussion of the disturbance is referred to that report, as only highlights and observations will be made in this report.

First, it would be appropriate to make a comparison between the CANUSE Interconnection and our own Northwest Power Pool. The following table shows this comparison of important items and characteristics:

	Northwest Power Pool	CANUSE Interconnection
Area Covered - Square Miles	370,000	80,000
Area Population	10,000,000	30,000,000
Generating Capability-Megawatts	20,100	34,500
Hydro Generating Capability	88%	26%
Thermal & Misc. Capability	12%	74%
Load Control Areas	14	16
Interconnections between Load Control Areas	125	55

The disturbance in the CANUSE Interconnection started with the relaying of one of five 230 Kv lines feeding power north from the Beck #2 hydro station on the Ontario Hydro Sys-

tem. What caused the initial tripping of the first 230 Kv line has never been determined, but line loadings at the time of the disturbance were within 20 megawatts of the settings of the backup relays on these lines. It is possible that a small surge of power due to load or generation in or remote from the area could have been sufficient to raise the line loading to the relay pickup level.

Tripping of the first line then resulted in cascading of the other four lines within less than 3 seconds. Tripping of these five lines caused a power surge of about 1600 megawatts into the upper New York systems. This surge of power caused the last two interconnections between the New York systems and Ontario Hydro at the St. Lawrence project to open and resulted in instability of the transmission system in New York. In about four seconds, the CANUSE Interconnection had been split into six isolated areas, with further splits within these areas.

Generating units were lost due to instability during the initial disturbance. With the split in the interconnection, some areas in upper New York experienced high speed and additional units, both hydro and thermal, tripped off due to the high frequency. In lower New York state and New England, except Maine and most of New Hampshire, low frequency was experienced, and within twelve minutes resulted in the near-total collapse of generating capability in this area. Some damage to generating units was experienced, due mostly to wiped bearings during the shutdown period.

With the split in the interconnection and almost total shutdown in some areas, then began the large task of restoring service. The first problem was in restoring generating capability and then picking up customer load. The restoration of generating capability was hampered by the lack of start-up power at major thermal stations. In some cases, this meant re-routing power from hydro or thermal stations which had stayed on the line serving local load, or waiting until neighboring systems had power available.

Those systems having extensive underground systems were further hampered by the requirement for sufficient generating capability to handle the energizing of sections of the underground system.

Certain observations and comments concerning the disturbance follow; however, it should be recognized that these are made after the fact:

1. It is apparent that there was an oversight or lack of coordination in regard to the relaying scheme at Beck #2 in relation to the line loadings at the time of the disturbance. This points up the need for close coordination between relay and operating departments.

2. It is evident that start-up power is required either at a thermal station or at a point where it can be made readily available to the station.

3. The disturbance points up the requirement to have auxiliary power supply for communication channels, instrumentation, control equipment and dispatching centers.

4. Finally, the need for a coordinated load relief program employing automatic equipment for use during emergencies is evident in order to prevent loss of generating capability on account of excessive load.

APPENDIX B

ACKNOWLEDGEMENTS

The cooperation of the Bonneville Power Administration and the various public and private utility organizations is gratefully appreciated. Special appreciation is due the technical experts listed below who participated in the December 17, 1965 meeting and assisted in preparing the report on the inherent strength and reliability of the Northwest Power Pool:

S. K. Billingsley	Washington Public Power Supply System
M. L. Blair	The Washington Water Power Company
Castle Bradeen	Seattle City Light
John R. Church	Washington Public Power Supply System
David A. Garrett	Pend Oreille County PUD
Lyle L. Gleason	Seattle City Light
John A. Gregg	Douglas County PUD
Donald E. Hughes	Cowlitz County PUD
John P. Jolliffe	Bonneville Power Administration
Vivan B. Jones	Tacoma City Light
Kenneth M. Klein	Bonneville Power Administration
D. H. Knight	Puget Sound Power & Light Company
R. H. Lemagie	Tacoma City Light
R. B. Lisbakken	Pacific Power & Light Company
Robert L. McKinney	Cowlitz County PUD
E. C. Metcalf	Chelan County PUD
Robert R. Ries	Grant County PUD
R. G. Schafer	Chelan County PUD
James A. Sewell	Pend Oreille County PUD
E. F. Timme	Northwest Power Pool Coordinating Committee
Fred M. Treffinger	Puget Sound Power & Light Company

The Commission appreciates the information on emergency electric facilities provided by the communications companies, gas industries, railroads, The Department of Aeronautics, Department of Health, Department of Civil Defense, General Administration and others.

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