093708 CED-76-120
7-8-76

REPORT TO THE CONGRESS

BY THE COMPTROLLER GENERAL OF THE UNITED STATES

Federal Hydroelectric Plants Can Increase Power Sales

Department of the Interior

The Interior power-marketing agencies can increase the electric capacity available for sale from Federal hydroelectric systems by planning to purchase power from other systems during low-water years.

The Federal hydroelectric systems maintain larger generating reserves than are warranted. This excess could be reduced and made available for sale.

Interior feels that the potential for increased hydroelectric-generating capacity varies greatly from system to system. But Interior has agreed to study all of its power systems.

CED-76-120 ~~701461~~ JULY 8, 1976

COMPTROLLER GENERAL OF THE UNITED STATES
WASHINGTON, D.C. 20548

B-125042

To the President of the Senate and the
Speaker of the House of Representatives

This report discusses opportunities for the power-marketing agencies of the Department of the Interior to increase the hydroelectric generating capacity available for sale at Federal projects.

Our review was made to determine if additional Federal hydroelectric power could be made available for sale utilizing the existing Federal power system.

We made our review pursuant to the Budget and Accounting Act, 1921 (31 U.S.C. 53), and the Accounting and Auditing Act of 1950 (31 U.S.C. 67).

We are sending copies of this report to the Director, Office of Management and Budget, and the Secretary of the Interior.

Elmer B. Staats
Comptroller General
of the United States

Contents

ABBREVIATIONS

BPA	Bonneville Power Administration
CRSP	Colorado River Storage Project
CVP	Central Valley Project
FCRPS	Federal Columbia River Power System
GAO	General Accounting Office
MW	megawatts
SPA	Southwestern Power Administration
RRR	reserve responsibility ratio

COMPTROLLER GENERAL'S
REPORT TO THE CONGRESS

FEDERAL HYDROELECTRIC PLANTS
CAN INCREASE POWER SALES
Department of the Interior

D I G E S T

Hydroelectric power accounts for about 15 percent of the Nation's electric-generating capacity of which about 40 percent is Government owned. Five agencies within the Department of the Interior and the Tennessee Valley Authority market Federal power.

Additional hydroelectric dependable capacity (the ability of a system to provide its maximum output under adverse conditions for a specified period) can be made available for sale by

--changing the methods the Interior power-marketing agencies use in determining how much capacity can be sold and

--reassessing the amount of capacity which is held in reserve for contingencies.

Such additional capacity could delay or, in some instances, displace alternative construction of electric-generating capacity.

INCREASING DEPENDABLE CAPACITY

Generally, the Federal agencies limit dependable capacity sales to that amount of capacity which they estimate will be available from their systems during the anticipated lowest water year.

Interior power-marketing agencies can increase the dependable electric capacity available for sale from Federal hydroelectric systems by planning to purchase power from other systems during low-water years.

GAO estimates that using this approach could result in 110 megawatts of additional dependable peaking capacity in two of the Bureau of Reclamation regions. This additional capacity could meet the needs of approximately 75,000 residential customers during the periods with highest demand. The capital investment to construct 110 megawatts of capacity is about $13.2 million. (See p. 4.)

The power-marketing agencies use varying methods of determining low-water years resulting in the assumption of different risks as to the occurrence of low-water years. These methods need to be standardized. (See pp. 6 and 11.)

There are certain constraints to using such an approach but such constraints would not preclude its use. Such constraints include existing contracts with power-marketing customers and the ability to purchase capacity during low-water years. (See pp. 10 and 11.)

GAO recommends that the Secretary of the Interior have the Federal power-marketing agencies (see p. 11):

--Establish uniform guidelines for determining the Federal power system's generating capability under adverse conditions, recognizing the differences of the various Federal systems.

--Determine the feasibility of establishing dependable capacity based on purchases of power.

--Identify and obtain the modifications which would be required to implement this method, including a provision for enough money to purchase the power needed in low-water years.

--Sell any additional capacity as dependable based on the results of the above action.

REDUCING RESERVE CAPACITY REQUIREMENTS

Reserve capacity is maintained by power systems so that if a generating unit fails, demand can be met by another unit without interrupting service (operating reserves). (See p. 13.)

As a result of interconnecting transmission lines, adjoining power systems can exchange power with other power companies. This allows the companies, including Federal agencies, to form power pools and share resources, thus reducing total reserve needs of an area served by the power-pool members.

GAO observed that:

--In addition to operating reserves, the Bureau of Reclamation requires that reserves be maintained for maintenance and customer load growth. These factors should not affect the requirements because the Federal systems are not responsible for meeting customer load growth, and maintenance is scheduled during offpeak seasons so that it does not have an impact on reserves. (See p. 14.)

--Power-pooling agreements which state the reserve requirements for its members do not adequately recognize that hydroelectric systems do not break down as often as other forms of power generation. (See p. 17.)

--The Bureau's Upper Missouri Region can sell reserves in excess of its power-pool requirements. (See p. 21.)

--The Bonneville Power Administration does not use its most accurate estimate of reserve needs. (See p. 22.)

If reserves more realistically represented expected conditions, the Federal reserves could be reduced. The additional capacity thus made available could be sold. (See p. 23.)

GAO recommends that the Secretary of the Interior require (see pp. 23 and 24):

--The Bureau of Reclamation to redetermine the reserve requirements for each power system, considering the benefits derived from pooling arrangements and the elimination of reserves based on load growth and maintenance.

--The Federal power-marketing agencies, when entering into new, or revising existing, power-pool agreements, to negotiate for more equitable reserve requirements taking into consideration the historical reliability of hydroelectric facilities.

--The Federal power-marketing agencies to sell the capacity that may become available as a result of redetermining reserve requirements.

AGENCY COMMENTS

Interior said that it was impossible to generalize on the potential for adopting GAO recommendations. It pointed out that the recommendations may be very workable for some systems and impractical or have no significant impact on the capacity of other systems.

Interior said it would make appropriate studies to determine the feasibility of implementing GAO recommendations on a system-by-system basis. (See pp. 12 and 24.)

CHAPTER 1

INTRODUCTION

The National Electric Reliability Council[1] reported that postponements and cancellations in new electric generating capacity would result in more than 100,000 megawatts[2] less capacity in the United States by 1984 than was projected in 1974. This condition, as reported by the council, could have an adverse impact on the adequacy and reliability of the Nation's bulk power supply.

The potential shortages in electric generation facilities and the environmental effects associated with electrical energy production by thermal plants, increases the value of optimizing the use of existing Federal hydroelectric capabilities. Converting fossil and nuclear fuels into energy (thermal plants) leads to air and water pollution and creation of solid wastes. Hydroelectric plants do not consume water, contribute to air pollution, or add heat to rivers and streams in the same manner as thermal plants.

Hydroelectric power accounts for about 15 percent of the Nation's electric-generating capacity. About 40 percent of the hydroelectric capacity is Government owned and is marketed by the Tennessee Valley Authority and agencies of the Department of the Interior--Bureau of Reclamation, Bonneville Power Administration (BPA), Southeastern Power Administration, Southwestern Power Administration (SPA), and Alaska Power Administration[3]--which administers 15 power-marketing systems. The hydroelectric facilities from which the Interior agencies market the power are constructed either by the Bureau of Reclamation or the Corps of Engineers. Nearly all the Federal power is sold at wholesale rates to large industrial customers, municipalities, and other electric systems. Federal laws require that the power from

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[1]An organization formed by the Nation's utilities to direct national efforts to augment the reliability and adequacy of bulk power supply in the electric utility systems of North America.

[2]One megawatt equals 1 million watts.

[3]See appendix I for a description of the power-marketing agencies included in our review.

Federal projects be sold in a way that (1) encourages the most widespread use at the lowest possible rate, (2) is consistent with sound business principles, and (3) gives preference to public bodies and cooperatives.

CAPACITY AND ENERGY

The generating capacity[1] of a power system is its capability to meet electric demand (load). This capacity must be large enough to supply load requirements at peak periods. In a hydroelectric system, capacity is a function of the turbines and generators at a dam and the amount of water pressure provided by the falling water stored behind the dam. As the level of the stored water is lowered, the generating capacity at the dam is reduced because there is less waterpower to turn the turbines. Energy is the ability of a system to do work (e.g., operating an electric appliance). The energy produced by the power system is related to how long a load is placed on the generators.

The following is an illustration explaining the distinction between energy and capacity.

> A chandelier with 10 100-watt bulbs is a 1,000-watt, or 1-kilowatt, light fixture. To illuminate all 10 bulbs at the same time, a power source with the capacity to produce 1 kilowatt is required. If the chandelier is illuminated for 1 hour, 1 kilowatt hour of energy is consumed; if it is illuminated for 2 hours, 2 kilowatt hours of energy are consumed. Energy is the amount of power used, and capacity is the rate at which the power is produced. The capacity stays the same but the energy changes depending on the length of time the lights are on.

Capacity can be sold as dependable--the ability of a system to supply energy under adverse conditions for a specified period--or as nondependable on the basis of availability at a specific period. Dependable capacity has a higher economic value than nondependable capacity since the former represents a reliable supply. Therefore, dependable capacity can be relied on by the utilities when considering future construction to meet capacity requirements.

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[1] Capacity is the maximum power output or load for which a machine, apparatus, station, or system is rated.

SCOPE OF REVIEW

Our review was made primarily at the Bureau's Mid-Pacific, Upper Colorado, Lower Colorado, Upper Missouri, and Lower Missouri Regions; BPA; and SPA. We examined the pertinent documents, records, reports, and files relating to Interior's determination of electric power available for sale and discussed such methods with Interior officials.

CHAPTER 2

INCREASING DEPENDABLE CAPACITY

An opportunity exists for Federal power-marketing agencies to increase the dependable capacity available for sale from Federal hydroelectric systems by planning to purchase power from other systems during low-water years of a water cycle. To take advantage of this opportunity, however, the power-marketing agencies would have to change their method of determining dependable capacity from one based primarily on the lowest water year in a water cycle to one that also considers the maximum dependable capacity supportable with supplemental purchases of power from other systems. Limitations on such determinations would be the availability of supplemental power during low-water years and the economic feasibility of such purchases. Determining dependable capacity on such a basis is referred to as the economic method.

We estimated that using the economic method could result in 110 megawatts of additional dependable peaking capacity in two of the Bureau regions. This additional peaking capacity could meet the peaking needs of approximately 75,000 residential customers.

The construction of such capacity by utilities would require a capital investment of about $13,200,000.[1]

Dependable capacity is defined as the load-carrying ability of a hydroelectric system under adverse conditions. These conditions are based on low streamflows associated with historic drought cycles. When a system's capacity is determined in this manner, power is guaranteed to be available to the users even during a drought.

The Bureau of Reclamation's policy provides that marketable (dependable) capacity should be based on the most adverse expectations. (See app. II for a description of the methodologies.) The Federal Power Commission,[2] however,

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1 Based on a Federal Power Commission estimate of cost per megawatt ($120,000) to construct combustion turbine generators (which consume natural gas or oil).

2 The Federal Power Commission regulates the interstate aspects of the electric utility and natural gas industries.

defines dependable hydroelectric capacity as the load and reserve-carrying ability of a system under the most adverse flow conditions. The Commission also states that dependable capacity can be increased by utilizing offpeak energy[1] from other systems. Therefore, under the Commission's definition increases in dependable capacity can be achieved by obtaining supplemental energy from other sources.

If the economic method was used to determine dependable capacity, increased revenues generated from the additional sales during normal- or high-water years could offset the increased costs to purchase or maintain sufficient water levels to support the additional capacity sales during low-water conditions. The additional dependable capacity thus made available could delay or displace constructing an equivalent amount of generating capacity.

Because adverse water conditions are the limiting factor Federal power-marketing agencies use for determining the dependable capacity for power systems, additional capacity is actually available from a system in all water cycle years other than the adverse years. This additional capacity, however, is considered nondependable and, therefore, cannot be relied on to meet long-term customer needs.

The following schedule shows, for the Federal power systems included in our review, the maximum operating capacity of the Federal generating equipment, and the amount of that capacity which is dependable. The difference is available for reserves (see ch. 3) and nondependable capacity sales. Additional dependable capacity probably could be made available from part of this difference if the Federal power-marketing agencies used the economic method to evaluate the feasibility of purchasing sufficient supplemental power to make the additional dependable capacity available during low-water years.

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[1]Offpeak energy is the energy supplied during periods of low system loads. This contrasts to onpeak energy which is energy supplied during periods of high system loads.

Power system	Maximum operating capacity (note a)	Dependable capacity	Difference
	------------megawatts------------		
Bonneville Power Administration	12,387	12,253	134
Southwestern Power Administration	2,126	2,004	122
Bureau of Reclamation:			
Upper Missouri Region	2,627	[b]1,801	826
Lower Missouri Region	607	[b]378	229
Upper Colorado Region	1,345	[b]1,171	174
Lower Colorado Region (note c)	324	[b,d]254	70
Mid-Pacific Region	1,505	[e]950	555

[a]Maximum operating capacity ranges from 111 to 118 percent of installed or nameplate capacity.

[b]Highest of summer or winter capability.

[c]Excludes Hoover Dam which the Government does not operate.

[d]Includes 40 MW pumping demand.

[e]Includes 70 MW pumping demand.

POWER SYSTEMS' METHODS OF DETERMINING ADVERSE CONDITIONS VARY

Although most power systems consider adverse conditions in determining dependable capacity the methods vary. As a result, each system may assume a different risk that sufficient water will be available to meet the loads. The different risk assumptions would result in different quantities of dependable capacity if they were applied in the same system. To the extent that any risk is assumed, however, the system must anticipate that it will be required to purchase some power from a supplemental source for emergencies (e.g., lower than average water year). Presently, the Federal systems generally do not consider the optimum economic tradeoffs in establishing these risks.

A description is given in appendix II of the various methods the power-marketing agencies use in determining dependable capacity. The exact risk each assumes is difficult to determine because the variable the agencies use includes combinations of weather forecasts, historical waterflows, and future capacity construction judgments. Also, differences in climatological time cycles (i.e., 1-year versus 3-year periods) make any comparison of risk difficult. However, our calculations indicate that the risk the Federal power-marketing agencies assume of not being able to furnish the amount of dependable capacity they market may vary from 0 for some regions to 12 percent for others.

USING THE ECONOMIC METHOD WOULD INCREASE DEPENDABLE CAPACITY

Although Interior's power-marketing agencies consistently used considerations of adverse water conditions in computing dependable capacity, the methodology used varied and resulted in the agencies assuming different risks that such adverse water conditions would occur. The agencies generally did not systematically consider economic factors in establishing the degree of risk to be assumed. To illustrate the possible effect of using the economic method to calculate dependable capacity available for sale, we applied the method in two of the Bureau's regions--Upper Colorado and Mid-Pacific.

We assumed the systems sold an amount of dependable capacity higher than that available from project generation in the low-water year so that revenues gained in better water years would offset the estimated costs of the systems purchasing power in the low-water year to support the same level of dependable capacity sales. This would allow more dependable capacity to be available for sale from the Federal systems and displace or delay the construction of alternative capacity in the Nation.

Any sale of capacity higher than adverse capability requires the ability to purchase, and the availability of power, from outside sources whenever the low-water year or water cycle is experienced. This supportive purchasing can be accomplished by buying capacity from any available source during the low-water year or by making energy purchases when insufficient water flows are experienced to provide the committed amount of capacity. The latter method of making energy purchases supports the reservoir level by not releasing water during certain periods in the low-water year so that the marketed amount of capacity is assured during peak periods.

For example, the Southwestern Power Administration, to market more dependable capacity, plans to purchase thermal-generated energy to support its dependable capacity in average, as well as low-water years. This allows them to conserve hydro resources by retaining water levels to support increased capacity sales. Using this method SPA markets 105 percent of its installed capacity, whereas it could market only 52 percent as dependable without such energy purchases. Generally, when using this method, offpeak energy purchases are made for supplying to customers, and the water normally released to meet these demands is held for later (onpeak) use.

The purchase of capacity in a low-water year presupposes that an onpeak source of capacity will be available. Bureau regional officials estimated that such capacity may cost as much as $50 to $60 a kilowatt year in some areas in the future. This is compared to the present Federal sales price of approximately $15 a kilowatt year. Therefore, the selection of either method--capacity purchases or offpeak energy purchases to support the water level in the reservoir--should be based on realistic estimates of expected conditions for the area under consideration.

Examples of potential increase in capacity in the Upper Colorado and Mid-Pacific Regions

We estimated that an additional 110 megawatts of dependable capacity could be made available from the Bureau's systems in the Upper Colorado and Mid-Pacific Regions by making power purchases from other sources during adverse water periods. To illustrate, we chose a 1-in-10 water cycle (1 adverse period in 10) because (1) it was within the present risk level assumed by 2 Bureau regions and (2) it resulted in a favorable benefit-to-cost ratio (power revenues to power purchases). Since the economic considerations for determining the risk level would vary by specific power area, the most realistic alternatives should be selected for determining what additional dependable capacity could be sold on the basis of all pertinent factors (e.g., reservoir storage capacity and dependence on hydroelectric power). Therefore, the 1-in-10 water cycle used in our example is not necessarily the best risk factor but is used only for demonstrating the benefits which can accrue by determining dependable capacity available using the economic method.

Furthermore, since the interpretations of the low-water year concept vary among the Federal power-marketing agencies, there is a need for Interior to establish uniform criteria which would be sufficiently flexible to recognize power system differences and yet provide for optimizing the determinations of the power system's generating capability under adverse conditions. Such uniform criteria would be beneficial under the present methods used by the Federal power-marketing agencies. Because Federal power systems have different reservoir sizes, streamflows, and generating equipment, such uniform criteria would have to recognize such differences.

For the Bureau's power system in the Upper Colorado Region, we estimated that using a 1-to-10 water cycle for determining dependable capacity would give an additional 49 megawatts of winter, and 48 megawatts of summer, dependable capacity over the amount determined by the Bureau under its present risk assumptions. At $1.32 a kilowatt month (the present rate charged for dependable capacity in that system), the extra capacity would provide $768,000 yearly in revenues, or $7.68 million over a 10-year period. Assuming the additional capacity was unavailable from the system in 1 of every 10 water cycles, or to simplify the analysis, once in every 10 years, Upper Colorado could draw upon its power-pool[1] reserves, as other pool members do periodically, and pay $797,000, based on a $.045 a kilowatt day charge made by the pool for the required capacity. After considering the additional revenues and costs, this process would provide an estimated net revenue of $6,886,000 over 10 years[2]. The Upper Colorado Region does market its excess capacity but not as dependable. If the excess capacity was sold as dependable, it could delay or displace alternative capacity construction.

The Supervisor of Power in the Bureau's Upper Colorado Region stated that the risk of finding a source of capacity in the low-water year might be too great to implement the economic method; whereas, the Chief of the Hydrologic Division believed that sales based on this method could be made only on a 5- to 10-year basis. Both officials were concerned with the difficulty of purchasing dependable capacity during the low-water year. We believe that if dependable capacity could not be purchased during low-water years, a potential for implementing this method still exists by purchasing energy during offpeak periods so that energy (water) can be stored for use during peak periods.

We estimated that the use of a 1-in-10 water cycle in the Mid-Pacific Region would result in 62 megawatts of additional dependable capacity being determined as available for sale. At $1.15 a kilowatt month (the present rate charged for dependable capacity in that system), this additional capacity would provide $852,000 a year additional revenue, or $8.52 million over a 10-year period.

Assuming capacity was unavailable from the system in 1 low-water year and therefore would have to be purchased, the Mid-Pacific Region could draw on a capacity account it has with a private utility company.

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[1] Power pools are made up of electric utilities who interchange power. (See p. 13.)

[2] Our analysis is used to illustrate potential economic benefits. We did not include such variables as inflation, present value, interest costs, and other related elements.

When the region provided its excess capacity to the utility, it received credit to the capacity account. The region would have, according to the Bureau, an estimated unused balance of 3,227 megawatts through the year 2005. This capacity is available to the region by contract whenever it needs it to support a firm load. A Bureau regional official estimated that the rate charged the Bureau would be $2 a kilowatt month; therefore, the cost in the low-water year would be $1,482,000 for the 62 megawatts. After considering the additional revenue and cost, an estimated net revenue would accrue to the Bureau of $7,040,000 over 10 years. Mid-Pacific Region officials stated that the concept we used was sound, but that Bureau policy and certain contract clauses would have to be changed before such a program could be implemented in their region.

The benefits of increasing the dependable capacity amounts also accrue to local and interconnected power service areas of the Federal system, because dependable capacity can be relied on to meet growing loads. Any additional dependable capacity from the Federal power systems can, therefore, delay or displace alternative construction of more inefficient generating capacity or help meet some of the Nation's future capacity needs. At present peaking capacity construction costs, the 110 megawatts of additional capacity in the two regions would require an alternative investment of about $13,200,000.

CONSTRAINTS TO THE ECONOMIC METHOD

Contractual and physical (e.g., reservoir storage capability) limitations in the Bureau's Mid-Pacific and Lower Missouri Regions, respectively, could act as a constraint to the changeover in these regions of the methodology for determining dependable capacity.

In the Mid-Pacific Region, a long-term contract with a private utility would have to be amended because the present dependable capacity methodology is included in the contract. In the Lower Missouri Region, the relatively small amount of reservoir storage capability would limit offpeak retention of water, thereby reducing the amount of additional capacity they could support. We do not believe that either constraint completely removes the potential for using the economic method in these regions because (1) the Mid-Pacific contract provides for reviewing the methods and criteria of determining dependable capacity when contract changes are contemplated and (2) there is some storage flexibility in the Lower Missouri Region.

A Bureau headquarters official stated that using power purchases to support increased dependable capacity sales, using the economic method, was a sound concept. However, he stated that departmental policy and funding restrictions generally prohibited the practice of making such purchases, except in emergencies. He further said that any additional net revenues received from such sales would be used to offset the need for future rate increases.

In our opinion, any power purchases that support increasing dependable capacity sales would not result in a long-term cost to the Government providing the economic method was used.

CONCLUSIONS AND RECOMMENDATIONS

The criteria of employing estimates of adverse conditions to determine dependable capacity are subjectively applied by Interior power-marketing agencies and results in various levels of dependable capacity under differing risks that water will be available to provide such capacity.

The Nation's need for electric power is growing; therefore, using either approach--purchasing capacity or offpeak energy--as the basis for determining dependable capacity, considering the benefits available to the agencies as well as to the Nation, seems reasonable and desirable.

Accordingly, we recommend that the Secretary of the Interior have the Federal power-marketing agencies:

--Establish uniform guidelines for determining the Federal power system's generating capability under adverse conditions, recognizing the diversity of the various systems.

--Determine the feasibility of establishing dependable capacity based on using capacity or offpeak energy purchases, considering both agency and national benefits.

--Identify and obtain the modifications which would be required to implement the economic method, including provision for sufficient funds to purchase the power needed in adverse years.

--Market any additional capacity, based on the results of the above action, as dependable with energy return provisions, if needed.

AGENCY COMMENTS

In its letter of June 2, 1976 (see app. III), Interior said that the feasibility of implementing our proposed economic method of increasing the capacity available for sale was highly dependent on operating conditions of the individual systems and the diversity, load patterns, and pooling arrangements with adjacent systems. In addition, Interior pointed out that one important constraint was the lack of potential availability of purchased power in the advent of a low-water year. It said, therefore, that it was impossible to generalize on the potential for adopting our recommendations, but that the recommendations may be very workable for some systems and be impractical or have no significant impact on the capacity of other systems.

With respect to our first recommendation, the Assistant Secretaries, to whom the power-marketing agencies report, are to collaborate on a study to explore its feasibility and to develop uniform guidelines if found practical.

Several other recommendations deal with implementing the economic method. Interior said that this would require system-by-system consideration, which would be undertaken. In addition, it said that the Bureau, which administered 6 of the 15 power-marketing systems, would include such determinations as part of a major Bureau study to identify and appraise ways to expand water-related energy production in the western United States. Initial results are expected to be available in September 1976.

We believe that the actions suggested by Interior, if properly implemented, should result in the power-marketing agencies giving appropriate consideration to our recommendations.

CHAPTER 3

REDUCING RESERVE CAPACITY REQUIREMENTS

The Federal hydroelectric systems maintain larger generating reserves than we believe are warranted by the nature of their mission, the reliability of their systems, or, in some cases, the requirements of the power pools to which they belong. If such reserves could be reduced and made available for sale, then additional revenues could be earned by the Federal power systems and, in some cases, postpone or reduce the need for additional generating capacity to be constructed.

Reserve capacity--capacity in excess of load--is maintained by power systems so that if there is a failure of a generating unit, the electric load can be picked up by another unit (or units) without interrupting service. Such reserves for emergency conditions are called operating reserves. In addition, some capacity is usually held in reserve to meet such contingencies as load growth[1] and maintenance requirements. The combination of all reserves is referred to as design or planning reserves in the Bureau systems. Historically, hydroelectric systems have maintained reserves sufficient to cover their largest potential loss[2]--usually the largest generator in the system--or 10 percent of the system's maximum peakload.

Due to interconnecting transmission lines, adjoining power systems can exchange power with other power companies. This allows power systems to form power pools and share resources, thus reducing the total reserve needs of the area served by power-pool members. Some pooling agreements have enabled individual systems to substantially reduce their reserves by allowing the pool members' required total reserves to be equivalent to the entire pool's largest potential loss, plus some margin. After the pool requirements are determined, each member is then apportioned a pro rata share of the pool reserve requirement.

Although pooling arrangements often result in reserve reductions and, in some cases, result in the sale of reserves on an interruptible basis, Federal systems have not taken full advantage of these benefits. Our review indicates that

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[1]Load growth is the anticipated increase in customers' electric loads.

[2]May be referred to as largest hazard or largest contingency.

--the Bureau requires that maintenance and load growth reserve capacity be maintained although, in our opinion, these are factors that should not have an impact on the Bureau's reserve requirements,

--power-pooling agreements require reserve requirements for both the Bureau and power-marketing agencies which, in our opinion, do not adequately reflect the reliability of hydroelectric systems,

--one Bureau region does not take advantage of the pooling agreement which would allow them to sell reserves on an interruptible basis, and

--the most accurate estimates of reserve needs are not always used.

Reducing reserve requirements could free capacity previously held in reserve, thereby making it available for sale to customers as dependable capacity. For example, if Federal reserves at the Upper Colorado and Lower Missouri Regions were reduced to the level required by the Inland Power Pool,[1] the excess capacity could be sold as dependable capacity, and $4.08 million for constructing electric peaking capacity could be deferred or displaced. By providing hydroelectric peaking capacity and selling it on a firm basis, hydroelectric systems could reduce their customers' need for inefficient peaking generators.

FULL PLANNING-RESERVE REQUIREMENTS NOT NEEDED AT BUREAU PROJECTS

Bureau policy requires that each region maintain planning reserves of 10 percent of its maximum peakload or its share of the operating reserves required by power-pool agreements, whichever is greater. The Bureau requires planning reserves to cover:

--Load regulation,[2] instantaneous changes in load demands.

--Maintenance, scheduled maintenance of generating equipment which takes it out of service.

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[1]At the time of our review, membership included the United States; Colorado Ute Electric Association, Inc.; Public Service Company of Colorado; and Salt River Project Agricultural Improvement and Power District.

[2]Also called regulating margin. This amount is often included as part of operating reserves.

--Load growth, anticipated load increases of the service area.

--Operating reserves, reserves held to meet unscheduled outages of generating equipment, usually equal to the greatest single potential outage; i.e., generator, transformer, or transmission line.

Operating reserves are maintained by Bureau regions in amounts ranging from 5 percent to 11.2 percent of their loads. These operating reserves are the Bureau's share of the pool reserves, which may represent from the pool's largest contingency to 150 percent of the pool's largest contingency.

The following schedule shows the amounts of operating reserves and planning reserves maintained by each region.

Region	Operating reserves maintained	Planning reserves maintained
	-----------percent of load	-------------
Upper Colorado	7.8	10
Lower Colorado	11.2	11.2
Upper Missouri	5	10
Lower Missouri	6	10

The Bureau's planning reserves include allowances for load growth and maintenance. In our opinion, load growth and maintenance reserves should not be maintained by the Bureau because unlike a public utility it does not have the responsibility to meet its customers' load growth, and the Bureau schedules maintenance during the offpeak season when excess reserves are available thereby having a negligible impact on reserve requirements.

A Department of the Interior solicitor in a November 26, 1974, memorandum to the Commissioner of Reclamation said that the general responsibility of the Secretary of the Interior was to dispose of the power and energy available from Federal hydroelectric power projects but not to serve as a utility and meet the customers' load growth. In addition, regional officials told us that maintenance on Federal hydroelectric facilities was scheduled during offpeak seasons so that the out-of-service time did not prohibit meeting loads.

In our opinion, the Bureau's practice of maintaining reserves based on 10 percent of maximum peakload or the pools' operating reserve requirement, which ever is greater, should be reconsidered. We believe that the amount of reserves which are allotted to load growth and onpeak maintenance should not be included when establishing the Bureau's reserve requirement. The following example demonstrates the effect of the Bureau's requirement on the reserves at the Upper Colorado and Lower Missouri Regions.

Examples of potential reserve reductions at the Upper Colorado and Lower Missouri Regions

The Bureau's Upper Colorado and Lower Missouri Regions combined resources and entered the Inland Power Pool as a single entity representing the United States. The Bureau, as a single entity, is assigned reserve requirements by the pool on the basis of the combined resources of the two regions. A memorandum of agreement between the regions allocates the reserve requirements. The pool criteria for operating reserves requires the United States to maintain about 100 megawatts of reserve. The Upper Colorado maintains about 75 megawatts and the Lower Missouri maintains about 25 megawatts of these resources, according to the agreement.

After joining the pool, Upper Colorado proposed to sell on a long-term basis a part of the capacity which the reserve reduction freed.

Before joining the pool, Upper Colorado had maintained 154 megawatts of reserves which they proposed to reduce to 100 megawatts.[1] After joining the pool, Upper Colorado proposed to sell on a long-term basis the 54 megawatts of dependable capacity which the reserve reduction freed. Bureau headquarters, however, rejected the proposal because Bureau policy required a minimum of 10 percent (124 megawatts) of load as design or planning reserves.

According to the Chief of the Power Division at Bureau headquarters, design reserves are required to cover load regulation, maintenance, load growth, and operating reserves. This Bureau requirement--which is additional to that required by the pool agreement--increased Upper Colorado's proposed

[1]Includes 75 megawatts operating reserves the pool requires plus 25 megawatts regulating margin. The Chief of the Power Control Branch for the Upper Colorado Region believes this is a sufficient amount of reserves and that capacity above this amount can be marketed on a firm basis.

100 megawatt reserve by 24. These 24 megawatts, marketed as dependable capacity, could guarantee annual revenues of $380,160 and defer construction of $2.88 million of peaking capacity facilities. The Bureau allows all but 20 of the 124 megawatt reserve to be sold as interruptible, or nondependable, power. However, nondependable capacity generally is not as valuable as dependable capacity and, because it is not reliable, does not defer or replace alternate generating capacity.

Before the pool agreement, Lower Missouri maintained 35 to 37 megawatts of reserves--enough to cover the loss of its largest generator. Although the pool allows a reduction to about 25 megawatts for operating purposes, the Lower Missouri still maintains 10 percent of its load as planning reserves because of the Bureau's policy noted earlier in this report. The planning reserve presently maintained is between 35 to 38 megawatts, which is roughly equal to the reserves maintained before joining the pool. Thus, Lower Missouri has neither decreased its reserves nor increased its sale of dependable capacity, as a result of joining the pool. If the Lower Missouri maintained reserves at the level allowed by the pool and sold the remaining 10 megawatts as dependable capacity, annual firm revenues of $152,400 would be guaranteed and $1.2 million in alternative construction could be avoided. The 10 megawatts have been sold on a short-term basis; however, the sales have been intermittent.

A Bureau headquarters official stated that, if the reserves were marketed by the Lower Missouri and Upper Colorado Regions as suggested and the pool later increased its requirements, the Bureau would be unable to continue to participate because it would not have the capacity to meet the increased reserve requirements.

The pool contract, however, is, by its terms, effective until May 2009 and does not provide for changing the method for establishing the Federal reserve requirements before that time. We believe that such possibility should not be a concern to the Bureau because, eventually, the pool could establish additional reserve requirements which could exceed the excess capacity the Bureau has in its system and the same situation could occur.

POWER-POOLING AGREEMENTS SHOULD MORE ACCURATELY RECOGNIZE HYDROELECTRIC RELIABILITY

Historically, hydoelectric generators have been more reliable than conventional thermal generators in that their frequency of forced outages has been lower. We believe that hydroelectric generators' reliabilty has not been adequately considered in some pooling agreements. Consequently, Federal hydroelectric projects carry more reserves than their history of outages seem to merit.

We believe the methods of determining reserve obligation for the pool, and apportioning such reserve obligation to each pool member, should be based on the forced outage history of the generating units. The following illustrations describe situations where we believe excess Federal reserves are required because the reliability of Federal hydroelectric systems are not adequately considered.

Inland Power Pool

The Inland Power Pool Agreement--of which the Upper Colorado and Lower Missouri Regions are signatories--calls for operating reserve capacity as follows:

> Pool reserves cannot be less than the greater of
>
> "--7 percent of the combined electric system load supplied by thermal generation and 5 percent of the electric system load supplied by hydro generation for the then current clock hour;[1] or
>
> "--the number of kilowatts associated with the largest possible single contingency loss of generation due to the loss of any single synchronized generating unit or single transmission circuit on or serving the combined electric system, plus 1 percent * * * of the aggregate load of the parties to cover regulating margin."

The second option is greater and is, therefore, used to determine operating reserve capacity. Each member is then required to maintain its pro rata share of operating reserve capacity (known as its operating reserve quota), which is equal to the pool's total operating reserve capacity multiplied by the member's reserve responsibility ratio (RRR). RRR is computed by taking 25 percent of the monthly load of the party's system, plus 100 percent of the number of kilowatts associated with the largest single contingency loss of generation for thermal generation, or 71 percent for hydrogeneration, divided by the sum of the individual values determined by the above.

---

[1]Current load (demand).

We believe that the above formula does not adequately consider the relative infrequency of hydroelectric outages. We calculated that the forced hydroelectric outages rates in the Upper Colorado Region have averaged over the life of the projects (November 1963 to August 1975) less than one-hundredth of 1 percent, and in the Lower Missouri Region these outages averaged less than 1 percent (.56 percent) from 1972 to 1974. Our calculations were based on forced outages only. From 1964 to 1973 the forced outage rate for all fossil steam units was 4.63 percent, as reported by Edison Electric Institute. For large fossil steam units (600 megawatts and up) the outage rate went up to 16.5 percent.

According to a Federal Energy Administration report, which utilized Edison Electric Institute data, there were instances where utilities did not report fossil fuel plant outages caused by major equipment failures as forced outages because management decided to use the outage time for performing planned maintenance. Therefore, the outage was reported as a planned outage rather than a forced outage. We believe the figures for forced outages for fossil-fired units may be underestimated.

Using pool criteria, a hydroelectric system with 1,000 megawatts of load and a single largest generating contingency of 150 megawatts would be required to carry 89 percent of the reserve quota that a thermal system with the same contingency and load would be required to carry. Since hydroelectric systems are not 89 percent as likely to have a forced outage, this causes the hydroelectric systems to carry more of a burden than their likelihood of outages warrants. We believe a more equitable way to determine reserve quotas is to consider the frequency of both hydroelectric and thermal outages in the formula which determines RRR.

A Bureau headquarters official said that by joining the pool, the Government obtained other benefits which he believed offset any additional reserves which it must maintain. The primary benefit he mentioned was an energy exchange agreement whereby the Government has 1 1/2 kilowatt hours returned for every kilowatt hour it provides to other pool members. We believe, however, that reserve requirements should be established on as realistic a basis as possible and that other arrangements in pooling agreements should also be established on a fair and equitable basis. Attempting to trade-off the advantages and disadvantages of different provisions of an agreement established individually is not, in our opinion, a sound contracting procedure.

Arizona-Nevada Power Pool

The Parker Davis System of the Lower Colorado Region maintains reserves in accordance with the Arizona-Nevada Power Pool[1]. The Lower Colorado maintains 35 megawatts as its portion of the pool's reserves. Reserves for the pool are at least the greater of

> "--7 percent of the combined electric system load for the then current clock hour; or
>
> "--the number of kilowatts associated with the largest possible single contingency loss of generation due to the loss of any single synchronized generating unit or single transmission circuit on or serving the combined electric system."

The second option is greater and, therefore, determines the pool's reserves.

Each member's reserve requirement is then obtained by multiplying the pool requirement by the member's RRR. RRR for all parties, whether steam or hydro, is determined by taking 25 percent of the system's monthly demand plus the system's largest hazard remaining after subtracting the number of kilowatt power contracted for by another party hereto or outside parties contingent on its operation, divided by the sum of the values of the three parties to the pool. In no event is the spinning reserve[2] quota to be less than 7 percent of that party's electric system load for the current clock hour.

Lower Colorado officials commented that thermal outages are much more frequent than hydroelectric outages, although they have no specific information on the percentage of thermal outages. The Lower Colorado hydroelectric system has had only three forced outages since 1948. However, the pool agreement requires the hydroelectric system to carry the same proportion of reserves as thermal systems. The pool agreement, therefore, does not consider the greater reliability of the hydroelectric units.

---

[1]Present membership includes the United States, Nevada Power Company, and the Salt River Project Agricultural Improvement and Power District.

[2]Ready reserve.

The Chief of the System Engineering and Operation Branch in the Lower Colorado Region commented that the loss-of-load probability method is currently being considered for power pools. Under this method each party would be required to develop a history of generation outages so future pooling agreements could consider the performance of individual generating units.

UPPER MISSOURI REGION SHOULD SELL EXCESS RESERVES AS INTERRUPTIBLE POWER

The Upper Missouri Region is a member of the Mid-Continent Area Power Pool. The required planning reserve level for the Bureau's hydroelectric systems is 10 percent of the systems annual peakload. Operating reserves for the pool--designed to maintain continuity of service--are 150 percent of the largest generator in the pool. Upper Missouri's share is 88 megawatts which is included in its planning reserves.

The pooling agreement did not free any capacity for sale on a dependable basis. Upper Missouri maintained 10 percent of its load as planning reserves before becoming a member of the pool, and they still maintained this amount in accordance with the pool criteria.

The pooling agreement does, however, allow its members to sell as replacement energy[1] or interruptible power those reserves in excess of the operating reserve requirement. Upper Missouri prefers, however, to keep 5 percent, or 123 megawatts in excess of operating reserves of the annual system demand available at all times. This leaves 35 megawatts that could be sold as replacement energy. The Chief of the Power Marketing Branch said that 5 percent of load is the minimum needed to handle load regulation. The Chief of the Power Division added that it is just "good practice" to keep 5 percent of load in reserve. We believe, in light of the current energy crisis, the Bureau should reevaluate this practice with the objective of selling as much capacity as it can as replacement energy or interruptible power.

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[1]Replacement energy usually displaces the use of scarce fossil fuels in thermal systems by providing hydroelectric energy to anyone who could use it instead of oil.

MOST ACCURATE ESTIMATES OF RESERVE NEEDS SHOULD BE USED IN PLANNING

The Bonneville Power Administration markets the power generated at the Federal hydroelectric power projects which are operated by the Bureau of Reclamation and Corps of Engineers. These projects, together with BPA's transmission system, are referred to as the Federal Columbia River Power System (FCRPS).

FCRPS maintains reserves of 1,668 megawatts. The FCRPS allocation of total area reserves[1] represents 15.3 percent of FCRPS's peakload. FCRPS reserves include the following types and amounts for fiscal year 1975.

Type of reserves	Capacity in megawatts
Forced outage reserves	701
Load growth reserves	581
Planning reserves	386
Total	1,668

BPA used the 1,668 amount for long-term planning. BPA computed forced outage reserve for planning (701 megawatts) at 5 percent of hydroelectric plants' capacity. BPA uses the 5 percent figure because it has been used in the past as "a rule of thumb." A different method was employed to estimate the forced outage reserves utilized in operations.

Operational forced outage reserves (511 megawatts), specified in the Pacific Northwest Coordination Agreement,[2]

---

[1]Total area reserves for 1975 were calculated as 12 percent of Pacific Northwest area peakloads. In future planning this reserve factor increases by 1 percent each year, reaching a maximum of 20 percent. FCRPS is allocated a part of this.

[2]BPA participates in, and is subject to, the terms of the Pacific Northwest Coordination Agreement. FCRPS bases its planning reserves on the greater of its part of the Pacific Northwest area loads or the reserves as calculated under this agreement.

were calculated using a complex probabilistic approach. This approach considers the probability of outage based on the history of each FCRPS facility and determines the probability of load loss. According to a BPA official, if this figure, which in our opinion is more realistic, is used in planning, the thermal reserve requirement will increase about 190 megawatts, but BPA's reserve requirements will be correspondingly less. The BPA official said that the Federal hydroelectric systems can bear the cost burden of carrying large reserves better than utilities with thermal systems can.

We believe that the method which most realistically represents the expected conditions should be used for determining reserve requirements. The operational forced outage reserves (511 megawatts) meets this standard. If the 190 (701 less 511) megawatt difference between operational reserves and planning reserves were sold as dependable capacity, it could bring firm revenues to BPA of $2,280,000 annually, and in accordance with the requirements of pertinent laws, contribute to BPA marketing its power at the lowest rates possible. However, such additional reserves may not delay any future construction of generating capacity in the region or the Nation.

CONCLUSIONS AND RECOMMENDATIONS

We believe that more reserve capacity is maintained by Federal hydroelectric systems than is merited. If reserves more realistically represented expected conditions, the Federal reserves could be reduced. The additional capacity thus made available--depending on the circumstances in each case--could be sold as dependable capacity. Such sales would not only result in additional Federal revenues but could help meet the Nation's need for additional dependable power.

Therefore, we recommend that the Secretary of the Interior require:

--The Bureau of Reclamation to redetermine the reserve requirements for each power system, giving full consideration to the benefits derived from pooling arrangements and to the elimination of reserves based on load growth and maintenance factors.

--The Federal power-marketing agencies, when entering into new or revising existing power-pool agreements, to negotiate for more equitable reserve requirements taking into consideration the historical reliability of hydroelectric facilities.

--The Federal power-marketing agencies to sell the capacity that may become available as a result of the redetermination of reserve requirements.

Agency comments

In its letter of June 2, 1976, (see app. III), the Department of the Interior said that while there were some existing constraints because of long-term contracts and industry standards it had directed the Bureau to assess the potential and effects of our recommendations as part of the previously mentioned energy study. (See p.12.) In addition, Interior said that because of pooling arrangements, reserve capacity of other power-pool members, reliability of the mix of generating units, and other factors which affect the reserve requirements, it was not appropriate to mandate that the power-marketing agencies negotiate more equitable reserve requirements.

Interior said, however, it would require the power-marketing agencies to restudy those power systems which include a reserve requirement. When such studies show that reserves are excessive or inequitable, the agencies will seek a more equitable reserve requirement when entering into new or revising existing power-pool agreements.

BACKGROUND ON POWER-MARKETING AGENCIES

COVERED BY OUR REVIEW

Bonneville Power Administration

The Bonneville Power Administration is the wholesale power-marketing agency for all Corps of Engineers and Bureau of Reclamation multipurpose dams in the Columbia River basin. These dams and the BPA transmission system make up the Federal Columbia River Power System which supplies about half of the Pacific Northwest's electric power needs.

BPA's service area includes Oregon; Washington; Idaho, western Montana; and parts of California, Nevada, Utah, and Wyoming. In fiscal year 1973, it sold wholesale power to 149 customers, including 109 public utilities, 11 privately owned utilities, 19 industrial operations, and 10 Government agencies.

Twenty-six Federal multipurpose dams were in operation on June 30, 1973, with an intalled capacity of 10,485,900 kilowatts. Additional capacity is under construction at five new and four existing projects that will bring the total to 17,148,780 kilowatts.

Southwestern Power Administration

The Southwestern Federal Power System includes the facilities and operations of the Southwestern Power Administration and the hydroelectrical dams constructed and operated by the Corps of Engineers for which SPA is the marketing agent.

SPA markets power in the six-State area of Kansas, Oklahoma, Texas, Missouri, Arkansas, and Louisiana. Power is delivered to municipalities, rural electric cooperatives, defense installations, and private utilities over SPA's transmission system, as well as other utilities' transmission systems.

Twenty-one Corps of Engineers plants were in operation June 30, 1974, with an installed capacity of 1,916,700 kilowatts. Two new projects are under construction which will increase the installed generating capacity to 2,134,700 kilowatts.

Bureau of Reclamation

The Bureau administers its power-marketing activities through seven regional offices. Descriptions of the regions covered in our review follow.

Mid-Pacific Region

This region operates the Central Valle· Project (CVP) located in California. CVP is a multipurpose project consisting of 19 dams and related water conveyance systems and power generation and transmission facilities. CVP's primary purpose is to provide irrigation water to the Sacramento and San Joaquin Valleys. The existing seven power plants and two pumping-generating plants, with a total installed capacity of 1,321,840 kilowatts, are integrated directly with a private utility's power system. An additional 650,000 kilowatts is scheduled to be in service about 1982.

Power CVP generates is dedicated first to meeting the power requirements of its irrigation pumping facilities. The remaining power capability is used to provide wholesale power to about 50 preference customers in northern California.

Upper Colorado Region

This region operates the Colorado River Storage Project (CRSP). CRSP is a basinwide, multipurpose program for the development and use of water resources of the Upper Colorado River. Main storage units on the Colorado and main tributary rivers even out erratic river flows so that water commitments to the Lower Basin States--below CRSP--can be met in low-water years. Delivery of water to Upper Basin customers is done by CRSP participating projects.

CRSP power plants have an installed capacity of 1,248,000 kilowatts. Two projects are under construction that will increase the total to over 1,400,000 kilowatts. Power generated at existing power plants is marketed to more than 200 preference customers in Arizona, New Mexico, Utah, Colorado, Wyoming, and parts of California and Nevada.

Lower Colorado Region

This region encompasses parts of California, Nevada, Utah, New Mexico, and almost all of Arizona. It consists of two major projects: The Boulder Canyon Project and the Parker Davis Project.

Hoover Dam is the key feature of the Boulder Canyon Project. Its reservoir, Lake Mead, backs up 115 miles behind the dam and is capable of storing nearly 30 million acre-feet of water.

The Parker-Davis Project is comprised of Davis Dam and Power Plant, Parker Dam and Power Plant, and a 1,600 mile transmission system serving Nevada, California, and Arizona. Davis Dam was built primarily for regulating Colorado River water delivered to Mexico at the international boundary as required by the Mexican Water Treaty. Parker Dam, 88 miles downstream from Davis Dam, was designed and constructed by the Bureau of Reclamation with funds advanced by the Metropolitan Water District of Southern California. It provides a forebay and desilting basin for the district's Colorado River Aqueduct and 120,000 kilowatts of capacity. The district owns one-half of this capacity.

The combined installed capacity of the Hoover, Parker, and Davis power plants is 1,629,800 kilowatts, exclusive of district ownership.

Lower Missouri Region

This region administers the activities of the Pick Sloan-Missouri Basin Program--Western Division. The Western Division includes parts of Wyoming east of the Continental Divide, parts of Colorado, and western Nebraska. The power-generating system, which includes one-half of Yellowtail Dam which is shared with the Upper Missouri Region, has an installed capacity of 516,162 kilowatts. Power is marketed to about 50 wholesale preference customers.

Upper Missouri Region

This region administers the activities of the Pick Sloan-Missouri Basin Program--Eastern Division. The Eastern Division includes the area of Montana east of the Continental Divide, North and South Dakota, central and eastern Nebraska, western Minnesota, and western Iowa. Power is generated from two Bureau- and six Corps-operated power plants with a total installed capacity of 2,223,000 kilowatts (excluding one-half of Yellowtail allocated to the Western Division).

Eastern Division power is marketed to approximately 240 preference customers consisting of municipal power systems, cooperatives, public power districts, and State and Federal agencies.

METHODS OF DETERMINING DEPENDABLE CAPACITY

Power system	Method of determining dependable capacity
Bonneville Power Administration	It analyzed streamflows for a 30-year period (1928-58) and found 1936-37 to be the most adverse sequence of annual streamflows. Dependable capacity was established as the capability during January (peak month) of the 1936-37 period which was not the worst January during the 30-year period. BPA computed its risk of not being able to provide dependable capacity at .9 percent.
Southwestern Power Administration	It analyzed streamflows for a 42-year period (1928-70) to find the most adverse streamflows which occurred during an August of that period. August was used to determine what could be dependably provided from within its system during the peak month. However, in order to market more dependable capacity, it plans for the purchase of thermal energy to support dependable capacity in average, as well as low, water years. This allows SPA to conserve hydroelectric resources by retaining water levels to support capacity. Using this method, SPA markets 105 percent of its installed capacity, whereas it could market only 52 percent as dependable without energy purchases.
Upper Missouri Region	It uses a Corps of Engineers study on all but two dams in its region. This method is based on 1898 to 1971 streamflows on the main stem of the Missouri River. Different winter and summer capabilities are carried out using the following variables.

Power system	Method of determining dependable capacity
	Winter: --Eighty percent of the forecasted inflows for the next 7 months. --Followed by inflows of 2 lower quartile years (represented by 1932 water flows). --Followed by 10 months' inflows of an adverse year (represented by 1919 water flows). Summer: --Eighty percent of the forecasted inflows for the next 7 months. --Followed by 3 lower quartile year inflows (1932). --Followed by 10 months of inflows of an adverse year (1919). The 1919 year was selected as an adverse year; however, it was not the most adverse year on record. The most adverse year (1931) was excluded because it fell within a 1930 to 1940 drought period, for which the Weather Bureau in 1953 had estimated a recurrence interval of 3,300 years. For the two Bureau plants in the region, dependable capacity is estimated to be the plants' full capability. This is based on the premise that alternative steam capacity could be constructed to meet the hydrocapacity lost due to poor streamflows after experiencing 2 years of a drought.
Lower Missouri Region	It operates under a 1956 dependable capacity study based on 1906 to 1954 water flows. Supporting information for the study was not

Power system	Method of determining dependable capacity
	available, although regional officials informed us that the study was based on the assumption that dependable capacity would be available in 90 percent or more of the years. A new study has been prepared; however, it was not being used for marketing purposes at the time of our field work.
Upper Colorado Region	It analyzed 1906 to 1968 water flows after assuming a starting point at the actual reservoir levels of September 1974. With this information, a series of adverse cycles were put into the study to determine what combination of historic annual flows would result in the least amount of available capacity. Water flows of the single worst year, the 2 worse successive years, 3 worst successive years, and so on, through the worst successive 15 years were run. The capacity levels at the last year of each cycle were compared to find the lowest combination of years. The 13-year period of 1953 through 1965 resulted in the lowest dependable capacity. This is the level of dependable capacity marketed by the region. We computed this to an 11.6 percent risk of not being able to provide dependable capacity.
Lower Colorado Region	The three power plants in the Lower Colorado Region--Hoover, Parker, and Davis--are unique as compared to other Federal dams. The generators at Hoover Dam are operated by non-Federal lessees. They generate electricity for their benefit based on water releases required by downstream commitments. As a result, the water flowing to the federally operated Parker and

Power system	Method of determining dependable capacity
	and Davis Dams--located immediately downstream from Hoover--is fairly constant. For this reason, the effect of an adverse water year is not experienced at these federally operated projects since the water flows are stabilized behind the larger Hoover Dam.
Mid-Pacific Region	It analyzed streamflows during the period of 1922-66, and concluded that 1928-34 was the most adverse water cycle ever recorded. It negotiated its dependable capacity based on May 1930 through December 1934 streamflows with the private utility which transmits the Bureau's power. We computed this to be a 5.1 percent risk of not being able to provide dependable capacity.

 APPENDIX III

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

June 2, 1976

Mr. Henry Eschwege
Director, Resources and
Economic Development Division
General Accounting Office
Washington, D.C. 20548

Dear Mr. Eschwege:

We have reviewed your proposed report to the Congress entitled "Opportunities to Increase Hydroelectric Generating Capacity Available for Sale at Federal Projects."

GAO believes that additional hydroelectric capacity can be made available for sale (1) by changing the methods Interior power marketing agencies use in determining how much capacity can be sold and (2) by reassessing the amount of capacity which is held in reserve for contingencies. The report states that such additional capacity could delay, or in some instances displace, alternative construction of electric generating capacity.

As your draft report notes, the Department has five power marketing agencies. But more pertinent to an understanding of the extent of effort required to judge the merits of GAO's recommendations is the fact that these power marketing agencies administer 15 power marketing systems.

GAO proposed economic methods of increasing the capacity available for sale are highly dependent upon the operating conditions of the individual systems and the diversity, load patterns, and pooling arrangements with adjacent systems. It is therefore impossible to generalize on the potential for adopting GAO recommendations. They may be very workable for some systems and be impractical or have no significant impact on the capacity of other systems. In fact, one of our power marketing agencies advised that the economic method would increase the capacity of their power systems only slightly or not at all. A second agency advised that it is applying an economic method, based on other than the most adverse year as a base, arrangements for power exchanges with adjacent systems, and supplementing capacity and firm energy with off peak energy purchases. And a third agency also uses supplemental energy purchases to increase dependable capacity. However, in this latter instance, we are presently in the situation in which long-term contracts were entered into on reasonable assumptions at the time as to availability and cost of non-Federal energy. The massive unanticipated increases as the result of the international oil embargo and subsequent price increases, however, have greatly increased the cost of the purchased energy, producing severe distortions in our current rate structure.

Your draft audit report makes several recommendations directed at increasing dependable energy capacity through adoption of the economic method of determining the power systems' generating capability. The first of these recommendations is to establish uniform guidelines for our power agencies to apply the economic analysis. As indicated in the preceding paragraph, the diversity between systems may be such that uniformity would be meaningless. Nonetheless, I have instructed the Assistant Secretaries to whom the power marketing agencies report to collaborate on a study to explore the feasibility of this recommendation and to develop uniform guidelines if found practical.

Several other recommendations deal with the implementation of the economic method. This will require a system-by-system determination, which will be undertaken. The Bureau of Reclamation, which administers 6 of the total of 15 power marketing systems of the Department, will include such determinations as a part of a major Bureau study to identify and appraise ways to expand water related energy production in the Western United States. Called the Western Energy Expansion Study, this effort was undertaken in February 1976. Initial results are expected to be available in September 1976.

The second major issue raised in your draft report relates to obtaining additional hydroelectric capacity for sale by reassessing and reducing where feasible the amount of capacity which is held in reserve for contingencies. You recommend that the Bureau of Reclamation be required to redetermine reserve requirements for each power system based on load growth and maintenance factors. While there are some existing constraints because of long-term contracts and industry standards, the Bureau has been directed to assess the potential and effects of such a change as part of the previously mentioned Western Energy Expansion Study.

You also recommend that power marketing agencies be required, when entering into new or revising existing power pool agreements, to negotiate more equitable reserve requirements and to sell the added capacity made available. Again, there are different situations that pertain to each power system. At least several already have no reserve capacity. But another power marketing agency reports that existing reserves for its systems have been found insufficient. In both instances, pooling arrangements, reserve capacity of other power pool members, reliability of the mix of generating units and other factors affect the reserve requirements of our power systems. Accordingly, it is not appropriate to mandate that the power marketing agencies negotiate more equitable reserve requirements. One important constraint for most of our power systems is the lack of potential availability of purchased power in the event of an adverse water year. This could result in brownouts or blackouts. Even if available, the power would be quite expensive and significant additional funding would be required.

We will require our power marketing agencies to restudy those power systems which include a reserve requirement. When such studies show that reserves are excessive or inequitable, the agencies will seek a more equitable reserve requirement when entering into new or revising existing power pool agreements.

Thank you for the opportunity to review and comment on your draft report. We are enclosing for your consideration suggested changes to clarify certain facts set forth in the report.

Sincerely,

Deputy Under Secretary

Enclosure (See GAO note below.)

GAO note: The enclosure is not included here but was considered in this report.

PRINCIPAL OFFICIALS RESPONSIBLE

FOR ADMINISTERING ACTIVITIES

DISCUSSED IN THIS REPORT

	Tenure of office From	To
DEPARTMENT OF THE INTERIOR		
SECRETARY OF THE INTERIOR:		
Thomas S. Kleppe	Oct. 1975	Present
Kent Frizzell (acting)	July 1975	Oct. 1975
Stanley K. Hathaway	June 1975	July 1975
Kent Frizzell (acting)	May 1975	June 1975
Rogers C.B. Morton	Jan. 1971	Apr. 1975
Fred J. Russell (acting)	Nov. 1970	Dec. 1970
Walter J. Hickel	Jan. 1969	Nov. 1970
Stewart L. Udall	Jan. 1961	Jan. 1969
ASSISTANT SECRETARY--ENERGY AND MINERALS (note a):		
Jack W. Carlson	Aug. 1974	Present
C. King Mallory (acting)	May 1974	July 1974
Stephen A. Wakefield	Mar. 1973	Apr. 1974
James R. Smith	Mar. 1969	Feb. 1973
Kenneth Holum	Jan. 1961	Mar. 1969
ASSISTANT SECRETARY--LAND AND WATER RESOURCES (note a):		
Jack O. Horton	Mar. 1973	Present
ADMINISTRATOR, BONNEVILLE POWER ADMINISTRATION:		
Donald P. Hodel	Dec. 1972	Present
Henry R. Richmond	Sept. 1967	Dec. 1972
ADMINISTRATOR, SOUTHWESTERN POWER ADMINISTRATION:		
Peter C. King	July 1969	Present
Douglas G. Wright	Sept. 1943	July 1969
COMMISSIONER OF RECLAMATION:		
Gilbert G. Stamm	May 1973	Present
Gilbert G. Stamm (acting)	Apr. 1973	May 1973
Ellis L. Armstrong	Nov. 1969	Apr. 1973
Floyd E. Dominy	May 1959	Oct. 1969

[a]Secretary of the Interior Order No. 2951, dated February 6, 1973, established the Office of Assistant Secretary--Land and Water Resources, formerly the Office of Water and Power Resources, and the Office of Assistant Secretary--Energy and Minerals.

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