RELEASED 110949

~~12079~~

REPORT BY THE Comptroller General OF THE UNITED STATES

Montana's Libby Dam Project: More Study Needed Before Adding Generators And A Reregulating Dam

The U.S. Army Corps of Engineers has not shown that its proposed project to add more generators to the Libby Dam and a reregulating dam downstream is economically justified or the best alternative for meeting Pacific Northwest electricity peaking needs.

GAO questions the Corps method of calculating the project's benefits. The Corps plans to reassess the benefit-cost ratio using a better method and submit the results to the Congress by early 1980.

Neither the Corps nor the Bonneville Power Administration has adequately studied other ways of meeting forecasted peak power shortages. Combustion turbines, cogeneration, power exchanges, load management, and peak pricing options should be evaluated before the proposed project proceeds.

This report responds to a request from Senator Baucus.

UNITED STATES GENERAL ACCOUNTING OFFICE

EMD-80-25
NOVEMBER 20, 1979

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

B-163310

The Honorable Max Baucus
United States Senate

Dear Senator Baucus:

In accordance with your June 20, 1979, request and questions raised by another member of the Montana congressional delegation, this report discusses the Corps of Engineers proposal to add generators to Libby Dam on the AGC00305
10 Kootenai River in Montana and to construct a reregulating dam nearby. This report contains recommendations to the Corps and to the Bonneville Power Administration that AGC00465
further study of alternatives and economic justification are needed before the project progresses further.

At your request, we did not obtain written agency comments. The matters covered in the report, however, were discussed with agency officials, and their comments were incorporated where appropriate.

As agreed with your office, a copy of this report is being sent to Congressman Pat Williams and will be restricted from further distribution for 30 days from the date of the report unless the report contents are publicly released.

Sincerely yours,

Elmer B. Staats

Comptroller General
of the United States

COMPTROLLER GENERAL'S REPORT TO THE HONORABLE MAX BAUCUS UNITED STATES SENATE

MONTANA'S LIBBY DAM PROJECT: MORE STUDY NEEDED BEFORE ADDING GENERATORS AND A REREGULATING DAM

DIGEST

On June 20, 1979, Senator Max Baucus of Montana asked GAO to answer several questions regarding the proposed Libby additional generating units and reregulating dam project in Montana, including an analysis of the economic justification. In response to Senator Baucus' request and concerns expressed by another member of the Montana delegation, GAO addresses three main issues in this report:

--Did the Corps of Engineers use valid assumptions and appropriate methods in preparing the benefit-cost study for the proposed project?

--Are there alternatives in lieu of the Libby project that could be used in the Pacific Northwest to meet or to better manage future peaking demands?

--What would be the impact on power benefits if the maximum river fluctuation limits downstream were reduced to a lower level?

The existing Libby Dam on the Kootenai River in northwestern Montana was completed in 1973, and the Corps recently began to modify the dam to increase its generating capacity. This increased generating capability at the main dam would produce virtually no more electricity than the existing facility, but would help meet high-demand daytime needs.

The proposed modifications, which would cost an estimated $300 million, include installing four more generators and constructing a reregulating dam 10 miles downstream from the main dam. Because a peaking hydroelectric facility releases water in surges, a secondary dam is necessary to reduce water fluctuations downstream and to minimize environmental and safety hazards. The Corps has also proposed to the Congress additional generators for the reregulating dam. These generators would provide additional power at the site, but they have not been authorized for construction.

For several years the project has been the subject of controversy as to its proposed operating features and its need. Based on its studies, the Corps contends that the additional generating capacity at Libby is necessary to help meet the peak power needs
10 in the Pacific Northwest. Others, however--including environmentalists, and State of Montana officials--have questioned whether the Congress has authorized the Corps to modify the dam and/or whether the project is economically and environmentally sound.

THE CORPS HAS OVERSTATED
PROJECT BENEFITS

In making its benefit-cost analysis of the proposed Libby project, the Corps used methods which no longer apply to the Pacific Northwest where power sources have moved away from mainly a hydroelectric system to a mix of hydropower and thermal plants.

Corps officials have acknowledged that calculating benefit-costs by past methods overestimates benefits for projects where peak generating capacity is added to existing hydropower plants and used very little. Between 1975 and 1978, the Corps analyzed several alternative calculation methods and, by May 1978, reported that a better method--called the production cost model--had been developed for some types of projects. The Corps tested the method on other proposed additional units projects but not on the proposed Libby project.

At GAO's request, the Corps applied the production cost model concepts to the proposed Libby project, recognizing that certain data would not be precise. The result was an estimated benefit-cost ratio of 1.02 to 1, significantly lower than the 2.3 to 1 ratio given to the Congress in February 1979.

GAO examined the 1.02 to 1 ratio and found several questionable values and assumptions which, if revised, reduce the ratio to about 0.6 to 1. GAO's adjustments to the benefit-cost ratio reflect changes in the discount rate, power values, and project costs used by the Corps.

The Corps plans to undertake a new benefit-cost study for the project applying the production cost model and using more precise data. It hopes to complete the analysis and submit the results to the Congress by early 1980.

REDUCED RIVER FLUCTUATION LIMITS COULD IMPAIR OPERATING FLEXIBILITY OF THE MAIN DAM AND DECREASE POWER BENEFITS AT THE REREGULATING DAM

State of Montana officials and others suggested at one time that fluctuation limits be reduced for safety reasons and to lessen the effects on the river environment, particularly the fish population. The fluctuation limits below the reregulating dam, if it becomes operational, will be the same as the limits for the existing facility--1 foot an hour, but not more than 4 feet a day, during the summer, and 2 feet an hour, but not more than 6 feet a day, during the winter.

The Corps has opposed reducing the river fluctuation limits, contending that major reductions would reduce annual power benefits substantially. A recent Corps study showed that while scaling back the daily fluctuation limits by about one-half would have no measurable impact on power benefits from the main dam, up to $3.5 million in power benefits would be lost from the reregulating dam generators, if they are installed. The study showed that lower fluctuation limits could also reduce the Corps' flexibility to bring Libby Dam online quickly during rapid increases in demand or power emergencies.

GAO found no comprehensive studies or other evidence which show the need to reduce fluctuation limits, particularly since the fishery below Libby Dam is apparently flourishing.

FIVE POTENTIAL ALTERNATIVES TO THE PROPOSED LIBBY PROJECT ARE AVAILABLE IN THE PACIFIC NORTHWEST

GAO identified five potentially viable alternatives to the proposed Libby project, both to increase generating resources and to better manage future peak demand. Most alternatives were not analyzed thoroughly by the Corps before it started work on the project.

The alternatives are:

--Combustion turbines, which are similar to aircraft engines except that they drive electric generators (see page 18).

--Cogeneration, which uses heat from industrial operations to power electrical generators (see page 19).

--Power exchanges using the intertie, which stretches from California to Washington and has an existing capacity of 4,100 MW (see page 20).

--Load management, which can smooth out the peaks in electricity use by means of remote control switches, thermostats and circuit breakers in homes and businesses (see page 22).

--Peak pricing options, which involve increasing power prices during periods of heaviest demand (see page 23).

RECOMMENDATIONS

The Corps has not shown that the proposed Libby project is economically justified or that this project is the best available option for meeting Pacific Northwest peaking needs. Because of this, GAO believes that the proposed Libby Dam project should proceed no further until the Congress has more information on it. Accordingly, GAO recommends that the Secretary of the Army direct the Chief of Engineers to recompute and to report to the Congress the costs and benefits for the project, using the production cost model approach, and taking care to select the authorized discount rate, valid power values, and all applicable costs.

As part of this study and included as part of the Corps' report, the Secretary of Energy should direct the Administrator of the Bonneville Power Administration to conduct a comprehensive analysis of regional peaking alternatives, including the proposed project. This study should measure the incremental effect of each alternative on the combined hydro-thermal system, and should be the basis for prioritizing alternatives for implementation.

In the longer term, the Bonneville Power Administration should routinely prepare and update the analysis of peaking alternatives. If options such as conservation, load management, and peak pricing prove to be economically feasible, the Bonneville Power Administration should develop and implement equitable methods to encourage utilities and electricity customers to adopt them.

As agreed with Senator Baucus, we did not obtain written agency comments. The matters presented in the report, however, were discussed with appropriate officials who agreed that further studies are warranted.

Contents

ABBREVIATIONS

BPA	Bonneville Power Administration
c.f.s.	cubic feet a second
FERC	Federal Energy Regulatory Commission
FWS	U.S. Fish and Wildlife Service
GAO	General Accounting Office
kWh	kilowatt-hour
LAURD	Libby Additional Units and Reregulating Dam Project
LRIC	long-run incremental cost pricing
MDF&G	Montana State Department of Fish and Game
MW	megawatt
NEPA	National Environmental Policy Act
PNUCC	Pacific Northwest Utilities Conference

GLOSSARY

acre-foot	Measurement of water volume that would cover 1 acre to a depth of 1 foot.
baseload	The minimum load in a power system over a given period of time.
benefit-cost ratio	A comparison of a water project's expected benefits with its anticipated costs.
capacity	Maximum power output, expressed in kilowatts or megawatts. Equivalent terms: peak capability, peak generation, firm peakload, and carrying capability. In transmission, the maximum load a transmission line is capable of carrying.
capacity factor	The ratio of the average load on a generating resource to its capacity rating during a specified period of time, expressed in percent.
cogeneration	Utilizing heat produced by industrial operations to power electrical generators.
combined-cycle plant	Fossil fuel fired thermal plant, similar to aircraft engines, used to drive electric generators, and using the exhaust heat to operate a boiler in a steam-electric generation system.
combustion turbine plant	Fossil fuel fired thermal plant, similar to aircraft engines, used to drive electric generators.

conservation	Improving the efficiency of energy use; using less energy to produce the same product.
diversity capacity exchange	The transfer of excess capacity or energy between regions from existing generating plants.
energy	The ability to do work; the average power production over a stated interval of time; expressed in kilowatt-hours, megawatt-hours, average kilowatts, or average megawatts. Equivalent terms: energy capability, average generation, and firm-energy-load-carrying capability.
forced outage reserves	An amount of peak generating capability planned to be available to serve peakloads during forced outages of generating units.
fossil fuels	Coal, oil, natural gas, and other fuels originating from fossilized geologic deposits and depending on oxidation for release of energy.
hydroelectric plant	An electric powerplant in which the turbine-generator units are driven by falling water. A conventional hydroelectric plant is one in which all the power is produced from natural streamflow as regulated by available storage.
intertie	Transmission lines between the Pacific Northwest and Pacific Southwest for the transfer of surplus energy and capacity.
kilowatt (kW)	The electrical unit of power which equals 1,000 watts.

kilowatt-hour (kWh)	A basic unit of electrical energy which equals 1 kilowatt of power applied for 1 hour.
load	In a public utility context, the rate at which electric energy is delivered to or by a system, expressed in kilowatts or megawatts over any designated period.
load management	Influencing the level and state of the demand for electrical energy so that demand conforms to individual present supply situations and longrun objectives and constraints.
longrun incremental cost pricing	Pricing associated with meeting the cost of customer requirements for additional increments in utility service on a continuing basis, when the utility has fully adjusted its operation and facilities to the most efficient means of meeting the increased total demand. It includes the immediate expenses the utility incurs in taking on new customers, as well as the cost of utility plant and associated costs necessary to provide and maintain utility service.
megawatt (MW)	The electrical unit of power which equals 1,000,000 watts or 1,000 kilowatts.
megawatt-hour (MWh)	A basic unit of electrical energy which equals 1 megawatt of power applied for 1 hour.
mill	A monetary unit equaling one-tenth of a cent ($0.001).

offpeak	A period of relatively low system demand for electrical energy as specified by the supplier, such as in the middle of the night.
peaking	Operation of generating facilities to meet maximum instantaneous electrical demands.
peaking capability	The maximum peakload that can be supplied by a generating unit, station, or system in a stated time period. It may be the maximum instantaneous load or the maximum average load over a designated interval of time.
peaking capacity	Generating equipment normally operated only during the hours of highest daily, weekly, or seasonal loads. Some generating equipment may be operated at certain times to serve loads on a round-the-clock basis.
peakload	The maximum electrical load consumed or produced in a stated period of time. It may be the maximum instantaneous load (or the maximum average load) within a designated interval of the stated period of time.
pumped storage	A pumped storage hydroelectric plant is one in which power is produced during peakload periods by using water previously pumped from a lower reservoir to an upper reservoir during offpeak periods.

reserve capacity (operating & generating)	Extra generating capacity available to meet unanticipated demands for power or to generate power in the event of loss of generation resulting from scheduled outages of regularly used generating capacity. Reserve capacity provided to meet the latter is also known as forced outage reserve.
seasonal pricing	Pricing associated with the higher level of demand for electricity during the winter months and relatively lower prices during the summer months.
thermal generation	Generation of electricity by applying heat to a fluid or gas to drive a turbine generator.
time-of-day pricing	Rates imposing higher charges during those periods of the day when the higher costs to the utility are incurred.

CHAPTER 1

INTRODUCTION

In 1950 the Congress authorized the Corps of Engineers to construct the Libby Dam on the Kootenai River in northwestern Montana. Completed in 1973 by the Seattle District, Corps of Engineers, the dam began producing electricity 2 years later to meet the energy demands of the Pacific Northwest. As a second phase of the project, the Corps has now begun major modifications to double the dam's generating capacity and to change its operating mode. This increased generating capacity will cost an estimated $300 million and will involve increasing the number of generators from four to eight and constructing a reregulating dam 10 miles downstream from the main dam. The reregulating dam is necessary because the Corps plans to increase the peaking capability of the project. The Corps has also proposed as a separate project, that generators be installed in the reregulating dam. These generators would provide additional power at the site, but they have not been authorized for construction.

Unlike a baseload facility which is designed to produce a steady continuous flow of electricity by releasing water over a long period, a peaking facility releases more water in surges over a shorter time to produce electricity for high-demand peak periods. In the case of Libby, the installation of four more generators would produce virtually no more electricity than the existing facility, but would help meet daytime peak power needs.

Because a peaking plant releases water in surges, a secondary dam a short way downstream becomes necessary to reduce the water fluctuations and to minimize environmental and safety hazards. For example, if eight units are installed in Libby Dam and the plant is used for peaking, flows below the main dam could go from zero to 45,000 cubic feet per second in minutes with water level fluctuations up to 18 feet. Therefore, a reregulating dam would be mandatory to reduce the surges and release water downstream at a steadier rate.

For several years the project has been the subject of controversy as to its proposed operating features and its need. Based on its studies, the Corps contends that the additional generating capacity is necessary to help meet the forecasted peak power needs in the 1980s, 1990s, and beyond. Others, however--including environmentalists, State of Montana officials, and the courts--have questioned whether the Congress has authorized the Corps to modify the dam and/or whether the project is economically and environmentally sound. In early 1979, the U.S. Court of Appeals for the Ninth Circuit ruled that the Congress had not authorized the Corps to build the reregulating dam at Libby and enjoined the Corps from further work on the project 1/. The court allowed work to continue, however, on the four additional generating units. As of October 1, 1979, the Corps had spent about $26 million on the generators which cannot be used effectively unless the reregulating dam is built.

Because of this controversy and pending congressional legislation on the Libby project, Senator Max Baucus of Montana requested that we:

1. Review and provide observations on the assumptions used in the Corps benefit-cost study to add four generating units at the Libby main dam and to construct a reregulating dam with generating facilities.

2. Review the methodology to see if the Corps followed water resource principles and standards in preparing the benefit-cost study.

3. Review and analyze the values assigned as benefits to peaking power.

4. Assess the impact on power benefits if the Corps' maximum allowable flow fluctuations downstream are scaled back to a lower level.

5. Identify options other than the Libby project (including nongenerating options) which could be used in the Pacific Northwest for meeting or decreasing peaking demands. In identifying these options, Senator Baucus asked us to outline the advantages and disadvantages of each and, if possible, to provide available information on the economic aspects of each and how these alternatives could be brought about.

SCOPE OF REVIEW

During this study we reviewed records, instructions, guidelines, and other data concerning the economic justification for and the alternatives to the Libby additional units and reregulating dam (LAURD). We worked at the

---

1/Libby Rod and Gun vs. Poteat, 594F2742 (1979).

Corps' Seattle District and the North Pacific Division in Portland, Oregon; the Bonneville Power Administration (BPA), Portland, Oregon; and the Federal Energy Regulatory Commission in San Francisco, California.

To better understand the questions raised about the project and their potential impacts, we visited the Libby damsite, toured the area around the proposed reregulating dam, talked with Corps officials operating the dam, and met with representatives of the Libby Rod and Gun Club. Also, we talked with officials from the Montana State Departments of Fish and Game and Natural Resources in Helena about the LAURD project.

Two consultants--George W. Hinman and Walter R. Butcher, highly knowledgeable about energy technologies--assisted us in evaluating alternatives to constructing the LAURD project. In addition, we contacted representatives from Puget Sound Power and Light, Portland General Electric, Seattle City Light, and Southern California Edison companies for data used during our analysis of the LAURD benefit-cost ratio and alternatives.

Although the Corps has proposed adding generators to the reregulating dam, we did not include them in our evaluation of the Corps' benefit-cost study for LAURD because the Congress has not authorized their construction.

CHAPTER 2

BENEFIT-COST ANALYSIS

The Corps has not shown the proposed LAURD project to be economically justified. The Corps calculated a benefit-cost ratio for LAURD of 2.3 to 1, using a method which did not properly evaluate either (1) Libby Dam's present use in meeting high daytime peak power needs and (2) the complexities of today's Pacific Northwest power system. Recent Corps recalculations using a better method show a benefit-cost ratio for LAURD of about 1.02 to 1. However, our adjustments to the discount rate and certain costs reduce this ratio to about 0.6 to 1. The Corps has begun a new LAURD benefit-cost study to submit to the Congress in early 1980.

BENEFIT-COST ANALYSES FOR HYDROPOWER

The benefit-cost analysis is one of the major tools the Congress uses when making decisions on proposed Federal water projects. This analysis compares a proposed project's expected benefits with its expected costs. The analysis is used to evaluate a project's economic justification after a need for the facility has been established. Projects are seldom authorized unless their average estimated benefits exceed their average estimated costs annually.

Criteria for benefit-cost analyses are developed by the Water Resources Council and implemented in Corps regulations. To achieve uniform analyses, the Water Resources Council establishes policies and methods for water resource project evaluation.

The Federal Energy Regulatory Commission (FERC) also provides values and guidelines for evaluating power benefits, including estimates of the costs of such alternative projects as nuclear and combustion turbine plants.

Corps evaluation method for LAURD

Electrical power is the only benefit that the Corps has claimed for LAURD. The Corps determined power benefits for the additional units by computing the value of the proposed eight units (four existing plus four additional) designed to meet peakloads and then by subtracting the value of the four units now in service.

To assign power values, the Corps used the cost of presumed equivalent alternative projects. Specifically, the Corps compared the planned eight-unit peaking system to a combined-cycle 1/ thermal plant and compared the existing four-unit facility to a nuclear plant. Thus, the Corps computed the power benefits for LAURD by subtracting the fixed and variable costs of a baseload nuclear plant from the fixed and variable costs of a combined-cycle thermal plant. The following illustrates this method.

Power benefits attributable to LAURD	=	Value of planned 8-units (4 existing plus 4 additional) used for peaking	-	Value of existing 4 units

AND THUS:

Power benefits attributable to LAURD	=	Value of combined-cycle thermal plant operated like the planned 8 peaking units	-	Value of nuclear plant operated as a baseload plant

BETTER METHOD IS AVAILABLE

The Corps method evaluated the present Libby Dam as if it were operating as a baseload plant which provides a steady continuous amount of power. This technique overlooked the fact that Libby is now providing considerably more power during the daytime than it is at night. The Corps has developed a better method for calculating benefits for added units projects. The better method still relies on measuring project benefits by selecting the least costly alternative project, but also considers the effects on system energy costs brought about by alternate projects.

1/A combined-cycle plant produces electricity from turbine engines connected to generators and uses heat recovered from those turbines to run one or two more generators. This design produces additional electricity without using additional fuel.

The present Libby Dam operates as a baseload plant only part of the time; thus, it is not comparable to a nuclear plant. During the last 3 years, Libby has been used to create an average of 133 more megawatts during days than nights, excluding spring fill periods. The LAURD benefit-cost analysis should reflect Libby's present use in meeting daytime power needs much of the year and should measure benefits as the incremental value LAURD would provide.

In addition, the Corps method of computing power benefits is no longer applicable, as the Pacific Northwest power sources have become diverse. The past method applied when a baseload thermal plant was the alternative to a baseload hydropower plant in an all-hydropower system. The measure of benefit was the cost of building and operating a baseload thermal plant. However, a mix of hydropower plants (baseload and peaking), baseload thermal plants, and combustion turbine peaking plants now furnish power to the Pacific Northwest. Past methods of calculating benefits and costs no longer apply, because it is increasingly difficult to evaluate the least costly alternative energy source, particularly for additions to existing hydropower plants which will be used very little.

Corps officials acknowledge that past benefit-cost calculation methods significantly overestimated benefits from additions to existing projects. In fact the Corps recognized these calculation weaknesses as early as 1975, when officials began to evaluate ways of improving benefit-cost calculations for additional units projects. Between 1975 and 1978 the Corps analyzed several alternative calculation methods and, by May 1978, reported that it had developed a better method which was operational, at least for certain kinds of projects.

The Corps can use its newer method--called the "production cost model"--to estimate system energy costs for hydropower and alternative projects as they would actually operate in the Pacific Northwest power system. The model identifies and values the most economical alternatives to a proposed project by calculating power system operating costs under alternative power demand situations. Alternative plants and combinations of plants can be tested under future operating conditions, and the resulting production costs, together with capital costs, can be used to select the most economical combination of resources to meet future loads.

In May 1979, the Water Resources Council proposed that system energy costs be taken into account (such as done by the Corps' production cost model) when computing the value of hydropower energy. According to Corps officials, this approach has been used by the Tennessee Valley Authority and FERC for many years, is now widely used, and is the approach now advocated by the Bureau of Reclamation and the Water Resources Council.

The Corps tested the method on other proposed additional units projects (at McNary and Chief Joseph dams), but did not apply it to recalculate LAURD benefits and costs.

At our request the Corps estimated the LAURD benefit-cost ratio, using production cost model concepts and applying judgment to the results of past applications. A benefit-cost ratio of 1.02 to 1 1/ resulted--significantly lower than the 2.3 to 1 ratio the Corps gave to the Congress in February 1979. Corps officials were uncertain about the validity of the model results, stating that they had developed the model for projects which would be used more than 40 percent of the time. LAURD would be used less than 20 percent of the time. Further refinement of the model by the Corps may result in a different benefit-cost ratio.

GAO ADJUSTMENTS TO CORPS PRODUCTION COST MODEL CALCULATIONS

Our examination of the 1.02 to 1 ratio developed by the production cost model disclosed several questionable values and assumptions which, if revised, reduce the ratio to about 0.6 to 1, as shown in the following table.

1/This ratio was based on fuel costs exceeding average inflation by 2 percent a year for 30 years. The Corps also developed a 1.17 to 1 ratio using a 3-percent fuel cost escalation rate. Our adjustments reduce the 1.17 to 1 ratio to about 0.63 to 1.

GAO Analysis of Corps Benefit-Cost Ratio Calculated by Production Cost Model

	Benefit-cost ratio
Corps calculated benefit-cost ratio from production cost model	1.02 to 1
GAO adjustments	
Change in discount rate from 3.8 percent used by Corps to 7.125 percent established by Water Resources Council	0.69 to 1
Decrease in combustion turbine construction cost from $21.56 a kilowatt-year national value to $16.67 a kilowatt-year regional average	0.61 to 1
Increase of $757,476 in estimated annual project costs for highway improvements and cultural resources preservation, and additional interest during construction	0.59 to 1
Disbenefits of $333,300 annually due to losses in wildlife lands, day-use recreation and fishing opportunities in the 10-mile stretch between the two dams	0.58 to 1

Explanation of GAO adjustments

Our adjustments to the benefit-cost ratio for LAURD which the Corps developed from the production cost model reflect changes in the discount rate, combustion turbine plant construction costs, and the inclusion of certain project costs:

--Discount rate. The Corps used a 3.8-percent discount rate in determining present value of future energy costs. This rate is significantly lower than that prescribed by the Water Resources Council. Corps officials believed the lower rate would provide an inflation-free analysis, and they used it to avoid reducing the impacts intended from the application of an escalation factor to reflect expected real cost growth in future fuel costs. For the interest rate, however, the Corps used the 7.125-percent rate established by the Water Resources Council.

Federal regulations clearly specify that both the discount and interest rates will be the current federally prescribed rate. Water Resources Council guidelines do not allow adjusting the discount rate. Economists and officials of other agencies told us that a 2- or 3-percent fuel-cost escalation factor and a 7.125-percent discount rate were reasonable. Using a 7.125-percent discount rate lowers the benefit-cost ratio to about 0.7 to 1.

--Combustion turbine construction costs. The Corps production cost model identified combustion turbines as the least costly alternative to LAURD. A $21.56 a kilowatt-year construction cost based on FERC data was used as a measure of the dependable capacity. We obtained the costs that regional utilities had estimated for planned combustion turbine plants, compared them to an in-service plant (combined-cycle without heat recovery), and developed a $16.67 a kilowatt-year average cost.

--LAURD construction costs. The Corps excluded two types of costs from the benefit-cost ratio--highway improvements and cultural resources preservation. Corps regulations allow these costs to be excluded because they do not directly benefit the project. But these costs, totaling about $8.8 million, should be recognized and included in the analysis because they are unavoidable and necessary expenses brought about by the project.

Also, the Corps planned for LAURD to be completed and operating by 1984. However, Corps officials told us that the court injunction and project authorization process would delay project completion until at least 1986--possibly until 1990--if the Congress decides to build. The minimum 2-year delay would increase interest during construction on the $26 million already spent as of fiscal year 1979 by about $1,852,500.

Total estimated project costs for highway improvements and cultural resources preservation, and additional interest during construction are $10.7 million, or $757,476 annually.

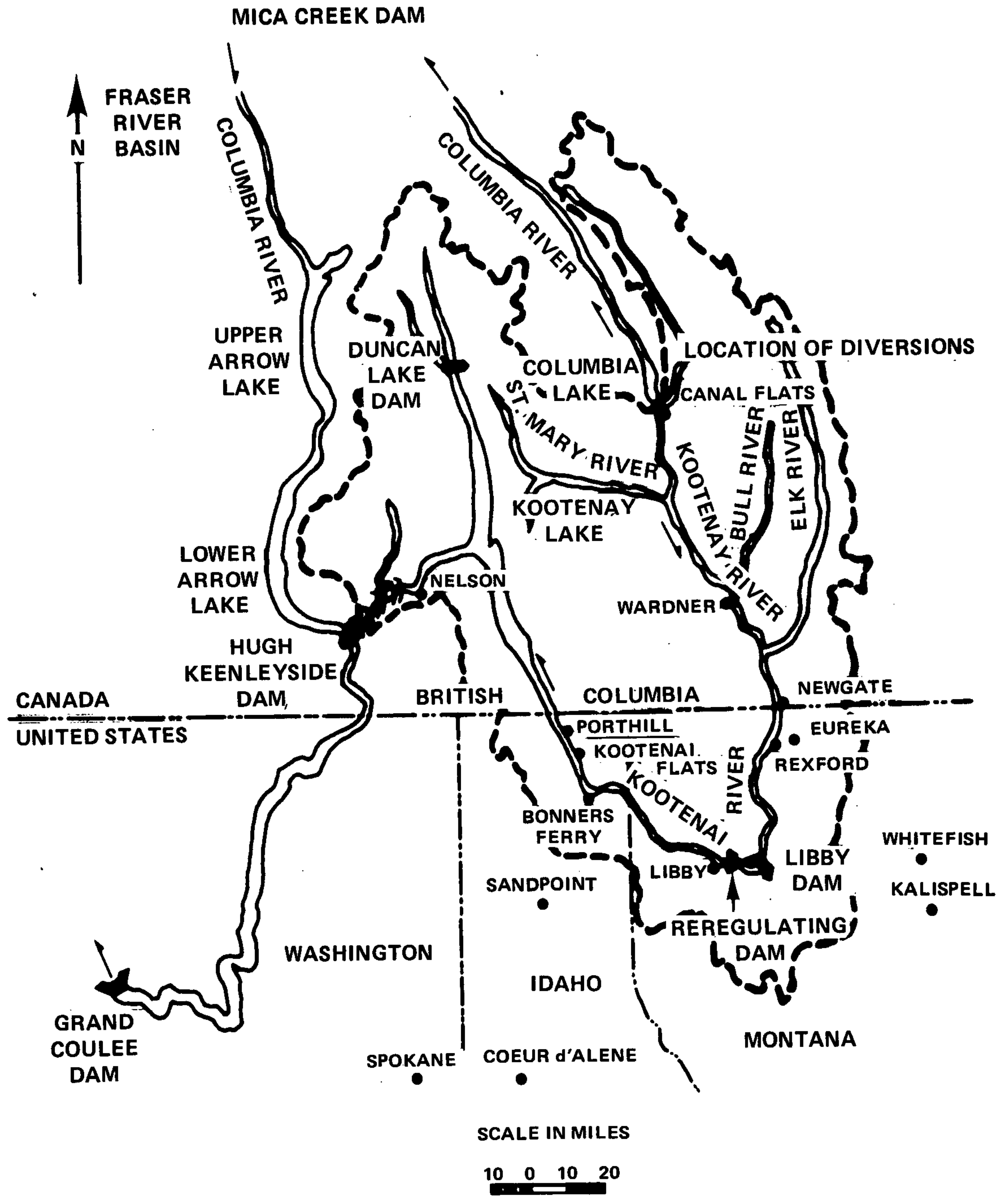
--Wildlife and recreation losses. The Corps recognized that wildlife lands, day-use recreation, and fishing opportunities would be lost in the 10-mile stretch between the Libby main dam and the proposed reregulating dam. While the Corps calculated annual wildlife and recreation losses of $333,300, they did not include these losses when calculating the LAURD benefit-cost ratio.

Factor not evaluated

The 1.02 to 1 benefit-cost ratio did not reflect the full effects of the 1964 United States-Canada Columbia River Treaty, under which Canada may divert water from the Kootenai River in three stages at a point in Canada 50 miles from the border. (See map on p. 11.) The treaty allows the first diversion after 1984, with the second and third allowed after 2024 and 2044, respectively. The Corps benefit-cost ratio included only the projected effects of the first diversion. Additional water diversions would reduce the average streamflow and reduce the average energy potential of Libby Dam.

CORPS WILL DEVELOP NEW BENEFIT-COST RATIO

Corps officials said that they plan to recalculate the benefit-cost ratio for LAURD using the production cost model. In so doing, they plan to use better data and eliminate the need for judgment estimates. The officials told us they hope to provide the results of the recalculation to the Congress in early 1980. They attributed the planned LAURD recalculation to congressional interest and our review.



KOOTENAI RIVER BASIN

CHAPTER 3

EFFECT OF REDUCED FLUCTUATION CRITERIA

ON POWER BENEFITS

AND OPERATING FLEXIBILITY OF LIBBY DAM

The Corps designed the LAURD project to permit the main dam, with eight units, and a reregulating dam to operate within the same flow and fluctuation limits as the present facility with four generating units. Water fluctuation limits below the reregulating dam would continue at a maximum of 1 foot an hour, but not more than 4 feet a day, during May through September, and a maximum of 2 feet an hour, but not more than 6 feet a day, during October through April. The minimum allowable water discharge would also be the same, or 2,000 cubic feet a second (c.f.s.).

State of Montana officials and others have suggested lowering these fluctuation levels and/or increasing flows further to reduce effects on the environment and for safety reasons. The Corps has opposed such moves, contending that major reductions would significantly reduce annual power benefits. A Corps study completed during our review showed that there would be a substantial reduction in benefits for peak power at the reregulating dam if the maximum allowable flow fluctuations were scaled back by about one-half the current levels. A reduction in fluctuation limits could also limit somewhat the Corps' flexibility to bring Libby Dam online quickly during rapid increases in demand or power emergencies.

BACKGROUND AND STATUS

History

Since the early 1960s considerable discussion has occurred regarding flow fluctuations and the minimum discharge downstream from Libby Dam. In 1962 the Corps proposed minimum flow criterion of 2,000 c.f.s. and a maximum fluctuation criterion of 2 feet an hour in the winter and 1 foot an hour in the summer. The Corps proposed these levels after consulting with BPA, the U.S. Fish and Wildlife Service (FWS), Montana State Department of Fish and Game (MDF&G), and others. However, these agencies did not endorse the Corps' criteria at that time.

In 1965 the FWS, concurring with MDF&G, recommended discharge rates from the dam of not less than 2,500 c.f.s. and fluctuation rates of no more than 1 foot an hour. According to the FWS, these criteria would minimize detrimental effects on fish and aquatic life and reduce hazards to anglers. The Corps retained its hourly fluctuation limits, but later revised its criteria to limit maximum daily fluctuations to 4 feet during May through September and 6 feet during October through April.

In 1975 FWS and MDF&G concluded that a minimum discharge limit of 2,000 c.f.s. would be adequate, but that a minimum flow of at least 3,000 c.f.s. would be preferable. After further study, the FWS recommended in 1977 that levels of at least 4,000 c.f.s. would be better during April through June and October through November to enhance spawning in the river. Also, FWS told the Corps that to enhance spawning it would be preferable to operate the reregulation dam so that some fluctuation in the river occurred on a daily basis. In response to FWS concerns, the Corps stated that minimum flows from the reregulating dam will be 4,000 c.f.s. whenever possible, and that a 2,000-c.f.s. flow would occur infrequently.

Prompted by former Montana Senator Paul Hatfield's 1978 inquiry to the Corps concerning the flow and fluctuation rates at Libby Dam, the MDF&G again revised its position on the Corps criteria. In September 1978, MDF&G recommended that the Corps (1) reduce fluctuations to a maximum of 3 feet each day and 1/2 foot an hour year round, (2) maintain a minimum flow of 4,000 c.f.s., and (3) maintain a steady flow from 3 hours before sunset until dark and a steady flow on weekends during May through October. These recommendations were made to accommodate anglers and to increase spawning.

The Corps responded to these recommendations by repeating the reasons for its fluctuation and flow criteria. More restrictive fluctuation criteria, the Corps said, would significantly reduce power benefits. The Corps also said that it must have the flexibility to (1) reduce the flow to 3,000 c.f.s. for reservoir refill capability and (2) reduce the flow to 2,000 c.f.s. during power emergencies. The Corps does not expect these emergencies to occur on the average more than four times a year.

Current status

In August 1979, the director of MDF&G told us that MDF&G does not oppose the Corps flow and fluctuation criteria for Libby Dam if the Corps abides by the existing criteria. He said that the fishery below Libby Dam is flourishing and MDF&G has no reason to support reducing these criteria. Representatives from the Libby Rod and Gun Club, who have questioned the need for the LAURD project, also agreed that the fishery below the Libby Dam is good and that no evidence exists to support the need to reduce the fluctuation criteria. The club opposes the project, however, because 10 more miles of the river (behind the reregulating dam) would be "lost" to sports fishing.

On the other hand, a cognizant FWS official from the Billings, Montana, area office told us that FWS favors a minimum flow level of 4,000 c.f.s. He said that further studies should be made to determine suitable flow criteria for the protection of fish and aquatic life in the river.

EFFECT OF REDUCED CRITERIA ON POWER BENEFITS

The Corps has contended for some time that any major reduction in fluctuation and flow criteria at Libby Dam would significantly affect power benefits for the project. In July 1978 the Corps told former Montana Senator Paul Hatfield that, if the fluctuation limit were reduced to 3 feet a day year round, the benefits from three of the proposed generating units at the main dam would be lost at an estimated annual cost of about $26 million. A Corps October 1978 policy paper also estimated that the capacity of three generating units would be lost. These losses were based on engineering judgment, however, rather than a detailed analysis.

In September 1979 the Corps completed a more thorough analysis on the effect of reduced fluctuation levels on power benefits. In this study the Corps used a minimum flow of 4,000 c.f.s. and a fluctuation limit of 1 foot an hour and 3 feet each 12-hour period (6-foot limit a day) during the winter months. We believe the study results are also valid when the daily limit is about 3 feet, because only 3 feet of fluctuation was actually needed in the study. Corps officials agreed.

While the study focused on the effects of a reduced criteria on the reregulating dam, it concluded that by careful scheduling the full capacity of the main dam can be made available at least 90 percent of the time during the critical winter months. As a result, there would be little change in the measurable power benefits from the main dam, although Corps officials contend that some non-quantifiable benefit would be lost. If generators are installed in the reregulating dam as proposed, however, the power benefits from the reregulating dam--which are not included in the benefit-cost analysis--would be reduced. The study showed that these lower fluctuation levels would reduce average generation about 3 megawatt-years and would reduce dependable capacity about 40 megawatts for the reregulating dam. The estimated loss in measurable benefits would be between $2.6 and $3.5 million annually.

Because of the time required, we did not analyze the effect on benefits of other fluctuation criteria. In our opinion, however, more restrictive criteria would generally cause the benefits to decrease by reducing the dependable capacity of Libby Dam.

EFFECT OF REDUCED CRITERIA ON FLEXIBILITY

Federal officials have been concerned that more restrictive fluctuation criteria would reduce the flexibility to operate as planned, but recent Corps and BPA simulation studies show that the flexibility loss resulting from a 3-foot daily fluctuation limit would not be a problem most of the time. In their simulations, both the Corps and BPA assumed that the reregulating pond would be almost full on weekday evenings and full on Friday evening to maintain flows of 4,000 c.f.s. at night and over the weekend when water from the main dam was shut off. Using these operating assumptions, the flexibility of Libby Dam to meet sudden power demands could be reduced somewhat if the demand were to occur in the evening, particularly on Friday. Overall, however, the studies showed that the project could operate efficiently to meet scheduled daily peak loads.

Reducing criteria might also affect Libby Dam's ability to provide operating reserves. However, BPA and the Corps thought this type of situation would not pose serious problems, for they could make necessary adjustments in the way they operated the project. Corps officials told us that because of the longer lead-times necessary to increase or reduce power significantly, they would have to schedule Libby Dam's operation well in advance. They did not think that the reduced criteria would keep them from generating power as needed, only make it harder. The official responsible for BPA's simulation study said that the reduced criteria would occasionally limit their flexibility in using the project. He said, however, there is such a critical need for units like Libby, which can change their output rapidly, that BPA was willing to forego some dependable capacity to gain the flexibility that the reregulating dam would provide. (See app. II.)

CONCLUSIONS

If fluctuation levels are scaled back by about half the present levels, there will be no measurable decrease in annual power benefits related to the main dam, but there will be some loss in its operational flexibility. Also, if the proposed generators in the reregulating dam are added, lower fluctuation limits would substantially reduce the power benefits related to the reregulating dam. There are no comprehensive studies and other data, however, which point to the need to reduce fluctuation levels, given that the fishery below Libby Dam is apparently flourishing. Hence, we believe that before any decision is made to reduce the fluctuation limits beyond established levels, a determination should be made that any beneficial effects on the river's environment outweigh "costs" in terms of operational flexibility and decreases in power benefits.

CHAPTER 4

ALTERNATIVES TO MEET PACIFIC NORTHWEST PEAKING NEEDS

Adding generators and a reregulating dam at Libby is not the only means of meeting peaking power shortfalls predicted for the Pacific Northwest. Other alternatives exist which involve either reducing peak power demands or adding more peaking capability. While construction programs offer the most immediate and controllable actions for meeting predicted needs, they should not be undertaken until full consideration has been given to other options.

FORECASTS SHOW PEAKING NEED

Justification for LAURD was predicated on forecasts by the Pacific Northwest Utilities Conference Committee (PNUCC)--an association of northwest utilities. The committee prepares the forecasts annually, by compiling individual forecasts developed and submitted by over 100 utilities. It compares predicted load to resources for a 20-year period, the difference between them being the regional deficit or surplus. It is the only peaking forecast which is made for the region.

Although the forecasted peakloads have been reduced considerably since the project was begun, the 1979 forecast still shows a deficit in resources available to meet the predicted peakloads for most years. (See app. III for the complete forecast.) In light of this projected deficit, the Pacific Northwest region faces many important and difficult decisions in electricity management. But, as we recently reported 1/, no entity is responsible for determining the best options to meet regional energy needs, or for encouraging utilities and customers to adopt measures to better manage power use. BPA, which markets half of the region's electricity and owns and operates 80 percent of the region's high-voltage transmission lines, seems best qualified to assume this leadership role.

We found that several alternatives exist, which could reduce the forecasted peak deficit by lowering the peak demand or by increasing the region's peak generating resources. However, BPA or the Corps did not thoroughly analyze these alternatives before starting work on LAURD.

1/"Region at the Crossroads--The Pacific Northwest Searches for New Sources of Electrical Energy (EMD-78-76, Aug. 10, 1978).

We believe that BPA and the Corps should make this analysis before LAURD is proposed to the Congress as the best option.

ALTERNATIVES WHICH INCREASE PEAKING RESOURCES

The historical approach to meeting demand in the Pacific Northwest has been to increase the region's generating capacity, mostly by adding hydroelectric plants. The LAURD project would continue this approach. However, other generating methods might also help to supply peaking power. We reviewed several conventional and nonconventional electrical generating methods to see whether they could be alternatives to LAURD. In our opinion, however, only three options--combustion turbines/combined cycle, cogeneration, and seasonal peak exchanges--could be potential alternatives to LAURD.

Combustion turbines/combined-cycle generating plants

Combustion turbines are similar to aircraft engines, except that they drive electric generators. Because they can be started quickly and operated remotely, combustion turbines are well suited for meeting peakloads and for providing reserve power. In addition, they do not need cooling water, can be located relatively close to load centers or existing transmission facilities, can respond rapidly to changing loads, require a low initial capital expenditure to construct, and are quick and easy to install. For example, they require a construction time of 12 to 18 months as opposed to 5 to 12 years for other types of thermal plants.

Combustion turbines require a low initial capital expenditure per kilowatt of generating capacity installed. On the other hand, they are expensive to operate because they are relatively inefficient, and they generally burn expensive fossil fuels. Efficiency can be improved to a level comparable with a modern oil-fired, steam-electric plant, however, by routing the turbine's exhaust heat to a boiler in a steam-electric generating system. This is called a combined cycle. Although a combined-cycle plant offers much the same benefits as a combustion turbine, it cannot be used to serve short daily peaks because it takes longer to heat the boiler and steam turbine. Combined-cycle plants provide a high degree of flexibility, for they can function either as a combustion turbine for intermittent use or as a combined turbine/steam system.

Combustion turbine and combined-cycle plants have several disadvantages. First, both use nonrenewable fossil fuels, a practice that may be contrary to national policy to reduce the Nation's dependence on relatively scarce fossil fuels. Second, both plants add to noise and air pollution.

Costwise, these two generating systems may be alternatives to LAURD under certain operating conditions. For example, while LAURD will cost about $300 million to build, a similarly sized combustion turbine would cost only about $70 million and a combined-cycle plant would cost about $180 million. However, plant operating costs, mainly for fuel, are expensive compared to the operating costs for the LAURD project. Whether combustion turbines or combined-cycle plants are less costly overall than LAURD depends on how frequently they will have to be used.

We believe the additional four units may not generate more than about 12 percent of their maximum potential power output. If so, a 350 MW combustion turbine generating plant might be as economical as LAURD. In making our analysis, we assumed that Libby Dam would be used primarily during the 50 peak hours each week. Further, we assumed that units 1-4 in the existing facility would be used first, and that the additional units (5-8) would be used only when the existing units could not make use of all available water during the peak period. The Corps did not agree with this approach to approximating the incremental use of the additional units, but they had no better information available.

One Pacific Northwest utility has recently proposed building combustion turbines because of delays in building the region's nuclear plants. These and other possible future units represent new resources, which are not shown in the PNUCC forecasts.

Cogeneration

Cogeneration consists of using heat from existing industrial operations to power electrical generators. One type of cogeneration--the steam topping cycle method--offers a possible alternative for supplying peak power in lieu of LAURD. In this concept, an industrial plant generates steam at high pressure and temperature. It first runs the steam through a turbine to generate electricity and then uses the emerging steam for industrial processes or space heating.

Cogeneration can be viewed as a peak power resource in two ways. First, an industrial plant with installed cogeneration capacity could produce electricity for its own use during peak hours, thereby displacing some peak power normally supplied by a utility. Second, a utility, through prior agreement with an industrial plant, could use all or part of the plant's cogeneration capacity to serve other customers during peak hours.

Many Pacific Northwest industries offer potential for cogeneration, namely, the wood products and the food processing industries. The phase I report from a cogeneration study underway by the Rocket Research Corporation for BPA shows that cogeneration potential at industrial sites in the region is 1,430 MW, including about 400 MW which currently exists. About 34 percent of this potential would have to be achieved to equal LAURD's peak power production. The regional forecast includes little of this cogeneration potential as a firm peak resource.

Since cogeneration relies on state-of-the-art hardware, it requires no technological development. In fact, more than 400 MW of cogeneration already exists in the region, and more can be expected as the costs of electricity and fuels rise. New units can be operational within 5 years after arrangements with the affected industries are made.

One principal obstacle to achieving the regional cogeneration potential is the possible reluctance of industries to install cogeneration equipment. Incentives and/or subsidies may be needed to make this alternative economical, but we did not evaluate the framework and the effect of these incentives/subsidies in achieving the cogeneration potential in the Pacific Northwest.

The Rocket Research Corporation is making an economic analysis of cogeneration for the Pacific Northwest for BPA, but results are not available. Pending completion of the Rocket Research study and formulation of BPA policy on cogeneration, we believe that the cogeneration alternative should be considered as a potential option to LAURD.

<u>Power exchanges using the intertie</u>

The Pacific Northwest-Pacific Southwest Intertie consists of three transmission lines stretching over 800 miles from the Columbia River to Southern California. They have a present capacity of about 4,100 MW and can be upgraded to about 4,500 MW. They are used mainly to transfer Pacific Northwest hydropower to California utilities.

The major contracts for transfers over the intertie, however, will expire between 1982 and 1989. One potential use for the intertie as transmission capacity becomes available is to take advantage of differences in peak power demands between the Northwest and Southwest. Currently, the Northwest's peak loads occur in the winter, while the Southwest's peak loads occur in the summer. This difference is known as seasonal diversity. Therefore, the two regions could possibly exchange power during each other's peak periods. Any excess Northwest capacity would be available for use in the Southwest during the summer, while the opposite would occur in the winter.

Another possible use of the intertie is for meeting reserve requirements (reserve pooling). In this case, the regions would make no scheduled power transfers, but the excess capacity in one region would be available to supply the load in case of a forced outage in the other region. Each region would benefit through this arrangement by reducing the need for new construction to meet their reserve requirement. According to BPA officials, the potential exists for about 800 MW of reserve pooling.

The principal advantage of a diversity capacity exchange is its low cost. While the LAURD project will cost about $300 million, capacity exchange could be realized using the existing intertie. The seasonal energy exchange between regions would come from either the excess capacity of existing peaking plants or baseload thermal plants planned or being constructed to meet energy needs. Realizing only about 12 percent of the present capacity of 4,100 MW for this type of exchange would equal the increase in dependable capacity that LAURD would provide.

While an official from the California Energy Commission was enthusiatic about arranging a diversity exchange, BPA officials were not as optimistic. According to one BPA official, additional research is needed before either the full potential for diversity capacity exchanges or its effect on power operations is known. He pointed out that (1) the intertie is less reliable than the Northwest's transmission system, (2) delays in constructing thermal plants could jeopardize or reduce the Northwest's ability to meet its portion of the agreement, and (3) reduced water levels in storage reservoirs would have an adverse impact on recreational opportunities if substantial amounts of hydropower are used for the exchange. Further, BPA cannot count on reaching agreement with California utilities on capacity exchanges and does not want to jeopardize meeting future peaking needs by delaying construction of the Libby additions hoping that agreements can be reached and implemented by 1985.

ALTERNATIVES WHICH REDUCE THE NEED FOR PEAK POWER

Peak power demands may be reduced in several ways to avoid the need to construct peaking facilities such as LAURD. In our opinion, two of the methods--load management and peak pricing--are potential alternatives to LAURD, and BPA and the Corps should analyze them more thoroughly. Conservation would also reduce peak needs as well as energy use. However, because conservation measures cannot be simply and directly controlled, no accurate way exists to predict energy savings from conservation efforts or to schedule conservation to come online by 1985 to replace the LAURD project. Hence, while conservation should be pursued to reduce both energy consumption and long-term peaking needs, it should not be compared directly to LAURD.

Load management

Load management is the reduction of daytime peak power demand through shifts in certain power uses to nighttime periods. Such shifts may be brought about by timed or remote-controlled devices through which utilities regulate energy use to respond precisely to demand. Examples of load management devices are

--equipment attached to commercial and residential space heaters, appliances, or water heaters which utilities can activate through remote controls to interrupt use;

--clock-controlled switches which turn appliances on or off at certain times during the day;

--interlocks which permit only a few appliances to be used simultaneously; and

--storage systems which absorb heat at night and release it during the day.

Load management has not been widely practiced in the United States but is commonplace in many parts of the world. However, several programs by utilities in the midwest and eastern United States have been successful. About 20 percent of the water heaters in the United States are already on off-peak controlled systems--but not in the Pacific Northwest. For example, Detroit Edison adopted a program in 1968 to control customer's water heaters. The system has reduced peak demand, averted the need for new construction, reduced operating costs (savings in 1977, for example, were about $1.7 million) and conserved energy. Further, a study of 63 load management programs in the United States found excellent customer acceptance regardless of the use of financial incentives.

With escalating fuel and plant construction costs, some experts believe that load management will become a way of life within the next few years. BPA is currently studying the feasibility of load management in the Northwest. If load management devices are determined to be cost effective in the Northwest, they could significantly reduce the requirement for installation of expensive peak generating facilities with their attendant environmental problems. In fact, load management might be one of the few environmentally acceptable ways of meeting peaking problems by the mid-1980s.

Pricing options for peak power demands

The customary pricing system combines the cost of building generating facilities necessary to meet the highest power demand with all other costs to arrive at an average price per kilowatt used. An alternative to building more generating capacity is to charge more for electricity during peak periods. The higher price during the peak periods should decrease the demand during those times, thus reducing the need to build so much peaking capacity. Such a pricing system would be more equitable, especially to customers who do not have a high demand during peak periods. It would also promote efficiency because customers presently use electricity during the peak demand periods as though it cost no more to produce than at other times. As a result, they may overlook or bypass peak-reducing opportunities that are less expensive or involve a sacrifice that costs less than building more peaking capacity.

The results of any peak pricing plans depend on the customer's responsiveness to higher prices during peak periods. Several studies prepared by the Electric Power Research Institute and the Department of Energy have concluded that peakload pricing, either seasonally or by time of day, is likely to even out seasonal and daily load patterns. Space heating and water heating demands are the most sensitive to changes in electricity rates, whereas others, such as lighting, may be less sensitive. Thus, higher prices throughout the winter peak would probably result in vigorous conservation efforts by consumers followed by significant fuel substitution for space heating and water heating after the customer has had sufficient time to change to alternate heating equipment. We reviewed three pricing mechanisms--long-run incremental cost pricing, seasonal pricing, and time-of-day pricing.

Long-run incremental cost pricing

Long-run incremental cost pricing (LRIC) involves pricing each unit of electricity at the average cost of the last units produced. According to a 1975 analysis prepared during the Northwest Energy Policy Project, the LRIC of electricity in the Pacific Northwest will be approximately 19 mills/kWh in 1990 (in 1975 prices) as compared to 4.7 mills/kWh average costs. Pricing at LRIC would reduce demand in 1990 by about 10,500 MW. The cost attributable to reducing demand by only 350 MW--the dependable capacity of the Libby additions--would be about $30 million compared to the estimated $300 million LAURD investment.

If LRIC increased the price of electricity from 4.7 mills to 19 mills per kilowatt hour, however, utilities would generate surplus revenues. Although LRIC would be more costly for the consumer, we assumed that this surplus would be redistributed in some manner and therefore would not be a net cost to the public. Developing an equitable procedure for distributing the surplus revenue is one of the major disadvantages of LRIC pricing. Another problem to overcome is convincing the power supply establishment and the customers of the long-run gains that they could realize from LRIC pricing.

Seasonal pricing

Another form of peakload pricing is seasonal pricing, wherein electricity rates would be higher during the peak season and relatively lower during nonpeak months. A 1977 study by the National Economic Research Associates as part of the Electric Utility Rate Design Study addressed seasonal pricing for the Northwest and suggested winter rates of 45 percent above summer rates for residential customers, and a 58-percent differential for commercial and light industrial customers. These seasonal differences, combined with cautious estimates of probable demand response throughout the region, could result in a demand decrease of over 4,500 MW in the winter and an increase of 2,000 MW in the summer within about 10 years after implementation of seasonal differentials.

The principal advantage of seasonal pricing is that this method could be implemented without additional metering expenses. Customers who substitute other fuels for electricity would incur some additional costs to convert. In aggregate, these costs would be partially offset by a net reduction in electrical energy demand which would result in fuel savings and avoidance of a capital investment for a thermal plant. All in all, the costs of the seasonal pricing method would be about one-fifth of LAURD's cost.

The most serious objection to seasonal price differentials in rates would undoubtedly come from customers, who would naturally like to continue to have inexpensive power for peak season uses. A more gradual price adjustment could help ease the objections without affecting the demand response. Another disadvantage could be the greater use of natural gas, which is considered a scarce fossil fuel over the long run.

Time-of-day pricing

Time-of-day pricing has been suggested as a means of reducing daily demands for peak power. If rates were increased for use during peak daytime periods and lowered during off-peak night periods, customers would probably shift some of their demand to the cheaper period. But implementing time-of-day pricing would require installation and maintenance of meters in each residence or business to monitor power use. Also, the amount of response to this pricing method cannot be accurately predicted. If the response is very low, the metering costs and customer costs of effecting a peak to off-peak shift may be as high or higher than the costs to install more peaking capacity. This will probably be the case for some residential or small commercial customers, where the potential for shifting loads to off-peak hours would be quite small. However, large commercial and industrial customers already have the required metering and good potential for shifting consumption or simply curtailing demand during the peak hours.

New policies or actions needed

Implementing any of these pricing options depends on developing rate schedules that are accepted as reasonable and are not unfair to any of the diverse types of electricity customers. Regional utilities and regulatory bodies have already taken the first steps to develop these rate schedules. In addition, pricing experiments and studies are being done at the National level. Further implementation will probably proceed gradually without requiring any major legislative change. An important exception requiring major change would be any plan to deal with surplus revenues by some form of taxation and redistribution to the businesses and residents of the region.

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

The Corps has not shown that the proposed LAURD project is economically justified or that this project is the best available alternative for meeting the Pacific Northwest peaking needs. Because of this, we believe that, before proceeding, (1) the Corps should reassess the benefit-cost analysis for the project and (2) BPA should thoroughly evaluate other alternatives to LAURD, particularly peaking options identified in this report.

In analyzing the benefits and costs of LAURD, the Corps used methods which overestimated project benefits. A better method--called the production cost model--has been developed. Using the concepts of the model, the Corps recalculated a benefit-cost ratio of about 1.02 to 1. Our adjustments reduced this ratio below 1 to 1. The Corps now plans to complete another benefit-cost analysis by early 1980.

We identified five potential alternatives to LAURD--combustion turbine, cogeneration, intertie power exchanges, load management, and peak load pricing. However, the Corps had not thoroughly analyzed these and many other generating and nongenerating alternatives to LAURD before starting the project.

GAO recently reported that the Pacific Northwest needed improved leadership in electric power planning and policymaking. In our opinion, the questions surrounding the viability of LAURD represent another example of the leadership void in this region. No entity is responsible for determining the best options to meet regional energy needs or for encouraging utilities and customers to adopt measures to better manage power use. Without such leadership and perspective, independent agencies such as the Corps can construct multimillion dollar projects that may be much more costly than other available options, including load management, conservation, and peak load pricing. As the dominant Northwest power marketing agency, BPA is the agency best qualified to assume this leadership role through analysis of economic, environmental, and social costs of competing alternatives.

RECOMMENDATIONS

GAO believes that the proposed Libby project should proceed no further until the Congress has more information on it. Accordingly, we recommend that the Secretary of the Army direct the Chief of Engineers to recompute and to report to the Congress the costs and benefits for the project, using the production cost model approach and taking care to select the authorized discount rate, valid power values, and all applicable costs. As part of this study and included as part of the Corps' report, the Secretary of Energy should direct the Administrator of the Bonneville Power Administration to conduct a comprehensive analysis of peaking alternatives in the region, including the proposed project. This study should measure the incremental effect of each alternative on the combined hydro-thermal system, and it should be the basis for prioritizing alternatives for implementation.

In the longer term, BPA should routinely prepare and update the analysis of peaking alternatives. If options such as conservation, load management and peak pricing prove to be economically feasible, BPA should develop and implement equitable methods to encourage utilities and electricity customers to adopt them.

Max Baucus
Montana

1107 Dirksen Office Building
Washington, D.C. 20510
(202) 224-2651

Montana Toll Free Number
1-800-332-6106

United States Senate

WASHINGTON, D.C. 20510

June 20, 1979

COMMITTEE ON FINANCE
Chairman, Subcommittee on the Oversight of the Internal Revenue Service
COMMITTEE ON JUDICIARY
Chairman, Subcommittee on Limitations on Contracted and Delegated Authority
SELECT COMMITTEE ON SMALL BUSINESS

Mr. Elmer B. Staats
Comptroller General
General Accounting Office
Washington, D.C. 20548

Dear Elmer:

First, let me thank you for GAO's work to date concerning my February 23, 1979 request and subsequent correspondence about the proposed Libby, Montana, reregulating dam.

As stated in my May 10, 1979 letter to you on this subject, I had in April asked the Army Corps of Engineers to re-examine its economic justification for the proposed dam.

The Corps has declined such a re-examination, and as I emphasized in my recent meeting with J. Dexter Peach, Mark Heatwole and John Brown of your staff, Congress must soon decide whether to proceed or halt this controversial $250 million project.

Nevertheless, controversy and charges continue to grow and surround the economic justification for the Libby project. It is difficult for a layman to make an informed judgment from the storm of charges and counter-charges.

Your previous work in looking at the peaking power in the Pacific Northwest needs has been most helpful, but I continue to believe a clear and informed picture of the Libby economic justification is necessary. I therefore, request the General Accounting Office to:

1. Review and provide observations on the assumptions used in the Corps' benefit-cost study to add four generating units at Libby main dam and construct a reregulating dam with generation facilities;

2. Review the methodology to see if water resource principles and standards were followed in preparing the benefit-cost study;

3. Review and analyze the values assigned as benefits to peaking power;

4. Assess the impact on power benefits if the maximum allowable flow fluctuations downstream are scaled back to a lower level; and

STATE OFFICES: (AREA CODE 406)

Billings	Butte	Great Falls	Helena	Missoula
657-6790	792-6700	761-1574	449-5480	728-2043

5. Identify options (including non-generating) which could be used in the Pacific Northwest for meeting or decreasing peaking demands, in lieu of the Libby project.

   In identifying these options, outline the advantages and disadvantages of each and, if possible, provide available information on the economic aspects of each and what you think it would take to bring about these alternatives.

Because of pending legislation bearing on the Libby situation, it is important that this evaluation be done immediately. I ask your staff to contact my office periodically to provide me with updated information on the status of the review. I further request that your study be finished and provide me a briefing on your findings by October 15, 1979, to be followed by a report on your study and findings by November 15, 1979. My office stands ready to assist you in any way and further contacts should be with Mike Shields of my staff at 224-2651.

As confirmed in discussion between your staff and mine, I will assume that the final report will be a formal "blue cover" report with the customary thirty-day hold for my review.

With best personal wishes, I am

Sincerely,

Max Baucus

EXAMPLES OF IMPACT ON LAURD OPERATING FLEXIBILITY

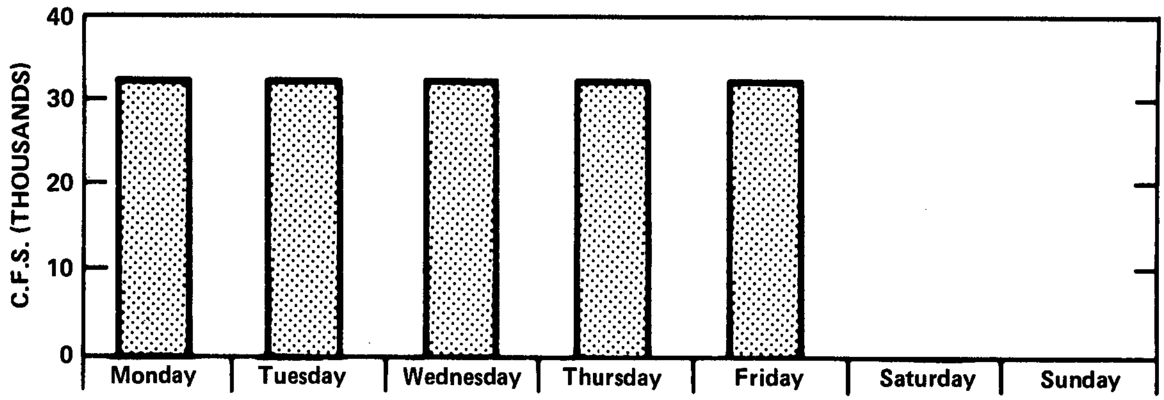
IF FLUCTUATION CRITERIA IS REDUCED

As BPA and the Corps see the project, they would use it (1) to maintain a relatively high power output during peak daytime hours and to reduce power output to almost zero at night; and (2) as a standby generating reserve to meet power system emergencies, such as a powerplant breakdown at another location. The flexibility to operate the LAURD project like this basically depends on the size of the reregulating reservoir and the fluctuation and minimum-flow criteria. Since the project's design fixes the reregulating ponds' capacity, the fluctuation criterion is the main controllable variable.

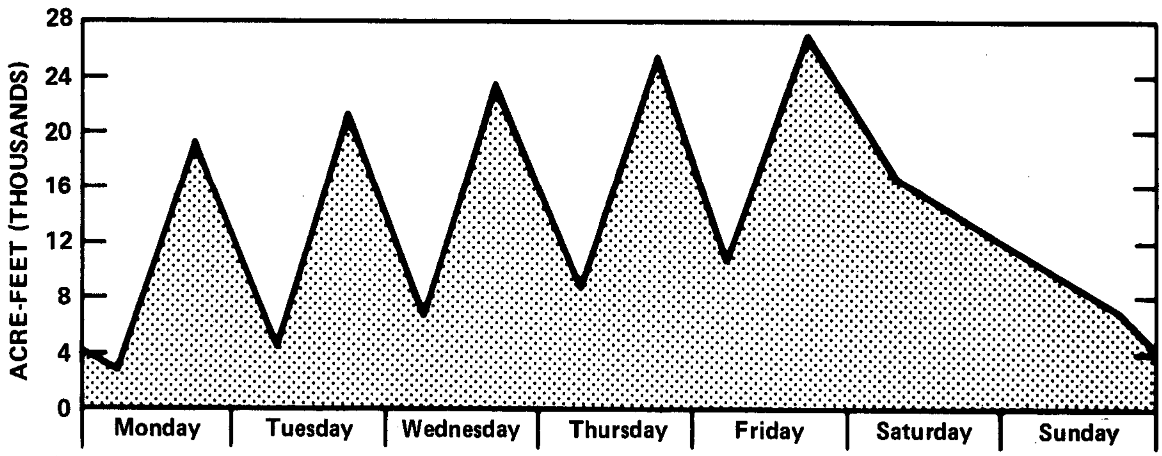
If the Corps builds the reregulating dam, the principal function of the main dam would be to provide power to meet the high daytime demand. The Corps would frequently shut down the main dam at night and over the weekends, during which time the water in the reregulating pond would be used to maintain necessary flows in the Kootenai River. Thus, the reregulation pond normally will be almost empty on Monday morning and then fill during the day and empty at night. The reregulating reservoir's outflow would be relatively stable during this operation. This cycle would be repeated until Friday evening, at which time the Corps would reduce the flow from the reregulating dam to about 4,000 c.f.s. The following graphs show this cycle.

TYPICAL WEEKLY CYCLE WHEN PEAKING

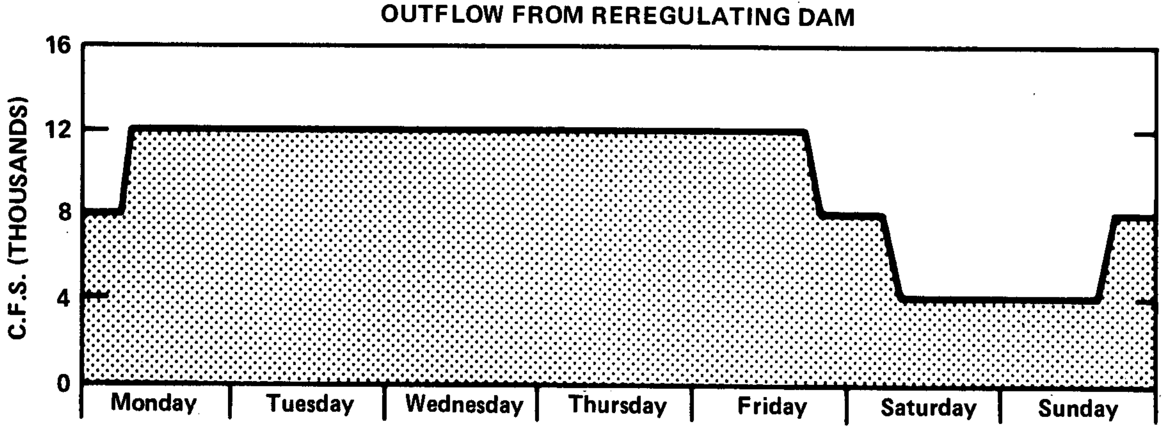
OUTFLOW FROM MAIN DAM



REREGULATING POND STORAGE USED



OUTFLOW FROM REREGULATING DAM



Under the existing criteria, for example, the Corps could reduce the flow from the reregulating dam on Friday evening from 23,000 c.f.s. to 4,000 c.f.s. in 2 hours and maintain it at that level until Monday morning. However, if fluctuations were limited to 3 feet a day, the Corps could not reduce the flow to the 4,000 c.f.s. level until Saturday evening. Similarly, the Corps would have to increase the flow to 12,000 c.f.s. on Sunday morning if a 23,000-c.f.s. outflow is needed again on Monday to compensate for the large releases from the main dam. Hence, about 32,000 acre-feet of additional water would be used to maintain necessary flows if the 3-foot criteria were used. If the reregulating pond were too small to provide this additional 32,000 acre-feet, then the Corps would have to counteract by releasing more water from the main dam. Water released from the main dam during an off-peak period would not be available if needed later during more critical periods.

More restrictive fluctuation limits could also reduce the flexibility to operate as planned. Suppose, for example, that the pond behind the reregulating dam were almost full and a sudden demand for power arose which required the use of all eight generators. The Corps would have to release water from the reregulating pond before a sufficient amount of water from the main dam (to produce needed energy) could be added. If, however, the downstream water fluctuation limits were too restrictive, the Corps could not release water from the pond fast enough to compensate for the large inflow from the main dam. The Corps' only alternative, short of violating the fluctuation limits, would be to operate fewer generators at the main dam until river levels below the reregulating dam were high enough to allow greater discharges from the main dam. For several hours or even days then, Libby Dam could not produce the power that the region would need.

Table 1, p. 1
W. G. Area

Peak Power Loads and Resources for the Pacific Northwest through 1999

Figures are January Peak and Contract Year Average Energy in Megawatts

Table 1

	1979-80 PK	1979-80 AVG	1980-81 PK	1980-81 AVG	1981-82 PK	1981-82 AVG	1982-83 PK	1982-83 AVG	1983-84 PK	1983-84 AVG	1984-85 PK	1984-85 AVG	1985-86 PK	1985-86 AVG
LOADS														
1 SYSTEM LOADS	26040	16744	27344	17570	28675	18390	30046	19326	31163	20028	32296	20720	33514	21422
2 EXPORTS	2066	629	2108	665	1754	562	1760	351	1562	203	1563	205	1565	207
3 TOTAL LOADS	28106	17373	29452	18235	30429	18952	31806	19677	32725	20231	33859	20925	35079	21629
RESOURCES														
4 MAIN HYDRO	28846	11603	28970	11635	29422	11669	29713	11667	30232	11696	30401	11694	30543	11667
5 INDEPENDENT HYDRO	659	434	659	434	659	434	659	434	659	434	659	434	659	434
6 TOTAL HYDRO	29505	12037	29629	12069	30081	12103	30372	12101	30891	12130	31060	12128	31202	12181
7 EX. SM. THRM. & MISC.	224	54	218	53	218	53	218	53	218	53	218	53	211	52
8 COMB. TURBINES	1198	109	1196	109	1198	109	1198	109	1198	109	1198	109	1198	109
9 HANFORD	0	515	0	515	0	515	0	515	0	0	0	0	0	0
10 IMPORTS	1324	1489	1415	1503	1840	1657	1781	1640	1641	1494	1572	1455	1498	1426
11 CENTRALIA	1313	903	1313	902	1313	957	1313	913	1313	1000	1313	957	1313	870
12 TROJAN	1130	800	1130	800	1130	800	1130	800	1130	800	1130	800	1130	800
13 COLSTRIP 1 & 2	330	251	330	251	330	251	330	251	330	251	330	251	330	251
14 WNP 2	0	0	0	0	1100	550	1100	798	1100	825	1100	825	1100	825
15 BOARDMAN (CARTY COAL)	0	0	477	191	477	334	477	358	477	358	477	358	477	358
16 COLSTRIP 3 & 4	0	0	0	0	0	0	0	0	420	294	840	577	840	630
17 WNP 1	0	0	0	0	0	0	0	0	1250	438	1250	860	1250	938
18 WNP 4	0	0	0	0	0	0	0	0	0	0	0	62	1250	765
19 WNP 3	0	0	0	0	0	0	0	0	0	0	0	248	1240	806
20 SKAGIT 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21 WNP 5	0	0	0	0	0	0	0	0	0	0	0	0	0	62
22 PEBBLE SPRINGS 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23 SKAGIT 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24 PEBBLE SPRINGS 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25 TOTAL RESOURCES	35024	16158	35710	16393	37667	17329	37919	17538	39968	17752	40488	18683	43039	19993
26 HYDRO,SM.THML.& MISC.RES.	1546	0	1552	0	1575	0	1589	0	1615	0	1624	0	1631	0
27 LARGE THERMAL RES.	416	0	488	0	652	0	653	0	903	0	966	0	1340	0
28 PLANNING RESERVES	604	0	981	0	1221	0	1725	0	1911	0	2306	0	2463	0
29 LOAD GROWTH RESERVES	559	330	534	318	566	330	540	325	557	324	594	336	599	349
30 SUS. PKNG. ADJUSTMENT	3963	0	3978	0	4033	0	4063	0	2552	0	2573	0	2589	0
31 HYDRO MAINTENANCE	0	34	0	34	0	34	0	34	0	32	0	33	0	33
32 BPA NW-SW INTERTIE LOSSES	84	20	84	20	57	11	57	1	50	0	50	0	50	0
33 NET RESOURCES	27852	15774	28093	16021	29583	16954	29292	17178	32380	17396	32375	18314	34367	19611
34 SURPLUS OR DEFICIT	-254	-1599	-1359	-2214	-846	-1998	-2514	-2459	-345	-2835	-1484	-2611	-712	-2018
35 BPA IND. INTERRUPTIBLE	1026	1015	1079	1066	1077	1050	1068	1058	1078	1068	1088	1078	1098	1088

APPENDIX III

APPENDIX III

Table 1, p. 2
W. G. Area

Peak Power Loads and Resources for the Pacific Northwest through 1999

Figures are January Peak and Contract Year Average Energy in Megawatts

	1986-87 PK	1986-87 AVG	1987-88 PK	1987-88 AVG	1988-89 PK	1988-89 AVG	1989-90 PK	1989-90 AVG	1990-91 PK	1990-91 AVG	1991-92 PK	1991-92 AVG	1992-93 PK	1992-93 AVG
LOADS														
1 SYSTEM LOADS	34785	22157	36100	22922	37462	23717	38845	24538	40320	25404	41752	26270	43306	27182
2 EXPORTS	989	209	248	201	106	174	108	177	105	174	105	174	105	174
3 TOTAL LOADS	35774	22366	36348	23123	37568	23891	38953	24715	40425	25578	41857	26444	43411	27356
RESOURCES														
4 MAIN HYDRO	30480	11674	30590	11703	30528	11697	30554	11647	30554	11647	30554	11647	30554	11647
5 INDEPENDENT HYDRO	659	434	659	434	659	434	659	434	659	434	659	434	659	434
6 TOTAL HYDRO	31139	12108	31249	12117	31187	12131	31213	12081	31213	12081	31213	12081	31213	12081
7 EX. SM. THRM. & MISC.	211	52	211	52	211	52	211	52	211	52	211	52	211	52
8 COMB. TURBINES	1198	109	1198	109	1198	109	1198	109	1198	109	1198	109	1198	109
9 HANFORD	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 IMPORTS	1417	1215	1332	955	1240	807	1142	734	1036	671	923	591	800	505
11 CENTRALIA	1313	914	1313	935	1313	957	1313	935	1313	935	1313	935	1313	935
12 TROJAN	1130	800	1130	800	1130	800	1130	800	1130	800	1130	800	1130	800
13 COLSTRIP 1 & 2	330	251	330	251	330	251	330	251	330	251	330	251	330	251
14 WNP 2	1100	825	1100	825	1100	825	1100	825	1100	825	1100	825	1100	825
15 BOARDMAN (CARTY COAL)	477	358	477	358	477	358	477	358	477	358	477	358	477	358
16 COLSTRIP 3 & 4	840	630	840	630	840	630	840	630	840	630	840	630	840	630
17 WNP 1	1250	938	1250	938	1250	938	1250	938	1250	938	1250	938	1250	938
18 WNP 4	1250	938	1250	938	1250	938	1250	938	1250	938	1250	938	1250	938
19 WNP 3	1240	930	1240	930	1240	930	1240	930	1240	930	1240	930	1240	930
20 SKAGIT 1	1288	515	1288	902	1288	966	1288	966	1288	966	1288	966	1288	966
21 WNP 5	1240	759	1240	930	1240	930	1240	930	1240	930	1240	930	1240	930
22 PEBBLE SPRINGS 1	0	252	1260	819	1260	945	1260	945	1260	945	1260	945	1260	945
23 SKAGIT 2	0	0	0	0	1288	515	1288	902	1288	966	1288	966	1288	966
24 PEBBLE SPRINGS 2	0	0	0	0	0	189	1260	803	1260	945	1260	945	1260	945
25 TOTAL RESOURCES	45423	21594	46708	22509	47842	23271	49030	24127	48924	24270	48811	24190	48688	24104
26 HYDRO, SM.THML.& MISC.RES.	1627	0	1633	0	1630	0	1631	0	1631	0	1631	0	1631	0
27 LARGE THERMAL RES.	1719	0	1908	0	2101	0	2290	0	2290	0	2290	0	2290	0
28 PLANNING RESERVES	2644	0	3039	0	3107	0	3152	0	3441	0	3695	0	3991	0
29 LOAD GROWTH RESERVES	619	356	640	368	654	380	696	398	702	409	734	425	749	439
30 SUS. PKNG. ADJUSTMENT	2582	0	2595	0	2587	0	2590	0	2590	0	2590	0	2590	0
31 HYDRO MAINTENANCE	0	34	0	34	0	34	0	34	0	34	0	34	0	34
32 BPA NW-SW INTERTIE LOSSES	26	0	1	0	0	0	0	0	0	0	0	0	0	0
33 NET RESOURCES	36206	21204	36892	22107	37763	22857	38671	23695	38270	23827	37871	23731	37437	23631
34 SURPLUS OR DEFICIT	432	-1162	544	-1016	195	-1034	-282	-1020	-2155	-1751	-3986	-2713	-5974	-3725
35 BPA INT. INTERRUPTIBLE	1108	1098	1118	1107	1127	1117	1137	1127	1147	1137	1157	1147	1167	1157

APPENDIX III

Table 1, p. 3
W. G. Aren

Peak Power Loads and Resources for the Pacific Northwest through 1999

Figures are January Peak and Contract Year Average Energy in Megawatts

	1993-94 PK	1993-94 AVG	1994-95 PK	1994-95 AVG	1995-96 PK	1995-96 AVG	1996-97 PK	1996-97 AVG	1997-98 PK	1997-98 AVG	1998-99 PK	1998-99 AVG
LOADS												
1 SYSTEM LOADS	44892	28123	46519	29080	48236	30067	49996	31094	51831	32166	53795	33289
2 EXPORTS	105	174	105	174	105	174	28	109	28	109	28	109
3 TOTAL LOADS	44997	28297	46624	29254	48341	30241	50024	31203	51859	32275	53823	33398
RESOURCES												
4 MAIN HYDRO	30554	11647	30554	11647	30554	11647	30554	11647	30554	11647	30554	11647
5 INDEPENDENT HYDRO	659	434	659	434	659	434	659	434	659	434	659	434
6 TOTAL HYDRO	31213	12081	31213	12081	31213	12081	31213	12081	31213	12081	31213	12081
7 EX. SM. THRM. & MISC.	211	52	211	52	211	52	211	52	211	52	211	52
8 COMB. TURBINES	1198	109	1198	109	1198	109	1198	109	1198	109	1198	109
9 HANFORD	0	0	0	0	0	0	0	0	0	0	0	0
10 IMPORTS	671	412	530	312	378	205	240	121	240	70	240	67
11 CENTRALIA	1313	935	1313	935	1313	935	1313	935	1313	935	1313	935
12 TROJAN	1130	800	1130	800	1130	800	1130	800	1130	800	1130	800
13 COLSTRIP 1 & 2	330	251	330	251	330	251	330	251	330	251	330	251
14 2	1100	825	1100	825	1100	825	1100	825	1100	825	1100	825
15 BOARDMAN (CARTY COAL)	477	358	477	358	477	358	477	358	477	358	477	358
16 COLSTRIP 3 & 4	840	630	840	630	840	630	840	630	840	630	840	630
17 WNP 1	1250	938	1250	938	1250	936	1250	938	1250	938	1250	938
18 WNP 4	1250	938	1250	938	1250	938	1250	938	1250	938	1250	938
19 WNP 3	1240	930	1240	930	1240	930	1240	930	1240	930	1240	930
20 SKAGIT 1	1288	966	1288	966	1288	966	1288	966	1288	966	1288	966
21 WNP 5	1240	930	1240	930	1240	930	1240	930	1240	930	1240	930
22 PEBBLE SPRINGS 1	1260	945	1260	945	1260	945	1260	945	1260	945	1260	945
23 SKAGIT 2	1288	966	1288	966	1288	966	1288	966	1288	966	1288	966
24 PEBBLE SPRINGS 2	1260	945	1260	945	1260	945	1260	945	1260	945	1260	945
25 TOTAL RESOURCES	48559	24811	48418	23311	48266	23504	48128	23720	48128	23669	48128	23666
26 HYDRO.SH.THRL.& MISC.RES.	1631	0	1631	0	1631	0	1631	0	1631	0	1631	0
27 LARGE THERMAL RES.	2290	0	2290	0	2290	0	2290	0	2290	0	2290	0
28 PLANNING RESERVES	4289	0	4571	0	4886	0	5212	0	5516	0	5842	0
29 LOAD GROWTH RESERVES	768	448	812	462	840	486	866	505	929	532	996	559
30 SUS. PKNG. ADJUSTMENT	2590	0	2590	0	2590	0	2590	0	2590	0	2590	0
31 HYDRO MAINTENANCE	0	34	0	51	0	51	0	51	0	51	0	51
32 BPA NW-SW INTERTIE LOSSES	0	0	0	0	0	0	0	0	0	0	0	0
33 NET RESOURCES	36991	23529	36524	23398	36029	23267	35539	23164	35172	23086	34779	23056
34 SURPLUS OR DEFICIT	-8006	-4768	-10100	-5856	-12312	-6974	-14485	-9039	-16687	-9189	-19044	-10342
35 BPA IND. INTERRUPTIBLE	1177	1167	1187	1176	1197	1186	1207	1196	1217	1206	1226	1215

GAO ENERGY CONSULTANTS

Walter R. Butcher, Professor of Agricultural Economics, Washington State University; teaches economics of naatural resources; participated in Northwest Energy Policy Project conservation study and in Pacific Northwest Regional Commission energy study; member of steering committee, Washington Energy Research Center; participated in several studies dealing with water resource planning development and use.

George W. Hinman, Director, Environmental Research Center, Washington State University; teaches graduate level courses in conventional and alternative energy supplies and systems; participated in NEPP conservation study and in Pacific Northwest Regional Commission energy study; participated in energy impact assessments for U.S. Department of Energy; performed several energy-related studies for State and local agencies; member of several Washington State energy advisory committees.

(008928)