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U.S. Army Corps of Engineers
Washington, D.C. 20314-1000

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Change 1

Manual
No. 1110-2-1701

5 June 1989

Engineering and Design
HYDROPOWER

1. This change to EM 1110-2-1701, 31 December 1985, updates telephones and addresses for offices of North American Electric Reliability Council, Power Marketing Administrations, and the Federal Energy Regulatory Commission.

2. Substitute the attached pages as indicated below:

Remove Pages	Insert Pages
3-9 and 3-10	3-9 and 3-10
3-11 and 3-12	3-11 and 3-12
3-13 and 3-14	3-13 and 3-14
7-53 and 7-54	7-53 and 7-54
7-67 and 7-68	7-67 and 7-68

3. Changed material is indicated by an asterisk.

4. File this change sheet in front of the publication for reference purposes.

FOR THE COMMANDER:

ALBERT J. GENETTI, JR.
Colonel, Corps of Engineers
Chief of Staff

DEPARTMENT OF THE ARMY
U.S. Army Corps of Engineers
Washington, DC 20314-1000

EM 1110-2-1701

DAEN-CWH-Y

Engineer Manual
No. 1110-2-1701

31 December 1985

Engineering and Design
HYDROPOWER

1. Purpose. This manual provides guidance on estimating the energy potential of a hydropower site, selecting a project's installed capacity, determining the need for the project's output, evaluating hydropower benefits, and estimating powerhouse costs.

2. Applicability. This EM applies to all HQ, USACE/OCE elements and all field operating activities having civil works design responsibilities.

3. General. This manual describes evaluation techniques for both large and small hydro projects, as well as pumped-storage hydro. These procedures can be applied to the modification or rehabilitation of existing hydro projects as well as to new projects. Information is presented on power system operation and the role of hydropower, the development of data for making hydropower studies, the flow-duration and sequential routing techniques of estimating energy potential, the considerations involved in sizing of powerplants, computer models available for making power studies, the use of reservoir storage for hydropower, special problems involved in estimating costs for hydro projects, techniques for establishing need for hydro projects, alternative approaches for evaluating hydropower benefits, and the methodology for computing power values. Techniques are presented for evaluating multi-project systems as well as single projects, and for incorporating power production in multiple purpose project or system operation. Appendixes include example calculations, a glossary, a list of references, and a table of conversion factors. An outline of the steps in a hydropower study is provided together with an appendix summarizing the technical material to be presented in a hydropower study report. Information on coordination required with the regional Federal Power Marketing Administrations and the Federal Energy Regulatory Commission is also presented.

FOR THE COMMANDER:

Arthur E Williams

ARTHUR E. WILLIAMS
Colonel, Corps of Engineers
Chief of Staff

DEPARTMENT OF THE ARMY
US Army Corps of Engineers
Washington, D.C. 20314-1000

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APPENDIXES

CHAPTER 1

INTRODUCTION

1-1. Purpose. This manual provides guidance on the technical aspects of hydroelectric power studies, from the preauthorization level through the General Design Memorandum (GDM) stage. It also defines the appropriate level of effort required, and the study requirements and technical procedures required for each stage of study. Specific areas covered include need for power, determination of streamflows and other project characteristics, estimation of energy potential, sizing of powerplants, cost estimating, and power benefit analysis. Subjects such as powerhouse design and selection of turbines and generators are treated in other manuals.

1-2. Applicability. This manual is applicable to all field operating activities having civil works design responsibilities.

1-3. References.

a. ER 10-1-41, Corps-Wide Centralized Functions and Special Missions Assigned to Divisions and Districts

b. ER 37-2-10, Accounting and Reporting Civil Works Activities

c. ER 1105-2 series, Planning Guidance Notebook

d. ER 1110-2-1, Provisions for Hydroelectric Installation at Corps of Engineers Projects

e. ER 1110-2-1402, Hydrologic Investigation Requirements for Water Quality Control

f. EM 1110-2-1301, Cost Estimates - Planning and Design Stages

g. EM 1110-2-3001, Planning and Design of Hydroelectric Power Plant Structures

h. EM 1110-2-3106, Selecting Reaction Type Hydraulic Turbines and Pump-Turbines at Corps of Engineers Projects

i. EM 1110-2-3600, Reservoir Regulation

1-4. Bibliography. Appendix T consists of a selected bibliography of literature pertaining to hydropower studies. References in the text to specific publications are indicated throughout the manual by bracketed numbers which correspond to the publication number as listed in Appendix T.

1-5. Glossary. Appendix S contains definitions of terms relating to hydropower and electric power systems.

1-6. Conversion Factors. Appendix R contains a listing of some of the common conversion factors used in hydropower studies. Factors for converting English system units to metric units are also included.

1-7. Hydroelectric Design Centers. Three Corps of Engineer offices have been designated as Corps-wide Hydroelectric Design Centers: North Pacific Division, Omaha District, and Mobile District. These offices have special expertise in powerhouse design and can provide services ranging from preliminary layouts and cost estimates through turbine selection and preparation of construction plans and specifications. In accordance with ER 10-1-41 (Change 2), these offices have responsibility for all Corps powerhouse design work beyond the feasibility stage. To insure continuity throughout the planning and design stages, it is recommended that the Design Centers also be utilized where possible at the reconnaissance and feasibility stages. The primary Design Center, North Pacific Division, will be given first priority for work performed for all districts within the Corps, except that Omaha District will generally perform work within Missouri River Division and Mobile District will perform work within South Atlantic Division. The Design Centers also have supporting offices which can provide assistance in power studies and power benefit analyses.

1-8. Organization of a Power Study. Figure 1-1 outlines in flowchart form the basic steps in a power study. A brief discussion of each step follows, with references to the section(s) in this manual that describe the technical studies required for each step.

a. Need for Power. Define the power system and compare projected loads with projected resources to determine the type, amount, and scheduling of additional power (Chapter 3).

b. Hydrologic Data Preparation. Develop streamflows, reservoir characteristics, and related data for the proposed site (Chapter 4).

c. Preliminary Power Studies. Using the data from step (b), determine the approximate energy potential of the proposed site (Chapter 5).

d. Environmental/Operational Studies. Based on environmental characteristics and non-power river uses and project functions, identify factors which may limit operation for power (Chapters 4 & 6).

e. Type of Project. Using physical site characteristics and data gathered during steps (a) through (d), determine what type of project(s) should be considered for the site (Chapter 6).

f. Range of Plant Sizes. With data from steps (c) and (e), determine the range of installed capacities that should be examined (Chapter 6).

g. Detailed Power Studies. With data from steps (b), (d), (e), and (f), conduct power studies to determine energy output and dependable capacity for each alternative development (Chapters 5 & 6).

h. Cost Estimates. Make a preliminary estimate of annual cost for each alternative development (Chapter 8).

i. Basis for Benefits. With information on project size, type of power supplied, and characteristics of the local power systems, determine the appropriate method for measuring hydropower benefits, considering the likely alternative means of meeting projected demand in the absence of the proposed hydro project (Chapter 9).

j. Power Values. Determine unit value of hydropower project output using data on the market value of power or the alternative cost of meeting demand (Chapter 9).

k. Power Benefits. Compute power benefits using energy output and dependable capacity values from step (g) and unit power values from step (j) (Chapter 9).

l. Net Benefits. Determine net benefits for each alternative development using cost data from step (h) and benefit data from step (k).

m. Marketability Study. Using data from steps (d), (g), and (h), the regional Federal Power Marketing Administration makes marketability study (Chapters 3 & 9).

n. Select Plan. With net benefit data from step (l), environmental and operational data from step (d), marketability data from step (m), and any other relevant data, select plan to be recommended for development (Chapter 9).

o. Successive Iterations. Figure 1-1 depicts a power study as a single-pass analysis. In most cases, selection of the best power installation is an iterative process, with some of the steps being repeated two or more times in successively greater detail for a successively smaller number of alternative plans. It should also be noted that the above discussion relates to a single-purpose power study. When hydropower is one of several functions being considered for a proposed project, the steps shown on Figure 1-1 would be integrated into a multi-objective planning study. This manual touches only briefly on environmental studies, net benefit analysis, and plan selection. Primary guidance on these subjects and on multi-objective planning is found in the Planning Guidance Notebook (49).

1-9. Hydropower Reports. In accordance with the Planning Guidance Notebook, the basic results of the hydropower studies must be summarized in reconnaissance and feasibility reports. It is recommended that hydropower reports also contain a technical appendix which includes the material necessary to understand assumptions and procedures underlying the power studies. This appendix should also include sufficient data and back-up computations to permit tracking the determination of (a) need for power (where required), (b) power output, and (c) power benefits. This allows effective review and facilitates follow-up studies. Appendix A presents an outline of material which should be considered for inclusion in a hydropower technical appendix.

1-10. Small Hydro Projects. The procedures included in this manual are applicable to small hydro projects (less than 25 MW), as well as to larger installations. Additional information on the analysis of small hydro projects can be found in references (6), (17), (36), and (39).

1-11. Coordination with Other Agencies.

(1) The normal coordination procedures with Federal, State, and local agencies apply to hydropower studies. Special mention should be made of coordination with the Federal Energy Regulatory Commission (FERC), and the regional Federal Power Marketing Administrations (Section 15-4 of reference (37)).

(2) The Corps of Engineers cooperates with the FERC in evaluating power benefits on the basis of unit power values developed by that agency (Section 9-5k). FERC reviews cost allocations for Corps hydro projects and, where authorizing legislation requires, is responsible for preparation of the final cost allocation. FERC is also responsible for assessing the falling water charges that apply to non-Federal entities that construct powerplants at Corps of Engineers

facilities (Section 9-10h), and they are involved in the evaluation of minimum provisions for future power at Corps projects (Section 9-10b).

(3) The 1944 Flood Control Act and related Acts give the Secretary of Energy the responsibility for marketing the power from Corps of Engineers hydro projects, and this is handled by the five regional Power Marketing Administrations (PMA's) (Sections 3-5c, 3-12, and 9-9). As a part of the feasibility level planning study, the PMA prepares a marketability report in order to determine if the costs of the proposed hydro project can be recovered as required by law. Close coordination with the PMA should be maintained at all levels of planning.

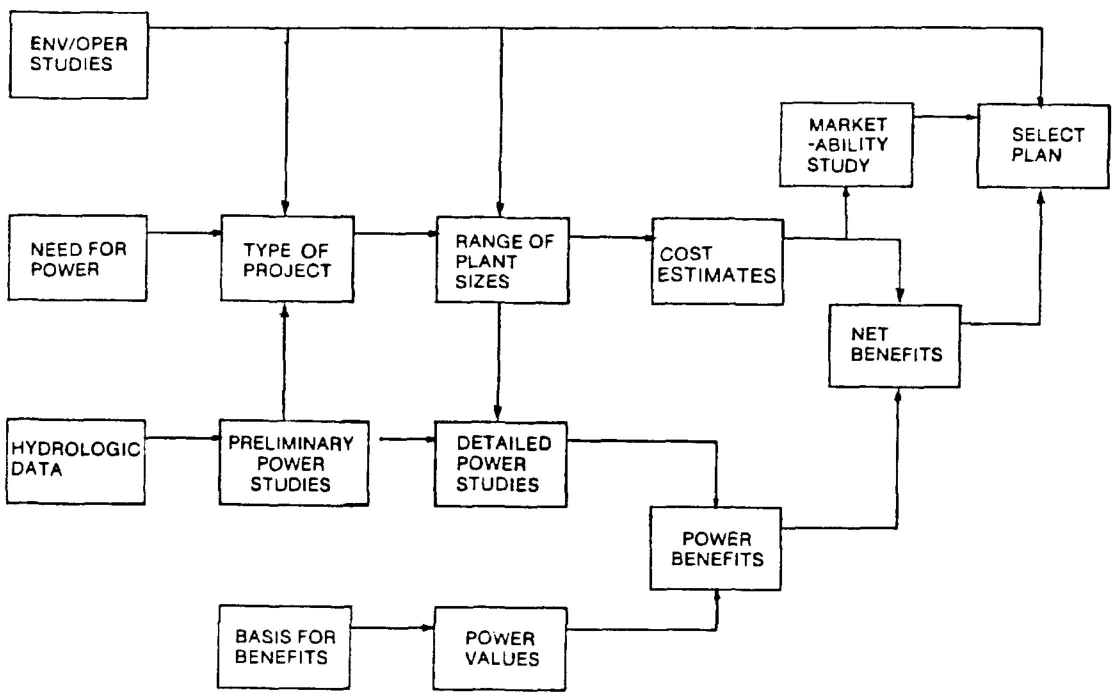


Figure 1-1. Power planning flow chart

Figure 1-2. Generator installation at Wilson Lock and Dam, the first major hydroelectric project to be designed and constructed by the Corps of Engineers. The project was placed in service in 1925 and was transferred to the Tennessee Valley Authority in 1933 (Nashville District).

CHAPTER 2

GENERAL FEATURES OF HYDROELECTRIC DEVELOPMENT AND THE ROLE OF HYDROPOWER

2-1. Introduction. This chapter briefly describes the general concepts of power system operation, the use of hydro projects in power systems, the various types of hydroelectric development, the components of a typical hydro project, the components of a powerhouse, and the various types of turbines that are available.

2-2. Power System Operation. The purpose of this section is to describe power system operation. Topics include loads (demand for power), resources (types of powerplants), use of resources to meet loads, and the role of hydropower in power system operation.

a. Organization of the Power Industry.

(1) Electric Power Utilities. Most power generated in the United States is produced by the electric power utilities. Utilities can be divided into three categories: investor-owned utilities, which supply about 78 percent of the nation's electrical energy; publicly owned systems (municipalities, public utility districts, etc.), which provide about 15 percent; and the customer-owned rural electric cooperatives, which supply the remaining 7 percent. Most of the investor-owned systems, municipal systems and cooperatives produce their own power, but others purchase their power either from the generating utilities or from the Federal government.

(2) Federal Hydropower Projects. In 1982, about 120,000,000 MWh, or 5 percent of the nation's electrical energy requirements, was produced by Federal hydroelectric projects, operated by the Corps of Engineers, the Bureau of Reclamation, and the Tennessee Valley Authority. These projects are multiple-purpose projects, and power production is just one of the functions they serve. Under the terms of the 1944 Flood Control Act and related legislation, power from Corps and Bureau hydro projects is marketed to the utilities by the five regional Power Marketing Administrations (PMA's) of the Department of Energy (see Sections 3-5b and 3-12). In addition to marketing, some of the PMA's also provide transmission and dispatching services. The Tennessee Valley Authority is directly responsible for the marketing, dispatching, and transmission of power produced at its own plants. Legislation gives preference to publicly owned utilities and cooperatives in the purchase of power produced at Federal projects.

b. Definitions. Some of the basic definitions relating to power system operation follow. Figure 2-1 illustrates many of these parameters.

(1) Energy. Energy is that which is capable of doing work. Mechanical energy is expressed in foot-pounds, while electrical energy is expressed in kilowatt-hours (1 kWh = 2,656,000 ft-lbs.). The output of a hydroelectric plant is called electrical energy.

(2) Power. Power is the rate at which energy is produced or used, expressed in either horsepower or kilowatts. While this is the technical definition of power, the term is often used in a broad sense to describe the commodity of electricity, which includes both energy and power.

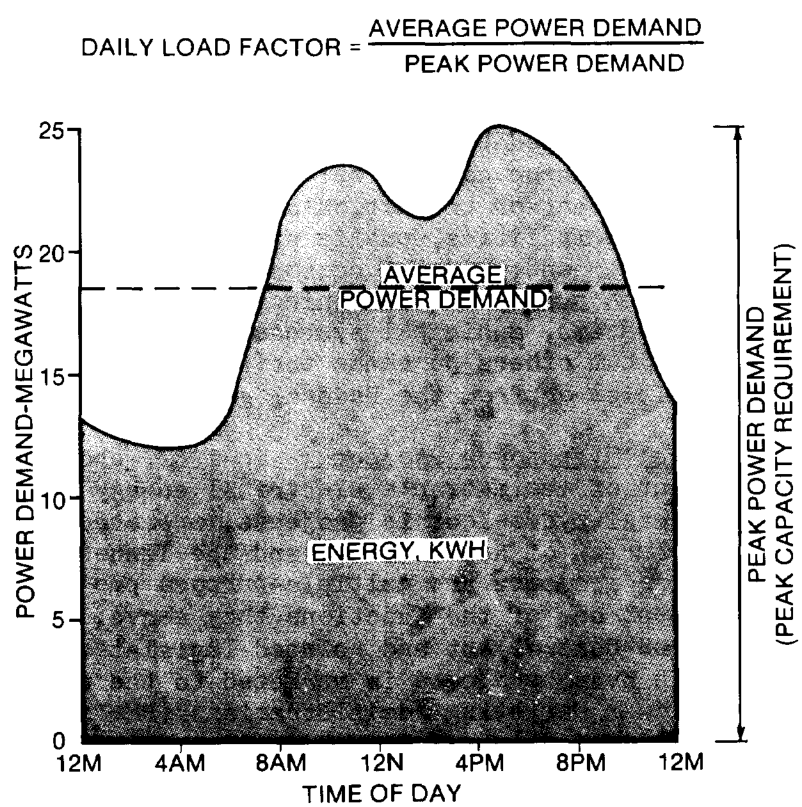


Figure 2-1. Daily load shape showing common power terms

(3) Capacity. Capacity is the maximum amount of power that a generating plant can deliver, expressed in kilowatts.

(4) Load. Load is demand for electricity. Load can be expressed in terms of energy demand (average power demand), or capacity demand (peak power demand). For planning purposes, capacity demand is measured in terms of the expected maximum annual capacity demand, or "annual peak load." Energy demand is normally measured in terms of average annual energy.

(5) Resources. Resources are sources of electrical power. A system's power resources could include both generating plants and imports from adjacent power systems.

(6) Load Factor. A load factor is the ratio of average power demand to peak power demand for the period being considered. Load factor can be computed on a daily, weekly, monthly, or annual basis. For example,

$$\text{daily load factor} = \frac{\text{(average power demand for day)}}{\text{(peak power demand for day)}}$$

c. Power Loads.

(1) General. An understanding of how loads are classified and how they vary with time is basic to an understanding of power system operation.

(2) Daily Load Shapes. Load or demand for electric power varies from hour to hour, from day to day, and from season to season in response to the needs and living patterns of the power users. The daily load shape in Figure 2-1 illustrates this concept. Demand for power is at a low point in the early morning hours, when most of the population is at rest. Demand increases markedly at 6 am, as people get up and begin going to work, and reaches a peak in the late morning hours. It remains high through the daytime hours, often reaching another peak about suppertime, and then decreases in the evening hours, as activity drops off.

(3) Weekly Load Shapes. Figure 6-1 (see Chapter 6) illustrates the weekly load pattern. Daytime loads, which are at a high level during the five weekdays, are somewhat lower on Saturdays and at their lowest levels on Sundays and holidays. This pattern reflects the impact of industrial and commercial activity on power demand.

(4) Seasonal Demand Pattern. The seasonal load pattern reflects the effects of weather and hours of daylight. Weather can cause two seasonal peaks, one due to winter heating loads and one due to summer air conditioning loads. Demand is usually highest in these seasons and relatively low in the spring and fall months. Winter peaks predominate in New England and the Pacific Northwest, while the Southern states, from California to the Carolinas, experience their highest loads in the summer months. Most of the rest of the country has high demand periods in both the summer and the winter. Figure 2-2 illustrates seasonal demand patterns for the Pacific Northwest, West North Central and South Central States.

(5) Load Types. The load shape is divided into three segments: base load, intermediate load, and peaking load (Figure 2-3). The base load is the minimum load in a stated period of time. The peaking load is that portion of the load which occurs eight hours per day or less. The intermediate load is the load between the base and peaking loads. Powerplants are often categorized as base load, intermediate (or cycling), and peaking, but operational definitions vary somewhat from load definitions (see Section 6-3). An intermediate load or cycling plant would operate 8 to 14 hours a day, and a base load plant would carry the portion of the load below the intermediate plant.

(6) Load Classes. Loads can also be classified by consumer. Following is a listing of the major load classes and the approximate portions of the total load that each comprises (nationally):

. industrial	35 percent
. residential	35 percent
. commercial	25 percent
. irrigation and street lighting	5 percent

(7) Load Forecasts. When planning future system construction and operation requirements, it is necessary to forecast loads for a number of years into the future. Load forecasts and their use in Corps planning reports are discussed in Chapter 3.

d. Power Resources.

(1) Introduction. Power resources are sources of electric power for meeting loads. A power system's resources could include power-plants, power supply contracts from outside the system (imports), and interruptible loads. A brief description of the major types of powerplants and other power resources currently being used in the United States follows. Approximate costs are presented in 1983 dollars for purposes of comparison.

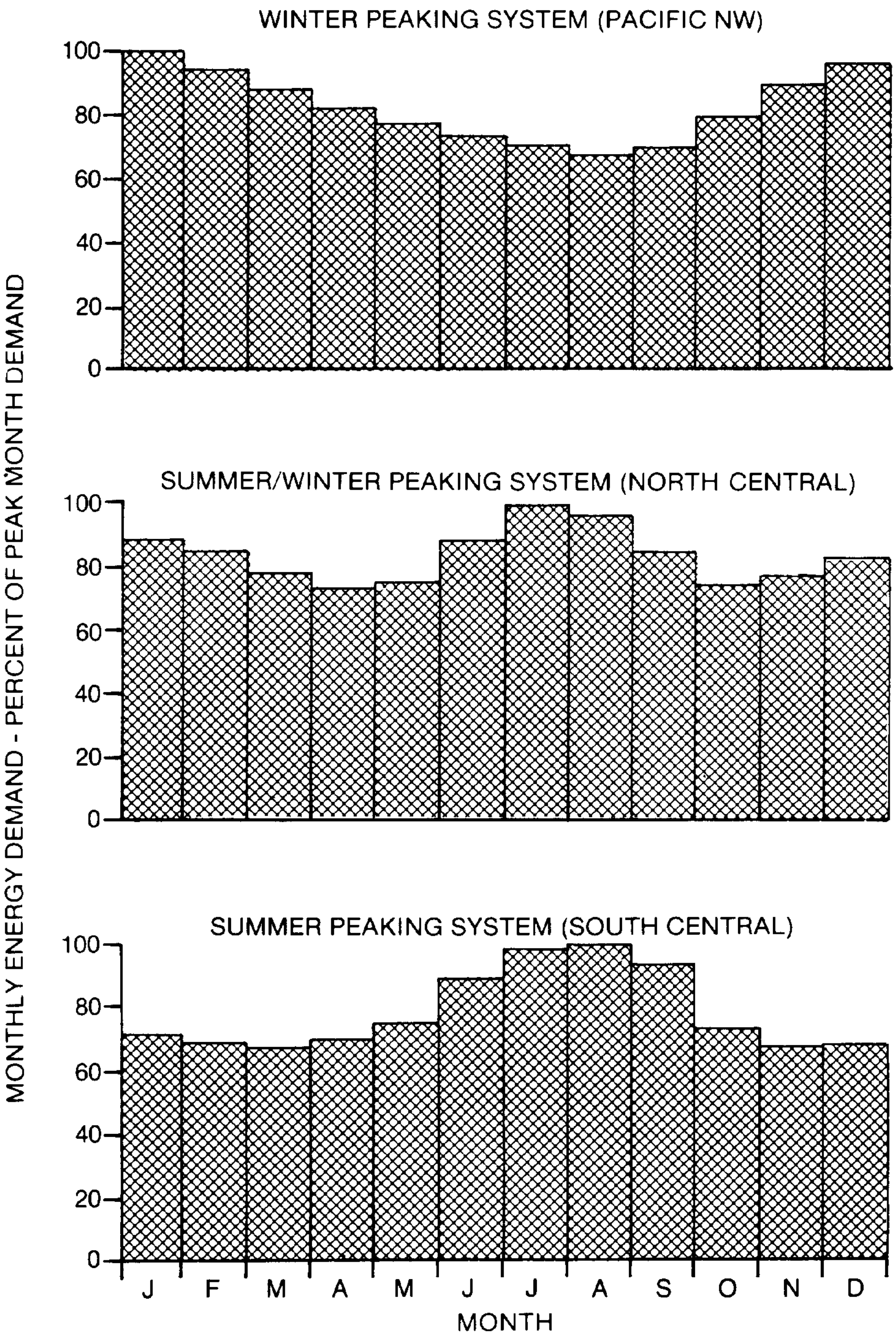


Figure 2-2. Seasonal demand patterns

(2) <u>Fossil-Fuel Steam.</u> Steam plants fired by fossil fuel (Figure 2-4) are the nation's largest single source of electric power. Fuel is burned in a steam plant's boiler to produce steam to drive a turbine. This process converts 30 to 40 percent of the energy content of the fuel to electrical energy. Steam plants may be designed to operate on coal, natural gas, oil, or a combination of fuels. Although smaller units have been constructed in the past, most modern steam plants have units in the 300 to 700 megawatt range. Most of the newer. more efficient units are used in base load service. Older, smaller units are typically used for cycling (intermediate loads),

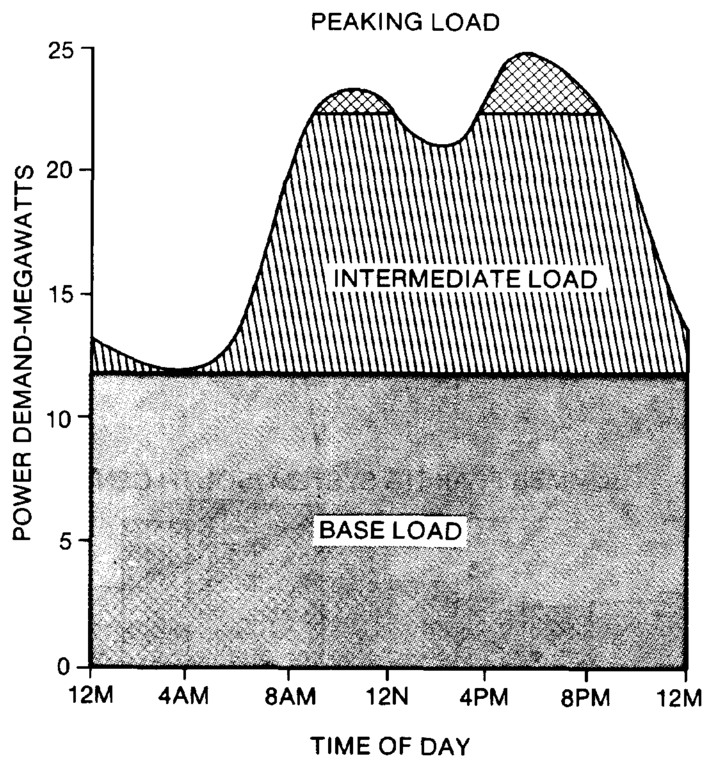


Figure 2-3. Daily load shape showing load types

although some new plants have been constructed in recent years for cycling service. Because of the complexity of their operating systems, steam plants require several hours for startup. While they have some peaking capability, they do not respond as rapidly to change in load as other types of plants. Capital costs are relatively high ($1000/kW or more in 1983). Fuel costs range from 5 to 20 mills/kWh for coal to 60 mills/kWh or more for oil. Coal plants require four to six weeks of maintenance each year and have forced outage rates (which vary with plant size) of 10 to 20 percent. The resulting overall availability (maximum possible plant factor) ranges from 65 to 85 percent, depending on plant size.

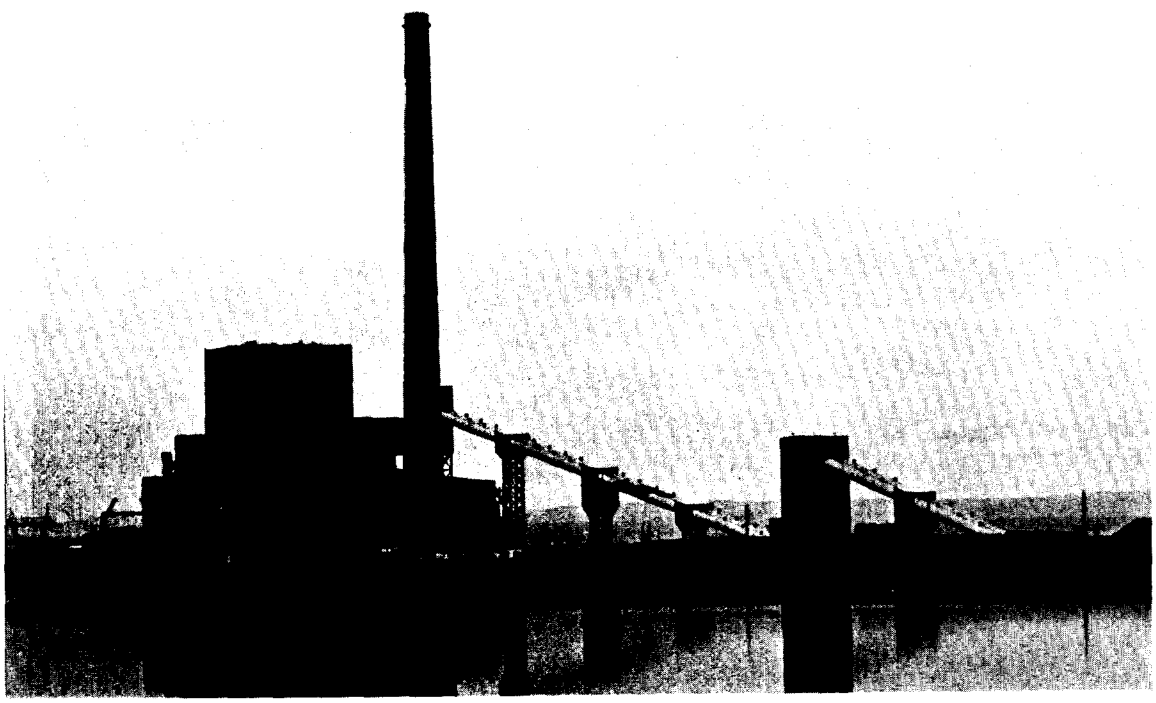


Figure 2-4. Boardman coal-fired steam plant
(Courtesy of Portland General Electric Company)

(3) Nuclear. Nuclear plants (Figure 2-5) are similar to fossil-fuel steam plants except that nuclear fission produces the heat required to generate the steam. Thermal efficiency, at about 33 percent, is somewhat lower than that of coal plants because nuclear steam systems operate at a lower pressure and temperature. Plant sizes are typically in the 800 to 1250 MW range. Because of their low fuel costs (5 to 10 mills/kWh) and high capital costs ($1200/kW or more), as well as other operational characteristics, nuclear plants are used almost exclusively for base load service. Nuclear plants are normally out of service for about eight weeks a year for scheduled maintenance and refueling. Forced outage rates average about 15 percent, which results in an overall availability of 65 to 70 percent.

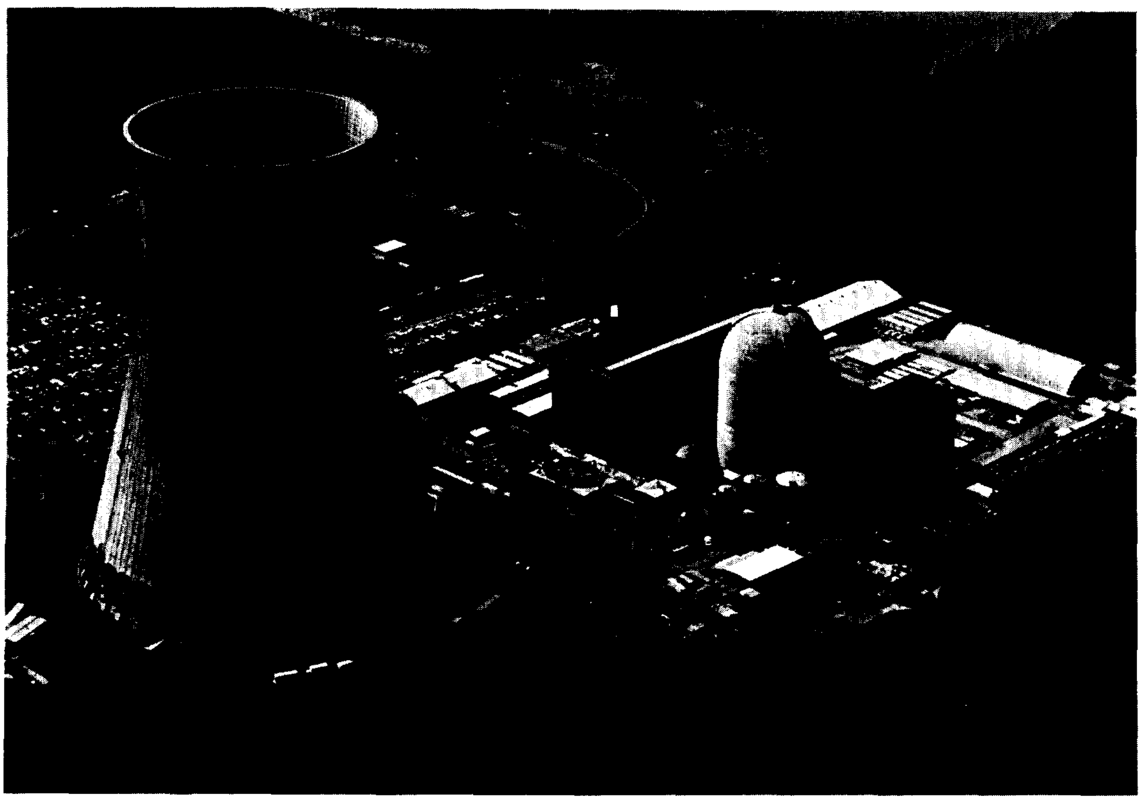


Figure 2-5. Trojan nuclear power plant
(Courtesy of Portland General Electric Company)

(4) Combustion Turbine. A combustion turbine (Figure 2-6) is basically a jet engine connected to a generator. Combustion turbines can run on natural gas or distillate oil, and their overall efficiency is between 25 and 30 percent. Sizes are in the 10 to 100 MW range. They are often constructed in pairs (two combustion turbines connected to a single generator), and installations may consist of several pairs of units. Capital costs are low (about $225/kW), and fuel costs are high (90 to 100 mills/kWh when fired by oil). Combustion turbines can be started in a matter of minutes and can be used for load-following by varying the number of units that are on line. Because of their high fuel costs and fast-start characteristics, combustion turbines are normally used for peaking and standby reserve service. Average annual plant factors are typically 10 percent or less, although in periods of power shortage, combustion turbines have operated at much higher plant factors. In Alaska, where low-cost natural gas is available, combustion turbines are the major source of electric power in some areas and operate at annual plant factors in excess of 50 percent.

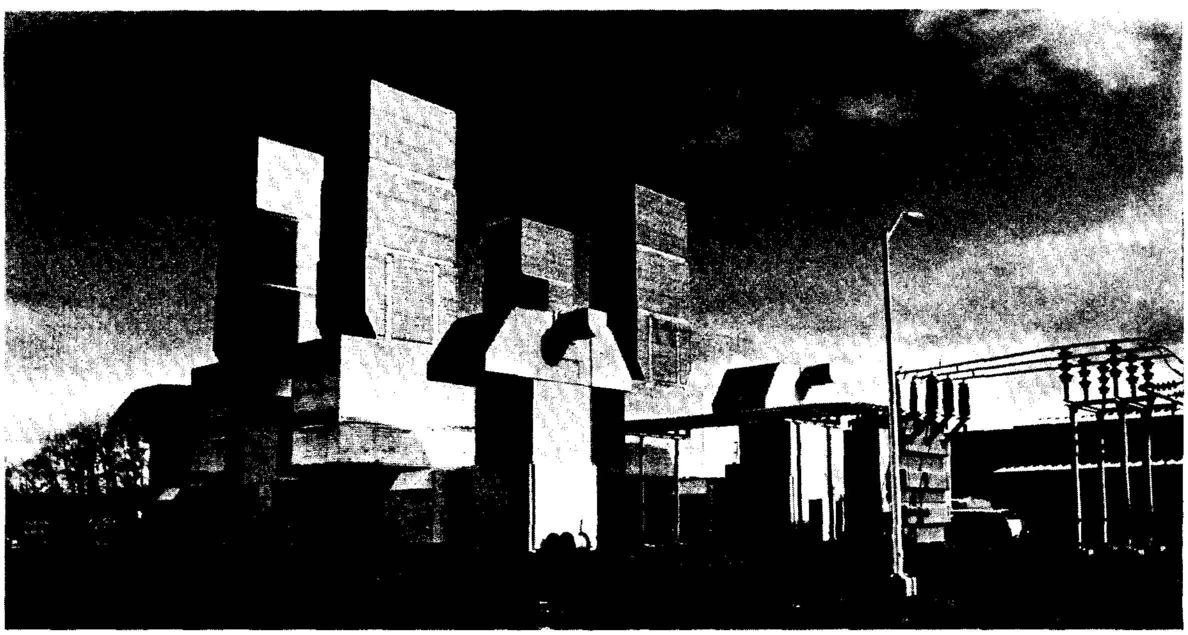


Figure 2-6. Bethel combustion turbine power plant
(Courtesy of Portland General Electric Company)

(5) Combined Cycle. A combined cycle plant (Figure 2-7) is a series of combustion turbines with heat extractors on their exhausts. Steam from the heat extractors is used to drive a conventional turbine-generator. The addition of the steam cycle increases overall efficiency to about 40 percent. Capital costs are higher than combustion turbines (about $500/kW), but due to their higher efficiency, fuel costs are lower (60 mills/kWh or more for oil). Combined cycle plants are designed primarily for cycling operation or extended operation in periods of high demand.

(6) Conventional Hydro. The various types of hydro plants are described in Section 2-3, but some of their basic operating characteristics will be summarized here. Hydro differs from other types of powerplants in that the quantity of "fuel" (i.e. water) that is available at any given time is fixed. Techniques such as seasonal storage or daily/weekly pondage can be used in many cases to make the distribution of streamflow better fit the power demand pattern, but the total amount of water that is available for power generation at a given site is fixed. Increasing plant size may, in some cases, increase the percentage of the potential energy that is utilized, but it cannot increase the total supply. On the positive side, fuel costs are essentially zero. However, capital costs are relatively high, ranging from $500 to $2,000/kW for new projects. Hydro has by far the

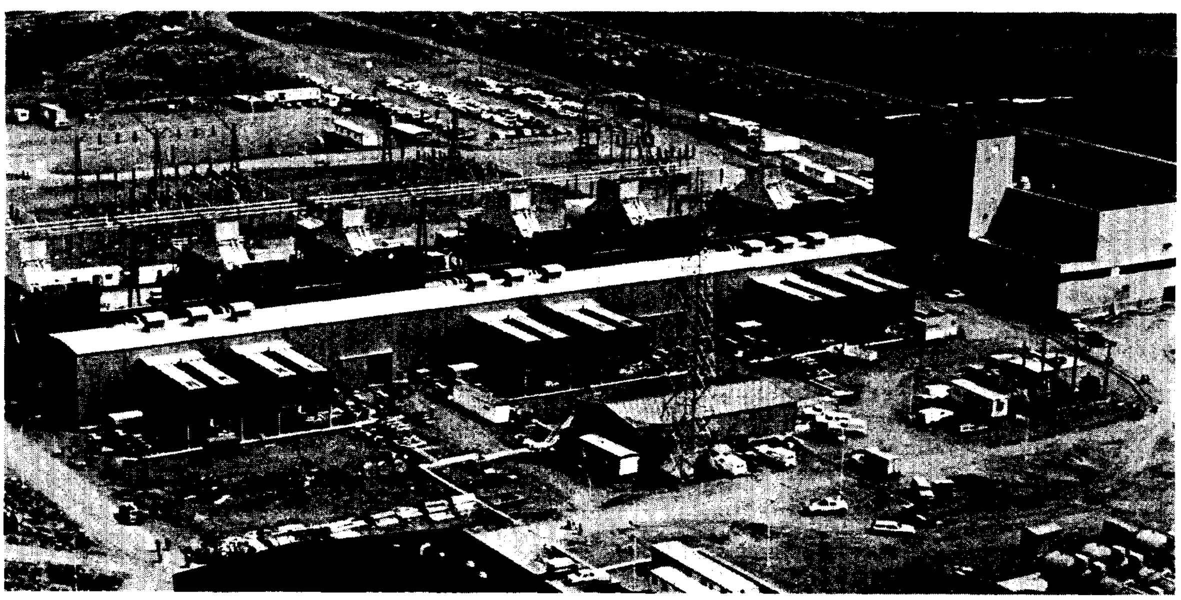


Figure 2-7. Beaver combined cycle power plant
(Courtesy of Portland General Electric Company)

highest energy conversion efficiency, at 80 to 90 percent. Hydropower units can be placed on-line rapidly and can respond quickly to changes in loading. Hydro is well-suited for peaking or load-following operation and is generally used for this service if storage or pondage is available and if river conditions permit. If the project has no controllable storage or if operating restrictions preclude load-following, hydro energy can be produced only when water is available (run-of-river operation). Forced outage rates on hydro are very low (2 to 4 percent), and average availability (which includes scheduled maintenence) is about 95 percent.

(7) Pumped-Storage Hydro. Pumped-storage hydro is a form of energy storage. Relatively low-cost electrical energy, usually from coal-fired steam plants, is used to pump water into an upper storage reservoir during periods of low power demand (nights and weekends). During high demand periods, when energy is most valuable, water is released to produce power. Further details on pumped-storage operation can be found in Section 2-3e and Chapter 7. Because of mechanical and electrical losses in the pumping and generating processes, overall efficiency is about 65 to 75 percent. Pumped-storage has quick-start capability, and because of its relatively high "fuel" cost (the cost of the off-peak pumping energy divided by the overall efficiency), it is normally used for peaking service. Construction costs are moderately high ($500 - $800/kW) and forced outage rates are about five percent.

(8) Other Types of Powerplants. Other types of powerplants are geothermal steam, wind, solar, and tidal. However, they are presently in limited use because they are in the developmental stage, or because the resource itself is limited. One additional type of powerplant, the diesel or internal combustion unit, is widely used to provide power in isolated areas where loads are relatively small or for emergency service, but such units are seldom operated in the larger power systems of the continental United States.

(9) Imports. An additional resource available to some power systems is the import of power from adjacent power systems. Imports fall into several categories. First, there are firm or assured sales contracts, which usually become available when a utility has a temporary surplus of generation. These contracts are normally of relatively short duration (one to ten years). Another category is the exchange contract, which is designed to take advantage of seasonal or daily diversity in load or resource capabilities. Exchange contracts are usually firm contracts and are of longer duration (10 years or more). The third major category is low-cost "dump" power, which may be available from outside the system on a short-term interruptible basis. This power can be used to cut system fuel costs, but it is not considered a firm power system resource.

(10) Interruptible Loads. A portion of the load in some systems can be interrupted during periods of high demand and this "interruptible" load serves in effect as a resource available to the operator to insure that firm system loads will be met. One example is the rotating short-term interruption of individual water heaters or air conditioners during the peak demand hours of the day. Another example is the long-term interruption of service to certain types of industrial customers during extended periods of shortage. The latter might include electro-process industries, which may pay relatively low power rates in exchange for allowing a portion of their loads to be interruptible.

e. Reserves. Having just enough resources to meet expected peak loads is not sufficient to guarantee a reliable service to customers. Additional capacity must be available to cover forced outages, maintenance outages, abnormal loads, and other contingencies. Typically, power system resource planning is based on providing about 20 percent reserve capacity above the expected annual peak load. This capacity is called the system planning reserve. In day to day system operation, an operating reserve of 5 to 10 percent of the load being carried must be maintained at all times. Half of this must be spinning reserve (capacity which is rotating but not under load) and the remainder is standby reserve, which must be available in a matter of minutes. The spinning reserve is used to handle moment-by-moment load changes, while standby reserve is used to cover unexpected powerplant outages.

f. Meeting Loads with Resources.

(1) This section shows how a given set of power resources is used to meet system loads. When planning a program of resource construction to meet expected future demands, both fixed (capital) and operating costs must be considered. However, to illustrate the principles of system operation, only operating costs (primarily fuel costs) will be considered. In order to simplify the discussion, the operation of an all-thermal system will be examined first. Section 2-2g will address the operation of power systems that include hydropower plants.

(2) A simplified example based on a single week of operation will illustrate these concepts. A load-duration curve is commonly used to describe system operation. Figure 2-8 shows the derivation of a load-duration curve from a weekly load curve. The example assumes that a 20 percent reserve margin must be maintained. When evaluating average system operating costs, the occasional use of reserve generation to cover forced outages must be accounted for. Since techniques for doing this are complex (see Section 6-9f), operation to cover forced outages will not be considered in this example.

(3) The expected peak load for the example system is assumed to be 5000 MW, so an additional 1000 MW of generating capacity is required to provide a 20 percent reserve margin. Table 2-1 lists the powerplants available for meeting this load and their respective operating costs.

(4) The basic objective of system operation is to minimize costs by placing the plants in the load in order of increasing cost. The plant with the lowest operating cost is NUKE-1 at 6 mills/kWh. It would be operated at the base of the load. The next lowest operating cost is 8 mills/kWh for COAL-2, so it would be loaded next. The other plants would be loaded in the weekly load-duration curve as shown in Figure 2-9, with CMBT-1 being loaded at the peak and CMBT-2 and -3 providing the reserve capacity. Costs would be computed for each plant by multiplying the plant capacity by the number of hours operated in the week and the energy cost in mills/kWh. Table 2-2 shows the computation of system costs for the week. Table 2-2 and Figure 2-9 show that this loading order produces the lowest system operating cost.

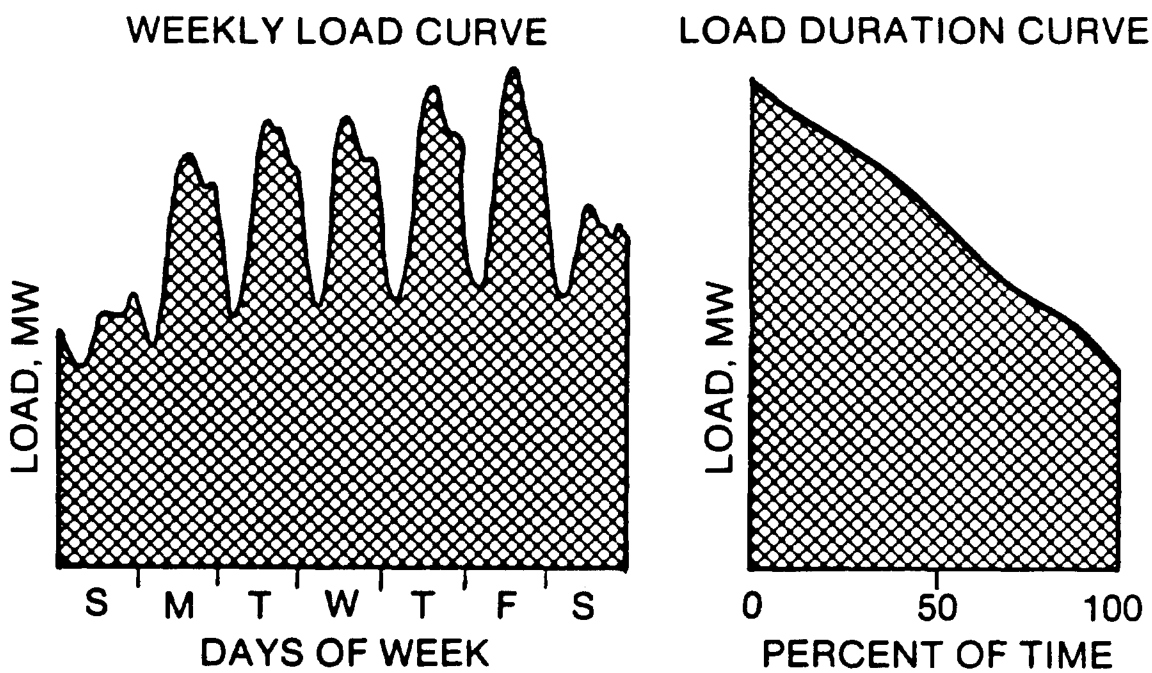


Figure 2-8. Derivation of load duration curve from weekly load curve.

TABLE 2-1
Generating Plants Available for Meeting Loads - Base Case

Plant	Symbol	MW	Mills/kWh
Base load coal	COAL-1	500	15
Base load coal	COAL-2	750	8
Base load coal	COAL-3	750	9
Cycling coal	CYCL-1	500	20
Cycling coal	CYCL-2	500	30
Combined cycle	CMCY-1	500	60
Combustion turbine	CMBT-1	500	80
Combustion turbine	CMBT-2	500	90
Combustion turbine	CMBT-3	500	100
Nuclear	NUKE-1	1000	6
TOTAL		6000	

(5) This simplified example ignores the costs of operation to cover forced outages. It fails to account for possible ramp rate and minimum down time constraints on plants operating in the variable portion of the load. It also does not reflect the fact that spinning reserve requirements are usually met by operating some plants at partial loading. However, the example does illustrate the general concept of system operation.

g. The Use of Hydropower.

(1) Hydropower can be used in a power system in several ways: for peaking, for meeting intermediate loads, for base load operation, or for meeting a combination of these loads. These alternative operations can best be illustrated by adding hydro to the system described in the preceding section. Given the same load shape and resources as shown in Figure 2-9 and a hydro project with an average power putput for the week of 250 MW (250 MW x 168 hours = 42,000 MWh), several possible system operations are considered.

(2) Hydro energy has a fuel cost of approximately zero mills/kWh. The best loading of hydro to minimize system operating cost would be in the peak of the load. A 1000 MW installation would fit almost in the peak of the load and would displace CMBT-1 at 80 mills/kWh and CMCY-1 at 60 mills/kWh (Figure 2-10). The resulting system cost for the week would be $5,306,000, saving $1,950,000

compared to the all-thermal system (Table 2-3). If the hydro plant were constructed as a base load plant, only 250 MW of capacity would be required to fully utilize the 42,000 MWh of energy which is available, and it would be loaded as shown in Figure 2-11. The system operating cost would be $6,159,000 and the savings only $1,097,000 (Table 2-4). Alternative hydro plant sizes could be tested by loading them at intermediate points in the loading order, but none would result in a lower system operating cost than loading the hydro in the peak.

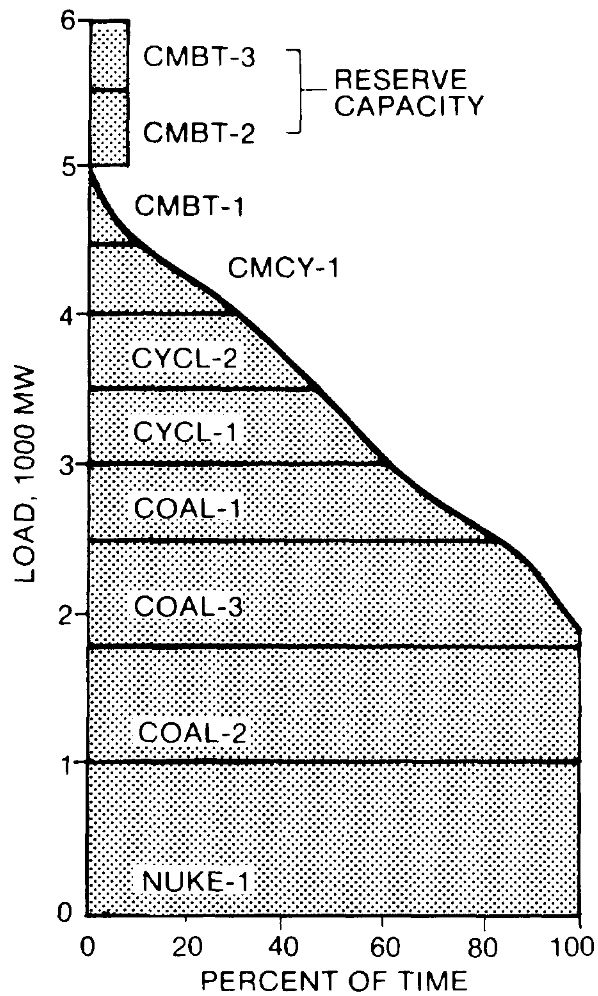


Figure 2-9. Duration curve showing operation of all-thermal power system

TABLE 2-2
Cost of Operating All-Thermal Base System for One Week
(From Figure 2-9)

Plant Symbol	Capacity (MW)	Plant Factor(%)	Energy (1000 MWh)	Unit Cost (Mills/kWh)	Cost ($1000)
CMBT-3	500	0	0	100	0
CMBT-2	500	0	0	90	0
CMBT-1	500	4	3	80	240
CMCY-1	500	21	18	60	1080
CYCL-2	500	40	34	30	1020
CYCL-1	500	55	46	20	920
COAL-1	500	72	60	15	900
COAL-3	750	95	120	9	1080
COAL-2	750	100	126	8	1008
NUKE-1	1000	100	168	6	1008
HYDRO	0	0	0	0	0
TOTALS	6000	68 2/	575	12.6	7256

1/ Energy = (capacity, MW)x(plant factor, %)x(168 hrs/wk)/100
2/ System load factor, based on 5000 MW peak load

(3) The above analysis considers only system operating costs, and does not account for the capital costs of the alternative hydro installations, which obviously increase with installed capacity. Nor does the analysis account for the displacement of an equivalent amount of thermal plant capacity by the hydro capacity. These points must be considered when determining the best plant size, and the economic evaluation procedures described in Chapter 9 are designed to do this.

(4) It is possible to make some general observations regarding the use of hydro. Much of the cost associated with the construction of a hydro plant is independent of plant size: i.e., the costs of the main dam, spillway, reservoir, relocations, and fish and wildlife protection and mitigation. The incremental costs of larger plant sizes at a given site are often relatively low. Because of this and hydro's ability to come on-line rapidly and respond quickly to load changes, it is traditionally viewed as a peaking resource.

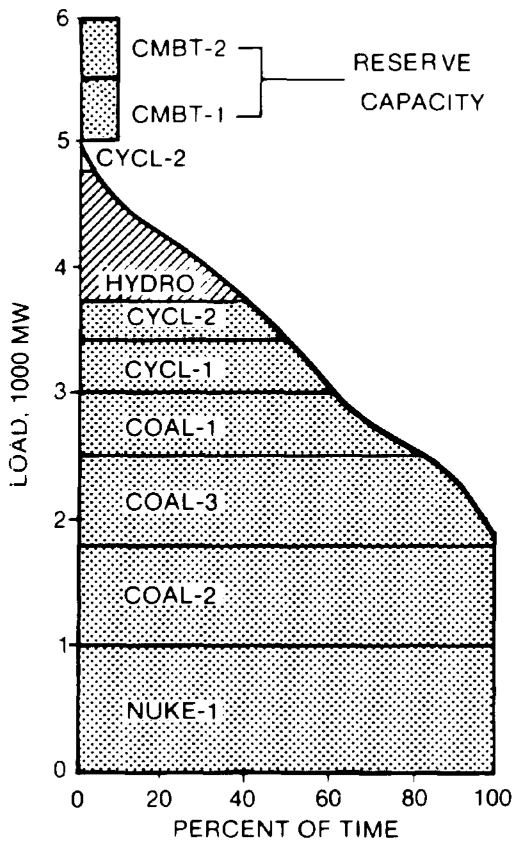


Figure 2-10. Duration curve showing operation of system with hydro plant in peaking mode

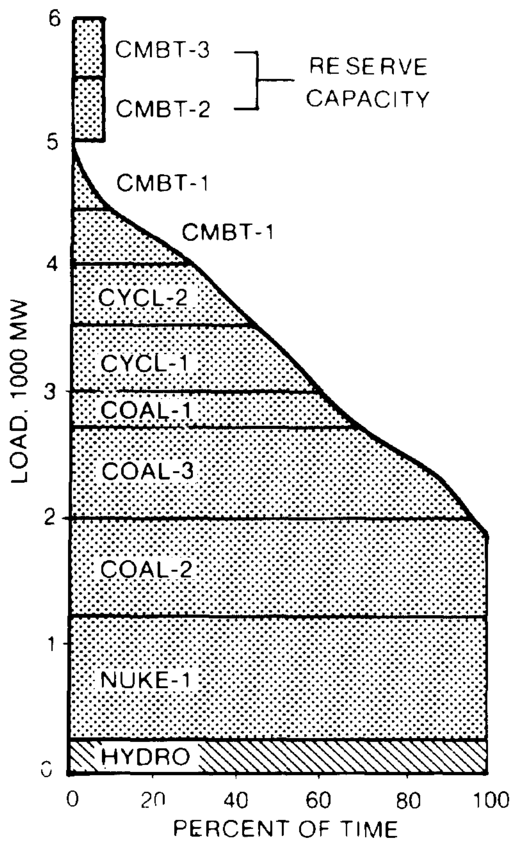


Figure 2-11. Duration curve showing operation of system with hydro plant as base load

(5) However. some potential hydro developments are constrained from peaking operation by operating limits designed to protect the environment and other project purposes (Section 6-5). Others are constrained from the daily and weekly shaping of power discharges to fit power demand by lack of storage or pondage. However, it is sometimes possible to do some load-following within those constraints. Figure 2-12 illustrates a case where a portion of the generation is operated base load in order to meet minimum flow requirements, and the remainder is used for peaking.

(6) The use of hydro is most limited where storage or pondage is not available. Where streamflow is dependable, the hydro plant may displace an increment of thermal capacity. Where it is not, the hydro energy may be usable only for displacement of the energy output of existing thermal plants (Figure 2-13). However, in some cases, the

TABLE 2-3
Cost of Operating System for One Week with Hydro Used for Peaking
(from Figure 2-10)

Plant Symbol	Capacity (MW)	Plant Factor (%)	Energy (1000 MWh)	Unit Cost (mills/kWh)	Cost ($1000)
CMBT-2	500	0	0	90	0
CMBT-1	500	0	0	80	0
HYDRO	1000	25	42	0	0
CYCL-2	500	15	13	30	390
CYCL-1	500	55	46	20	920
COAL-1	500	72	60	15	900
COAL-3	750	95	120	9	1080
COAL-2	750	100	126	8	1008
NUKE-1	1000	100	168	6	1008
TOTALS	6000	68 1/	575	10.5	5306

TABLE 2-4
Cost of Operating System for One Week with Hydro Used as Base Load
(from Figure 2-11)

Plant Symbol	Capacity (MW)	Plant Factor (%)	Energy (1000 MWh)	Unit Cost (mills/kWh)	Cost ($1000)
CMBT-3	500	0	0	100	0
CMBT-2	500	0	0	90	0
CMBT-1	500	1	1	80	80
CMCY-1	500	13	11	60	660
CYCL-2	500	33	28	30	840
CYCL-1	500	48	40	20	820
COAL-1	500	62	52	15	780
COAL-3	750	85	107	9	963
HYDRO	(250)	100	42	0	0
COAL-2	750	100	126	8	1008
NUKE-1	1000	100	168	6	1008
TOTALS	6000	68 1/	575	10.8	6159

1/ System load factor. based on 5000 MW peak load value of energy being displaced may be high. In California and New England, where a substantial portion of the generation is oil-fired steam, the benefits attributable to this type of operation may be substantial.

(7) The operation of pumped-storage hydro, which differs somewhat from conventional hydro, is discussed in Chapter 7.

2-3. Types of Hydropower Projects.

a. General. Hydropower projects can be classified by type of operation, which is in turn a function of the amount of storage available for the regulation of power output. The major types of

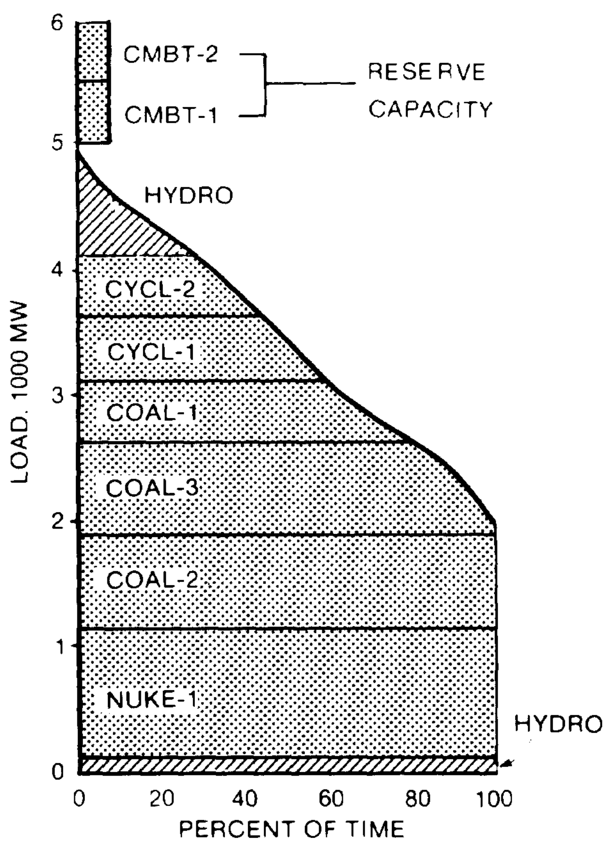


Figure 2-12. Duration curve showing operation of system with hydro plant carrying both base and peaking loads

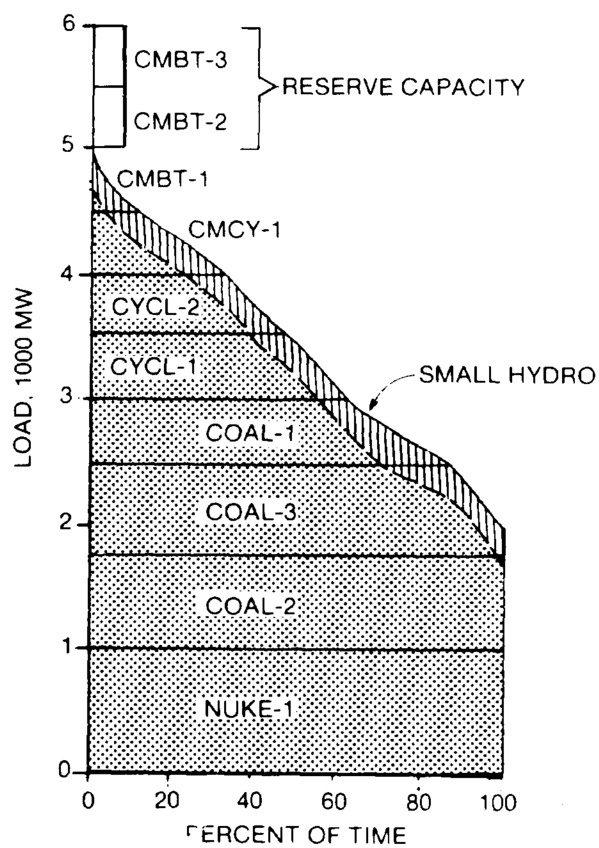


Figure 2-13. Duration curve showing operation of system with pure run-of-river hydropower plant

conventional hydro projects are run-of-river, pondage, storage, and reregulating. Pumped-storage projects can be categorized as off-stream or pump-back.

b. Run-of-River Projects.

(1) A pure run-of-river project (Figure 2-14) has no usable storage. Power output at any time is strictly a function of inflow. Typical run-of-river projects include navigation projects where the pool must be maintained at a constant elevation, irrigation diversion dams, and single-purpose hydro projects where the topography upstream from the dam site does not allow for pondage or seasonal storage. Powerplants on irrigation canals and water supply pipelines can also be classified as run-of-river projects.

(2) The term "run-of-river" also refers to an operating mode. A storage project can operate in the run-of-river mode if it is just passing inflow. Another example would be a powerplant installed at a project with storage regulated only for flood control and non-power conservation purposes such as water supply. No special regulation would be permitted for power. either on a daily/weekly or on a

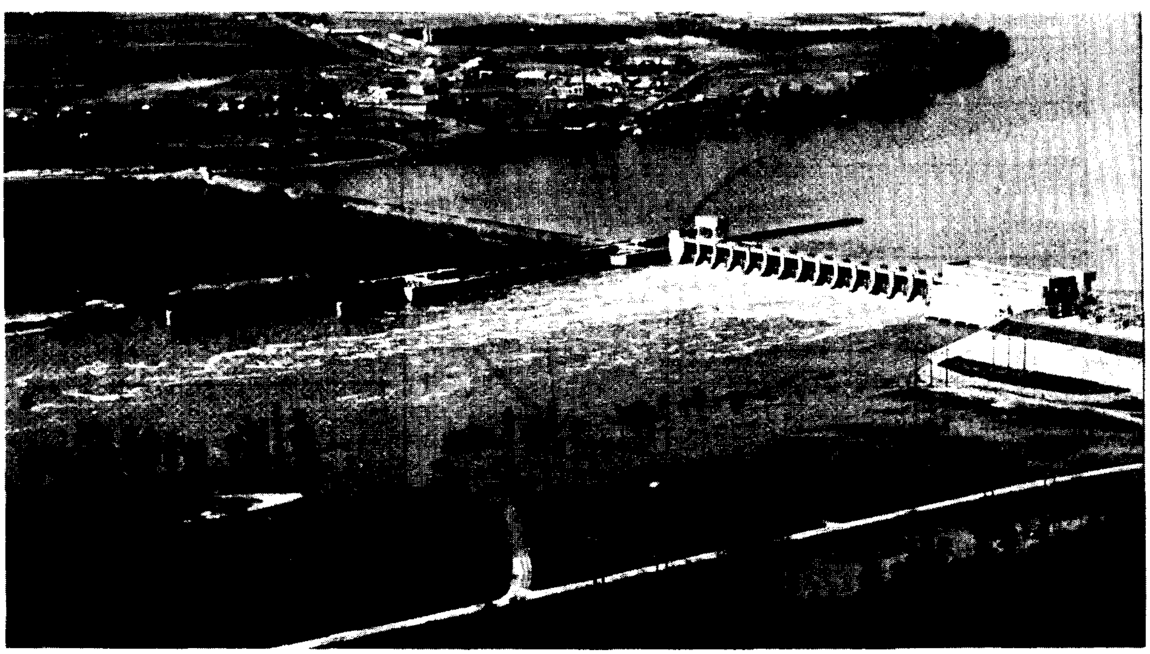


Figure 2-14. Jim Woodruff Dam and Reservoir, a pure run-of-river project (Mobile District)

seasonal basis. Discharges would be regulated for non-power purposes so that power production would use whatever flows happen to be available as a result of the non-power regulation. Run-of-river projects can be considered to be base load plants in terms of use in meeting loads.

c. Pondage Projects. Some projects have insufficient storage space for seasonal flow regulation. The storage can be used, however, to shape discharges to follow the daily and, in some cases, weekly load patterns. Daily/weekly storage is referred to as "pondage", and the use of pondage permits a project to serve intermediate and peaking loads. Some navigation projects are designed to permit fluctuations of several feet without adversely affecting navigation. Many of the small to medium-sized single-purpose power projects constructed in this country have pondage. These two types of projects are sometimes called run-of-river projects with pondage (Figure 2-15). Some flood control reservoirs with powerplants are designed with several feet of pondage. They are examples of projects with seasonal storage regulated strictly for non-power purposes, but with sufficient flexibility to permit fluctuation of daily releases for peaking

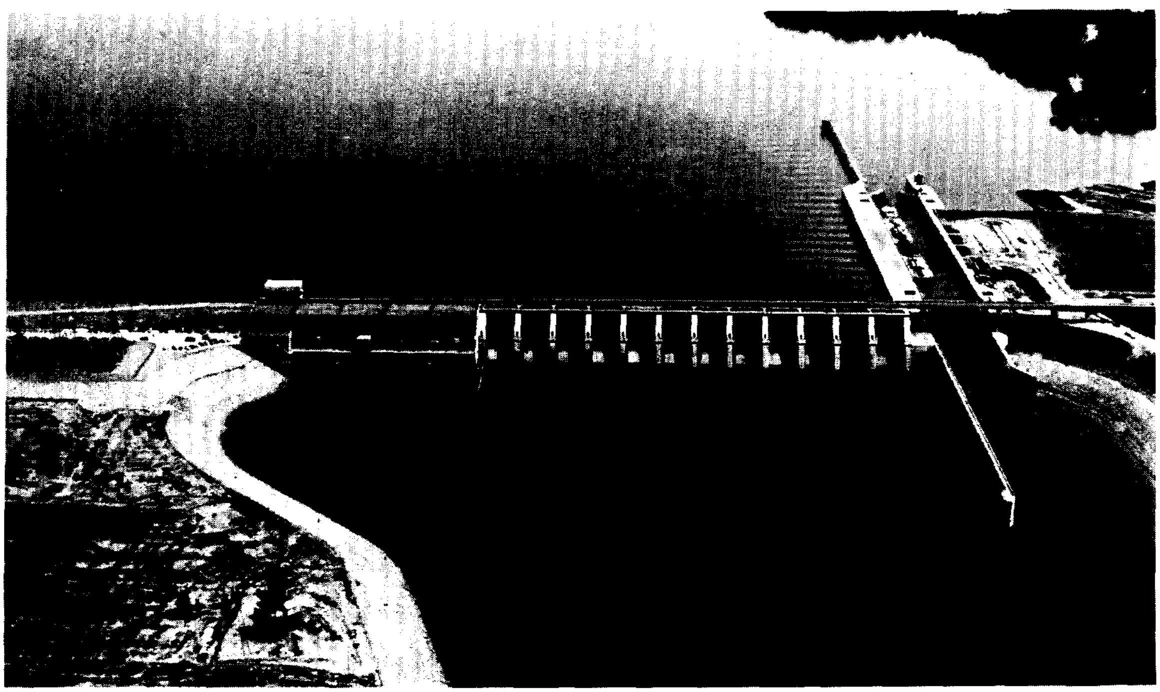


Figure 2-15. Barkley Lock and Dam, a run-of-river project with pondage (Nashville District)

operation. The amount of load following that can be accomplished at many pondage projects may be limited by the amount of pondage available or by operating constraints such as minimum discharge requirements.

d. Storage Projects. The term "storage" generally refers to projects which have seasonal regulation capability (Figure 2-16). A project with power storage can be used to regulate seasonal discharges in order to more closely follow the seasonal power demand pattern. Although there are some single-purpose power storage projects in this country, most storage projects are regulated for multiple purposes (see Section 5-12). While power storage can be used to benefit at-site power production, it is often used to improve production at downstream power projects (Section 5-14). Power storage projects inherently have pondage operation capability and thus can be used to serve intermediate and peaking loads as well as the base load if downstream conditions permit. Where operating restrictions prohibit large fluctuations in releases, a small reregulating reservoir can be constructed downstream of the main dam in order to maintain required discharge conditions.

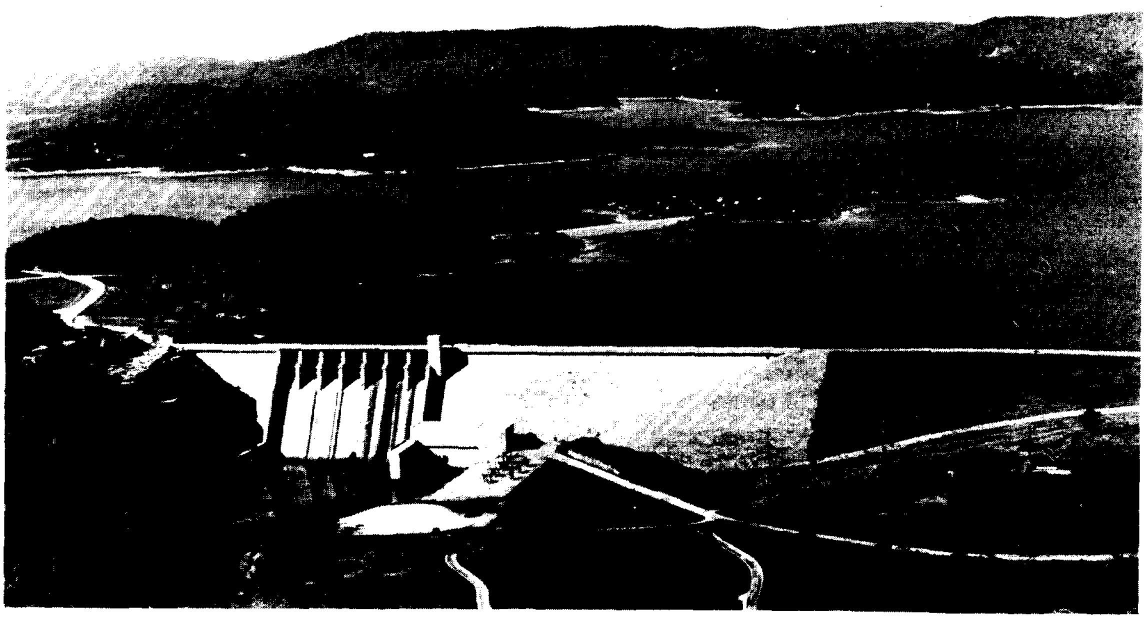


Figure 2-16. Beaver Lake Dam and Reservoir, a seasonal storage project (Little Rock District)

e. Pumped-Storage Projects.

(1) General. Pumped-storage projects are designed to convert low value off-peak energy to high value on-peak energy. Low cost energy is used to pump water to an upper reservoir at nights and on weekends, and the water is released during high demand hours to generate peaking power. There are two basic types of pumped-storage projects: off-stream and pump-back. Pump-back projects use two reservoirs in series to transfer energy, while an off-stream project uses an adjacent reservoir to store water. A brief description of each type follows, and Chapter 7 provides more detailed information on the planning and operation of pumped-storage projects.

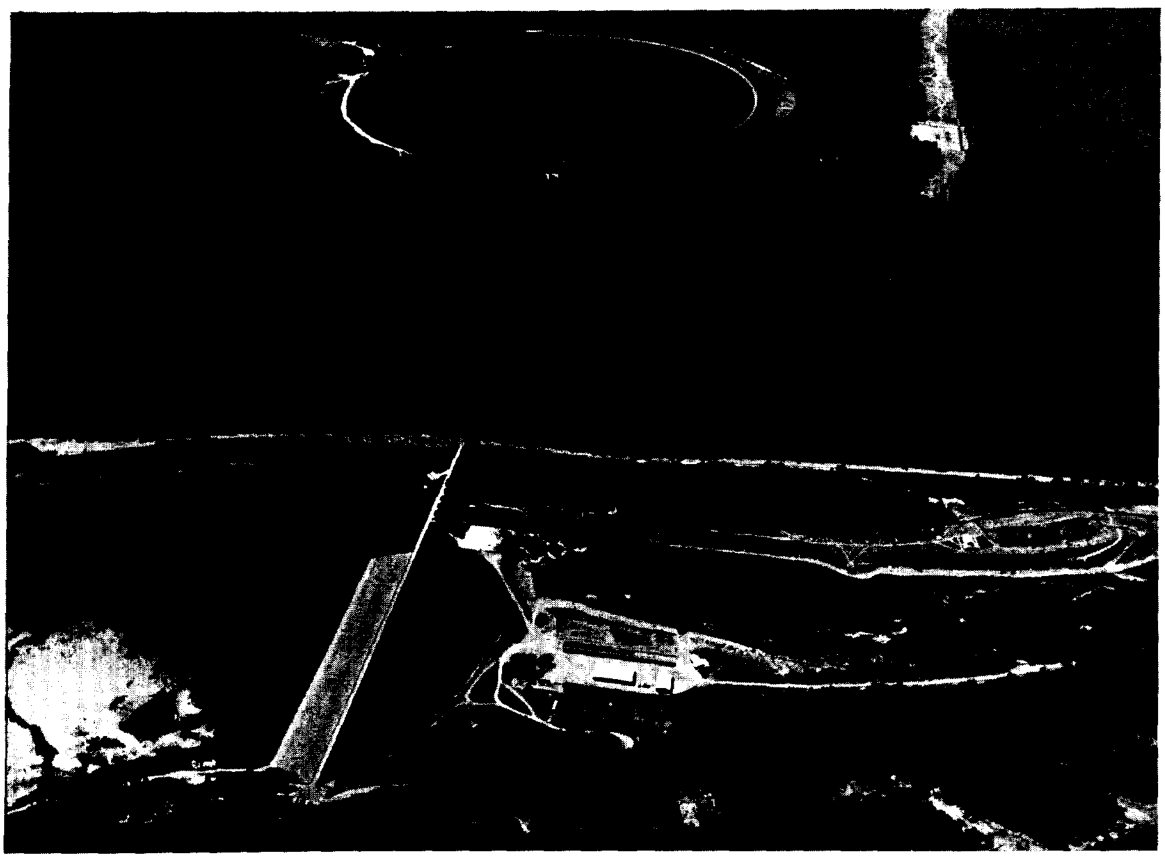


Figure 2-17. Seneca off-stream pumped-storage project, which uses the Allegheny Reservoir behind Kinzua Dam as its lower reservoir (Courtesy Pennsylvania Electric Company and Cleveland Electric Illuminating Company)

(2) Off-Stream. An off-stream pumped-storage project (Figure 2-17) consists of a lower reservoir on a stream or other water source and a reservoir located off-stream at a higher elevation. Water is pumped to the higher reservoir during periods of energy surplus and is released through the turbines during periods of energy demand. Off-stream pumped-storage projects are usually dependent exclusively on pumped water as their source of energy. They frequently utilize existing reservoirs as lower reservoirs, and because the resulting peaking operation does not have a major impact on the river downstream, installed capacities can often be very large.

(3) Pump-Back. A pump-back project, also known as on-stream or integral pumped-storage, consists of a conventional hydro project with a pumped-storage cycle superimposed on the normal power operation. As with off-stream pumped-storage, two reservoirs are involved, but both are located in tandem on the same stream (Figure 2-18). The main dam usually forms the upper reservoir, and the lower reservoir could be (a) another multiple-purpose project located immediately downstream or

Figure 2-18. Carters pump-back project (Mobile District)

(b) a special reservoir designed to serve as a combination pumped-storage afterbay and reregulating dam. The principal power installation would generally be located at the main dam, but the lower reservoir might have a powerplant also. The purpose of pump-back is to increase the firm peaking capability of the main dam. A given site may physically be ideal for a hydro project, but flows may be inadequate to support a large peaking installation. Recycling the limited amount of available water between the main reservoir and the lower reservoir would make it possible to install a larger plant. The project would operate as a conventional hydro plant part of the time, but when flows are low or when peak demands are high, the project would operate in the pumped-storage mode. Some water would normally be passed downstream, however, even during pumped-storage operation. All of the units at some pump-back projects are reversible. At others, only a portion of the generating units need to be reversible in order to firm up peaking capacity.

f. Reregulating Projects. Reregulating reservoirs (Figure 2-19) are designed to receive fluctuating discharges from large peaking plants and release them downstream in a pattern which meets downstream minimum flow and rate of change of discharge criteria. Reregulating

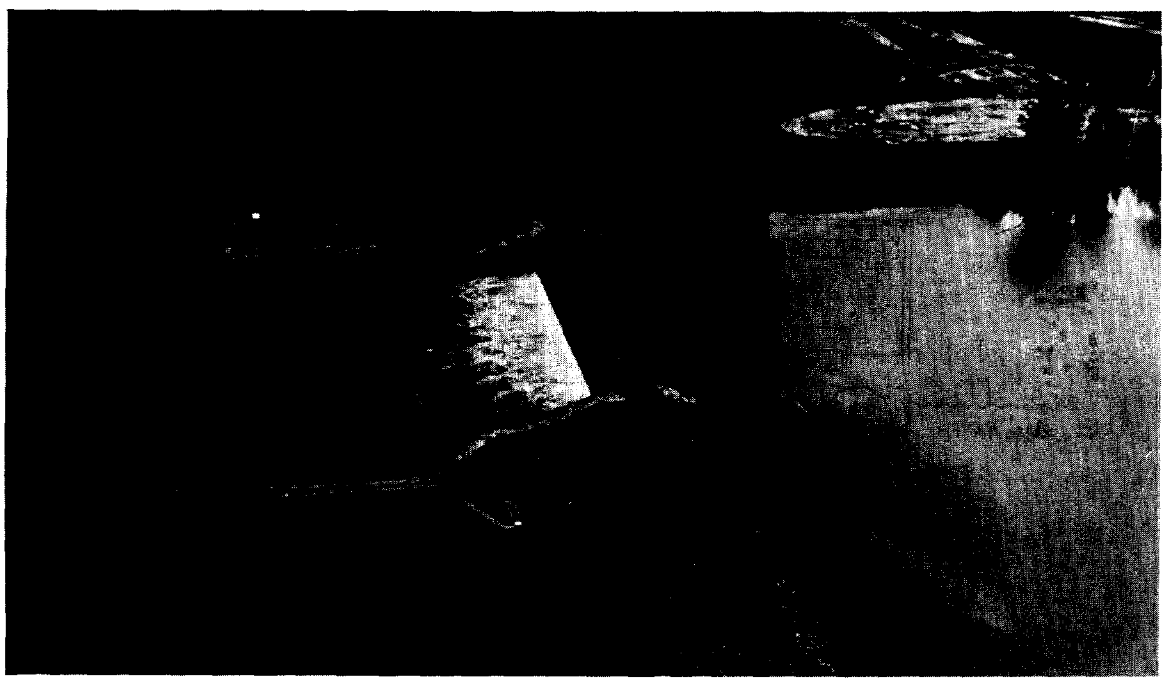


Figure 2-19. Reregulating dam for the DeGrey project (Vicksburg District)

projects (also sometimes known as afterbay reservoirs) may be constructed in conjunction with a conventional hydro peaking plant or a pump-back installation. A downstream project may serve as a reregulator for a series of hydro projects located on the same stream.

2-4. Components of Hydro Projects.

a. General. Three basic elements are necessary in order to generate power from water: a means of creating head, a conduit to convey water. and a powerplant. To provide these functions, the following components are used: dam. reservoir, intake, conduit or penstock, surge tank, powerhouse, draft tube, and tailrace (see Figure 2-20).

b. Dam. The dam performs two major functions. It creates the head necessary to move the turbines, and impounds the storage used to maintain the daily or seasonal flow release pattern. The height of

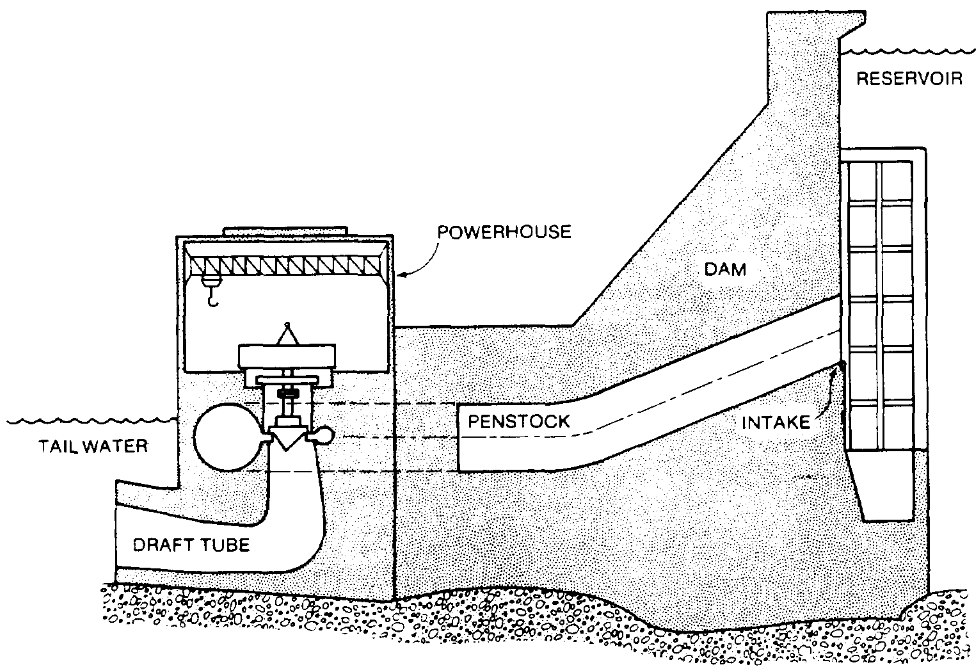


Figure 2-20. Components of a hydropower project

the dam establishes the generating head and the amount of water storage available for power plant operation. Power projects can utilize either existing or new dam structures. Fitting powerplants to existing dams is a task that must be undertaken carefully in order to prevent degradation of the dam's structural integrity. The publication, Feasibility Studies for Small Scale Hydropower Additions, (39) provides information on engineering and evaluation of some of the problems unique to powerplant retrofitting.

c. Reservoir. A reservoir consists of the water impoundment behind a dam. Storage capacity is the volume of a reservoir available to store water. This storage is divided into active and inactive storage. Active storage is that portion of the storage capacity in which water will normally be stored or withdrawn for beneficial uses. Inactive storage is that portion of the storage capacity from which water is not normally withdrawn, in accordance with operating agreements or restrictions. Inactive storage includes dead storage, which is storage that lies below the invert of the lowest outlet and thus cannot be evacuated by gravity. A pure run-of-river project would have no storage. Storage used for daily or weekly flow regulation is called pondage and storage used for seasonal regulation is called seasonal storage. Seasonal storage often serves other functions in addition to hydropower. The reservoir water surface at the power intake may be called the forebay, headrace, headwater, or simply the pool elevation.

d. Intake. Intake structures direct water from the reservoir into the penstock or power conduit (see Figure 2-21). Gates or valves are used to shut off the flow of water to permit emergency unit shutdown or turbine and penstock maintenance. Racks or screens prevent trash and debris from entering the turbine units. Where the powerhouse is integral with the dam, the intake is part of the dam structure. Where the powerhouse is not part of the dam, a separate intake structure must be provided. Projects that are required to use water at a selected temperature must have multi-level intakes in order to control inlet water quality by mixing waters obtained from different levels.

e. Penstock. The penstock conveys water from the intake structure to the powerhouse and can take many configurations, depending upon the project layout (see Figure 2-22). Where the powerhouse is an integral part of the dam, the penstock is simply a passage through the upstream portion of the dam. A canal, pipe, or tunnel is required where the powerhouse is separated from the intake. A penstock may be several miles long at diversion-type projects. Water may be conveyed most of the distance at an elevation close to the forebay elevation via an open canal or a low pressure pipe or tunnel. The remainder of the penstock, where most of the drop in elevation occurs, would be a pressurized tunnel or pipe. Because the cost of a pressurized tunnel or pipe is much greater than that of a low pressure tunnel or pipe, it is usually desirable to minimize the length of the high pressure penstock. When the powerhouse is located adjacent to the dam but is not an integral part of the structure, water would be conveyed through or around the dam via a pressure tunnel. For multi-unit installations, it is often desirable to serve several units with a single penstock, and manifolds or bifurcation structures are provided to direct flow to individual units. Guidance on penstock design can be found in EM 1110-2-3001.

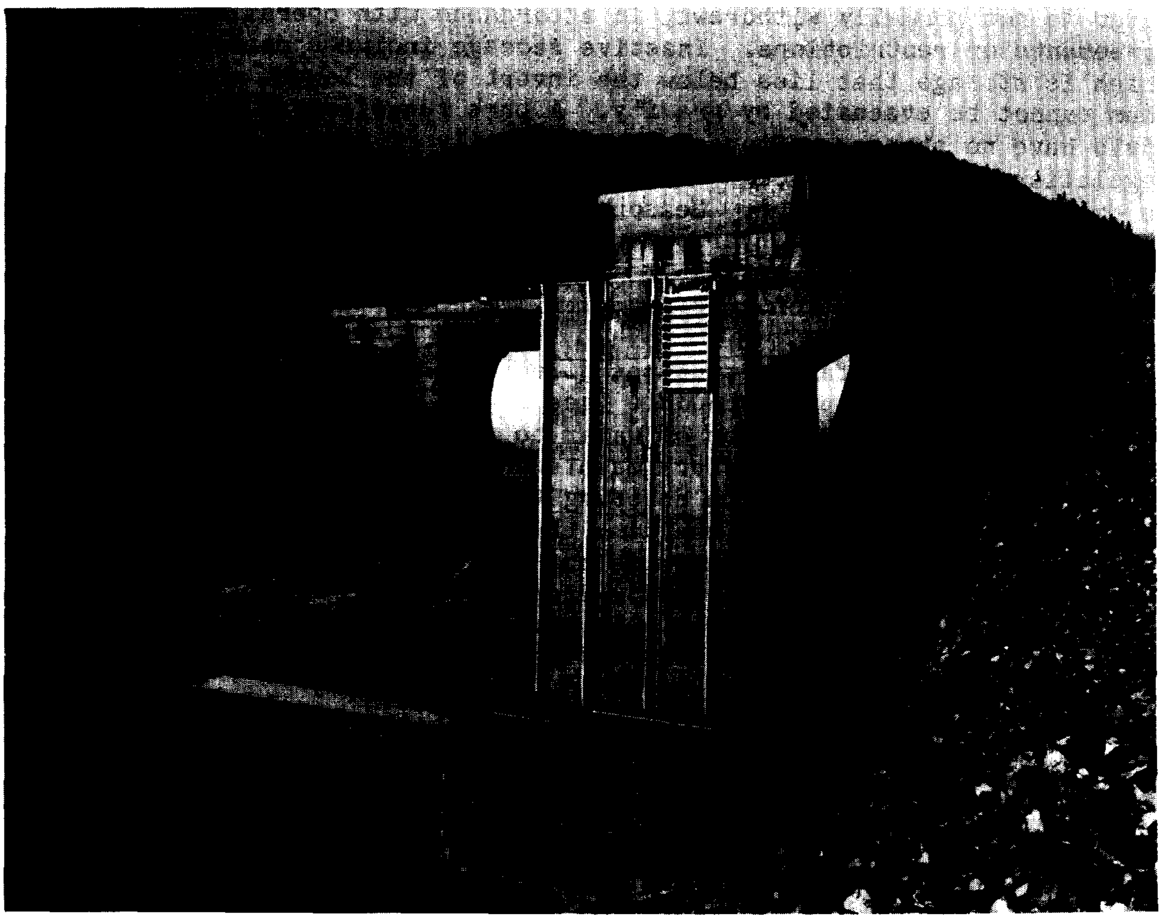


Figure 2-21. Intake tower, Hills Creek Dam. Power intake is on the left, regulating outlet intake is on the right. Trashracks are not yet in place (Portland District)

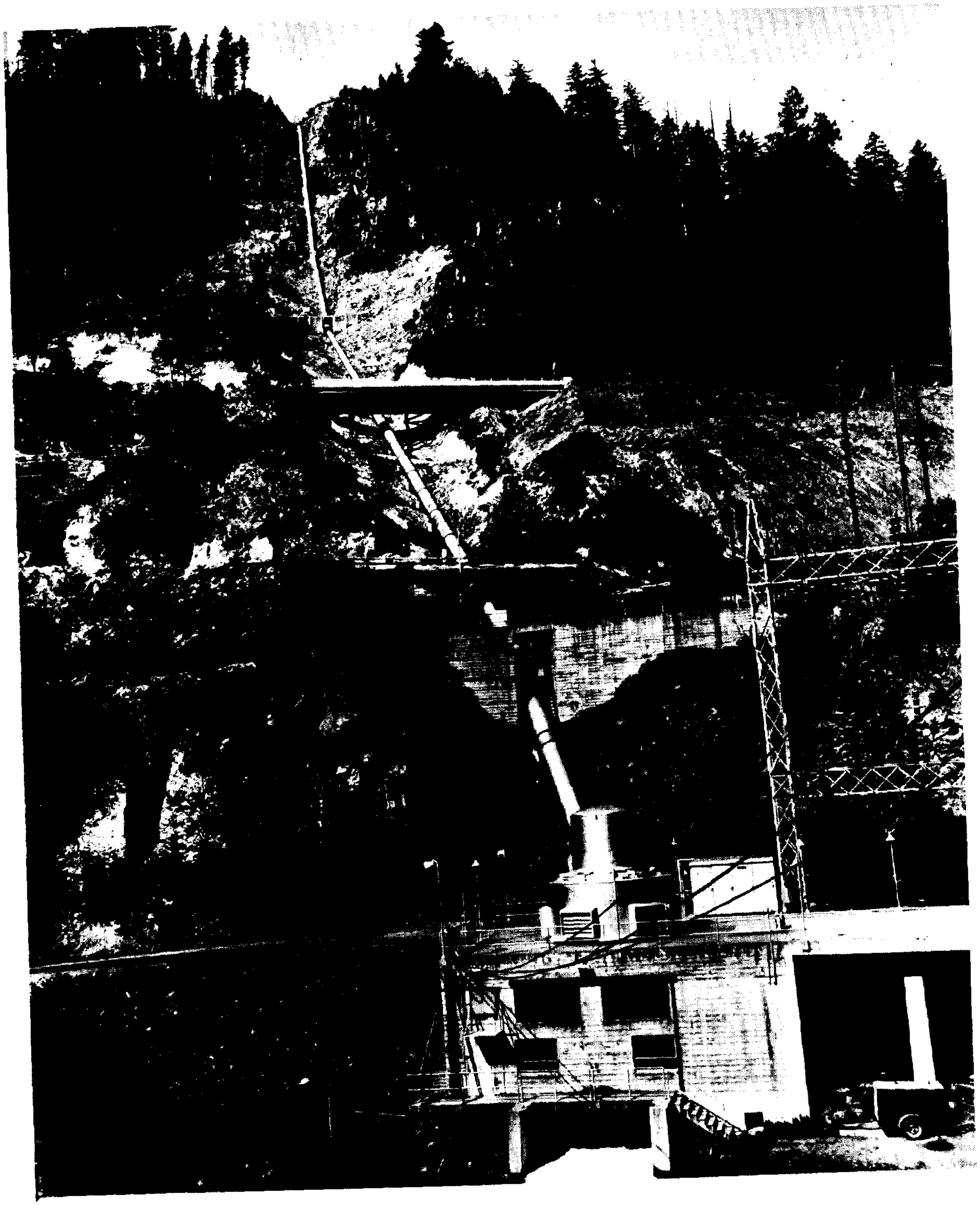


Figure 2-22. Penstock and outdoor powerhouse, Fish Creek Project (Courtesy of Pacific Power and Light Company)

f. Surge Tanks.

(1) Flow through a penstock can change rapidly during the operation of a power project. As long as flow is steady and constant, pressure changes on the conveyance conduit are minimal. However, pressure changes within the conduit become greater as the rate of change of flow increases. This phenomenon is known as water hammer and is caused by a change of momentum within the water column. When the changes in flow are gradual, water hammer problems are usually minor. However, when there are rapid changes in flow, water hammer effects can become serious. Surge tanks are sometimes constructed on the conduit to reduce momentum changes due to water hammer effects (see Figure 2-23).

(2) Water hammer effects start at the wicket gates, in response to a sudden change in loading on the generating unit, and travel up the penstock to the reservoir and then back to the turbine. Therefore, the penstocks must be designed for water hammer pressure waves. The conduit located above the surge tank also must be reinforced for water hammer effects, as well as surge from mass oscillation (rises in

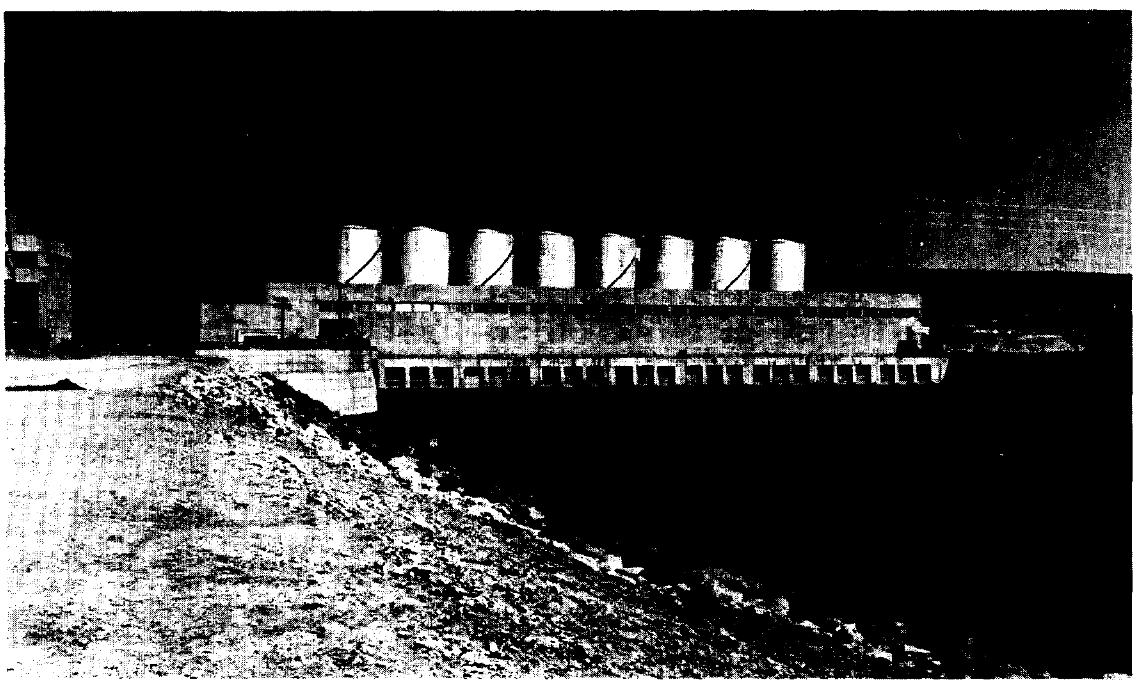


Figure 2-23. Surge tanks and indoor powerhouse, Fort Randall Dam (Omaha District)

surge tank water level). Surge tanks are often necessary in medium and high head hydropower projects, particularly where there is a considerable distance between the water source and power unit. Alternative measures, such as synchronous bypass valves, may be used for smaller installations. Surge tanks or chambers can also be provided on the draft tube where discharge conduits are very long. Additional guidance on this topic can be found in EM 1110-2-3001.

(3) A comprehensive computer program named WHAMO computes the effect of water hammer and mass oscillation at Corps of Engineers projects. Final design of powerplants should be verified by a Hydroelectric Design Center, using this program.

g. Powerhouse.

(1) General. The powerhouse shelters the turbines, generating units, control and auxiliary equipment, and sometimes erection and service areas. The powerhouse location and size is determined by site conditions and project layout. It could be located within the dam structure, adjacent to it, or some distance away from the dam. The powerhouse would be located to economically maximize available head while observing site physical and environmental constraints.

(2) Powerhouse Type. There are four types of powerhouse structures, three of which are classified according to how the main generating units are housed.

- Indoor. This type of structure encloses all of the powerhouse components under one roof (Figure 2-23).

- Semi-outdoor. This powerhouse has a fully enclosed generator room. The main hoisting and transfer equipment is located on the roof of the plant and equipment is handled through hatches located in the roof (see Figure 2-24).

- Outdoor. A generator room is not provided with this type of powerhouse structure. Generators are inclosed in weatherproof individual cubicles or enclosures and are recessed into the powerhouse floor (see Figure 2-22).

- Underground. This type of powerhouse is often used in mountainous areas where there is limited space available to locate a powerplant (Figure 2-25). It is also used to minimize penstock length in these areas because it can often be located directly below the reservoir. Pumped-storage powerhouses are often located underground in order to shorten the penstock and obtain deep settings on the turbines.

The selection of powerhouse structure should be based upon both fixed and operation and maintenance (O&M) costs. The lower capital cost associated with outdoor and semi-outdoor plants is often offset by increased equipment and O&M costs. The final selection of powerhouse type for any given site would be made after a detailed cost study, usually performed in the design memorandum stage.

(3) Erection Bay. The erection bay is an area provided for the assembly and disassembly of major generating components. It is often located at one end of the generator room, and generally at the same floor elevation. Erection areas at smaller powerplants are often built outside the powerhouse. The length of an erection bay is approximately equal to at least one generator bay. Its exact area is determined by providing space for all individual powerplant parts which may be removed during an overhaul period. Vertical clearance

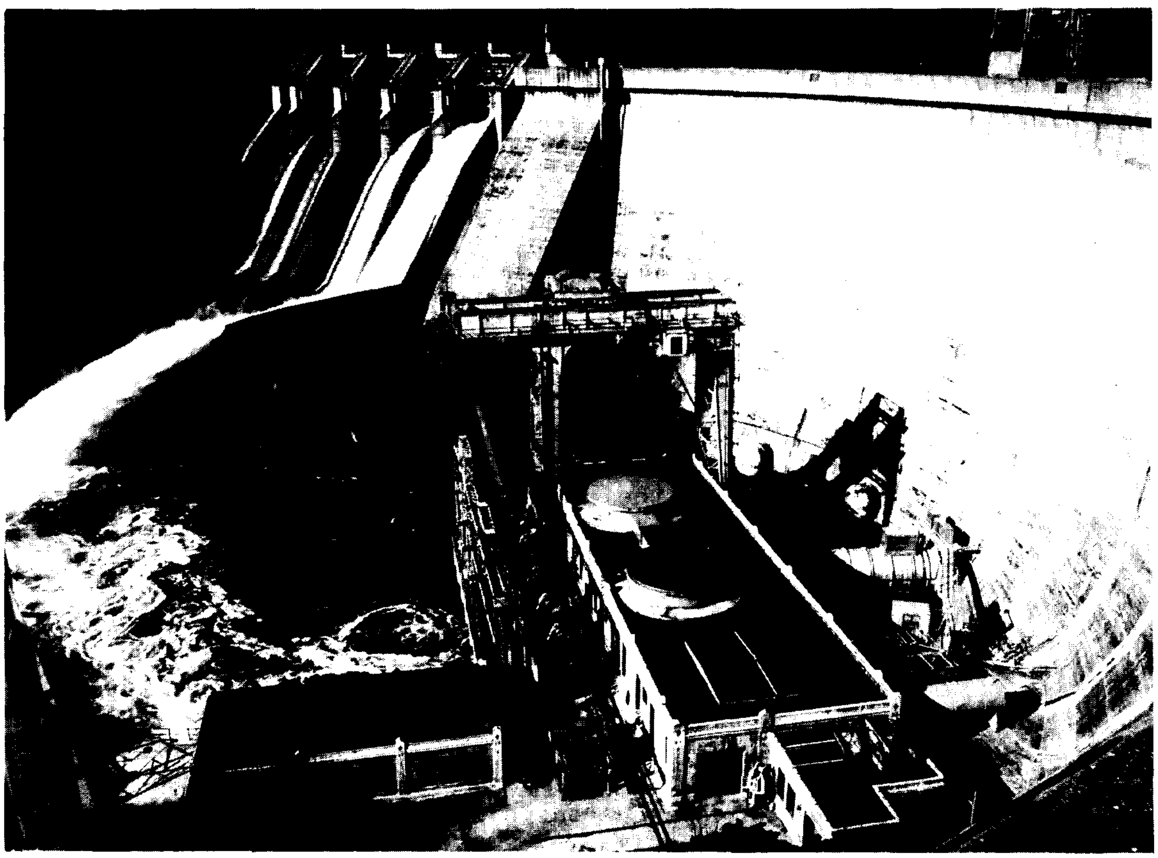


Figure 2-24. Semi-outdoor powerhouse and overhead crane, Merwin Dam (Courtesy of Pacific Power and Light Company)

should be sufficient to disassemble the turbines and generators. Erection bays at large power projects are usually constructed within the powerhouse.

(4) Service Areas. Service areas include offices, control and testing rooms, storage rooms, maintenance shops, auxiliary equipment rooms, and other areas for special uses. The amount of space required is a function of the size and location of the project, but space for service requirements is normally small at small hydropower installations. A separate service building can frequently be constructed at a cost savings due to flexibility in site location. However, space will still be required in the main powerhouse structure for the service equipment required by the generating unit.

Figure 2-25. Underground powerhouse, Snettisham Project (Alaska District)

h. Draft Tube and Tailrace. The powerhouse discharges water into the tailrace or tailwater. The draft tube conveys the water from the discharge side of the turbine to the tailrace. It is normally a part of the powerhouse structure, and is designed to minimize exit losses. The tailrace could be an open stream, the reservoir of a downstream project, a canal, or, in the case of an underground powerhouse, a tunnel. The primary function of the tailrace is to maintain a minimum tailwater elevation below the power plant and to keep the turbine's draft tube submerged. It is important to keep the draft tube submerged, even when there is no flow in the downstream channel or tailrace, in order to improve turbine startup performance. This can be done by excavating the channel immediately downstream of the powerplant so that an adequate water depth will be maintained, or by including a control structure to maintain tailwater at a constant elevation. Impulse or pelton turbines rotate in the open air, rather than underwater, so tailwater would not be maintained on the turbine discharge. At projects having a wide range of tailwater elevation, tailwater may at times encroach on the turbine runner. When this occurs, air under pressure is maintained in the turbine enclosure in order to keep the water level down.

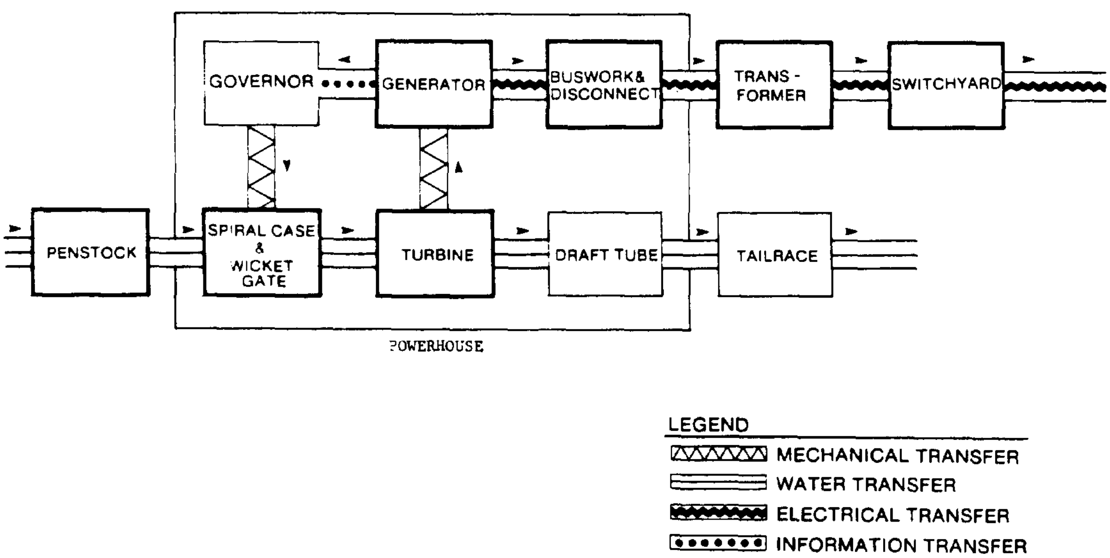


Figure 2-26. Powerhouse systems network

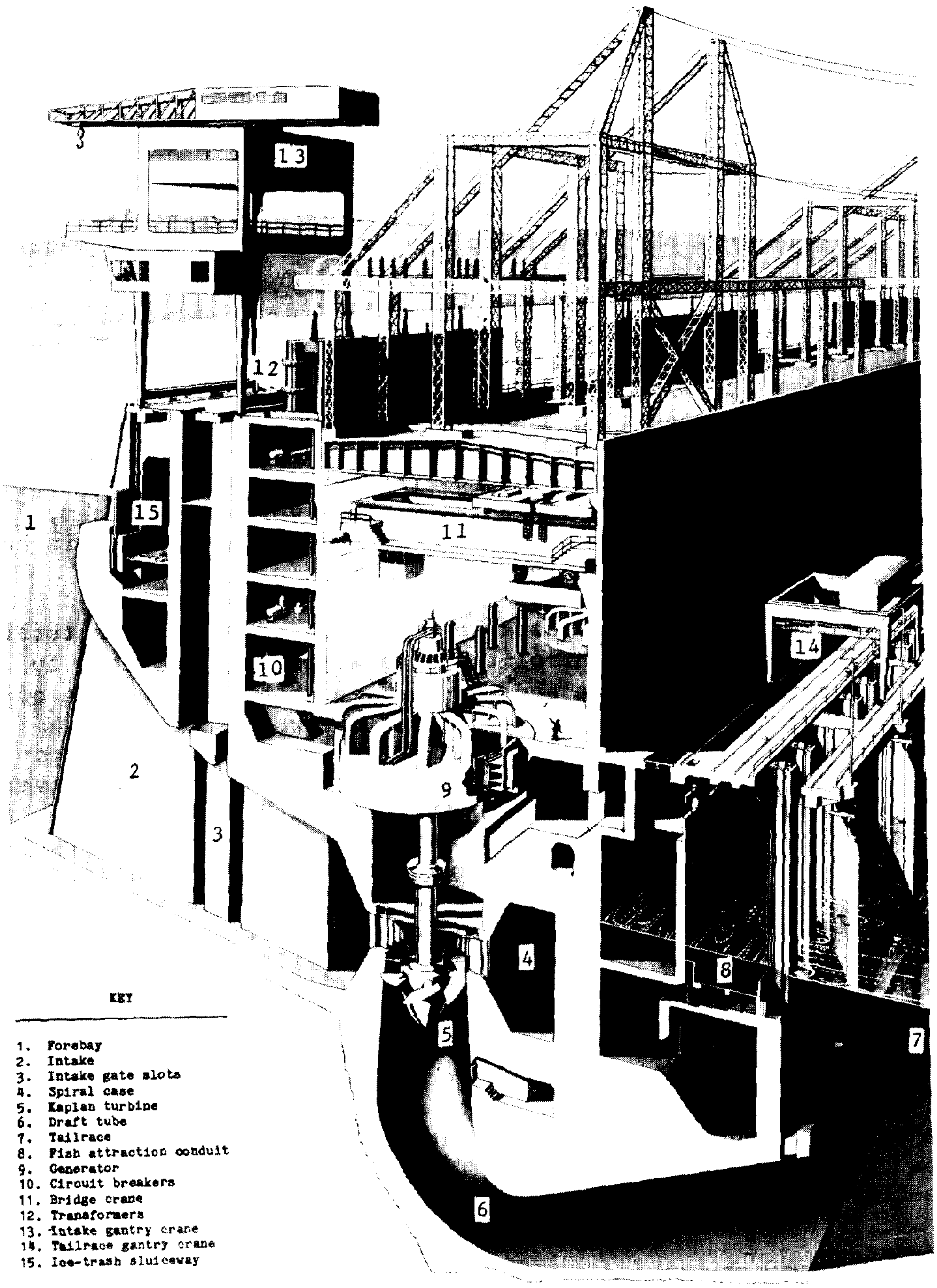


Figure 2-27. Cross-section of The Dalles powerhouse (Portland District)

2-5. Components of a Powerhouse.

a. General. Figure 2-26 shows the two major powerhouse systems and how they interrelate. The water-related (hydraulic) system is indicated by the lower level of boxes, and the electrical system is represented by the upper series of boxes. These two major systems are interconnected by mechanical transfers at the governor and generator. The primary flow of energy is represented by those boxes with a heavy outline. Figure 2-27 shows an example of a powerhouse cross section.

b. Spiral Case and Wicket Gates.

(1) The spiral case and wicket gates (Figure 2-28) are used in reaction turbines to direct and control the water entering the turbine runner. The spiral case is a steel-lined conduit connected to the penstock or intake conduit, and it distributes flow uniformly into the turbine. "Semi-spiral" cases, made of reinforced formed concrete, are used in powerhouses that pass relatively large volumes of water, usually at heads of 100 feet or less. The spiral case design is based upon the type and size of turbine used.

(2) Wicket gates are adjustable vanes that surround the turbine runner entrances and they control the area available for water to enter the turbine. This area and the head establish the volume of water that produces energy. The amount of water passing into the turbine at a specific wicket gate opening will vary depending upon the head on the unit. Wicket gate settings are controlled by the governor (or gate positioner, if frequency control is not required). When the wicket gates are fully open, the turbine is said to be operating at "full gate". Wicket gates in the form of pie-shaped radial segments control the flow tubular type axial-flow turbines (such as bulb, pit, and rim units) and units with "S" type draft tubes.

c. Turbine. The turbine converts the potential energy of water into mechanical energy, which in turn drives the generator. Water under pressure enters the turbine through the wicket gates and is discharged through the draft tube after its energy is extracted. The amount of power the turbine is able to produce depends upon the head on the turbine, the rate of flow of water passing through the unit, and the efficiency of the turbine. Types of turbines and their uses are described in Section 2-6.

d. Generator.

(1) General. The generator converts the mechanical power produced by the turbine into electrical power. The two major components of the generator are the rotor and stator. The rotor is the rotating assembly, which is attached by a connecting shaft to the

turbine, and the stator is the fixed portion of the generator (Figure 2-29). The generator is coupled as closely as possible to the turbine in order to minimize costs and mechanical problems. The two major types of generators are briefly described below.

Figure 2-28. Spiral case and wicket gates, Norris Dam. This is an older plant (1936) featuring riveted rather than welded construction, but the photo dramatically illustrates the shape of the water passageway (Courtesy of Tennessee Valley Authority)

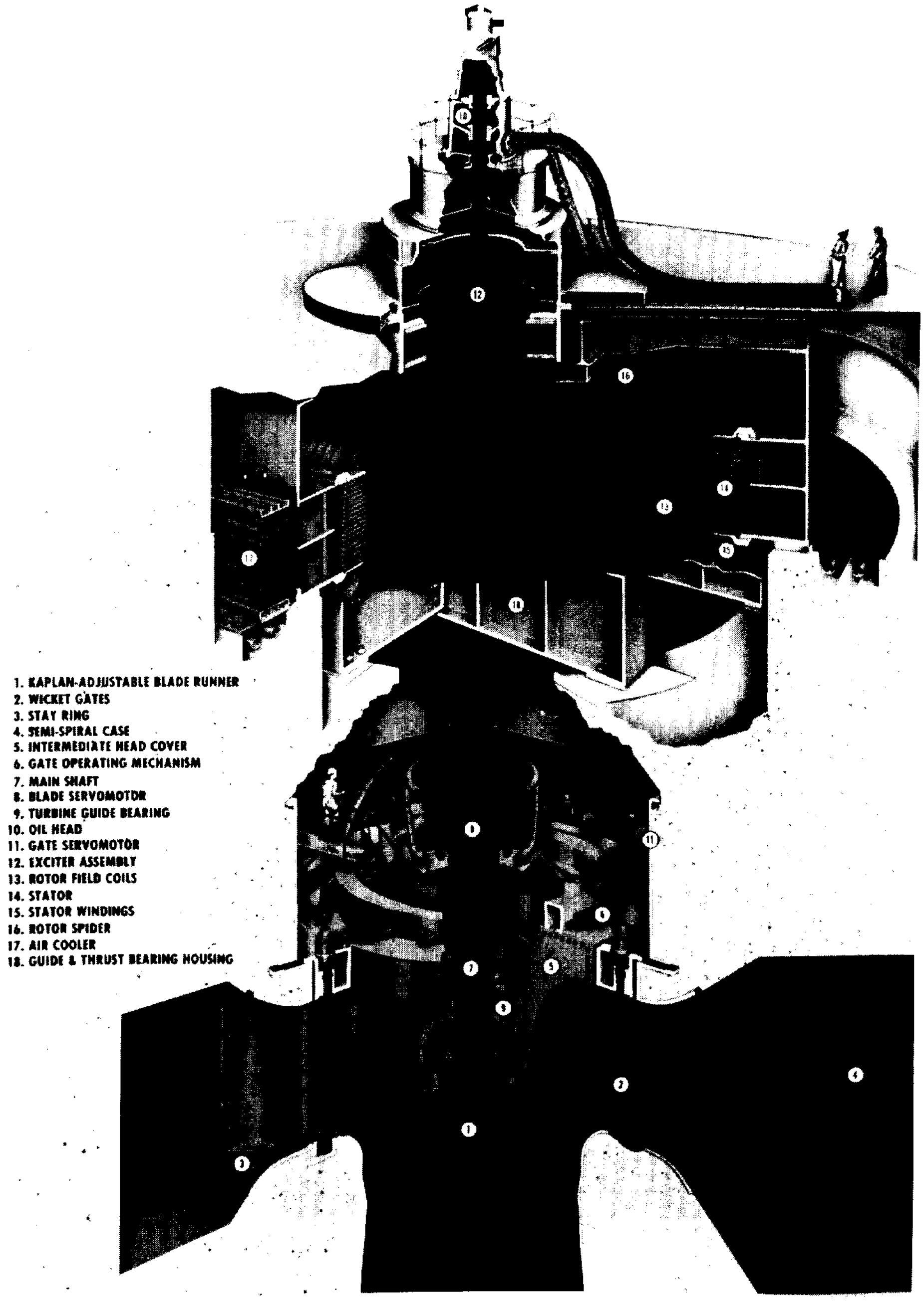


Figure 2-29. Turbine generator (Courtesy of Allis-Chalmers Corporation, Milwaukee, Wisconsin, U.S.A.)

(2) Synchronous Generators. A synchronous generator is synchronized to the power system voltage, frequency, and phase angle before the generator is tied into the power grid. The generator excitation is direct current (DC). Sychronous generator excitation is controlled to provide lead and lag reactive power required by the power system for power factor correction. Synchronous generators are used in power systems where the generator output provides a significant portion of the power system load. Most generators larger than 2 MW are synchronous because they are capable of correcting the power factor of the system caused by inductive loads (motors).

(3) Induction Generators. The induction generator also consists of two parts, a rotor and a stator. The major difference between the induction and synchronous generators is that the induction generator cannot generate while disconnected from the power system, because it is incapable of providing its own excitation current. Induction generators and their associated electrical equipment are less expensive than synchronous generators but are generally limited to capacities of less than 5 MW. Induction generators cannot correct power factor.

(4) Cooling. The generator is usually cooled by passing air through the stator and rotor coils. This cooling can be assisted by passing the air through water-cooled heat exchangers. For both indoor and outdoor plants, the generator and associated cooling equipment are enclosed in a housing. Direct water cooled windings have also been successfully used on very large units. Some small units do not have an air housing, and they use powerhouse air for cooling.

e. Governor.

(1) Hydraulic turbine governors (Figure 2-31) are designed to regulate the speed and output of turbine-generator units by controlling the wicket gates to adjust water flow through the turbine. A Kaplan turbine governor also controls the turbine blade angle to maximize turbine efficiency. Governors for large units (or small units which produce a significant portion of their system's energy output) have both power and speed responsive elements. The governors sense changes in load (or speed) and respond with a movement of the wicket gates in order to maintain synchronous speed.

(2) If the turbine-generator is small compared to the size of the power system, gate and blade positioners can be used for control of the wicket gates and turbine blades.

(3) Figure 2-30 illustrates the basic governor operating sequence. If system load increases, the generator is no longer able to meet load with existing turbine inflow and the unit begins to slow

down. The governor speed sensor (3) receives a message from the speed signal generator (2), which is mounted on the generator shaft, and determines that turbine inflow must be increased so that the generator will be restored to the rotating speed required to maintain the desired system frequency. The speed sensor sends a signal to the pilot servo (4), which activates the main governor valve (5). This valve sends oil under pressure to the turbine servo motor (6), which

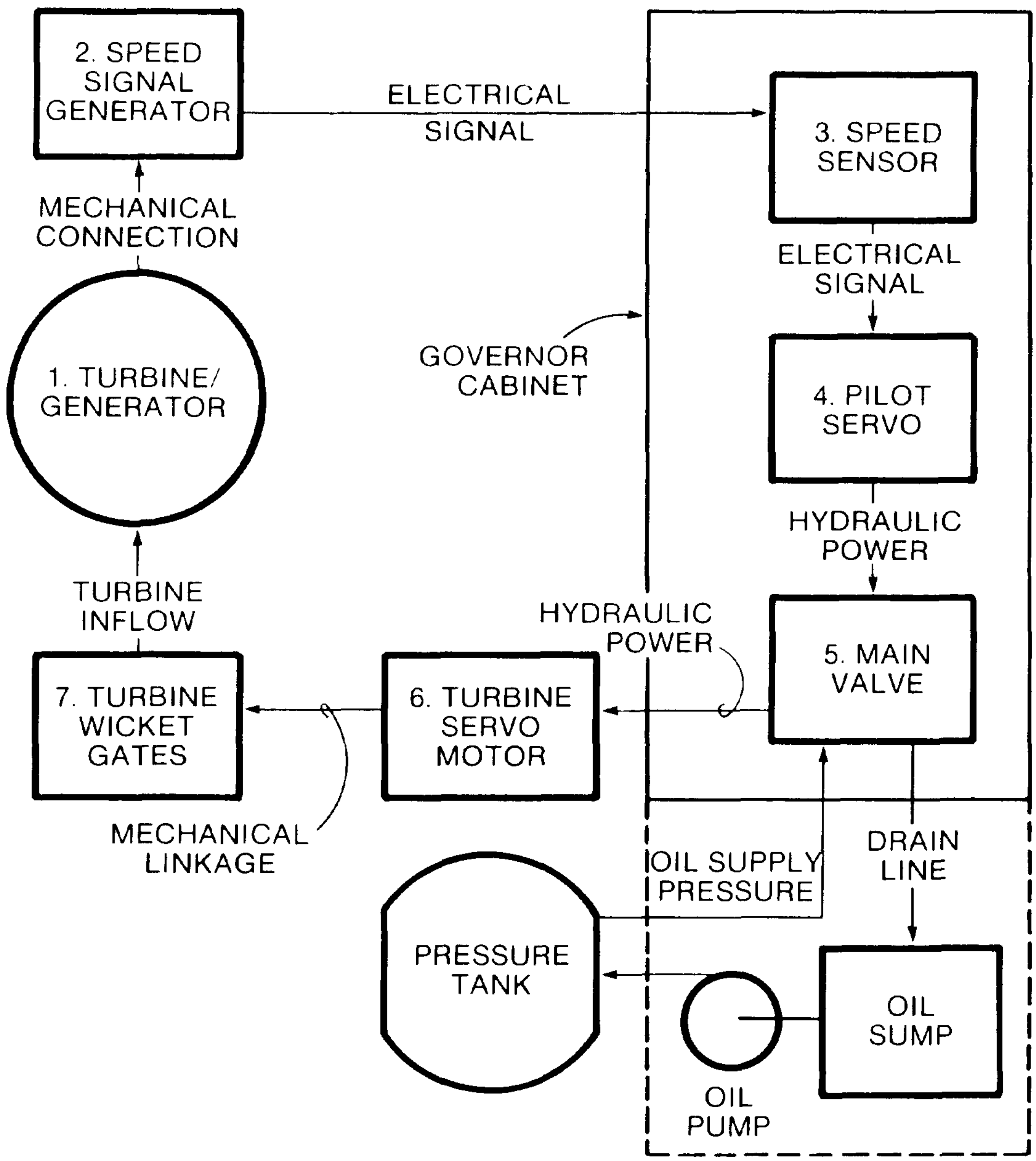


Figure 2-30. Simplified schematic diagram of governor system

operates a linkage opening the turbine wicket gates (7). With the gates open wider, more water passes into the turbine, thus generating the increased load while restoring the turbine/generator rotating speed to the level required to maintain system frequency. When the load decreases, the process serves to close the wicket gates, thus reducing turbine inflow.

(4) Most generators are synchronous and are connected to a relatively large power grid. While the turbine governors are sensitive to very small speed or load changes in the system, it is important that they be adjusted so that each governor does not attempt to correct the total system error by itself. Because of this adjustment, referred to as droop, the governor action alone does not

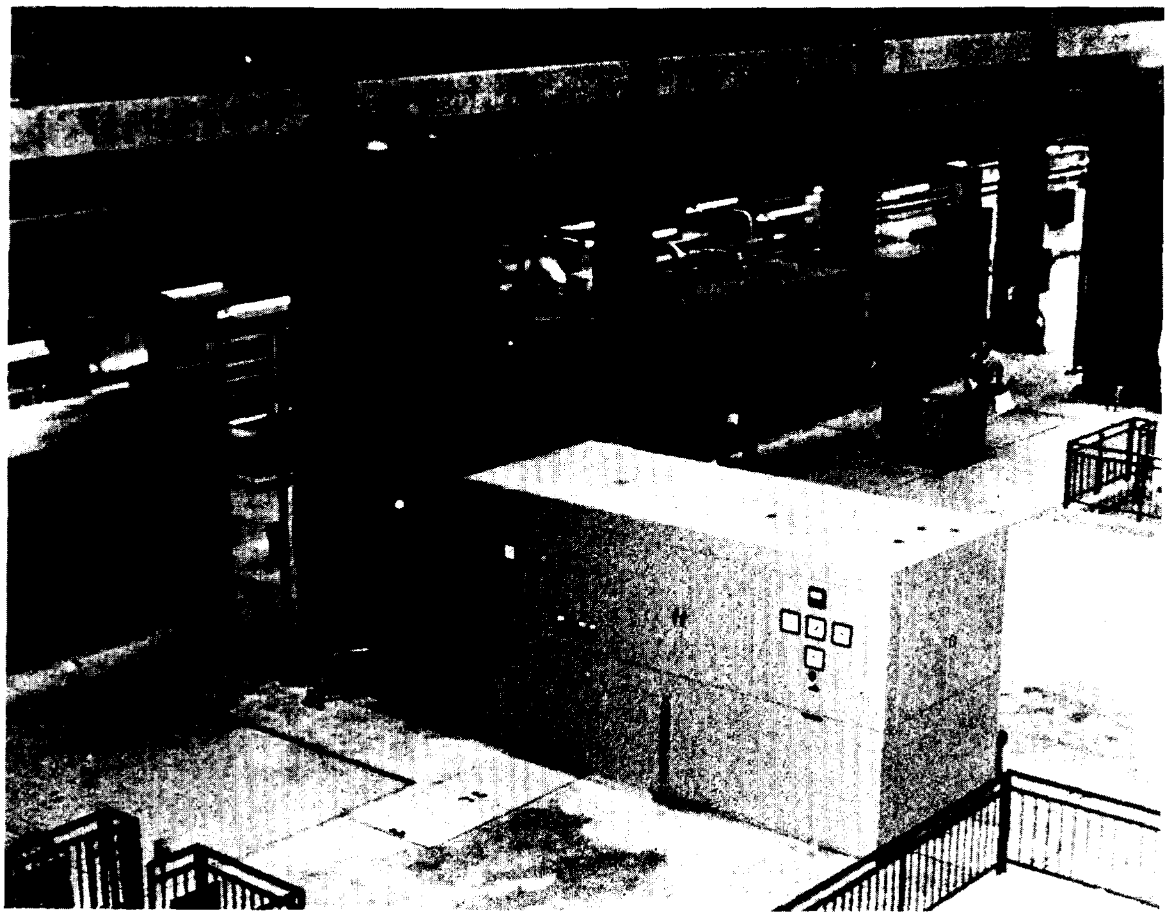


Figure 2-31. Turbine governor (Courtesy of Woodward Governor Company, Rockford, Illinois, U.S.A.)

return the system frequency exactly to the desired level. Automatic generation control (AGC) equipment is also used to readjust the speed set point at one or more of the system's large units or plants so that part of the effort needed to return the frequency to normal is supplied by some of the governors on droop. In an isolated system, droop is set at zero, and the governors alone maintain correct system frequency.

Figure 2-32. Generator buswork and circuit breakers (Bonneville second powerhouse, Portland District)

(5) In many cases, however, the amount of control that a governor has over the unit's power loading is limited. Most generators are synchronous and are connected to a relatively large power grid, and these large systems have frequency excursions which are usually too small for the governor's speed sensing elements (particularly the mechanical type) to detect. In this case, automatic generation control equipment monitors system frequency and controls generation to meet the load.

(6) A simpler governing device, such as a load or speed controller, can be used for small generation units on large, stable systems. These devices rely on the system for unit stability.

f. Buswork, Circuit Breakers, and Disconnects. Buswork, circuit breakers, and disconnects link the generator to the power grid. Buswork consists of the electrical conduits that transfer power output

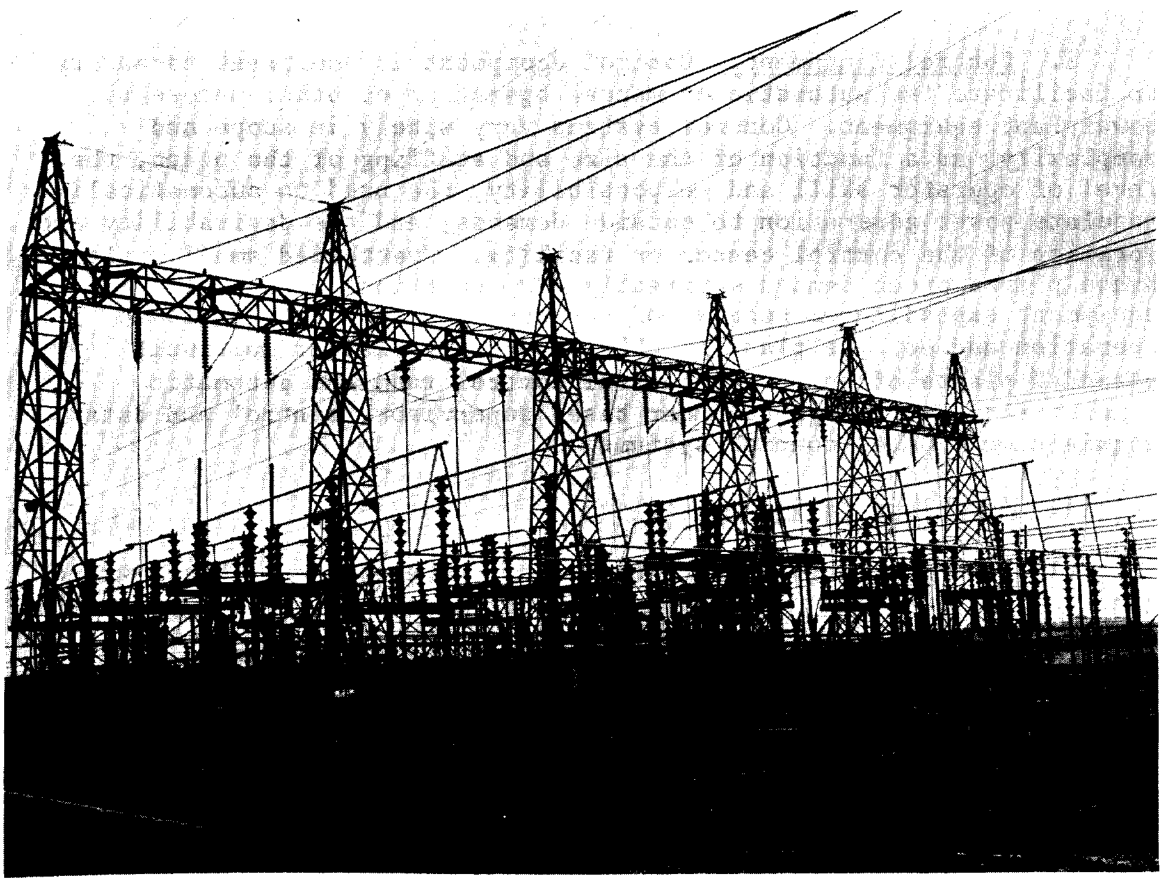


Figure 2-33. Switchyard, Fort Gibson Dam (Tulsa District)

from the generator to the step-up transformers (Figure 2-32). Disconnects or circuit breakers are switches that connect and disconnect the generator to the power grid. Circuit breakers interrupt the circuit when it is under load, and disconnects isolate equipment once the load has been interrupted.

g. Transformers. Transformers (Figure 2-34) are electrical devices that increase generator output voltage to match the voltage level of the transmission line. In most cases they are located close to the generators in order to minimize losses. Transformers are often cooled with oil-to-air fin type radiators. Fans alone or combined with oil circulating pumps may be employed to augment cooling.

h. Switchyard. The switching and delivering of power is the final link to the power grid. The switchyard (Figure 2-33) consists of line circuit breakers and disconnect switches. Often, in large powerplants, the switchyard can deliver power to a number of different transmission lines, sometimes at different line voltages.

i. Control Equipment. Control equipment is equipment necessary to facilitate the automatic or manual operation of other necessary powerplant equipment. Control systems vary widely in scope and complexity, as a function of the size and staffing of the plant, the level of operator skill and responsibility, the need to automatically regulate power generation to outside demands, and the desirability and location of the control center or facility. Unattended small scale hydro plants often demand apparently disproportionate control equipment expenditures because of the need for automatic failsafe operation and outside plant trouble reporting. Larger multiunit attended plants often have a central control room and automatic control requiring large computer based supervisory control and data acquisition (SCADA) control systems.

j. Auxiliary Equipment.

(1) Auxiliary equipment consists of the electrical, heating and ventilation, generator cooling, piping, fire protection, and drainage systems. These systems are necessary to support the primary function of the powerhouse and are located within the powerhouse. They can vary in complexity depending upon the size of powerplant. For power projects that are remotely operated, the heating, ventilating and plumbing systems are kept to a minimum. However, in plants where personnel are expected to be on duty throughout the day, these systems must be designed for human comfort.

(2) Another major piece of auxiliary equipment is the overhead crane, which is used to assemble and maintain the generating units (Figure 2-24). Permanent cranes at larger projects are included as a

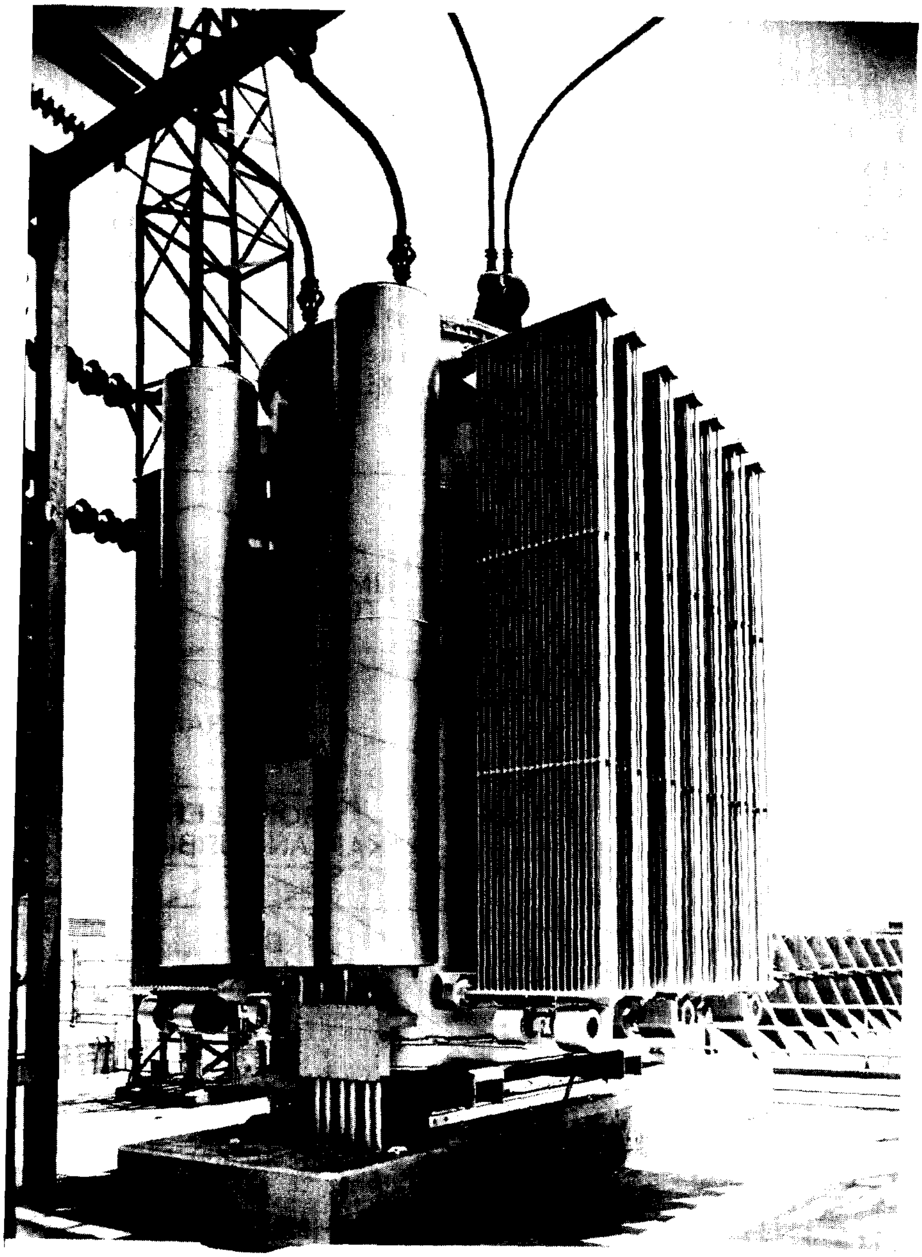


Figure 2-34. Power transformer
(Courtesy of Tennessee Valley Authority)

part of the powerhouse equipment. Mobile cranes may be brought into smaller installations when required.

2-6. Types of Turbines.

a. General.

(1) Modern turbines can develop power from almost any combination of head and flow. The many turbine models can be divided into two categories: impulse and reaction units. Impulse turbines extract power from the impact of water jets on their runners. Reaction units, in addition to extracting power from the kinetic energy of water, also are driven by the difference in pressure between the front and the back of each runner blade. The common application ranges for conventional hydraulic turbines are shown in Figure 2-35. Turbine efficiency curves are shown on Figure 2-36.

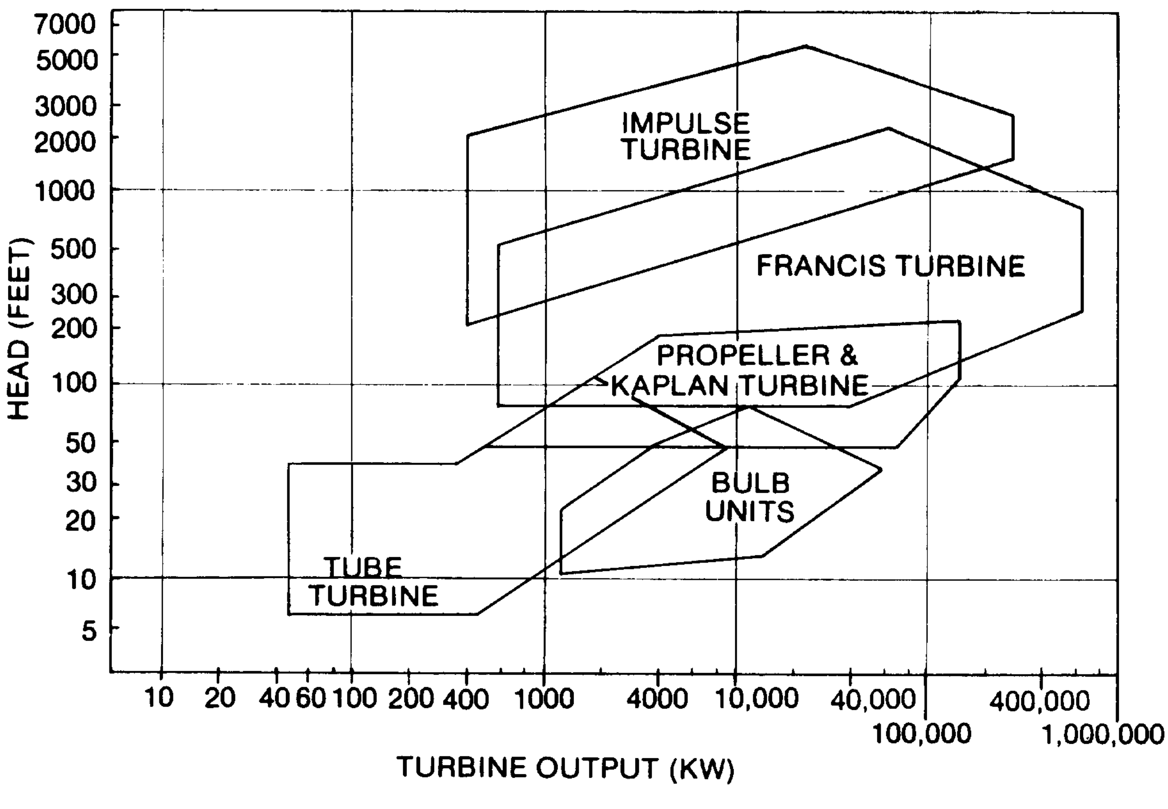


Figure 2-35. Application ranges for standard and custom hydraulic turbines (Courtesy of Allis-Chalmers Corporation, Milwaukee, Wisconsin, U.S.A.)

(2) The characterisics of the major turbine types are described in the following sections, and generalized performance curves are presented for Francis, Kaplan, fixed-blade propeller, and tubular turbines. These curves are plotted in terms of percent of rated capacity, rated head, and rated discharge. As will be discussed in Section 5-5, a given turbine could be rated at any one of a variety of operating conditions. The rating points upon which Figures 2-39, 2-41, 2-43 and 2-45 are based are typical rating points for the respective types of turbines, but they do not represent the only

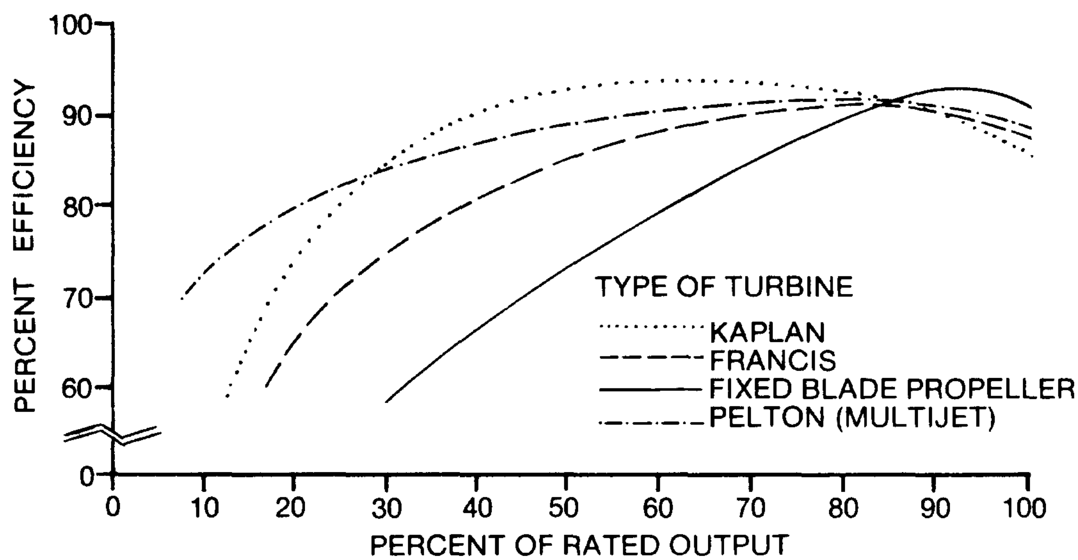


Figure 2-36. Turbine efficiency curves

points at which the units could be rated. To illustrate this, Section 5-5g describes three different ways in which a given Francis unit could be rated.

b. Impulse Turbines.

(1) The impulse turbine (commonly called Pelton turbine) has a runner with numerous spoon shaped "buckets" attached to its periphery. It is driven by one or more jets of water issuing from fixed or

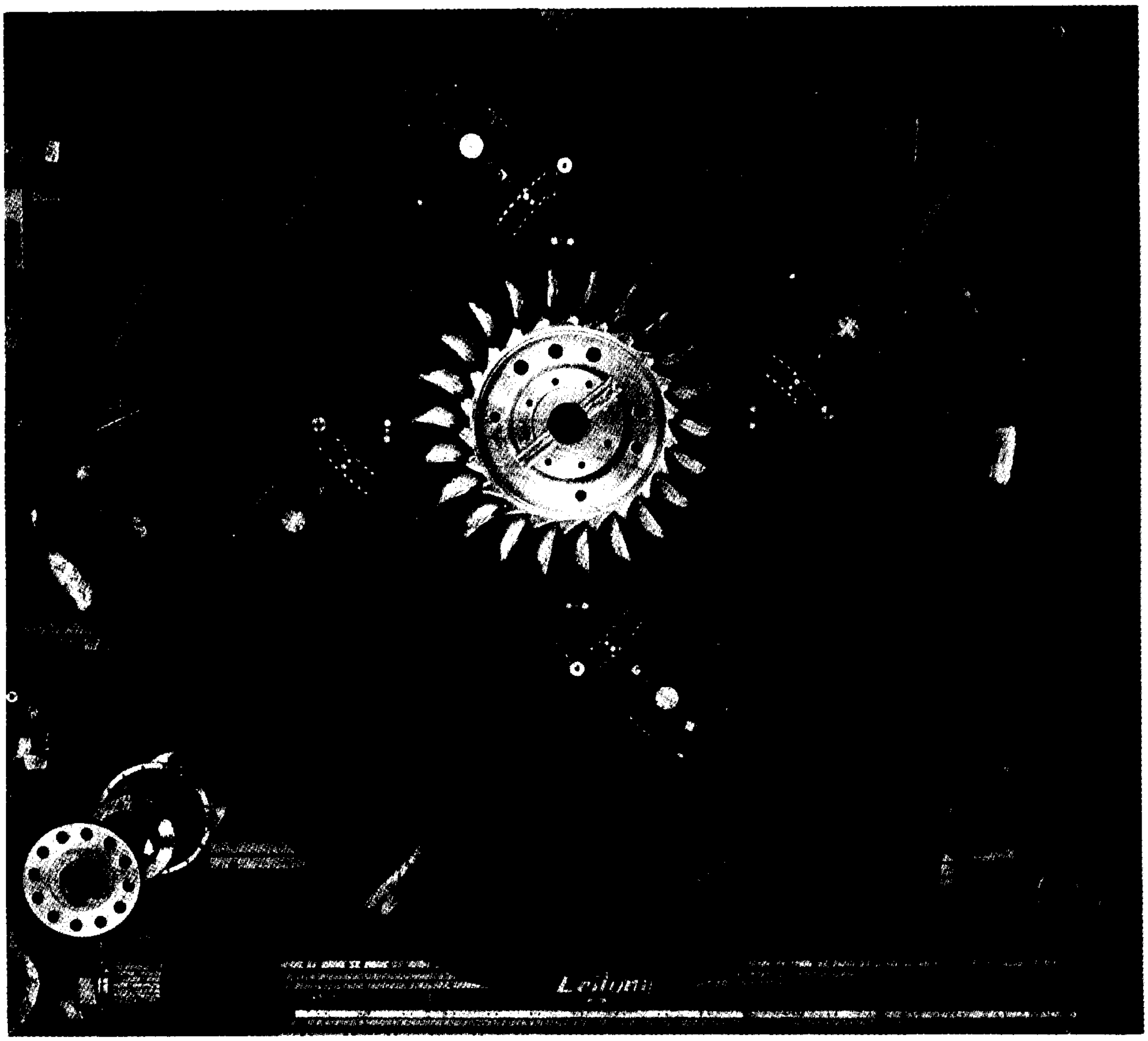


Figure 2-37. Pelton turbine and nozzle layout
(Courtesy of Sulzer-Escher Wyss Ltd.)

adjustable nozzles. A maximum of six jets can be used on vertical shaft units. A maximum of two jets may be used on horizontal shaft units in order to keep ejected water from re-entering the wheel, resulting in a loss of efficiency. A photograph of a Pelton turbine is shown in Figure 2-37.

(2) Large Pelton units are typically used at heads above 1,000 feet. Smaller "standardized" units can operate at reasonable efficiencies at heads of 100 feet and less. Impulse turbines operate best at nearly constant heads and have a relatively flat efficiency curve down to 20-25 percent of rated output, a useful characteristic where flow range is wide. Unit sizes range up to 300

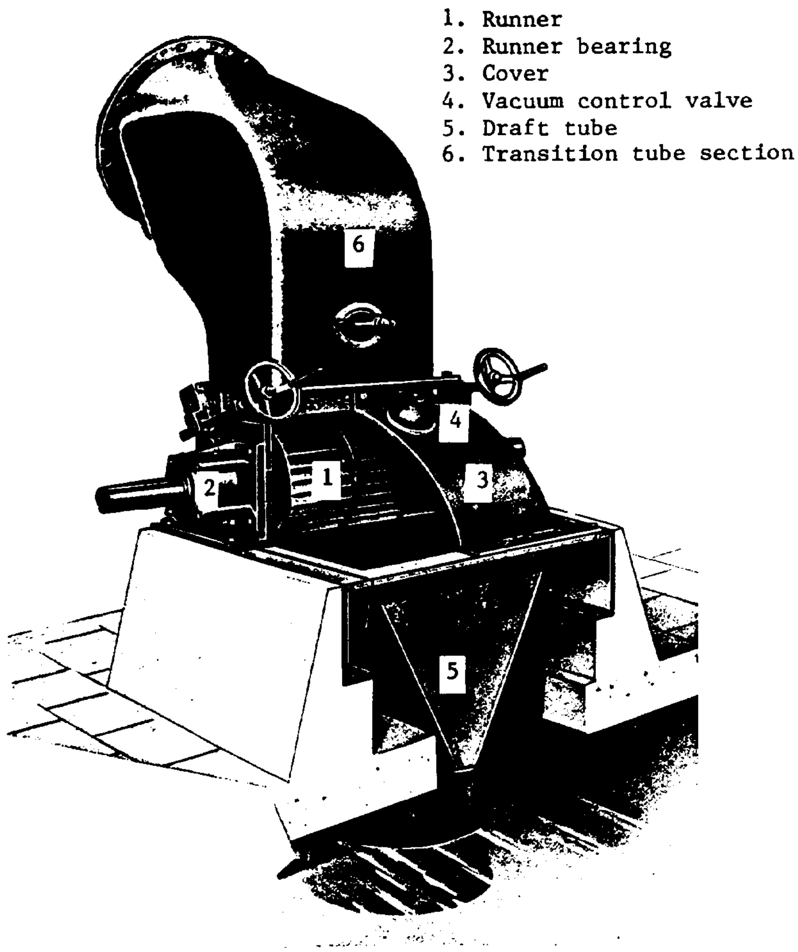


Figure 2-38. Detail view of crossflow (Ossberger) turbine (Courtesy of F. W. E. Stapenhorst, Inc., Pointe Claire, Quebec)

MW. A good source of information on estimating the size and speed of impulse turbines is the Bureau of Reclamation's Design Standards No. 6, "Turbines and Pumps."

(3) Turgo and crossflow units are also classified as impulse turbines. The Turgo is a side impulse type turbine with water jets passing through the wheel at an angle of less than 90 degrees to the shaft axis. The crossflow or Ossberger type resembles a "squirrel cage" fan. Water enters the wheel from one side, crosses through the middle, and discharges through the other side (Figure 2-38). It uses guide vanes instead of needle valves to control flow. Both of these turbines are used for lower heads than the Pelton type.

c. Reaction Turbines.

(1) Francis Turbines. The Francis turbine is constructed so that water enters the runner radially and then flows towards the center and along the turbine shaft axis. These units are most often applied under heads ranging from 100 to 1500 feet and are usually the economic choice in the 150 to 1000 foot head range. However, small Francis units can operate satisfactorily under heads as low as 20

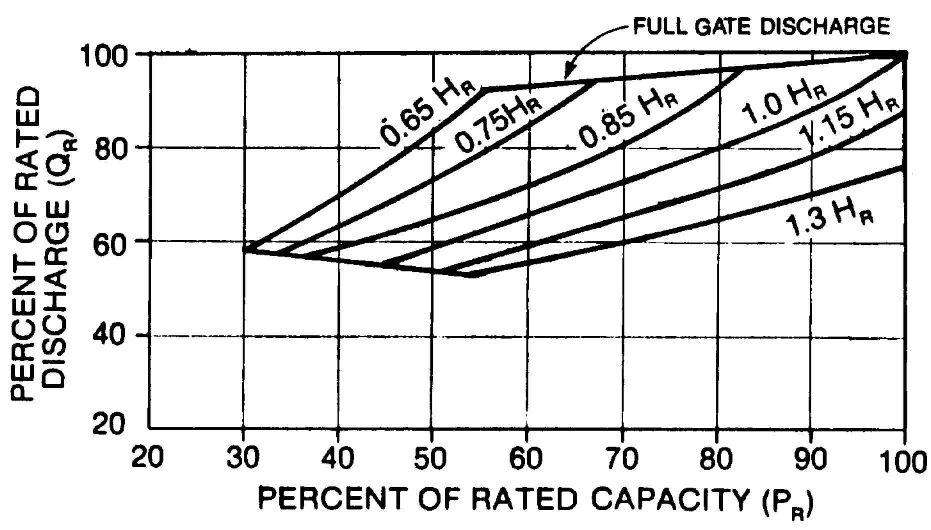


Figure 2-39. Francis turbine generalized performance curves

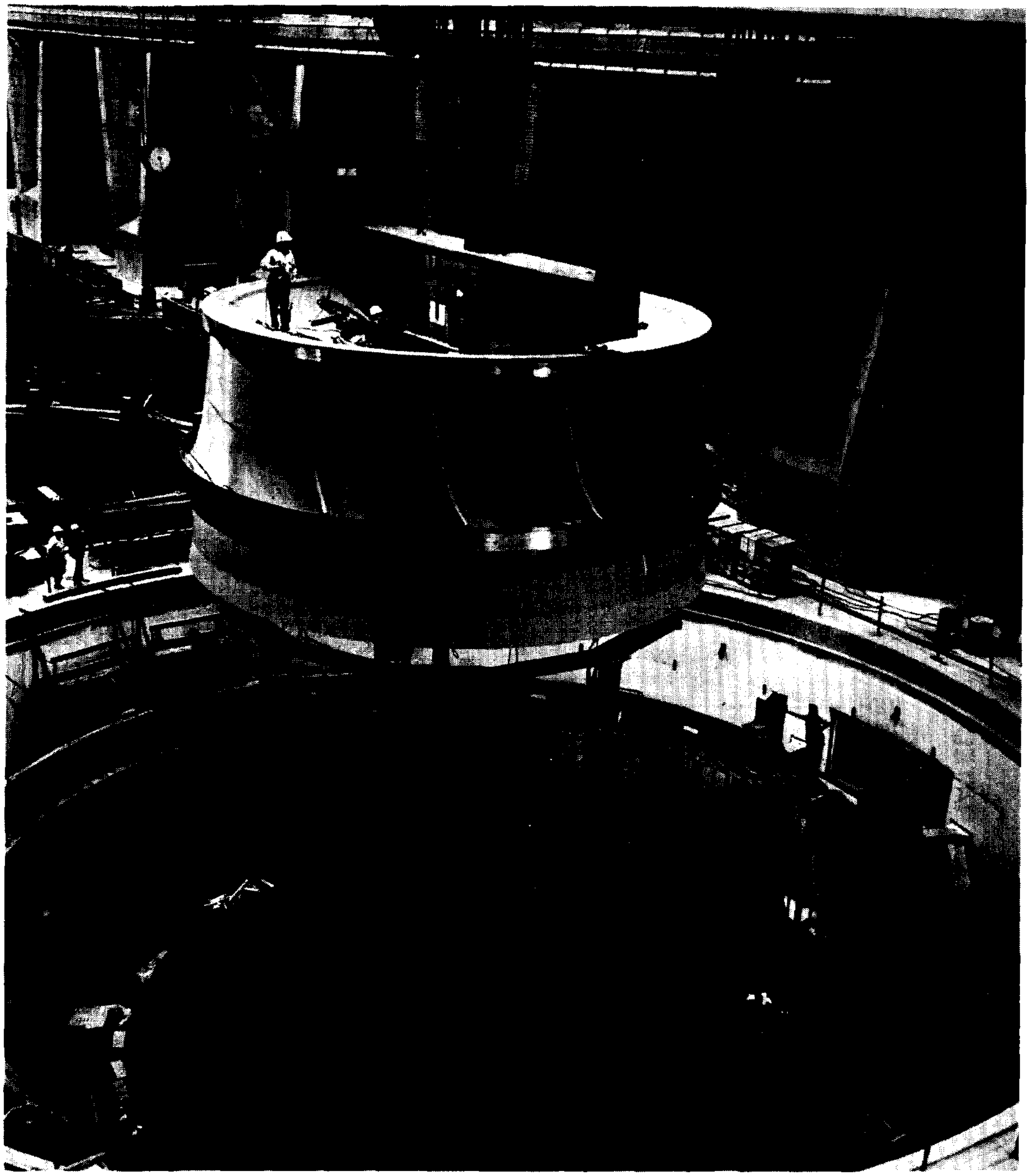


Figure 2-40. Francis turbine, Grand Coulee Dam
(Courtesy of the Bureau of Reclamation)

feet. Operational considerations limit minimum discharge to about 40 percent of rated capacity, and efficiency varies widely with head and discharge, ranging from 75 to 95 percent. The operating head range extends down to 50 percent of maximum head. Unit sizes range from 1 kW to 1000 MW. A photograph of a Francis turbine is shown in Figure 2-40 and generalized performance curves are shown in Figure 2-39.

(2) Fixed Blade Propeller Turbines. The propeller turbine passes water through its propeller blades in an axial direction. Propeller turbines can be designed for heads ranging from 10 to 200 feet but are usually an economic choice in the 50 to 150 foot head range. Units as small as 0.5 MW can be obtained, but most are 10 MW or larger (up to 150 MW). A fixed blade propeller turbine has a sharply peaked efficiency curve in comparison to Kaplan units (Figure 2-36) and operates efficiently over a limited range of output. Therefore, it is normally used where it can be operated close to its design discharge. Its normal head range varies down to 40 percent of maximum head, and the minimum discharge is typically 70 percent of full gate output. A photograph of a fixed-blade turbine is shown in Figure 2-42 and generalized performance curves are shown in Figure 2-41.

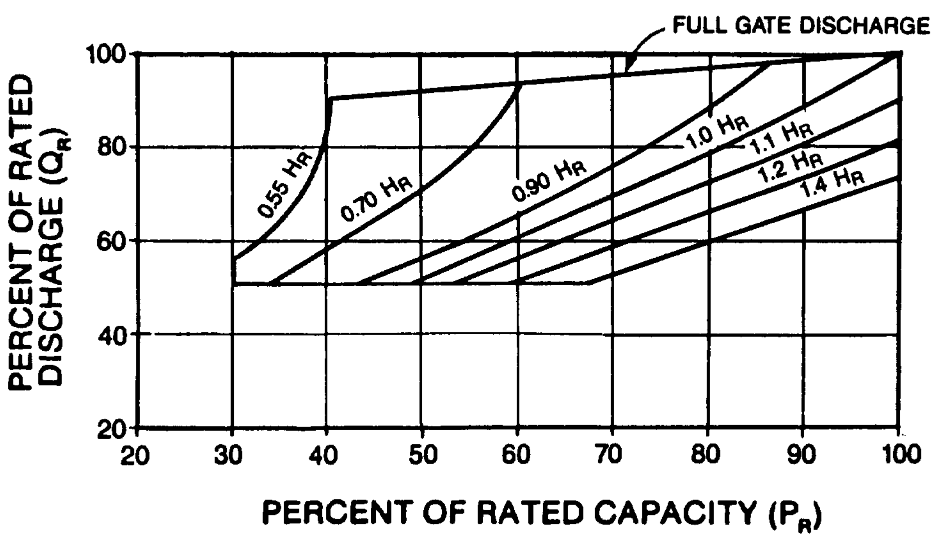


Figure 2-41. Fixed blade propeller turbine generalized performance curves

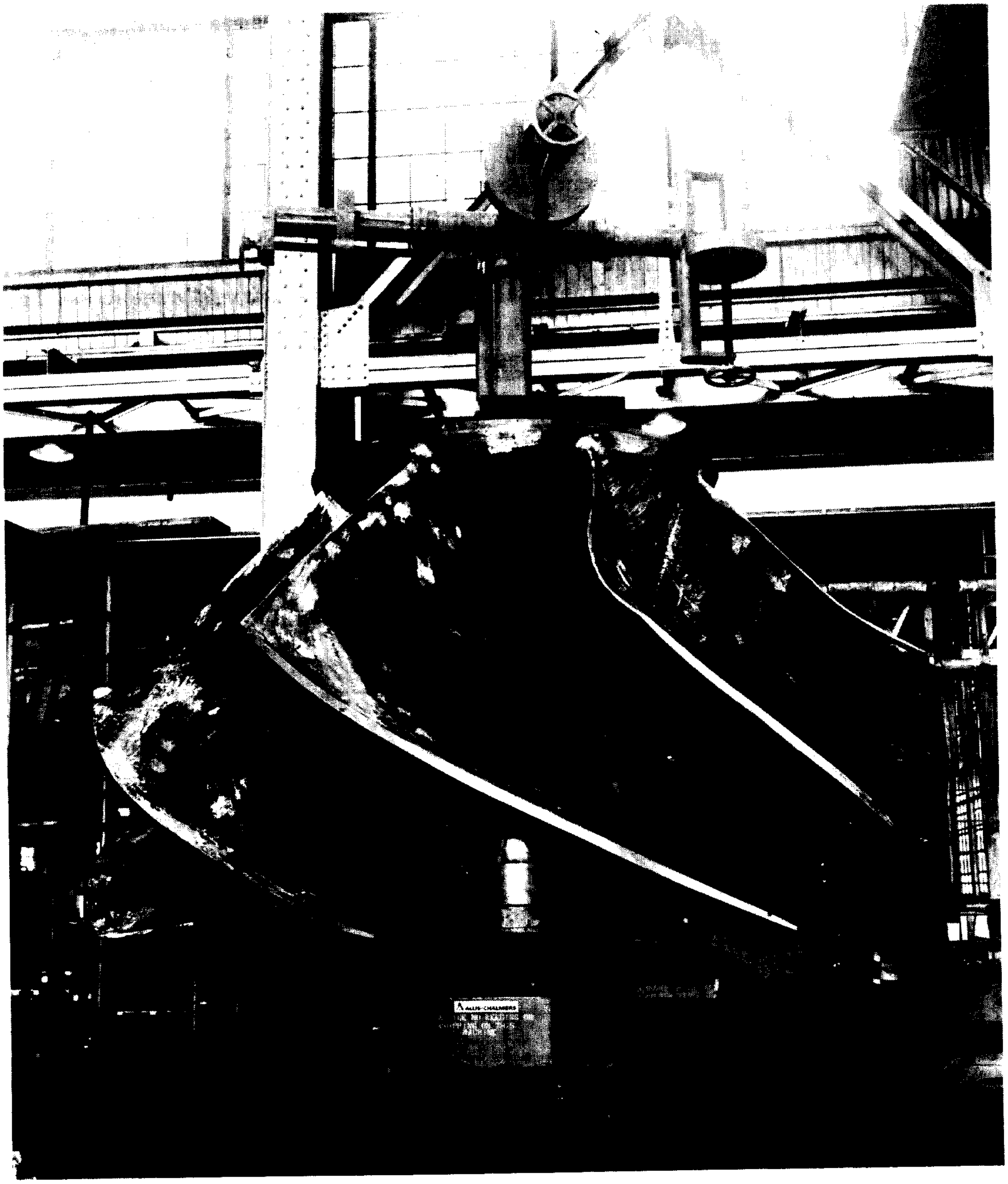


Figure 2-42. Fixed blade propeller turbine being manufactured for the Safe Harbor Project (Courtesy of Allis-Chalmers Corporation, Milwaukee, Wisconsin, U.S.A.)

(3) Kaplan Turbines. Kaplan turbines are propeller turbines with adjustable pitch blades which operate in the same general head range as propeller turbines. They are available in unit sizes ranging from 1 kW to 150 MW. Kaplan turbines have a relatively flat efficiency curve over a wide range of head and flow (Figure 2-36). Its normal head range varies down to 40 percent of maximum head, and its minimum discharge is about 40 percent of full gate output. Kaplan units are more expensive than fixed blade propeller units but are often the economic choice in the 50 to 150 foot head range where high efficiencies are important and where individual units must operate over a wide range of output. An example of this type of turbine is shown in Figure 2-44 and generalized performance curves are shown in Figure 2-43.

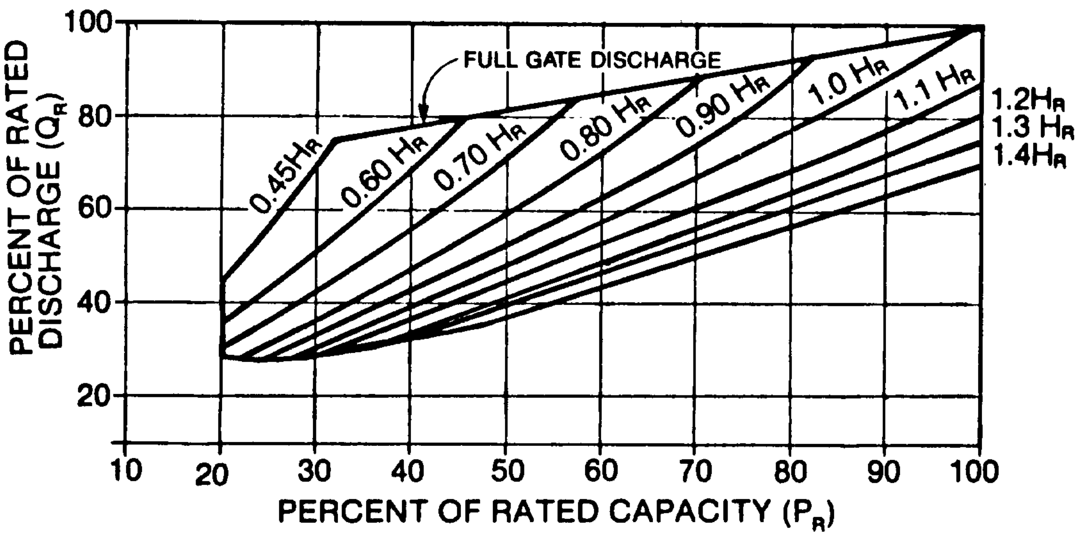


Figure 2-43. Kaplan turbine generalized performance curves

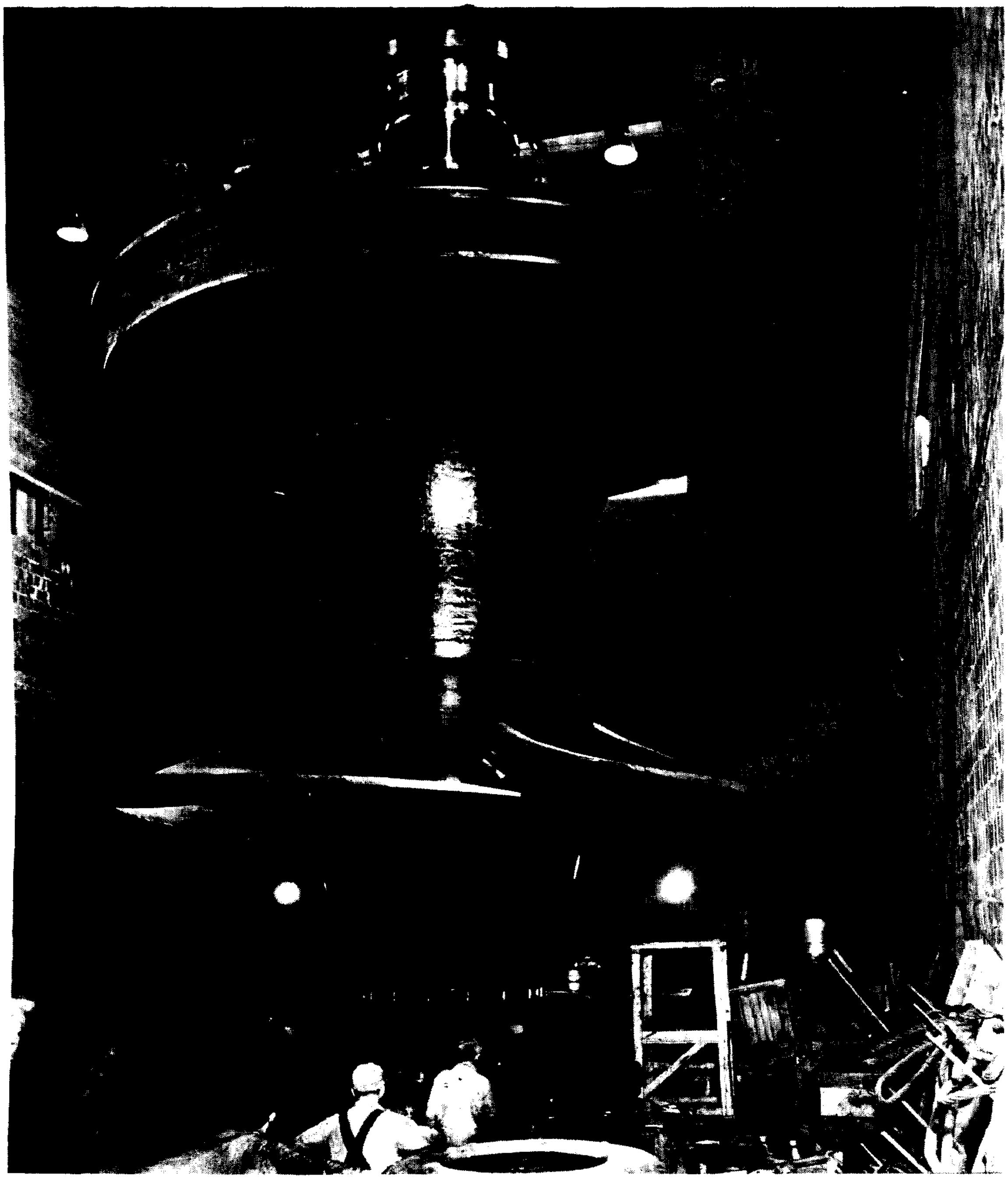


Figure 2-44. Kaplan turbine runner, Chickamauga Dam
(Courtesy of the Tennessee Valley Authority)

(4) Tubular Turbines. Tubular turbines may be vertical, horizontal, or slant-mounted axial flow units. The guide vane assembly is in line with the turbine and contributes to the tubular shape (Figure 2-46). Generators are located outside of the water passageway. Performance characteristics are similar to those of conventional propeller turbines, and both wicket gates and blades may be either adjustable or fixed in position for heads typically ranging from 10 to 50 feet and in sizes up to 10 MW. Smaller horizontal units with 'S' type draft tubes and vertical units with elbow draft tubes have been standardized to reduce costs. These turbines may have lower efficiencies than custom built units but also may be more cost effective. Tubular turbines are sometimes the economic choice for small units with heads of less than 50 feet. Generalized tubular turbine performance curves are shown in Figure 2-45.

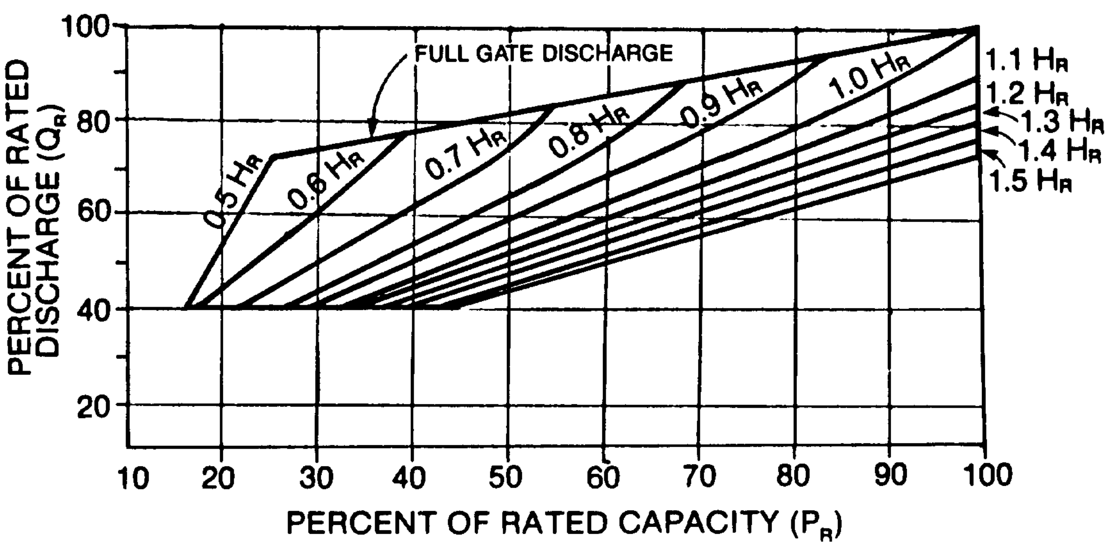


Figure 2-45. Tubular turbine generalized performance curves

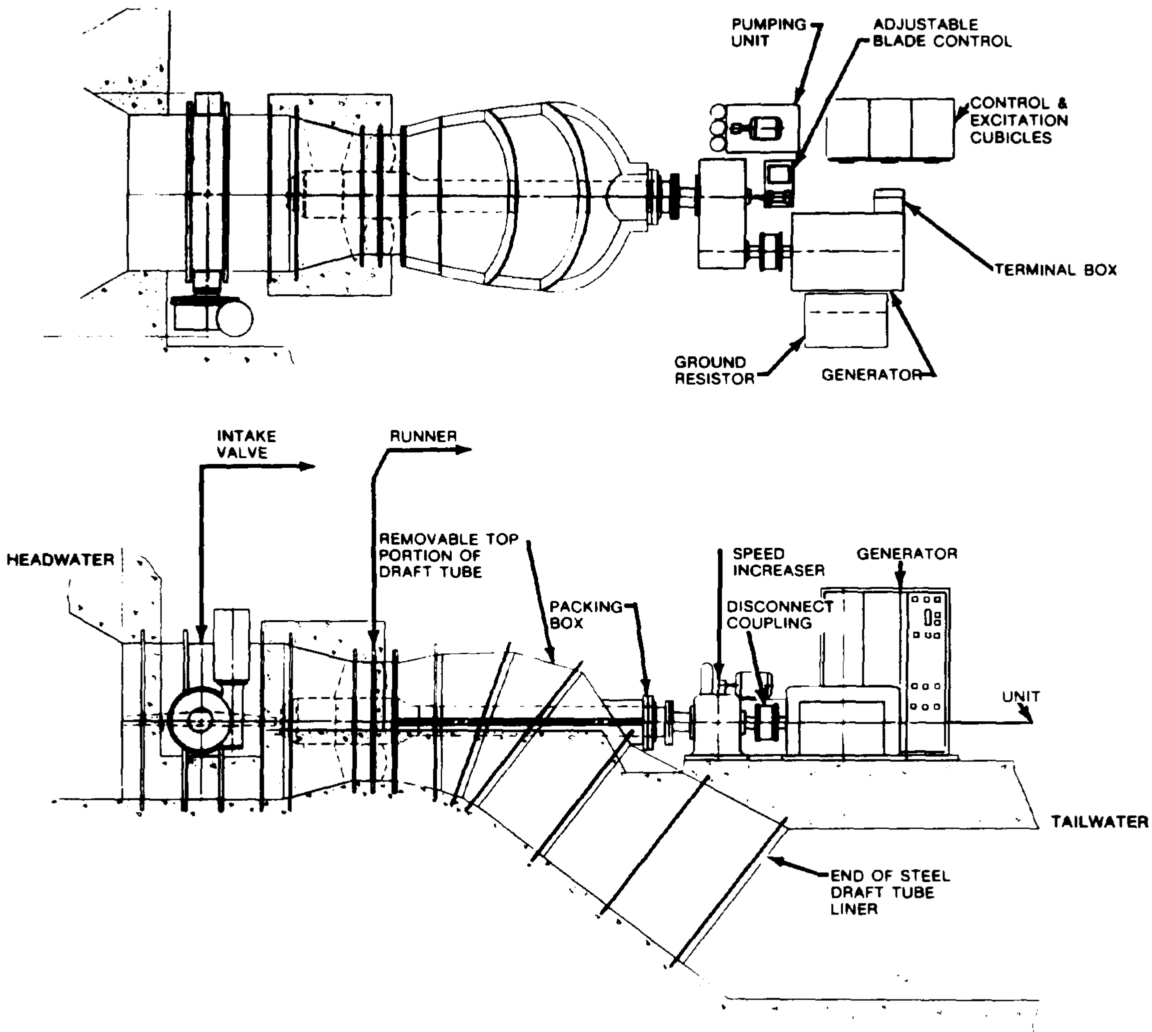


Figure 2-46. Plan and section of tubular turbine

(5) Bulb and Pit Turbines. Bulb Turbines (Figure 2-47) are horizontal axial-flow units with a turbine runner connected either directly to a generator or through a speed increasing gearbox (usually an epicyclic type). The generator and its appurtunances are housed in a water tight enclosure (or bulb) located in the water passageway. They can be considered to be a specialized, custom-built variation of the tubular turbine, but because of their shape, they have become more commonly known as bulb turbines. Fixed or variable pitch blades and wicket gates are available. Fitting a bulb turbine with a gearbox permits the generator to run at a higher speed. This results in a smaller bulb diameter and often permits the unit to be designed for easier disassembly. Performance is similar to propeller and tubular turbines, except that efficiency is increased approximately two percent over comparable propeller or Kaplan units because of an essentially straight water passageway. However, high trashrack and draft tube outlet velocities may in some cases reduce the overall system efficiency to less than that of a vertical unit. Heads of 10 to 75 feet can be utilized, and unit sizes range from 25 kW to 50 MW. Bulb turbines are frequently the best choice for large units at heads less than 50 feet due to savings in civil works costs. Some manufacturers have standardized their design of small bulb units. These units may have a right angle gear drive with the generator located outside the water passage. Pit turbines are similar to bulb turbines, except that the small upper access shafts are replaced by a single access shaft (or access "pit") large enough to permit removing some of the machinery without disassembling the bulb.

(6) Rim Turbines. The rim turbine (Figure 2-48) is similar to the bulb turbine except that the generator is mounted on the periphery of the turbine runner blades. A seal must be provided to prevent water from entering the generator. This seal is critical to the satisfactory operation of the units. Rim turbines are suitable for the 10 to 100 foot head range and sizes of up to about 20 MW. Performance characteristics are similar to those of bulb turbines. Wicket gates can be installed to regulate flow, and both fixed and adjustable pitch blades are available. The rim turbine provides the most compact powerhouse layout of any type of unit in this head range. However, the limited number of manufacturers that design and build this type of turbine may result in uncompetitive bids.

(7) Submersible Turbine-Generators. For very small plants, and/or where a unit is to be placed in a pipeline, standardized submersible axial-flow turbine-generators are available. They resemble a bulb turbine except for their size. Typical head ranges are from 20 to 50 feet and power ranges are from 20 to 500 kW are typical.

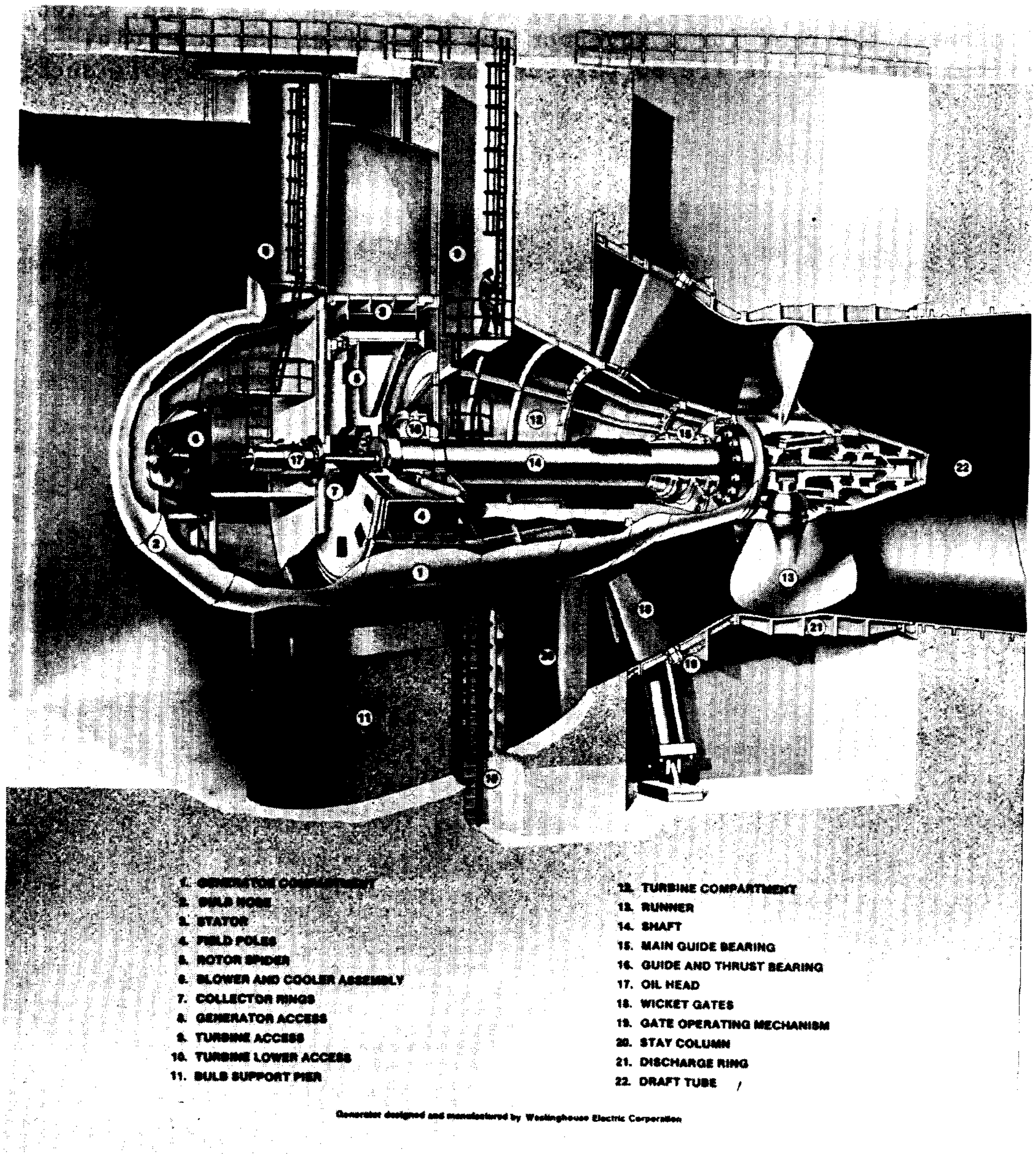


Figure 2-47. Detail view of bulb turbine (Courtesy Allis-Chalmers Corporation, Milwaukee, Wisconsin, U.S.A.)

(8) Pumps as Turbines. Pumps rotating in reverse and operating as turbines may be used for small plants where head is relatively constant. These units will deliver a fixed output of power and discharge at operating head, and multiple units of various sizes may be required to cover the available flow range. Usually a butterfly valve and induction motor (running as a generator) are used, which eliminates the need for a governor and simplifies the controls. Maximum efficiencies are 80 percent for end suction or double suction

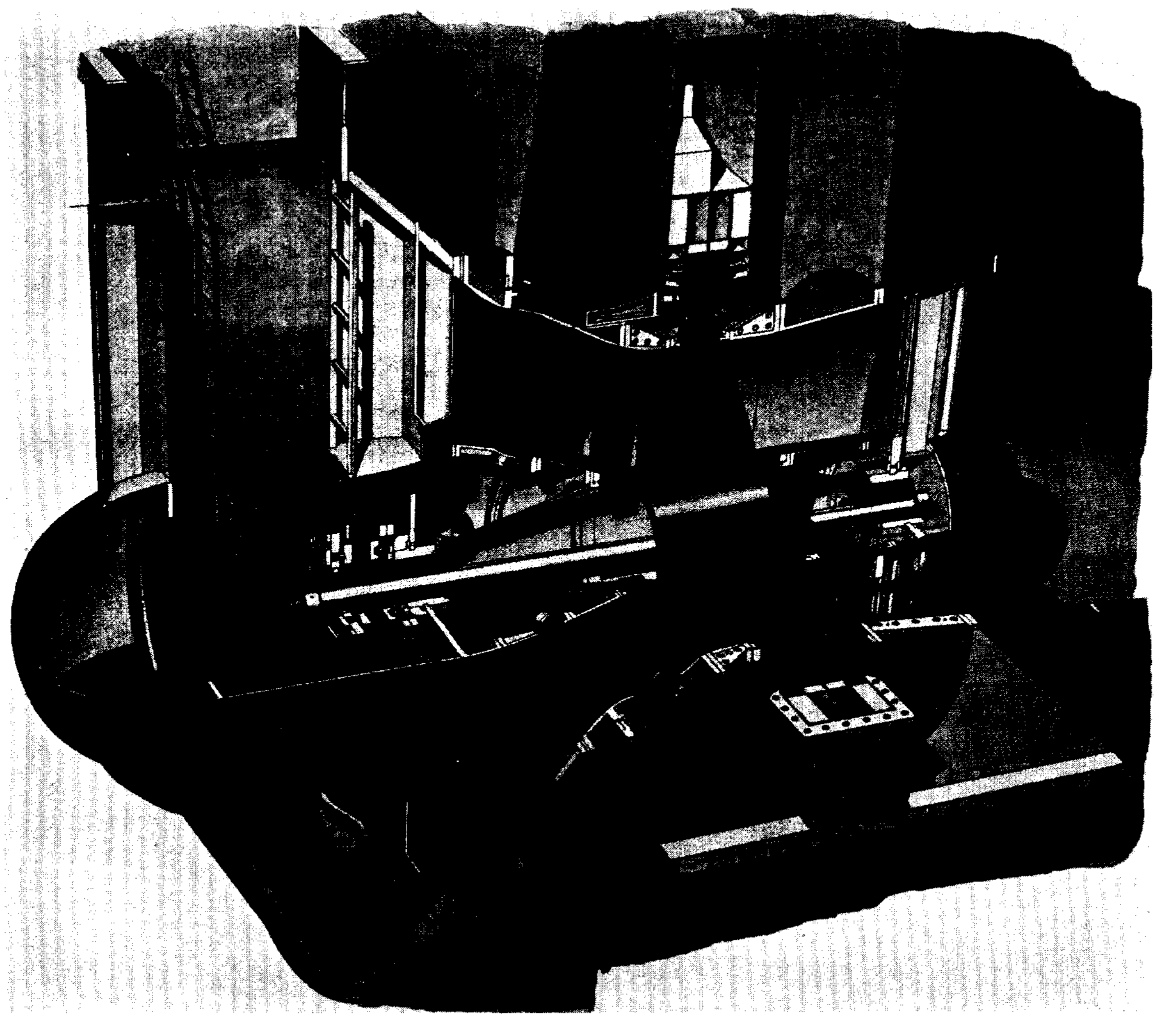


Figure 2-48. Rim turbine (Courtesy of Sulzer-Escher Wyss Ltd.)

pumps and 90 percent for axial flow propeller pumps. A diffuser cone (draft tube) is usually necessary. First costs of these turbines are quite low because they are regular pumps with minor modifications.

d. Turbine Selection. Figure 2-35 provides some general information on the types of turbines that are best suited to different operating conditions. However, it is not generally possible to apply "cookbook" procedures or rules of thumb to turbine selection because operational ranges overlap. The peculiarities of each site must be taken into account when selecting suitable turbine types. In advanced studies, it is usually desirable to consider all applicable types of units that could be adapted to the given head and plant size in order to determine which is most economical. These types of analyses should be made in conjunction with one of the Hydroelectric Design Centers. References (35), (36), (39), (60), and (64) provide further information on turbine selection and characteristics.

Figure 2-49. Fixed-blade propeller turbine being
transported by bridge crane, Big Bend Dam (Omaha District)

CHAPTER 3

LOAD-RESOURCE ANALYSIS

3-1. Introduction.

a. General. An analysis to establish the need for a project's power output is an integral part of the hydropower feasibility study. Generally, this analysis consists of a comparison of projected supply (power resources) and demand (power loads). For small projects, a marketability statement can sometimes be substituted for a full load-resource analysis.

b. Scope. The Engineering Regulations and Circulars (ER's and EC's) contained in the Planning Guidance Notebook (49) provide general guidance on the information required to establish the need for water resources projects, as well as the format in which this material is to be presented. This chapter concentrates on the specific material to be developed for evaluating hydropower projects and covers the requirements of Principles and Guidelines (77). Subjects covered include (a) types of load forecasts, (b) sources of information on load forecasts and resource projections, (c) the guidelines for selection of a forecast, (d) marketability requirements, and (e) the type of material to be presented at various study levels.

3-2. Purpose of Analysis.

a. The purpose of the load-resource analysis is to determine the need for and the timing of proposed hydropower projects. Need refers to the existence of power deficits, which occur when the sum of the forecasted power demand and reserve requirements exceeds the planned power supply, while timing refers to the point in time when the need for additional generation occurs. Forecasts are generally made for peak loads and resources (measured in megawatts) and for average energy loads and resources (measured in either megawatt-hours or average megawatts). Generation planning in most regions is based primarily on an analysis of peak loads and resources. An analysis of energy loads and resources may also be required in regions that have a high proportion of energy-limited resources such as hydropower.

b. The above discussion applies to the determination of the need for additional generating capacity. A hydro project could also be used to displace the output of existing thermal power plants. Since the need for the project would be based primarily on economic viability of fuel displacement, a load-resource comparison would not be required. Section 3-11 provides further information on this type of analysis.

3-3. Scope of Analysis.

a. General.

(1) The scope of the forecast is prescribed in the Water Resources Council's Economic and Environmental Principles and Guidelines for Water and Related Land Resource Implementation Studies, which is referred to hereafter as simply Principles and Guidelines (77). Principles and Guidelines is also incorporated in the Planning Guidance Notebook as a part of EM 1105-2-40. Two sections of Principles and Guidelines apply to evaluating the need for hydropower: Section 2.5.4(b), which covers small hydro projects, and Section 2.5.6, which generally applies to larger projects.

(2) Section 2.5.4(b) permits an analysis of marketability to be substituted for a determination of need for future generation when evaluating single purpose, small scale hydro projects (80 MW or less) at existing Federal facilities. The marketability analysis is discussed further in Section 3-12 of this chapter.

(3) However, there are cases where load-resource analyses should be provided for small projects. Where a proposed hydro project would meet a substantial portion of a system's new generation requirements over a period of one or more years, a load-resource analysis would be appropriate regardless of the size of the project. However, the degree of detail included in the analysis should be consistent with the project size.

(4) As noted earlier, analyzing need when the hydro project's output is used for displacing generation from existing thermal plants is also a special case, which is discussed in Section 3-11. The balance of this chapter deals with the determination of need, which is described in Section 2.5.6 of Principles and Guidelines. The major steps outlined in Section 2.5.6 are as follows:

b. Major Steps.

(1) Identify System for Analysis. Generally, the system to be analyzed should be the system in which power from the proposed hydro project will be used. For small projects, the system may consist of a single utility, but for larger projects, the system may consist of several utilities or even a power pool. Definition of the system should be made in consultation with the regional Power Marketing Administration and/or the FERC Regional Office.

(2) Estimate Future Demand for Electric Power. Forecasts of electric power loads are generally made in terms of annual peak demand (capacity demand). A forecast of annual energy demand should also be made where more than one-third of a system's firm energy is met by hydropower or other energy-limited resources. Weekly system load shapes are sometimes defined in order to help determine the type of load that a hydropower project should carry. In order to describe the full range of expected conditions, weekly load shapes should be constructed for a minimum of three periods in the year (e.g., typical summer, winter and spring or fall weeks). Load forecasts should reflect the effects of all load management and conservation measures that, on the basis of present and future public and private programs, can reasonably be expected to be implemented during the forecast period. Load forecasts should be made and analyzed by sector use (residential, commercial, industrial, irrigation, etc.). Load estimates should be made at increments of 5 to 10 years (intervals shorter than 10 years are preferred to adequately define trends), from the present to a time when the proposed hydro plant will be operating in a manner representative of the majority of its project life. Loads for intermediate years can be obtained through interpolation. In the case of staged hydropower development (Section 9-10f), or where generation system resource mixes may change markedly (Section 9-6), load-resource analyses may be required for 20 years or more beyond the hydro project's initial operation date. Estimates should account for system exports and reserve requirements (Section 2-2e) as well as the system loads themselves.

(3) Define Base System Generating Resources. Identify the generating resources and imports that will be available to the system at various points in time without the proposed hydropower project in the system (the "without project" scenario). Resource estimates are normally based on the resources' peaking capability, but data on annual energy production should also be developed for systems where a high proportion of the generation is hydropower. Data is usually readily available on projected system resources for the next 10 years. Resource additions beyond that time should be based on system studies or estimates. Retirement of older plants should be accounted for, as well as the reduction in the output of some plants due to age or environmental constraints. The capacity contribution of hydro projects should generally be based on dependable capacity rather than on installed capacity (see Section 6-7).

(4) Evaluate Need for Additional Generation. Compare the loads identified in step (2) above, with the resources identified in step (3) to determine: (a) when generating resource deficits will occur, (b) the magnitude of these deficits, and (c) what portion of these deficits could be met by the hydropower project. If nonstructural measures are components of one or more of the plans being considered

TABLE 3-1. Summer Peaking Capacity, Peak Demand, Reserves, and

	1981	1982	1983	1984
Planned capacity (MW)	53,600	56,781	61,205	64,013
Net imports/exports (MW)	795	813	941	707
Peak demand (MW)	44,383	46,398	48,238	50,317
Total reserve (MW) 3/	10,012	11,196	13,908	14,403
Total reserve (%)	22.6	24.1	28.8	28.6
Scheduled maintenance (MW)	0	301	331	354
Full forced outages & unavail. cap'y (MW) 1/	4,567	4,824	5,288	5,593
Actual reserves (MW) 2/	5,445	6,071	8,289	8,456
Actual reserve (%)	12.3	13.1	17.2	16.8
Capacity needed but unscheduled (MW) 3/	0	0	0	0
Annual energy (gWh)	216,003	226,074	235,006	245,218
Annual load factor (%) 4/	55.6	55.6	55.6	55.6

1/ Full forced outages and unavailable capacity are calculated based on historical data.

2/ Reserve less scheduled maintenance and full forced outages.

Annual Energy for the Southwest Power Pool Region, 1981-1990

1985	1986	1987	1988	1989	1990
65,688	67,031	68,881	70,306	72,310	74,682
440	356	348	294	107	-28
52,302	54,382	56,342	58,535	60,728	63,069
13,826	13,005	12,887	12,065	11,688	11,585
26.4	23.9	22.9	20.6	19.2	18.4
360	363	377	383	401	413
5,707	5,800	5,996	6,120	6,371	6,572
7,759	6,842	6,514	5,562	4,917	4,600
14.8	12.6	11.7	9.5	8.1	7.3
0	590	1,198	2,568	3,494	4,182
55,389	266,543	277,729	289,760	300,414	313,362
55.7	56.0	56.3	56.5	56.5	56.7

3/ Capacity needed to insure that total reserve margin is 25 percent of peak demand and actual reserve is 15 percent of peak demand

4/ (Annual energy, gWh)/(8760 hours x peak demand, MW) and these measures will reduce system loads (see Section 3-9), the amount of such reduction will reduce system deficits correspondingly. Some hydropower sites can be developed to provide either base load, midrange or peaking service. Where these options are available, the system demand for each class of hydropower generation should be evaluated (see Section 6-3). Simple tabulation of annual peak and energy loads and resources is generally adequate for preliminary studies and for detailed analysis of base load plants. It is often desirable to use system load resource models in order to evaluate the need for mid-range and peaking plants, including pumped-storage projects. These models account for load characteristics and generating plant operating characteristics.

c. Display of Analysis. Load-resource information should be displayed year-by-year over a period starting several years prior to the hydro project on-line date and extending several years beyond the year when project output is fully usable in the system load. Table 3-1 is a sample of a typical load-resource analysis.

3-4. Authority and Responsibility of the Corps of Engineers.

a. The responsibility of the Corps is to satisfy all requirements specified by Principles and Guidelines when determining the need for future generation. As described above, this process includes a determination of (a) the time period when generating resource deficits occur, (b) the magnitude of those deficits, and (c) the portion of deficits that could be met by the proposed hydropower project.

b. Forecasts of loads and resource requirements are normally obtained from an outside source such as the Federal Energy Regulatory Commission, the regional Federal Power Marketing Administration, the local utilities or power pool, or a non-Federal government agency. The Corps normally does not perform load and resource projections, but they assume responsibility for the validity of the forecast when it is incorporated in a Corps report. Therefore, Corps staff should understand and support the forecasting methodology and assumptions used in the forecast.

c. There may be occasions when the Corps must develop the load-resource analysis. Examples would be where suitable existing data is not available, or where the entity which normally does load-resource analysis cannot develop the data in the required time frame. In these cases, Corps staff should work closely with these entities in order to develop the data. Consulting firms experienced in this type of work should also be considered.

3-5. Sources of Forecast Data.

a. General. Following is a list of the principal sources of load-resource information.

b. Regional Reliability Council Reports.

(1) The North American Electric Reliability Council (formerly the National Electric Reliablity Council) was formed in 1968 to promote the adequacy and reliability of bulk power supply in North American electric utility systems. NERC consists of nine Regional Reliability Councils which encompass essentially all of the power systems in the United States and Canada (Figure 3-1).

(2) One of the primary functions of the regional councils is to prepare annual load-resource analyses in response to the requirements of the Federal Power Act (as amended). These reports comprise the principal regularly-issued source of load-resource information generally available to the power planner, and they serve as the basis for reports prepared by a number of other entities.

(3) The key load-resource data required by the Act, as implemented by Department of Energy Form EP-411, is as follows:

- monthly energy and peak demand for the past year, the reporting year, and the following year
- annual energy and peak demand for the next eight years
- existing generating capability available at the beginning of the reporting year
- additions and retirements of generating capability for the following ten years
- peak demand and reserve margin for summer and winter seasons for the next ten years
- statement of criteria for determining reserve requirements

The data presented in some of the regional reports is further categorized by sub-region, and data is also presented for U.S. portions of those regions that include Canadian systems.

(4) The load data presented in the regional reports is compiled from the individual load forecasts prepared by member utilities. Although data is presented in a uniform manner, each utility uses its own techniques for preparing its forecasts.

(5) The Regional Reliability Council load-resource analyses have several distinct advantages: (a) they present adequate detail for most Corps studies, (b) they are updated annually, and (c) they are recognized industry-wide as a standard reference source. Disadvant-

ages are that (a) in some cases the regions or sub-regions are too large for properly evaluating a hydro project, (b) only a single load forecast is provided, rather than a range of forecasts, (c) the forecasts extend only ten years, which may be inadequate for some project analyses, and (d) in most cases it is not possible to identify assumptions regarding fuel prices, population and income growth rates, and other factors. However, because of its availability, level of detail, and general acceptance, the Regional Reliability Council forecast should be considered the basic data source in most areas.

(6) Copies of the regional reports are available from the offices of the Regional Reliability Councils (Table 3-2). However, the reports are printed in limited quantities, and availability may

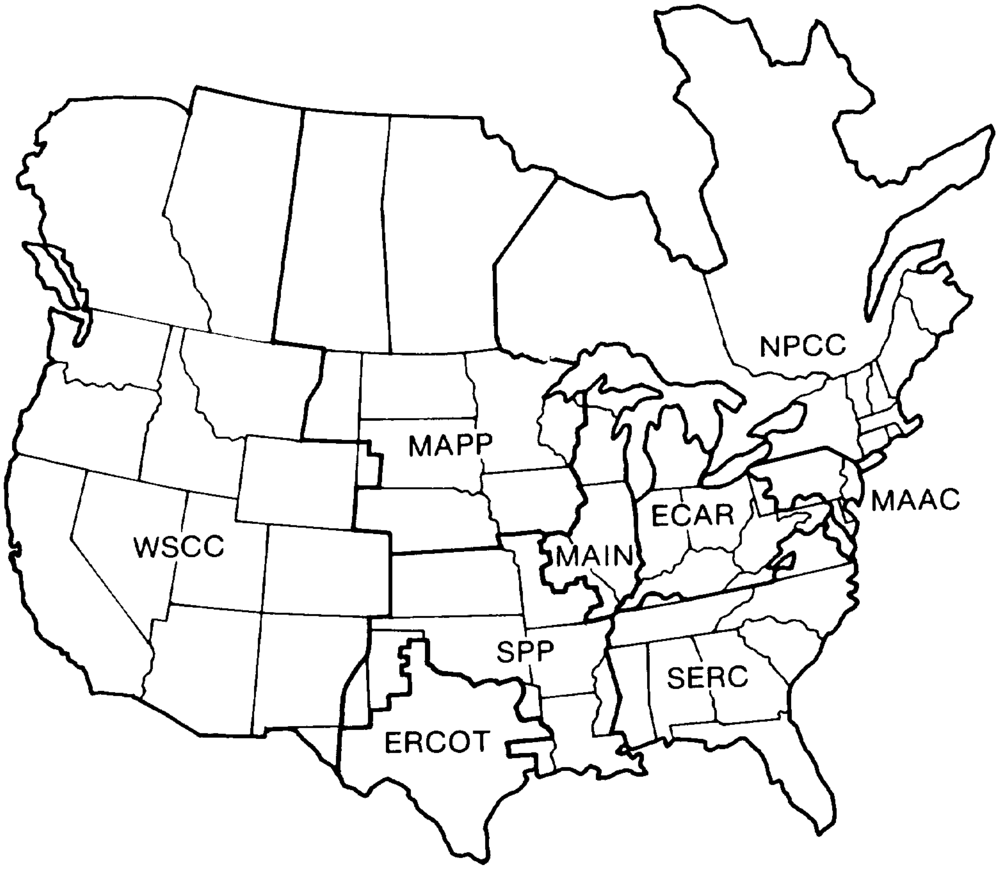


Figure 3-1. North American Electric Reliability Council

TABLE 3-2
North American Electric Reliability Council

North American Electric Reliability Council
101 College Road East
Princeton, NJ 08540-6601
Telephone: (609) 452-8060

* East Central Area Reliability Council (ECAR)
Post Office Box 21040
Canton, OH 44701-1040
Telephone: (216) 456-2844

Electric Reliability Council of Texas (ERCOT)
7200 MoPac Expressway, Suite 250
Austin, TX 78731
Telephone: (512) 343-7215

Mid-America Interpool Network (MAIN)
1N301 Swift Road
Lombard, Illinois 60148
Telephone: (312) 495-3664

Northeast Power Coordinating Council (NPCC)
1115 Avenue of the Americas, 28th Floor
New York, NY 10036
Telephone: (212) 840-1070

Southwest Power Pool (SPP)
4015 North McKinley
Plaza West, #700
Little Rock, AR 72205
Telephone: (501) 664-0145

Mid-Atlantic Area Council (MAAC)
Valley Forge Corporate Center
Norristown, PA 19403
Telephone: (215) 666-8801

Mid-Continent Area Power Pool (MAPP)
430 Century Plaza
1111 3rd Avenue South
Minneapolis, MN 55404
Telephone: (612) 341-4650

Southeastern Electric Reliability Council (SERC)
TVA 5N 53A Missionary Ridge Place
Chattanooga, TN 37402
Telephone: (615) 265-8278

Western System Coordinating Council (WSCC)
540 Arapeen Drive, #203
Salt Lake City, UT 84108
Telephone: (801) 582-0353 *

be limited. Summary reports (28) are available from the North American Electric Reliability Council, Research Park, Terhune Road, Princeton, NJ 08540.

c. Regional Power Marketing Administrations.

(1) Five regional Power Marketing Agencies or Administrations (PMA's) have been established under the U.S. Department of Energy (DOE) to market the power generated at Federal hydroelectric projects. The Tennessee Valley Authority markets much of the power from Corps projects adjacent to its service area in cooperation with the Southeastern Power Administration. The northeastern and midwestern states are not served by a regional PMA, but assistance in evaluating a project in these areas can be provided by the DOE's Office of Power Marketing Coordination (OPMC) in Washington, DC, or by an existing PMA as designated by OPMC. Figure 3-2 shows regional boundaries for the five PMA's and Table 3-3 lists their addresses.

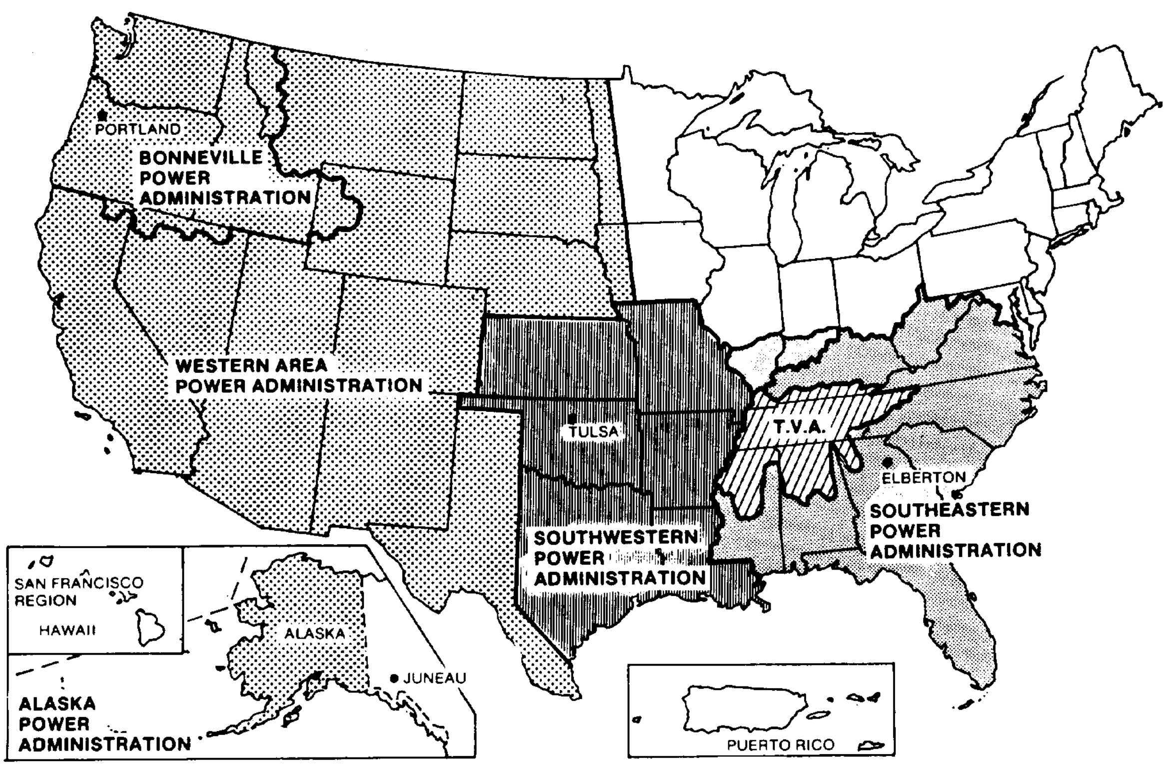


Figure 3-2. Federal Power Marketing Administration boundaries

TABLE 3-3
Federal Power Marketing Administrations

* Southeastern Power Administration Samuel Elbert Building Elberton, GA 30635 Telephone: (404) 283-9911	Alaska Power Administration P.O. Box 50 Juneau, AK 99802 Telephone: (907) 586-7405
Southwestern Power Administration P.O Drawer 1619 Tulsa, OK 74101 Telephone: (918) 581-7474	Bonneville Power Administration P.O. Box 3621 Portland, OR 97208 Telephone: (503) 230-3000
Western Area Power Administration P.O. Box 3402 Golden, CO 80401 Telephone: (303) 231-1511	

(2) The regional PMAs are required to prepare an analysis of marketability for each proposed Federal hydroelectric project (see Section 3-12). This analysis considers projected demand and resource availability. However, in most cases it does not meet the requirements of Section 2.5.6 of Principles and Guidelines, because it is restricted to a limited market (preference customers) and is based on the financial criteria unique to the individual PMAs. There are at least two exceptions. Alaska Power Administration prepares load-resource analyses for proposed Corps projects in Alaska, which is not included in a Reliability Council region. Bonneville Power Administration is required to prepare a regional load forecast pursuant to the Pacific Northwest Electric Power Planning and Conservation Act of 1980. The marketability reports are, however, adequate for establishing the need for single-purpose small-scale hydro projects at existing Federal projects (Section 2.5.4(b) of Principles and Guidelines).

(3) Those PMAs that do not provide formal load forecasts are generally available to provide assistance to Corps offices in evaluating load-resource studies prepared by Regional Reliability Councils and others. *

d. Other DOE Offices.

(1) Federal Energy Regulatory Commission regional offices are sometimes able to assist Corps offices in evaluating the need for hydro projects. Their studies are generally based on Regional Reliability Council reports, but the amount of assistance that can be provided is dependent on staff availability. Figure 3-3 shows FERC district boundaries and Table 3-4 lists their addresses.

(2) The Energy Information Administration (EIA) prepares a number of periodic reports on current electric power generation and related fuel consumption. For example, Electric Power Monthly (83), and Electric Power Quarterly (84) summarize net generation, net energy for load, peak load, and capability by state and NERC region. More detailed information is maintained in EIA's computerized data files. The "Energy Data Contacts Finder" provides a listing of the names and telephone numbers of the specialists responsible for maintaining the various data files. Copies are available from the National Energy Information Center, Energy Information Administration, Washington, DC 20585.

Figure 3-3. Federal Energy Regulatory Commission regional boundaries

TABLE 3-4
Federal Energy Regulatory Commission

* Federal Energy Regulatory Commission
825 North Capitol Street, NE
Washington, DC 20426

ATLANTA
Regional Engineer, FERC
730 Peachtree Street, NE
Room 800
Atlanta, GA 30308
Telephone: (404) 257-4134

NEW YORK
Regional Engineer, FERC
201 Varick Street, Room 664
New York, NY 10014
Telephone: (212) 264-2609

CHICAGO
Regional Engineer, FERC
Federal Building, Room 3130
230 South Dearborn Street
Chicago, IL 60604
Telephone: (312) 353-6171

SAN FRANCISCO
Regional Engineer, FERC
901 Market Street, 3rd Floor
San Francisco, CA 94103
Telephone: (415) 974-7150

PORTLAND
Regional Director, FERC
1120 SW Fifth Ave., Suite 1340
Portland, OR 97204
Telephone: (503) 326-5840

e. Utilities. Electric utilities routinely prepare load forecasts for generation planning and other purposes. These forecasts are also submitted to the Regional Reliability Councils for incorporation in their reports. The regional reports are satisfactory for most Corps studies, so it is not usually necessary to obtain data directly from utilities. However, in the case of hydro projects located in isolated areas (such as Hawaii or Puerto Rico), or projects which would be utilized in single power systems, evaluation of need on the basis of an individual utility's loads and resources would be warranted.

f. National Hydropower Study. The Corps' Institute for Water Resources prepared under contract a study on the magnitude and regional distribution of needs for hydropower, as a part of the National Hydropower Study (48c, 48d). This report was a one-time forecast of loads and resources, intended to identify by region and sub-region the potential need for hydro generation through the year 2000. Although * the study was based primarily on the 1979 Regional Reliability Council reports and is thus out-of-date, it contains useful information on load characteristics, the operation of individual regional power systems, and other related information.

g. Electric Power Research Institute (EPRI). EPRI was formed in 1973 to conduct a broad program of research and development in technologies related to electric power production, transmission, distribution and utilization. EPRI's activities are coordinated with those of the Federal government, state agencies, individual utilities, and research organizations in other countries. Numerous publications on load forecasting, rate designs, and power generation alternatives are available at cost from Electric Power Research Institute, 3412 Hillview Avenue, Palo Alto, CA 94304. A useful primer is Electric Load Forecasting: Probing the Issues with Models (13). Another helpful document is Synthetic Electric Utility Systems for Evaluating Advanced Technologies (15), which provides generalized weekly load shapes by region and by season and other related information on load characteristics.

h. States. Some states prepare load forecasts as a part of their planning and utility regulatory functions. In many cases these forecasts are based largely on utility-supplied information and are therefore comparable to the Regional Reliability Council data, except for the different geographical areas covered. In other cases, the states prepare independent forecasts, sometimes using economic modeling techniques.

i. Other Sources.

(1) Two additional categories of other load forecasts are available to the planner: (a) generalized forecasts intended to guide policy decisions, and (b) analyses prepared to evaluate the need for specific power projects. The generalized forecasts may be prepared on a national basis, but with data provided by region. An example of this type of forecast would be the quarterly Energy Review prepared by Data Resources, Inc. (4), which provides data on demand and price by region for all energy sources for the next 20 years. An econometric model is used to develop this data, and information is presented on the input assumptions underlying the forecast. Other generalized forecasts are developed for regional planning agencies, such as the Northwest Power Planning Council (29). Some of these forecasts may be published on a regular basis, but others may be one-time studies prepared for specific purposes.

(2) The second category refers to special studies intended for evaluating the need for large (and usually controversial) proposed power projects. For some projects, several forecasts may be avail-

able, each prepared by an entity with a different viewpoint. Forecasts may be developed by the sponsoring utilities, regulatory agencies, and special interest groups. These forecasts are generally one-time only studies, and sometimes are prepared by universities or consultants. State utility regulatory agencies can often help to identify the forecasts available for a given area.

3-6. Load Forecasting Methods. Three basic methods or models are used for load forecasting:

- trend analysis
- end-use analysis
- econometric analysis

Trend analysis is based on extending historical trends and modifying the resulting projections to reflect expected changes. End-use analysis involves constructing demand forecasts based on expected use of the electricity. For example, residential end use forecasts are compiled from estimates of electricity demand by appliance, saturation rates for each appliance, and projections of number of households. Econometric analysis is based on the relationships between electricity demand and the various factors that influence demand. At the present time, many forecasts are based on two or more of these methods. Appendix B describes the three forecasting methods in more detail.

3-7. Guidelines for Selecting a Forecast.

a. The forecast should be responsive to the requirements of Section 2.5.6 of Principles and Guidelines. The analysis should show forecasted resource and required reserve margins as well as loads so that it will be possible to identify a projected shortfall which can be met by the proposed hydro project.

b. The period of analysis should be appropriate to the planning period for the project being studied. The lead time required for planning, authorization, design, and construction of Federal hydro projects generally exceeds 10 years, so a 15 to 20 year analysis is usually required. This is especially true for large plants that require several years to be absorbed in the system load. Where projects are small compared to system load growth, shorter lead times are possible, and a 10-year forecast may be adequate.

c. A simple comparison of annual loads and resources is adequate to establish the need for most base load hydro projects. A more detailed analysis, including examination of daily load shapes, may be necessary in order to identify the need for peaking projects, including pumped-storage plants. It is also necessary to document the availability of off-peak pumping energy when evaluating pumped-storage projects.

d. The load forecast should be responsive to the price of electricity. If the price of electricity is rising due to the addition of high-cost generating resources, the forecast should reflect the resultant conservation measures, and the shift of some load to other energy sources.

e. For the sake of consistency, it is desirable to use the same forecasting source throughout all study stages. It is also desirable to use the same forecasting source that has been used historically on other hydropower studies performed within the district or division, providing that the forecast is current and meets the other criteria outlined in this section.

f. When the regional Federal PMA prepares a load-resource analysis that meets the criteria outlined in this section, it should normally be used as the base case forecast. In other areas, the Regional Reliability Council forecasts generally provide the best starting point. The PMA and Regional Reliability Council forecasts are generally summations of load and resource forecasts provided by individual utilities within the power marketing area, and they tend to represent the regional consensus among utilities and power planners on the need for power. These forecasts are generally updated and published annually, and they provide useful information on peak loads, scheduled resource additions, power imports and exports, and reserves. They are also useful for evaluating the accuracy of past forecasts and trends in forecast growth rates because they have been made for a number of years. In some cases, the PMA or regional power planning organization will also have an econometric load forecast that can be used to test the reasonableness of the load forecast prepared by summing individual utility forecasts. The econometric forecast will also provide information on input assumptions and load growth by residential, commercial and industrial sectors that can be used in intermediate and detailed studies.

g. Forecasts prepared by research groups, ad hoc task forces, special study commissions, non-Federal energy offices, and private consultants are best utilized in sensitivity analyses and in comparison with the selected forecast.

3-8. Variations in Load Forecasts.

a. Several forecasts, often prepared by different entities, may be available for a given area. These forecasts may vary widely, particularly if they are prepared by entities with opposing objectives. The Corps planner must determine why the forecasts differ and, if they vary significantly, how to treat this variation.

b. There are two basic reasons why forecasts give different results. In some uses, different forecasting methods are used. In other instances, different basic assumptions are used in the forecasts. These assumptions may be stated explicity as demand-influencing factors or implicitly as subjective factors which prompted the forecasters to modify historical growth rates or patterns. Even if the forecasting models were perfectly formulated and the associated statistical methodologies and data bases were absolutely correct (and they are not), the accuracy of the forecasts themselves would still depend upon the underlying assumptions. Future demand for a particular energy fuel, for example, is dependent on a variety of interactive changing factors. These include price of the fuel and its alternatives, population growth and lifestyle, employment, per capita income, the number and size of households, the rate at which existing housing and other buildings are replaced, appliance saturation and the rate at which appliances are replaced, industrial technology, and a host of other so-called independent intangibles.

c. In a sophisticated econometric demand model, several hundred different mathematical relationships between independent variables and demand for various energy fuels are statistically estimated for different areas and consumer classes. Not one of these demand influencing factors can be predicted with complete assurance. Accordingly, alternative forecasts should be interpreted as rough indications of the reasonable range of possible outcomes of energy growth, rather than precise computations of future energy consumption.

d. The most important demand-influencing factors (independent variables) are: population, number of households or customers (and type of customers), per capita real income, total personal income, and prices of electricity, natural gas, and oil. When comparing alternative load forecasts, it is sometimes helpful to prepare a table listing these key variables, 10-year historical growth rates for each variable, the present "base" value used for each variable, and the projected growth rate for each variable as assumed in each forecast. Unless there are major discrepancies in the structure of the models or the estimated coefficients or elasticities used in the models, comparing the assumed growth rate of these variables will normally account for most of the differences in the alternative load forecasts.

e. If several varying forecasts are available and they all meet the general requirements of Section 3-7, all should be considered for use in defining the need and timing for a proposed hydro project. As noted in Sections 3-5b and 3-7, the forecast prepared by the PMA or the Regional Reliability Council could serve as the base forecast, and alternative forecasts would be used as sensitivity tests. If the alternative forecasts would have an impact on the timing or need for the project, the planner should watch load growth closely as planning and design progresses, so that necessary adjustments can be made to the design and construction schedule. This periodic review of timing and need should be undertaken for any hydro project, but becomes particularly important when a wide range of load growth projections exist or when load growth is in a state of change.

f. Often forecasting entities will develop a range of load growth projections which reflect the uncertainty associated with many of the factors that influence load growth. In these cases, it is common to utilize the mid-range forecast as the basis for planning and utilize the high and low growth scenarios for sensitivity studies.

3-9. Level of Conservation in the Forecast.

a. Historically, load forecasts were developed on the basis of an implicit assumption that the real cost of elecricity would not rise. This led to another implicit assumption, that the cost of electricity would not induce consumers to reduce their consumption. As a result, electricity demand forecasts did not include adjustments to account for load reductions due to price or institutionally induced conservation measures. The rapidly rising energy and electricty prices beginning in the 1970's revealed the fallacy of these assumptions. The effect of price on the demand for electricity was dramatically demonstrated as forecasts were lowered year after year, and orders for new generating plants were canceled.

b. Since the 1970's, rising electricity prices, combined with government and utility sponsored conservation programs, have produced measurable energy savings. Electricity demand forecasting models have been developed that more accurately account for price-induced conservation and institutionally mandated conservation measures (see Appendix B). As a result, planners can now be reasonably confident that conservation effects are accounted for in most forecasts, at least those that are generated with input-output models. However, Corps planners must review forecast assumptions to assure themselves that price-induced and institutionally mandated conservation have in fact been included. The results of this review should be summarized in the text which documents the load forecast in the project feasibility report.

c. There may be some situations where the feasibility of or need for the proposed hydro project hinges on the load growth forecast, and there is some question as to whether or not conservation is adequately reflected in the forecast. In these cases, studies could be made to determine the load growth rates with prices based on the expected increases in the long-run average cost (LRAC) of electricity and on the long-run incremental cost (LRIC) of electricity. The forecast based on LRAC pricing would represent the most likely growth rate, while that based on LRIC pricing would represent the probable maximum attainable level of conservation. If the growth rate in the forecast being used in the study approximates the growth rate resulting from the LRAC study, it can be assumed that conservation is properly accounted for. LRAC and LRIC studies would have to be made using econometric models, and this would be justified only in the case of large projects.

d. The above discussion applies to conservation actions that would be taken and conservation measures which would be implemented in the absence of any new specific actions or measures. It addresses the without-project condition as it relates to non-structural means of reducing the need for additional generation resources. The analysis of conservation measures as an alternative to a proposed hydropower project (or as a part of a plan including the hydropower project) is discussed in Chapter 9.

3-10. Level of Detail Required in Reports.

a. General. The level of detail included in load and resource forecasts depends on the study type and stage. As described in Sections 3-11 and 3-12, load-resource analyses are not required in order to establish need for (a) hydro projects which displace generation from existing thermal plants, and (b) most small scale (80 MW or less) hydropower projects. Load-resource analyses of appropriate scope and detail are required for studies of all major hydropower projects not being analyzed as a fuel displacement project and those small scale projects not exempted as described in Section 3-12c.

b. Reconnaissance Phase Studies. A reconnaissance study must provide a preliminary finding of need, economic feasibility, and Federal interest within rigorous funding and time constraints. In order to satisfy these requirements, existing studies should be used as much as possible, and a complete load-resource analysis is not necessary if it is not readily available. In most cases, a simple statement of need from the regional Federal PMA, the regional office of FERC, or the local power pool or generation planning entity will be sufficient if more detailed data is not readily available.

as much as possible, and a complete load-resource analysis is not necessary if it is not readily available. In most cases, a simple statement of need from the regional Federal PMA, the regional office of FERC, or the local power pool or generation planning entity will be sufficient if more detailed data is not readily available.

c. Detailed Study Phase. Detailed feasibility studies of major hydropower projects could entail one or more iterations of load-resource analysis. Requirements for iterative refinements of the needs analysis will evolve from the overall plan formulation process (i.e., scope, complexity, and possible controversy associated with alternative plans), so the level of necessary effort will vary from study to study and may not be totally predictable at the outset of the detailed study phase. Within this typical planning environment, it is essential that the load-resource analysis made during the initial stage of the Detailed Study Phase be of adequate scope and detail to provide (a) for timely completion of reports on major projects which are not unduly complex or controversial, and (b) a solid foundation for the iterative refinements necessary to complete detailed studies of complex and controversial projects.

d. Basic Steps. The steps involved in an initial or base load-resource analysis are as described in the next section.

(1) Select the Study Area. For larger projects, this will be a power pool area, Regional Reliability Council area, or a subregion of a Regional Reliability Council area. For smaller projects or projects located in isolated service areas, it could be a smaller geographical area (see Section 3-3b(1)).

(2) Select the Forecast Period. See Section 3-7b.

(3) Select the Required Type of Analysis. In most areas, a peak load-resource analysis is sufficient. For those systems where hydro or other energy-limited generation carries a substantial portion of the load (33 percent or more), an energy load-resource analysis is also required.

(4) Identify the Peak Load Months. Alaska, New England, and the Pacific Northwest have their peak loads in the winter months. The southern portion of the country and a portion of the midwest (MAIN Reliability Council area) have summer peaks. Summer and winter peak load periods are comparable in the remainder of the country. For those areas with a single load season, the load-resource analysis need be done only for that season. Where there are two seasonal peaks, it may be desirable to analyze both seasons.

(6) Estimate Generation Requirements. This should also be done by year for the same period. Peak load requirements should include reserve requirements (Section 2-2e).

(7) Tabulate by Year the Peaking Capability of Existing and Planned Generation. Adjustments should be made for retirements and scheduled outages. Hydro capability should reflect only that capacity which is considered to be dependable in the peak demand months. Data on scheduled new generation can be obtained from Regional Reliability Council reports (Section 3-5b).

(8) Compute the Generation Surplus or Deficit Year by Year. This is done by deducting generation requirements (step 6) from peaking capability (step 7).

(9) Determine if the Proposed Project is Needed. By analyzing the dates and magnitudes of the projected deficits, it is possible to determine if the proposed hydro plant can be utilized in the system and, if so, the earliest date that it would be needed. This analysis would include the development of a resource schedule including the proposed hydro project (the "with-project" scenario) and a resource schedule without the hydro project (the "without-project" scenario). The latter information will serve as the basis for the economic evaluation (see Section 9-4). Tables 3-5 and 3-6 illustrate a load-resource analysis for a small power system in Alaska presented in a with- and without-project format, while Table 3-1 shows a generalized analysis for an entire power pool.

e. Peak Load vs. Energy Load Analysis. The above procedure describes a peak load-resource analysis. If an energy analysis is also required, the steps would be similar except that the analysis would be based on energy demand and the estimated energy output of generating resources. Hydro energy capability would be based on output in an adverse water year unless regional practice specifies otherwise. In energy analyses, it is sometimes necessary also to compare the seasonal demand pattern with the seasonal output of the hydro project, in order to determine if the hydro project's output is compatable with the demand pattern.

f. Additional Information. In addition to the load-resource analysis itself, the following information should be presented in the feasibility report:

TABLE 3-5. Load-Resource Analysis, Kenai

		1988	1989
Capacity Required, MW			
1.	Utility peak load	122.3	128.7
2.	Industrial peak load	28.8	29.6
3.	Total peak load	151.1	158.3
4.	Reserves required	40.0	70.0
5.	Total capacity required	191.1	228.3
Capacity Resources, MW			
6.	Bernice Lake C.T.	52.1	52.1
7.	Cooper Lake hydro	15.0	15.0
8.	Seward diesel	5.5	2.5
9.	Seldovia diesel	2.3	0.0
10.	Industrial generation	30.4	30.4
11.	115 KV Anchorage line	40.0	40.0
12.	Total existing capacity	145.3	140.0
13.	Net surplus or deficit	-45.8	-88.3
14.	Combustion turbine	36.0	36.0
15.	Bradley Lake	0.0	90.0
16.	135 KV Anchorage line	0.0	0.0
17.	Total capacity	181.3	266.0
18.	Adjusted surplus/deficit	-9.8	+37.7

Peninsula Subsystem with Bradley Lake

1990	1991	1992	1993	1994	1995
135.5	141.0	146.7	152.7	158.9	165.4
30.4	31.1	31.9	32.6	33.4	34.2
165.9	172.1	178.6	185.3	192.3	199.6
70.0	70.0	70.0	70.0	70.0	70.0
235.9	242.1	248.6	255.3	262.3	269.6
52.1	52.1	52.1	43.9	43.9	35.7
15.0	15.0	15.0	15.0	15.0	15.0
2.5	2.5	2.5	2.5	2.5	0.0
0.0	0.0	0.0	0.0	0.0	0.0
30.4	30.4	30.4	30.4	30.4	30.4
40.0	40.0	40.0	40.0	40.0	40.0
140.0	140.0	140.0	131.8	131.8	121.1
-95.9	-102.1	-108.6	-123.5	-130.5	-148.5
36.0	36.0	36.0	36.0	36.0	36.0
135.0	135.0	135.0	135.0	135.0	135.0
0.0	0.0	0.0	0.0	0.0	0.0
311.0	311.0	311.0	302.8	302.8	292.1
+75.1	+68.9	+62.4	+47.5	+40.5	+22.5

TABLE 3-6. Load-Resource Analysis, Kenai

		1985	1986	1987	1988
Capacity Required, MW					
1.	Utility peak load	104.7	110.2	116.5	122.3
2.	Industrial peak load	26.6	27.3	28.1	28.8
3.	Total peak load	131.3	137.5	144.6	151.1
4.	Reserves required	40.0	40.0	40.0	40.0
5.	Total capacity req'd	171.3	177.5	184.6	191.1
Capacity Resources, MW					
6.	Bernice Lake C.T.	52.1	52.1	52.1	52.1
7.	Cooper Lake hydro	15.0	15.0	15.0	15.0
8.	Seward diesel	5.5	5.5	5.5	5.5
9.	Seldovia diesel	2.3	2.3	2.3	2.3
10.	Industrial generation	30.4	30.4	30.4	30.4
11.	115 KV Anchorage line	40.0	40.0	40.0	40.0
12.	Total existing cap'y	145.3	145.3	145.3	145.3
13.	Net surplus or deficit	-26.0	-37.7	-39.3	-45.8
14.	Combustion turbine	18.0	36.0	36.0	54.0
15.	Bradley Lake	0.0	0.0	0.0	0.0
16.	135 KV Anchorage line	0.0	0.0	0.0	0.0
17.	Total capacity	163.3	181.3	181.3	199.3
18.	Adjusted Surplus/Deficit	-8.0	+3.8	-3.3	+8.2

Peninsula Subsystem without Bradley Lake

1989	1990	1991	1992	1993	1994	1995
128.7	135.5	141.0	146.7	152.7	158.9	165.4
29.6	30.4	31.1	31.9	32.6	33.4	34.2
158.3	165.9	172.1	178.6	185.3	192.3	199.6
40.0	40.0	40.0	40.0	40.0	40.0	60.0
198.3	205.9	212.1	218.6	225.3	232.3	259.6
52.1	52.1	52.1	52.1	52.1	52.1	35.7
15.0	15.0	15.0	15.0	15.0	15.0	15.0
2.5	2.5	2.5	2.5	2.5	2.5	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0
30.4	30.4	30.4	30.4	30.4	30.4	30.4
40.0	40.0	40.0	40.0	40.0	40.0	40.0
140.0	140.1	140.1	140.1	140.1	140.0	121.1
-58.3	-65.9	-72.1	-78.6	-85.3	-92.3	-138.5
54.0	72.0	72.0	90.0	90.0	90.0	90.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0
194.0	212.0	212.0	230.0	230.0	230.0	211.1
-4.3	+6.1	-0.1	+11.4	+4.7	-2.3	-48.5

- map of market area
- source of selected forecast
- type of forecast (e.g., single agency forecast or aggregation of multiple utility forecasts)
- forecast methodology and underlying assumptions (if available)
- a tabulation of actual loads for each of the past 10 years. The average annual growth should be computed and compared with the growth rate in the forecast
- a comparison of the growth rate for the selected load forecast with previous years' growth rates (i.e., are 10-year or 20-year growth rates rising or falling compared with forecasts made in the past 5 years). Explain upward or downward trends in terms of conservation, higher energy prices, economic growth or decline, etc.
- an evaluation of the accuracy of historic load forecasts. For example, compare actual load in a recent year with the load that was forecast for that year in forecasts dating back at least 5 years
- a listing of the major power plants under construction or proposed for construction that are included in the resource forecast, including information on type, installed capacity, average energy output (where an energy analysis is being made), and scheduled on-line date.

This evaluation process and information display should satisfy plan formulation and reporting requirements for major projects which are not unduly complex or controversial.

g. Load Forecast Requirements. Plan formulation and public involvement activities will generally identify necessary refinements of needs analysis for complex and controversial projects. Typical refinements include (a) separation of forecasted loads into residential, commercial, and industrial sectors to more clearly define source and projected growth of further demands, (b) more detailed definition of weekly/daily load shapes for representative periods of future demand years to more clearly display the type of load that the hydro project could serve, (c) the development of alternative load growth scenarios to determine the impact of load growth on timing and need for the project, and (d) comparison with other published load forecasts.

3-11. <u>Analysis of Energy Displacement Projects.</u> The output of some hydroelectric projects can best be used to displace generation from existing high-cost thermal plants. This could be the case in areas like California, Alaska and New England, where much of the energy demand is met by oil-fired steam generation. In these cases, the proposed hydro plant would not defer or displace an increment of new thermal capacity, and thus a load-resource study would not be required to establish need. The need would be tied instead to the analysis of economic feasibility. Studies that show that the cost of constructing and operating the proposed hydro plant is less than the cost of the existing generation displaced would be sufficient to establish need. The report, however, must include a description of the existing and expected future power system, with an explanation of how the hydro project would be used to displace thermal generation and what types of plants would be backed off. The energy displacement method for evaluation of hydro projects is discussed further in Section 9-6.

3-12. <u>Marketability Analysis.</u>

a. <u>Flood Control Act of 1944.</u> Under the provisions of Section 5 of the Flood Control Act of 1944 (Public Law 534, 78th Congress) and other acts, power developed at multiple-use reservoirs under the jurisdiction of the Chief of Engineers and Bureau of Reclamation is turned over to the Secretary of Energy for marketing. The Act requires that the Secretary shall transmit and dispose of power and energy so as to encourage the most widespread use at the lowest possible rates to consumers, consistent with sound business principles. It also provides that preference in the sale of power be given to public bodies and cooperatives. Rates for sale of power to recover allocated costs are established by DOE's regional Power Marketing Administrations (PMA's), and approved by the FERC. Figure 3-2 shows the location of the regional PMAs. As noted earlier, DOE's Office of Power Marketing Coordination will designate an adjacent PMA to handle the marketing function where a hydro project is located outside of the service areas of the established PMA's.

b. <u>Marketability Reports.</u> All feasibility reports for hydroelectric projects must contain a statement by the regional PMA that the power from the proposed project is marketable and that project costs allocated to power can be repaid with interest within fifty years (see Section 9-9). The marketability analysis in many cases is limited to the needs of preference customers, and the revenue rates upon which the analysis is based are frequently average costs, which include the costs of substantial amounts of older, low-cost generation. This type of analysis is consistent with the requirements of the Flood Control Act of 1944 which govern the PMA's, but does not meet the requirements of Principles and Guidelines (P&G) for a determination of need for an economic analysis.

c. Treatment of Small Projects. To insure efficiency in the use of planning resources, P&G encourages simplified procedures for small scale hydro projects. One area where simplifications are suggested is in establishment of the need for power. Section 2.5.4 of P&G states that ". . . an analysis of marketability may be substituted for determination of need for future generation for hydropower projects up to 80 MW at existing Federal facilities." The PMA marketability analysis described above would serve this purpose. Such a substitution would be particularly appropriate for large power systems where the annual load growth is so large that the small hydro project would have little or no effect on the scheduling of other new generating resources. However, where the proposed hydro project is large with respect to system loads, such as in small, isolated systems in Alaska, a full load-resource analysis would still be required.

CHAPTER 4

HYDROLOGIC DATA PREPARATION

4-1. Introduction.

a. This chapter identifies and briefly discusses the types and sources of hydrologic data required for hydropower studies. However, the details of hydrologic evaluation procedures used for developing this data are not described because they are already well documented in other EM's and standard hydrologic engineering references.

b. The most important type of hydrologic data required for a hydropower feasibility study is the long term streamflow record that represents the flow available for power production. Other important hydrologic data includes tailwater rating curves, reservoir storage-elevation tables, evaporation losses and other types of losses, sedimentation and water quality data, downstream flow requirements, streamflow routing criteria, and downstream channel constraints. The procedures used to develop this information are determined by the level of the study and the quality and quantity of data available. Detailed studies are not always necessary to develop reasonable estimates of this data, and sometimes, due to limitations in the type and amount of available information, detailed studies cannot be performed. Extrapolations of available data and simplified assumptions are sometimes necessary to compensate for lack of information.

4-2. Streamflow Records.

a. General. Streamflow records are the backbone of the hydropower study. Mean monthly discharges are sometimes adequate, but in other cases, weekly or daily values are necessary.

b. Data Collection. The U.S. Geological Survey (USGS) is the principal source of streamflow records. Currently, the USGS collects and disseminates the majority of the water data collected in the United States. Most data collected by the USGS is summarized in the Water Resources Data, an annual series of reports for each state or hydrologic region in the United States (75). Figure 4-1 is an example of data supplied by the USGS. Surface water records are also sometimes available from Federal, state, and local water management agencies and utilities.

c. <u>WATSTORE.</u> Surface water records collected by the USGS and others are stored in WATSTORE, the USGS's National Water Data Storage and Retrieval System. Access to the WATSTORE system is available to all Corps offices through an interagency agreement between the Corps of Engineers and the USGS. The WATSTORE data storage and retrieval system contains water resources data which includes surface runoff, ground water conditions, and water quality data for all 50 states, Puerto Rico, the Virgin Islands, and Canada. WATSTORE files contain daily, monthly, and yearly peak and mean flow data for gaging stations in the system. WATSTORE data can be displayed as standard-

PEND OREILLE RIVER BASIN

12323750 SILVER BOW CREEK AT WARM SPRINGS, MT

LOCATION.--Lat 46°11'07", long 112°46'04", in SE¼ sec.18, T.5 N., R.9 W., Deer Lodge County, on right bank 0.3 mi (0.5 km) upstream from county highway bridge, 0.2 mi (0.3 km) upstream from confluence with Warm Springs Creek, and 1.0 mi (1.6 km) northeast of Warm Springs.

DRAINAGE AREA.--483 mi² (1,251 km²).

PERIOD OF RECORD.--March 1972 to current year.

GAGE.--Water-stage recorder. Datum of gage is 4,787.05 ft (1,459.367 m) above sea level.

EXTREMES.--Current year: Maximum discharge, 1,320 ft³/s (37.4 m³/s) June 20, gage height, 7.47 ft (2.277 m); minimum daily, 24 ft³/s (0.680 m³/s) Jan. 3.

Period of record: Maximum discharge, 1,320 ft³/s (37.4 m³/s) June 20, 1975, gage height, 7.47 ft (2.277 m); maximum gage height, 8.64 ft (2.633 m) Jan. 16, 1974, (backwater from ice jam); minimum daily discharge, 15 ft³/s (0.43 m³/s) Sept. 12, 13, 1973.

REMARKS.--Records good. Flow can be regulated by dam on Anaconda Co. tailing ponds about 0.5 mi (0.8 km) upstream from gage. Diversions for irrigation of about 4,650 acres (18.8 km²) above station.

DISCHARGE, IN CUBIC FEET PER SECOND WATER YEAR OCTOBER 1974 TO SEPTEMBER 1975
MEAN VALUES

DAY	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
1	52	111	98	69	81	131	122	208	643	403	438	177
2	56	120	93	65	81	176	115	226	748	514	332	161
3	49	120	96	24	87	244	111	240	872	569	230	161
4	53	114	99	37	91	262	115	274	896	569	214	172
5	104	108	107	38	89	232	114	298	861	531	210	168
6	84	66	112	51	85	156	114	297	934	582	188	163
7	81	37	112	54	85	168	111	322	903	582	194	150
8	77	130	109	60	85	154	110	332	907	471	216	147
9	74	89	102	64	85	150	102	339	874	568	208	140
10	68	36	105	45	85	150	102	357	749	463	188	130
11	65	105	108	50	84	140	104	461	639	378	170	130
12	47	55	101	50	88	131	114	692	623	341	160	123
13	73	140	101	49	92	130	140	547	680	306	145	117
14	83	152	102	44	102	122	196	616	639	343	168	123
15	81	107	96	55	106	117	246	696	685	334	160	122
16	88	163	96	72	106	120	259	728	680	314	150	123
17	81	120	96	83	102	122	319	605	550	290	170	122
18	81	120	102	102	96	122	319	696	708	206	168	137
19	80	111	101	109	91	140	274	740	1170	207	172	131
20	81	43	101	111	89	161	254	632	1220	264	198	147
21	110	52	102	106	91	147	264	534	1060	205	206	144
22	160	125	93	101	101	142	283	463	915	272	150	130
23	137	202	84	96	104	130	337	442	763	277	181	140
24	118	102	88	96	98	120	300	454	805	260	264	137
25	114	53	77	94	98	120	307	418	706	228	241	89
26	112	163	77	90	105	112	319	382	676	204	222	135
27	115	165	73	84	110	108	284	388	641	190	206	145
28	111	130	80	88	115	102	242	302	531	176	190	120
29	103	122	84	75	—	102	229	432	630	176	154	114
30	102	101	77	88	—	115	202	498	630	247	122	112
31	103	—	73	88	—	126	—	549	—	306	206	—
TOTAL	2751	3352	2937	2214	2632	4460	6099	14322	23113	11044	6237	4110
MEAN	88.7	112	94.7	71.4	94.0	144	203	462	770	356	201	137
MAX	168	202	112	111	115	262	337	740	1240	569	438	177
MIN	47	37	73	24	81	102	102	208	630	176	122	89
AC-FT	5460	6650	5830	4390	5220	8860	12100	28410	45840	21910	12370	8170

CAL YR 1974 TOTAL 53741 MEAN 147 MAX 980 MIN 27 AC-FT 106600
WTR YR 1975 TOTAL 83207 MEAN 228 MAX 1220 MIN 24 AC-FT 165200

Figure 4-1. Example of USGS daily streamflow data ized tables or graphs. An example of WATSTORE output used in hydropower studies are shown in Figure 4-2. This data can be analyzed and plotted. WATSTORE is also capable of producing a magnetic tape of selected data.

d. Data Accuracy and Reliability. Users of WATSTORE should review individual station records carefully. Retrieved data should be verified for its reliability because the USGS may have made subsequent revisions to this data as a result of a reanalysis. These revisions are most commonly made to correct errors found during historic high and low streamflow conditions or when ice is present, but may include the entire period of record if the accuracy of the gaging station is questionable.

FILE TYPE	STATE CODE	AGENCY CODE	STATION IDENTIFICATION NUMBER	CROSS SECTION	SAMPLING DEPTH	PARAMETER CODE	YEAR	STAT CODE	MO VALUE INDICATOR	DIST CODE	COUNTY CODE	DRAINAGE AREA	CONTRIB. DRAINAGE AREA
R	42	USGS	01474500	999999.000	999999.000	00060	1974	00003	999999.0000	42	101	1893.00	0.00

STATION NAME OR LOCAL WELL NUMBER	WELL DEPTH	DATUM	HYDROLOGIC UNIT CODE	RTV SEQ NO	BEG MO	SITE CODE	STATION LOCATOR LAT-ITUDE	LONG-ITUDE	SEQ NO	GEOLOGIC UNIT CODE
SCHUYLKILL RIVER AT PHILADELPHIA, PA.	-99999.00	5.74	000000000	01	10	SW	395942	0751140	00	

DAY	10	11	12	01	02	03	04	05	06	07	08	09
1	1570.00	2250.00	1260.00	5830.00	4080.00	3110.00	11000	2060.00	1700.00	1650.00	965.000	1120.00
2	1610.00	1910.00	1030.00	5180.00	3580.00	3210.00	8310.00	1920.00	2120.00	2280.00	777.000	1360.00
3	1980.00	1660.00	929.000	4460.00	3370.00	2900.00	7320.00	2090.00	2050.00	1890.00	1030.00	2700.00
4	1530.00	1420.00	862.000	6170.00	3010.00	2760.00	8130.00	2410.00	1680.00	1500.00	1810.00	5530.00
5	1310.00	1280.00	1750.00	5380.00	2570.00	2610.00	12500	2060.00	1450.00	1480.00	3950.00	3400.00
6	1140.00	1240.00	6610.00	4240.00	2240.00	2470.00	12200	1870.00	1300.00	1320.00	1920.00	2150.00
7	1050.00	1130.00	4520.00	3910.00	2290.00	2330.00	9150.00	1950.00	1200.00	1250.00	1220.00	3260.00
8	997.000	1080.00	3220.00	3630.00	2240.00	2200.00	7530.00	1900.00	1180.00	1100.00	981.000	3650.00
9	1010.00	1060.00	5290.00	3210.00	2030.00	3110.00	13700	1860.00	1200.00	954.000	917.000	2410.00
10	568.000	972.000	9620.00	3260.00	1810.00	5370.00	9870.00	2990.00	1140.00	858.000	1390.00	1890.00
11	999.000	963.000	6630.00	5260.00	1770.00	5130.00	7080.00	2930.00	1090.00	790.000	1070.00	1610.00
12	996.000	909.000	4970.00	6380.00	1730.00	4330.00	5990.00	2780.00	996.000	812.000	927.000	1550.00
13	916.000	915.000	3970.00	4300.00	1650.00	3860.00	7690.00	11500	965.000	777.000	763.000	1410.00
14	907.000	904.000	6080.00	3160.00	1690.00	3370.00	8540.00	7040.00	933.000	729.000	651.000	2270.00
15	858.000	845.000	5610.00	3010.00	1620.00	3000.00	8660.00	4780.00	983.000	615.000	632.000	2570.00
16	806.000	840.000	4210.00	3150.00	1880.00	3230.00	7850.00	3860.00	2010.00	586.000	557.000	2060.00
17	783.000	764.000	3850.00	3100.00	1760.00	6290.00	5970.00	3200.00	2990.00	554.000	547.000	1670.00
18	740.000	789.000	3400.00	3050.00	1760.00	4640.00	5120.00	2810.00	1640.00	507.000	2460.00	1440.00
19	738.000	785.000	2820.00	3000.00	1800.00	3550.00	4630.00	2610.00	1230.00	553.000	1560.00	1280.00
20	739.000	791.000	2850.00	3000.00	2500.00	3250.00	4460.00	2320.00	1010.00	523.000	1000.00	1170.00
21	728.000	763.000	37400	4000.00	3120.00	5170.00	4000.00	2100.00	1150.00	540.000	743.000	1160.00
22	723.000	734.000	26400	5700.00	2510.00	9370.00	3640.00	1960.00	1520.00	503.000	626.000	1310.00
23	726.000	708.000	13600	9000.00	4060.00	5890.00	3640.00	2630.00	2260.00	461.000	2980.00	1280.00
24	742.000	713.000	9190.00	8100.00	4760.00	5010.00	3330.00	2560.00	2650.00	787.000	1160.00	1390.00
25	708.000	756.000	6800.00	7200.00	3950.00	4400.00	2920.00	2380.00	2470.00	936.000	870.000	957.000
26	684.000	831.000	10800	6000.00	3600.00	3760.00	2650.00	1820.00	1850.00	822.000	663.000	859.000
27	668.000	897.000	22000	6200.00	3110.00	3410.00	2490.00	1700.00	1540.00	687.000	974.000	793.000
28	630.000	1110.00	12000	6000.00	3010.00	3060.00	2330.00	1670.00	1480.00	610.000	777.000	1200.00
29	1730.00	1920.00	9190.00	6500.00	999999	2940.00	2270.00	1640.00	1880.00	550.000	701.000	8540.00
30	3760.00	1940.00	7530.00	5900.00	999999	5000.00	2200.00	1700.00	1770.00	1030.00	961.000	2610.00
31	3760.00	999999	6220.00	5300.00	999999	18600	999999	1680.00	999999	1080.00	1110.00	999999

Figure 4-2. Example WATSTORE output: daily streamflow data for a surface water gage

c. WATSTORE. Surface water records collected by the USGS and others are stored in WATSTORE, the USGS's National Water Data Storage and Retrieval System. Access to the WATSTORE system is available to all Corps offices through an interagency agreement between the Corps of Engineers and the USGS. The WATSTORE data storage and retrieval system contains water resources data which includes surface runoff, ground water conditions, and water quality data for all 50 states, Puerto Rico, the Virgin Islands, and Canada. WATSTORE files contain daily, monthly, and yearly peak and mean flow data for gaging stations in the system. WATSTORE data can be displayed as standardized tables or graphs. An example of WATSTORE output used in hydropower studies is shown in Figure 4-2. This data can be analyzed and plotted. WATSTORE is also capable of producing a magnetic tape of selected data.

d. Data Accuracy and Reliability. Users of WATSTORE should review individual station records carefully. Retrieved data should be verified for its reliability because the USGS may have made subsequent revisions to this data as a result of a reanalysis. These revisions are most commonly made to correct errors found during historic high and low streamflow conditions or when ice is present, but may include the entire period of record if the accuracy of the gaging station is questionable.

e. Data From Other Sources. There are some areas within the country where USGS streamflow information is not available or is insufficient. Local irrigation districts, public utility districts, private utility companies, state water resources agencies and Federal agencies, such as the Corps of Engineers, Bureau of Reclamation, and Tennessee Valley Authority may possess streamflow or reservoir storage data that is not in the USGS files. These potential sources should be investigated when adequate data is not available from the USGS.

4-3. Historical Records Adjustment.

a. General. Streamflow data obtained from the USGS or another agency may not be immediately usable for hydropower site analysis. Historical streamflow records, especially if they span a long period of time, may have to be adjusted to account for diversions, reservoir regulation, and upstream land use changes. This is done so that the streamflow record is consistent throughout the period of record and properly reflects conditions at some base level. This base level could represent present conditions or expected streamflow conditions at some future date. When analyzing a hydropower project on a stream where diversions or factors influencing streamflow are expected to change substantially with time, it may be necessary to develop modified flows for one or more future levels to insure that accurate long-term estimates of energy potential are developed. Adjustments may also be necessary to account for the differences in runoff between the gaging station and the study site.

b. Natural and Modified Streamflow Conditions.

(1) Natural Streamflows. When regional streamflow studies are performed, it is often necessary to modify observed streamflow data to represent an unregulated or "natural" basin condition. Streamflow data is developed to generate a set of hydrologically consistent data that reflects a base condition where the effects of diversions and withdrawals that have occurred at different times during the period of record are removed. This discharge data is obtained by adding back flow diversions or withdrawals of water that bypassed the gaging station. Reservoir storage-release records are also corrected for evaporation and percolation losses. It is also necessary in some cases to adjust discharge data for changes in long-term watershed conditions due to changes in land use.

(2) Modified Streamflows. It is not necessary to develop a set of natural streamflows if existing uses of water, such as irrigation withdrawals, are expected to continue in the future. In the latter case, a uniform basin condition is established for a specific point in time, where the effects of upstream regulation are accounted for during the entire period of record. In order to obtain uniform flow data, streamflows prior to the date that any diversion was initiated must be adjusted to reflect the selected base condition. The discharge record that is developed for this situation is called a modified flow record, which represents a basin condition at some point in time.

c. Estimating Flow at a Damsite. Correction to streamflow data is required if a gaging station is not located in the immediate vicinity of the study site. Standard hydrologic methods should be used to adjust the streamflow information of the gage to represent flow at each project site. Hydrologic characteristics of the watershed such as drainage area, topography, soil, and precipitation patterns should be considered. Streamflow evaluation at existing dams is often easier than at undeveloped sites because existing streamflow records and other hydrologic data can be used.

d. Extension of Historical Records.

(1) Although short-term records may be considered acceptable for reconnaissance studies, more detailed studies require longer periods of record. The decision to extend a short historical record should be based on the level of study and the type of analysis for which the record is to be used. Generally, streamflow records should be

extended if the available record is less than 20 to 30 years. Correlation and regression techniques can be used to extend a period of record if one or more sites with similar flow variations can be found. If good correlation does not exist, other techniques such as examination of precipitation records should be used to test the existing record to determine if it is representative of the long-term record.

(2) Streamflow extension can be accomplished by regression analysis. This method finds regression coefficients for simultaneous flows between a gage with a short term record and one or more gages with a long period of record. These coefficients are applied to the long record values to extend the short record. This technique requires that the station records have sufficient concurrent record to obtain satisfactory correlation.

(3) Stochastic techniques can also be used to generate a long synthetic record as a substitute for a short length of actual record. Stochastic techniques are also used to fill in missing periods of record. The program HEC-4, "Monthly Streamflow Simulation," is capable of generating monthly flows.

(4) Basin rainfall-runoff models are used when streamflow records are either too short, unreliable, or unavailable. These models use precipitation information and basin characteristics to generate additional streamflow information. A continuous simulation model, such as North Pacific Division's SSARR Model (Streamflow Synthesis and Reservoir Regulation), generates hourly or daily flows and is suitable for more detailed studies (56).

e. Future Flow Depletions. Future levels of consumptive uses must be evaluated when studying total water availability during the life of a project. Future demands for irrigation, municipal and industrial consumptive use, and population levels are quantities that should be determined and incorporated in the streamflow data used for making the power studies.

4-4. Types of Streamflow Data Used in Power Studies.

a. General. Streamflow data is used to develop estimates of water available for power generation. The most common types of streamflow data used for this process are mean daily, mean weekly and mean monthly flows. This data is often summarized in flow duration curves.

b. Mean Daily Data. This is the basic increment of hydrologic data available from the streamflow records. Daily flow data can be used directly to develop flow duration curves for estimating the power potential of small hydro projects. It is also used to help evaluate projects where little or no seasonal storage is available for power generation either at-site or upstream. Daily flows may also be required as supplemental information in studies based on monthly flows. An example would be a flood control project where flood flows are flashy and of short duration. Monthly average flows may be suitable for evaluating most of the year, but they could mask out the wide variations of discharge and reservoir elevation that would occur during the flood season. This type of operation may occur during only a small portion of the year, and monthly average flows may be suitable for evaluating the remainder of the year.

c. Mean Weekly and Monthly Data. Mean weekly and monthly data are obtained from mean daily flow records. These values are sometimes used in place of daily data in power calculations in order to reduce computation time. Because the mean value represents a series of flow values, care should be taken to verify that this value represents the useable flows available to the powerplant units. Where flows vary widely within the week or month, an average weekly or monthly value may overestimate the amount of streamflow available for generation. For example, a given monthly average flow may be well within a hydro plant's hydraulic capacity, but there may be many days during that month when the flow exceeds the hydraulic capacity, and water is spilled. On the other hand, where streamflows are relatively constant within the week or month, as is sometimes the case when flows are highly regulated, the use of weekly or monthly flows can save considerable computation time. Section 5-6b discusses this topic in more detail.

d. Flow-Duration Curves. Flow-duration curves are used to summarize streamflow characteristics and can be constructed from daily, weekly, or monthly streamflow data. Duration curves can be constructed with historical data from WATSTORE or with regulated flows from HEC-5, SUPER, or one of the other sequential routing models described in Appendix C. These curves show the percentage of time that flow equals or exceeds various values during the period of record. The disadvantages of the flow-duration curve is that it does not present flow in chronological sequence, does not describe the seasonal distribution of streamflow, and does not account for variations of head independent of streamflow. However, these curves are useful for evaluating the power output of run-of-river projects and for other power projects where head varies directly with flow. The procedures for constructing a flow-duration curve is presented in most standard hydrology texts. An example of a flow duration curve is shown as Figure 4-3.

e. Seasonal Flow Distribution. Regardless of the type of streamflow data used in making the power study, information should be presented showing seasonal distribution of runoff. This information, which could be presented in tabular or graphical form, is useful for evaluating the usability of the power from the project. Figure 4-4 shows an example of a graph showing period-of-record average streamflow by month.

4-5. Other Hydrologic Data.

a. Introduction. In addition to determining the annual and seasonal distribution of water available for power generation, hydrologic analysis can include other related studies. Common types of data required are tailwater rating curves, reservoir elevation-area-capacity tables, sedimentation data, water quality data, downstream flow information, water surface fluctuation data, and evaporation and seepage loss analyses.

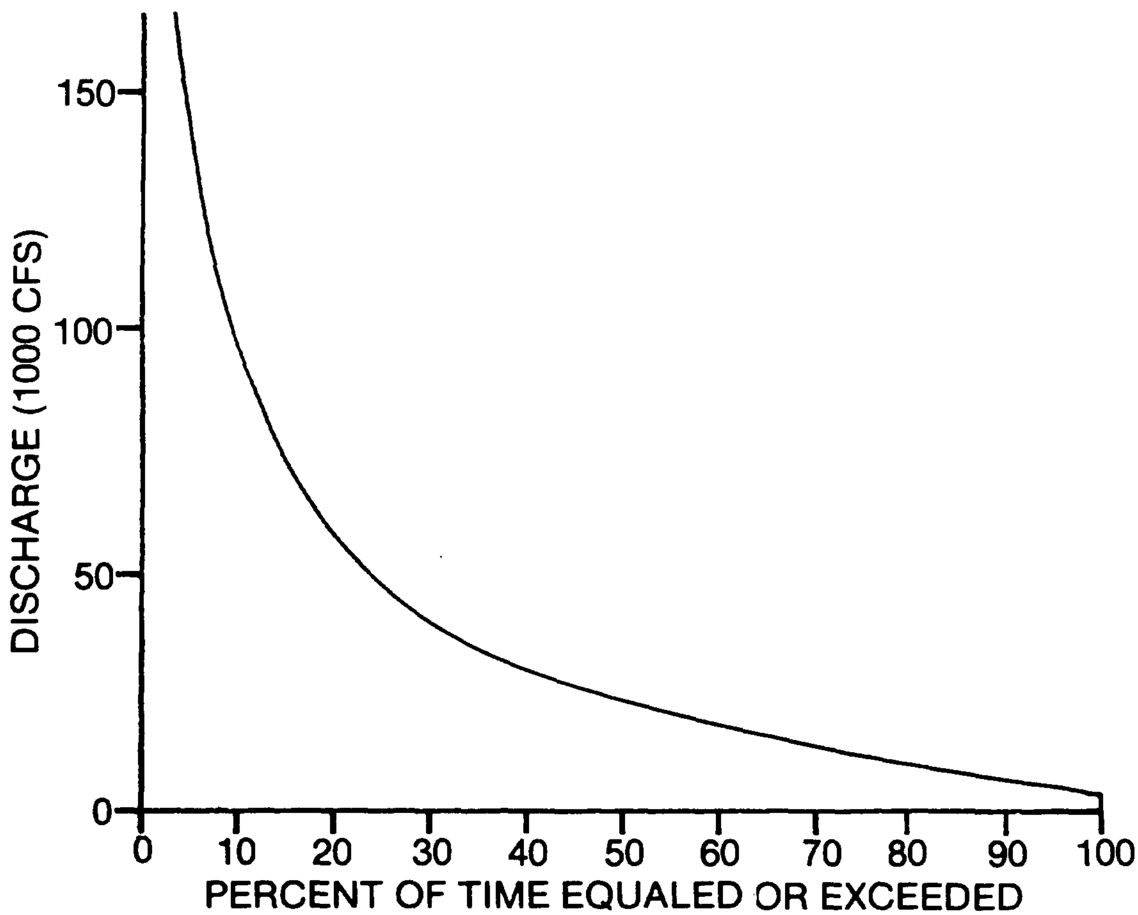


Figure 4-3. Flow-duration curve

b. Tailwater Rating Curves.

(1) General. Tailwater rating studies are made to define the variation of tailwater elevation with project flow discharge. This data is used to compute the generating head available at each discharge level. Tailwater elevation is a function of downstream channel geometry, project discharge, and downstream backwater effects. Tailwater restrictions can also limit the gross hydraulic capacity of the proposed powerhouse. Figure 4-5 is a typical example of a tailwater rating curve. For new projects, tailwater curves can be developed using the standard step method, with computer models such as HEC-2, "Water Surface Profiles".

(2) Run-of-River Projects. For pure run-of-river projects, such as lock and dam structures, the tailwater rating curve and the forebay elevation can often be used to develop a head vs. discharge curve.

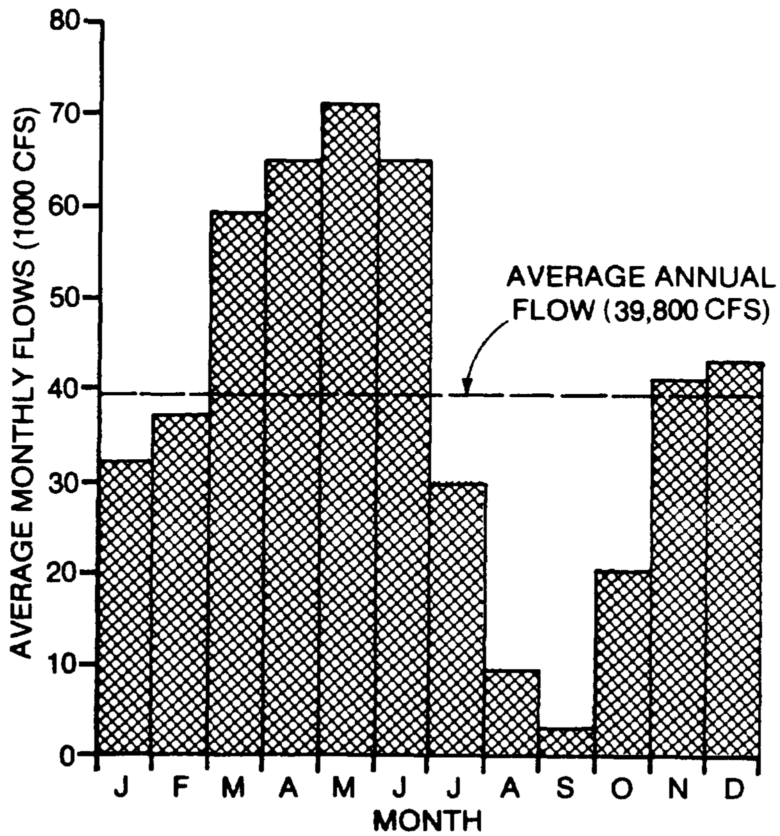


Figure 4-4. Monthly flow distribution

Data from this curve and the flow-duration curve can be combined to develop a generation-duration curve. Figure 4-6 shows an example of a head vs. discharge curve. For pure run-of-river projects, the forebay elevation can usually be assumed to be constant over a substantial flow range, but in many cases it begins to increase at high inflows.

(3) Peaking Projects. A peaking plant may typically operate at or near full output for part of the day and at zero or some minimum output during the remainder of the day. In these cases, the tailwater elevation during generation may be virtually independent of the average streamflow for the day, except perhaps during periods of high runoff. For projects of this type, a single tailwater elevation based upon the peaking discharge could be specified. This value could be a weighted average tailwater elevation, developed from hourly operation

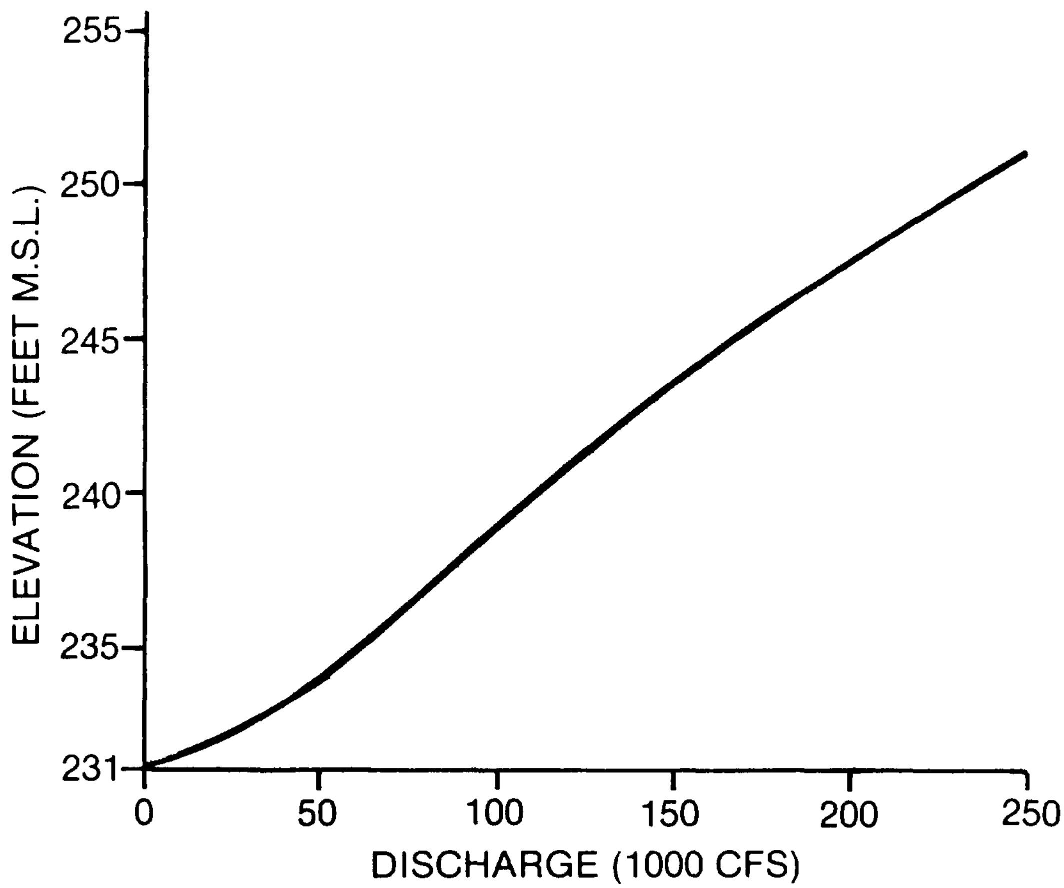


Figure 4-5. Tailwater rating curve

studies and weighted proportionally to the amount of generation produced in each hour of the period examined. Alternatively, it could be a "block-loaded" tailwater elevation, based on an assumed typical output level. The specific output level used for a "block-loaded" tailwater elevation could be based on (a) operation at full rated output, (b) output at best efficiency (typically 75 to 80 percent of full rated output for Francis turbines, for example), or (c) an output value developed in coordination with the agency which will be

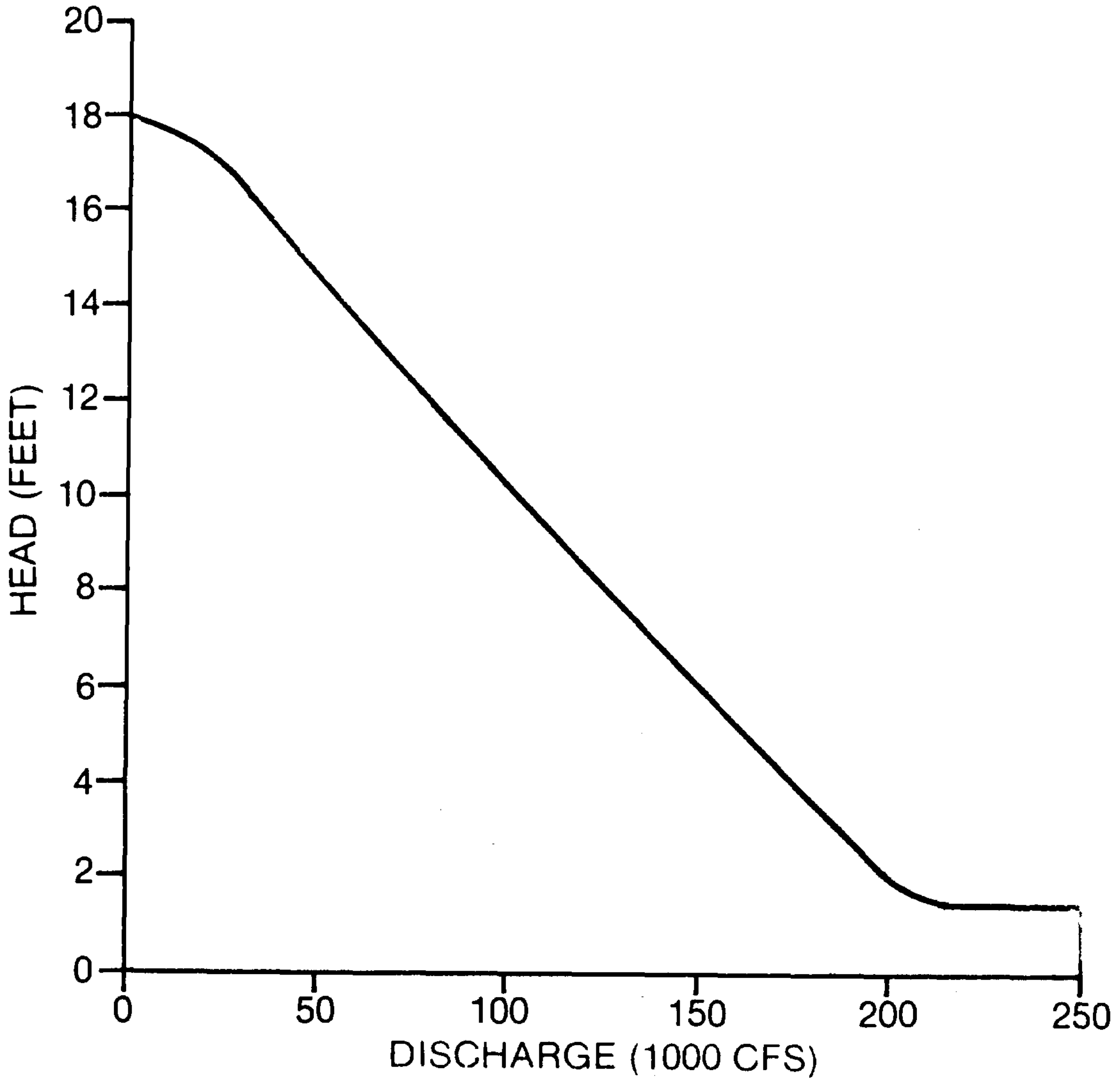


Figure 4-6. Head-discharge curve

marketing the project's power output. Figure 4-7 shows a tailwater curve modified to reflect "block-loading" in the low flow range. The loading would be generally similar to the loading shown on shown on Figure 5-23, except that it is assumed that the minimum discharge is zero instead of 150 cfs and the minimum number of hours on peak is five instead of eight).

(4) Existing Projects. A record of tailwater discharge-elevation relationships may be available to aid analysis of the addition of power to existing projects. A tailwater rating curve can be developed directly from this data.

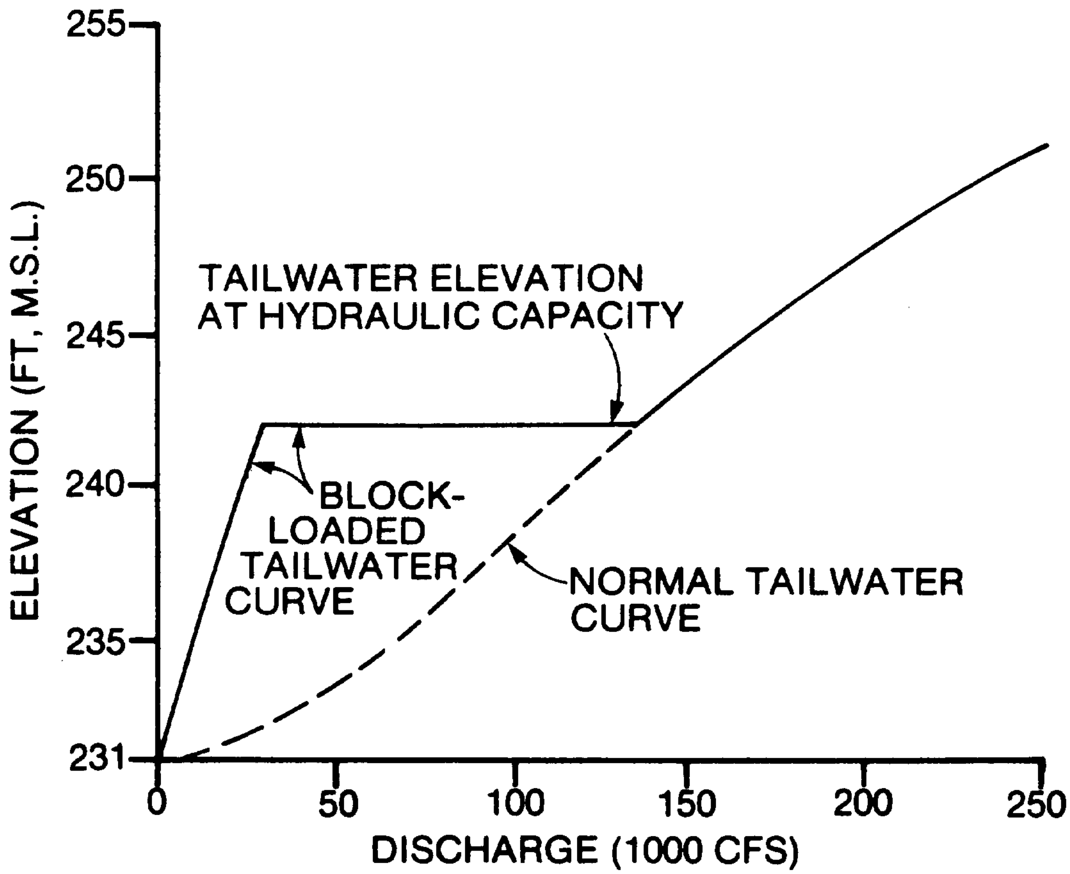


Figure 4-7. Block-loaded tailwater curve

(5) Hourly Studies. When evaluating peaking hydro projects, hourly streamflow routing studies are often made to estimate peaking capability and pondage requirements and to evaluate the impact of discharge fluctuation downstream from the project. In this type of study, it may be necessary to incorporate an hourly routing subroutine in the power generation model in order to accurately measure tailwater elevation and head. The actual tailwater elevation during hourly operation tends to "lag" the tailwater elevation obtained from the usual steady-state tailwater rating curve.

c. Reservoir Storage-Elevation and Area-Elevation Data.

(1) For storage projects, it is necessary to determine the storage-elevation and area-elevation characteristics of the reservoir. This information is used in reservoir regulation and evaporation studies. Figure 4-8 is an example of a typical reservoir elevation-area-capacity curve. This data can also be developed in tabular form for direct input to sequential streamflow routing programs.

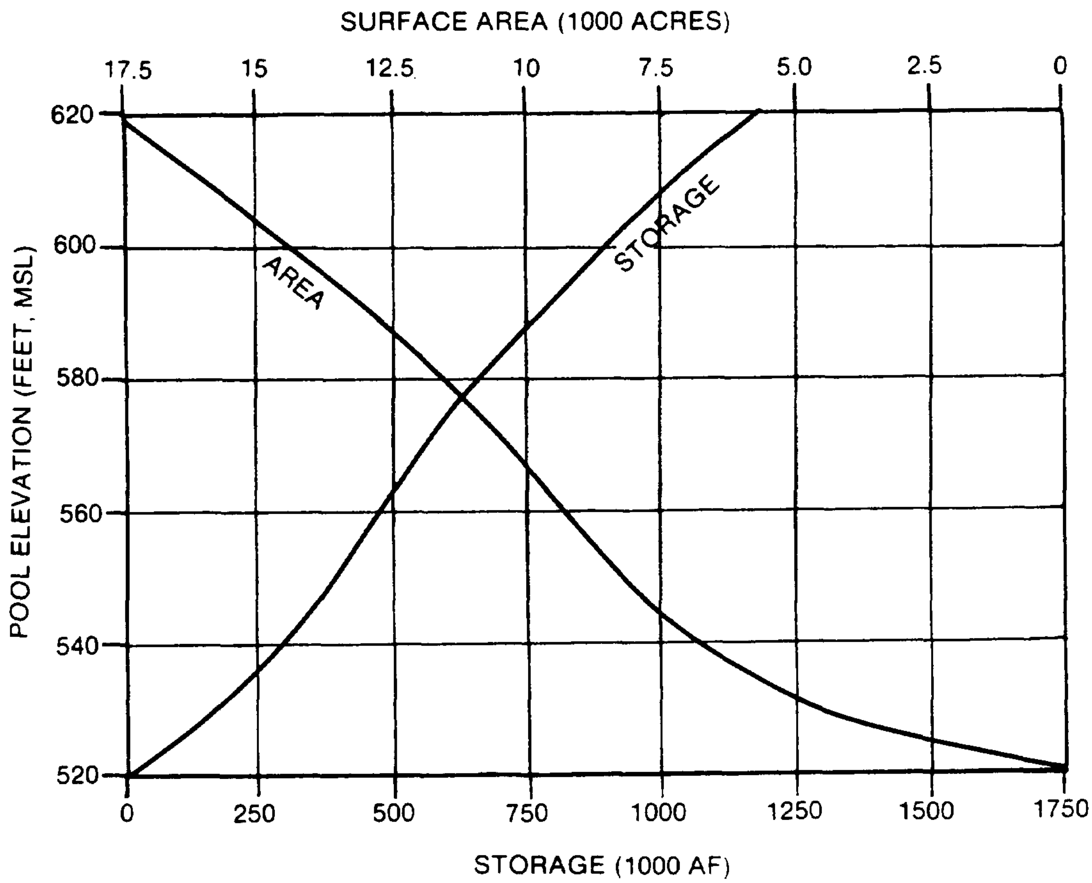


Figure 4-8. Storage-elevation and area-elevation curves

(2) Storage-elevation and area-elevation curves are generally developed from topographic maps by planimetering elevation contours upstream from the damsite. The "average end area" method is used to compute the volume between elevation curves. Increased accuracy is obtained by using large-scale, high resolution mapping and small elevation increments. HEC's computer program #723-G1-L233A, "Reservoir Area Capacity Tables by Conic Method", is a useful tool for developing this type of data.

d. Sedimentation Data. Sedimentation studies may be conducted for an existing or proposed reservoir in order to determine the rate reservoir storage capacity is being lost to deposited sediment. Sediment studies can also identify sediment source areas and may be used to develop sediment management programs. The results of these studies can also be used for updating storage-elevation curves and projecting future capacity losses at older reservoirs situated in high-sediment river basins. In addition to examining impacts within reservoirs, studies may also be made to investigate downstream channel capacity and other characteristics. Studies at project sites usually involve the laboratory analysis of suspended sediment samples and computer simulation to predict future sediment deposition in the reservoir. Three HEC computer progams may be of value in preliminary sedimentation studies: "Suspended Sediment Yield" (HEC #723-G2-L2240), "Deposition of Suspended Sediment" (HEC #723-G2-L2250), and "Scour and Deposition in Rivers and Reservoirs" (HEC-6).

e. Water Quality Data. Studies may be required to define the current status of water quality conditions at and below the hydropower site and to predict how these conditions would be altered by project operation. Requirements for water quality studies are established in ER 1110-2-1402, Hydrologic Investigation Requirements for Water Quality Control. Information on the downstream water quality effects of hydropower development is contained in the technical report, Effects of Reservoir Releases on Water Quality, Macroinvertebrates, and Fish In Tailwaters; Field Study Results (80). Availability of water quality data is often critical to the completion of the required studies. Water quality data needs must be defined early in the feasibility study in order to provide enough time to collect the needed data so that water quality problems can be assessed adequately.

f. Downstream Flow Requirements.

(1) Downstream flow requirements are sometimes established to ensure that the range of project discharges produced by power operations does not adversely impact the utilization of the stream. Streamflow uses which might be considered when establishing flow requirements include the following:

- navigation
- water quality
- municipal and industrial water supply
- irrigation
- fish and wildlife habitat
- migratory fish passage
- instream fishing
- recreational uses (boating and beaches)
- flood control discharge limitations

(2) Flow requirements can be expressed either as instantaneous or average flow values either at-site or at some downstream point. Limits may also be placed on the daily minimum or maximum discharge permitted and on daily or hourly rates of change in discharge. Flow requirements may originate in different ways. They may be based on an international treaty, an interstate river basin management compact, or on downstream water rights. Others may arise from court decisions or enabling legislation aimed at preventing a project from adversely impacting non-power uses of streamflow. In most cases, flow requirements result directly from project environmental and operations studies, which are often made in conjunction with other agencies and river use interests.

(3) The impact of proposed downstream flow requirements on power operation should be carefully evaluated. Maximum discharge limits may restrict the use of a project for peaking operations. Similarly, the imposition of high discharge requirements for downstream uses may limit the use of reservoir storage for power generation. The objective of the downstream flow requirement study should be to achieve a reasonable balance to insure that downstream river uses are protected without unnecessarily limiting the site's power potential.

g. Water Surface Fluctuation Studies. Advanced feasibility and GDM studies may require evaluation of the effect of power operations on the shoreline of the reservoir and riparian land downstream from the project site. Areas of concern may include safety of and access to shoreline areas for commercial and recreational activities; damage to waterfowl nesting areas; fish migration and spawning; and habitat areas of rare or endangered species. Fluctuation studies may be conducted using either conventional hydrologic routing techniques or more advanced hydraulic modeling techniques based on unsteady flow theory. Computer programs such as HEC-5 (40) and SSARR (56) are capable of performing hydrologic routings for these purposes.

h. Losses.

(1) General. Not all of the streamflow entering a reservoir may be available for power generation. Some flow may be lost due to

reservoir evaporation, transpiration, and to diversions from the reservoir for irrigation and water supply. Water may also be required at the dam for operation of a navigation lock, fish passage facilities, powerplant cooling, or other project operating purposes. There also may be losses due to leakage through or around the dam or other embankment structures and around gates. If these losses are not accounted for, a hydro project's power output may be substantially overestimated. Following are discussions of some of the major categories of losses.

(2) Evaporation. The purpose of the evaporation loss computation is to determine the net loss to evaporation resulting from the larger surface area of the reservoir compared to the river, prior to construction of the project. A rigorous analysis of this type would also account for the effects of infiltration, transpiration, and precipitation. Section 3.02 of Reservoir Yield (44c) describes several techniques for analyzing evaporation and related losses. Although accounting for net evaporation is very important for large reservoir projects, it can sometimes be neglected at small reservoirs and run-of-river projects.

(3) Irrigation and Water Supply Diversions. Reservoirs often serve as the source of water for adjacent irrigation projects or communities. Water may be pumped directly from the reservoir or diverted through a pipeline at the dam. Because irrigation or water supply is often included as a project purpose, data on these diversions is usually developed in the planning process, and this data can be used in the hydropower analysis. At existing projects, historical data may be available, although consideration should be given to the possibility of future increases in the level of diversion.

(4) Seepage and Leakage. There is usually some seepage under or around dams and other embankment structures, and there is sometimes leakage through the dam structure itself. In a few cases there may even be seepage losses to underground aquifers or other strata adjacent to the reservoir. As a rule, seepage or leakage is relatively small, and in most cases it is difficult to estimate before a project is actually constructed. However, this type of loss should be considered where significant leakage is a possibility. The amount of leakage is a function of the type and size of dam, the geologic conditions, and the pressure caused by water in the reservoir. The measured leakage at a similar type of dam in a similar geologic area may be used as a basis for estimating losses at a proposed project. The best source of data in this area would be the District foundation and materials branch.

(5) Gate Leakage. Leakage from spillway gates is a function of gate perimeter, type of seal, and the head on the gate. Leakage may be measured at existing projects with similar seals, and a leakage rate may then be computed per foot of perimeter for a given head. This leakage rate may then be used to compute estimated leakage for a proposed project.

(6) Navigation Lock Operation. The inclusion of a navigation lock at a dam requires that locking operations and leakage through the lock be considered. The leakage is dependent upon the lift, the type and size of lock, and the type of gates and seals. Again, estimates can be made from observed leakage at similar structures. Water required for locking operations should also be deducted from water available at the dam site. These demands can be computed by multiplying the volume of water required for a single locking operation times the number of operations anticipated in a given time period and converting the product to a flow rate over the given period.

(7) Fish Facilities. Some projects have facilities for passing migratory fish upstream or downstream, and others have fish hatcheries or spawning beds that are an integral part of project operation. Fish ladders or locks may be required for upstream passage, and water is often required for attracting fish to the fish passage facility entrances as well as for operation of the facilities themselves. In some case, streamflow may also be required for downstream migrant fish facilities, and in other cases spill may be required during the downstream migration season. Where fish hatcheries are constructed adjacent to the dam, water may be diverted directly from the reservoir to the hatchery and this must be accounted for also. Information on fish passage facility and fish hatchery water requirements can be obtained from fishery agencies, design personnel, or from operating experience at similar projects.

(8) Turbine Leakage. If a proposed project is to include power, and if the area demand is such that the turbines will sometimes be idle, it is advisable to estimate leakage through the turbines when closed. This leakage is a function of the type of penstock, type of turbine wicket gate, number of turbines, and head on the turbine. The measurement of turbine leakage at similar existing projects may be used to estimate leakage for a proposed project. Hydraulic machinery specialists at the Hydropower Design Centers would be another source of information on estimated turbine leakage. An estimate of the percent of time that a unit will be closed may be obtained from actual operation records for similar units in the same demand area. The measured or estimated leakage rate is then reduced by multiplying by the proportion of time the unit will be closed. For example, if leakage through a turbine has been measured at 1.0 cubic feet per

second (cfs), and the operation records indicate that the unit is closed 60% of the time. The average leakage rate for the turbine would be (0.6 x 1.0 cfs) = 0.6 cfs.

(9) Station Water Requirements. The use of water for purposes related to operation of a project is often treated as a loss. Station use for sanitary and drinking purposes, cooling water for generators, and water for condensing operations are typical station water requirements at hydro projects. Examination of operation records for comparable projects in a given study area may be useful in estimating these losses, and the Hydroelectric Design Centers would be additional sources of information. If a station service unit is included in a project to supply the project's power needs, data should be obtained from the designer in order to estimate water used by the house unit or units.

(10) Other Considerations. Some of the losses described above vary considerably by season, while others are relatively constant the year around. Irrigation diversions and evaporation losses vary widely with season, while seepage and leakage and station water requirements may be essentially constant the year around. Others, such as navigation lock requirements and fish facility requirements, may or may not vary, depending on the project. When the sum of the losses varies substantially by season, the data should be developed by month. In other cases, a single average annual value may be satisfactory. Where the data is to be used in a model which routes streamflow to downstream projects or control points, the total losses should be divided into consumptive and non-consumptive losses. Table 4-1 shows a typical summary of monthly streamflow losses.

TABLE 4-1.
Example Monthly Streamflow Loss Table

LOSS (cfs)	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Avg
Nonconsumptive													
Fish facilities 1/	50	100	100	100	100	100	100	100	100	100	100	100	100
Closed turbines 2/	30	30	25	16	12	10	10	10	12	15	25	30	19
Navigation locks 3/	22	22	22	22	36	50	50	50	50	36	22	22	29
Seepage 4/	15	15	15	15	15	15	15	15	15	15	15	15	15
Station use	8	8	8	8	8	8	8	8	8	8	8	8	8
Leakage 5/	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	125	175	170	161	171	183	183	183	185	174	170	175	172
Consumptive													
Net evaporation 6/	-44	-33	-20	-13	-30	-37	60	50	18	2	-23	-37	-3
Irrigation 7/	0	0	15	45	65	75	85	85	40	15	0	0	47
Water supply 7/	18	18	18	22	25	28	31	31	28	25	20	18	23
Total	-26	-15	13	55	60	140	176	166	86	42	-3	-19	56

1/ Shut down two weeks for maintenance in January.
2/ Average leakage through closed turbines is 40 cfs.
3/ Includes 8 cfs continuous leakage.
4/ Seepage through dam and reservoir (estimated).
5/ Leakage through spillway gates and conduits (projected).
6/ Net result of evaporation and precipitation on the surface of the reservoir. A net gain in water is shown as a negative loss.
7/ Water withdrawn from reservoir. Any water withdrawn below the dam is a loss to downstream projects only.

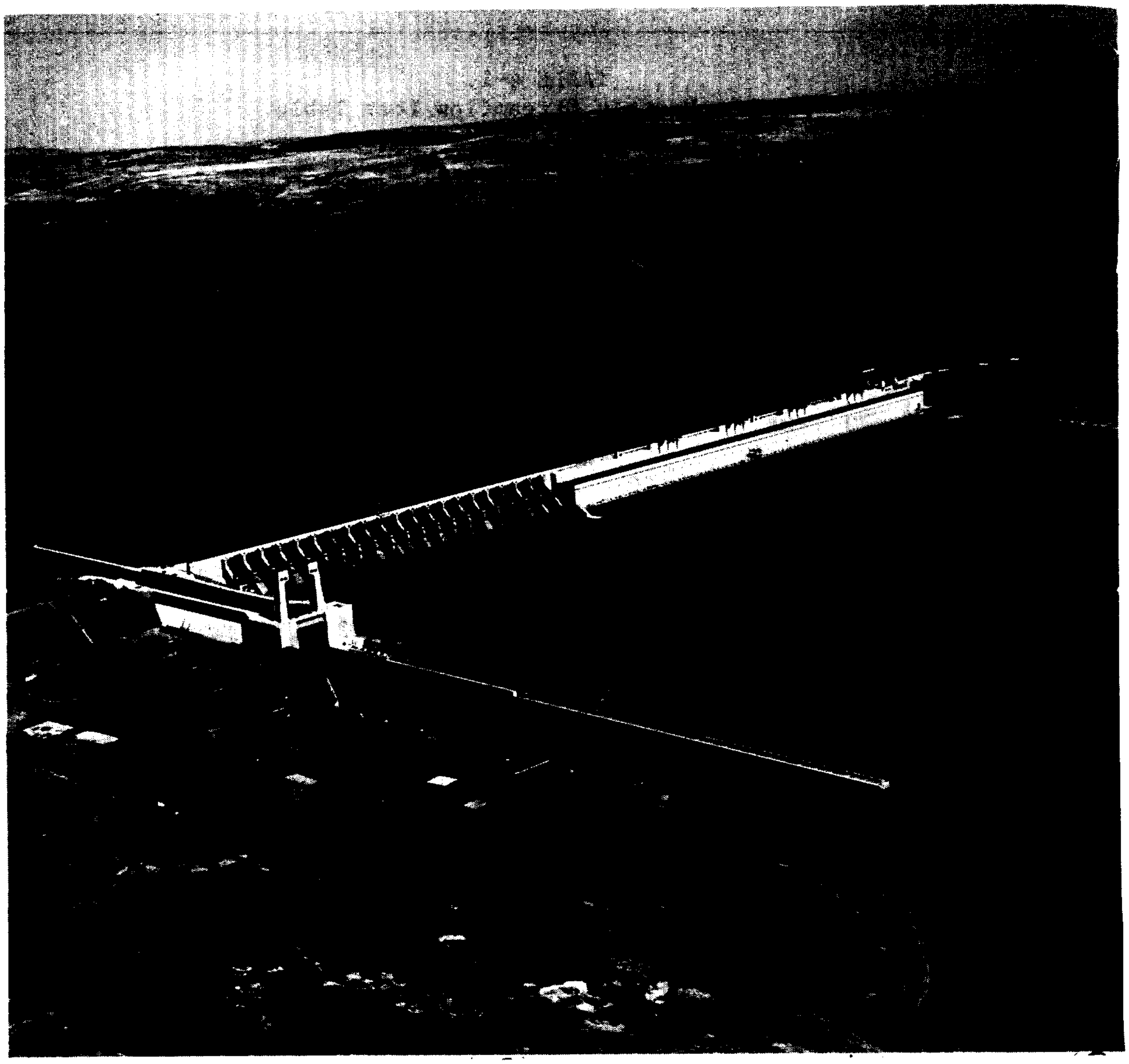


Figure 4-9. John Day Lock and Dam. With a peaking capacity of 2,484 MW, this is the largest hydroelectric project constructed by the Corps of Engineers (Portland and Walla Walla Districts)

CHAPTER 5

DETERMINING ENERGY POTENTIAL

5-1. Introduction.

a. Purpose and Scope. This chapter describes the process of estimating the energy potential of a hydropower site, given the streamflow characteristics and other data developed in Chapter 4. It also defines basic energy terms, reviews the water power equation, describes the two basic techniques for estimating energy (the sequential streamflow routing method, and the non-sequential or flow-duration method), and outlines data requirements for energy potential studies.

b. Relationship of Energy Analysis to Selection of Plant Size.

(1) While it is difficult to separate selection of plant size from estimation of energy potential, the two topics are treated separately in this manual in order to simplify the explanation of the techniques and processes used in each.

(2) Plant sizing is an iterative process. For a new project, the first step would be to select alternative configurations to be examined, such as alternative layouts, dam heights, and seasonal power storage volumes (if applicable). A preliminary energy potential estimate would be made for each alternative, either without being constrained by plant size or with assumed plant sizes. Based on these analyses, one or more alternatives would be selected for detailed study. A range of plant sizes would be developed for each, as described in Chapter 6, and specific energy estimates would be computed for each plant size.

(3) When adding power to an existing project, the process is usually much simpler. A preliminary energy estimate is first made to determine the approximate magnitude and distribution of the site's energy potential. Then, alternative plant sizes are selected using the procedure outlined in Chapter 6, and specific energy estimates are made for each.

5-2. Types of Hydroelectric Energy.

a. General. Hydroelectric energy is produced by converting the potential energy of water flowing from a higher elevation to a lower elevation by means of a hydraulic turbine connected to a generator. Electrical energy is usually measured in kilowatt-hours, but it can also be defined in terms of average kilowatts. Three classes of energy are of interest in hydropower studies: average annual, firm, and secondary.

b. Average Annual Energy. A hydro project's average annual energy is an estimate of the average amount of energy that could be generated by that project in a year, based on examination of a long period of historical streamflows. In sequential streamflow analysis, average annual energy is calculated by taking the mean of the annual generation values over the period of record. In non-sequential analysis, it is computed by measuring the area under the annual power-duration curve. In many power studies, energy benefits are based directly on average annual energy. In other cases, it is necessary to evaluate firm and secondary energy separately (see Section 9-10o).

c. Firm Energy.

(1) As defined from the marketing standpoint, firm energy is electrical energy that is available on an assured basis to meet a specified increment of load. For hydroelectric energy to be marketable as firm energy, the streamflow used to generate it must also be available on an assured basis. Thus, hydroelectric firm energy (also sometimes called primary energy) is usually based on a project's energy output over the most adverse sequence of flows in the existing streamflow record. This adverse sequence of flows is called the critical period (see Section 5-10d).

(2) Where a hydro plant or hydro system carries a large portion of a power system's load, the hydro plant's firm energy output must closely follow the seasonal demand pattern. Reservoir storage is often required to shape the energy output to fit the seasonal demand pattern. Where hydro comprises only a small part of a power system's resource base, a hydro plant's output does not necessarily have to match the seasonal demand pattern. Its firm output can frequently be utilized in combination with other generating plants and in this way will serve to increase the total system firm energy capability. However, in some systems, marketing constraints may preclude taking advantage of this flexibility.

(3) In the Pacific Northwest and parts of Alaska, where hydropower is the predominant source of generation, generation planning is based primarily on system energy requirements rather than peak load requirements (see Sections 2-2b and 3-3b). Thus, to determine a proposed hydro project's value to the system, it is necessary to compute that project's firm energy capability. Capacity consid-

erations are not ignored, however. Once sufficient resources have been scheduled to meet firm energy requirements, a capacity analysis is made to determine if additional capacity is needed in order to meet peak loads plus reserve requirements.

(4) In most parts of the United States, however, hydropower represents such a small portion of the power system's energy capability that a hydro project's firm energy capability is not as significant. The variation in a hydro project's output from year to year due to hydrologic variability is treated in the same way as the variations in thermal plant output from year to year due to forced outages. Thus, in thermal-based power systems, the hydro project's average annual energy output is usually the measure of energy output that has the greatest significance from the standpoint of benefit analysis. However, for projects having seasonal power storage, an estimate of the project's firm energy capability is usually made in order to develop criteria for regulating that storage. Also, estimates of firm energy are sometimes required by the power marketing agency.

(5) As noted earlier, firm (or primary) energy is based on the critical period, which may be a portion of a year, an entire year, or a period longer than a year. Where firm energy is based on a period other than a complete year, it can be converted to an equivalent annual firm energy, as described in Section 5-10g.

d. Secondary Energy. Energy generated in excess of a project or system's firm energy output is defined as secondary energy. Thus, it is produced in years outside of the critical period and is often concentrated primarily in the high runoff season of those years. Secondary energy is generally expressed as an annual average value and can be computed as the difference between annual firm energy and average annual energy. Figure 5-1 shows monthly energy output for a typical hydro project for the critical period and for an average water year. The unshaded areas represent the secondary energy production in an average water year.

5-3. The Water Power Equation.

a. General.

(1) Mechanical Power (hp). The amount of power that a hydraulic turbine can develop is a function of the quantity of water available, the net hydraulic head across the turbine, and the efficiency of the turbine. This relationship is expressed by the water power equation:

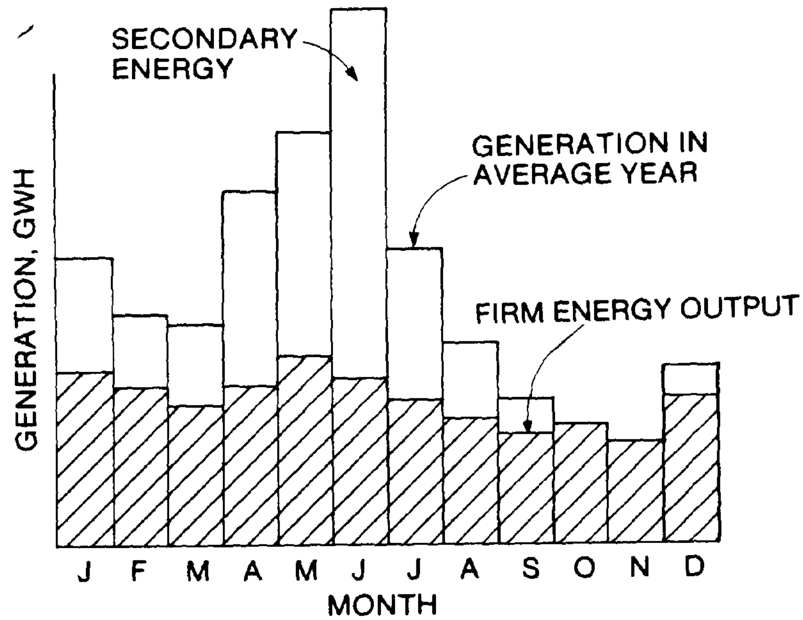


Figure 5-1. Monthly energy output of a typical hydro project

$$hp = \frac{QHe_t}{8.815} \qquad \text{(Eq. 5-1)}$$

where: hp = the theoretical horsepower available
Q = the discharge in cubic feet per second
H = the net available head in feet
e_t = the turbine efficiency

(2) Electrical Power (kW). Equation 5-1 can also be expressed in terms of kilowatts of electrical output:

$$kW = \frac{QHe}{11.81} \qquad \text{(Eq. 5-2)}$$

In this equation, the turbine efficiency (e_t) has been replaced by the overall efficiency (e) which is the product of the generator efficiency (e_g), and the turbine efficiency (e_t). For preliminary studies, a turbine and generator efficiency of 80 to 85 percent is sometimes used (see Section 5-5e). Equation 5-2 can be simplified by incorporating an 85 percent overall efficiency as follows:

$$kW = 0.072\ QH \qquad \text{(Eq. 5-3)}$$

(3) Energy (kWh). In order to convert a project's power output to energy, Equation 5-2 must be integrated over time.

$$kWh = \frac{1}{11.81} \int_{t=0}^{t=n} Q_t H_t e\,dt \qquad \text{(Eq. 5-4)}$$

The integration process is accomplished using either the sequential streamflow routing procedure or by flow-duration curve analysis. Following is a brief description of the sources of the parameters that make up the water power equation.

b. Flow. The values used for discharge in the water power equation would be the flows that are available for power generation. Where the sequential streamflow routing method is used to compute energy, discrete flows must be used for each time increment in the period being studied. In a non-sequential analysis, the series of expected flows are represented by a flow-duration curve. In either case, the streamflow used must represent the usable flow available for power generation. This usable flow must reflect at-site or upstream storage regulation; leakage and other losses; non-power water usage for fish passage, lockage, etc; and limitations imposed by turbine characteristics (minimum and maximum discharges and minimum and maximum allowable heads). The basic sources of flow data are described in Chapter 4.

c. Head.

(1) Gross or static head is determined by subtracting the water surface elevation at the tailwater of the powerhouse from the water surface elevation of the forebay (Figure 5-2). At most hydropower projects, the forebay and tailwater elevations do not remain constant, so the head will vary with project operation. For run-of-river projects, the forebay elevation may be essentially constant, but at storage projects the elevation may vary as the reservoir is regulated to meet hydropower and other discharge requirements. Tailwater elevation is a function of the total project discharge, the outlet channel geometry, and backwater effects and is

represented either by a tailwater rating curve or a constant elevation based on the weighted average tailwater elevation or on "block loaded" operation (see Section 5-6g).

(2) Net head represents the actual head available for power generation and should be used in calculating energy. Head losses due to intake structures, penstocks, and outlet works are deducted from the gross head to establish the net head. Information on estimating head loss is presented in Section 5-6l.

(3) A hydraulic turbine can only operate over a limited head range (the ratio of minimum head to maximum head should not exceed 50 percent in the case of a Francis turbine, for example) and this characteristic should also be reflected in power studies (see Sections 5-5c and 5-6i).

d. Efficiency. The efficiency term used in the water power equation represents the combined efficiencies of the turbine and generator (and in some cases, speed increasers). Section 5-5e provides information on estimating overall efficiency for power studies.

5-4. General Approaches to Estimating Energy.

a. Introduction. Two basic approaches are used in determining the energy potential of a hydropower site: (a) the non-sequential or flow-duration curve method, and (b) the sequential streamflow routing

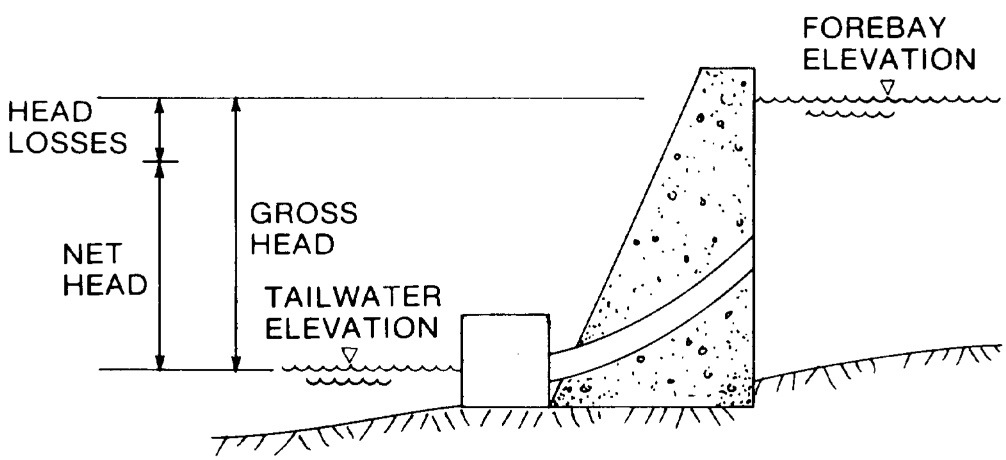


Figure 5-2. Gross head vs. net head

(SSR) method. In addition, there is the hybrid method, which combines features of the SSR and flow duration curve methods.

b. Flow-Duration Curve Method.

(1) The flow-duration curve method uses a duration curve developed from observed or estimated streamflow conditions as the starting point. Streamflows corresponding to selected percent exceedance values are applied to the water power equation (Equation 5-2) to obtain a power-duration curve. Forebay and tailwater elevations must be assumed to be constant or to vary with discharge, and thus the effects of storage operation at reservoir projects cannot be taken into account. A fixed average efficiency value or a value that varies with discharge may be used. When specific power installations are being examined, operating characteristics such as minimum single unit turbine discharge, minimum turbine operating head, and generator installed capacity are applied to limit generation to that which can actually be produced by that installation. The area under the power-duration curve provides an estimate of the plant's energy output.

(2) This method has the advantage of being relatively simple and fast, once the basic flow-duration curve has been developed, and thus it can be used economically for computing power output using daily streamflow data. The disadvantages are that it cannot accurately simulate the use of power storage to increase energy output, it cannot handle projects where head (i.e. forebay elevation and/or tailwater elevation) varies independently of flow, and it cannot be used to analyze systems of projects.

(3) The flow-duration method is described in detail in Section 5-7.

c. Sequential Streamflow Routing (SSR) Method.

(1) With the sequential streamflow routing method, the energy output is computed sequentially for each interval in the period of analysis. The method uses the continuity equation to route streamflow through the project, and thus it accounts for the variations in reservoir elevation resulting from reservoir regulation. This method can be used to simulate reservoir operation for hydropower as well as non-power objectives, such as flood control, water supply, and irrigation.

(2) The advantages of SSR are that it can be used to examine projects where head varies independently of streamflow, it can be used to model the effects of reservoir regulation for hydropower and/or other project purposes, and it can be used to investigate projects that are operated as a part of a system. The primary disadvantage of

SSR is its complexity. Because of the large amount of computer time required to do daily studies for long time periods, most sequential routings are based on weekly or monthly intervals. Generally, the use of weekly or monthly average flows is satisfactory. Where using weekly or monthly intervals results in an energy estimate that is substantially in error (see Section 5-6b(4)), SSR studies should be made using daily flows for all or part of the period of analysis.

(3) The sequential streamflow routing method is described in Sections 5-8 through 5-14.

d. Hybrid Method. The hybrid method combines features of both the duration curve and SSR methods. Historical streamflow and reservoir elevation data for the period of record are obtained either from historical records or from an existing SSR analysis (such as an operational study performed for evaluating existing project functions). Power output is computed sequentially for each interval in the period of record, and the resulting data is compiled into duration curve format for further evaluation. The hybrid method was developed primarily to investigate the addition of power at existing projects where head varies independently of flow. This includes flood control storage projects and projects with conservation storage regulated for non-power purposes. The hybrid method is usually faster than an SSR routing but slower than the flow-duration curve method. The hybrid method is described in Section 5-15.

e. Selection of Method.

(1) General. For very preliminary or screening studies, the flow-duration method can be used for almost any project, although energy estimates for projects with storage or where head varies independently of flow must be viewed with caution. Following is a discussion of the methods that would normally be used for the various types of projects.

(2) Run-of-River Projects. For the typical run-of-river project, where head is essentially fixed (high head projects) or where head varies with discharge (low head projects), the flow-duration method is generally the best choice. Where head varies independently of flow, the hybrid method should be used. SSR can also be used, but is usually not selected for single projects because the daily flow analysis required to get accurate results for run-of-river projects is usually too time consuming. However, it is often desirable to use SSR to analyze run-of-river projects that are operated as a part of a system which also includes storage projects. An alternative to the latter would be to use streamflows from an existing system SSR study as input for a flow-duration or hybrid analysis.

(3) Storage Projects. SSR is the only viable method for evaluating storage projects regulated for power or for multiple purposes including power. SSR would also normally be used for examining the feasibility of including power at new flood control projects or projects having conservation storage regulated for purposes other than power. The hybrid method can be used to examine the addition of power to an existing non-power storage project, if an adequate historical record exists and regulation procedures are not expected to change in the future. Otherwise, an SSR analysis must be made.

(4) Peaking Projects. Two types of studies are made in evaluating peaking projects: hourly operation studies and period-of-record studies based on longer time intervals. The power output of a peaking project must be delivered in the peak demand hours of the day (and of the week). Hourly operational studies are required to test the adequacy of pondage (daily/weekly storage) to support a peaking operation, and to evaluate the impacts of peaking operation on the river downstream. These problems, which are dealt with in more detail in Sections 6-8 and 6-9, require hourly SSR routings for analysis. These hourly routings should be made for selected weeks which are representative of the full range of expected streamflow, power demand, and other conditions. From these studies, it is possible to determine the level of peaking capacity that can be maintained at different flow levels. Period-of-record power studies would be made to determine the project's average annual energy output, and the method used would depend on the type of project as described in paragraphs (2) and (3) above. The results of the hourly studies would then be applied to the period-of-record power study to determine the project's dependable capacity (see Section 6-7i).

(5) Pumped-Storage Projects. The operation of off-stream pumped-storage projects is dictated more by the needs of the power system than by hydrologic conditions. Power system models (Section 6-9f) are normally used to estimate a project's required energy output However, hourly SSR routings are required to test adequacy of pondage and impact on non-power project and river uses. Where the lower reservoir is a storage project, period-of-record studies using the hybrid or SSR method may be required to determine the effect of storage regulation on the pumped-storage project's operating head.

(6) Pump-Back Projects. Analysis of pump-back projects (on-stream pumped-storage projects) also requires hourly SSR routing to define power operation, adequacy of pondage, and non-power impacts. Identification of the peak demand seasons and determination of the frequency of pumped-storage operation would be made using power system models, and this data would be used in conjunction with period-of-

record SSR routings to estimate annual energy output and dependable capacity (see Section 7-6).

(7) System Studies. Where a project is operated as a part of a system, SSR analysis is required to properly model the impact of system operation on that project's power output. The only case where the flow-duration or hybrid method might be used would be in the examination of a single existing project with no power storage, where an adequate historical record exists, no changes in project operation are expected, and no changes in streamflow resulting from the regulation of upstream projects are expected.

5-5. Turbine Characteristics and Selection.

a. General. Certain turbine characteristics, such as efficiency, usable head range, and minimum discharge, can have an effect on a hydro project's energy output. For preliminary power studies, it is usually sufficient to use a fixed efficiency value and ignore the minimum discharge constraint and possible head range limitations. However, for a feasibility level study, these characteristics should be accounted for in cases where they would have a significant impact on the results. This section presents some general information on the turbine characteristics required for making power studies and on the operating parameters involved in the selection of a specific turbine design.

b. Usable Head Range.

(1) A variety of turbine types are available, each of which is designed to operate in a particular head and flow range. Figure 2-35 illustrates the normal operating ranges for each type. In addition, a specific turbine is capable of operating within a limited head range. A horizontal Kaplan unit, for example, has a ratio of maximum head to minimum head of about 3 to 1. Table 5-1 (Section 5-6i) describes the usable operating head range for each of the major turbine types.

(2) Where possible, a runner design is selected such that the turbine can operate satisfactorily over the entire range of expected heads. This is especially important in the case of storage projects, where drawdown characteristics may be a major factor in selection of the type of turbine to be installed. At storage projects with a wide head range, it is sometimes possible to utilize interchangeable runners in order to maintain generation over the full head range.

(3) When adding power facilities to projects not originally designed for power operation, head ranges may exceed the capabilities of any turbine type. Examples are (a) low head projects where the

tailwater elevation is so high at high discharges that the head falls below the turbine's minimum head and the project "drowns out", and (b) new power installations at existing storage projects, where the range of head experienced in normal project operation exceeds the capabilities of a single turbine runner.

(4) In preliminary studies, it is not necessary to account for limitations on the turbine usable head range. However, they should be accounted for in feasibility level studies. This is done by specifying maximum and minimum operating heads in the power study. When making the routing (or duration curve analysis), no generation is permitted in those periods when the head falls outside of this range.

c. Design and Rated Heads.

(1) Design head is defined as the head at which the turbine will operate at best efficiency. The planner determines the head at which best efficiency is desired from the power studies and provides this value to the hydraulic machinery specialist for selection of an appropriate turbine design. Since it is usually desirable to obtain best efficiency in the head range where the project will operate most of the time, the design head is normally specified at or near average head. However, the design head should also be selected so that the desired range of operating heads is within the permissible operating range of the turbine.

(2) For single-purpose power storage projects, a preliminary estimate of average head can be obtained by determining the net head at the reservoir elevation where 25 percent of the power storage has been drafted. For multiple-purpose storage projects, including flood control and power, average head can be based on a draft of 33 to 50 percent. A more refined value of average head can be derived by averaging the heads computed for each interval in the period-of-record power routing studies. In some cases it is desirable to develop a weighted average head, with the head values for each period weighted by the corresponding power discharge.

(3) For run-of-river projects, design head can be determined from a head-duration curve by identifying the midpoint of the head range where the project is generating power (Figure 5-3). Design head would normally be based on operation over the entire year, but where dependable capacity is particularly important, it may be desirable to base it on operation in the peak demand months only. For pondage projects which operate primarily for peaking, design head is often based on a weighted average head, which is weighted by the amount of generation at each head.

$$\text{Weighted average head} = \frac{\Sigma\,(\text{head x generation})}{\Sigma\,(\text{generation})} \qquad \text{(Eq. 5-5)}$$

This analysis would be based on hourly routing studies. Because period-of-record hourly studies are not practical, the analysis would have to be limited to a sufficient number of weeks to be representative of the period of record.

(4) Rated head is defined as that head where rated power is obtained with turbine wicket gates fully opened. Thus, it is the minimum head at which rated output can be obtained. A generator is

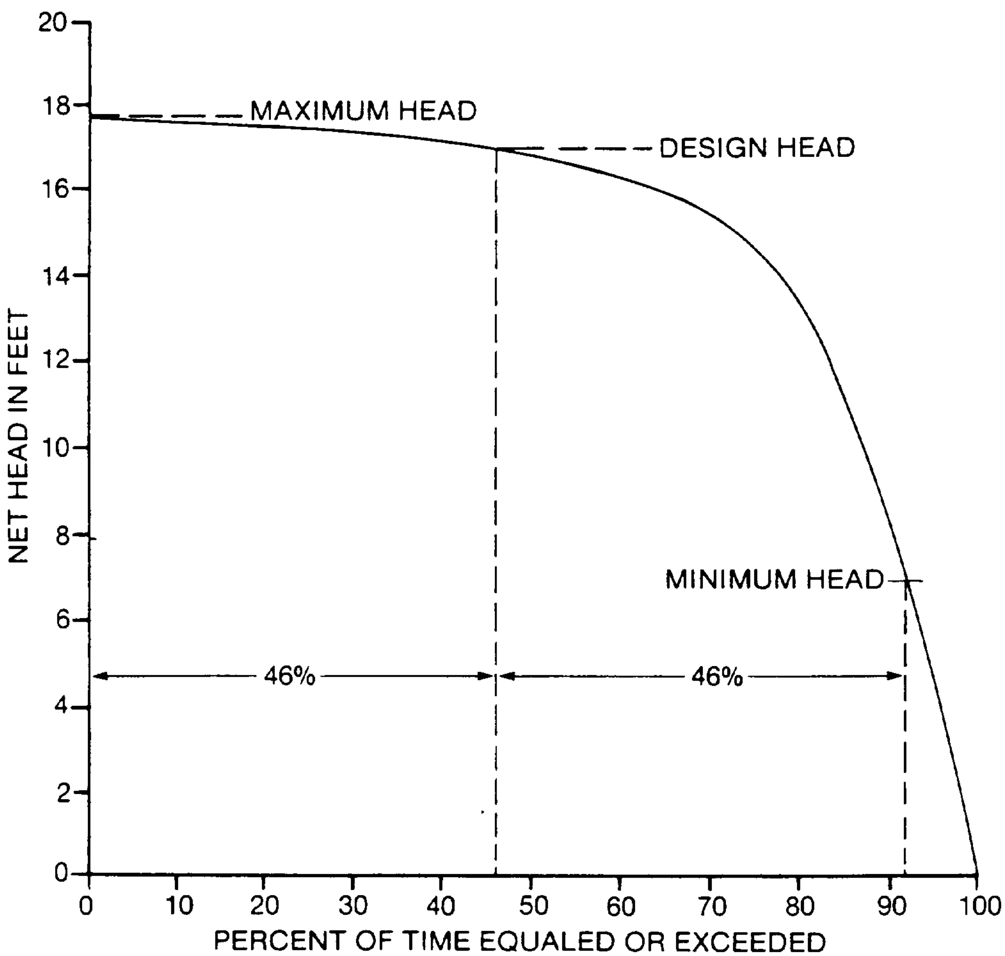


Figure 5-3. Head-duration curve for run-of-river project, showing how design head can be determined

selected with a rated capacity to match the rated power output of the turbine at a specific power factor (usually 0.95 for large synchronous generators). Above rated head, the generator capacity limits power output, so the unit's full rated capacity can be obtained at all heads above rated head. Below rated head, the maximum achievable power output with turbine gates fully open is less than rated capacity (Figure 5-4).

(5) The selection of rated head is generally a compromise based on cost, efficiency, and dependable capacity considerations. At some projects, the range of head experienced in normal operation is small enough that a unit can be selected such that rated output can be

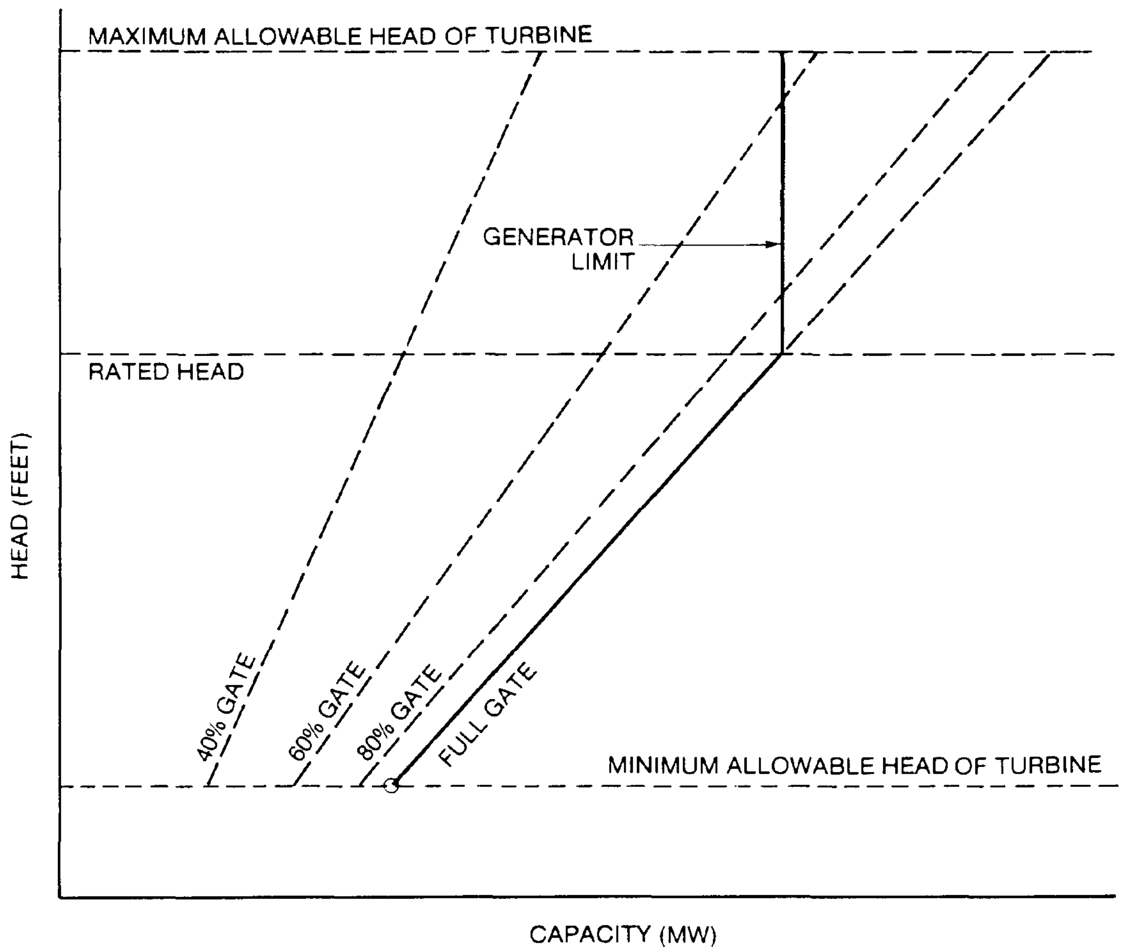


Figure 5-4. Turbine performance curve for a specific design (solid line represents maximum output of unit)

obtained over the entire operating range if desired (Figure 5-5). At other projects, the head range is such that the operating head drops below the rated head under some operating conditions, with a resulting decrease in generating capability. Examples of the latter are (a) a storage project with a large drawdown, where head drops below rated head at low pool elevations (Figure 5-6), and (b) a pondage project with a large installed capacity, where the tailwater encroachment at high plant discharges causes head to fall below rated head. Figure 5-7 illustrates a capacity versus discharge curve for various numbers of 5 megawatt units at a low head run-of-river project. This figure shows how output can drop off at the higher discharge levels due to tailwater encroachment.

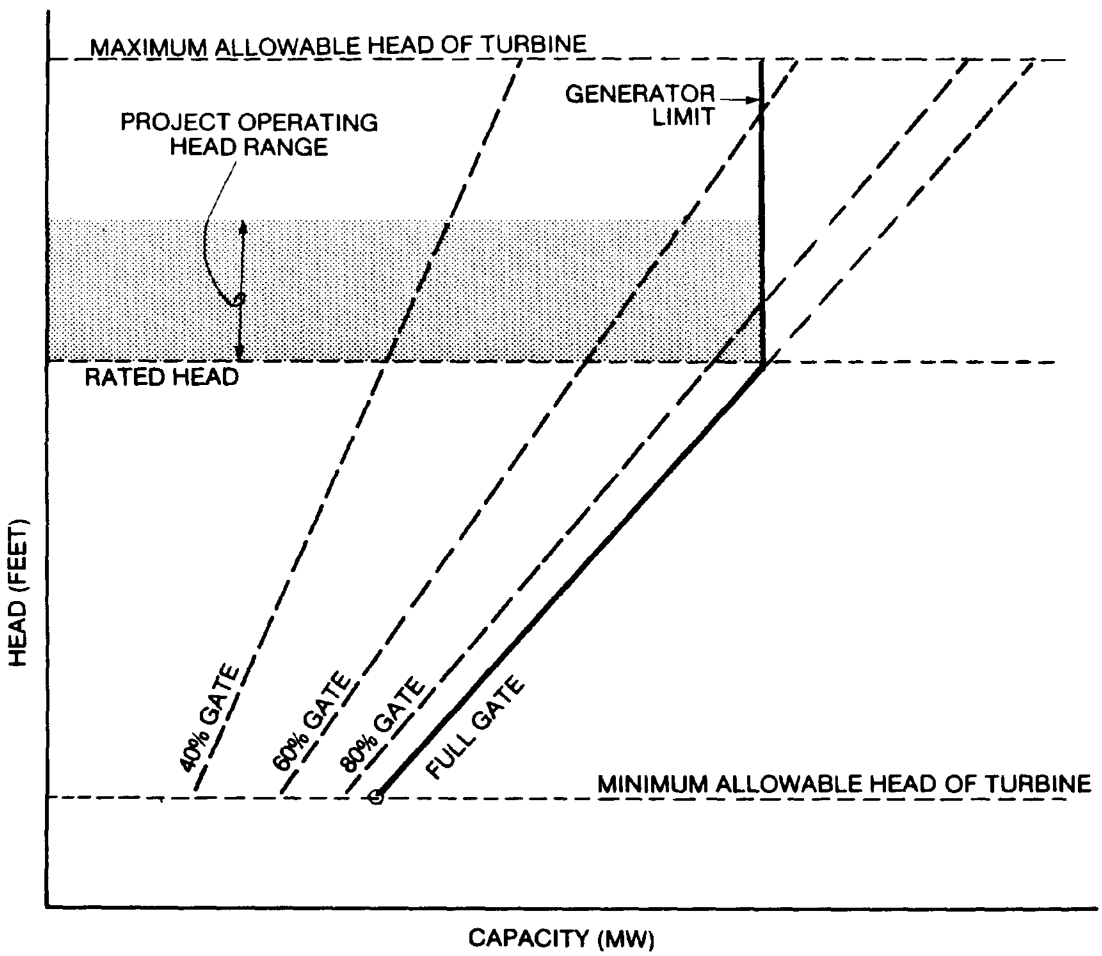


Figure 5-5. Turbine design from Figure 5-4 as applied to a project with a narrow operating head range

(6) It is difficult to generalize about the relationship between rated head and design head, because it is a function of the type of turbine and how the project is operated. However, there are some overall guidelines that may prove helpful. It is not usually cost-effective to select a rated head equal to the expected maximum or minimum head, because this would result in either an oversized turbine or oversized generator, respectively (see Section 5-5g). The only exception would be where the ratio of drawdown to maximum head is small (Figure 5-5), in which case the rated head might be equal to the minimum head.

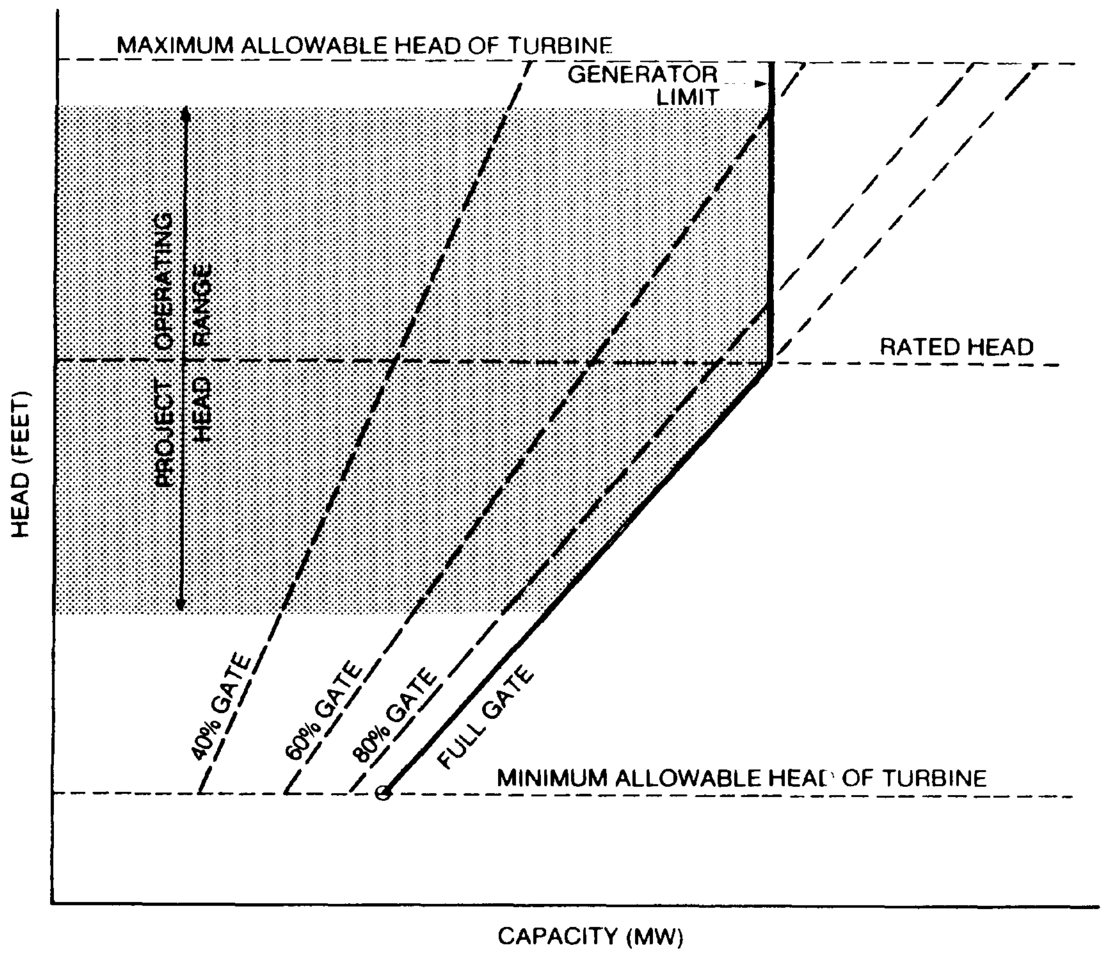


Figure 5-6. Turbine design from Figure 5-4 as applied to a storage project with large operating head range

(7) For a pure run-of-river project, the rated head is usually defined by the maximum plant discharge (hydraulic capacity). For example, a flow-duration curve would be examined, and one or more discharges would be selected for detailed study. For each alternative, the net streamflow available for power generation would be determined, and this would define the hydraulic capacity for that plant size. The net head available at the streamflow upon which the hydraulic capacity is based would be the rated head. The design head for this type of project would typically be based on the midpoint of the head range where the plant is generating power, and this would usually be higher than the rated head (see Figure 5-19).

(8) For projects with seasonal storage, it is usually desirable to obtain rated output over a range of heads. Hence, the rated head would typically be lower than the design head (the average head). For preliminary studies, a rated head equal to or slightly below (95 percent of) the estimated average head can usually be assumed. For more advanced studies, the rated head should be defined more specifi-

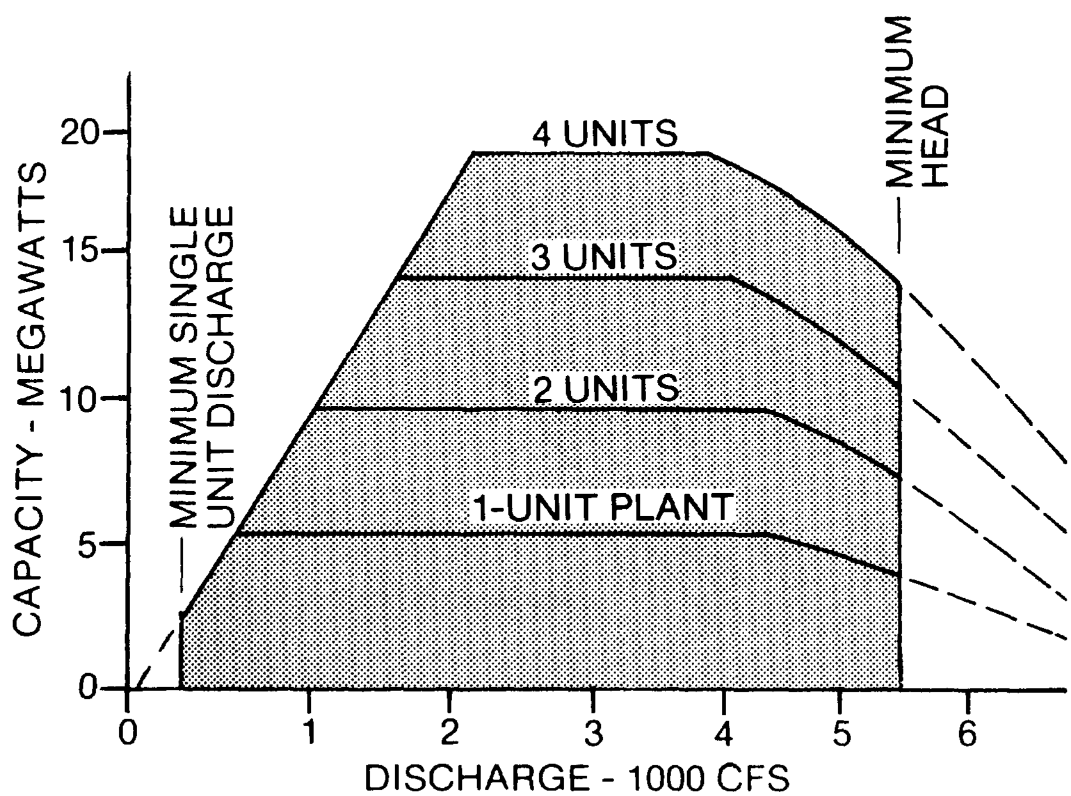


Figure 5-7. Capacity vs. discharge for run-of-river project for alternative plant sizes

cally. For a storage project, the design head could be estimated from the initial period-of-record sequential routings, as described in paragraph (2), above. The head range in which it is desired to obtain rated head could be defined by examining the routing in the light of power marketing considerations. For example, in systems where dependable capacity is important, it would be desirable to obtain rated capacity throughout the normal range of drawdown during the peak demand months. With this information, the hydraulic machinery specialist would select a turbine design that most closely meets these requirements, thereby defining the rated head. Head-duration curves are very helpful in selecting the rated head.

(9) Run-of-river projects with pondage would generally be treated similarly to storage projects, in that a turbine design would be selected which permits operation at a good efficiency level most of the time while permitting the delivery of rated output over the head range where the project operates most of the time. At some projects, the ratio of drawdown to maximum head is such that rated head can be delivered through the entire operating range (as in Figure 5-5). Hourly operation studies are often required to properly define the operating head range, and this would include the head range where the plant is expected to operate most of the time, as well as the extremes (see paragraph (3) and Section 6-9).

(10) Hydraulic capacity was mentioned as a key parameter in rating run-of-river projects, and it is important in rating projects with load-following capability as well. For multiple-unit plants, the units would normally be rated at the condition where all of the units in the plant are assumed to be operating at full gate discharge (i.e., with the plant operating at hydraulic capacity). The rated discharge of individual units would be the desired plant hydraulic capacity divided by the number of units. The rated head would be based on the tailwater conditions corresponding to the total plant's hydraulic capacity, and not the tailwater elevation corresponding to a single unit operating at full gate discharge. Further information on selection of hydraulic capacity (plant size) for peaking projects can be found in Section 6-6d.

(11) Rated head is the minimum head at which the turbine manufacturer must guarantee rated output. However, turbines are sometimes able to deliver rated capacity at heads below rated head, because the manufacturers typically build some cushion into their designs to insure that they meet specifications. The minimum head at which a specific turbine can actually deliver rated capacity is called the critical head. Although the term critical head is sometimes used synonomously with rated head, to be precise, a project's critical head cannot be identified until the turbines have been purchased and

tested. Therefore, only the term rated head should be used in planning and design studies.

d. Minimum Discharge.

(1) Cavitation and vibration problems limit turbines to a minimum discharge of 30 to 50 percent of rated discharge (rated discharge being discharge at rated head with wicket gates fully open). This characteristic should be accounted for in power studies, and it may in some cases influence the size and number of units to be installed at a given site. For example, if a minimum downstream release is to be maintained at a storage or pondage project for non-power purposes, and it is desired to maintain power production during these periods, a unit must be selected which is capable of generating at the required minimum discharge. For run-of-river projects, proper accounting for minimum discharge is equally important. Streamflows below the single-unit minimum discharge will be spilled, so flow-duration curves should be examined carefully to determine the size and number of units that will best develop the energy potential of a given site. The example in Section 6-6g illustrates the impact of single-unit minimum turbine discharge on a project's energy output.

(2) In preliminary power studies, minimum discharge can usually be ignored, but once a tentative selection of unit size or sizes has been made, a minimum single-unit turbine discharge must be applied to the energy computation. For more advanced studies, a minimum discharge based on the data presented in Table 5-1 (Section 5-6i) can be assumed. Once a specific turbine design has been selected, the minimum discharge associated with that unit should be used.

e. Efficiency.

(1) The efficiency term used in power studies reflects the combined efficiencies of the turbine and generator. Generator efficiency is usually assumed to remain constant at 98 percent for large units and 95 to 96 percent for units smaller than 5 MW. However, turbine efficiency varies with the operational parameters of discharge and head. The efficiency characteristics of a turbine vary with type and size of unit and runner design. Figure 5-8 shows typical performance curves for a Francis turbine.

(2) In reconnaissance level power studies, a fixed efficiency of 80 to 85 percent may be used to represent the combined efficiency of the turbines and generators. A value of 85 percent can be applied to installations where the larger custom-built turbines would be used. The smaller standardized Francis and tubular turbines and units requiring gearboxes have lower efficiencies, and an overall efficiency of 80 percent should be used for reconnaissance studies of projects

where this type of units would installed. In feasibility studies, it is necessary to look at the specific characteristics of the type of units being considered and the range of heads and flows under which they will operate to determine the appropriate efficiency value or values to use.

(3) Figure 2-36 shows that each turbine has a range of head and flow where efficiency remains relatively constant. Outside of this range, efficiency drops off rapidly. This characteristic is most apparent with units such as Francis and fixed blade propeller turbines. In power studies where the head and flow are expected to lie within the range of relatively constant efficiency, an average efficiency value can be used. However, where the units are expected to operate over a wide range of flows and/or head, an efficiency curve should be used instead of a fixed value.

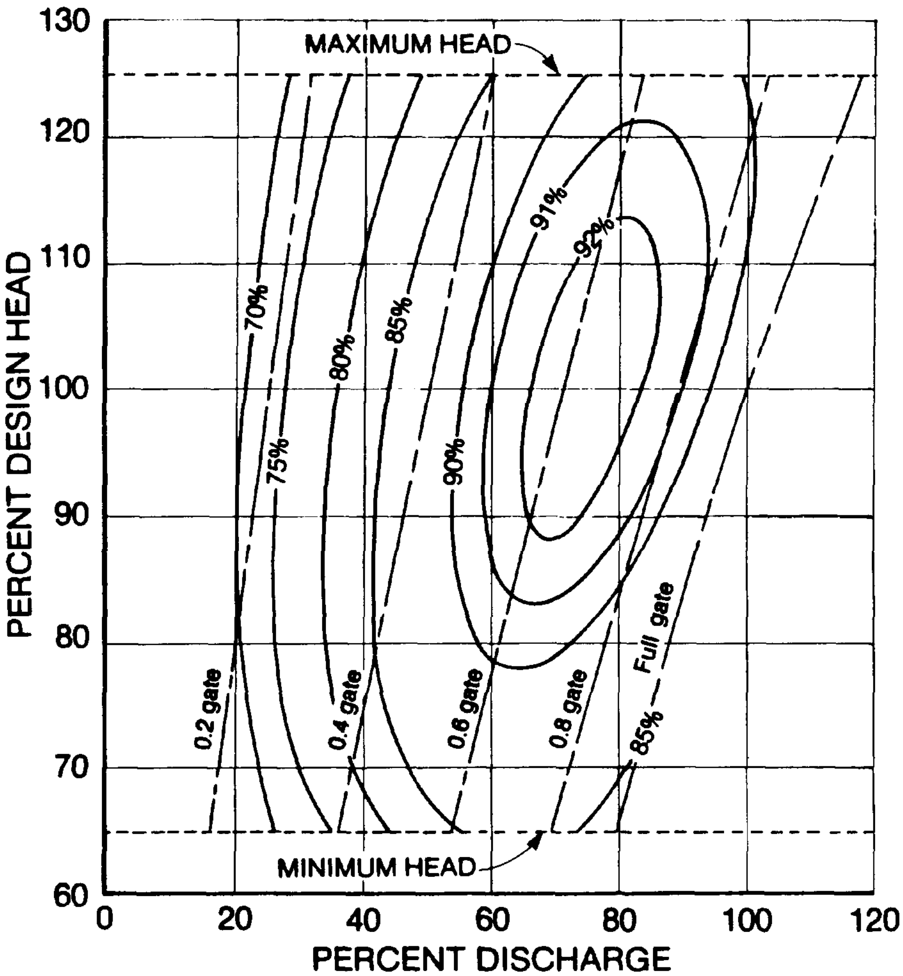


Figure 5-8. Typical Francis turbine performance curve

(4) The variation of efficiency with head can be quite significant at storage projects with large head ranges and at low-head run-of-river projects. Some sequential routing programs have provisions for modeling the variation of efficiency with head, and others can accomodate variation with both head and discharge. Where only variation with head is modeled, values of efficiency should be selected which are most representative of the discharge levels at which the plant will operate. When kW/cfs curves are used (see Appendix G), the variation of efficiency with head would be incorporated directly in that parameter. At other types of projects, the variation of efficiency with discharge can be an important consideration. Section 5-6k discusses the modeling of efficiency versus head and discharge in more detail.

f. Turbine Selection.

(1) Turbine selection is an iterative process, with preliminary power studies providing general information on approximate plant capacity, expected head range, and possibly an estimated design head. One or more preliminary turbine designs are then selected and their operating characteristics are provided as input for the more detailed power studies. The results of these studies make it possible to better identify the desired operating characteristics and thus permit final selection of the best turbine design and the best plant configuration (size and number of units).

(2) Turbine performance data for various types of turbines is essential to the selection process. While data can be obtained directly from the manufacturer, it is recommended that field offices work instead through one of the Corps Hydroelectric Design Centers. Hydraulic machinery specialists in these offices have access to performance data for a wide range of unit designs from various manufacturers, and they are able to recommend runner designs that are best suited to any given situation. Performance curves can then be provided to the field office for the selected turbine design.

(3) In preparing a request to a Hydroelectric Design Center for turbine selection, the following information should be provided.

- expected head range
- head-duration data (not required but very useful)
- design head (optional)
- total plant capacity (either hydraulic capacity in cfs or generator installed capacity in megawatts)
- minimum discharge at which generation is desired
- alternative combinations of size and number of units to be considered (optional)

- head range at which full rated capacity should be provided if possible (optional)
- tailwater rating curve

g. <u>Matching Generator to Turbine.</u>

(1) The rated output of a generator is chosen to match the output of the turbine at rated head and discharge. As was discussed earlier, the head at which the turbine is rated can vary depending on the type of operation as well as economics. An example will serve to illustrate some of the trade-offs involved in selecting this rating point.

(2) Assume that a power installation is being considered for a multiple-purpose storage project which is operated on an annual drawdown cycle, similar to that shown in Figure 5-12. The maximum head (head at full pool) is 625 feet, and the minimum head (head at minimum pool) is 325 feet. From the initial sequential routing studies, the average head is found to be 500 feet, and that head is used as the design head (head at which best efficiency is desired). It is proposed to investigate a plant which is capable of passing 1000 cfs at the design head.

(3) Assume that the turbine selection procedure outlined in Section 5-5f is followed, and it is found that a Francis turbine of the design shown in Figure 5-8 provides suitable performance for the specified range of operating conditions. Applying this turbine to these operating conditions, the performance curve shown as Case 2 on Figure 5-9 is obtained.

(4) Rating the unit at three different heads will be considered: design head, maximum head, and minimum head. These are not the only options available. They could be rated at any intermediate head as well, but examining these three alternatives will illustrate some of the factors involved in selecting the conditions for rating a generating unit.

(5) Consider first rating the unit at the design head. This would be a reasonable alternative to consider for rating units at a project with a head range of this magnitude. Case 1 on Figure 5-9 shows the performance characteristics of such a unit. The turbine would be rated to produce 36.0 megawatts at a head of 500 feet and a full-gate discharge of 1000 cfs. A generator of the same 36.0 megawatt rated output would be specified. Note that the turbine would actually be rated in terms of its horsepower output, but to simplify the discussion, its equivalent megawatt output will be used. The dashed line shows additional capability of the turbine which is not realized because of the limit imposed by the 36.0 megawatt generator.

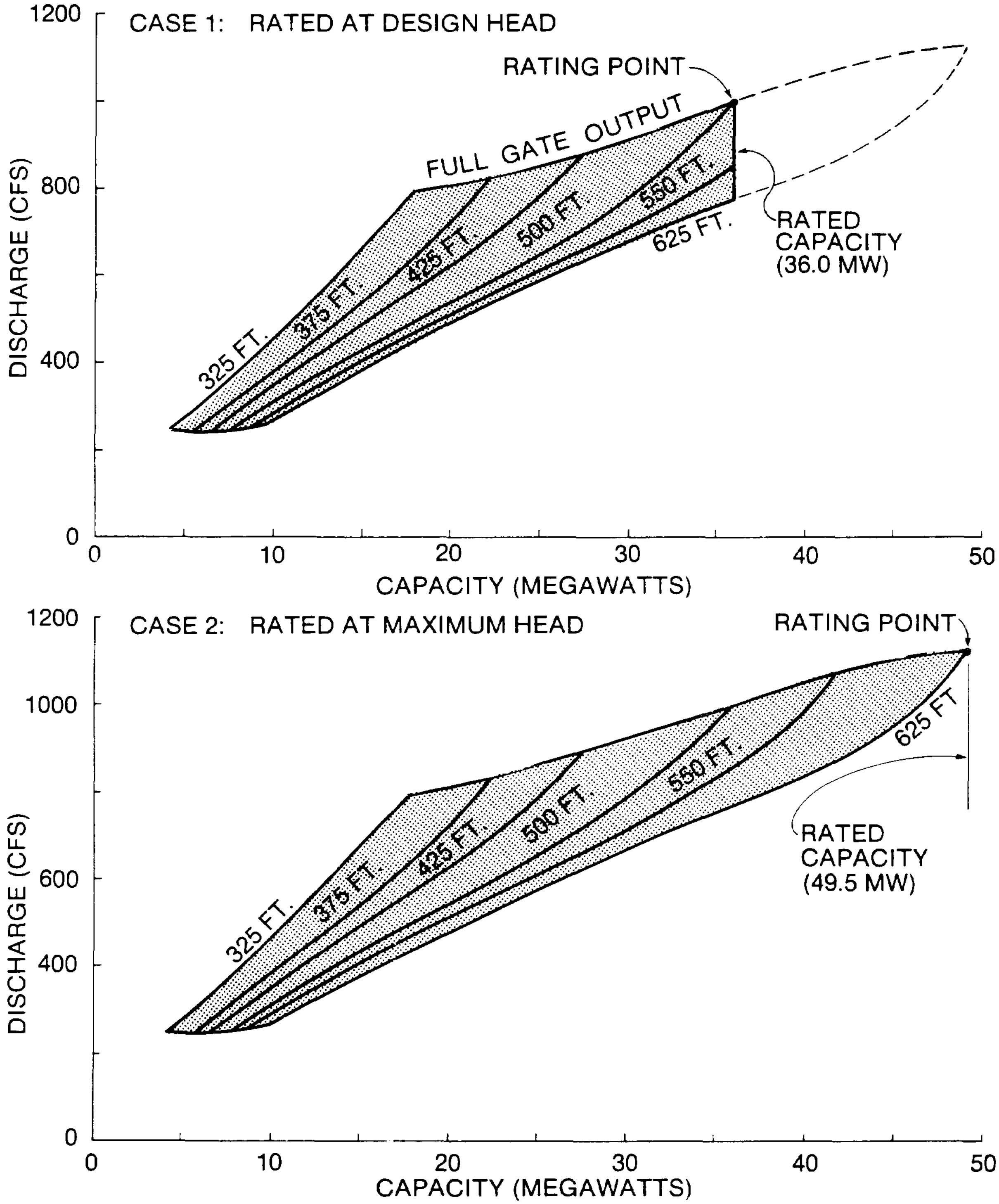


Figure 5-9. Alternative rating points for a given Francis turbine design applied to a given storage project

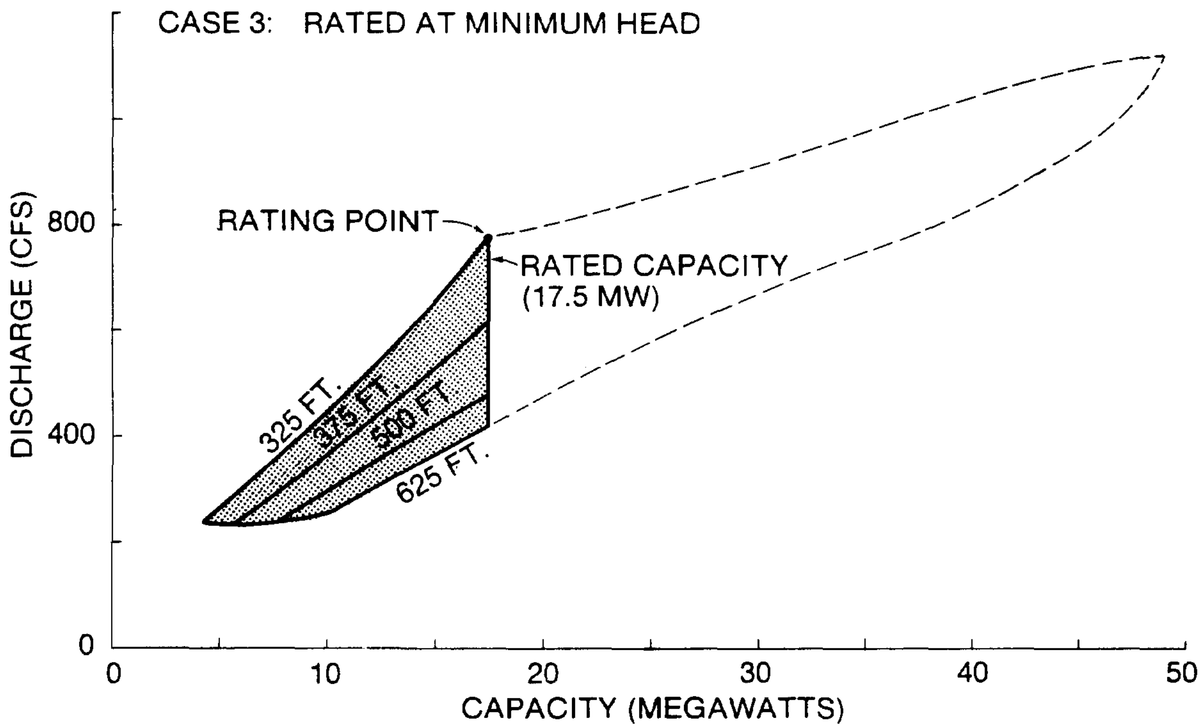


Figure 5-9 (continued)

Figure 5-10 shows the unit characteristics as applied to Figure 5-8, including the turbine efficiencies obtained under various operating conditions.

(6) Next, rating the unit at maximum head will be considered. The same turbine would be used, but in this case it will be rated to produce 49.5 megawatts at a head of 625 feet and a discharge of 1120 cfs. A 49.5 megawatt generator would also be specified (Case 2 on Figures 5-9 and 5-10). Rating the unit in this manner will insure that the turbine's full potential will be utilized, and that the maximum amount of energy can be produced. The additional energy production is realized because the unit is capable of greater output when high heads are accompanied by high discharges. However, this additional output is achieved at the expense of higher costs for the larger generator, transformer, and associated buswork and switchgear. In most cases, the amount of time a project would experience these combinations of high heads and high flows is too small to justify the additional costs, but this can be verified only through economic analysis.

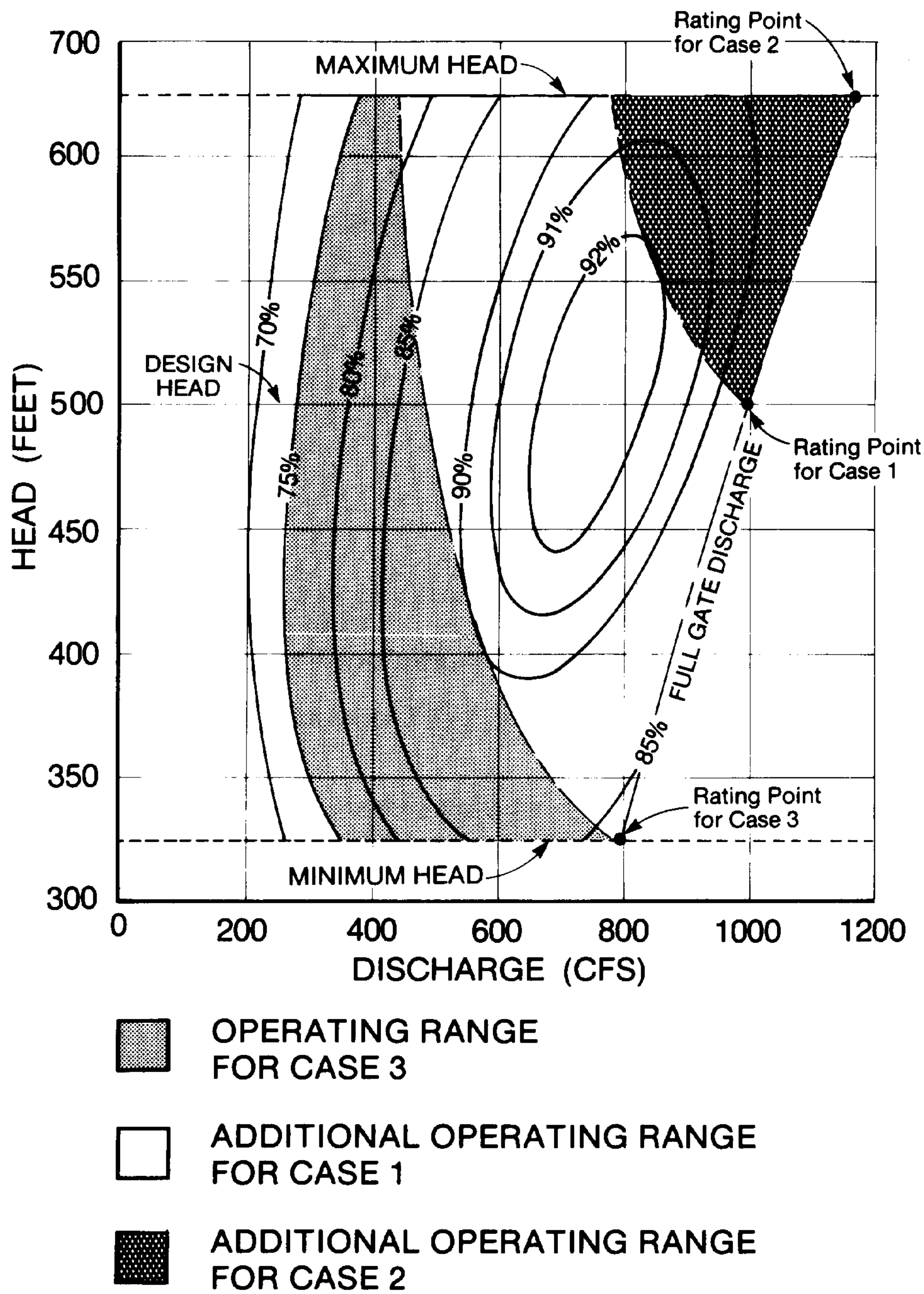


Figure 5-10. The operating ranges and efficiencies for the alternative turbine rating points shown on Figure 5-9

(7) The third option being considered is to rate the unit at minimum head. In this case, the turbine would be rated to produce 17.5 megawatts at a head of 325 feet and a discharge of 790 cfs (Case 3 in Figures 5-9 and 5-10). Using this approach, it will be possible to obtain the full rated output throughout the entire operating head range, and this may be a consideration if the project's dependable capacity output is of prime concern. However, it should also be noted that the maximum discharge at the 500 foot design head is only 480 cfs, well below the 1000 cfs requirement. To pass 1000 cfs at 500 feet of head, the unit would have to be rated to produce 36.4 megawatts at the rated head of 325 feet. This requirement could be met by installing a larger turbine runner of the same design. The corresponding rated discharge would be 1640 cfs. The larger unit will be able to capture some additional energy when high discharges are experienced in the low head range. This additional performance would be achieved at the cost of a larger runner, a larger penstock and spiral case, and perhaps larger intake and powerhouse structures. In addition, it can be seen from Figure 5-10 that the unit will be operating at relatively low efficiencies much of the time, which will result in a lower energy output over most of the operating range (compared to Cases 1 and 2) and which could result in rough operation of the unit.

(8) It can be seen from the examples that matching the generator to the turbine at either maximum head or minimum head is not usually desirable, at least not for a project with a large operating head range. Rating a unit at maximum head usually results in an oversized generator and rating the unit at minimum head results in an oversized turbine. However, the example does show the general effect of varying the rated head on project cost and performance. When making the final analysis of a proposed powerplant, it is common to test a range of rated heads, as well as different turbine runner designs, using economic analysis to select the recommended plan. However, this would not generally be done until the project reaches the design stage. At the planning stage, it is usually satisfactory to consider only a single rated head, selected using the general guidelines presented in Sections 5-5c (3) through (9), but also taking into account the relationships described above. As with the turbine selection process, the determination of rated head should be made in cooperation with hydraulic machinery specialists from one of the Hydroelectric Design Centers.

5-6. Data Requirements.

a. Introduction. This section describes the data required for energy potential studies. The data specifically required for a given study varies depending on the type of project and the method used for computing the energy. This section describes each data element in detail, and Tables 5-2, 5-3, 5-4, 5-12, and 6-2 summarize specific data required for each of the respective types of studies.

b. Routing Interval.

(1) The time interval used in a power study depends on the type of project being evaluated, the type of power operation being examined, the degree of at-site and upstream regulation, and the other functions served by the project or system. Longer time intervals, such as the month, are generally preferable from the standpoint of data handling. However, where flows and/or heads vary widely from day to day, shorter intervals may be required to accurately estimate energy output.

(2) A daily time interval should generally be used with the duration curve method. Weekly or monthly average flows tend to mask out the wide day-to-day variations that normally occur within each week or month. As a result, the higher and lower streamflow values are lost, and the amount of streamflow available for power generation may be substantially overestimated (see Figure 5-29). The only case where weekly or monthly average flows could be used would be where storage regulation minimizes day-to-day variations in flow.

(3) The time interval used for the sequential streamflow routing method depends on the type of project being studied. For projects with seasonal power storage, a weekly or monthly interval is normally used. A weekly interval would give better definition than a monthly interval, but where a large number of projects are being regulated over a long historical period, the monthly interval may be the most practical choice from the standpoint of data processing requirements. Where the monthly interval has been adopted but the hydrologic characteristics of the basin produce distinct operational changes in the middle of certain months, half-month intervals may be used. In some snowmelt basins, for example, reservoir refill typically begins in mid-April, and to model this operation accurately, Aprils are divided into two half-month intervals.

(4) During periods of flood regulation, streamflows may vary widely from day to day, and daily analysis may be required, both to accurately estimate energy potential and to properly model the flood regulation (if the routing model is being used to simultaneously do flood routing and power calculations). One approach is to use a daily or multi-hour routing during the flood season and weekly or monthly routing during the remainder of the year. Some sequential routing models, including HEC-5, can handle a mix of routing intervals.

(5) For SSR analysis of a run-of-river project with no upstream storage regulation, daily flows must be used. Where seasonal storage provides a high degree of streamflow regulation and streamflows at the run-of-river project remain relatively constant from day to day, weekly, bi-weekly, or monthly intervals may be used.

(6) For studies of peaking projects, pump-back projects, and off-stream pumped-storage projects, hourly sequential routing studies may be required (Section 6-9). These studies are generally made for selected weeks which are representative of the total period of record.

(7) When using the hybrid method (Section 5-4d), a daily routing interval should be used, for the same reasons as were cited for the duration curve method.

(8) The level of study may also influence the selection of the routing interval. In cases where daily data would be required at the feasibility level, weekly or monthly data may be adequate for screening or reconnaissance studies.

c. Streamflow Data.

(1) For sequential routing studies, historical streamflow records are normally used. The basic sources of historical streamflow data and methods for adjusting this data for hydrologic uniformity are described in Sections 4-3 and 4-4. To avoid biasing the results, only complete years should be used.

(2) Historical records are frequently used for flow-duration and hybrid method analyses also. However, the data must be consistent with respect to upstream regulation and diversion. In some cases, period-of-record sequential routing studies have previously been performed for the purposes of analyzing flood control operation or other project functions. Since these routings would already reflect actual operating criteria and other hydrologic adjustments, they should be used when they are available.

(3) For hourly studies, flow is usually obtained from the weekly or monthly period-of-record sequential routing studies that describe the long-term operation of the project being studied.

d. Length of Record.

(1) Thirty years of historical streamflow data is generally considered to be the minimum necessary to assure statistical reliability. However, for many sites, considerably less than 30 years of record is available. Where a shorter record exists, several alternatives for increasing data reliability are available.

(2) For a large project, particularly one with seasonal storage, the streamflow record should be extended using correlation techniques, basin rainfall-runoff models, or stochastic streamflow generation procedures (Section 4-3d).

(3) For small projects where energy potential is to be estimated using the flow-duration method, correlation techniques can also be used. A short-term daily flow-duration curve can be modified to reflect a longer period of record by correlating the streamflow with nearby long-term gaging stations.

(4) For small projects where sequential streamflow routing is to be used, and less than 30 years of flow data are available, the record should be tested by comparing with other nearby gaging stations to determine if it is representative of the long term. If so, the analysis could be based on the available record, but, if not, the record should be extended using one of the methods outlined in Section 4-3d.

(5) In examining the addition of power to an existing flood control storage project, the period of record for regulated project outflows may be relatively short, but a long term record of unregulated flows usually exists. If the available record of regulated flows is not representative of the long term, regulated flows for the entire period of record could be developed using a reservoir regulation model such as HEC-5 or SSARR.

(6) When evaluating a project with seasonal power storage (or conservation storage for multiple purposes including power), care should be taken to insure that the streamflow record includes an adverse sequence of streamflows having a recurrence interval suitable for properly analyzing the project's firm yield (say once in 50 years). This could be tested by comparing the available record with longer-term records from other gages or by analyzing basin precipitation records. If the available sequence does not include an adverse flow sequence suitable for reservoir yield analysis, it should be extended to include one.

(7) The discussion in the preceding paragraphs applies primarily to feasibility and other advanced studies. For reconnaissance studies, extensive hydrologic analysis can seldom be justified. An estimate of the project's energy output can be developed using the available record, and an approximate adjustment can be made if necessary to reflect longer term conditions.

e. Streamflow Losses.

(1) Not all of the streamflow passing a dam site may be available for power generation. Following is a list of some of the more common streamflow losses. The consumptive losses include:

- reservoir surface evaporation losses
- diversions for irrigation or water supply

The non-consumptive losses include:

- navigation lock requirements
- requirements of fish passage facilities
- other project water requirements
- leakage through or around dam and other embankment structures
- leakage around spillway or regulating outlet gates
- leakage through turbine wicket gates

(2) Techniques for estimating each of these losses are discussed in Section 4-5h. Losses may be assumed to be uniform the year around, or they can be specified on a monthly or seasonal basis. If the streamflow is to be routed to downstream projects or control points, it will be necessary to segregate the losses into consumptive and nonconsumptive categories. Otherwise, they can be aggregated into a single value for each period (or the year if no seasonal variation is assumed). As noted in Section 4-5h, evaporation losses at storage projects are treated as a function of surface area (and hence reservoir elevation).

(3) When examining the addition of power to an existing project, it is common to use either a historical record of project releases of an existing period-of-record sequential routing study. This data usually reflects consumptive losses already.

f. Reservoir Characteristics.

(1) In sequential streamflow routing studies, the type of reservoir data that must be provided depends on the type of project being examined. For storage projects, this would include storage volume versus reservoir elevation data, and (where evaporation losses are treated as a function of reservoir surface area) surface area versus elevation data. Examples of storage-elevation and area-elevation curves are shown in Section 4-5c. Where physical or operating limits exist, maximum and/or minimum reservoir elevations would also be identified.

(2) For some run-of-river projects, a constant reservoir elevation can be specified, but for others, it may be necessary to develop a forebay elevation versus discharge curve. For run-of-river projects with pondage, reservoir elevation will vary from hour to hour, and the average daily elevation may vary from day to day. In the hourly modeling of peaking operations, this variation in elevation must be accounted for, and storage-elevation data must be provided in the model. However, when these projects are being evaluated for energy potential, and daily, weekly, or monthly time intervals are being used, an average pool elevation should be specified. The average elevation can be estimated from hourly operation studies, and it may be specified as a single value or as varying seasonally (for example, assume a full pool in the high flow season and an average drawdown during the remainder of the year).

(3) When using the flow-duration method, either a fixed (average) reservoir elevation or an elevation versus discharge relationship must be assumed for all types of projects. When using the hybrid method, reservoir elevations are obtained for each interval from the historical record or from a base sequential streamflow routing study.

g. Tailwater Data.

(1) Three basic types of tailwater data may be provided:

- a tailwater rating curve
- a weighted average or "block-loaded" tailwater elevation
- elevation of a downstream reservoir

(2) For most run-of-river projects or projects with relatively constant daily releases, a tailwater rating curve would be used. At peaking projects, the plant may typically operate at or near full output for part of the day and at zero or some minimum output during the remainder of the day. In these cases, the tailwater elevation when generating may be virtually independent of the average streamflow, except perhaps during periods of high runoff. For projects of this type, a single tailwater elevation based on the peaking discharge is often specified. It could be a weighted average tailwater elevation, developed from hourly operation studies and weighted proportionally to the amount of generation produced in each hour of the period examined. In other cases, it might be appropriate to use a "block-loaded" tailwater elevation, based on an assumed typical output level (Figure 4-7).

(3) There is sometimes a situation where a downstream reservoir encroaches upon the project being studied: i.e., the project being studied discharges into a downstream reservoir instead of into an open

river reach. This encroachment may be in effect all of the time or just part of the time. During periods when encroachment occurs, the project tailwater elevation should be based on the elevation of the downstream reservoir.

(4) In some cases, two or more different tailwater situations may exist at a single project during the course of the year. It may operate as a peaking project most of the year, and during this period a "block-loaded" tailwater elevation may be most representative. During the high flow season, the tailwater rating curve may best describe the project's tailwater characteristics. Some energy models provide all three tailwater characteristics (rating curve, weighted average or block-loaded elevation, and elevation of downstream reservoir) and select the highest of the three for each interval.

(5) When SSR modeling is done on an hourly basis, it is necessary to reflect the dynamic variation of tailwater during peaking operations (i.e., the fact that the tailwater elevation response lags changes in discharge). A simple lag of the streamflow hydrograph may be applied to reflect the time required for tailwater to adjust to changes in discharges, or more sophisticated routing techniques may be applied. Section 4-5b provides additional information on developing tailwater data.

h. Installed Capacity.

(1) The powerplant installed capacity establishes an upper limit on the amount of energy that can be generated in a period. Installed capacity is one of the variables considered in evaluating a hydro project, and it is common to make energy estimates for several alternative plant sizes. However, when other variables, such as dam height, storage volume, and project layout are being considered as well, a systematic approach is needed to minimize the number of power studies made. A frequently used procedure is to assume a common plant sizing parameter for all project configurations, one which results in most of the energy being captured. This parameter could be a typical plant factor or, in the case of a duration curve analysis, a specific point on the flow-duration curve. Then, once the range of possible project configurations has been screened down to one or more most likely candidates, alternative plant sizes would be tested.

(2) For preliminary studies, energy estimates are sometimes made without applying an installed capacity constraint. The resulting value, which represents the total energy potential of the site, can be used to select a range of plant sizes for more detailed study.

(3) Formerly, plant capacity was specified in terms of both a rated or nameplate capacity and a somewhat higher overload capacity

(usually 115 percent of nameplate). At the present time, only a single rated capacity value is specified, and this value includes overload characteristics (see Section 6-1b). Chapter 6 gives additional information on plant size selection.

i. Turbine Characteristics.

(1) Maximum and minimum turbine discharge and the turbine's usable head range establish limits on the amount of energy that can be developed at a site. In making energy computations, it is necessary to check to insure that the net head and usable discharge values for each time interval fall within the allowable range for the type of turbines being considered, so these values must be identified. Sections 2-6 and 5-5 provide general information on turbine characteristics and turbine selection. Following is some specific data on discharge and head ranges for the various types of turbines.

(2) In planning studies, plant size is often specified initially in terms of hydraulic capacity. The hydraulic capacity would also be the plant's maximum discharge, and in most cases can be assumed to be the same as the plant's rated discharge (see Section 6-1b(8)). The maximum (or rated) discharge of individual units would be defined by the number and size of the units (see Section 6-6f).

(3) Cavitation problems and the possibility of rough operation preclude generation below a minimum discharge (see Section 5-5d), and the minimum discharge for a single unit establishes the plant's minimum allowable power discharge. Table 5-1 lists factors for computing minimum discharges for different types of turbines given a units rated discharge. These values can be used for initial power studies, but once a unit design has been selected, the specific minimum discharge characteristics of that unit should be used.

(4) Likewise, a turbine is only capable of operating satisfactorily over a limited head range (Section 5-5b), and this should be reflected in energy studies. For preliminary studies, the maximum head ranges listed in Table 5-1 should be used. These ranges are only approximate. Once a unit design has been selected, the specific head range characteristics of that unit should be used instead.

j. KW/cfs Curve. When hand routing techniques and certain computer programs are used to evaluate the energy output of a storage project, kW/cfs versus elevation and kW/cfs versus head curves are sometimes used to simplify the analysis. These curves account for the variation of powerplant efficiency with head, and the kW/cfs versus elevation curves account for head loss and tailwater elevation as

TABLE 5-1
Discharge and Head Ranges for Different Types of Turbines

Turbine Type	Ratio of Minimum Discharge to Rated Discharge	Ratio of Minimum Head to Maximum Head
Francis	0.40	0.50
Vertical shaft Kaplan	0.40	0.40
Horizontal shaft Kaplan	0.35	0.33
Fixed blade propeller	0.65	0.40
Fixed gate adjustable blade propeller	0.50	0.40
Fixed geometry units (pumps as turbines)	-	0.80
Pelton (adjustable nozzles)	0.20	0.80

well. Appendix G describes how kW/cfs curves can be developed and used.

k. Efficiency.

(1) The efficiency of turbine-generator units varies with both head and discharge and with turbine type. Section 5-5e describes these efficiency characteristics in some detail. The following paragraphs summarize how efficiency should be treated for different types of projects and studies.

(2) For preliminary studies, it is common to assume a fixed overall efficiency of 80 to 85 percent.

(3) A fixed efficiency value can also be used for feasibility level studies of small hydro projects where the head fluctuation is small compared to total head (less than 10 percent). A value of 80 to 85 percent can be used prior to turbine selection, but once a turbine design has been chosen, an average efficiency based on the characteristics of that unit should be used.

(4) For feasibility studies of large projects, or small projects where large head fluctuations are experienced, the variation of efficiency can have a significant effect on energy output. For small,

low-head projects, where head varies directly with discharge, an efficiency versus discharge relationship can be derived (see Section 5-7n).

(5) For projects where head varies independently of discharge, an efficiency versus discharge curve can be used if head does not vary substantially. Where head does vary substantially, several alternatives are available. For projects with four or more units, there is considerable flexibility of operation. The number of units that are placed on-line at any given discharge would be selected such that they would all be operating at or near the point of best efficiency for the given discharge. In these cases, an efficiency versus head curve can be developed. Figure 5-11 shows an efficiency vs. head curve for a multiple-unit Francis installation. This curve was developed from the turbine performance curve shown on Figure 5-8, based on the units operating at the point of best efficiency at each head. The efficiency values from Figure 5-8 were reduced by an additional two percent to account for generator losses. Where a project is normally "block loaded" (see Figure 5-10, the plant would always operate at or

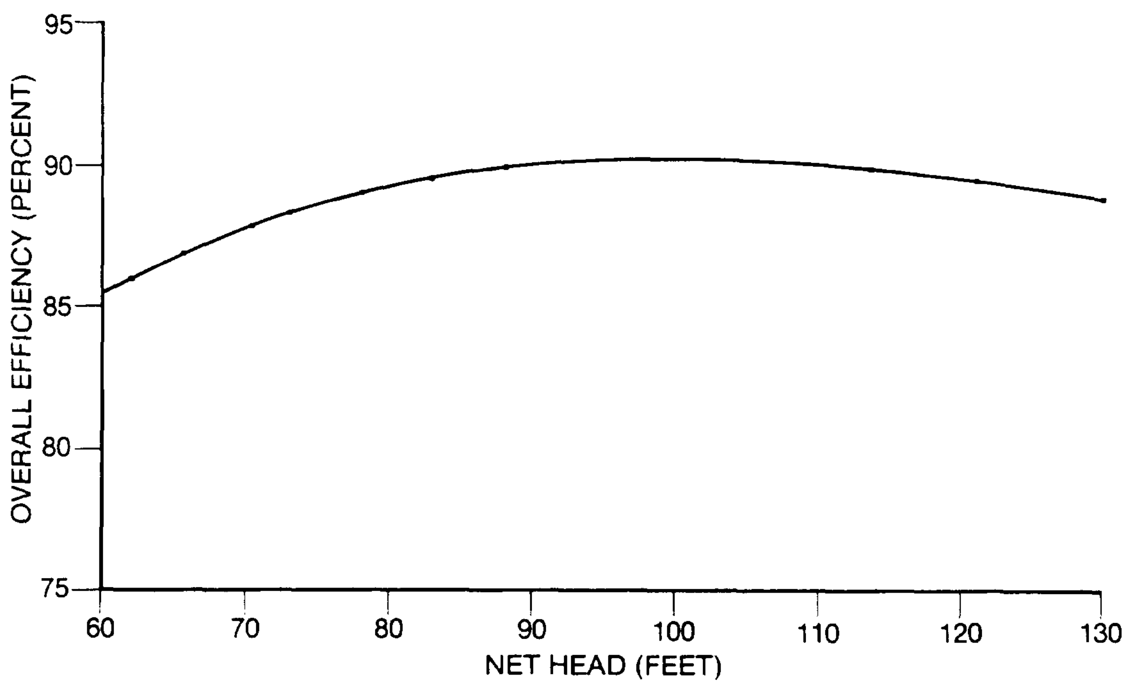


Figure 5-11. Net head vs. efficiency curve
for Francis turbine (multiple-unit installation)

near full plant output. An efficiency versus head curve could be developed for this type of project as well.

(6) Where it is considered necessary to model the variation of efficiency with both head and discharge, several techniques are available. One example is the procedure used in North Pacific Division's HYSSR model (see Appendix C), where three efficiency versus head curves are used:

- operation at best efficiency
- operation at full gate discharge
- operation at rated capacity (or overload capacity, if the units have an overload capacity)

Because all of the major plants in the NPD system are multiple-unit plants, it can be assumed that the number of units on line will be varied so that all plants will operate at or near the point of best efficiency for flows up to 80 percent of the plant's full gate hydraulic capacity. Between 80 percent and full gate discharge, the model interpolates between the best efficiency and full gate curves. Between full gate discharge and rated capacity, it interpolates between the full gate and rated capacity curves. At higher discharges, the rated capacity curve is used. At heads below rated head, the rated capacity curve would not apply.

(7) Other approaches for treating both head and discharge can be used as well, including table look-up, but care should be taken to insure that the efficiency algorithm will load the proper number of units to give the best overall plant efficiency at each discharge level. Also, if the project is a peaking plant, the algorithm should not utilize the average discharge for the period to compute efficiency. It should use instead either a weighted average discharge or a "block loading" discharge (see Section 5-6g), whichever best describes the project's operation.

(8) Accurately modeling the variation of efficiency with both head and discharge is a complex operation, and including such an algorithm in an energy model substantially increases running time. Accordingly, it should be used only for projects where the increased accuracy of results is important. For most projects, modeling the variation of efficiency with either discharge or head will provide satisfactory results.

l. Head Losses.

(1) In determining the net head available for power generation, it is necessary to account for head loss in the water passages. These losses include primarily friction losses in the trashrack, intake

structure, and penstock. Hydraulic losses between the entrance to the turbine and the draft tube exit are accounted for in the turbine efficiency.

(2) For projects where the intake is integral with the powerhouse structure, the losses across the trash racks are the major consideration. For most planning studies, a trash rack head loss of 1.0 feet can be assumed. This value is based on a typical entrance velocity of about 5.0 feet per second. For more detailed information on trash rack losses, reference should be made to the Bureau of Reclamation's Engineering Monograph No. 3 (62).

(3) Steel penstock head losses can be derived using the Scobey equation:

$$h_f = k_s \frac{V^{1.9}}{D^{1.1}} \qquad \text{(Eq. 5-6)}$$

where: h_f = friction loss in feet per thousand feet of penstock length
D = penstock diameter in feet
V = average velocity of flow in penstock in feet per second
k_s = a friction loss coefficient

The friction loss coefficient k_s is a function of the roughness of the penstock wall. For steel penstocks, a value of 0.34 can usually be assumed for k_s. Additional information on estimating penstock losses (including estimating losses for concrete-lined power tunnels) can be obtained from standard hydraulic design references, including the Bureau of Reclamation's Engineering Monograph No. 7 (61).

(4) For preliminary studies and for analysis of projects with short penstocks, it is usually satisfactory to use a fixed penstock head loss, based on the average discharge. For projects with longer penstocks, it is preferable to use a head loss versus discharge relationship. Where a fixed value is used, it would be based on the average daily discharge for a run-of-river plant, but for a peaking project, it should be based on the average discharge when generating.

(5) For projects with long penstocks, the size of the penstock will have a major impact on project costs, and to minimize costs it is desirable to minimize penstock diameter. However, smaller penstock diameters lead to larger losses in potential power benefits due to penstock friction losses. For projects where penstock costs are large, it is usually necessary in advanced stages of planning to make an analysis to determine the optimum penstock diameter considering

both costs and power losses. In earlier stages of study, and at projects where penstock costs are not a major cost component, a preliminary penstock diameter can be selected using a velocity of 17 percent of the spouting velocity.

$$V_R = 0.17(2gH)^{0.5} \qquad \text{(Eq. 5-6a)}$$

where: V_R = velocity of flow in the penstock at rated discharge, in feet per second
g = gravitation constant (32.2 feet/second^2)
H = gross head in feet

However, velocity should normally not exceed 25 feet per second and penstock diameters should not exceed 40 feet. For other than very short or very large penstocks, it is usually cost-effective to use a single penstock, branching just prior to entering the powerhouse.

(6) Hydraulic design references also provide equations for estimating intake and exit losses. Where the intake design permits a gradual increase in velocity, these losses are usually negligible, but where velocity increases sharply (as in square bellmouth intakes), intake losses should be computed. Engineering Monograph No. 3 (62) gives further information on computing intake losses and losses associated with gates and valves.

m. Non-Power Operating Criteria.

(1) A number of operating criteria may exist for governing project functions other than power, and these often affect the energy output of hydro projects, especially those projects having conservation or flood control storage. These constraints could include the following:

- minimum discharge requirements
- storage release schedules for downstream uses (navigation, irrigation, water supply, water quality, etc.)
- flood control requirements
- optimum pool elevation for reservoir recreation
- minimum pool elevation required to permit pumping from reservoir for irrigation and other purposes

(2) Where the addition of hydropower to existing projects is being considered, these requirements may be well-defined, and the specific details can be obtained from historical operating data or reservoir regulation manuals. For new projects, the non-power requirements must be developed concurrently with the hydropower operating criteria (see Section 5-12), and in such a way as to optimize total project benefits. Sequential streamflow routing models

such as HEC-5 are generally capable of integrating flood control and non-power storage regulation objectives in the power study (40). Figure 5-12 shows a rule curve for an existing flood control-conservation storage project, and it illustrates the type of criteria that sometimes must be observed in making power studies.

(3) The above discussion applies primarily to the sequential routing method. The duration curve and hybrid methods cannot explicitly account for non-power operating criteria. The only way in which they can be reflected is to utilize flow data which already incorporates these criteria. In hourly sequential routing studies, additional operating criteria often must be considered, and these are described in Section 6-9.

n. Channel Routing Characteristics.

(1) Channel routing characteristics are required to define (a) travel times between projects and/or control points, and (b) the moderating effect of channel storage on changes in discharge. These effects can usually be ignored in monthly and weekly studies, but they are important in daily and hourly studies, especially where multiple projects are being studied or where downstream non-power objectives (such as flood control or water supply) must be met concurrently with power operations. SSR models with daily or hourly capabilities

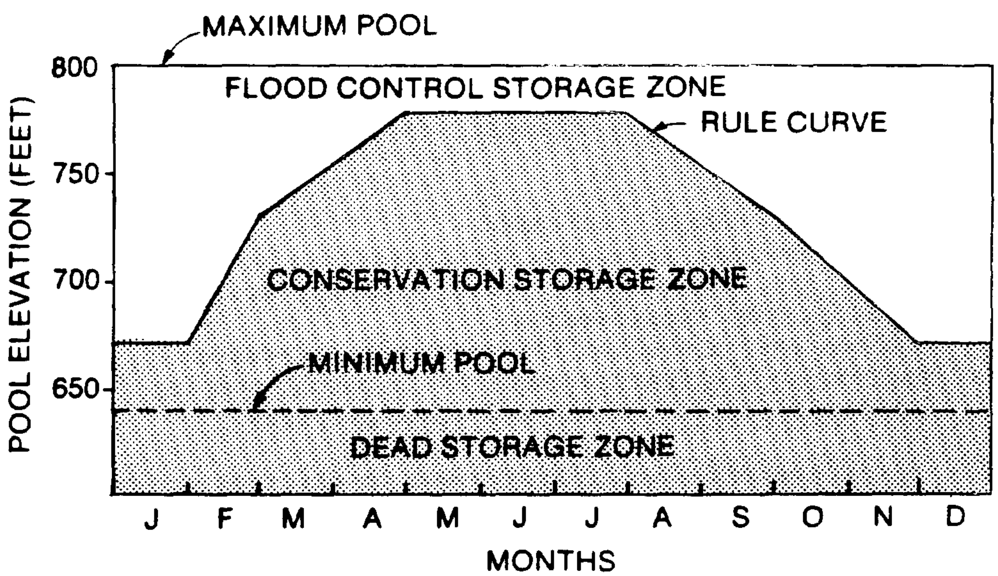


Figure 5-12. Rule curve for project with flood control and conservation storage

generally incorporate one or more channel routing routines, and reference should be made to the user manuals for these models to determine the specific input requirements.

(2) In evaluating the impact of project operation on non-power river uses and the environment, it may be necessary to obtain detailed hourly discharge and water surface elevation data at intermediate points within a reservoir or at downstream points. The hydrologic techniques of flood routing (modified Puls, Muskingum, etc.) are often used in these studies. However, when streambed slopes are very flat (less than two feet per mile), hydraulic routing techniques (using St. Venant equations) may be necessary to properly account for downstream effects.

o. Generation Requirements.

(1) At storage projects, power storage may be available to permit the seasonal shaping storage releases to fit power demand. Generation requirements can be specified either as month-by-month firm energy requirements (in kilowatt-hours) or as month-by-month percentage distributions of total annual firm energy production. Specific generation requirements would be used if the objective is to determine the amount of storage required to carry a given amount of load, while the percentage distribution would be specified if the objective is to determine the maximum firm energy potential of a given reservoir.

(2) In making weekly studies, the monthly energy values can be proportioned among the weeks to obtain a smooth annual distribution, or the monthly energy requirement can be distributed equally among the weeks within each month. In daily studies, it is common to assume a weekly cycle, with five equal weekday loads and proportionally smaller loads on Saturdays and Sundays (Figure 5-13).

(3) For hourly studies, hourly load distributions must be developed, generally for one week periods. Utilities are required each year to provide hourly loads for three representative weeks during the year: a summer week, a winter week, and a spring or fall week. These three load shapes can generally be used in combination with monthly loads to develop the hourly loads for an entire year. Reference (15) provides examples of typical hourly load distributions and describes how these can be used to develop hourly loads for the full year.

(4) Generation requirements are not usually needed for the duration curve and hybrid methods because it is generally assumed in studies of this type that all generation is usable in meeting power system demand. In remote areas, however, project energy output may

sometimes be limited by demand. When the duration curve method is used for evaluating projects in remote areas, power-duration curves can be developed for each month (or for groups of months with similar loads), and the curves can be adjusted manually to reflect usable energy (Figure 5-14). The same approach could also be used with the hybrid method. Alternatively, maximum usable generation values could be specified for each month and the model could be set to automatically limit generation to these values.

(5) The primary source of generation requirements for energy studies should be the regional Power Marketing Administration (PMA) responsible for marketing the power from the proposed hydro project. However, in some cases, the PMA's generation requirements reflect contractual constraints which would preclude developing an operating plan which maximizes NED benefits. Where this occurs, two separate plans should be developed: one which maximizes NED benefits, and one which meets the PMA's requirements. Both should be considered in the selection of the recommended plan. Sources of generation data are discussed in Section 3-5.

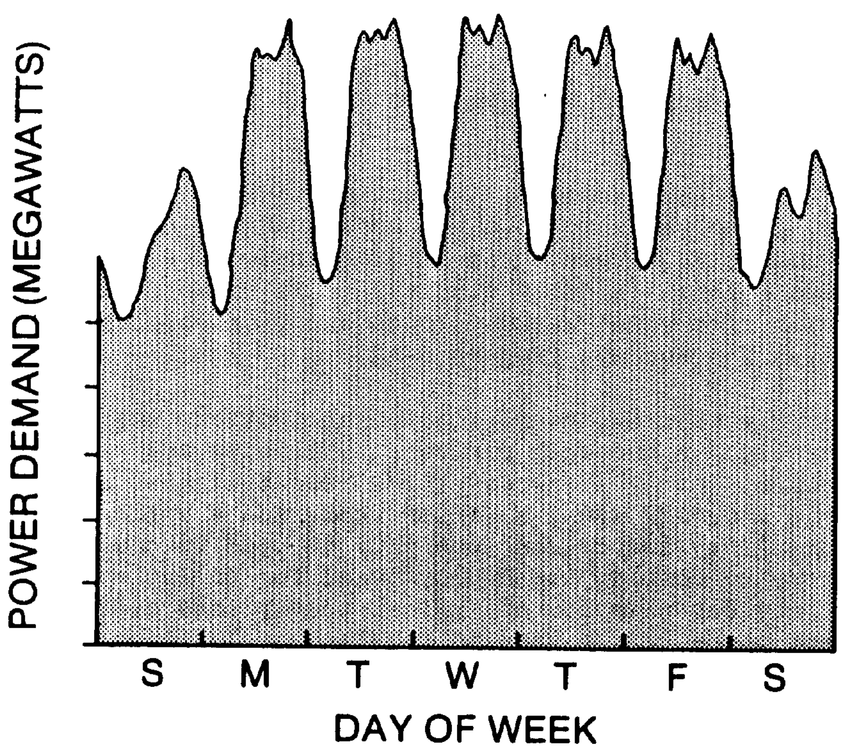


Figure 5-13. Weekly load shape

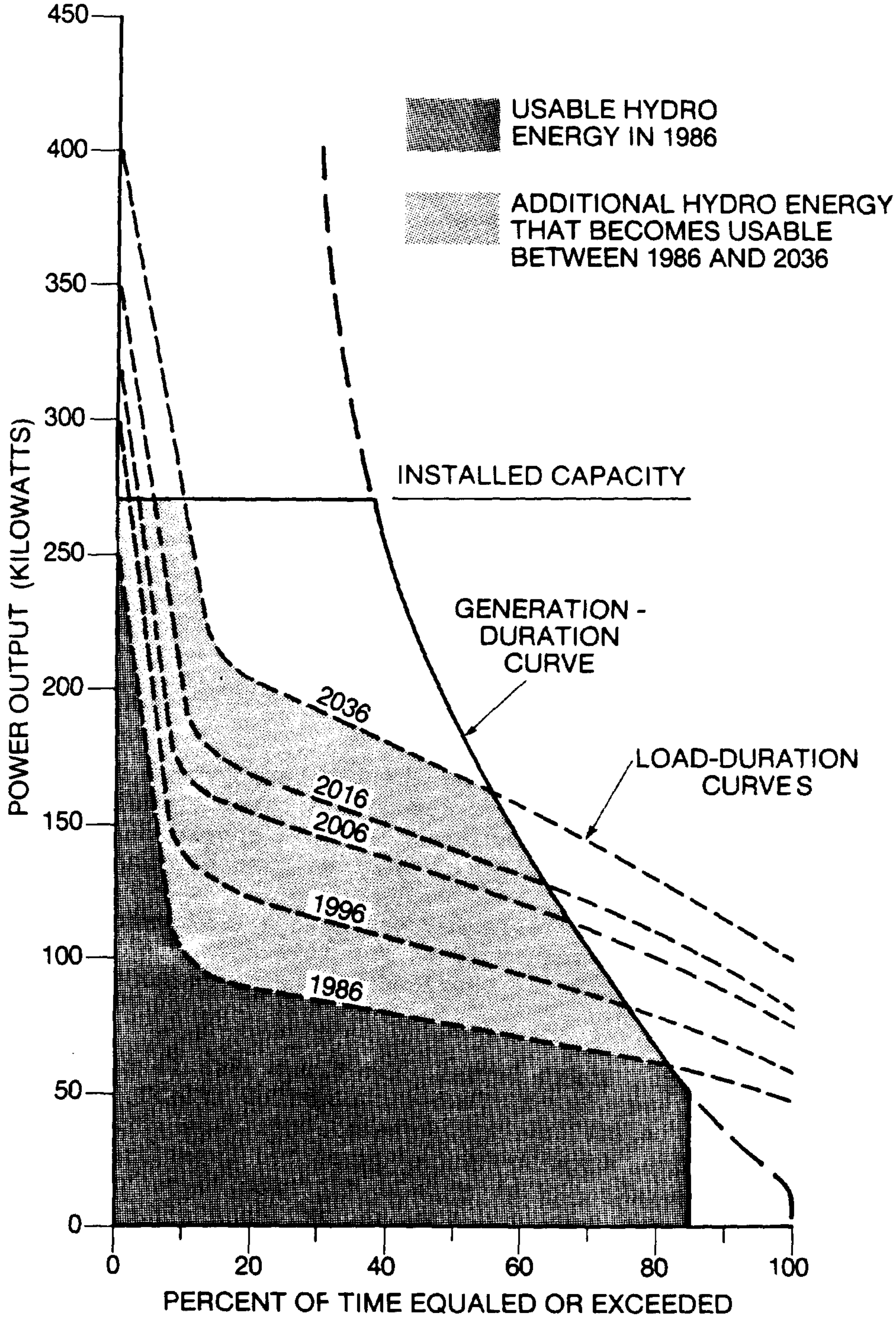


Figure 5-14. Diagram showing increase in usable energy with load growth for small hydro project serving isolated Alaskan community

5-7. Flow-Duration Method.

a. Introduction.

(1) The basis of this method is a flow-duration curve, usually constructed from historical records, which describes the percent of time different levels of streamflow are equaled or exceeded (Figure 5-15). This curve can be readily converted to a power-duration curve through application of the water power equation, and from the latter curve an estimate can be made of the site's energy potential. The primary advantages and disadvantages of the flow-duration method are summarized in Section 5-4b, together with a discussion of the types of studies for which this method is appropriate.

(2) Traditionally, duration-curve energy analyses have been based on flows for the entire year, and this is often satisfactory for preliminary energy potential studies. However, when a project advances to the point where marketing of the power is being studied, it is usually necessary to prepare duration curves describing the plant's energy output by month or by season. The dependable capacity for most small projects is based on the average capacity available during the peak demand months (Section 6-7g), and to do this analysis, it is necessary to have a power-duration curve based on flows for the peak demand months.

(3) The following sections describe the basic steps for computing average annual energy and dependable capacity using the flow-duration method. The discussion includes a sample calculation for a typical low-head run-of-river project with no pondage.

b. Data Requirements. Table 5-2 provides a summary of the basic assumptions and input data requirements for this method. Further information on specific items is provided in the corresponding paragraphs of Section 5-6.

c. Develop Flow-Duration Curve. The first step is to compile a flow-duration curve using the available streamflow record, adjusted if necessary to reflect depletions and current streamflow regulation. For preliminary studies, flow would be aggregated in classes (flow ranges) which would produce 20 to 30 well-distributed points on the duration curve. For more detailed studies, a larger number of classes should be used. The actual compilation of the duration curve is usually done with a computer model. Figure 5-15 illustrates a flow-duration curve for the example project. From the area under the curve, the average annual flow is computed to be 390 cfs.

d. Adjust Flow-Duration Curve. If less than thirty years of flow data is available, nearby stations with longer periods of record should be analyzed to determine if the available period of streamflow record is substantially wetter or drier than the long-term average. If so, the flow-duration curve should be adjusted by correlation with flow-duration curves from the stations with longer-term records.

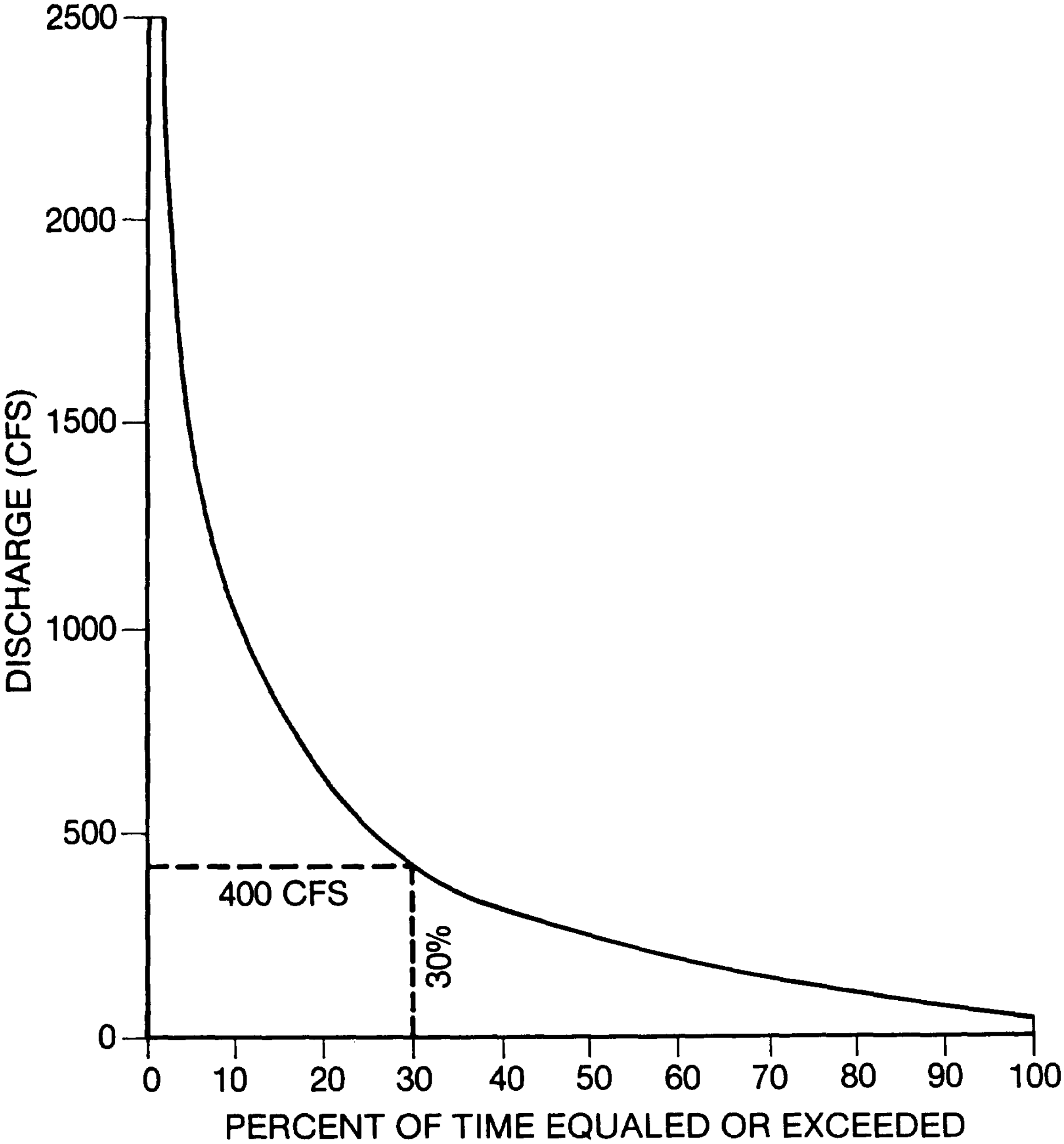


Figure 5-15. Flow-duration curve

TABLE 5-2
Summary of Data Requirements for Duration Curve Method

Input Data	Paragraph 1/	Data Required
Routing interval	5-6b	daily time interval
Streamflow data	5-6c	historical records or SSR regulation
Minimum length of record	5-6d	30 years or representative period
Streamflow losses		
Consumptive	5-6e	see Sections 4-5h(2) and (3)
Nonconsumptive	5-6e	see Sections 4-5h(4) thru (10)
Reservoir characteristics	5-6f	use elevation vs. discharge curve or assume fixed elevation
Tailwater data	5-6g	tailwater curve or fixed value
Installed capacity	5-6h	specify capacity for all but preliminary studies
Turbine characteristics	5-6i	specify maximum and minimum discharges and maximum and minimum heads
KW/cfs table	5-6j	not used
Efficiency	5-6k	fixed efficiency or efficiency vs. discharge curve
Head losses	5-6l	use fixed value or head loss vs. discharge curve
Non-power operating criteria	5-6m	use flow data which incorporates these criteria
Channel routing	5-6n	not required
Generation requirements	5-6o	not usually required

1/ For more detailed information on specific data requirements, refer to the paragraphs listed in this column.

e. Determine Flow Losses. Flow losses of various kinds often reduce the amount of streamflow available for power generation (see Section 5-6e). In the example, it will be assumed that net evaporation losses are minimal but an average loss of 20 cfs results from leakage around gates and the dam structure.

f. Develop Head Data.

(1) Head can be treated in several ways. One method is to develop a head versus discharge curve, which reflects the variation of tailwater elevation with discharge (and forebay elevation with discharge where such a relationship exists). Another approach is to include the head computation directly in the solution of the water power equation (Section 5-7i).

(2) A head-discharge curve would be computed by applying the following equation to a sufficient number of discharge levels to cover the range of flows at which generation would occur.

$$\text{Net head} = (\text{FB}) - (\text{TW}) - (\text{losses}) \qquad \text{(Eq. 5-7)}$$

where: FB = forebay elevation
TW = tailwater elevation
losses = trashrack and penstock head losses, in feet

The lower part of Figure 5-16 illustrates such a curve. The head curve is based on the tailwater curve shown in the upper part of Figure 5-16, a fixed forebay elevation of El. 268.0, and an average head loss of 1.0 ft.

(3) In Figure 5-16, a fixed head loss of 1.0 feet was assumed. Using a fixed head loss is reasonable if the penstock or water passage is short and if head losses are small. For projects with long penstocks, it is preferable to use a head loss versus discharge relationship (see Section 5-6l).

g. Select Plant Size.

(1) For very preliminary studies or to estimate the gross theoretical energy potential of the site, the plant size need not be specified. For reconnaissance studies, it is necessary to test only a single plant size, but as a practical matter, it is usually desirable to examine a range of plant sizes, especially if an initially assumed installation proves to be marginally economical. In more advanced studies, a range of plant sizes (and in some cases, combinations of sizes and numbers of units) would always be considered, to determine the optimum development.

(2) The selection of the plant size (or range of plant sizes) would be based on an examination of the shape of the duration curve with a view toward obtaining the maximum net benefit. Turbine characteristics such as maximum and minimum head and minimum single-unit discharge should be considered in this selection. Section 6-6 provides guidance on selection of a range of plant sizes (as well as

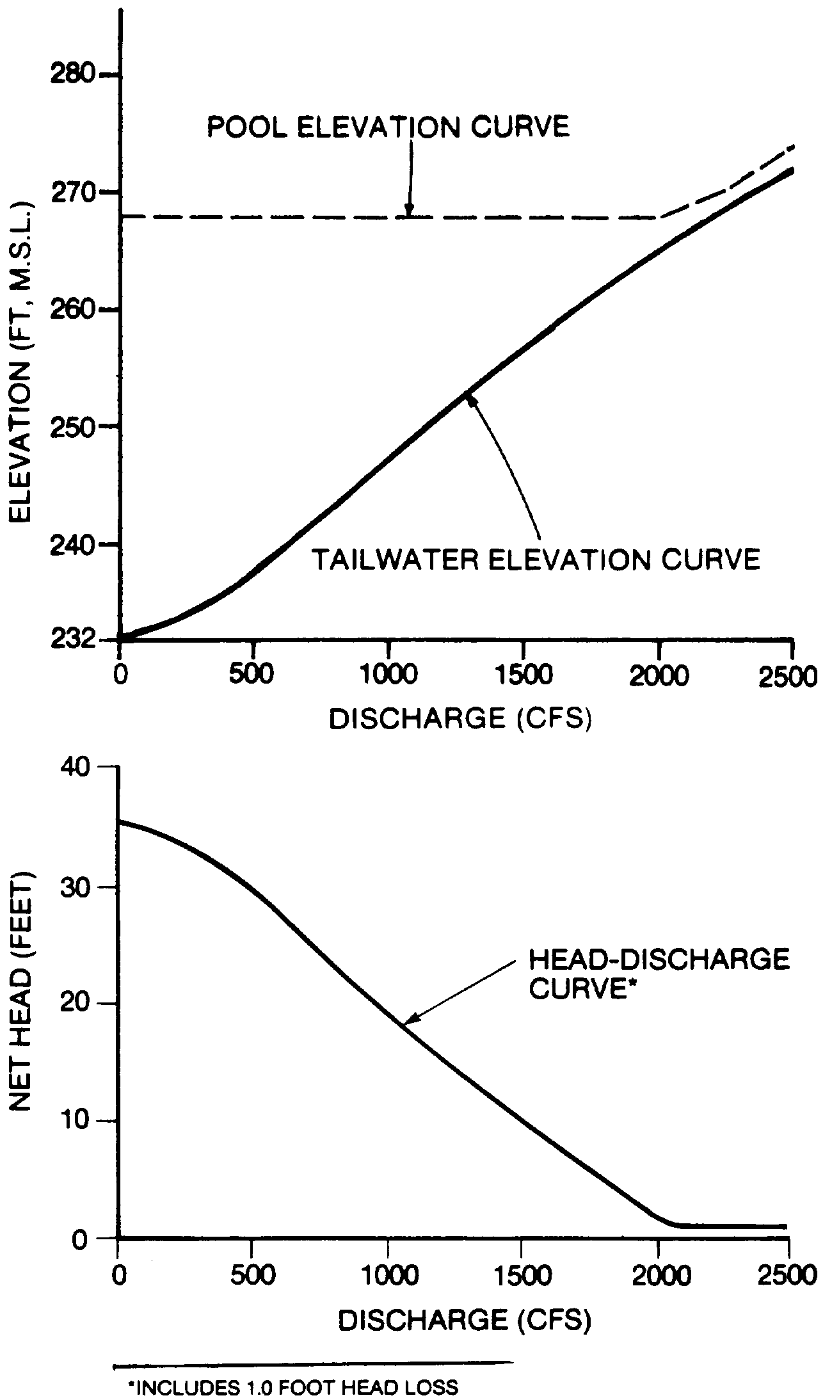


Figure 5-16. Tailwater and head-discharge curves

size and number of units) which could effectively utilize the flows available at the site.

(3) The first step in establishing plant size is to select the plant's hydraulic capacity (the maximum discharge that could be passed through the turbines). In preliminary studies, it is common to base the initial plant size on either the average annual flow or a point between 15 and 30 percent exceedence on the flow-duration curve (see Section 6-6c). In the following example, the initial plant size will be based on the 30 percent exceedance point, or 400 cfs (see Figure 5-15). Allowing for the 20 cfs average flow loss due to leakage, the plant hydraulic capacity would be 380 cfs.

(4) The next step is to compute the net head corresponding to the assumed hydraulic capacity. For pure run-of-river projects (run-of-river projects with no pondage), the discharge corresponding to the plant's hydraulic capacity (all units are running at full gate and no water is being spilled) normally defines the conditions at which the unit would be rated. Hence, the head at hydraulic capacity would be the rated head. For the example, the head corresponding to the 400 cfs discharge would be 31 feet (see Figure 5-17). Note that the 20 cfs leakage loss is included in the discharge used to determine rated head (see Section 5-7i(2)).

(5) Using the resulting hydraulic capacity and rated head, and an assumed overall efficiency, the plant's installed capacity is computed next, using the water power equation. For the example project, a fixed average overall efficiency of 85 percent will be assumed (Section 5-6k(2)). The installed capacity is computed as follows:

$$\text{kW} = \frac{\text{Qhe}}{11.81} = \frac{(400 - 20 \text{ cfs})(31 \text{ ft})(0.85)}{11.81} = 850 \text{ kW}$$

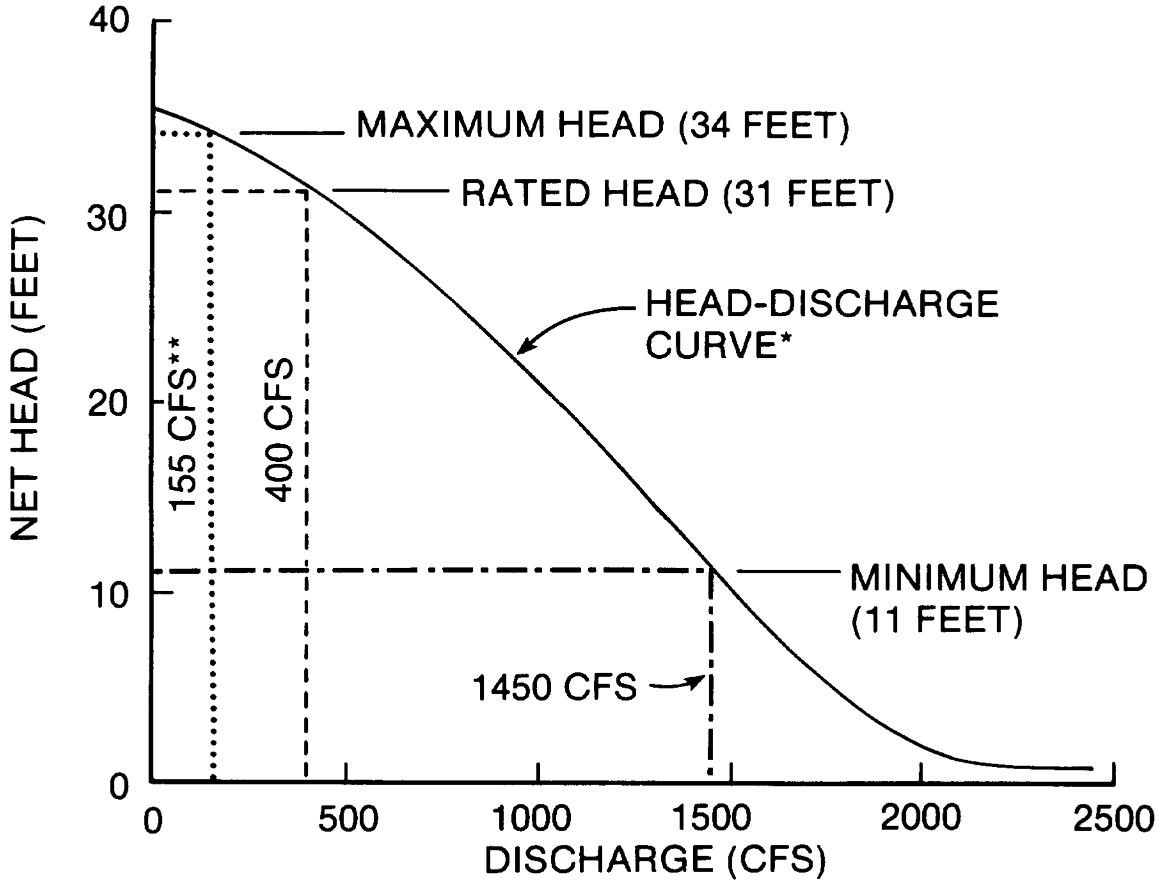
(6) Assume that a single tubular turbine with moveable blades (horizontal shaft Kaplan) will be installed. Table 5-1 summarizes the minimum head and minimum discharge characteristics of different types of turbines. The minimum discharge for a horizontal shaft Kaplan unit would be about 35 percent of the rated discharge. The rated discharge is identical to the hydraulic capacity for a single-unit plant, so the minimum discharge would be (0.35) x (400 - 20 cfs) = 135 cfs.

(7) The streamflow corresponding to the minimum turbine discharge would be 135 cfs plus the 20 cfs average flow loss, or 155 cfs. Figure 5-17 shows that this corresponds to a head of 34 feet. Because the example project is a pure run-of-river plant, heads of greater than 34 feet will occur only at streamflows of less than the

minimum generating streamflow of 155 cfs. Hence, 34 feet is the maximum generating head. The minimum head will be about 33 percent of the maximum head (see Table 5-1), or (0.33 x 34 feet) = 11 feet.

h. Define Usable Flow Range and Derive Head-Duration Curve.

(1) The portion of streamflow which can be used for power generation is limited by the turbine characteristics just discussed. Therefore, the flow-duration curve should be reduced to include only the usable flow range. The minimum discharge for the example project (including losses) is 155 cfs. For a pure run-of-river project, the



* Includes 1.0 foot head loss

** 135 cfs minimum turbine discharge plus 20 cfs flow loss

Figure 5-17. Net head-discharge curve showing maximum head, minimum head, and rated head minimum generating head defines the upper flow limit. In the example, the minimum head is 11 feet, which corresponds to a flow of 1450 cfs (obtained from head-discharge curve, Figure 5-17). Applying these limits, the usable portion of the flow-duration curve can be defined (the shaded area of Figure 5-18).

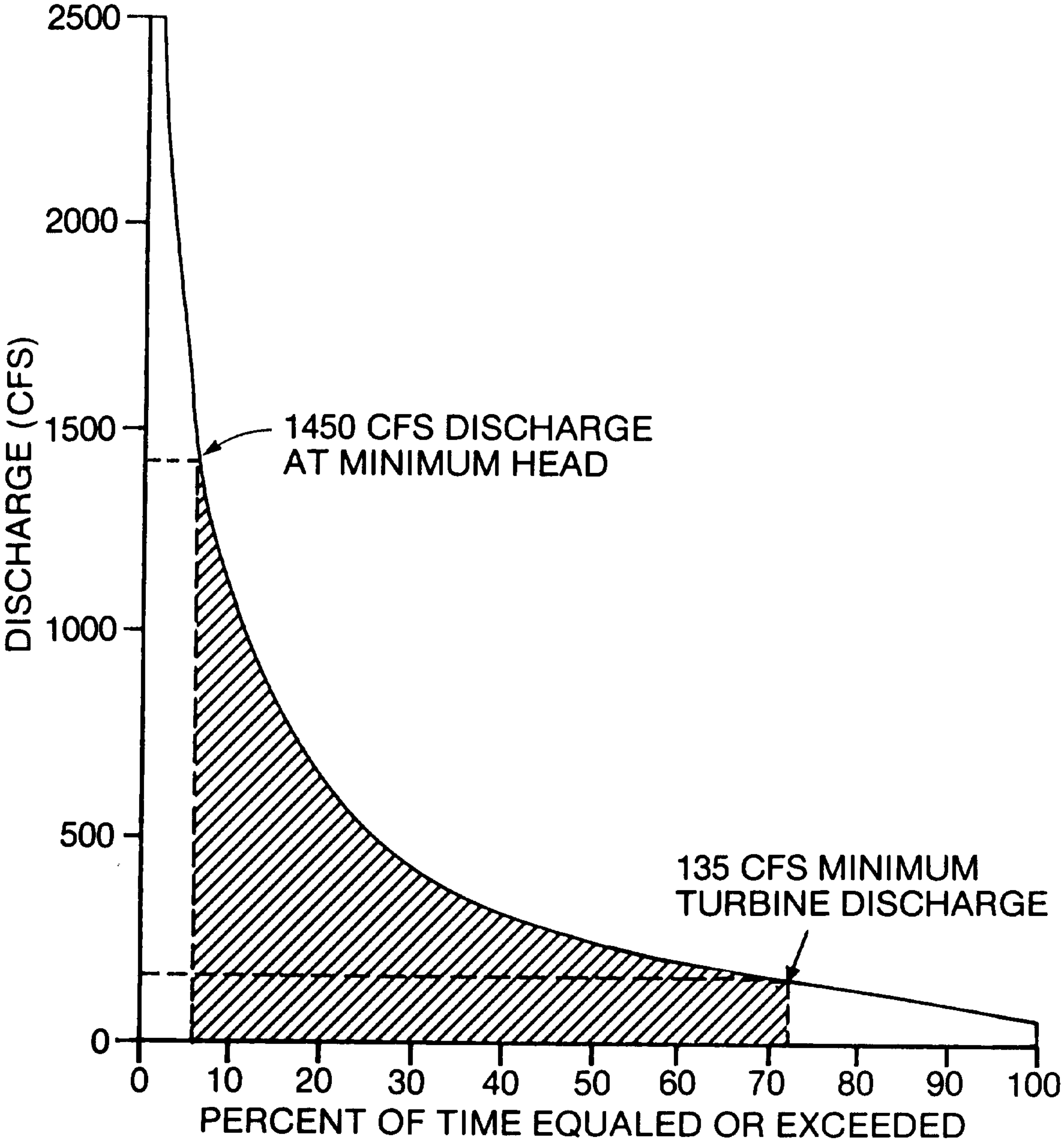


Figure 5-18. Total flow-duration curve showing limits imposed by minimum head and maximum discharge

(2) Using the flow-duration data from Figure 5-18 and the head versus discharge data from Figure 5-17, a head-duration curve can be constructed (Figure 5-19). The shaded area defines the head range where generation is produced. Figure 5-19 also shows the location of the rated head and the design head. Design head in this case is defined as the mid-point of the usable head range (see Section 5-5c(3)).

i. Derive Power-Duration Curve.

(1) Select 20 to 30 points on the flow-duration curve (Figure 5-19), and compute the power at each flow level using the water power equation. Heads can be computed for each point as described in Section 5-7f, or can be obtained from a previously derived head-

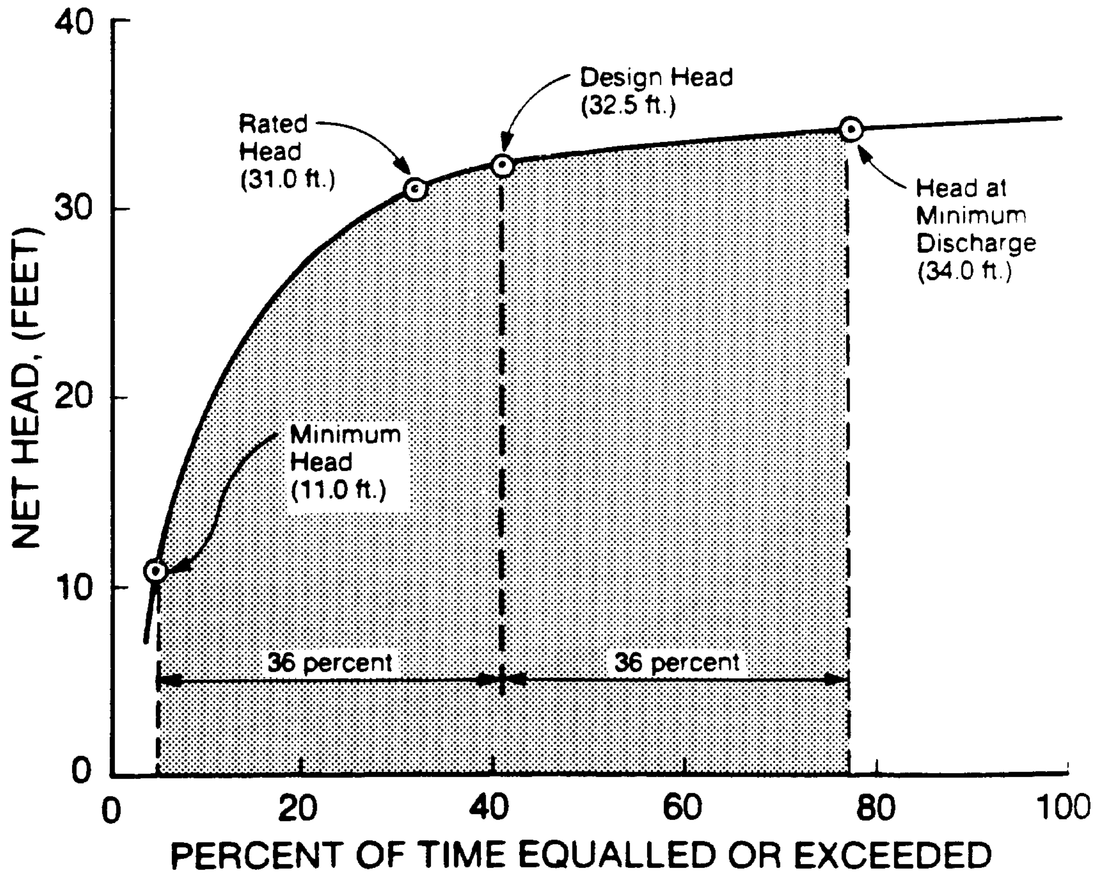


Figure 5-19. Head-duration curve showing minimum head, maximum head, design head, and rated head

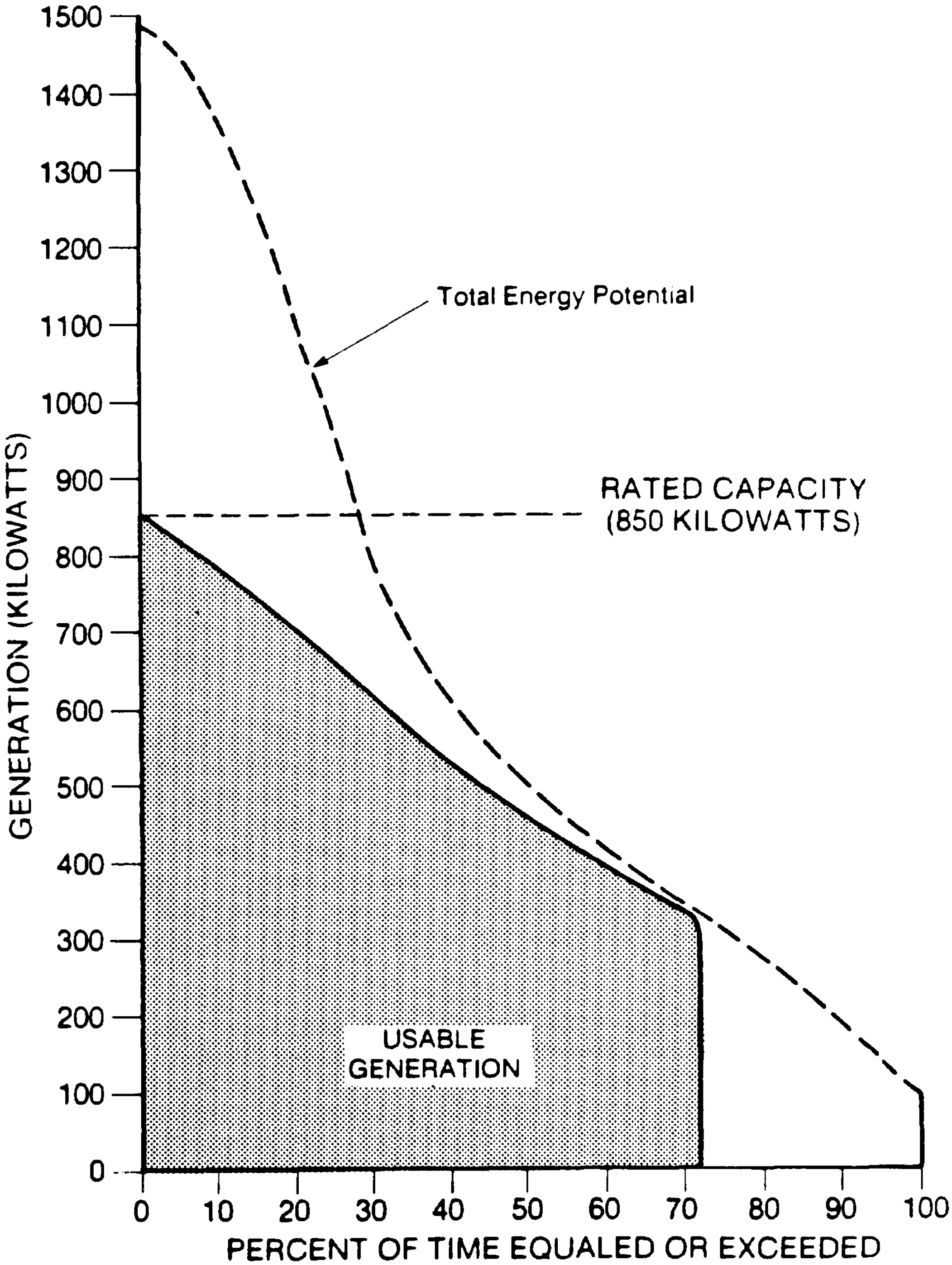


Figure 5-20. Usable power-duration curve

discharge curve. The flow losses identified in Section 5-7e should also be deducted from the flow obtained from the flow-duration curve. Following is a sample calculation for one point on the curve.

$$\text{kW} = \frac{QHe}{11.81} = \frac{(270 \text{ cfs} - 20 \text{ cfs})(33.2 \text{ feet})(0.85)}{11.81} = 597 \text{ kW}$$

Similar computations would be made for all points on the flow-duration curve, the result being the usable generation curve shown as a solid line on Figure 5-21. For comparison, the total power potential of the site is shown as a dashed curve. Sections D-2 and D-3 in Appendix D summarize the calculations used to derive the curve shown on Figure 5-21. Note that an average efficiency of 85 percent has been assumed for all flows. Section 5-7n describes how a variable efficiency would be treated.

(2) Figure 5-21 is not a true power-duration curve, because the generation values are plotted at the percent exceedence points corresponding to the flows upon which they are based (from Figure 5-18). At flows greater than rated discharge (the 32 percent exceedence point on Figures 5-18 and 5-19), there is a reduction in power output due to reduced head and other factors (see paragraph (5) below). The data from Figure 5-21 can be rearranged in true duration curve form as shown on Figure 5-20.

(3) In the example calculation in paragraph (1), the head was obtained from the head-discharge curve, using the gross discharge (270 cfs) because the flow losses are not consumptive. The head should be based on the flow actually passing through the project, so if the losses include some evaporation or diversion losses, they should be deducted from the gross flow before computing the head. In the case of hydro projects where the powerhouse is located remote from the dam, the head should be based on a tailwater elevation that reflects only the power discharges.

(4) Two simplifications were made in this analysis. An average overall efficiency has been assumed for all discharge levels, and the full gate discharge was assumed to be equal to the rated discharge of 380 cfs for all heads. In actual operation, turbine efficiencies may vary substantially with both head and discharge. At streamflows larger than the rated discharge, the full gate discharge decreases with the reduced head. For preliminary studies, such as that illustrated by Figures 5-20 and 5-21, these simplifications are appropriate, but for more advanced studies, these variables must be taken into account. Section D-4 describes how this can be done, and Figures D-3 and D-4 show how these adjustments would affect the estimated power output of the example project.

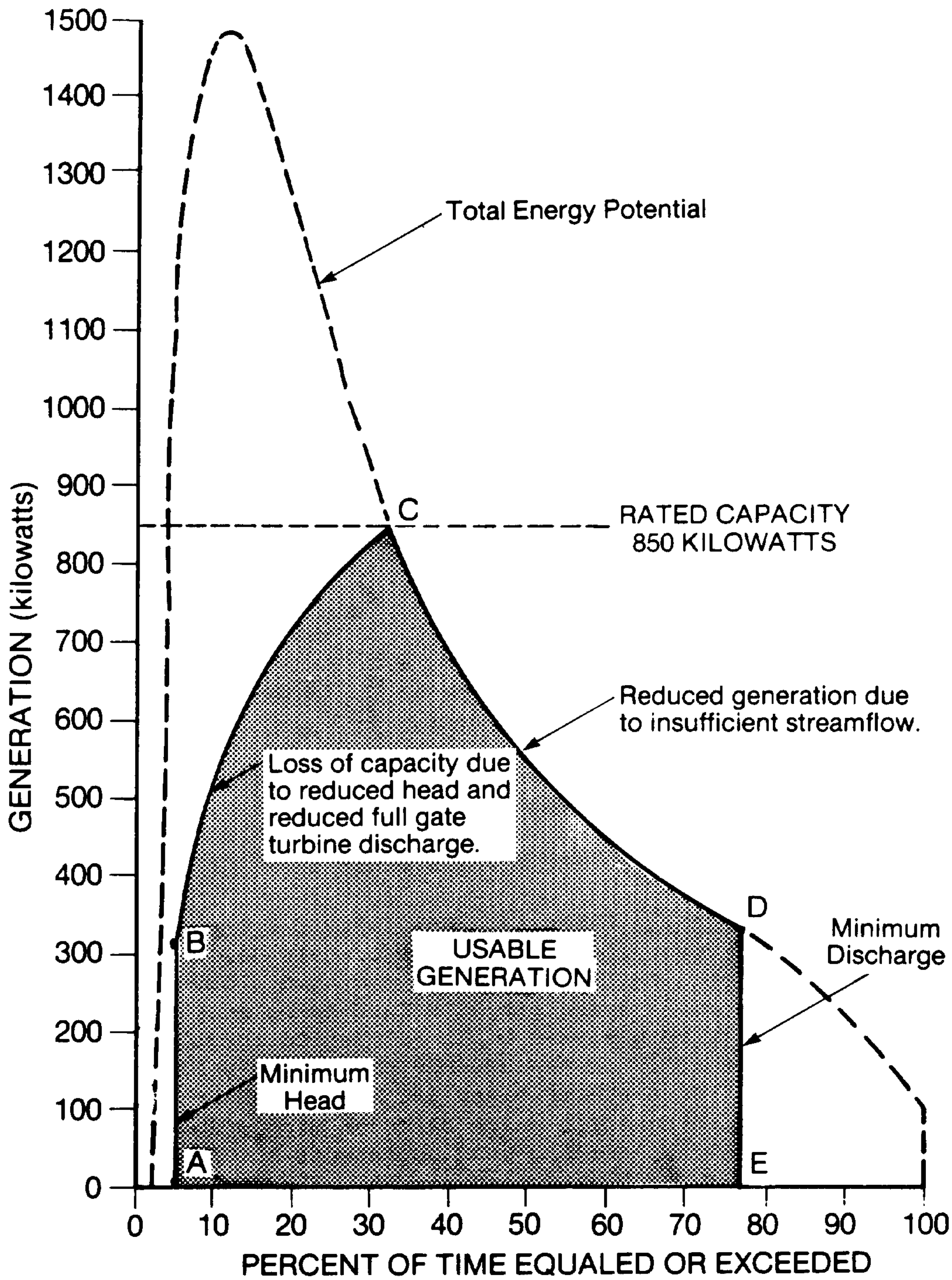


Figure 5-21. Usable generation-duration curve

(5) Figure 5-21 illustrates how the characteristics of the selected turbine-generator unit reduced the site's total energy potential to the usable generation. The shaded area in Figure 5-21 represents the usable generation (and corresponds to the shaded area in Figure 5-20). The rated capacity of 850 kW establishes an upper limit to the power that can be produced, eliminating the potential energy above that line. The 135 cfs minimum turbine discharge eliminates generation to the right of the 72.5 percent exceedance line (line D-E). The 11 foot minimum head eliminates generation to the left of the 6 percent exceedance line (line A-B). Reduced turbine capacity due to reduced head eliminates a portion of the potential generation between 6 and 32 percent exceedance (line B-C).

j. Compute Average Annual Energy. The power-duration curve shown on Figure 5-20 is based on all of the complete years in the period of record. Hence, it can be treated as an annual generation curve, describing the average annual output over the period of record. The average annual energy can be obtained by computing the area under the curve and multiplying by the number of hours in a year (8760).

$$\text{Annual energy (kWh)} = \frac{(8760 \text{ hrs})}{(100 \text{ percent})} \int_{0}^{100} P\,dp \qquad \text{(Eq. 5-8)}$$

where: P = power, kW
p = percent of time

The average annual energy for the example would be 3,390,000 kWh.

k. Compute Dependable Capacity: Run-of-River Projects Without Pondage. Section 6-7 describes the concept of dependable capacity and outlines several ways in which it could be computed. The approach recommended for most small hydro projects (and hence most projects where flow-duration curve analysis might be used to compute energy) is to base dependable capacity on the average capacity available in the peak demand months. For a run-of-river project, this would involve developing a generation-duration curve based on streamflows occurring in the peak demand months. Figure 5-22 represents the generation for the example project in the peak demand months. The dependable capacity would be the average power obtained from that curve.

$$\text{Dependable Capacity} = \text{Avg. Generation} = \frac{1}{100} \int_{0}^{100} P\,dp \qquad \text{(Eq. 5-9)}$$

The dependable capacity for the example would be 338 kW.

l. <u>Compute Dependable Capacity; Pondage Projects.</u>

(1) At some projects, pondage may be available for shaping releases to follow the daily power demand more closely. When using the duration curve method to evaluate projects of this type, a peaking capacity-duration curve must be developed to determine dependable capacity. A capacity-duration curve is similar to a power-duration curve except that it shows the percent of time that different levels

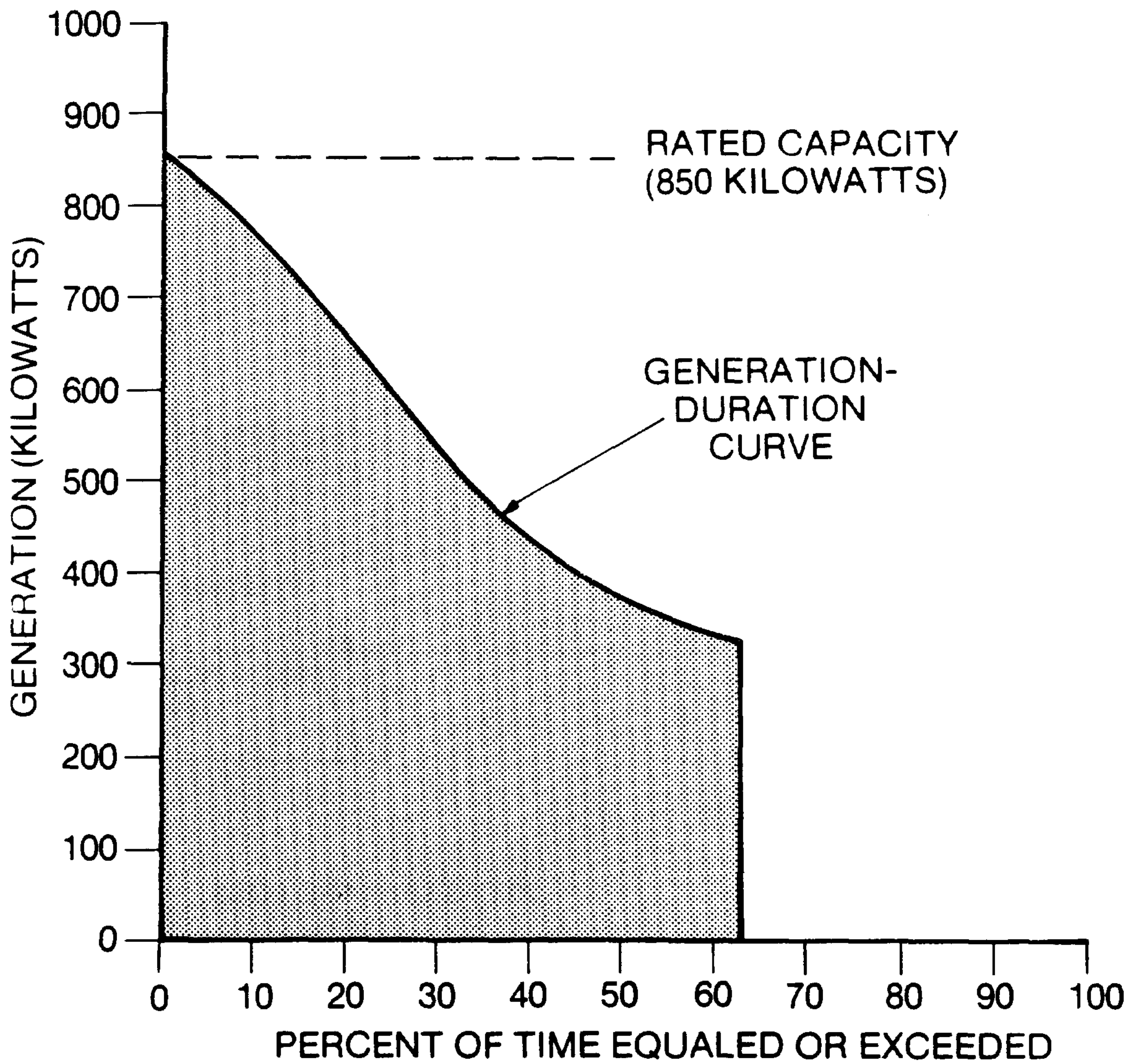


Figure 5-22. Generation-duration curve for peak demand months

of peaking capacity are available. For run-of-river projects without pondage, the power-duration curve and capacity-duration curve would be identical (see previous section).

(2) In developing a capacity-duration curve for a pondage project, the first step is to define a daily operation pattern, based on available pondage and operating limits. This would then be applied to the average daily discharge at various points on the flow-duration curve in order to derive a peaking flow-duration curve. Figure 5-23 shows the assumed daily pattern that was applied in the example problem, and Figure 5-24 shows the resulting peaking flow-duration curve. Section D-5 explains the computational procedure in more detail and summarizes the back-up computations for the example problem. Section 6-5 describes some of the operating limits and other factors to be considered in developing a daily operation pattern.

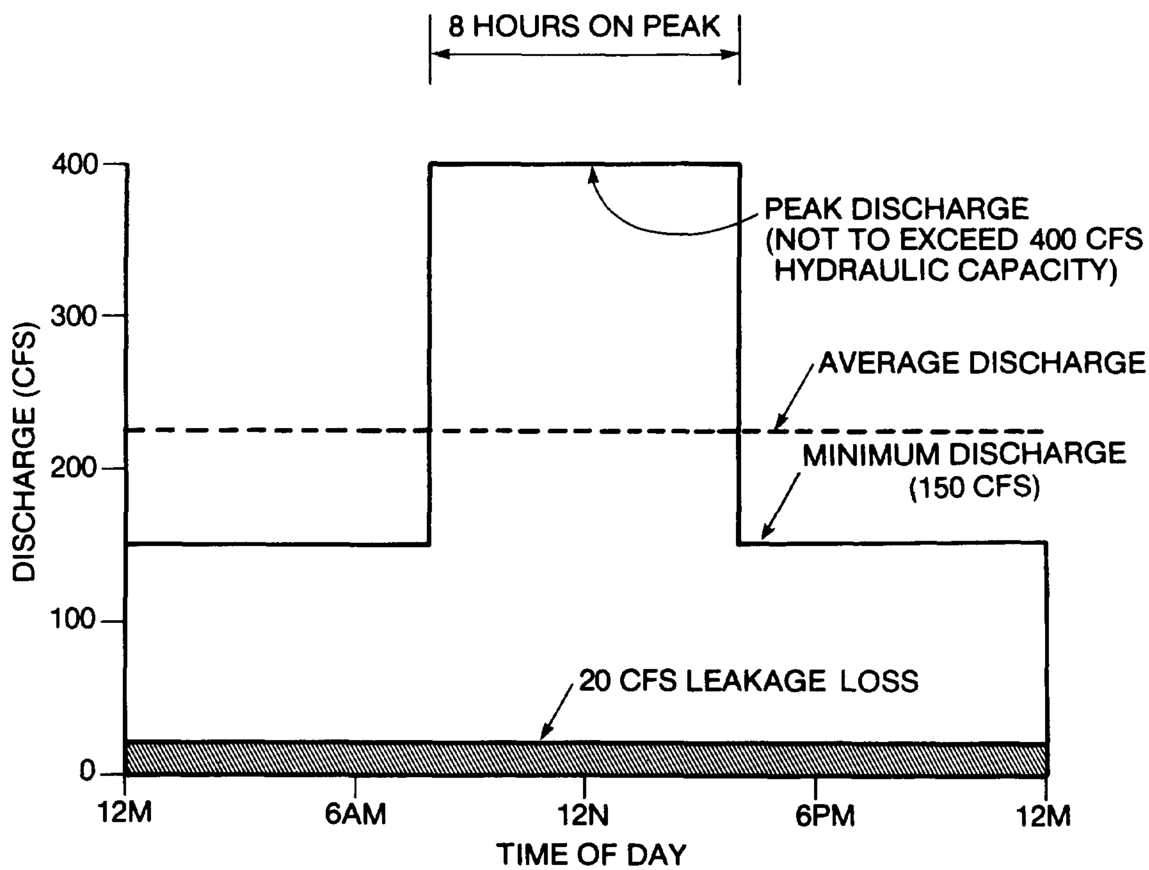


Figure 5-23. Assumed daily operation pattern

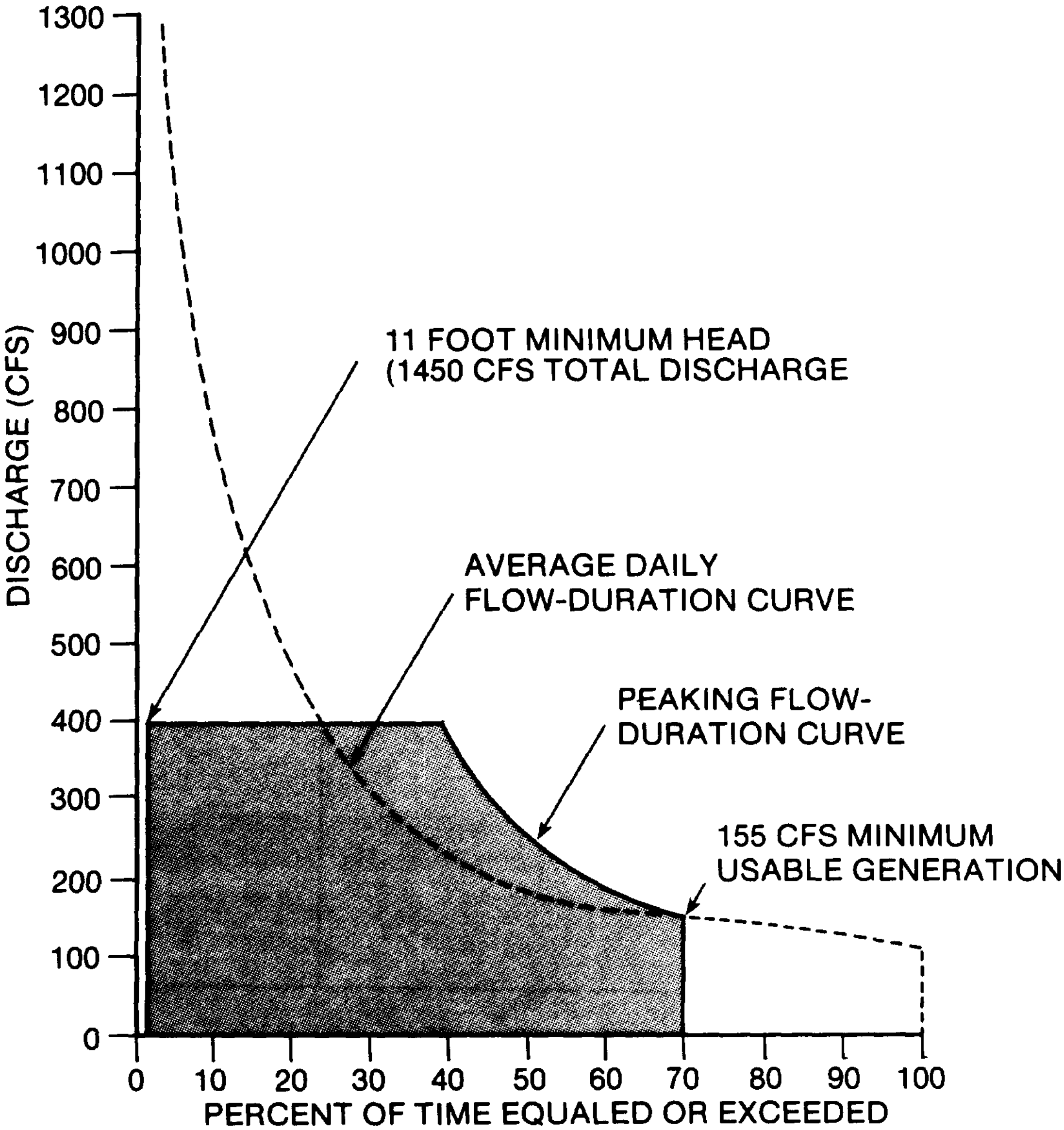


Figure 5-24. Peaking flow-duration curves (for peak demand months)

(3) A peaking capacity-duration curve would then be derived from the peaking flow-duration curve using the water power equation and the same basic procedures that were used to develop the power-duration curve (Section 5-7i). In computing head, an average forebay elevation would be used. Typically this would reflect 30 to 50 percent pondage drawdown. The tailwater elevation would be based on the peak discharge for the day rather than the average discharge.

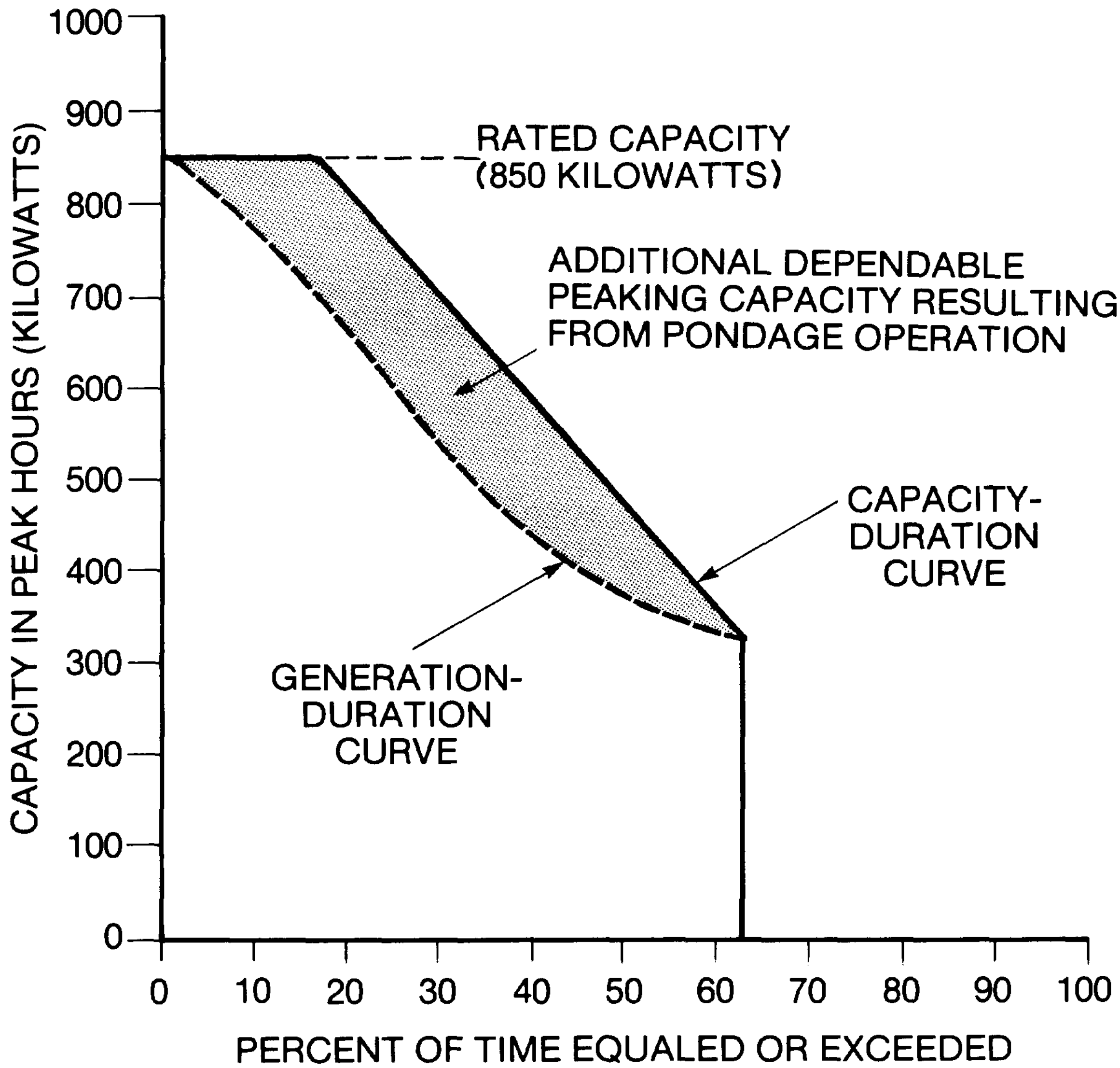


Figure 5-25. Capacity-duration curve for pondage project (for peak demand months)

Figure 5-25 shows a peaking capacity-duration curve for the peak demand months. Note that peaking capacity is limited by the 850 kW installed capacity. The dependable capacity (average peaking capacity for that period) would be computed using an equation similar to Equation 5-9, except that capacity would be substituted for power. The dependable capacity for the example shown on Figure 5-25 would be 415 kW, which is 23 percent higher than the value obtained for the project without pondage. The calculations used to derive Figure 5-25 are shown in Section D-6.

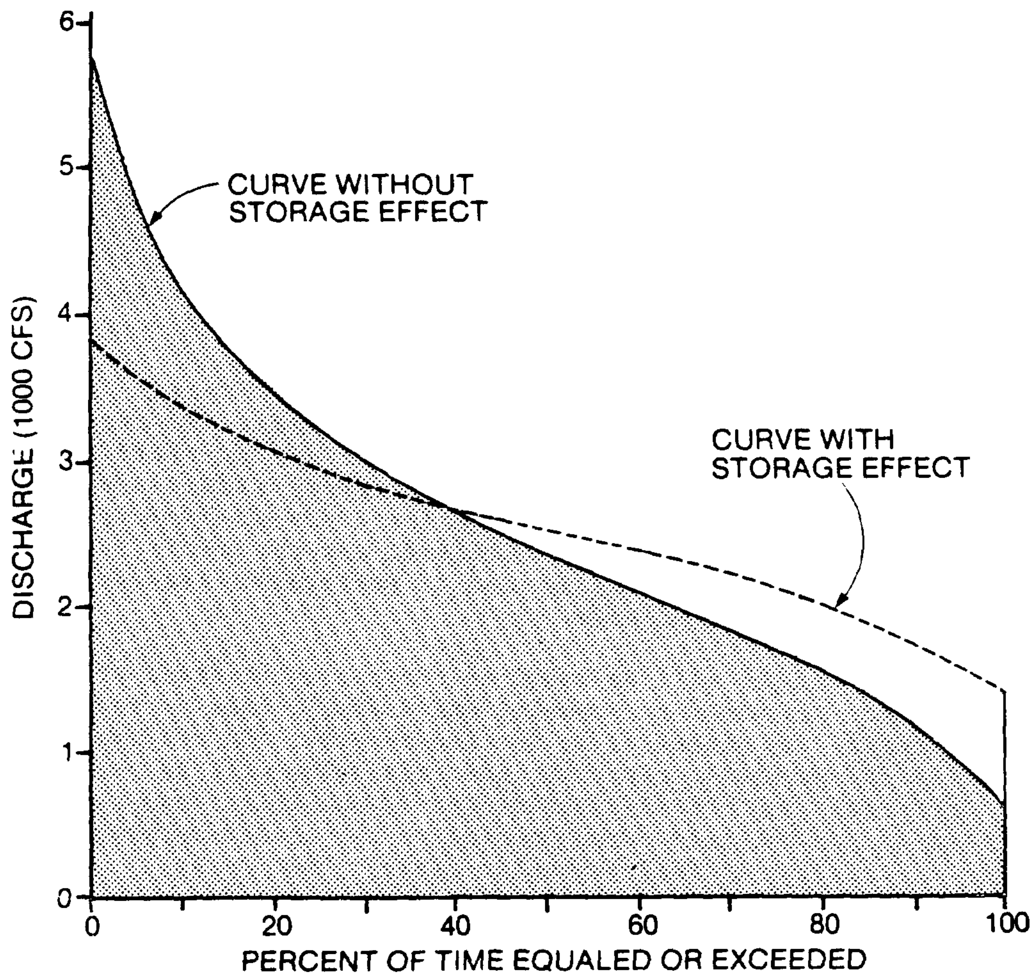


Figure 5-26. Flow-duration curve adjustment to reflect seasonal storage

m. Adjustment for Storage Effects. An optional routine is included in the HYDUR flow-duration model for adjusting a flow-duration curve to reflect seasonal storage regulation. The procedure basically involves flattening the curve using empirical techniques derived through the examination of a large number of existing reservoir projects (Figure 5-26). The procedure was developed primarily to expedite the analysis of many hundreds of reservoir projects for the National Hydropower Study (48m), and hence it should be considered only as a screening tool. Sequential streamflow routing techniques should normally be used for estimating the energy potential of storage projects. However, the adjusted flow-duration curve method may have applicability in some types of preliminary analyses. The procedure is described in references (45) and (57).

n. Treatment of Efficiency.

(1) A fixed average efficiency is frequently used in flow-duration curve power studies, and this is satisfactory for most preliminary studies and for more advanced studies of projects with small head variations. However, for studies of projects with wide variations in head (low-head projects, for example), the resulting wide variations in efficiency can have a significant impact on the project's energy output and dependable capacity. Also, in evaluating alternative turbine designs for a given project, efficiency characteristics may have a bearing on the selection of the proper unit. For these and other reasons, it is sometimes necessary to treat efficiency in more detail. Following is an approach which may be used to develop an efficiency-discharge curve for a run-of-river project. Turbine performance curves will be required, and the generalized curves shown in Section 2-6 can be used if performance curves for specific units are not available.

(2) This example will be based on the characteristics of the example project discussed previously, and a single tubular turbine will be assumed. As discussed in Section 5-7g(3), 380 cfs was selected as the hydraulic capacity, and this value will be used as the rated discharge. For run-of-river projects, the rated head is usually designated as the net head corresponding to the condition where the plant is discharging at full hydraulic capacity but no spill is occurring. In the example problem, the rated head would be the net head corresponding to the hydraulic capacity, or 31 feet (see Section 5-7g(4)).

(3) In the original example, the rated capacity (850 kW) was based on the assumed fixed average overall efficiency of 85 percent (see Section 5-7g(5)). In this example, it is assumed that the unit will operate at an efficiency of 86 percent at rated output. Hence, the rated capacity would be

$$kW = \frac{QHe}{11.81} = \frac{(400 - 20\ cfs)(31\ feet)(0.86)}{11.81} = 858\ kW.$$

(4) The objective will be to develop an efficiency-discharge curve corresponding to the range of discharges on the usable flow-duration curve (Figure 5-19). In the example, a specific turbine performance curve will be used (Figure D-2, Appendix D), and the analysis will be done for a single-unit installation. Turbine discharges and corresponding heads are obtained for a series of points on the flow-duration curve, and corresponding efficiencies are developed for each of these points. For example, the 50 percent exceedence point on Figure 5-19 corresponds to a total discharge of 240 cfs and a net turbine discharge of (240 - 20) = 220 cfs. This would be 60 percent of the 380 cfs rated discharge (0.6 Q_R). From Figure 5-16, the net head corresponding to 240 cfs would be 33 feet, or 107 percent of rated head (1.07 H_R).

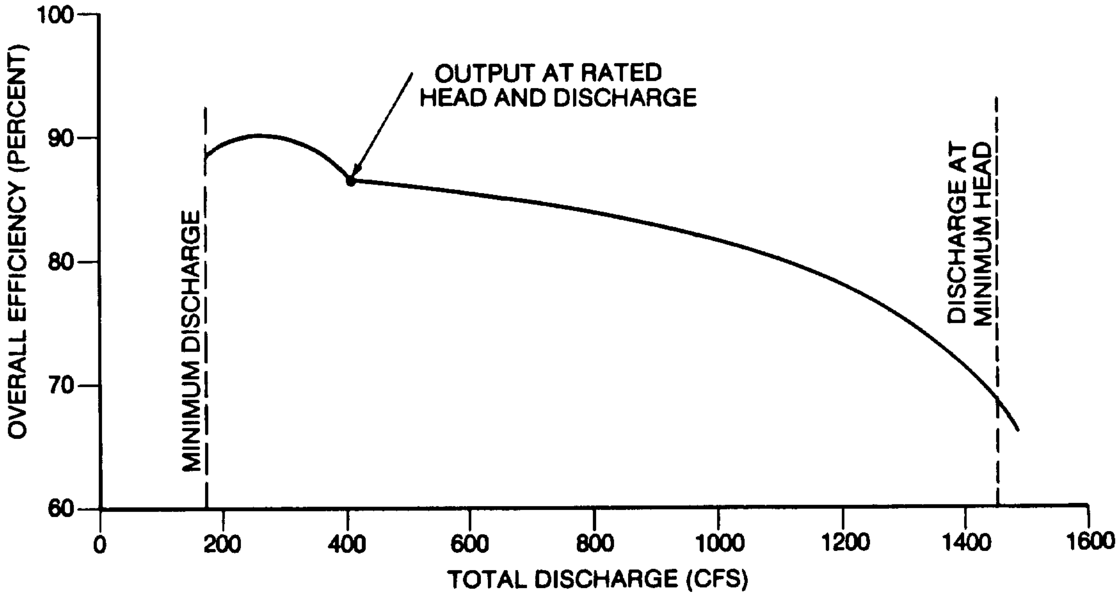


Figure 5-27. Efficiency-discharge curve for one 868 kilowatt unit

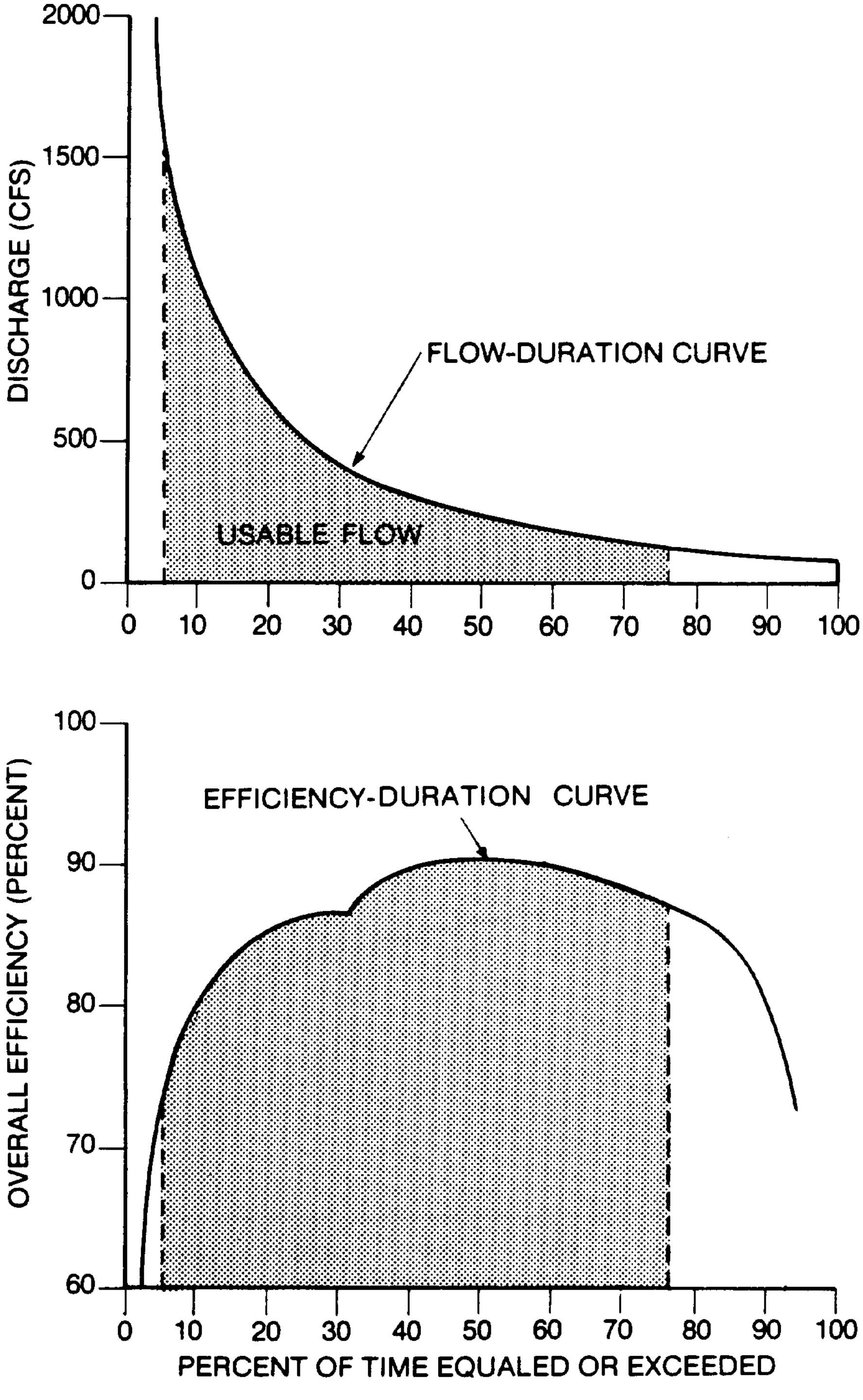


Figure 5-28. Flow-duration curve and efficiency-duration curves for one 868 kW unit

(5) Entering Figure D-2, the turbine efficiency is 92.0 percent. Applying a generator efficiency of 98 percent, the overall efficiency would be (0.92)(0.98) = 90.2 percent. Similar computations would be made for other points on the flow-duration curve, the results being plotted as Figure 5-27. The backup calculations are summarized in Section D-7. Figure 5-28 shows the efficiency data in duration curve form, which better illustrates the distribution of efficiency.

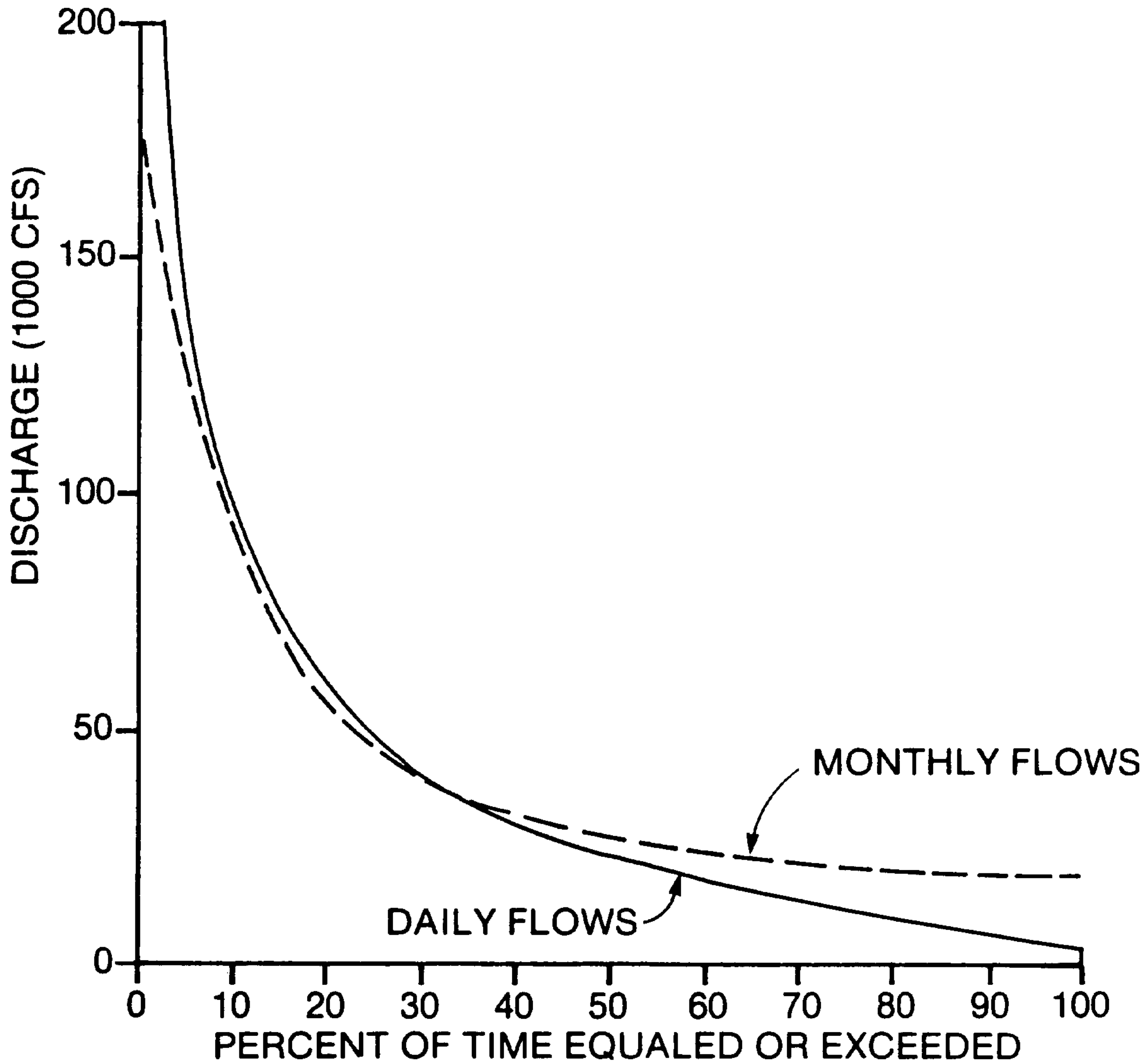


Figure 5-29. Comparison of flow-duration curves based on daily and monthly streamflow values

o. Computer Models of Duration-Curve Analysis. A number of computer models are available to estimate the energy potential of a hydro site using the duration-curve method. The models used most widely by the Corps of Engineers are briefly described in Sections C-2 and C-5 of Appendix C.

5-8. Sequential Streamflow Routing (SSR) Method.

a. General Approach.

(1) The sequential streamflow routing procedure was developed primarily for evaluating storage projects and systems of storage projects and is based on the continuity equation:

$$\Delta S = I - O - L \qquad \text{(Eq. 5-10)}$$

where: ΔS = change in reservoir storage
I = reservoir inflow
O = reservoir outflow
L = losses (evaporation, diversion, etc.)

This equation is applied sequentially for each time interval in the period being studied to obtain a continuous record of project operation. Sequential streamflow studies can be based on monthly, weekly, daily, or hourly time increments, depending on the nature of the study and the type of data available.

(2) Energy can be estimated at a hydro project by applying the reservoir outflow values to the water power equation. At storage projects, head and efficiency as well as flow may be affected by the operation of the conservation equation, through the ΔS component.

(3) Sequential streamflow routing can require considerable data manipulation and thus can best be accomplished through the use of a computer model. A number of sophisticated models have been developed which are capable of handling such functions as automatic optimization of firm energy production, evaluation of multi-project systems, and operation of projects or systems to meet the requirements of flood control and other functions simultaneously with power production. However, to provide an understanding of how these models work, a portion of this chapter is devoted to a description of the techniques involved in sequential streamflow regulation and the input data required for SSR power studies. In order to illustrate the mechanics of these procedures, examples of hand routing studies are included as Appendixes E, H, and I. Appendix C briefly describes the major computer models available within the Corps of Engineers for estimating energy potential.

b. Application of Sequential Analysis.

(1) Sequential streamflow routing methods can be applied to almost any type of hydropower analysis, including studies of the following types of projects:

- run-of-river projects
- run-of-river projects with pondage
- projects with flood control storage only
- projects with conservation storage not regulated for power
- projects with storage regulated only for power
- projects with storage regulated for multiple purposes including power
- peaking hydro projects
- pumped-storage hydro projects

(2) Run-of-river projects (including run-of-river projects with pondage) can often be evaluated more efficiently using the flow-duration curve method, but where head varies independently from flow, a sequential analysis is required to develop an accurate estimate of energy potential. Sequential analysis may also be used for analyzing run-of-river projects that are located downstream from a storage project (or projects). In these cases, the run-of-river projects are usually a part of a system operating in conjunction with the storage project and are usually included in the SSR model developed for evaluating the storage project.

(3) From the standpoint of power operation, projects having storage space for flood control only are essentially run-of-river projects, with both head and discharge varying in response to the flood control operation. In these cases, head frequently varies over a wide range but is independent of discharge. Sequential analysis is necessary to accurately estimate energy output as well as to model the flood control operation.

(4) Similarly, at a project with non-power conservation storage, head will vary independently from discharge, and sequential analysis is required to account for this and also to properly model the non-power storage regulation.

(5) For the three types of projects just described, power operation is essentially a run-of-river operation, with no at-site regulation for power, other than possibly pondage operation. This makes the SSR analysis a simple one-pass operation. Section 5-9 is devoted to the application of sequential analysis to projects without power storage. Some computer models do a single-pass SSR analysis and then compile the data in duration curve form for further analysis. These "hybrid" models are described in Section 5-15.

(6) In evaluating projects with seasonal power storage, the objective is to develop a schedule for regulating the storage in a manner that best meets the needs of the power system. For a project or system where maximizing firm energy is the objective, this requires (a) identifying the critical drawdown period, (b) making several passes to define the optimum critical period power operation, and (c) regulating the project over the entire period of record using the operating schedule developed for the critical period. When maximizing other output parameters, such as average annual energy or peaking capacity, the details of developing the reservoir operating criteria will vary, but the same general approach would be followed. Sections 5-10 through 5-14 describe the application of SSR to projects with power storage. The basic approach used for projects with single-purpose power storage can also be applied to multiple-purpose storage projects with power, the main difference being additional operating objectives and constraints.

(7) Sequential modeling techniques are also very useful in evaluating the peaking operation of both conventional and pumped-storage hydro projects. For these types of projects, the primary objective is to evaluate daily peaking capability rather than annual energy potential. Either hourly or multi-hour time increments are used, and typical weeks are examined rather than the entire period of record. Otherwise, the general procedure is essentially the same as for an SSR energy analysis. Section 6-9 explains in more detail the special considerations involved in hourly sequential modeling and Appendix C describes the models available for this purpose.

5-9. Application of SSR to Projects Without Power Storage.

a. General.

(1) This section describes the application of sequential streamflow routing to the evaluation of hydropower projects not having power storage. This includes run-of-river projects, projects with flood control storage only, and projects with conservation storage regulated for non-power purposes.

(2) Two types of basic data sources might be available: (a) historical streamflows (and in some cases pool elevations), or (b) the output from computer models which regulate the project for flood control and non-power conservation storage releases. In the latter case, it is assumed that the regulation criteria have already been developed prior to the power study, and the power study is essentially an "add-on" to an existing period-of-record regulation.

(3) The approach described in this section would apply primarily to analyzing the feasibility of adding power to an existing project with established non-power operating criteria. However, care should be taken not to overlook opportunities for revising the storage regulation procedures to include power generation as an objective. Such an approach may yield greater net benefits than simply adding run-of-river power to an existing non-power project operation. If revising the storage operation to include power is to be considered, the procedures outlined in Sections 5-10 through 5-14 would be followed.

b. Data Requirements. Table 5-3 summarizes the basic assumptions and data required when applying the SSR method to projects without power storage. Further details may be found in the corresponding subsections of Section 5-6.

c. The Routing Procedure.

(1) General. Following are the basic steps for computing energy potential using the sequential streamflow routing procedure for a run-of-river power operation. Only a single routing through the period of record will be required.

(2) Step 1: Select Plant Capacity. In planning studies, several different plant sizes are normally examined, representing a range of discharge capabilities (hydraulic capacities). Section 5-7g describes how rated capacity would be determined for a run-of-river project without pondage, given a desired hydraulic capacity. For pondage or seasonal storage projects, where head is independent of discharge, selection of rated capacity is more complex. Section 5-5 gives general guidance on selecting rated capacity for plants of this type. For preliminary studies, it is common to base rated capacity for pondage or storage projects on a head close to or equal to average head. In addition to selecting a range of rated (installed) capacities, it is necessary to identify the minimum head and minimum discharge for each plant size (see Section 5-6i). Minimum discharge is based on the single-unit rated discharge, so the size and number of units must be selected before the minimum discharge can be determined (see Sections 6-7f and 6-7g).

(3) Step 2: Compute Streamflow Available for Power Generation. The total discharge to be released through the project during the specified time interval is obtained from historical streamflow records or from the output of a reservoir regulation model. Losses due to seepage past dam, gate leakage, station service use, navigation lock operation, operation of fish passage facilities, and/or other losses are deducted to determine the net discharge available for power generation (Q). This value is then compared to the minimum hydraulic

TABLE 5-3
Summary of Data Requirements for SSR Method
(Project Without Power Storage)

Input Data	Paragraph 1/	Data Required
Routing interval	5-6b	daily, weekly, monthly, or combination
Streamflow data	5-6c	historical records
Minimum length of record	5-6d	30 years, if possible
Streamflow losses		
Consumptive	5-6e	see Section 4-5 (2) and (3)
Nonconsumptive	5-6e	see Section 4-5h (4) thru (10)
Reservoir characteristics	5-6f	storage-elevation and area-elevation curves
Tailwater data	5-6g	tailwater curve or fixed value
Installed capacity	5-6h	specify capacity for all but preliminary studies
Turbine characteristics	5-6i	specify maximum and minimum discharge, minimum head, and in some cases maximum head
KW/cfs table	5-6j	optional
Efficiency	5-6k	see Section 5-6k
Head losses	5-6l	see Section 5-6l
Non-power operating criteria	5-6m	incorporate criteria directly in analysis
Channel routing	5-6n	incorporate if daily interval is being used
Generation requirements	5-6o	not required (except possibly to limit generation).

1/ For more detailed information on specific data requirements, refer to the paragraphs listed in this column.

capacity of a single turbine, and if the net discharge is less than the minimum hydraulic capacity, the power generation for this time interval will be zero. If it is greater, continue to the next step.

(4) Step 3: Determine Average Pool Elevation. Obtain the pool elevation for each time interval. For some types of projects, the pool elevation may be fixed, and the same value would be used for all

periods. For projects where pool elevation varies with time, values would be obtained from the historical record or the output of a regulation model. If historical data or model output is used, care should be taken to insure that the pool elevation data corresponds to the same time intervals as the streamflow data. For daily studies, the daily average pool elevation would be used. For weekly or monthly studies, average pool elevation values would be computed for each period, based on the end-of-period value for the week or month being examined and the end-of-period value for the preceding week or month. For projects with pondage, an average drawdown can be assumed for most periods. However, for periods of high flow, the full pool elevation should be used.

(5) Step 4: Compute Net Head. Obtain the tailwater elevation corresponding to the discharge from Step 2 from a tailwater curve, a fixed tailwater elevation (for a pondage project), the pool elevation of a downstream project (for overlapping pools), or the highest value where two or more conditions apply (see Section 5-6g). Deduct the tailwater elevation from the pool elevation to determine the gross head. Deduct head losses from the gross head to determine the net head (H). Compare the net head to the turbine's minimum head and maximum head, and if the net head falls outside of the turbine operating range, the generation for that time interval will be zero. If not, proceed to the next step.

(6) Step 5: Estimate Efficiency (e). In many cases a fixed average efficiency will be assumed for the turbine and generator. Where a variable efficiency is used, obtain the efficiency from an efficiency-discharge curve, an efficiency-head curve, or other data (see Section 5-6k).

(7) Step 6: Compute Generation. Using the water power equation (Section 5-3, Equation 5-2 or 5-3), compute the average power output (in kW) for each time interval. Compare it to the installed capacity, and if the computed power output exceeds the installed capacity, limit average power output to the installed capacity. Multiply the average power output by the number of hours in the time interval (168 hours if a weekly time interval is being used, for example), to obtain energy (in kWh).

(8) Step 7: Compute Average Annual Energy. This process is repeated for each time interval in the total period being examined. The resulting data can then be assembled in duration curve form (see Section 5-15), or tabulated to determine (a) annual energy production for each year, (b) average annual energy, and (c) values of average energy output by month. Average weekly energy output values may also be required where power values are to be developed using a weekly production cost model (see Section 6-9f).

d. Other Considerations.

(1) Spilled Energy. In some cases it may be of interest to identify the amount of energy lost (or "spilled") due to insufficient generator capacity, insufficient head, or turbine minimum discharge constraints. In these cases, a second iteration can be made to compute the total energy potential by removing the constraints of the specific powerplant size and characteristics. The spill would then be the difference between the total energy potential and the energy output with the specified powerplant.

(2) Firm and Secondary Energy. If a power system critical period has been specified, the project's firm energy output can be computed as the energy output over the system's critical period. The annual firm energy can also be computed (see Appendix H, Section H-4c(6)). Secondary energy can be computed for each period by deducting the firm energy output from the total energy output. For example, for a monthly study where the critical period is calendar year 1936, the May firm energy output would be defined by the energy output in May, 1936. Thus, the secondary energy production for May, 1955 would be computed as follows:

$$(SE)_{\text{May 1955}} = (TE)_{\text{May 1955}} - (TE)_{\text{May 1936}} \qquad \text{(Eq. 5-11)}$$

where: SE = Secondary energy for period
TE = Total energy for period

Information on project firm and secondary output is sometimes required for marketing studies or for power benefit analysis for systems where firm and secondary energy have different values (see Section 9-10o).

e. Example. Appendix E illustrates an example of a daily sequential analysis for a hydro project that is being operated as a run-of-river project but where flood control operation results in fluctuations in pool elevation.

f. Use of Computer Models. In most cases, these energy analyses would be made using an SSR model. Where the basic source of streamflow data is an existing sequential routing, the model used for making that routing may already have the capability for doing the energy computations. In such cases, it is necessary only to specify the powerplant characteristics and related data, and re-run the regulation. Where historical streamflow data is being used, either DURAPLOT or one of the SSR models described in Appendix C can be used for the power computations.

5-10. <u>Application of SSR to Projects with Power Storage.</u>

a. <u>Introduction.</u>

(1) <u>General.</u> Estimating the energy potential of projects with power storage (or storage regulated for multiple purposes including hydropower) is much more complex than estimating the energy potential of run-of-river projects, and it can be done accurately only using the sequential streamflow routing method.

(2) <u>Regulation Strategies.</u> A number of different storage regulation strategies may be used to maximize hydropower benefits while meeting other project purposes, such as flood control, irrigation, and recreation. Some of these strategies are discussed in Sections 5-12 and 5-13. However, to illustrate the mechanics of storage regulation for hydropower, the regulation of a single-purpose power storage project to maximize firm energy will be examined first, and Sections 5-10c through 5-10g will address this problem. The discussion and examples are based on a monthly routing interval. The same basic approach would be followed when using other routing intervals. Section 5-14 addresses the problem of estimating energy output for systems of hydro projects.

(3) <u>Reservoir Size.</u> The first step in evaluating the energy potential of a storage project is to determine the amount of storage available for regulation. In some cases, the power storage volume may be fixed by physical constraints or non-power operating constraints (exclusive flood control storage requirements, for example). However, it is generally possible test several reservoir sizes, so that the optimum storage volume can be identified (see Section 9-8 c(2)). A specific reservoir size can be defined by establishing a dam height and deducting freeboard requirements and exclusive flood control storage requirements (if any), to obtain the maximum power pool elevation. The minimum power pool elevation would in turn be defined by turbine drawdown limitations (see Sections 5-5b and 5-6i), physical constraints, or non-power operating requirements. The usable power storage would then be the reservoir storage between the minimum and maximum pool elevations.

(4) <u>Basic Steps.</u> To determine the energy output of a project with a specified amount of power storage and where maximization of firm energy output is the primary objective, the following general steps would be undertaken:

- identify critical period
- make preliminary estimate of firm energy potential

- make one or more critical period SSR routings to determine the actual firm energy capability and to define operating criteria for the remainder of the period-of-record

- make SSR routing for period-of-record to determine average annual energy

- if desired, make additional period-of-record routings using alternative operating strategies to maximize power benefits.

Each of these operations may be done automatically using a computerized SSR routing model such as HEC-5, but to provide an understanding of the techniques involved, the steps are described in some detail in the following sections and examples of hand analyses of specific projects are shown in the Appendices.

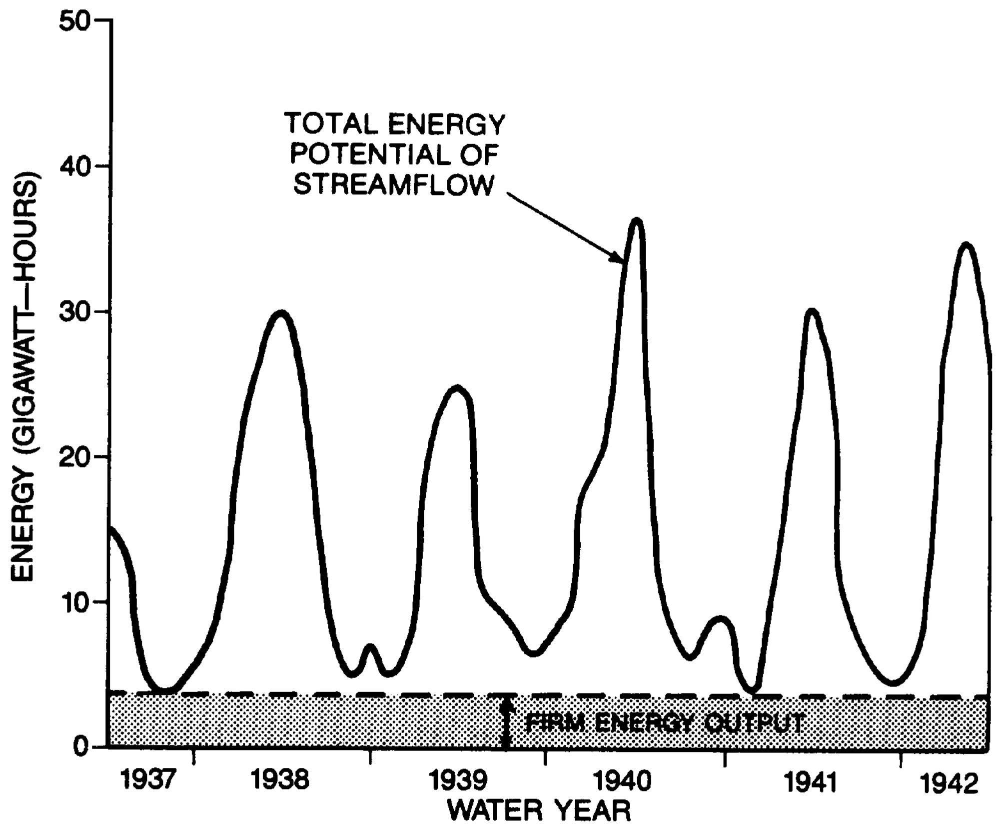


Figure 5-30. Energy potential and firm energy output of dam site without seasonal storage

b. Data Requirements. Table 5-4 summarizes the basic assumptions and data required for analyzing power storage projects using the SSR method. Further details may be found in the corresponding subsections of Section 5-6.

c. Regulation of Power Storage to Increase Firm Energy.

(1) The classic function of power storage is to increase firm energy (see Section 5-2c). Figure 5-30 shows the potential energy output at a dam site over a period of years which includes the most adverse flow sequence. The dashed line shows the firm energy that could be produced by a run-of-river development at that site (a constant monthly energy demand has been assumed to simplify the illustration). If seasonal power storage is added to the project, water could be stored in periods of high runoff to increase flow during the low flow periods. Figure 5-31 shows how storage can increase the site's firm energy output.

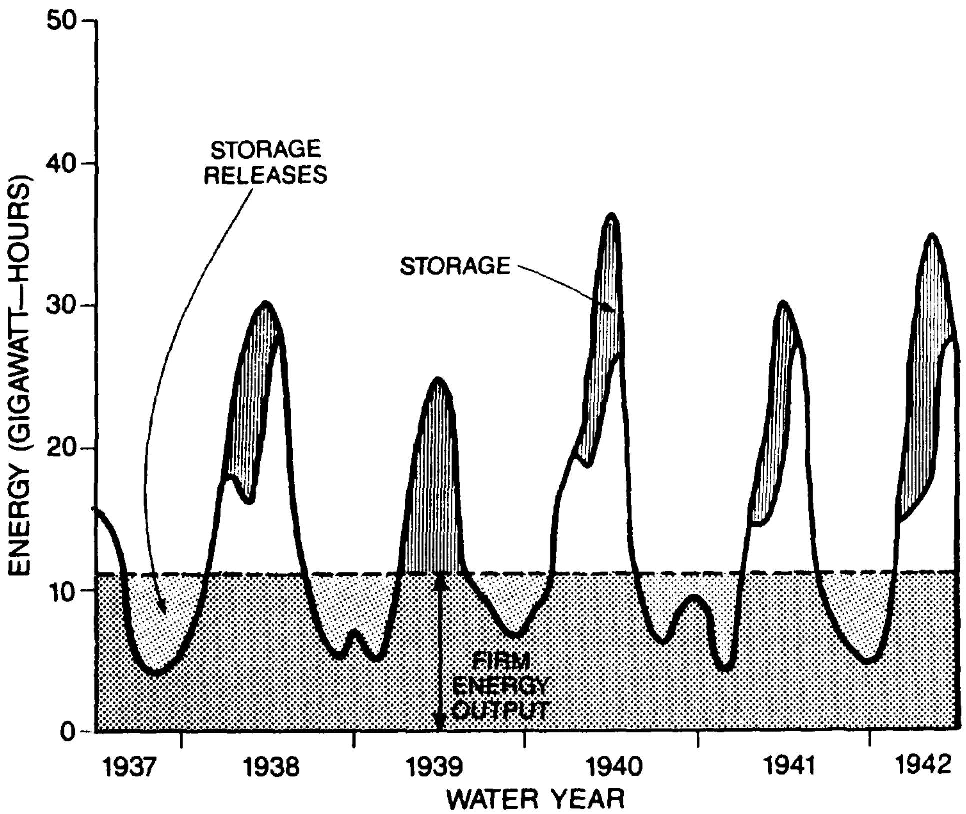


Figure 5-31. Energy potential and firm energy output of dam site with seasonal storage

TABLE 5-4
Summary of Data Requirements for SSR Method
(Projects With Power Storage)

Input Data	Paragraph 1/	Data Required
Routing interval	5-6b	daily, weekly, monthly, or combination
Streamflow data	5-6c	historical records
Minimum length of record	5-6d	30 years, if possible
Streamflow losses		
Consumptive	5-6e	see Section 4-5 (2) and (3)
Nonconsumptive	5-6e	see Section 4-5h (4) thru (10)
Reservoir characteristics	5-6f	storage-elevation and area-elevation curves
Tailwater data	5-6g	tailwater curve or fixed value
Installed capacity	5-6h	specify capacity for all but preliminary studies
Turbine characteristics	5-6i	specify maximum and minimum discharges, minimum head, and in some cases, maximum head
KW/cfs table	5-6j	optional
Efficiency	5-6k	see Section 5-6k
Head losses	5-6l	see Section 5-6l
Non-power operating criteria	5-6m	incorporate criteria directly in analysis
Channel routing	5-6n	incorporate if daily interval is being used
Generation requirements	5-6o	provide seasonal loads or load shapes

1/ For more detailed information on specific data requirements, refer to the paragraphs listed in this column.

(2) The example shows how storage can be utilized to increase at-site firm energy. Regulation of power storage can also be used to increase the firm energy output of downstream run-of-river projects as well. For example, the bulk of the firm energy capability of the Columbia River hydro system is produced at mainstem run-of-river projects, and headwater storage is responsible for a substantial

portion of the run-of-river project's firm output. Similar developments, where headwater storage is used to increase the firm output of run-of-river projects, are found in the Tennessee River Basin and several river basins in Canada. Five of the six tandem mainstem Missouri River hydro projects are storage projects, but seasonal storage regulation is normally provided only by the upstream projects, with the lower storage projects functioning essentially as run-of-river projects except during periods of extended drought. Other systems, such as the Arkansas-White and the Colorado, have some run-of-river projects, but the bulk of the firm energy is developed at the storage projects themselves. Section 5-14 addresses the problem of estimating energy output for systems of hydro projects.

d. Critical Period.

(1) The objective of maximizing firm yield is accomplished by operating the storage project (or projects) such that reservoir storage is fully utilized to supplement natural streamflows within the most adverse sequence of streamflows. "Fully utilizing" this storage means that, at some point during this adverse streamflow period, the usable storage will have been fully drafted, leaving the reservoir empty. Normally, this adverse streamflow period, which is called the critical period, is identified by examining the historical streamflow record.

(2) The use of the term "critical period" varies somewhat from region to region. It always refers to the most adverse streamflow period, and, by definition, it always begins at a point in time when the reservoir is full. In some power systems, the end of the "critical period" is identified as the point when the reservoir is empty, while in other systems, the end of the "critical period" is defined as the point when the reservoir has refilled following the drought period. For the purposes of this manual, the period ending with the reservoir empty will be identified as the "critical drawdown period," while the term "critical period" will refer to the complete cycle, ending with the reservoir full (see Figure 5-32).

(3) The larger the amount of reservoir storage, the higher the firm yield or firm energy output that can be sustained at a given site. Increasing the amount of reservoir storage also increases the length of the critical period, sometimes even changing the critical period to a completely different sequence of historical streamflows. For example, increasing system reservoir storage in the Columbia River Basin by the addition of the Canadian Treaty reservoirs changed the critical drawdown period from 8-1/2 months (1936-1937) to 42-1/2 months (1928-1932).

(4) Identification of the critical period can be accomplished in several ways. The mass curve method has long been used as a manual technique for identifying the critical period, and since it is a graphical method, it serves well to illustrate the concept of the critical period. Appendix F describes the mass curve method and shows several examples of critical period identification.

(5) Other methods may also be used to identify the critical period. It is possible to do a series of period-of-record SSR studies using alternative firm energy requirements to determine by trial and error the level of firm energy output that will completely utilize the available storage once during the period of record. This can require considerable computer time, but it is usually the most practical solution where a computerized SSR model is available. The HEC-5 model utilizes an empirical storage-to-average runoff volume relationship to

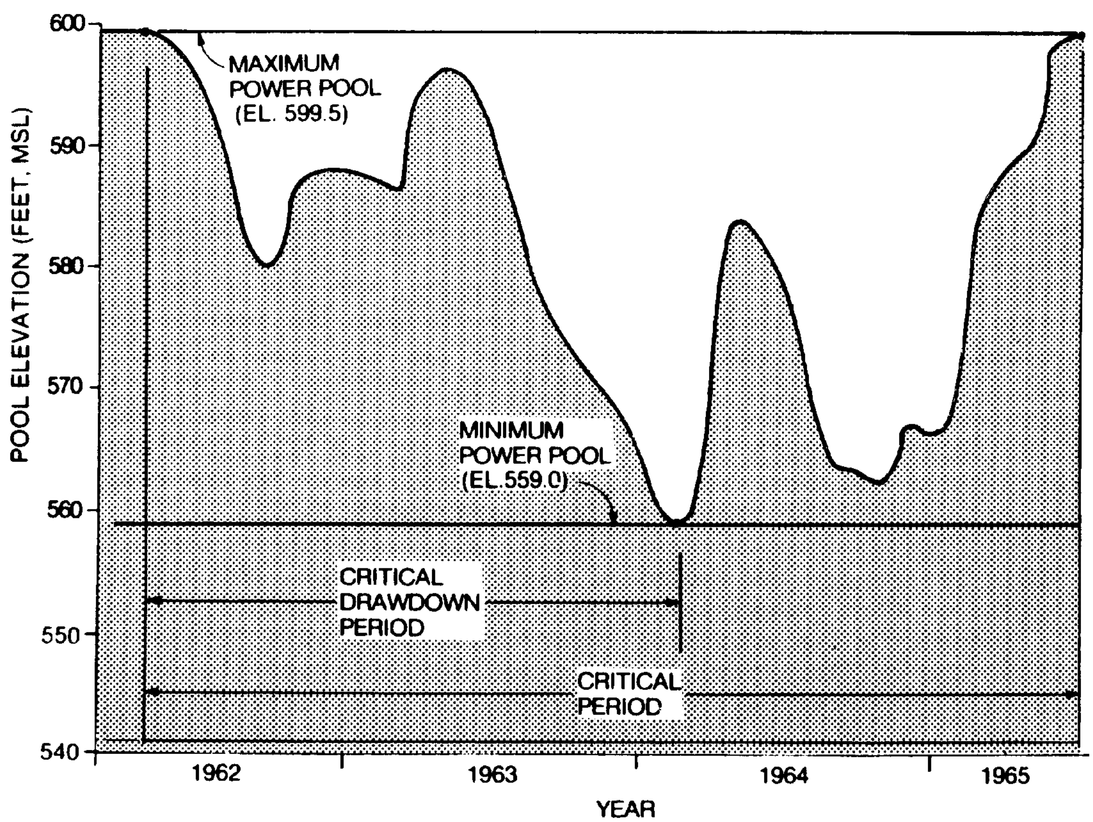


Figure 5-32. Critical period and critical drawdown period

make a preliminary estimate of critical period and firm energy yield, reducing substantially the number of trial and error iterations.

(6) In some systems, a large amount of power storage may already exist, and thus the system critical period may already be defined. Additional storage might, in such cases, have little or no effect on the critical period, so the firm energy output of a proposed new project would be derived by SSR analysis of the system critical period. For some multiple-purpose storage projects, regulation of storage for higher priority project functions, such as irrigation or municipal and industrial water supply, may define the critical period.

e. Preliminary Firm Energy Estimate.

(1) In order to achieve a sequential routing for the critical period which exactly utilizes the power storage, it is necessary to do a number of iterations. The number of iterations required is a function of the accuracy of the assumed initial firm energy estimate. Some SSR models (including HEC-5), incorporate a routine for automatically developing an initial energy estimate. For hand routings and other SSR models, an initial firm energy estimate must be made separately.

(2) Section H-2 in Appendix H illustrates the derivation of an initial firm energy estimate for a typical project. The example also shows how the total firm energy output is converted to an equivalent annual firm energy output and further subdivided into monthly firm energy values, to serve as preliminary input data for the sequential streamflow routing.

f. The Sequential Routing Procedure.

(1) The basis for the sequential streamflow routing analysis is again the continuity equation, but because regulation of storage is involved, the procedure is more complex than that described in Section 5-9c. In its simplest form the equation would be as defined in Section 5-8a, specifically:

$$\Delta S = I - O - L \qquad \text{(Eq. 5-12)}$$

where: ΔS = change in reservoir storage
I = reservoir inflow
O = reservoir outflow
L = losses (evaporation, diversions, etc.)

The reservoir outflow would include powerplant discharge plus outflow not available for generation: e.g., spill, leakage, and project water requirements (station service, navigation lock and fish ladder operation, etc.). Reservoir inflow would be obtained from streamflow records. Losses would be (a) the net gain or loss in reservoir storage as a result of evaporation and precipitation falling on the reservoir (see Section 4-5h(2)), plus (b) any withdrawals from the reservoir for water supply or irrigation.

(2) For purposes of illustrating the application of the continuity equation to a storage project, a single-purpose power reservoir will be examined using monthly flows. The first objective in the regulation process is to determine more precisely the firm energy output. Therefore, the initial regulation will be limited to the critical period. The objective in each monthly time increment will be to determine how reservoir storage will be used to insure that the monthly firm energy demand will be met. In periods of high reservoir inflow, inflow may be greater than the required discharge for power, and the excess water will be stored if possible. In low flow periods, storage will be drafted to supplement inflow. The task then will be to solve the continuity equation for change in storage (ΔS) in each interval during the critical period.

(3) Expanding Equation 5-12 to include all categories of losses and all outflow components, the continuity equation, expressed in cfs, becomes

$$\Delta S = I - (Q_P + Q_L + Q_S) - (E + W) \qquad \text{(Eq. 5-13)}$$

where:
- ΔS = change in storage during the routing interval
- Q_P = power discharge
- Q_L = leakage and non-consumptive project water requirements
- Q_S = spill
- I = inflow
- E = net evaporation losses (evaporation minus precipitation onto reservoir surface)
- W = withdrawals for water supply, irrigation, etc.

Also, the ΔS for a given time increment can be further defined as

$$\Delta S = \frac{(S_2 - S_1)}{C_S} \qquad \text{(Eq. 5-14)}$$

where:
- S_1 = start-of-period storage, AF
- S_2 = end-of-period storage, AF
- C_S = discharge to storage conversion factor (see Table 5-5)

TABLE 5-5
Factors for Converting Discharge to Storage for Various Routing Intervals

Routing Interval	Conversion Factor (C_s)
Month (31 days)	61.49 AF/cfs-month
Month (30 days)	59.50 AF/cfs-month
Month (29 days)	57.52 AF/cfs-month
Month (28 days)	55.54 AF/cfs-month
Week	13.99 AF/cfs-week
Day	1.983 AF/cfs-day
Hour	0.08264 AF/cfs-hour

(4) Substituting Equation 5-14 into Equation 5-13 and rearranging the terms, the following equation is obtained:

$$S_2 = S_1 - C_s(I - Q_P - Q_L - Q_S - E - W) \qquad \text{(Eq. 5-15)}$$

This equation is expressed in acre-feet and is used to solve for the principal unknown, the end-of-period storage. In the critical period, spill (Q_S) would normally be zero. The only exception would be the case where another reservoir purpose, such as irrigation for example, required a total discharge greater than (Q_P+ Q_L). However, this would be an unlikely event in actual operation, because the firm power marketing arrangement can usually be adapted to utilize the firm release for irrigation or non-power purposes, even though it does not precisely fit the seasonal power demand pattern.

(5) The first iteration through the critical period would be based on the preliminary monthly firm energy requirements, obtained as described in Section 5-10e. Using these requirements, the sequential routing will be performed to determine if all of the power storage is used and if the project is able to refill at the end of the critical period.

(6) To assist in the solution of Equation 5-15, a form such as Table 5-6 can be used and the inflow and demands can be entered in appropriate columns for each period of the study (Table 5-7 describes the data to be entered in the various columns of Table 5-6). A starting value of reservoir storage must be assumed, and since the critical period is defined as beginning with the reservoir full, the

TABLE 5-6.

Routing Interval Month	Routing Interval Year	Inflow 'I' (cfs)	Evapo-ration 'E' (cfs)	With-drawals 'W' (cfs)	Net Inflow (cfs)	Energy Require-ment (MWh)	Average Pool Elev. (feet)	Net Head or kW/cfs
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)

(COLUMN NUMBERS)

Routing Worksheet

REQ'D DISCHARGES		Total	Δ STORAGE, ($S_1 - S_2$)		END OF PERIOD RESERVOIR STATUS			Total Energy
Power 'Q_p' (cfs)	Nonpower (cfs)	Discharge (cfs)	(cfs)	(AF)	(AF)	(Elev.)	(area)	(MWh)
(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)

(COLUMN NUMBERS)

TABLE 5-7.

Columns 1 and 2 - Date of routing period (routing interval) may be hour, day, week or month, depending on type of study.

Column 3 - Average reservoir inflow for period, in cfs. (input)

Column 4 - Net reservoir evaporation loss for period (including precipitation) converted to discharge, in cfs.

Column 5 - Consumptive withdrawals from reservoir for irrigation, M&I water supply, etc., in cfs (input).

Column 6 - Net reservoir inflow for the period in cfs: (Column 3) - (Column 4) - (Column 5).

Column 7 - Energy requirement for the period in kWh or MWh. Initial values may come from preliminary firm energy estimate (Section 5-10e).

Column 8 - Average pool elevation for period: average of end-of-period elevation for previous period and estimated end-of-period elevation for period being examined.

Column 9 - KW per cfs factor corresponding to the elevation in Column 8 or the net head corresponding to that elevation, depending on how the study is being done. In the former case, the kW per cfs factor is obtained from a previously prepared table or curve (as described in Appendix G). In the latter case, net head is computed from the pool elevation in Column 8, estimated tailwater elevation (should correspond to power discharge in Column 10 or 11), and head losses (see also Section 7-10f(7)).

Column 10 - Required power discharge, which can be computed directly from energy requirement (Column 7) and kW per cfs factor (Column 9) as follows: (Energy requirement, kWh)/(kW/cfs factor x hours in period) = required power discharge. Where the kW/cfs factor is not used, the required power discharge is computed with Equation 5-16, using the energy requirement from Column 7 and the net head from Column 9.

Column 11 - Minimum discharge for downstream requirements, for purposes such as navigation, water quality, or fish and wildlife enhancement. This could vary seasonally or could be a fixed value over the period of record.

Column 12 - Total discharge in cfs. This would be the larger of the three following values:

(a) Required power discharge (Column 10) plus nonconsumptive losses
(b) Discharge requirement for non-power purposes (Column 11)

Explanation of Data in Table 5-6

(c) Discharge required to keep reservoir elevation on the rule curve: (Column 3) - (Column 4) - (Column 5) + (value from Column 13 required to put end-of-period reservoir elevation (Column 16) on the rule curve). This criterion would apply only if a rule curve exists. The rule curve could be a flood control rule curve or could reflect a composite of operational requirements.

Nonconsumptive losses (Q_L) comprises water passing downstream which is not available for power generation. This could include leakage past the dam, lockage and fish passage requirements, powerplant cooling water requirements, minimum discharge requirements, etc.

Column 13 - Change in reservoir storage during the period, in average cfs. Generally, this represents (a) the storage draft required to meet energy requirements or other discharge requirements, or (b) the amount of water stored, if inflow minus losses exceeds these requirements. Thus, Column 13 = (Column 3 - Column 4 - Column 5 - Column 11). The exception would be where such draft or storage would violate a rule curve, in which case Column 12 would be the required draft or storage as described by the rule curve.

Column 14 - Δ Storage in acre-feet: (Column 13) x (C_s), where C_s is the discharge to storage conversion factor (Table 5-5).

Column 15 - Storage at the end of the period: (Column 15) = (Column 15 for the previous period) + (Column 14)

Column 16 - Pool elevation at the end of the period. This is obtained from the storage-elevation curve or table using storage from Column 15. Where the resulting value violates a rule curve, the rule curve elevation should be used instead, and Columns 15, 14, 13, 12, and 18 should be recomputed (in that order) based on the rule curve elevation.

Column 17 - Reservoir area at the end-of-period pool elevation. This would be used when evaporation is computed for each routing period.

Column 18 - Energy output in kWh or MWh. This could be computed using the total discharge from Column 12 minus nonconsumptive losses, the kW/cfs factor, and the number of hours in the period: (Column 9) x (Column 11) x (hours in period) = energy output. Alternatively, it could be computed with the water power equation, using the net head from Column 9 and the discharge from Column 11. The energy output should not exceed the maximum plant capability of the proposed power installation.

starting value would be the storage at the top of the power pool. Next, the various demands for the period (including power) are examined to determine the total outflow needed to supply these requirements. The required outflow must be checked to insure that none of the physical constraints (such as powerplant total discharge, or downstream channel capacity) are violated, and that it includes leakage and non-consumptive project water requirements (Q_L). The outflow is then subtracted from the sum of initial storage plus inflow minus losses (E + W) to determine the storage at the end of the first period. This computational sequence is repeated for each period in turn, using the end-of-period storage of the previous period as the start-of-period storage. Power demands are usually specified in terms of energy requirements in kilowatt-hours per period. The conversion of this demand to a water volume is dependent upon the head available during the period and the number of hours in the period.

(7) This conversion introduces a complication. The head may vary significantly during the course of a single routing period. Therefore, power computations should be based on average head during the routing period rather than on the head at the beginning of the period. The average head during a period is based on the reservoir elevation corresponding to the average reservoir storage for the period. The average storage is the average of the beginning and ending storage values for the period (S_1 and S_2), respectively. The ending storage, however, is dependent upon total outflow during the period, which is in turn determined by the head. In other words, the average head cannot be determined accurately until the end-of-period reservoir elevation is known; the end-of-period reservoir elevation cannot be determined until the power discharge is determined; and the power discharge needed to meet the specified generation requirement cannot be determined until the head is known. The computation for each period, therefore, requires successive approximations.

(8) This can be accomplished as follows. The average flow required for power generation is computed with the following equation:

$$Q_P = \frac{11.81(\text{kWh})}{\text{Het}} \qquad \text{(Eq. 5-16)}$$

where: Q_P = required power discharge in cfs
kWh = energy required in kilowatt-hours
H = average head in feet
t = number of hours in the period
e = power plant efficiency, expressed as a decimal fraction.

In the solution of Equation 5-16, both Q_p and H are unknown. The normal procedure is to assume a value for H, usually based on the reservoir elevation corresponding to the start-of-period storage (the ending storage for the previous period), and then compute a value for Q_p. The ending storage for the current period (S_2) is then calculated using Equation 5-15. A new value of H is then determined from the average of (a) the reservoir elevation corresponding to the start-of-period storage (S_1) and (b) the reservoir elevation corresponding to the ending storage for the current period (S_2). The power discharge (Q_p) is then recalculated, and the process is repeated until the values of H on two successive trials do not differ significantly. Table 5-8 illustrates this process, and in this example, convergence is achieved in the second iteration (average head equals estimated average head). In some cases, the changes in head within a routing period are small, and this adjustment is not necessary. Most computer models used for estimating energy automatically make this adjustment.

(9) Evaporation is normally expressed in terms of inches per day. It can be converted to volume (acre-feet per period or average cfs) by multiplying by the reservoir surface area.

$$\text{Evaporation, AF} = \frac{(\text{EVAP})(\text{A})(\text{t})}{288} \qquad \text{(Eq. 5-17)}$$

$$\text{Evaporation, cfs} = 0.042(\text{EVAP})(\text{A}) \qquad \text{(Eq. 5-18)}$$

where: EVAP = evaporation rate, inches/day
A = reservoir surface area, acres
t = routing interval, hours

To be precise, the average reservoir surface area for the period must be used. Like average head, the average surface area can be determined only through several iterations. In most cases, however, the net evaporation is relatively small, and using an evaporation rate based on the surface area of the start-of-period reservoir elevation is satisfactory.

(10) Section H-3 of Appendix H illustrates a hand routing of a multiple purpose reservoir through the critical period, to determine its firm energy output. Besides being regulated for power, the reservoir is also regulated for flood control (using a fixed annual flood control zone above the top of the conservation pool) and water quality (specified minimum downstream flows must be maintained).

(11) In this example, a kW/cfs vs. reservoir elevation curve was used rather than estimating head, efficiency, losses, and tailwater elevation for each period in the analysis. When using this method,

TABLE 5-8. Adjustment of Average Head to Agree With Power Discharge

Given: Reservoir with storage-elevation curve, Figure 4-8
Average tailwater = El. 242.0
Average overall efficiency = 0.85
Head loss = 2.0 feet
Length of period = one 30-day month (720 hours)
Energy required for period = 28,800,000 kWh
C_s for 30-day month = 59.50 AF/cfs
Start-of-period reservoir storage (S_1) = 1,000,000 AF
Average inflow for period (I) = 200 cfs
Assume that in this example Q_L, Q_S, E, and W are zero

	Iteration 1	Iteration 2
Start-of-period storage (S_1), 1000 AF	1000	1000
Reservoir elevation at S_1, feet	609.0	609.0
Estimated reservoir elev. at S_2, feet	609.0	602.0
Est. average reservoir elev., feet 1/	609.0	605.5
Estimated average head, feet 2/	365.0	361.5
Power discharge (Q_P), cfs 3/	1523	1537
Reservoir inflow (I), cfs	200	200
Change in storage (ΔS), cfs 4/	-1323	-1337
ΔS, 1000 AF 5/	-79	-80
End-of-period storage (S_2), 1000 AF	-921	-920
Reservoir elevation at S_2, feet 6/	602.0	602.0
Average reservoir elev., feet	605.5 7/	605.5
Average head, feet 2/	361.5	361.5

1/ (1/2)(reservoir elevation at S_1 + estimated reservoir elev. at S_2)
2/ (average reservoir elev.) - (tailwater elev.) - (head loss)

3/ $$Q_P = \frac{(11.81)(\text{kWh})}{\text{Het}} = \frac{11.81(28{,}800{,}000 \text{ kWh})}{(\text{est. avg. head})(0.85)(720 \text{ hours})}$$

4/ Use Equation 5-13. Since Q_L, Q_S, E and W are all zero,
ΔS (cfs) = I - Q_P

5/ ΔS (AF) = C_s x ΔS (cfs)

6/ From Figure 4-8
7/ Average head does not equal estimated average head. Try again using estimated average head of 605.5 feet.

Equation 5-16 would be revised to the following form:

$$Q_p = \frac{(\text{kWh})}{(\text{kW/cfs})t} \qquad \text{(Eq. 5-19)}$$

where: kWh = energy required in kilowatt-hours
kW/cfs = the kW/cfs conversion factor
t = number of hours in the period

The remainder of the procedure would be the same. The kW/cfs method is usually faster, but certain assumptions must be made with respect to plant loading and efficiency. Appendix G describes how a kW/cfs curve can be developed and used.

g. Determining Firm Energy.

(1) The storage project is regulated through the critical period as described in the previous section, using the preliminary monthly energy requirements (Section H-2 of Appendix H). If the following criteria are satisfied, the routing has provided an accurate estimate of the project's firm energy output:

- firm energy requirements are exactly met in all months during the critical drawdown period
- storage is fully drafted at one point in the critical period
- the project refills at the end of the critical period.

Figure 5-33 illustrates such a routing.

(2) If the project fails to use all of the storage (Figure 5-34), the preliminary energy estimate understates the project's firm capability. The monthly energy requirements should then be increased and the sequential routing re-run in an effort to fully use the storage. The monthly energy requirements to be used in the next trial routing can be estimated as described in Section H-4 of Appendix H.

(3) If the project is drafted below the bottom of the power pool (or fails to meet the monthly energy requirement in the last month of the critical drawdown period), the preliminary power requirement estimate was too high. An adjustment would be made similar to that described for the previous situation, except that the energy adjustment would be based on the amount of overdraft (or the energy shortfall). In either case, one or more additional iterations may be required before the regulation exactly utilizes the power storage and the reservoir fully refills. Once a satisfactory

regulation is obtained, the project's firm energy output will have been determined. An estimate of the annual firm energy output can be obtained by summing the monthly energy requirements that can be met for all twelve months.

(4) There is also the possibility that the incorrect critical period was identified. This will become apparent when the period-of-record routing is made (see Section 5-10h). This routing will be based on the monthly firm energy requirements derived as described above. If the project is drafted below the bottom of the power pool (or fails to meet firm energy requirements) at some point outside of the assumed critical drawdown period, then the wrong period was selected. The new critical drawdown period must then be defined (it would end with the month with the greatest overdraft). The monthly firm energy requirements would be adjusted as described in the preceding paragraph, and one or more iterations would be made for the new critical period in order to determine the final firm energy output.

(5) The above discussion applies to estimation of firm energy using hand routing techniques. Sequential routing computer models follow the same basic procedure, except that the computations may

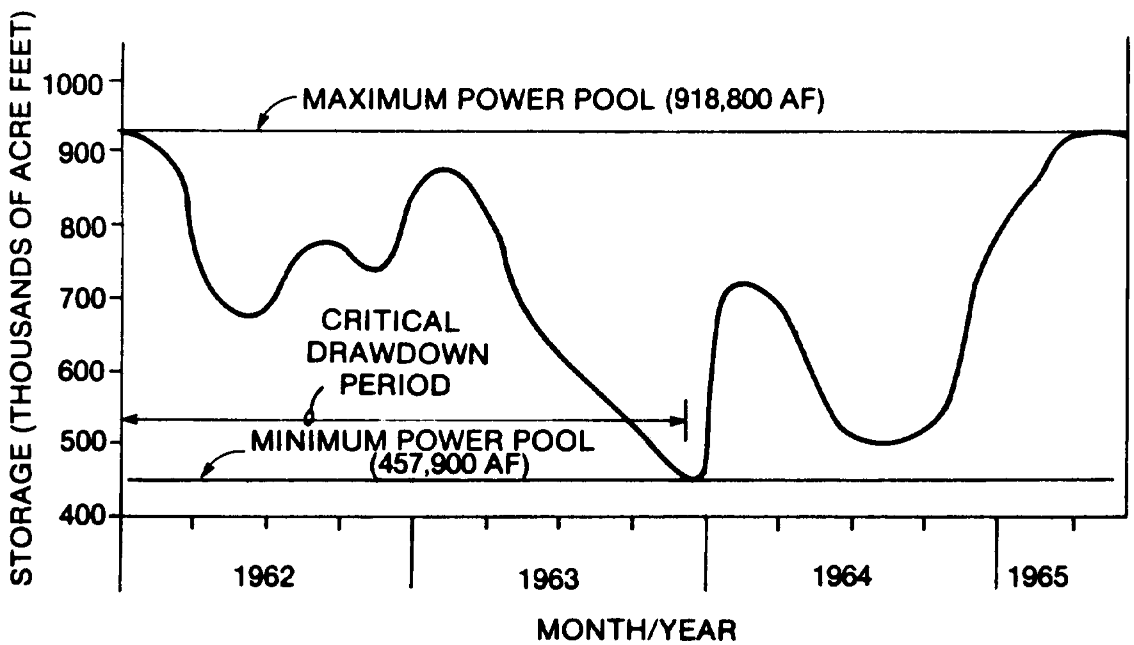


Figure 5-33. Routing of Broken Bow Reservoir, Oklahoma through critical period.

follow a somewhat different sequence and routines may be available to automatically optimize firm energy output. Appendix C describes some of the SSR models that are readily available to Corps power planners, and Appendix K describes how HEC-5 is used for estimating firm energy output.

h. Average Annual Energy.

(1) Once the firm energy estimate has been made, the next step is to determine the project's average annual energy output. To determine the average annual energy, a sequential routing would be made for the entire period of record using the monthly firm energy requirements derived from the critical period routing. The project's average annual energy would be the average of the annual energy production values for all of the years in the period of record. The average annual secondary energy would be the difference between the average annual energy and the annual firm energy.

(2) Several alternative strategies are available for operating in better than critical streamflow conditions. The simplest is to operate primarily to meet the firm energy requirements, producing secondary energy only when the reservoir is at the maximum power pool

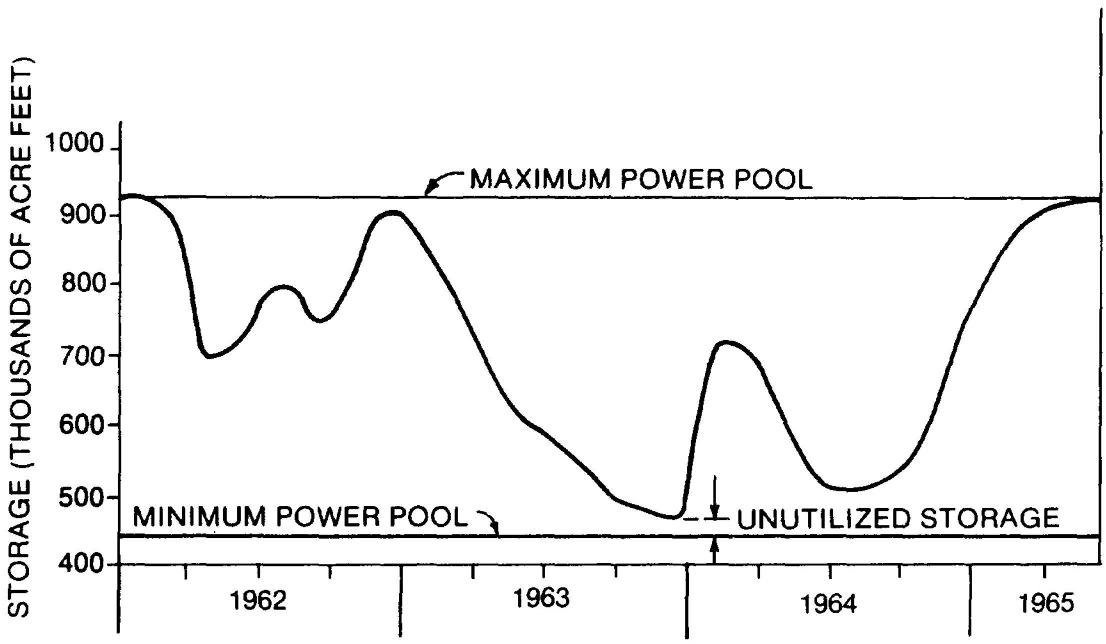


Figure 5-34. Critical period routing of a reservoir that does not utilize all of conservation storage.

and when net reservoir inflow exceeds the discharge required to meet firm energy requirements. Where a project has flood control storage space above the power pool, secondary energy could also be generated when evacuating the flood control space during flood control operations. Figure 5-35 illustrates a regulation through an average water year following this strategy. The back-up computations are shown as Case 1 in Appendix I, the project being the same as that used in the firm energy example (Figure 5-33 and Appendix H).

(3) The strategy described above may be appropriate for single-purpose power storage projects operating in an all-hydro system, where no market for secondary energy exists and there are no alternative uses for the stored water. This approach might also be used where at-site recreation is an important project use and it is desired to keep

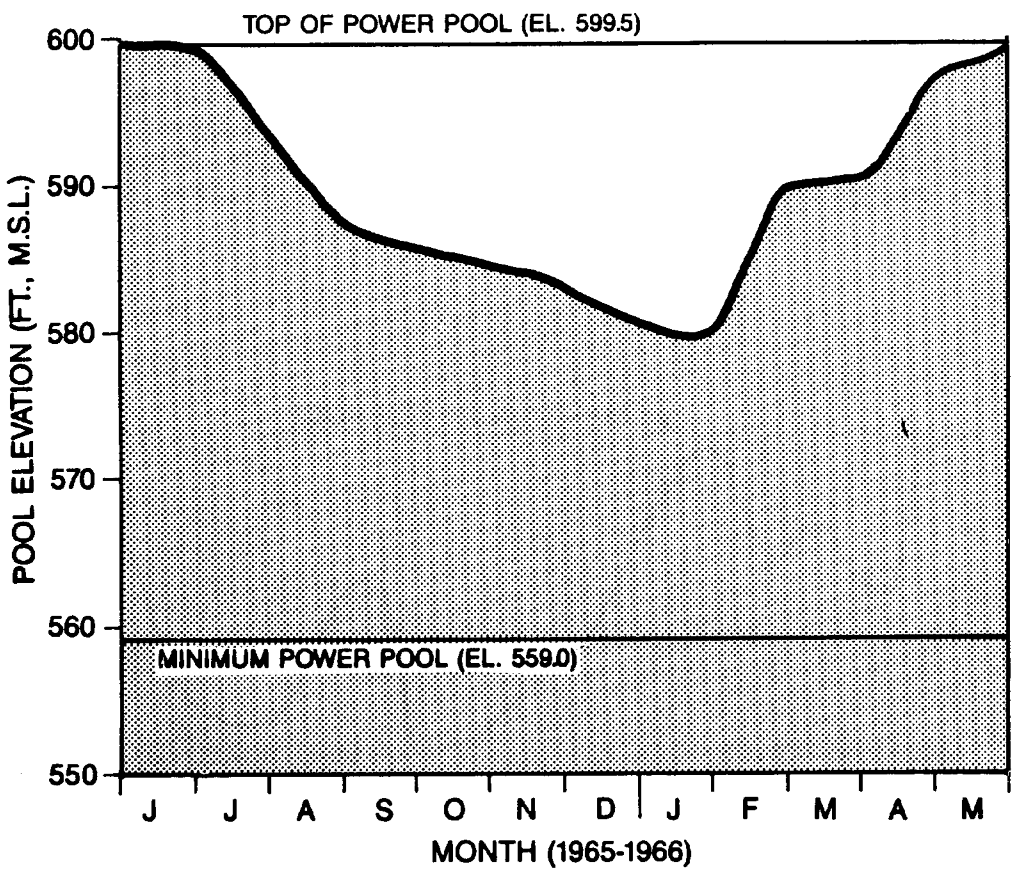


Figure 5-35. Regulation of a reservoir through an average water year drafting storage only to meet firm energy requirements (Case 1, Appendix I)

the reservoir close to the full power pool elevation as much of the time as possible. However, this approach permits no flexibility of operation during periods of better than critical streamflow. To permit better use of secondary energy and more flexibility in using storage for non-power river uses, rule curves may be developed to govern reservoir regulation. Where rule curves are used, average annual energy would be developed as follows: (a) make sequential streamflow routing for the critical period and for other low flow periods, (b) develop the rule curves, (c) regulate the project over the period of record using the rule curves, and (d) estimate average annual energy from the period-of-record regulation.

5-11. Power Rule Curves.

a. General.

(1) A rule curve is a guideline for reservoir operation, and is generally based on detailed sequential analysis of various critical combinations of hydrologic conditions and demands. Rule curves may be developed for flood control operation as well as to govern use of conservation storage for irrigation, water supply, hydropower, and other purposes. The development and use of a single-purpose rule curve for power operation will be examined in this section. The constraints of flood control operation and the development of rule curves to meet both functions are addressed in Section 5-12. The development of rule curves to meet multiple conservation storage functions will also be discussed in Section 5-12.

(2) The power operating rule curve was defined by the United States Inter-Agency Committee on Water Resources as ". . . a curve, or family of curves, indicating how a reservoir is to be operated under specific conditions to obtain best or predetermined results." Although rule curves are generally developed for individual reservoirs, there may be instances where a single rule curve for a hydraulically integrated system of storage plants would better serve the needs of the system operation. Rule curves for power operation may assume many forms, depending upon the nature of the power system, the hydrologic characteristics of the basin, and the operating constraints associated with the storage plants involved.

(3) A rule curve for power operation of a typical storage project is shown in Figure 5-36. The curve defines the minimum reservoir elevation (and consequently the minimum storage) required to assure generation of firm power at any time of the year. The general shape of the rule curve is tailored to the hydrologic and power demands of the area: (a) power storage must be at a maximum during the middle of the calendar year in anticipation of high summer power

demands coincident with low inflows; (b) droughts usually begin during the late spring and early summer; and (c) a low pool elevation is acceptable in the fall and winter season, because power demands are lower and winter and spring inflows are higher.

(4) Firm energy can be defined as that generation which would exactly draw the reservoir level to the bottom of the power pool during the most severe drought of record. Therefore, if (a) all potential droughts begin with the reservoir level on or above the rule curve elevation, (b) generation is to be limited to firm energy production, and (c) the generation pattern is in general agreement with the assumed monthly distribution used in the studies, the pool should not fall below rule curve unless a drought more severe than any of record is experienced. Such a rule curve can be constructed by regulating all of the major droughts in the period of record and developing a rule curve which encloses all of these regulations. Appendix J illustrates how a rule curve of this type can be developed.

(5) Appendix J describes the derivation of a rule curve to govern use of power or conservation storage in an exclusive storage use zone. Using Figure 5-36 as an example, the storage between "Minimum Power Pool" and "Top of Power Pool" is reserved exclusively for power. Flood control storage (if any) would be located above the "Top of Power Pool." Rule curves governing storage that is jointly used for both flood control and

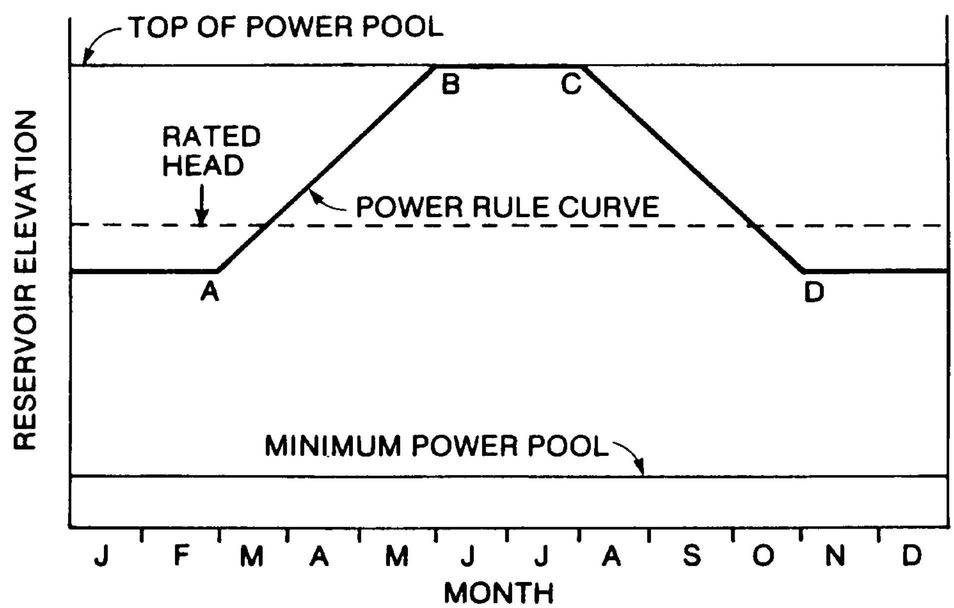


Figure 5-36. Rule curve for power operation of a typical storage project

power (or flood control and multiple conservation purposes including power) would be derived somewhat differently (see Section 5-12e). Likewise, Figure 5-36 illustrates a fixed rule curve. For river basins where much of the runoff comes from snowmelt, the runoff volume is to some extent predictable, and variable rule curves can be developed to maximize the use of the energy potential (see Section 5-12f).

b. Project Operation Using Power Rule Curves.

(1) The regulation of a project using a power rule curve can be illustrated by examining the operation of a project having a zone of exclusive power storage and a fixed power rule curve (Figure 5-36).

(2) Assume that the rule curve was derived as described in Appendix J and that the primary objective of regulating power storage is to meet firm energy requirements. Most of the time, streamflows will be greater than the adverse flows used to derive the curve, and it will be possible to meet firm energy demands while maintaining the reservoir level at or above the rule curve. In addition, it may also be possible to generate secondary energy in some periods. However, if a sequence of adverse flows occurs, it may be necessary to draft storage below the rule curve, but as long as the reservoir is below the rule curve, releases will be limited to those required to meet firm energy requirements.

(3) Because the rule curve is based on the most adverse sequence of flows in the period of record, the project can be operated through the period of record without any failure to meet firm energy requirements or any violation of the minimum power pool. However, in actual operation, there is always the possibility that a more adverse sequence of flows will occur. Hence, if an extended period of low flows occurs, and the reservoir falls well below the rule curve, contingency measures would likely be taken to conserve the remaining storage. First, attempts might be made to purchase thermal generation to help meet the firm energy requirement. If this is not enough, opportunities for reducing firm load would then be examined.

(4) Operation above the rule curve could vary, depending on the time of year, the state of the power system, and other project purposes to be served. During that period when the project is maintained at the top of power pool (B-C on Figure 5-36), the total net inflow (inflow minus evaporation minus withdrawals) must be passed through the project. Streamflow in excess of firm generation requirements will be used to produce secondary energy, up to the plant's maximum generating capability, and the remainder of the flow (if any) will be spilled (for projects with flood control storage above top of power pool, see Section 5-12d.

(5) During the period C-D-A-B, several operating strategies are possible. One extreme would be to maintain the resrvoir as high as possible, limiting generation to firm energy requirements, except that higher discharges would sometimes be required during periods of high inflow to prevent the reservoir elevation from exceeding the top of the power pool. This approach would maximize head and maintain capacity at high levels, and, under some circumstances, it could maximize average annual energy. On the other hand, this operation could have a high risk of spilling, specifically whenever inflows exceeding plant capacity occur at times the reservoir is at the top of the power pool. The other extreme would be to follow the rule curve as closely as possible, operating the powerplant at full output whenever the reservoir elevation is above the rule curve. This approach would minimize the possibility of spilling, but it would increase the risk of not meeting firm energy requirements should a streamflow sequence more adverse than the critical period occur.

(6) In some systems, the reservoir might be operated somewhere between the two curves, depending on the value of secondary energy at any given time. If opportunities exist for displacing very expensive thermal generation, the project may be drafted below the top of power pool to maximize secondary energy production. The closer the draft approaches the rule curve, the greater the risk to firm energy capability and the greater the potential energy loss due to reduced head, so the operator has to balance these potential losses and risks against the value of the immediate secondary sale. When the value of secondary energy drops, generation would be reduced, possibly to firm energy requirements, and the reservoir allowed to refill. Tennessee Valley Authority has developed a series of intermediate "rule curves" (economic guide curves) based on probabilistic analysis, which ties secondary energy production to the current value of the energy (see Figure 5-49).

(7) Another approach would be to operate using a power guide curve similar to that shown as Figure 5-51. When the reservoir is at or below the rule curve, only firm energy would be produced. When the reservoir is above the power rule curve (in the shaded area in the upper diagram on Figure 5-51), the plant would operate at a plant factor that is a function of the distance above the rule curve, up to a maximum of 100 percent plant factor at full pool.

(8) An additional consideration is that the power plant's rated head may be above the lower portion of the rule curve. If the pool is allowed to drop below rated head, the plant's dependable capacity will be reduced, and this is an important consideration at projects which are operated primarily for peaking. The dashed line on Figure 5-36 illustrates a possible soft limit defined by the rated head. One possible operating strategy would be not to draft the reservoir below rated head

except: (a) to meet firm energy requirements, or (b) in response to unusual power system requirements (severe combinations of loads and/or power plant outages).

(9) While it is important to recognize that there are virtually an infinite number of ways to utilize power storage in better-than-critical streamflow conditions, it would be difficult to model these permutations in a planning study. The most important consideration in the planning stage is to insure that as much flexibility as possible is built into the reservoir operation.

c. Computing Average Energy Using Rule Curves.

(1) While flexibility is important from the standpoint of actual day-to-day project operation, the regulation of storage above the rule curve must be defined more precisely when making a period-of-record sequential analysis for the purpose of estimating average annual energy. As described earlier, the simplest approach is to base the sequential routing on maintaining the reservoir at the top of the power pool at all times except when drafts are necessary to meet firm energy requirements (Figure 5-35 and Appendix I, Case 1). Secondary energy would only be generated when the reservoir is at the top of power pool and inflow exceeds firm energy discharge requirements.

(2) An alternative analysis could be made, based on a maximum allowable drawdown through the entire period of record, to bracket the range of secondary energy output. Such a regulation could be based on following the power rule curve as closely as possible in all years, with storing above the rule curve being permitted only when net inflow exceeds the power plant capacity and when such storing will not exceed the top of power pool. The reservoir would be drafted below the rule curve, if required, to meet firm energy requirements. Case 2 in Appendix I describes the regulation of the example project through the same water year as Case 1 except that the power operation rule curve is followed as closely as possible. The resulting regulation is shown as Figure 5-37.

(3) Another approach would be to meet a level of power requirements greater than the firm requirement whenever the reservoir is above the rule curve. This requirement could be fixed (e.g. 120 percent of the firm requirement), it could vary by month, or it could vary with zone. In the case of variation by zone, the storage between the rule curve and the top of power pool would be divided into several zones, each having a different percentage of the firm requirement. The top zone would have the highest percentage, the bottom zone would be close to the firm requirement, and the zones in between would have intermediate values.

(4) In some cases, it may be possible to define operating parameters for operation in better than critical streamflow years by examining historical records for similar projects located in the system where the proposed project's output would be marketed. An example is the power guide curve developed by Tulsa District in their analysis of the use of power storage in the Arkansas-White system (Section 5-13d(3)).

(5) The above discussion applies to computation of average energy using regulation strategies designed to maximize firm energy production. This strategy may be appropriate for some power systems, but for thermal-based systems, maximizing average annual energy or maximizing peaking capability may produce greater benefits. In some cases, a system's reservoir storage may be regulated primarily for another function, such as irrigation, and the power operation may be

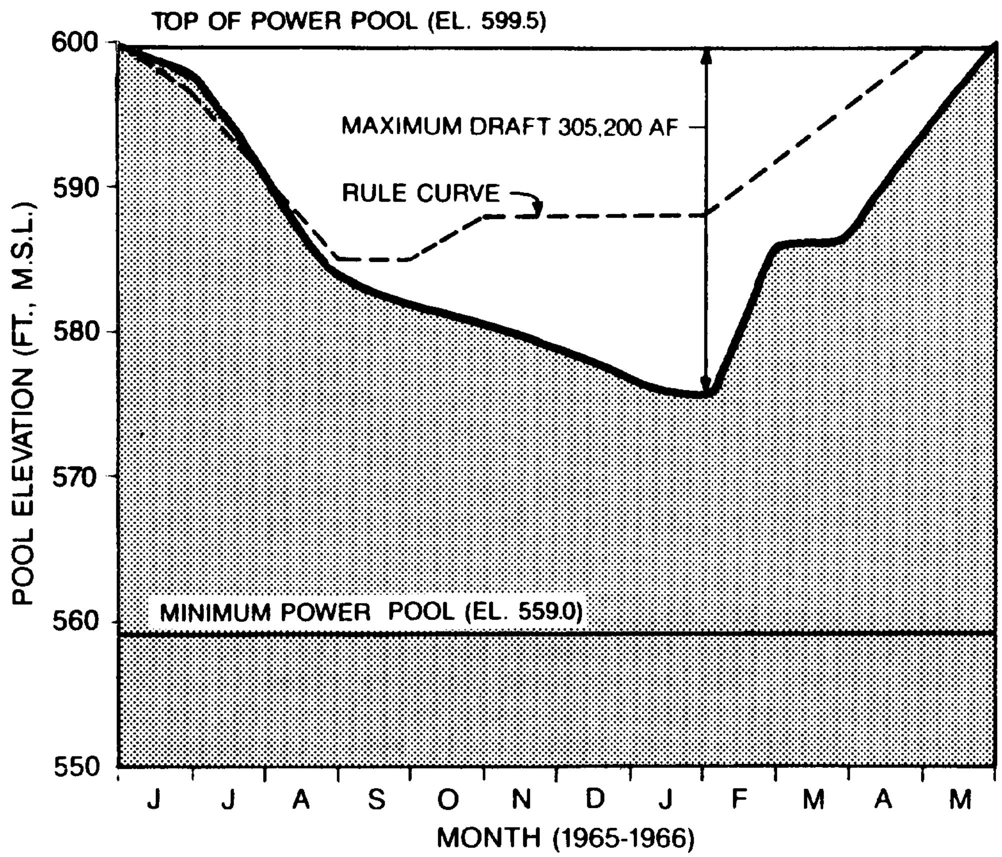


Figure 5-37. Regulation of reservoir through an average water year using a power rule curve (Case 2, Appendix I)

heavily influenced by this operation. Section 5-13m describes some of the alternative power regulation strategies and how average energy might be derived using those strategies.

(6) A final point to consider is that the value of secondary energy often varies with time, depending on the state of the total power system, and in some cases, it may have no value at all. The latter situation would arise only in a system with a substantial amount of hydro, but in these systems, the market for secondary energy may sometimes be limited. For example, in the Columbia River power system, potential secondary generation from existing hydro projects in freshet seasons with high runoff may exceed the secondary market (sum of the displaceable thermal generation within the region and the transmission capability for exporting secondary energy outside the region). A proposed hydro project may be capable of producing additional secondary energy in these periods, but it would have no value.

(7) In an all-hydro system, secondary energy may have no value at all. While all-hydro systems are rare in the United States, some isolated systems in Alaska may operate entirely on hydro at least part of the time, and the value of secondary energy in such systems should be examined very carefully.

5-12. Multiple-Purpose Storage Operation.

a. General. Most Corps of Engineers storage projects having power storage also provide space for flood control regulation, and at some projects, the conservation storage meets other water needs in addition to power production. This section addresses how the other functions are integrated with power operations in an SSR analysis to achieve a balanced operation.

b. Storage Zones. Discussion of multiple-purpose operation can best be described by dividing total reservoir storage into functional zones, as shown in Figure 5-38. The top zone would be the flood control storage space, which would be kept empty except when regulating floods. Below the flood control zone would be the conservation storage zone. This space would store water to be used to serve various at-site and downstream water uses, which could include power generation, irrigation, municipal and industrial water supply, navigation, water quality, fish and wildlife, and recreation. The term power storage is sometimes used instead of conservation storage when discussing power operation (as in Section 5-10), but conservation storage is the term most often used when describing multiple-purpose operation. Below the conservation zone is the dead storage zone, which is kept full at all times to provide minimum head for power generation, sedimentation storage space, etc.

c. Conservation Storage Zone. The conservation storage zone is often subdivided into two or more zones, based on the level of service that can be provided with the amount of available storage. A common division is into (a) an upper zone, where releases can be made in excess of those required to meet firm or minimum requirements, and (b) a lower zone (sometimes called a buffer zone), where releases are made only to meet firm or minimum requirements. The division between the upper and lower zone may vary seasonally. The power rule curve shown on Figure 5-36 is an example of a seasonally varying division.

d. Fixed Flood Control Zone. The simplest flood control configuration is that where a fixed amount of storage space is maintained above the top of the conservation pool the year around. This approach is followed in basins where large floods can be expected at any time of the year, such as in the South Atlantic coastal basins. The reservoir is normally maintained at or below the top of conservation pool, with the flood control space being filled only to control floods. Following the flood, this space is evacuated as quickly as possible within the limits of downstream channel capacity. During the period when flood runoff is being stored, it is sometimes necessary to reduce reservoir releases to zero in order to minimize downstream flooding, and this results in the interruption of power production. During the evacuation period, the reservoir releases required to evacuate the flood control space in the specified time period may exceed the power plant capacity, resulting in spilled

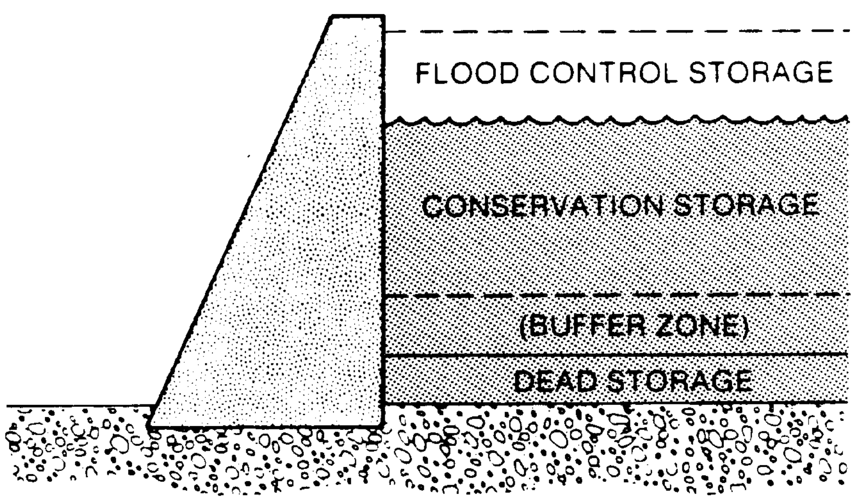


Figure 5-38. Storage zones

energy. To reduce this loss, it is sometimes possible to divide the flood control space into two zones, an upper zone, which must be evacuated as rapidly as possible, and a lower zone, which can be evacuated at a rate equal to the power plant hydraulic capacity (Figure 5-39).

e. Joint-Use Storage.

(1) In many river basins, major floods are concentrated in one season of the year. This permits establishment of a joint-use storage zone, which can be used for flood regulation during part of the year and conservation storage in the remainder of the year (Figure 5-40). Such an allocation requires less total reservoir storage than providing separate exclusive storage zones for flood control and conservation, so the utilization of joint-use storage should be considered wherever hydrologic conditions permit.

(2) Because the joint use zone must be evacuated annually, not all of the conservation storage may contribute to the project's firm energy capability. The refill curve (A-B on Figure 5-40) would be

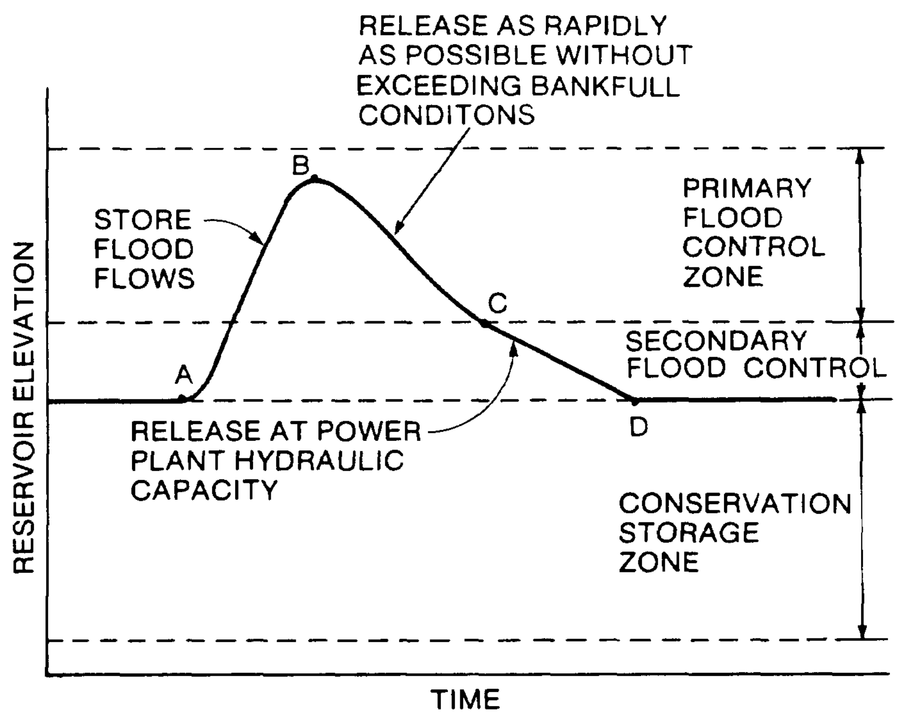


Figure 5-39. Primary and secondary flood control zones

defined by a careful balancing of the probability of floods of various magnitude in each interval within the refill period against the probability of sufficient runoff to permit refill. At some projects, it may be impossible to develop a rule curve that always satisfies the needs of both flood control and conservation storage. Take Figure 5-40 as an example. If flood control is the dominant function, and the flood control rule curve must be followed at all times, there may be some years where the spring runoff may not be sufficient to refill the conservation storage. The project's firm energy capability would therefore be based on a starting reservoir elevation (May 1st) that could be assured in all (or nearly all) water years. The conservation storage would in effect have two zones. Storage below the assured May

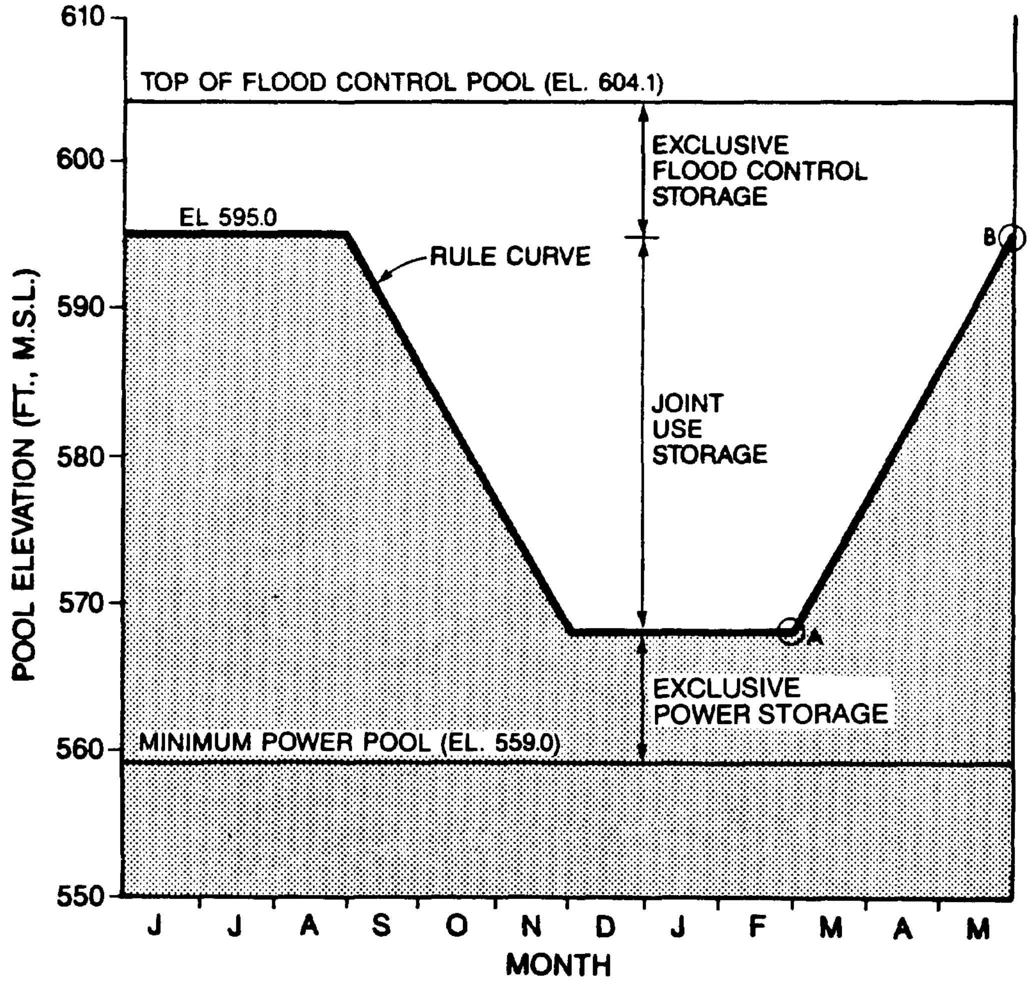


Figure 5-40. Rule curve for regulating joint-use storage

1st reservoir elevation would be primary conservation storage, and storage above that elevation would be secondary conservation storage.

(3) Figure 5-41 illustrates such a case, the lower curve being the firm power rule curve, which defines the project's firm energy capability. The upper curve defines the storage required for flood control. Typically, a project of this type would be refilled in the spring to the extent possible without violating flood control requirements. If runoff permits filling conservation storage above the power rule curve, that storage could be drafted as required (based on power system needs and the value of that energy for thermal displacement). The rate of draft would be such that firm energy capability would be protected while meeting the drawdown requirements

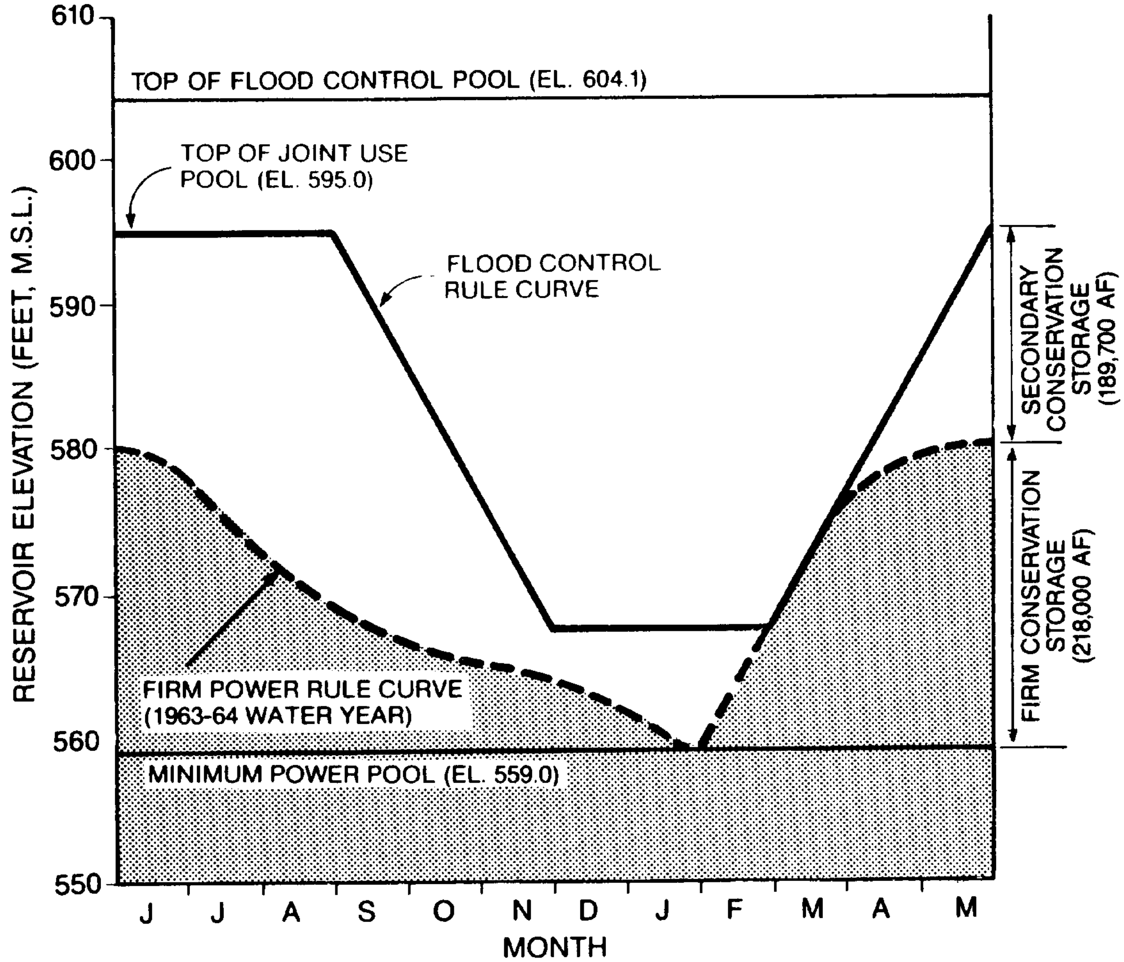


Figure 5-41. Firm and secondary conservation storage

for winter flood control. However, at many projects of this type, other project functions may help define the rate of draft. For example, at-site recreation requirements may encourage maintaining the pool level as high as possible in June, July, and August, but this may be offset by storage drafts for other uses, such as downstream water quality. Also, there would be little incentive to provide for secondary conservation storage unless it fills in a reasonably high percentage of the years. However, if (in the case of the example project), secondary energy has a higher value in July and August than it does during the refill season, providing secondary conservation storage to retain this energy might prove to be economically attractive.

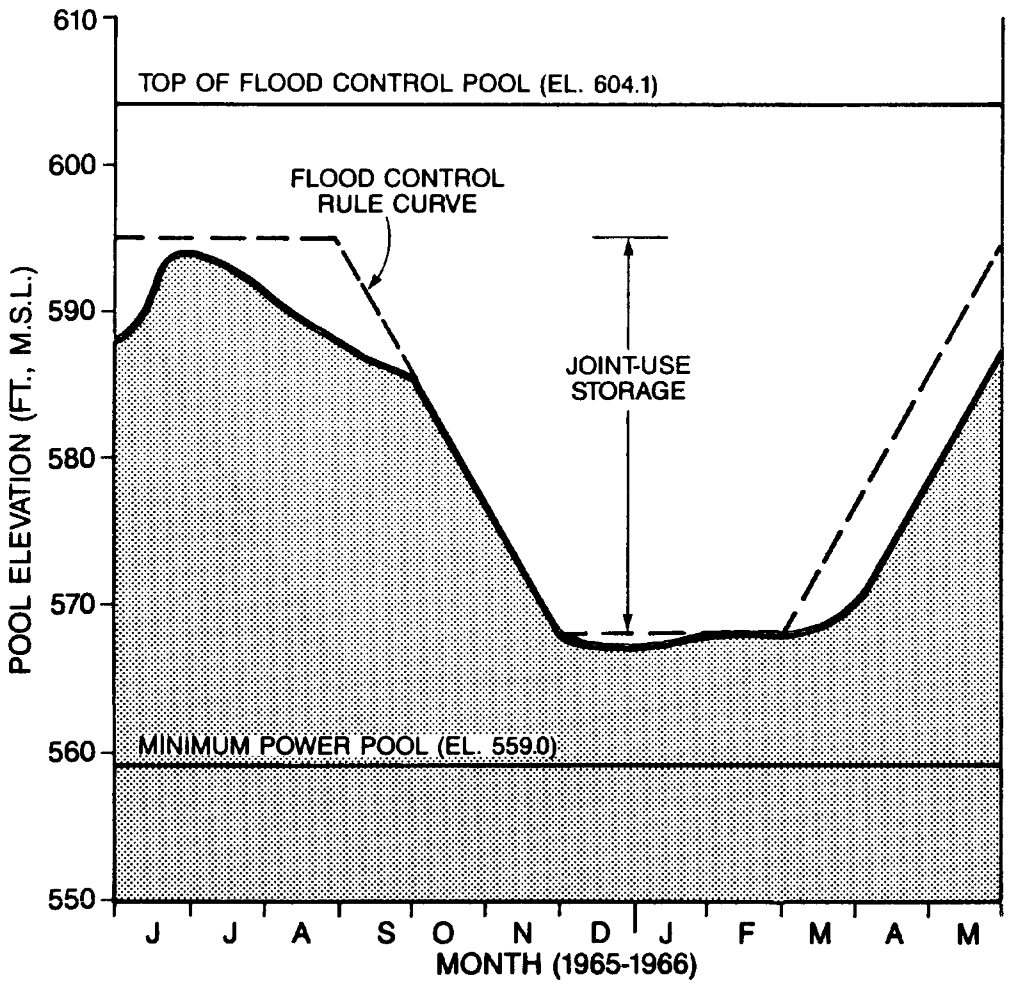


Figure 5-42. Regulation of a reservoir with joint-use storage through an average water year (Case 3, Appendix I)

(4) Figure 5-42 illustrates regulation of a reservoir with joint-use storage for flood control, hydropower, at-site recreation, and downstream water quality through an average water year. The supporting computations, which include the computations of the project's energy output, are included in Appendix I as Case 3. It should be noted that to simplify the example, monthly average flows have been used to estimate energy output in the flood season. Because of the wide day-to-day variation of releases during the flood season, daily routings would normally be required to provide an accurate estimate of energy output.

f. Joint-use Storage with Snowmelt Runoff.

(1) In the mountainous river basins of the western United States, much of the runoff is from snowmelt, and the magnitude of that runoff can be forecasted several months in advance with some degree of confidence. This makes it possible to manage joint use storage space more efficiently. Precipitation occurs primarily in the winter months, and the first forecasts of runoff volume are available in January or February. Drafts for flood control are scheduled to insure that sufficient flood control space is provided to maintain the required level of protection, while at the same time, sufficient conservation storage is maintained to permit refill in most years. Through the remainder of the winter and into the spring runoff season, forecasts are periodically updated, and the reservoir draft and refill schedules adjusted accordingly. In a low runoff year, flood control drafts are limited, to insure that sufficient conservation storage is available at the end of the runoff season to meet the coming year's firm power and other conservation requirements. In a high runoff year, the heavy drafts required to provide adequate flood control space also permit generation of secondary energy at a time when it is more readily marketable. Figure 5-43 illustrates regulation patterns for such a reservoir in both low and high runoff years.

(2) The Columbia, Colorado, and Sacramento-San Joaquin River Basins are examples of this type of hydrologic regime, and the way in which they are operated to meet flood control and conservation requirements is discussed in Appendix M. The papers by Green and Jones in reference (34) describe the complex system of rule curves that are used to regulate the operation of reservoirs in the Columbia River System.

g. Flood Control Storage Requirements. Extensive reservoir regulation and flood routing studies must be made to determine the amount of flood control space that must be maintained at various times of the year. Reference should made to publications such as EM 1110-2-3600, Reservoir Regulation (52), ER 1110-2-240, Reservoir Regulation, and Reservoir Operation for Flood Control (44b). Many of the SSR models used for making power studies also have the capability for doing the flood control regulation at the same time, provided that downstream flood control objectives have been established (see Appendix C).

h. Non-Power Conservation Requirements.

(1) At most projects having power storage, releases must also be scheduled to meet other downstream uses, which might include navigation, irrigation, municipal and industrial water supply, fish and wildlife, water quality, and recreation. In some cases, these requirements may be determined independently of the reservoir regulation study, such as (a) a minimum flow required to maintain sufficient depth to permit navigation in the reach below the reservoir, (b) the water supply requirements of a downstream community, or (c) minimum releases to maintain downstream fish populations. These requirements may be constant or they may vary seasonally. Sometimes, two levels of discharge may be specified, (a) a desired flow level that should be met as long as storage is above the critical rule curve, and (b) an absolute minimum flow that must be

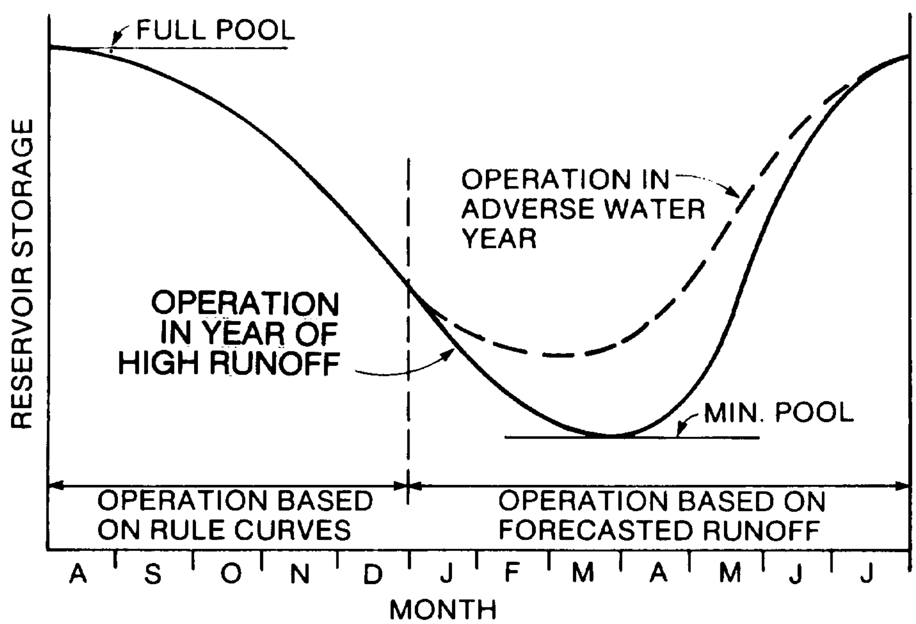


Figure 5-43. Regulation of a reservoir with joint-use storage where runoff can be forecasted (Libby Reservoir, Montana)

maintained at all times and is hence a part of the firm discharge requirement.

(2) The water quality requirement in the regulation in Appendix H is an example of a requirement that was established outside of the regulation study but had to be maintained throughout the period of analysis. In this case, releases for power were large enough in all months to maintain the water quality requirement, but in other cases, releases for other functions may constrain power operations.

(3) Sometimes the level of non-power requirements that can be maintained is determined in the regulation study. An example would be a project intended to provide both power generation and releases for irrigation. Each function could have different seasonal demand pattern (see Figure 5-44). To determine the optimum regulation would require a series of studies to test alternative storage release patterns, with the regulation providing maximum net benefits being selected as the optimum plan. In some cases, where multiple

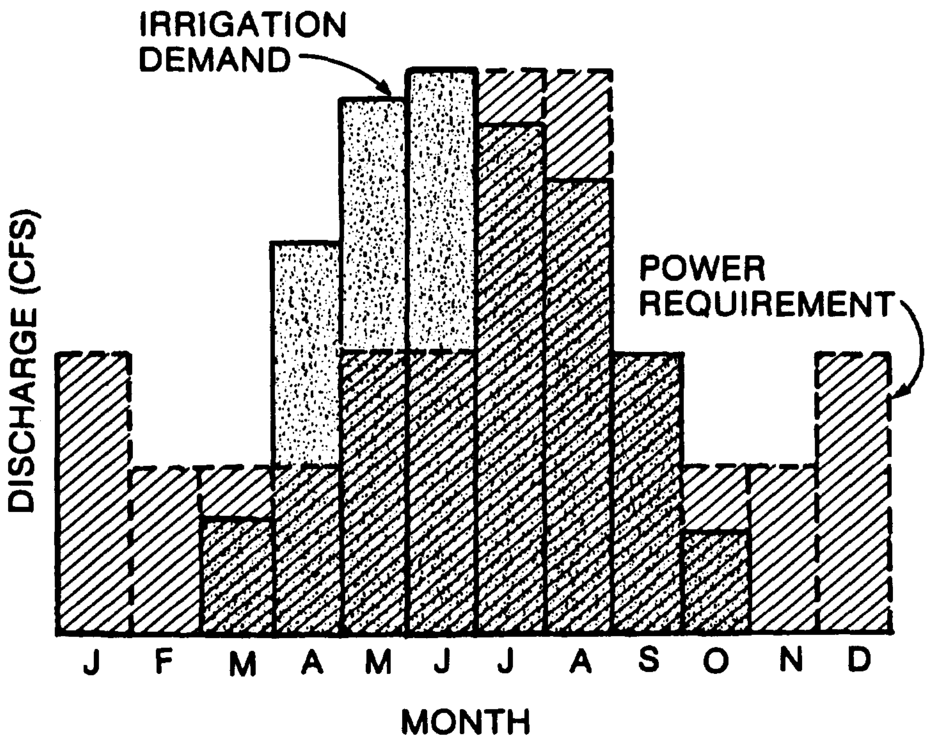


Figure 5-44. Irrigation demand vs. power requirements

objectives have been identified, it may not be possible to quantify the benefits for all functions, and judgement may be required to select the best plan. The 1981 operation policy analysis the Sam Rayburn Reservoir in Texas is an example of such a study (16).

i. Multiple-Purpose Operational Studies.

(1) Making an operational SSR study to determine the energy output of a project serving multiple purposes is basically the same as making a study for a single-purpose power storage reservoir. The steps described in Section 5-10 would be followed, and the requirements of other functions would be superimposed on the power regulation. In some periods, it may not be possible to meet all requirements. This requires a set of operating rules which establish priorities, and it is sometimes necessary to make alternative studies with different priority orders to identify the plan that maximizes net benefits. Other considerations may also help establish the priority order, or at least limit the alternatives that need to be considered. Within this context, it is important to recognize that priorities among the various water resource purposes vary with locale, with water rights, with the relative demands of the different water users, with legal and political considerations, and with social, cultural, and environmental conditions.

(2) Although these variations make it impossible to specify a priority system that applies in all cases, it is possible to identify a set of priorities that would be typical of many projects. Operation for the safety of the structure has the highest priority unless the consequences of failure of the structure are minor (which is seldom the case). Of the functional purposes, flood control must have a high priority, particularly where downstream levees, bridges, or other vital structures are threatened. It is not unusual for conservation operations to cease entirely during periods of flood regulation if a significant reduction in flooding can be realized thereby. Among the conservation purposes, municipal and industrial water supply and hydroelectric power generation are often given a high priority, particularly where alternatives supplies are not readily available. High priority is also usually assigned to minimum flows required for fish and wildlife. Navigation and irrigation may receive a somewhat lower priority, and water-quality management and other low-flow augmentation priorities would be somewhat lower yet, because temporary shortages are usually not disastrous. Finally, recreation and aesthetic considerations would usually have the lowest priority, although these functions sometimes warrant higher priorities. It should be emphasized again that: (a) there can be marked exceptions in the relative priorities as listed above, (b) there are regional differences in relative needs, and (c) legal and institutional factors may greatly affect priorities.

(3) Table 5-9 illustrates a listing of rules for hypothetical storage project in descending order of priority. Figure 5-45 describes the storage zones and rule curves for this project. It is possible to follow all of these rules in a hand regulation, but the advantages of computerized SSR models become obvious when the rules are numerous and complex.

(4) A considerable body of literature exists on multiple-purpose reservoir regulation. In addition to EM 1110-2-3600, Reservoir Regulation (52), and Volumes 1, 7, 8 and 9 of Hydrologic Engineering Methods for Water Resources Development (44), references (19) and (34) would be good starting points. Appendix M to this manual describes how multiple operating objectives are accomodated in the operation of several representative U.S. reservoir power systems.

5-13. Alternative Power Operation Strategies.

a. Introduction. The power regulation procedures described in the preceding sections are designed to insure that firm energy capability will be provided in all years in the period of record. Several alternative strategies might be considered in regulating power storage.

b. Maximize Average Annual Energy.

(1) Average annual energy could theoretically be maximized by maintaining the reservoir at maximum power pool (maximum head) at all times. However, this may not be a satisfactory operation because (a) the powerplant may not have sufficient capacity to fully utilize streamflows during the high runoff season, or (b) the value of energy in the high runoff season may be substantially less than during other periods. In these cases, some use of storage may be desirable to avoid spill and to maximize power benefits.

(2) One approach would be to apply monthly energy requirements greater than the firm energy output. Different levels of energy requirements could be tested to determine which level maximizes average annual energy. When a project is required to meet energy requirements greater than the firm, there will be months when those requirements cannot be met (at the end of the critical drawdown period, for example). This type of regulation would be implemented only in power systems where thermal energy is available to make up the shortfall in months when the energy requirement cannot be met. Section 5-13d(3) describes a technique for applying variable energy requirements, depending on pool elevation and/or time of year. This technique may not maximize average annual energy, but it might prove to be a satisfactory procedure for some projects.

TABLE 5-9
Operating Rules for Hypothetical Storage Project

1. When reservoir elevation approaches the top of flood control pool, spillway gates are opened to pass inflow, to prevent overtopping of dam.
2. Flood control storage space requirements are as follows:

December through February:	600,000 AF
June through August:	300,000 AF

   Storage in spring and fall months will follow the proportional rule curve shown in Figure 5-45. Flood control storage space is not to be filled except to control floods.
3. Flood control storage will be regulated to maintain a maximum flow of 10,000 cfs at the Fort Mudge gage, 15 miles downstream of this project.
4. Flood control regulation may require total project discharge to be reduced to zero, thus discontinuing power generation and releases for fish.
5. Primary flood control zone (upper two-thirds of flood control storage) is to be evacuated as rapidly as possible following the flood without exceeding downstream channel capacity.
6. Secondary flood control zone (lower third of flood control storage) is to be evacuated as rapidly as possible within constraints of power plant hydraulic capacity.
7. The diversions shown on Table 5-10 must be provided at the dam for a local municipal water system.
8. A minimum discharge of 200 cfs is required between April and September to maintain fish population in reach below dam.
9. The firm energy requirements shown on Table 5-10 must be met.
10. If reservoir is at or below critical rule curve, (power rule curve) only firm power requirements will be met.
11. The minimum desirable discharges shown on Table 5-10 will be met if possible for downstream navigation and water quality.
12. To protect dependable capacity, the reservoir will not be drafted below rated head (El. 737.0) except to meet firm energy requirements.
13. While in the conservation storage zone, discharge will not exceed powerplant hydraulic capacity.
14. Reservoir will be maintained as close to top of conservation pool as possible from Memorial Day through Labor Day for at-site recreation.
15. Maximum possible energy will be generated from October through February.

(3) In some cases, maximizing average annual energy may not produce maximum energy benefits. In order to determine the optimum regulation, the analysis would have to consider the cost of purchasing thermal energy in months of shortfall as well as the benefits of the increased average annual energy.

(4) If the value of energy varies from month to month, specific values could be assigned to the energy output in each month, and

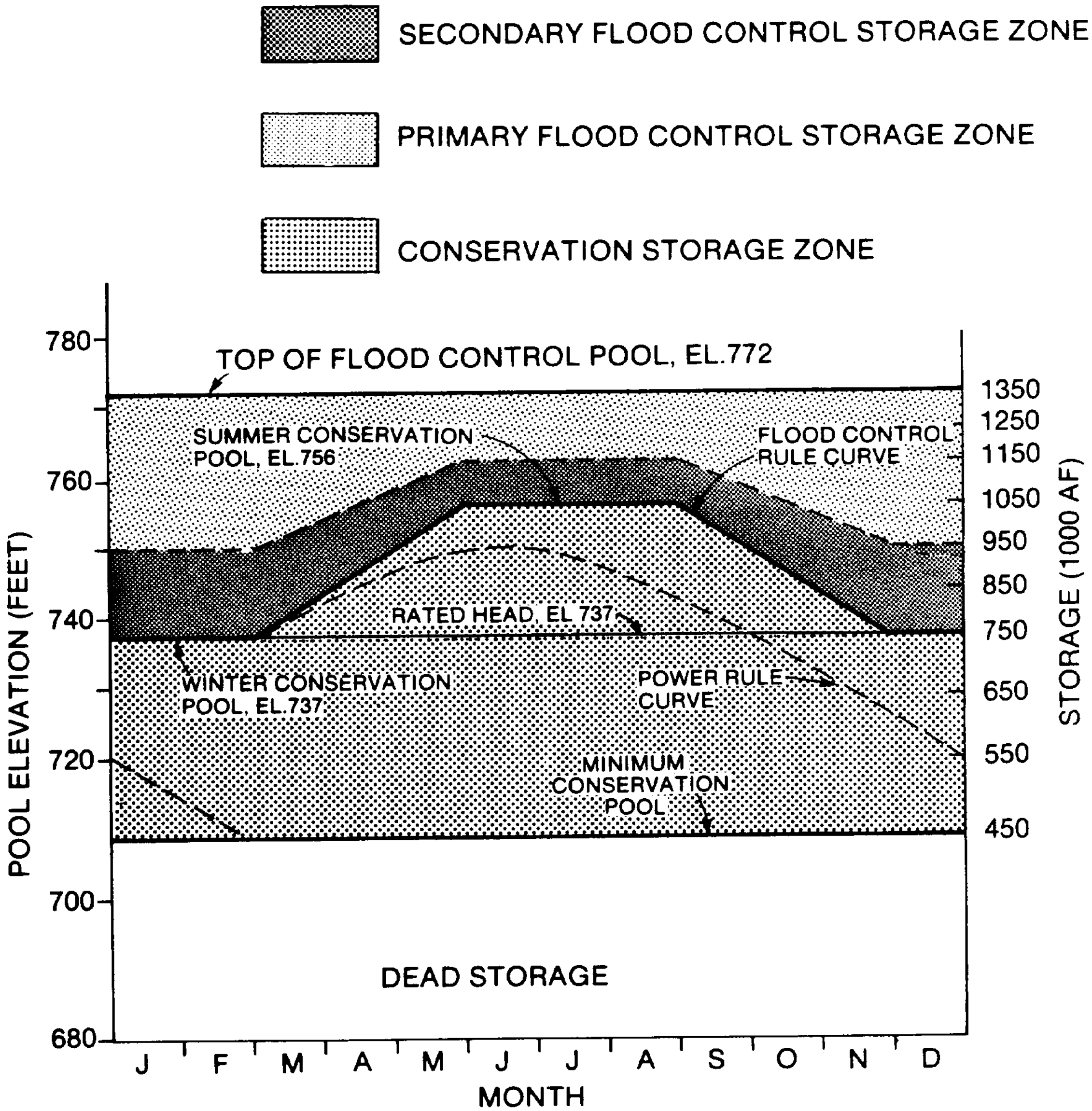


Figure 5-45. Storage zones and rule curves for hypothetical storage project

TABLE 5-10
Monthly Operational Requirements for Multiple-Purpose Storage Project Described in Table 5-9 and Figure 5-45

Month	Muncipal Water Diversion (cfs)	Required Minimum Discharge 1/ (cfs)	Desired Minimum Discharge 2/ (cfs)	Firm Energy (kWh)
January	35	0	300	13,700
February	35	0	300	11,800
March	35	0	300	12,300
April	37	200	300	11,600
May	43	200	300	11,300
June	65	200	400	10,800
July	87	200	400	11,300
August	83	200	400	11,300
September	61	200	400	10,900
October	43	0	400	11,600
November	39	0	300	11,900
December	35	0	300	13,200

1/ For fish and wildlife.

2/ For navigation and water quality.

successive iterations made to develop operating rules which maximize energy benefits. It should be noted that operating rules of this type would have to be updated periodically as the relative monthly energy values change. Figure 5-46 shows operation in an average year based on following operating rules designed to maximize energy benefits compared to an operation when the reservoir was maintained as close to the top of the power pool as possible the year around. Based on the energy values shown in Appendix I (Figure I-1), the energy output and energy benefits for that year would be as follows:

	Energy (gWh)	Energy Benefits ($1,000)
Maintain full power pool	95,500	3,350
Maximize energy benefits	92,600	3,770

The backup computations are shown as Cases 4 and 5 in Appendix I. Note that the operating rules used in Case 5 may not be the rules that would give the absolute maximum power benefits over the period-of-record, but they do illustrate how power benefits can be increased by taking into consideration seasonal variations in the value of energy.

c. Maximize Dependable Capacity.

(1) The objective in this case would be to maintain the reservoir at or above the rated head, to insure that the project's full rated capacity is available at all times. This would maximize the project's dependable capacity (assuming that dependable capacity is measured as described in either Section 6-7d or 6-7g). Theoretically, this could be assured by maintaining the reservoir at full

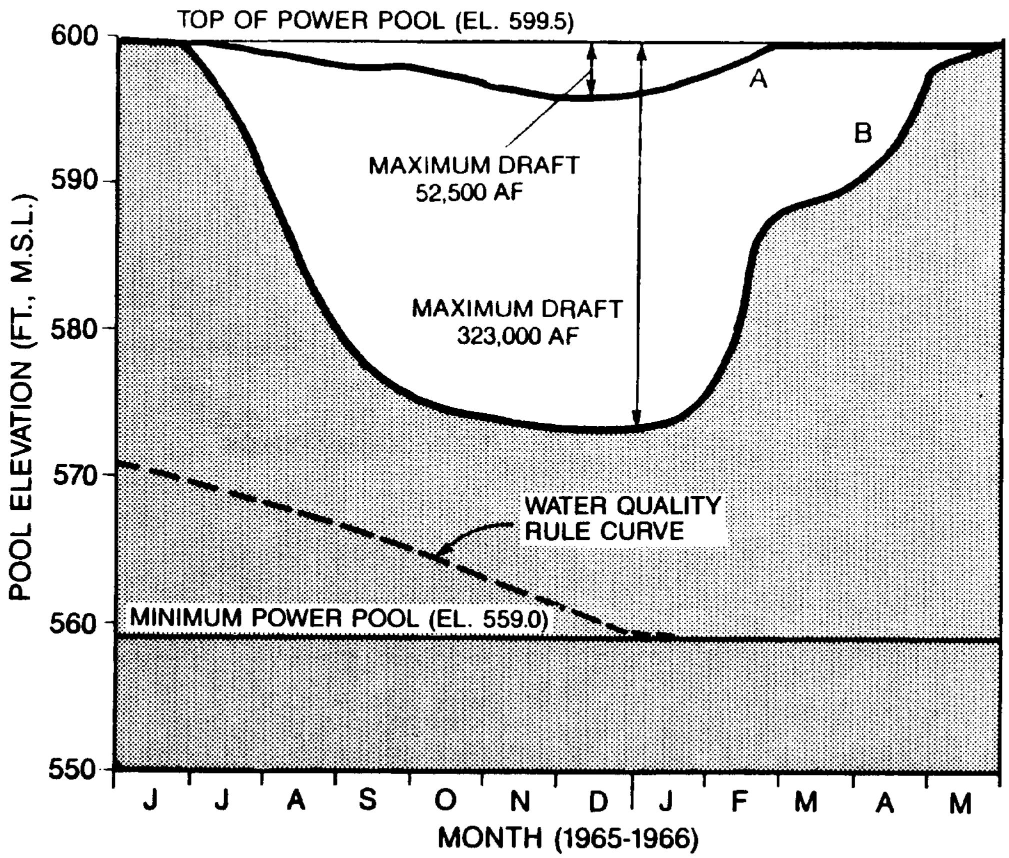


Figure 5-46. Reservoir operation in an average water year based on maximizing average energy (Curve A), and maximizing energy benefits (Curve B)

power pool at all times. However, for the capacity to be of value, it must be supported by sufficient energy to permit it to be operated for a specified number of hours in each period. For example, in some systems, for the capacity to be marketable, it must be supported by a specified amount of firm energy in each week or month. Storage drafts would be required to provide this energy in periods of low flow. This could be accomplished by developing a critical period rule curve based on only the storage available above critical head. Figure 5-47 indicates how the example project might be operated in an adverse water year, following the rule curve based on dependable capacity. Following this rule curve would insure that rated capacity would be available at all times. However, some firm energy capability would be sacrificed. For comparison, the regulation based on maximizing firm energy is also shown on Figure 5-33. The annual firm energy output in the two cases would be as follows:

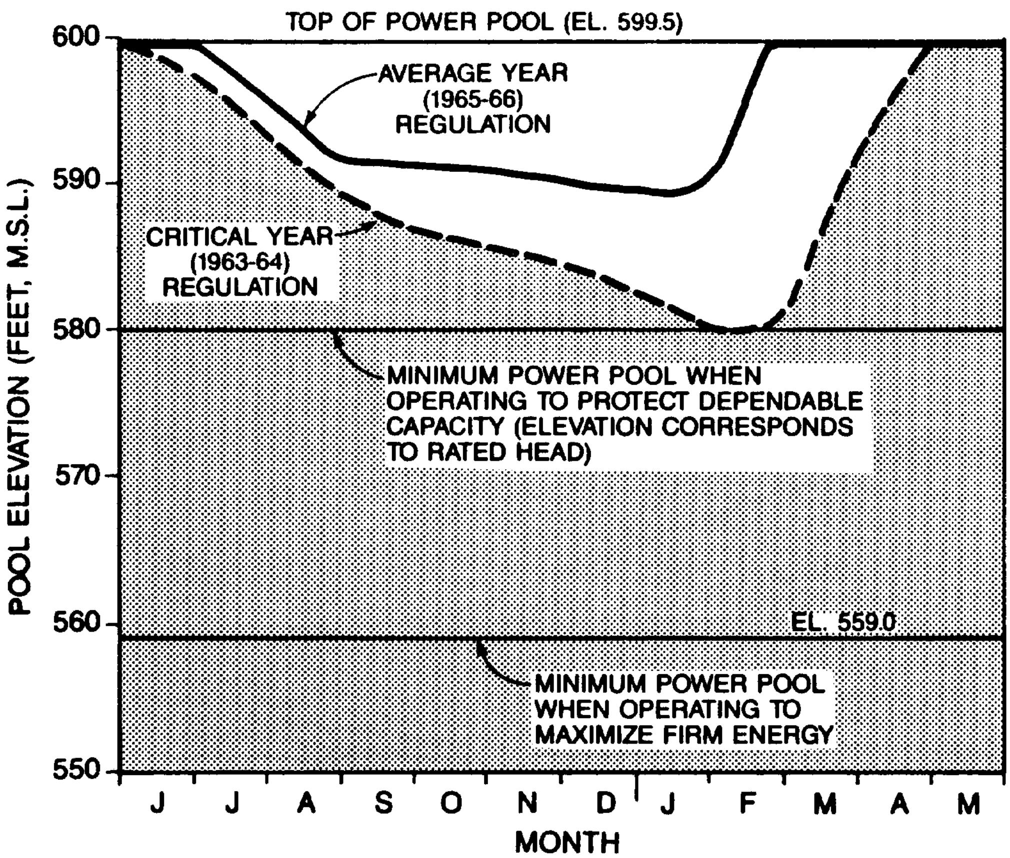


Figure 5-47. Operation of reservoir to maximize dependable capacity, in critical and average water years (Case 6, Appendix I)

Maximize firm energy 74,000 MWh

Maximize dependable capacity 45,700 MWh

Figure 5-47 also shows the dependable capacity operation in an average streamflow year. The backup calculations are shown as Case 6 in Appendix I, and the calculations for the routing to maximize firm energy are shown in Appendix H.

(2) A variation on this approach would be to maintain the pool at or above rated head through the end of the peak demand season

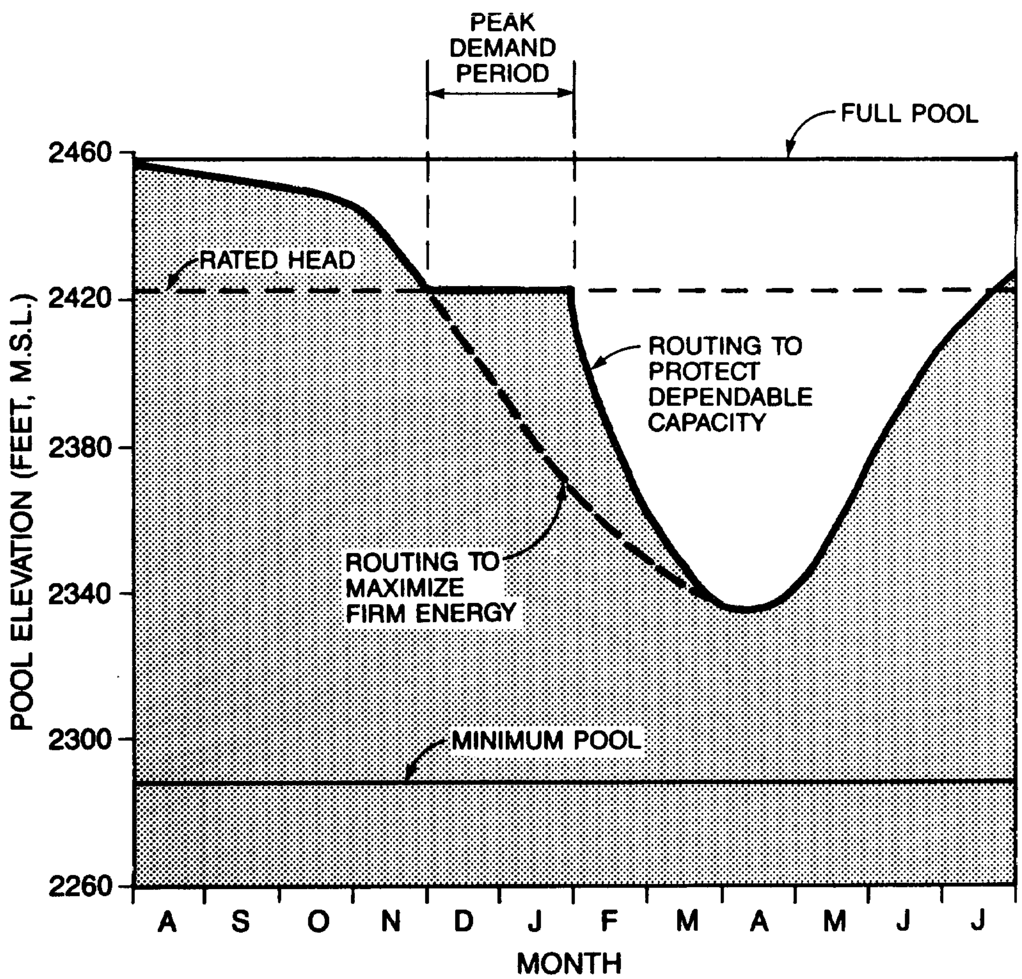


Figure 5-48. Operation of reservoir with joint use storage to maximize dependable capacity (in average year)

and then draft below that elevation to maximize average energy production during the interval prior to the refill season. This approach would be particularly attractive for a system where runoff is from snowmelt, where the amount of draft following the peak demand period would be based on forecasted runoff (see Figure 5-48).

d. Variable Draft.

(1) Another approach, which is now being used either explicitly or implicitly in several U.S. hydropower systems, is to base draft of power storage for secondary energy production on the market value of energy at the time. Such an operation might be superimposed on the primary objective of maximizing firm energy output. This means that the project would operate between the top of power pool and the critical year rule curve. During adverse water years, the project would operate on the rule curve and generate only firm energy. In good water years, drafting storage above the rule curve to produce secondary energy would be based on the value of the energy.

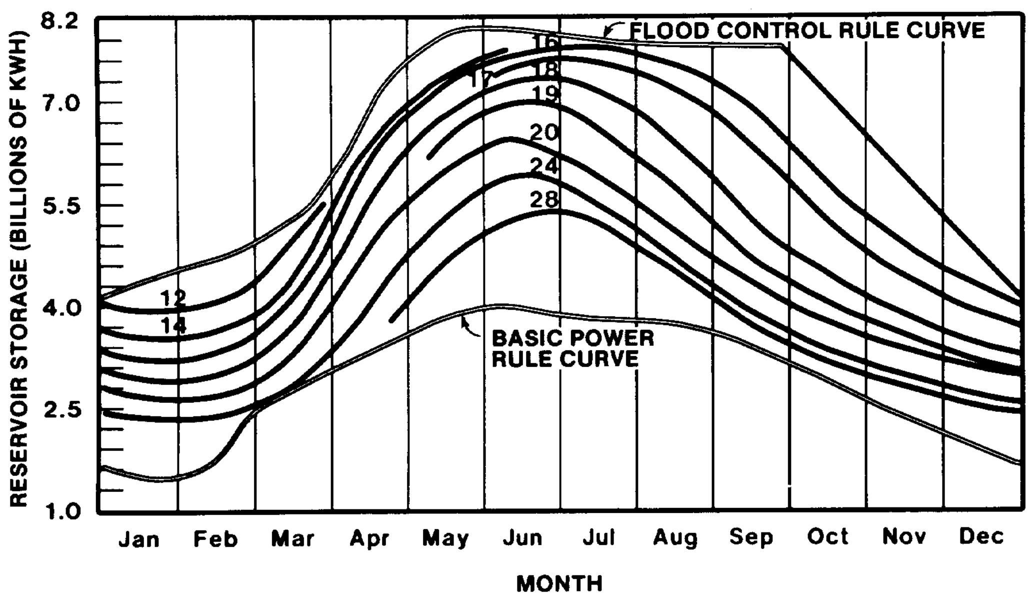


Figure 5-49. TVA intermediate guide curves for 1979. The curves between the flood control rule curve and the basic power rule curve are the intermediate guide curves. The numerical values above the curves represent the value of storage in mills/kWh.

(2) The most sophisticated example of an operation of this type is in the TVA system, where a series of intermediate (or economy) guide curves is developed which shows what the value of secondary energy must be for storage to be drafted to that level (Figure 5-49). Similar operations are followed in other systems as well, except that the decision whether to draft may be more judgemental, and may be based on non-power considerations as well as the present and expected future value of the secondary energy.

(3) In the Arkansas-White River power system, a variable draft strategy is employed by the marketing agency to protect dependable capacity as well as firm energy capability, while attempting to maximize energy output and yet maintain a satisfactory pool elevation for recreation. Studies by Tulsa District have succeeded in empirically quantifying this somewhat complex operation. In order to protect dependable capacity (and reservoir recreation), the reservoirs are almost never drafted below the elevations where 80 hours of power storage remains. To help maintain this elevation and still meet firm energy obligations, the marketing agency purchases low

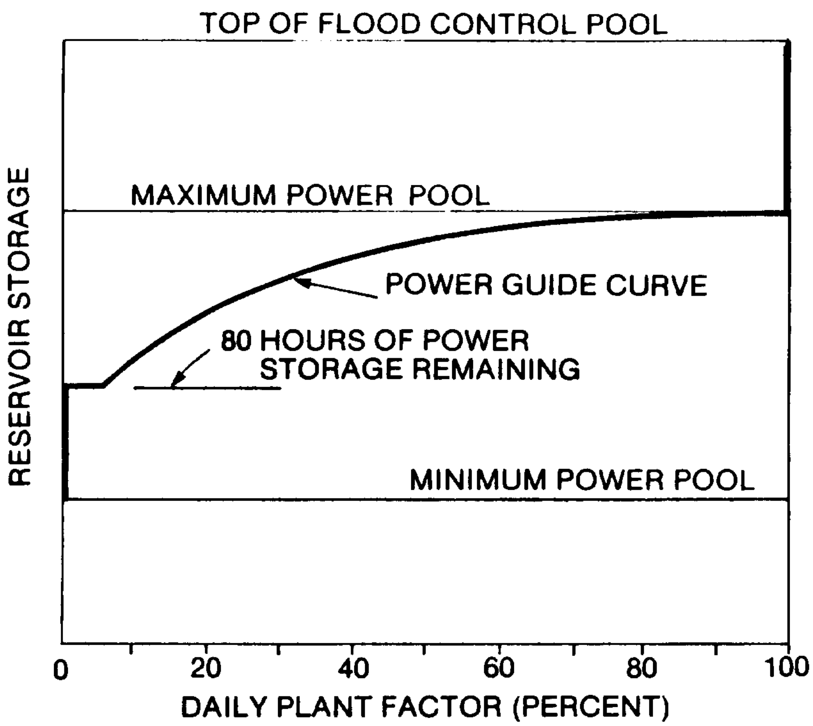


Figure 5-50. Power guide curve for Arkansas-White system

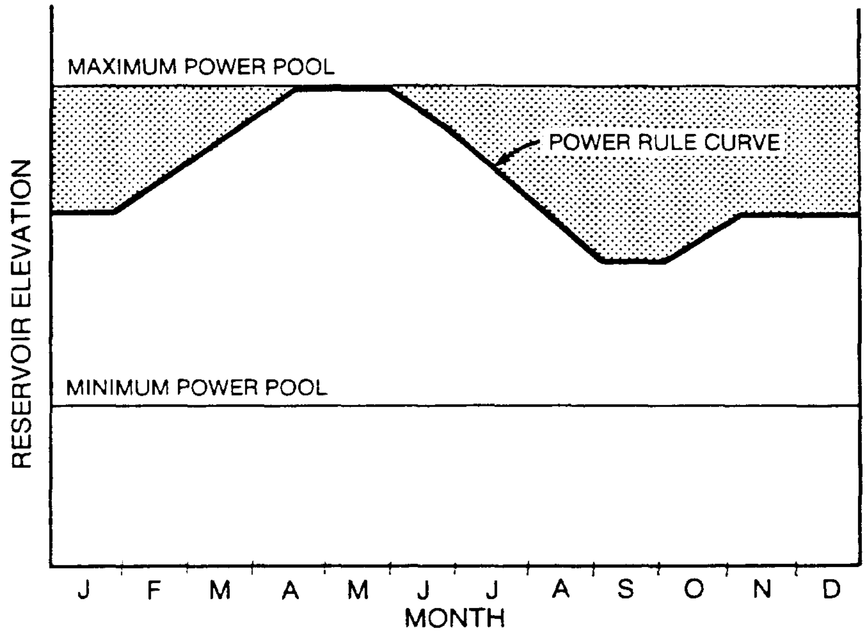
cost thermal energy whenever available. When the reservoir is above the 80-hour elevation, releases are made for power at a daily plant factor that is a function of pool elevation. This plant factor varies from 100 percent while in the flood control pool (i.e., at or above the top of power pool) to about 5 percent at the 80-hour elevation (see Figure 5-50). The 80 hours of storage is held in reserve, being used only in emergency situations, such as a severe heat storm occurring at a time when reservoir inflows are low and thermal energy is not available for purchase. Tulsa District has used a guide curve of this type to simulate the power operation of new power projects which would be operated in the coordinated Arkansas-White River power system. Both the HEC-5 and SUPER models have been adapted to simulate this type of operation.

(4) It should be noted that the 80-hour limit described above is based on historical operation experience in the early 1980's. The 80-hour limit corresponds to 40 percent of power storage remaining. The regional Power Marketing Administration expects this limit to move up, perhaps as high as 75 of percent power storage remaining by the 1990's. Where this approach is used, the studies should be closely coordinated with the regional PMA to insure that the guide curves reflect expected future operations.

(5) The power guide curve concept could also be applied to a reservoir that is regulated using a seasonally varying power rule curve (Section 5-11). The power guide curve would be flexible, expanding or contracting to fit the distance between the power rule curve and the maximum power pool (Figure 5-51). Using this approach, the plant factor required to produce firm energy could be varied seasonally also.

(6) A similar but somewhat simpler approach would be to use a series of intermediate rule curves to govern operation between the power rule curve and the maximum power pool. These curves would define zones within which the plant would operate at a fixed plant factor. These plant factors would vary with elevation in a manner similar to the power guide curve.

e. System Power Reserve. In systems with a high percentage of hydropower, it may be acceptable to draft below the critical rule curve to meet firm load during periods when base load thermal plant outages are higher than normal, with the expectation that later, when the thermal plants are back in service, they can operate at full output until the storage projects return to their rule curves. However, such departures from the rule curve would normally be limited. In the event of extended outage, other actions would be taken, such as purchasing energy from outside of the system and attempting to reduce loads.



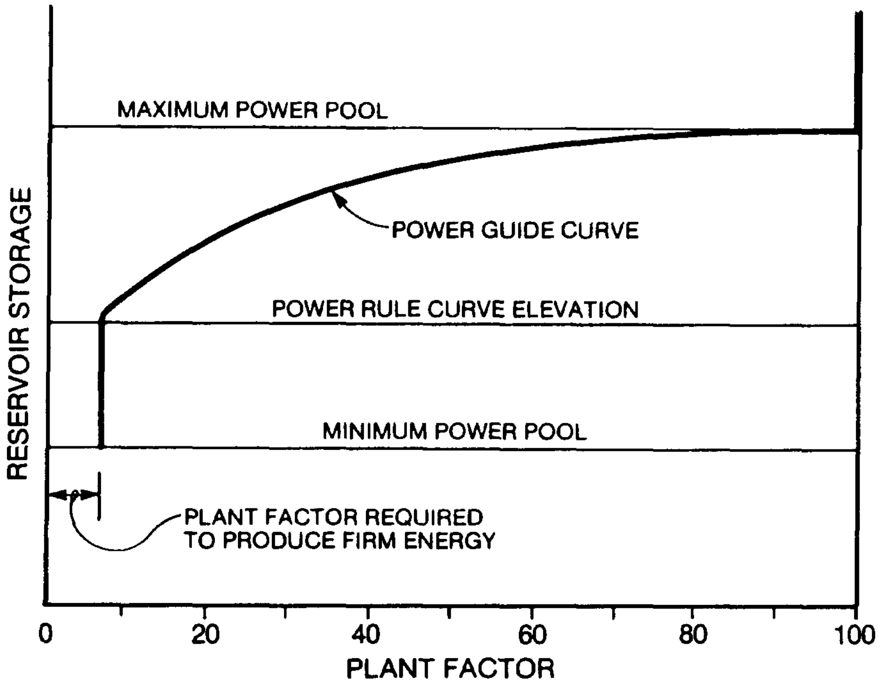


Figure 5-51. Appliction of power guide curve to reservoir operated using a power rule curve

f. Composite Energy Operation. In the mainstem Missouri River system, storage is several times the average annual runoff, thus permitting considerable flexibility in operation. System storage is divided into two zones, an upper or "Annual Multiple-Purpose Storage Zone" and a lower or "Carry-Over Storage Zone." In most years runoff is sufficient to operate in the upper zone, and regulating the project to meet normal flood control and navigation requirements usually results in power output close to average annual energy. During extended periods of drought (2 years or more), the operating strategy will result in the reservoir elevations dropping into the carry-over zone. When this occurs, energy production is reduced to the firm requirement until the reservoirs return to their normal operating range.

5-14. System Analysis.

a. Introduction.

(1) The analysis of a system of hydropower projects follows the same basic principles as single hydro storage project. The major difference is that analysis of a hydropower system is more complex, and when the system is operated for multiple purposes, the analysis is even more complex. For adequate analysis of systems, computerized SSR models become a necessity.

(2) In the context of this section, a "system" refers to a multi-reservoir system where the operation of all projects is coordinated to maximize power benefits (within the constraints of other project and system functions). System studies might be required at the planning stage for several reasons:

- to examine new hydropower systems
- to examine the proper sequence of construction for projects in a hydropower system
- to examine the addition of new projects to an existing system
- to examine the desirability of operating existing hydropower projects as a system instead of as independent projects
- to examine multiple-purpose aspects of reservoir system design and operation

- to examine the desirability of modifying the operation of an existing system to reflect changed operating requirements (either power or non-power)

(3) In the following paragraphs the general principles of reservoir system operation will be discussed, several examples will be presented, and sources of additional information will be cited.

b. Storage Effectiveness.

(1) The basic problem in operating a system of reservoir projects (Figure 5-52, for example), is to determine the order of drafting storage from the various reservoirs which will maximize power output. The overall approach to sequence of drafting can be understood by examining the storage effectiveness concept.

(2) When storage is drafted from a reservoir, (a) energy is generated from the water which was drafted, both at-site and at downstream projects, and (b), as a result of the removal of the storage, there is a loss in generating head at the storage project's powerplant. This loss of head reduces generation in subsequent months (until the reservoir fills once again). In order to determine the

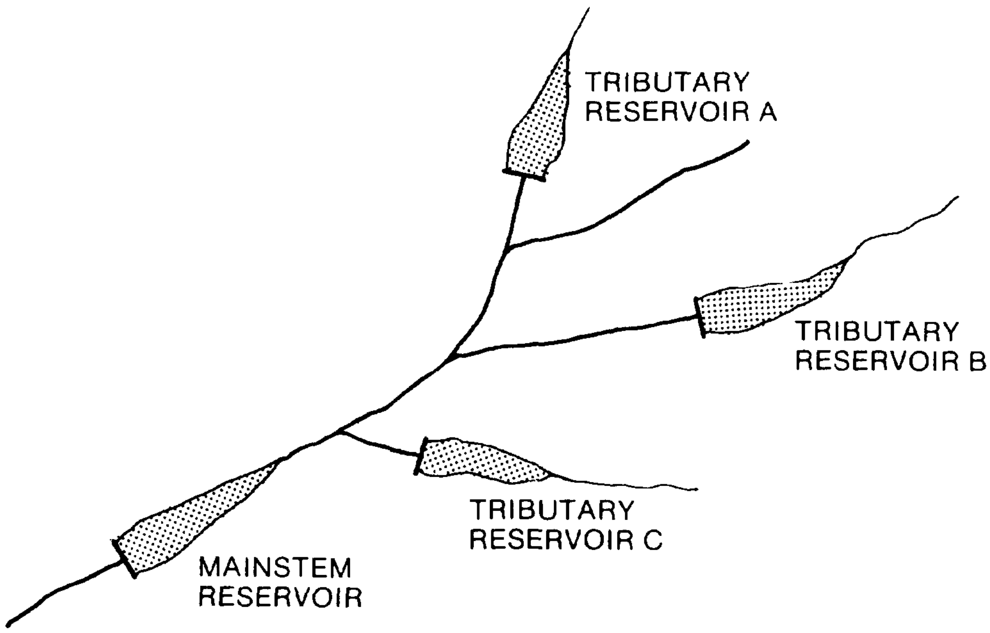


Figure 5-52. System of reservoir projects

order of reservoir draft, both the produced generation and the resulting loss in head must be taken into account. This can be achieved through the use of the storage effectiveness index, which is the inverse ratio of the gain in generation in a given routing interval to the generation loss in subsequent intervals:

$$\text{Storage Effectiveness Index} = \frac{\text{kWh lost in subsequent intervals}}{\text{kWh from storage release}}$$

At the start of each month, for example, storage effectiveness indices might be computed for each reservoir, and water would be drafted from the one with the most favorable (lowest) index.

c. General Approach.

(1) To illustrate the storage effectiveness concept, several different types of reservoir combinations will be examined. In order to simplify the explanation, it will be assumed that the system is being regulated only for hydropower and the objective is to maximize the system's firm energy output. The monthly routing interval will be used in the examples.

(2) The following steps would apply to the analysis of such a system:

- identify the historical streamflow period that appears most likely to be the system critical period.
- estimate the load that is to be carried by the system in each month of the critical drawdown period.
- for the first month in the period, determine the generation that can be produced by operating all powerplants using only reservoir inflow.
- determine the generation shortfall for that month by deducting the generation resulting from inflow from the required generation. This shortfall will then be met by drafting storage from one or more reservoirs.
- compute storage effectiveness indices for each reservoir
- select the project or projects with the lowest storage effectiveness index and draft sufficient storage to cover the generation shortfall
- repeat the four preceding steps for each subsequent month

(3) If the firm load which can be met by the hydro system has been estimated correctly, the loads will have been met in all months and all reservoirs will have been fully drafted by the end of the critical drawdown period. If the reservoirs have been drafted prior to the end of the critical drawdown period, the load estimate was too high. If storage remains at the end of the period, the estimate was too low. If the load estimate is either too high or too low, the load estimate must be adjusted and another routing must be made (see Section 5-10g).

(4) Once a routing is made which exactly uses the available storage, the system's firm energy output will have been identified for each month in the critical drawdown period. Using these firm energy requirements, a routing must be done for the entire period of record in order to (a) verify that the proper critical period has been selected, and (b) to determine the system's average annual energy production. If the reservoirs fully draft and loads cannot be met in some months, then another period is more critical. The entire process must then be repeated using the new critical drawdown period.

d. System Critical Period.

(1) The critical period for the system is defined by the regulating capability of the total amount of storage available to the system. As a result, it may be different than the critical period of individual projects operated independently.

(2) When a computerized SSR model is being used, the system critical period is usually identified by making trial routings. Various historical adverse flow sequences are tested in order to identify the period that is most adverse (produces the least amount of firm energy).

(3) If components of the system are located in hydrologically dissimilar basins or sub-basins, it may be necessary to identify one or more potential critical periods for each sub-area and test each with the entire system.

e. Estimate System Firm Energy Loads.

(1) Making a preliminary estimate of the firm energy load that could be carried by a system of projects is much more complicated than estimating the firm output of a single reservoir. Rather than attempting to make such an estimate, the usual approach when using computerized routing models is to determine the system's firm energy output by trial and error, applying various loads until the reservoirs are all exactly drafted at the end of the critical drawdown period (see Section 5-14c).

(2) In hydro-based power systems, some complicating factors may occur, particularly when examining the operation in the immediate future. Reasonably accurate estimates of expected loads and expected thermal resource capabilities (if any) are usually available. Hence, the hydro system would be operated against actual expected net loads. In some cases, this may result in a firm energy surplus or deficit, rather than an operation in which firm loads are exactly met. This could be handled by applying the surplus or deficit uniformly to all months in the critical drawdown period. This approach would simulate, in the case of a surplus, the shutting down of the most expensive thermal plants for the entire critical period, and, in the case of a deficit, accepting a uniform shortage over the entire critical period.

(3) In the case of a deficit, another approach would be to apply the deficit to the last months in the critical drawdown period. This would result in larger shortfalls in those months (compared to applying a uniform deficit to all months). However, extended low flow periods are usually infrequent occurrences, so over the long term, the system will seldom reach the state where deficits will actually occur. If it does appear that the system is entering an extended low flow period, actions would be taken to accomodate the resulting deficits (reduce loads, make purchases from outside systems, etc.).

f. Examples of Storage Effectiveness.

(1) General. Several examples of two-reservoir systems will be examined using the storage effectiveness technique in order to illustrate the principles of system operations. Detailed calculations will be shown only for the first example. For subsequent examples, the calculations used to derive the storage effectiveness ratios are summarized in Appendix L. The appendix also includes the storage-elevation curves for the three major reservoir configurations.

(2) Identical Reservoirs in Tandem. Figure 5-53 shows two identical reservoirs in tandem, both with at-site generation. Both also have 100 feet of head at full pool and 200,000 AF of power storage, located in the top 40 feet of the reservoir. Each reservoir has 80,000 AF of dead storage, so the total storage at full pool would be 280,000 AF. It is assumed that (a) there is no local inflow between the projects, so the same unregulated inflow applies to both projects, (b) net evaporation, leakage, withdrawals, and other losses are zero, and (c) the elevation of Reservoir A has no effect on the tailwater elevation at Reservoir B. The critical drawdown period is assumed to be eight months, June through January, and to simplify the problem, an inflow of 1000 cfs is assumed to apply to all months in the critical drawdown period. All months are assumed to be 30 days in length. The energy calculations are made using the water power equation.

(3) Estimate Energy Shortfall. It is assumed that the monthly firm energy requirement is 14,800 MWh for all months. The first step is to calculate the generation from natural inflow, using the water power equation (Eq. 5-4). Drafting storage from the downstream reservoir (Reservoir A) will be examined first. The energy output at the upstream reservoir for the first month would be

$$\text{kWh} = \frac{\text{QHet}}{11.81} = \frac{(1000 \text{ cfs})(100 \text{ feet})(0.85)(720 \text{ hours})}{11.81} = 5{,}200 \text{ MWh.}$$

At the downstream project, the average available head would be less than 100 feet, because some head will be lost when storage is drafted to meet the deficit. An average head of 95 feet is assumed (note that more than one iteration may be required to reach a solution for the storage draft for a given month). The generation from inflow at Reservoir A would therefore be

$$\text{kWh} = \frac{(1000 \text{ cfs})(95 \text{ feet})(0.85)(720 \text{ hours})}{(11.81)} = 4{,}900{,}000 \text{ KWh}$$

The energy shortfall would therefore be

$$(14{,}800 - 5{,}200 - 4{,}900) = 4{,}700 \text{ MWh.}$$

(4) Draft Required from Reservoir A. If the draft is made at Reservoir A, the full 4,700 MWh of additional generation would have

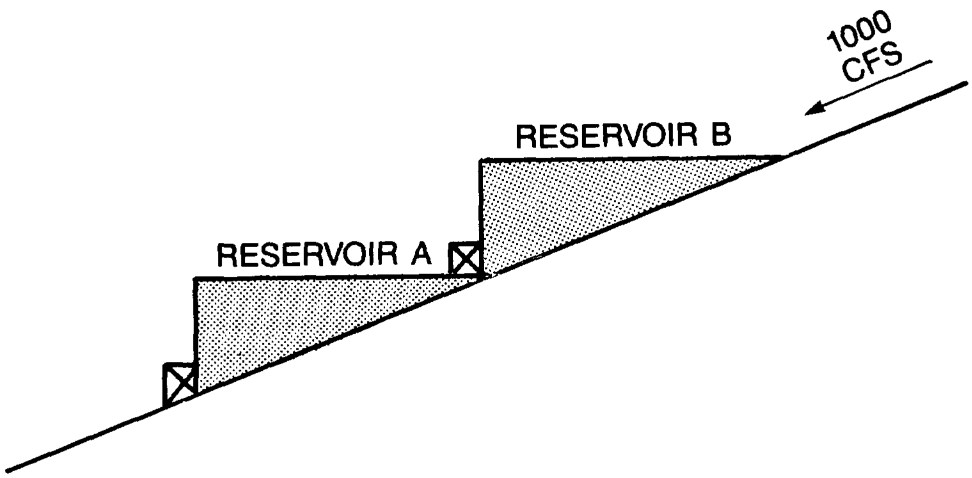


Figure 5-53. Two identical reservoirs in tandem, both with at-site generation (Case 1)

to be produced at that reservoir's powerplant. The average discharge required through the powerplant to produce 4,700 MWh would be

$$Q = \frac{11.81\ \text{kWh}}{\text{Het}} = \frac{(11.81)(4{,}700{,}000\ \text{kWh})}{(95\ \text{feet})(0.85)(720\ \text{hours})} = 955\ \text{cfs.}$$

This corresponds to a storage draft of

(955 cfs)(59.5 AF/cfs) = 56,800 AF,

where 59.5 AF/cfs is the conversion factor for a 30-day month (Table 5-5).

Deducting the storage draft from the starting storage, the end-of-month storage is found to be (280,000 AF - 56,800 AF) = 223,200 AF. Referring to Figure L-1, the end-of-period head is found to be about 90 feet. The average head for the period would therefore be (0.5)(100 + 90) = 95 feet, which verifies the head assumed in previous steps.

(5) Loss in Subsequent Months. The loss of head at Reservoir A at the end of the first month would be (100 - 90) = 10 feet, which would in turn affect generation in the remaining seven months in the critical drawdown period. The average streamflow passing through the powerplant at Reservoir A through the remainder of the critical period would be the sum of (a) the unregulated inflow and (b) the remaining power storage at the two reservoirs, drafted over the course of the remaining seven months.

At-site unregulated inflow = 1000 cfs

$$\text{Releases from Reservoir B} = \frac{(200{,}000\ \text{AF})}{(59.5\ \text{AF/cfs})(7\ \text{months})} = 480\ \text{cfs.}$$

$$\text{Releases from Reservoir A} = \frac{(200{,}000 - 56{,}800\ \text{AF})}{(59.5\ \text{AF/cfs})(7\ \text{months})} = 344\ \text{cfs.}$$

The total average flow would be (1000 + 480 + 344) = 1824 cfs. The resulting energy loss would therefore be

$$\text{kWh} = \frac{\text{QHet}}{11.81} = \frac{(1824 \text{ cfs})(10 \text{ ft})(0.85)(7 \text{ X } 720 \text{ hrs})}{11.81} = 6{,}600 \text{ MWh.}$$

(6) Storage Effectiveness Index For Reservoir A. The storage effectiveness index for Reservoir A would be the ratio of the energy loss in subsequent months to the energy produced in the month being evaluated, or

$$\text{Storage Effectiveness Index} = \frac{6{,}600 \text{ MWh}}{4{,}700 \text{ MWh}} = 1.40$$

(7) Analysis of Reservoir B. Reservoir B would be analyzed in the same way. The resulting storage effectiveness index is 0.47. The backup calculations are summarized as Case 1 in Appendix L.

(8) Sequence of Drafting. Reservoir B has a much lower storage effectiveness index (0.47) than Reservoir A (1.40). Hence, it is obvious that the first draft should be made from the upstream Reservoir B. Drafts from Reservoir B will pass through a larger generating head, and thus require less draft to produce a given amount of generation. If storage is drafted from Reservoir A, not only will a larger head loss occur because of the larger draft, but the resulting head loss will affect subsequent generation from storage releases from both Reservoirs A and B. For these reasons, upstream reservoirs should generally be drafted first. The only possible exception (other than non-power operating constraints) would be where the upper reservoir has a much steeper storage-elevation relationship than the lower reservoir. The upstream project would therefore suffer a much larger loss in head in order to provide the required draft, and this may produce a higher storage effectiveness index at the upstream reservoir. In most cases, however, there is local inflow between tandem reservoirs, so the loss in head due to storage draft at the lower reservoir would cause a proportionately larger loss in generation in subsequent months, making drafts from the upper reservoir even more effective.

(9) Regulation Over the Critical Drawdown Period. Routing the two reservoirs shown in Figure 5-53 through the critical drawdown period would result in the regulation shown on Figure 5-54. The upstream Reservoir B would be completely drafted before storage is drawn from Reservoir A. Note also that the downstream reservoir is filled first, for the same basic reasons that it was drafted last. Refilling the downstream reservoir first also increases the probability that it will refill, and that generation of secondary energy will be maximized in the spring months of high runoff years.

The plots for the critical drawdown period could be used as rule curves to guide the operation of the reservoirs through the total period of record.

(10) Two Identical Reservoirs in Parallel. Figure 5-55 shows two identical reservoirs in parallel with the same characteristics as Reservoirs A and B. Assume first that both have identical inflows and both have powerplants. In this case, both would also have identical storage effectiveness indices of 0.91 for the first month in the critical drawdown period (Case 2, Appendix L), so the two would be drafted at the same rate.

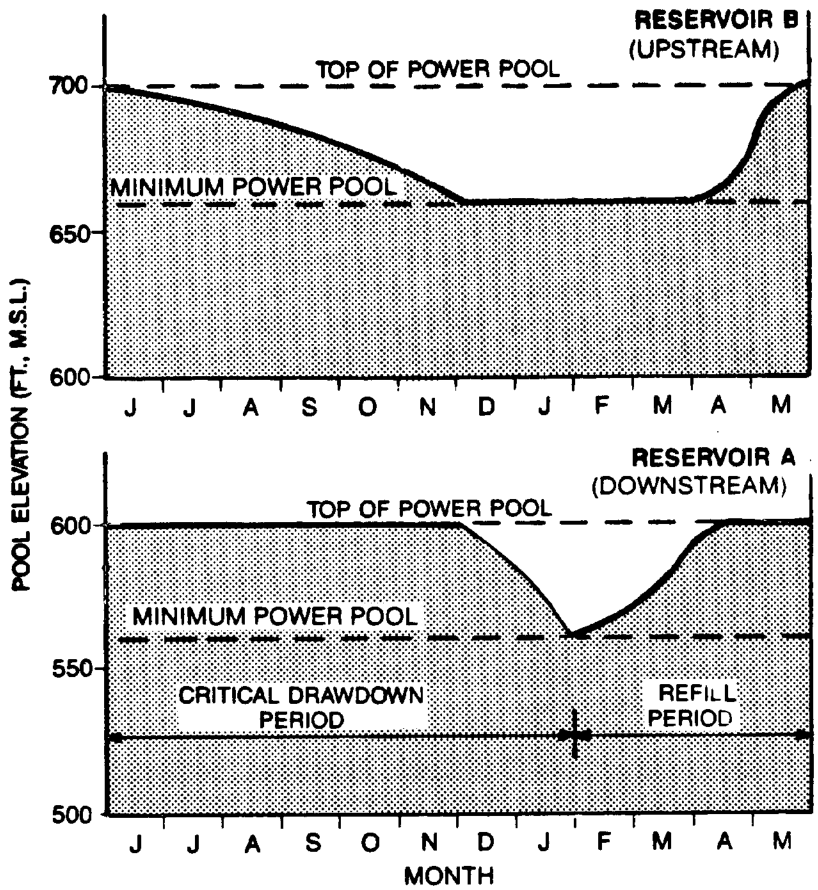


Figure 5-54. Regulation of two identical tandem reservoirs over the critical drawdown period

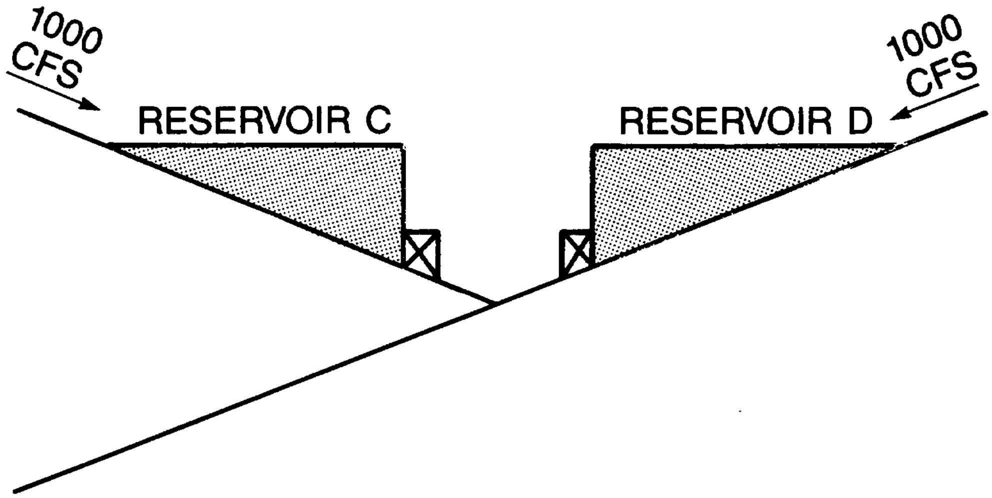


Figure 5-55. Two identical reservoirs in parallel (Case 2)

(11) Two Identical Reservoirs in Parallel (One with Downstream Power). Assume the same situation as in the previous example, except that a run-of-river plant with 30 feet of head is located just downstream from Reservoir D (Figure 5-56). Because the effective head of releases from Reservoir D is increased by 30 feet, the draft required from that reservoir to meet a given increment of load is reduced, resulting in a higher average head at-site and reduced losses in subsequent months. The first-month storage effectiveness index for

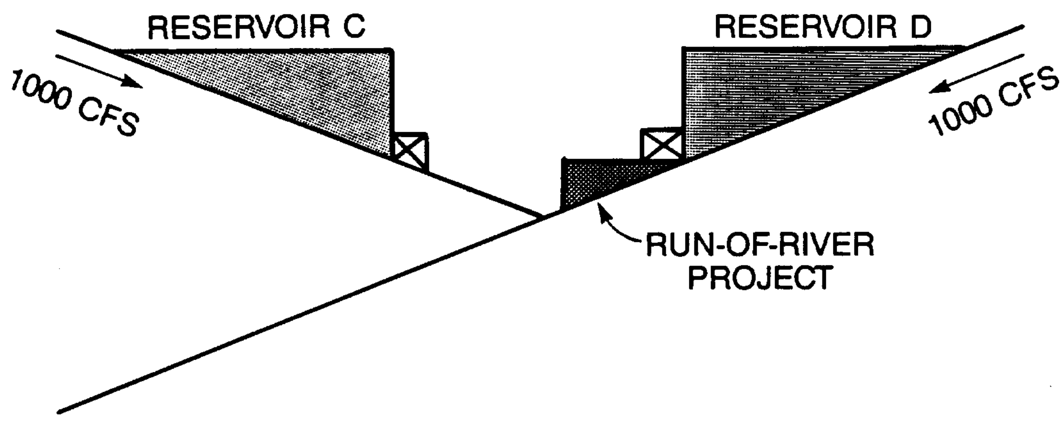


Figure 5-56. Two identical reservoirs in parallel (one with downstream power) (Case 3)

Reservoir D would be 0.70 (Case 3, Appendix L), compared to 0.97 for Reservoir C, making Reservoir D the first reservoir to draft. Note that as Reservoir D is drafted, its head is reduced. Before the storage is fully drafted the sum of the head at Reservoir D and the run-of-river plant will be less than the head at a full Reservoir C. Thus, at some point during the critical drawdown period, the storage effectiveness indexes of the two reservoirs could become equal, at which time simultaneous drafts would be made from both reservoirs.

(12) Two Identical Reservoirs in Parallel (One Without Power). Consider a situation similar to the preceding example, but where only Reservoir C has at-site power and there are run-of-river projects located below the confluence of the two streams (Figure 5-57). Even though Reservoir D has no at-site power, storage releases would be usable for increasing generation at the run-of-river projects. It can be seen without computations that the loss in generation at Reservoir D in subsequent months due to reduced head will be zero, because there is no at-site generation. Hence, the storage effectiveness index for Reservoir D will be zero, and it should be drafted before drafting Reservoir C. Where power generation is the only consideration, reservoirs without at-site power should be drafted in preference to those with at-site power. However, it is not always desirable to fully draft the reservoir without at-site power prior to drafting the one with at-site power. Consideration should also be given to insuring that Reservoir D has a reasonable probability of refill in normal water years. This could be accomplished by developing an assured refill level (or curve) for each reservoir. As long as a reservoir is not drafted below this level, it will refill in most water years. In the example, Reservoir D would be drafted to the

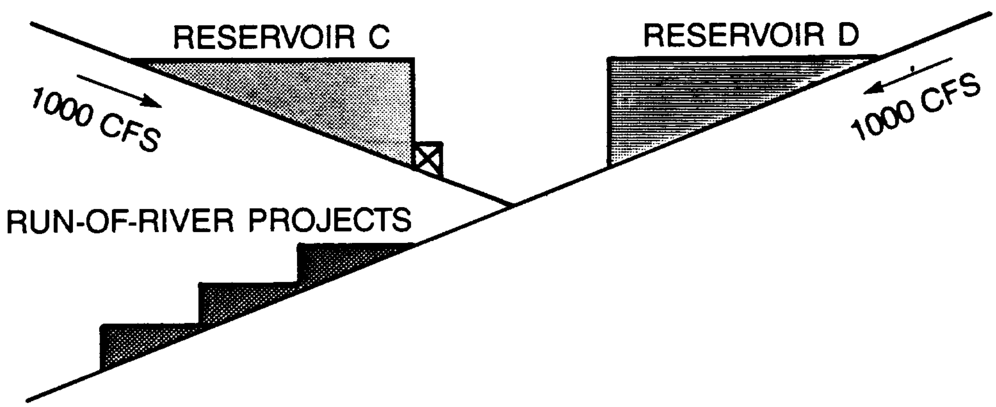


Figure 5-57. Two identical reservoirs in parallel (only one with power)

assured refill level. Then, Reservoir C would be drafted to its assured refill level. Finally, in years when further draft is required, the remaining storage in both reservoirs would be drafted. Such a strategy would tend to reduce firm energy slightly, but would increase energy production in most years. Pages 302-309 of reference (23) discuss the regulation of multiple reservoirs with no at-site power.

(13) Two Equal Reservoirs in Parallel (Unequal Inflow). Assume again that there are two identical reservoirs in parallel, both with at-site power, but that the inflow at Reservoir D is half of the inflow at Reservoir C (Figure 5-58). The same draft would be required at each reservoir to meet a given increment of generation. However, because of the smaller inflow at Reservoir D, the generation loss in subsequent months due to loss in head will be less than the loss at Reservoir C. Hence, Reservoir D has a lower storage effectiveness index (0.59) than Reservoir C (0.99) and would be drafted first (Case 4, Appendix L).

(14) Two Reservoirs of Different Slope in Parallel. Assume in this case that there are two reservoirs of equal storage (200,000 AF) located in parallel, but Reservoir E has a steep storage-elevation curve, while Reservoir F has a flat storage-elevation curve (Figures 5-59 and L-1). The heads at full pool are assumed to be 150 feet at Reservoir E and and 50 feet at Reservoir F. Assume that both have at-site power and that both have identical inflows (1000 cfs). Because of the greater head, less draft will be required to produce a given increment of generation at Reservoir E than at Reservoir F (Case 5,

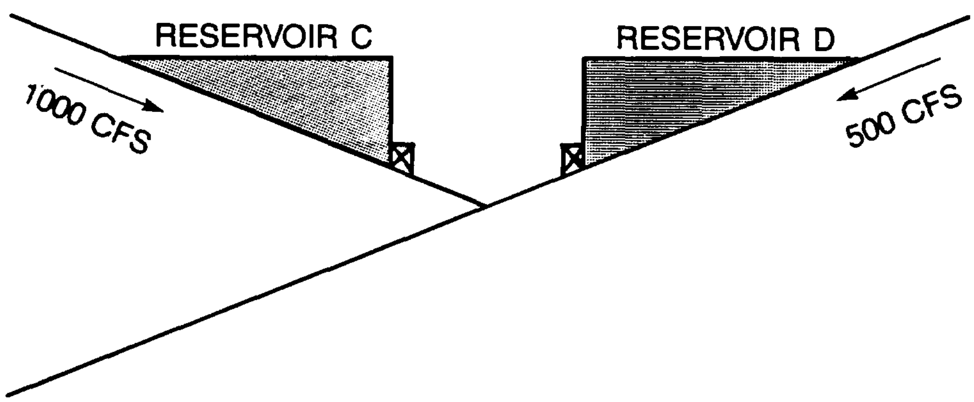


Figure 5-58. Two identical reservoirs in parallel with unequal inflow (Case 4)

Appendix L). However, because of the steeper storage-elevation relationship, Reservoir E incurs about the same amount of head loss as Reservoir F. Even though the head loss is the same at both reservoirs, the energy loss in subsequent months is less at Reservoir F than at Reservoir E, because not as much storage remains to augment inflow. Hence, the storage effectiveness index at Reservoir F (0.91) is less than at Reservoir E (0.96), so Reservoir F should be drafted. However, it should be noted that the indices are relatively close.

g. Discussion of Storage Effectiveness Examples.

(1) Six different two-reservoir systems were analyzed in the previous section using the storage effectiveness concept. Other combinations could have been examined also, but the ones presented are sufficient to permit making some general statements about the optimum sequence of drafting for multiple-reservoir systems.

- reservoirs without at-site power should be drafted before reservoirs with at-site power.

- when reservoirs are located in series (tandem), the upstream reservoir should usually be drafted first.

- a flatter storage-elevation relationship tends to favor early draft.

- a lower total at-site discharge (inflow plus storage draft) over the critical drawdown period tends to favor early draft.

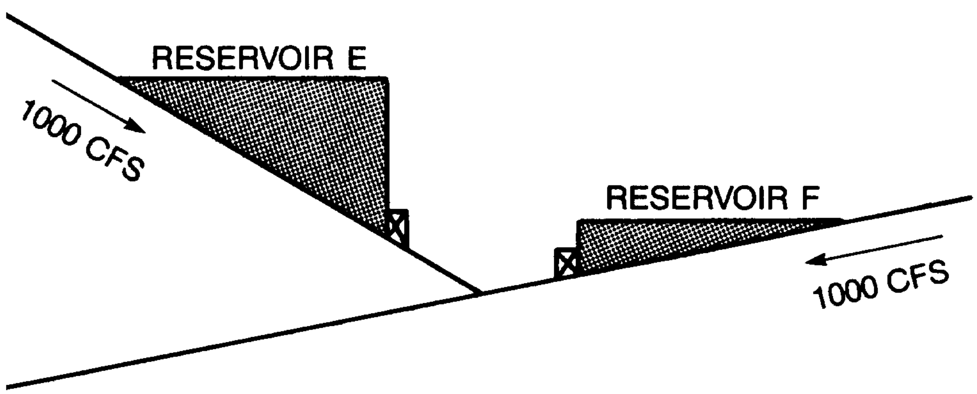


Figure 5-59. Two reservoirs of equal size but different slope in parallel (Case 5)

- a higher effective head (at-site head plus total head at downstream projects) tends to favor early draft.

(2) In many systems, however, the configuration of projects and the characteristics of reservoirs and the streams on which they are located are such that the optimum sequence of draft is not obvious. Development of a plan for regulating a system of reservoirs often requires a large number of trial-and-error iterations, and this can be accomplished effectively only with computerized SSR models.

(3) Computerized SSR models for evaluating the hydropower output of reservoir systems fall into three general categories:

- models which use some type of storage effectiveness index (although not necessarily the one described above) as the basis for selecting the reservoir(s) to draft in each time increment.

- models which run a large number of combinations of draft sequences to determine the optimum sequence (practical only for analyzing relatively simple systems only).

- models of complex existing systems, where the draft sequence is based on rule curves (which are the result of many trial-and-error iterations, augmented by actual system operating experience).

A good model is essential for reservoir system analysis, but the model can be used effectively only if the operator understands how the routings are made and how reservoirs are selected for draft. This knowledge is essential first of all to insure that the proper model has been selected and that the various projects are accurately represented in the model. Such knowledge is also necessary to permit the operator to review the output, to determine if a given routing has been done correctly, and to enable him to modify a routing to improve the system's performance.

(4) The examples discussed above are based on a single-year critical period. In systems having a multi-year critical period, some of the reservoirs may fully draft in each year, either because of flood control requirements, or because they have a relatively small proportion of storage to runoff. Others may have carry-over storage, and will not reach the bottom of the power pool until the last year of the critical period. The multi-year or "cyclical" reservoirs would have a relatively large ratio of storage volume to runoff volume compared to the annual reservoirs. The draft schedule would have to reflect the different characteristics of these two types of reservoirs.

(5) Some projects in a system may be under the control of entities which do not elect to participate in coordinated operations. These projects may have to be operated according to fixed rules rather than be operated for the benefit of the system.

(6) An additional problem that is sometimes encountered is "trapped storage." This can occur at projects where there are natural restrictions (such as the channel capacity of the outlet of a natural lake that is being regulated for power), or where there is a limited powerplant hydraulic capacity, either at the storage project or at a downstream project. At projects like this, it might not be possible to evacuate the usable power storage at the time and rate that system analysis studies determine is optimum, because the natural restrictions limit flow or because the powerplant hydraulic capacity would be exceeded and spill would occur. In such cases, it may be necessary to adjust the draft sequence to work around these constraints.

(7) The examples discussed above were all based on operating the system to maximize firm energy output. The same basic concepts could also be used to regulate a system to meet one of the other objectives described in Section 5-13, such as maximizing dependable capacity or maximizing average annual energy.

h. Multiple-Purpose Operating Considerations.

(1) The examples discussed above were also based on single-purpose power operation. In most real situations, however, the system is operated to meet other objectives as well, such as providing storage for flood control, maintaining minimum discharges for environmental purposes, and maintaining high reservoir levels in the summer months for recreation. The same basic principles as were outlined earlier in this section would be followed for a multiple-purpose system analysis except that non-power operating requirements must also be followed. The application of these requirements could lead to a completely different sequence of drafting than would be indicated by power considerations alone.

(2) In making the routings, successive iterations are often required in order to develop a viable multiple-purpose operating plan. One approach would be to first perform the reservoir drafts required to meet mandatory non-power operating requirements. If such a regulation does not in itself meet the firm energy requirements, further drafts would then be made based upon storage effectiveness criteria. In some cases, storage drafts for non-power requirements conflict with the optimum draft schedule for power. In these cases, it is usually necessary to develop operating rule curves based on a compromise between the power and non-power objectives (see Section 5-12).

i. Coordination with Other Entities.

(1) In some systems, all of the hydro plants may be under the control of a single entity, but in other systems, two or more entities may be involved. While benefits can almost always be gained through coordinated operation, in some cases these benefits may not be realized because of institutional constraints, or because of the differing operational objectives of the various entities involved in the coordination. Where opportunities for coordinated operation exist and Federal projects would be involved, Corps field offices should explore such possibilities, in the interest of increasing both project and system NED benefits.

(2) An example of a system where such coordination has been achieved is the Columbia River power system. The Federal government controls a large share of the power storage, either through direct ownership of the reservoirs, or through the Columbia River Treaty with Canada. However, some of the storage is controlled by non-Federal entities. The mainstem run-of-river projects, where most of the system's energy is produced, are also divided between Federal and non-Federal ownership. Altogether, 18 different entities are involved, including three Federal agencies and the British Columbia Hydro Authority (representing the Canadian government), and 14 electric power utilities. Coordination of the seasonal operation of the storage projects is achieved through the Pacific Northwest Coordination Agreement (among the various U.S. entities), and the Columbia River Treaty (between the United States and Canada). The hourly operation of the Grand Coulee storage project and the chain of six pondage projects located immediately downstream is coordinated through another operating agreement. Although the development and implementation of these agreements has not been without its problems, the overall operation has been very successful. It should be noted that the system is operated to provide flood control, navigation, irrigation, fish and wildlife, and recreation benefits in addition to power production. Section M-8 of Appendix M briefly describes the Columbia River power system, and references (2), (30), (85), and papers in references (19) and (34) describe various aspects of the operational agreements.

j. Sources of Further Information.

(1) References (19), (34), and (52) provide further information on the analyses of power systems. Reference (19) also includes an extensive bibliography. Additional references may be found in the proceedings of the American Society of Civil Engineers and the Institute of Electrical and Electronic Engineers, and in the journal Water Power and Dam Construction (formerly Water Power).

(2) Most of the SSR models described in Appendix C have system analysis capabilities. The documentation of these models provides some insight into the system analysis techniques used in each. For example, Appendix K contains a brief description of the techniques used by HEC-5 to make system power studies. The analysts responsible for operating and maintaining these models can provide further assistance on system analysis techniques and on the application of their respective models to power system problems.

(3) The field offices of the agencies responsible for operating the major hydropower and multiple-purpose reservoir systems in the United States would be additional sources of information. Table 5-11 provides a listing of some of these systems, and a brief discussion of the characteristics of these systems is included in Appendix M. Special attention should be given to those systems that most closely resemble the hydrologic characteristics and operating objectives of the system being studied.

(4) In addition, the Hydrologic Engineering Center is capable of assisting Corps field offices in system analysis problems, and both North Pacific Division and Southwestern Division have experience in applying their models to the analysis of systems outside of their geographic area of responsibility. Because of the complexity of system analysis and the fact that development of effective operating rules is to some extent an art, field offices are encouraged to consult with those who are experienced in working with these problems.

k. Examples of Existing Hydropower Systems. Table 5-11 lists eight major existing water resources systems which are regulated for multiple purposes including hydropower. A description of the individual system characteristics and operating criteria for most of these systems is presented in Appendix M.

5-15. Hybrid Method.

a. Introduction. The hybrid method is designed to examine the addition of power at projects where head varies independently of streamflow, but there is no regulation of seasonal storage for hydropower. Examples would be a flood control reservoir or a storage project where the conservation storage is regulated entirely for non-power purposes. The hybrid method does the power computations sequentially and then arrays the results in duration curve format for further analysis.

b. Data Requirements. Data requirements (Table 5-12) would be essentially the same as for the flow-duration curve method except that daily values of reservoir elevation must be provided in addition to

TABLE 5-11
Major Existing Water Resources Systems in the United States
Regulated for Multiple Purposes Including Hydropower

System	Area
South Atlantic	Georgia, Alabama, Florida, South Carolina
Cumberland River	Kentucky, Tennessee
Tennessee River	Tennessee, North Carolina, Georgia, Alabama, Kentucky
Arkansas-White Rivers	Oklahoma, Arkansas, Missouri
Mainstem Missouri River	Montana, North Dakota, South Dakota, Nebraska
Colorado River	Colorado, Wyoming, Utah, Arizona, California, Nevada, New Mexico
Central Valley Project	California
Columbia River	Montana, Idaho, Washington, Oregon

daily streamflow values. This data could be obtained from USGS records, project operating records, or from system regulation models such as SUPER. As with the flow-duration method, daily data would be used in most cases.

c. Methodology. Basically, the method involves computing the project's power output day-by-day for the period of record using sequential streamflows and reservoir (forebay) elevations obtained from the historical record or a regulation model. The procedure followed is essentially the same as that described in Section 5-9. The results are then arranged in power-duration curve format, either for the year or for specified months or seasons. Normally, computations would be made both for specified power installations and without the constraint of a specified plant size. The results can then be plotted to show what portion of the site's energy potential is developed by the specified power installation (Figure 5-60). With DURAPLOT, the turbine characteristics (minimum and maximum heads and

TABLE 5-12
Summary of Data Reguirements for Hybrid Method

Input Data	Paragraph 1/	Data Required
Routing interval	5-6b	daily time interval
Streamflow data	5-6c	historical records or SSR regulations
Minimum length of record	5-6d	30 years or representative period
Streamflow losses		
Consumptive	5-6e	normally included in streamflows
Nonconsumptive	5-6e	see Section 4-5h (4) thru (10)
Reservoir characteristics	5-6f	use (a) elevation vs. discharge curve, (b) fixed elevation, or (c) data from historical records or SSR regulation
Tailwater data	5-6g	tailwater curve or fixed value
Installed capacity	5-6h	can specify capacity or let model determine plant size
Turbine characteristics	5-6i	specify maximum and minimum discharges and maximum and minimum heads
KW/cfs table	5-6j	not used
Efficiency	5-6k	fixed efficiency or efficiency curve
Head losses	5-6l	use fixed value or head loss vs. discharge curve
Non-power operating criteria	5-6m	use flow data which incorporates these criteria
Channel routing	5-6n	not required
Generation requirements	5-6o	not required

1/ For more detailed information on specific data requirements, refer to the paragraphs listed in this column.

minimum and maximum discharges) can be specified, and the program will automatically select the proper plant size.

d. Models. North Pacific Division's DURAPLOT is the only specifically designed hybrid model currently being used in the Corps. It is described in Section C-4b of Appendix C.

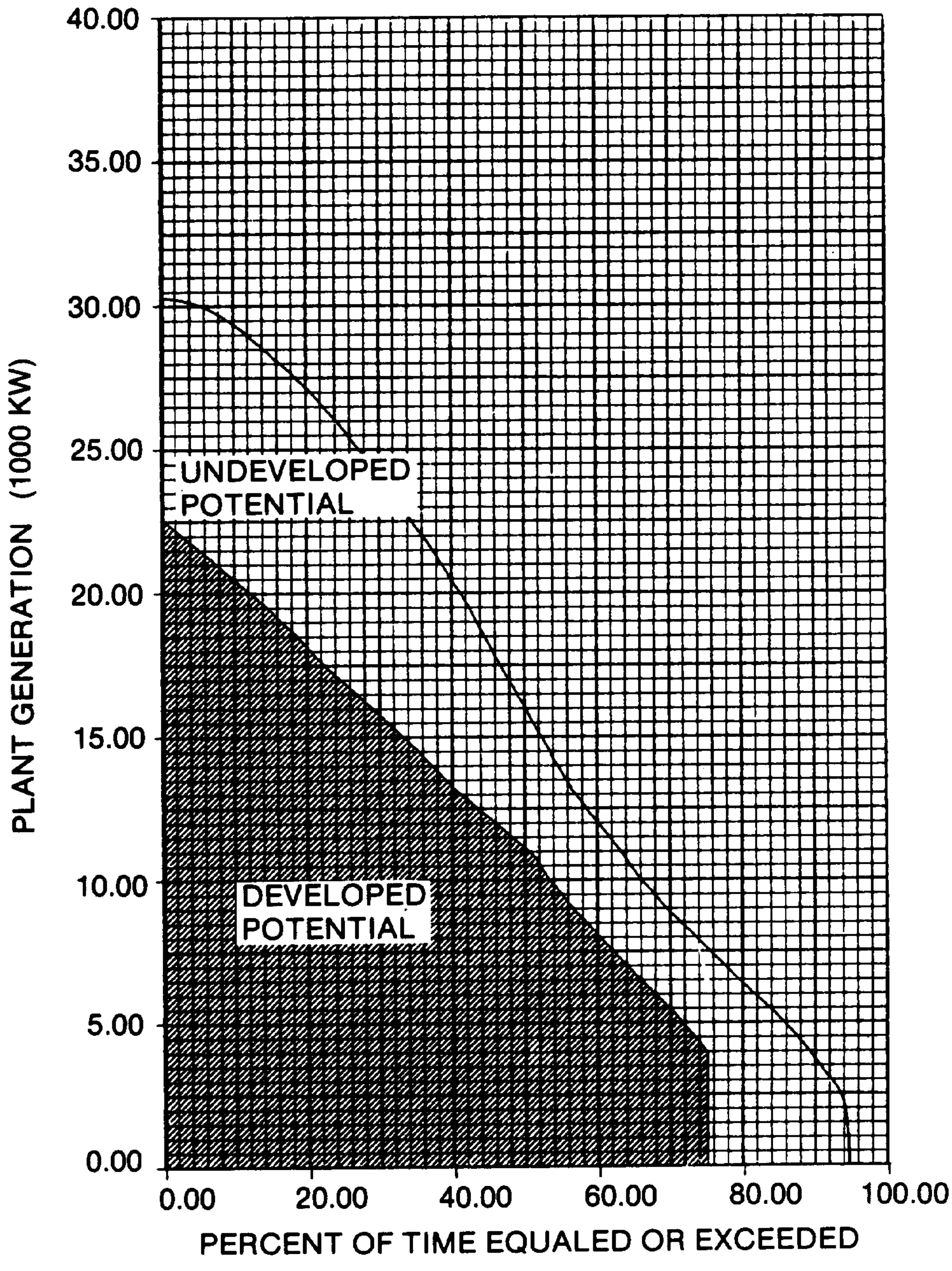


Figure 5-60. Annual power-duration curve from DURAPLOT model showing total energy potential and energy developed by 22.5 MW plant

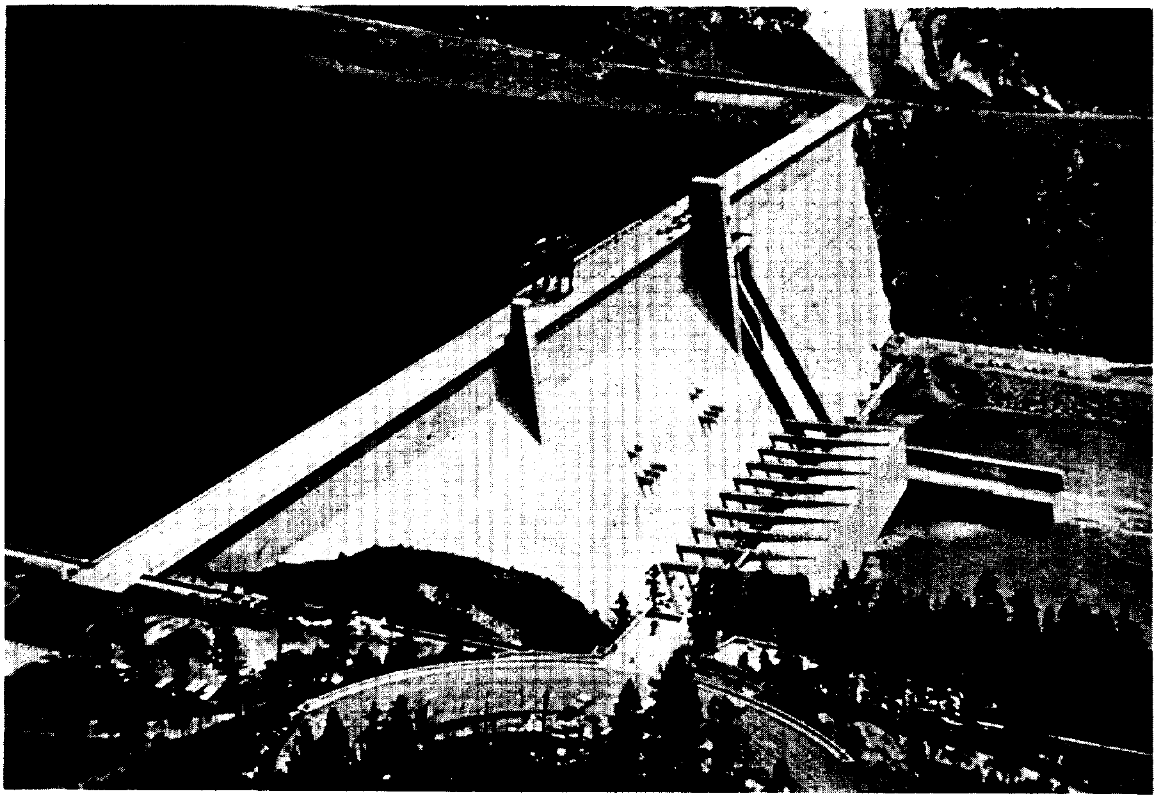


Figure 5-61. Libby Dam and Lake Koocanusa, the Corps of Engineers' largest storage project, with 4,980,000 AF of joint-use storage regulated for hydropower, flood control, and other purposes (Seattle District)

CHAPTER 6

POWERPLANT SIZING

6-1. Introduction.

a. Purpose and Scope.

(1) Once the approximate energy potential of a proposed hydropower site has been estimated, the next step is to identify a range of plant size and operating options. If alternative development configurations (dam heights, reservoir capacities, project layouts, etc.) are being considered at a site, a range of plant sizes would be developed for each. The range of plant sizes to be considered may be influenced by power system requirements and marketability considerations, environmental factors, physical constraints, and non-power operating constraints. The purpose of this chapter is to outline how these factors are to be evaluated in selecting a viable range of alternative installations at a given site.

(2) This chapter discusses the key steps and tools available for conducting a powerplant sizing analysis. Sections are also devoted to procedures for establishing dependable capacity, methods for improving the dependability of hydro capacity, procedures for determining the appropriate number and size of units for a given total plant capacity, and the use of hourly operation studies.

(3) Economic analysis plays a key role in the selection of the best plant size from a range of alternatives. Chapter 9 describes procedures used for economic evaluation of hydropower projects, with Section 9-8c illustrating several typical examples of plant sizing.

b. Definitions.

(1) General. Basic to the powerplant sizing process is an understanding of the various terms relating to capacity.

(2) Rated Capacity. The rated capacity of a generating unit is the capacity that it is designed to deliver. As discussed in Section 5-5c, the range of operating conditions within which a unit must operate is specified, and a turbine design is selected which best meets these requirements. This design is specified in terms of rated characteristics: that is, the turbine must produce its rated output (in horsepower) at a given head, discharge, and efficiency. A generator is selected to match that turbine output (Section 5-5g), and the corresponding generator output (in kilowatts) is called the

generator rated capacity. The turbine and generator suppliers affix nameplates specifying the rated output of the machines to the generator barrel or some other suitable location. Hence, rated capacity is sometimes called "nameplate" capacity. From the standpoint of the planner, the rated capacity is useful as the nominal output of the generating units. However, because of tailwater encroachment and other factors, the aggregate rated capacity is not necessarily the maximum output which the project can deliver, nor the value upon which capacity benefits are based.

(3) Overload Capacity. Overload capacity refers to the level of output that a generator can deliver in excess of rated capacity under specified conditions. In the past, generators at Corps projects were typically purchased with an overload capacity 15 percent greater than rated or nameplate capacity. This term has caused some confusion because, at many projects, the units were intended to operate on a regular basis at overload capacity, and in order to accomplish this effectively, the generators were matched to the turbines at overload capacity. Thus the units were in reality "rated" at overload capacity, so the term "overload" lost its significance. In order to clear up this confusion, and to be consistent with industry standards, the practice of specifying dual ratings has been discontinued by the Corps of Engineers. Generator nameplate ratings are now the 100 percent duty ratings, and no additional overload capability is specified. When doing studies which involve older units or powerplants, the existence of these dual ratings must be recognized.

(4) Installed Capacity. The nominal capacity of a powerplant is sometimes called its installed capacity. The installed capacity is usually the aggregate of the rated (or nameplate) capacities of all of the units in the plant.

(5) Peaking Capacity. Peaking capacity is the maximum capacity that can actually be achieved by a powerplant, allowing for the head loss that sometimes results due to high tailwater elevation when the plant is operating at maximum discharge (hydraulic capacity). Peaking capacity is also sometimes called peaking capability.

(6) Dependable Capacity. Dependable capacity is intended to measure the amount of capacity that a powerplant can reliably contribute towards meeting system peak power demands. It has been traditionally defined as the load-carrying ability of a powerplant under adverse load and flow conditions. In computing power benefits, dependable capacity is intended to provide a measure of the amount of thermal generating capacity that would be displaced by a hydro plant. The way in which dependable capacity is computed varies with the type of project and the system in which it would operate. Section 6-7 describes the various procedures for estimating dependable capacity.

(7) Sustained Peaking Capacity. This term describes the amount of peaking capacity that a hydro plant can carry effectively in the load: that is, peaking capacity is usable only if it is supported by sufficient energy to permit it to carry an increment of load. A project's sustained peaking capacity can be defined, for example, as the amount of capacity available for meeting a specified daily (or weekly) load shape (see Section 6-7i). Sustained peaking capacity is sometimes used to define a project's dependable capacity.

(8) Hydraulic Capacity. This is the maximum flow which a hydroelectric plant can use for power generation. Hydraulic capacity varies with head, and is a maximum at rated head. Above rated head, it is limited by generator capacity, and below rated head it is limited by the full gate discharge at that head. A plant's nominal or "design" hydraulic capacity usually corresponds to output at rated head. Some older plants have turbines rated at different heads, and in these cases, the nominal hydraulic capacity would be the maximum discharge at the head that represents the average of the various rated heads.

(9) Plant Factor. Plant factor is the ratio of the average load on a plant for the time period being considered to its aggregate rated capacity (installed capacity). For example, the average annual plant factor would be defined as follows:

$$\text{Annual plant factor} = \frac{(\text{Average annual energy})}{(8760)(\text{Installed capacity})} \qquad (\text{Eq. 6-1})$$

where the average annual energy is expressed in kilowatt-hours and the installed capacity is in kilowatts. Plant factors are usually based on the plant's aggregate rated capacity, but it is sometimes more meaningful to base it on the plant's actual peaking capability.

(10) Capacity Factor. Capacity factor is similar to plant factor but is a more general term. It can be applied to an individual unit, a plant, or even the total resource capability of a system.

6-2. Procedure for Sizing Powerplants.

a. General. The plant sizing procedure is an iterative process, and the exact sequence of steps followed will depend on the stage of study and the characteristics of the project. A reconnaissance analysis might consider only a single plant size, perhaps based on a typical plant factor. If the site study proceeds to the feasibility stage, the analysis would be extended to a range of alternatives in order to identify the most economical plant size. This analysis would also consider the physical, environmental, operational, and marketability factors that might limit the range of viable installations.

b. Basic Steps.

(1) The hydro plant sizing process follows the general planning procedures outlined in the Planning Guidance Notebook (49). However, within this framework, the following specific steps can be applied to the selection of a power installation (see also Figure 1-1). Note that this procedure refers only to selecting the proper power installation for a given project configuration. Paragraph 6-2c describes how plant sizing would be superimposed on an analysis where alternative dam sites, reservoir sizes, operating plans, or other variables are being considered as well.

- make a preliminary estimate of the project's energy output using either a typical plant size or without being constrained by plant size (Chapter 5).
- determine the type (or types) of power generation which are needed in the system and which could be provided by the project (Section 6-3).
- on the basis of the preceding steps, select a range of power installations (Section 6-6).
- select number and size(s) of generating units for each plant size (Section 6-6f).
- recompute energy output for each installation to reflect limits established by plant size (Chapter 5).
- identify physical constraints, environmental constraints, and non-power operating considerations which could limit power operation (Sections 6-4 and 6-5).
- make hourly operation studies, if necessary, to determine if the desired power output can be achieved within environmental or non-power operating constraints (Section 6-9).
- consider measures such as increased pondage, provision of a reregulating dam, or installation of reversible units to increase dependability of capacity (Section 6-8).

- determine dependable capacity for each plan (Section 6-7).

- compute capacity and energy benefits for each plan (Chapter 9).

- on the basis of the net benefit analysis and other considerations, select the best plant size.

(2) Not all of the steps in this outline need to be considered for all projects. For example, hourly operation studies would not be required for a run-of-river project with no pondage. A detailed analysis of size and number of units would be made in feasibility studies only if it would have a significant impact on power output. The order of the steps is also intended to provide only general guidance. Plant sizing is an iterative process, and some steps may have to be performed several times before the best plan is identified. The remaining sections of this chapter discuss in detail the steps included in the outline. Section 9-8c illustrates some examples of net benefit analysis where plant sizing is involved.

c. Treatment of Multiple Alternatives.

(1) The preceding outline refers to the examination of alternative plant sizes for a given project configuration. At most new projects, other options may be available, such as alternative dam heights, reservoir sizes, dam sites or project layouts, and combinations of project purposes. Each of these possibilities increases the total number of alternative plans that are possible.

(2) The Planning Guidance Notebook (49) describes the general approach to be followed when examining projects having a complex array of alternatives. However, the general approach described in Section 6-2b would still be followed in order to identify the optimum plant size for each alternative plan. For example, it might be desirable to examine a range of plant sizes for each of a series of alternative dam heights (see Table 6-1). Costs and benefits would be computed for each combination of dam height and plant size, and a matrix would be constructed to permit selection of the best plan.

(3) If three or more variables are considered, the number of alternative plans to be studied becomes very large, and it may be difficult to justify the cost of studying all of the alternatives in detail. The number of alternatives can usually be reduced to a viable number through preliminary screening studies or through initial examination of a few of the "most likely" development plans. In this way, it may be possible to direct the study to the alternatives that have the greatest net benefits.

TABLE 6-1
Matrix of Alternative Plant Sizes Considered
for the Bradley Lake Project, Alaska 1/

Top of Power Pool	60 Percent Plant Factor	40 Percent Plant Factor	20 Percent Plant Factor
El. 1160	59.7 MW	86.8 MW	132.5 MW
El. 1170	60.0 MW	90.0 MW	135.0 MW
El. 1180	61.8 MW	92.8 MW	137.2 MW
El. 1190	63.8 MW	95.7 MW	139.4 MW
El. 1200	65.7 MW	98.5 MW	141.7 MW
El. 1210	67.6 MW	101.5 MW	143.9 MW

1/ A proposed seasonal storage project, which would be regulated to maximize firm energy

6-3. Power System Requirements and Marketability Considerations.

a. General.

(1) A key step in scoping a hydropower project is identifying the different ways in which a plant could be used in the local power system. This consists of analyzing the power system in terms of (a) loads and expected load growth, (b) daily, weekly and seasonal load shapes, and (c) existing and planned generating resources, in order to determine what types of generation will be needed in future years. This information would then be correlated with the characteristics of the hydro site in order to determine what type(s) of generation the project could provide.

(2) The load-resource studies described in Chapter 3 would serve as the starting point for such an analysis. The regional Power Marketing Administration (PMA) can often provide information on the types of generation that will be needed, timing of the need for such generation, and related data (Section 3-5c). Assistance can also be obtained in many cases from the regional FERC office or the power

pool serving the area. Close coordination should be maintained with these offices throughout the planning process. Once the recommended plant size is selected, the PMA will conduct its marketability analysis to verify that the type of power that the project will deliver is usable in the power system (Section 3-12).

b. Operating Modes.

(1) General. Marketability criteria are usually related to the type of load a project is intended to carry. Plants may be described as base load, intermediate, or peaking, depending on what portion of the load they carry (Figure 6-1).

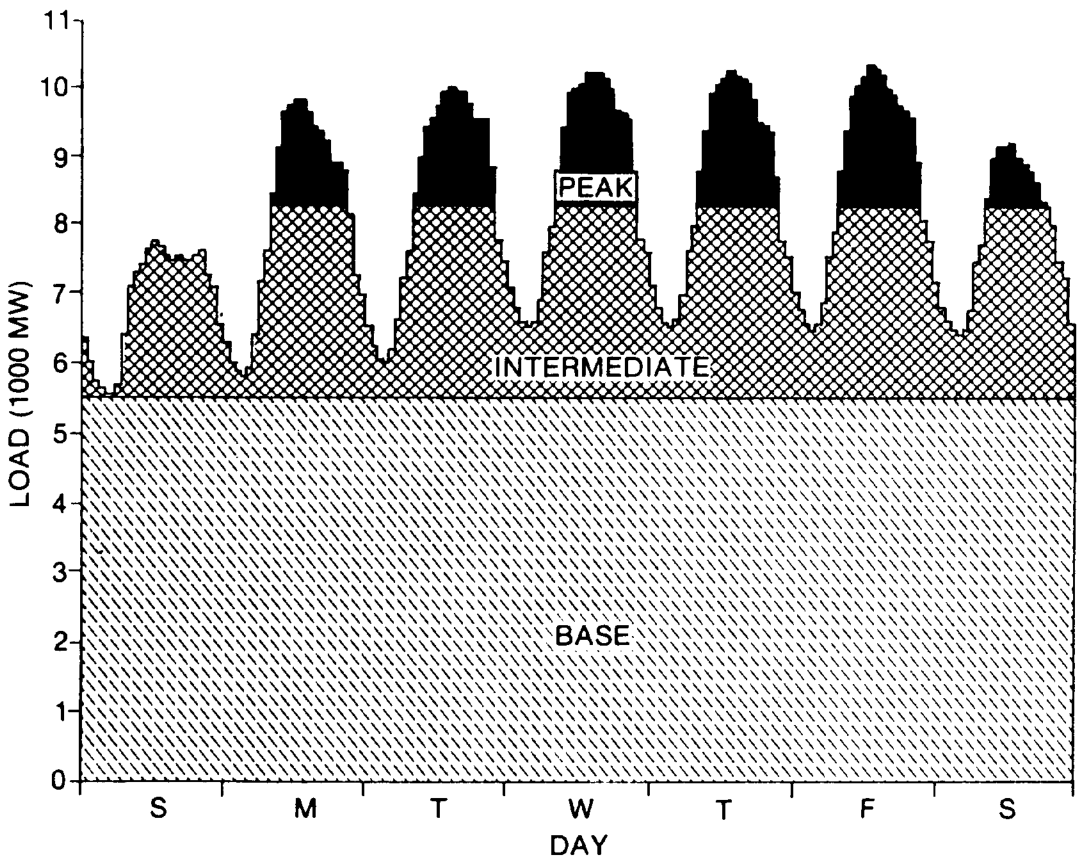


Figure 6-1. Weekly load shape showing load types

(2) Base Load Operation. Base load refers to the minimum load in a time period and is often used to describe the portion of the power demand that occurs 24 hours a day. Base load plants operate primarily in that mode, although some hour-to-hour variation in output occurs at many base load plants.

(3) Base Load Plant Factors. Base load plants are sometimes called energy plants because their major role is to provide energy rather than capacity. Typically, a plant is considered a base load plant if its average annual plant factor exceeds 50 percent. The annual plant factor includes down time for scheduled maintenance and forced outages (Section 0-2d). It also reflects the fact that, in many systems, base load plants seldom operate at full output because some of their capacity must be allocated to spinning reserve. In addition, system loads seldom require all base load plants to operate at full output at all times (plants COAL-1 and COAL-3 in Figure 2-9, for example). Thus, some "base load" plants may have plant factors as low as 40 percent.

(4) Use of Hydro Plants for Carrying Base Load. Hydro plants may be used for base load service in systems where hydropower is a major resource, but in thermal-based power systems, the preferred role for hydropower is carrying intermediate or peaking loads. However, some hydro plants may be assigned to base load operation because either (a) storage is not available to permit hourly shaping of power releases to follow power demand, or (b) because downstream flow requirements do not permit hourly variations in discharge. At many hydro plants, minimum downstream flow requirements result in a portion of the plant's output being allocated to base load operation.

(5) Intermediate Load. The intermediate load is that part of the load that occurs 9 to 14 hours per day. The Powerplant and Industrial Fuel Use Act of 1978 defines intermediate plants as those plants that operate between 1,500 and 4,000 hours per year, so hydro plant intended for intermediate load operation would be expected to have a plant factor in the 17 to 40 percent range. It might operate for 14, 20, or even 24 hours a day at full output during high load periods, and a fewer number of hours (often at reduced output), at other times. Water availability has a major effect on the type of load the project can carry at any given time. Daily or weekly pondage is needed to permit shaping of flows to meet the hourly power demand pattern. Because the intermediate load is difficult to carry economically with thermal plants, hydro is frequently called upon to operate in this mode. Many of the major hydro plants in the United States can be classified as intermediate load plants.

(6) Peak Load. The peak portion of the load is that part which is above the intermediate load (Figure 6-1) and which extends for less

than 8 hours per day. Pure peaking plants may have average annual plant factors of up to about 17 percent. A typical peaking plant may be required to operate 4 to 8 hours per day at full output during high demand periods and for shorter periods or at reduced output for the remainder of the time. Some thermal peaking plants may operate very little or not at all during the low demand season, serving mainly as reserve generation. A number of hydro plants in the United States serve primarily as peaking plants, and are designed to provide firm (critical period) peaking capacity in the 5 to 20 percent annual plant factor range. During periods of higher flows, the additional energy can be used either to extend the hours of peak load generation or to displace thermal generation. As with the intermediate load plants, pondage is required to shape streamflows to fit the peak load demand pattern.

(7) Reserve Capacity. A power system is required to provide reserve generating capacity in excess of forecasted peak loads. This insures that loads will be met if they are higher than anticipated or if some plants are shut down because of forced (unscheduled) outages (see Section 2-2e). Typically, an operating reserve margin of 5 to 10 percent is provided in excess of system peak loads. Some of this generation must be spinning reserve (generating units operating at partial or zero loading), and some must be ready reserve (units capable of being brought on-line in a manner of minutes).

(8) Hydro as Reserve Capacity. Hydro performs very well in both of these roles because of its quick start capability and its ability to respond rapidly to changing loads. As a result, hydro capacity can often be credited with reserve capability whenever it is not carrying load. Hydro has some limitations, however. If only limited pondage or storage is available at-site or immediately upstream, the reserve capacity must be considered available only for short-term emergency operation. At some projects, operating restrictions may limit the rate at which load can be picked up, thus reducing the usefulness of the generation for reserve purposes.

(9) Economic Limitations on Hydro as Reserve Capacity. Typically, generation provided exclusively to maintain system reserve requirements operates at an average annual plant factor of less than five percent. Because of the relatively low cost of providing combustion turbine capacity to fill this role, it is seldom feasible to construct highly capital-intensive hydro generation solely for reserve purposes. However, future fuel costs and availability may alter this situation. In the Pacific Northwest, skeleton bays were provided at some projects for future units, and most of these units have now been installed. The cost of these additional units has been low enough that it has been feasible to allocate some of this capacity to system operating reserve. This capacity is used to provide both

short term operating reserves to cover for temporary outages, and long term energy reserves to cover for thermal plants which are shut down for extended outages.

(10) Energy Displacement. A hydro project may have considerable benefit in some power systems even though the project's capacity may not be dependable for meeting peak loads. This would occur in systems with a considerable amount of high cost oil- or gas-fired generation, where the hydro project's output would be used to displace output from existing thermal plants, rather than defer the construction of future plants (see Section 9-6).

(11) Combinations. Some hydro projects operate exclusively in one load-carrying mode, but many projects operate in two or more modes. For example, many hydro projects in the Pacific Northwest and Alaska must carry a share of the entire system load, base load as well as intermediate and peaking load. At other projects, part of the generation must be assigned to base load operation in order to maintain minimum downstream flows, while the remainder may be used for peaking or intermediate load operation. Some projects may operate in the peaking mode during low flow periods and produce intermediate or base load power in high flow periods. Many "peaking" projects actually carry both intermediate and peak loads much of the time, and some plants may have a portion of their capacity assigned to system reserve during much of the year. The capability of individual projects to carry different types of loads depends on marketing considerations, water availability, and non-power operating constraints.

(12) Improvement of System Power Factor. Hydro units can also be used as synchronous condensers in order to improve system power factor. When operating in this mode, the wicket gates are closed and the unit is motored "in the dry," adding inductive reactance to the system. This operation offsets transmission line capacitive reactance, improving system power factor and permitting the lines to carry more real power. Most hydro units can be motored if the runner is above tailwater. If the runner setting is below tailwater, a water depression system must be provided. These systems rapidly inject large quantities of compressed air into the draft tube, forcing the water level below the bottom of the turbine runner and permitting the unit to rotate with less resistance. Units would be operated to improve system power factor only when the capacity is not required to meet load.

c. Other Considerations.

(1) A number of other factors must often be considered when evaluating the types of power which a hydro project might be designed

to deliver. Although some of these factors are discussed below, others may only be identified in the course of coordination with the marketing agency.

(2) Seasonality of Output and Demand. Both the demand for power and the generation available from a hydro plant vary with season. Hydropower is most valuable if it can be produced when it is most needed. For example, a hydro plant's output may be highly marketable if a substantial portion of its output is produced in the peak load months, even though little or no power is produced during the remainder of the year. Correspondingly, a hydro project may have little value as a peaking project if its output is limited during the high demand period, even though the capacity is dependable throughout the remainder of the year. A project of the latter type might best be evaluated as an energy displacement project. Seasonality considerations will ultimately be reflected in the project's power benefits through the measurement of dependable capacity and, to a lesser extent, the energy benefits (through the energy value adjustment, Section 9-5e). However, time and effort can often be saved if seasonal characteristics are evaluated early in the planning process.

(3) Dependability of Capacity. Dependability of capacity and its impact on economic benefits is discussed in Section 6-7. In some cases, marketing criteria may be imposed on capacity in order for it to be considered dependable. An example would be a required quantity of firm energy per kilowatt of capacity (see Section 6-7e).

(4) Marketability of Secondary Energy. Some hydro projects may be capable of producing substantial amounts of secondary energy in good water years, particularly at certain times of the year (see Section 5-2d). The desirability of sizing a powerplant to capture this energy is dependent on the availability of a market and on the value of such power. In most large thermal-based power systems, all energy can be readily assimilated in the load, and it is seldom necessary to distinguish between firm and secondary energy.

(5) Limitation on Marketability of Secondary Energy. In hydro-based power systems, there is often a limitation on the amount of secondary energy that can be used in the load, especially during periods of high runoff. This should be recognized in the estimate of energy for which benefits are claimed. This type of limitation could be illustrated by considering a relatively large hydro project in an isolated system, where secondary generation is concentrated in the low demand months -- a situation that could easily occur in Alaska, for example. In cases such as this, secondary energy benefits may be limited, or even nonexistent. Similarly, in the Pacific Northwest, secondary energy generated in the spring months may have limited value in high runoff years. On the other hand, secondary energy may have

high value if it is produced during high demand periods or if it can be exported to adjacent thermal-based power systems. In systems where large amounts of secondary energy are available, interruptible load markets may be developed or transmission lines may be constructed to transfer this energy to power systems where it has high value.

(6) Transmission Costs and Losses. The location of a hydro project with respect to the power system's load centers and existing generating resources and transmission lines may affect the hydro plant's feasibility. Generally, the effects of location will be reflected in the magnitude of the transmission costs and losses incurred in bringing the hydro project's output to the market (Section 9-5g). However, there may be some additional system flexibility benefits realized by projects located at favorable locations within the regional power grid (Section 6-71).

6-4. Physical Constraints.

a. Frequently, physical factors establish constraints which limit the range of power installations that can be considered. These factors can be particularly severe in the case of adding power to existing non-power projects. Some of the physical factors that could limit plant size are listed below:

- lack of space for the powerhouse
- limitations on forebay storage (pondage) available for shaping flow to follow demand pattern
- limited downstream channel capacity, which creates excessive tailwater rise for large power installations
- limited tunnel capacity where an existing regulating outlet is used as the power tunnel
- head range exceeds the practical operating range of a single turbine runner design (Section 5-5b(3)).

b. While some physical constraints serve as absolute limits, in other cases they serve to stimulate creative engineering to adapt the site to power generation. Examples of designs to circumvent physical limitations include (a) use of the powerhouse as part of an emergency spillway structure, (b) incorporation of a powerhouse in a regulating outlet structure, (c) increasing dam height to increase pondage and/or generating head, and (d) use of interchangeable turbine runners to utilize large head range.

6-5. Environmental and Non-Power Operating Constraints.

a. Types of Constraints. Environmental considerations and non-power river uses may result in the establishment of operating constraints which could limit the size or operation of hydro plants. Some of these limitations are:

- minimum discharges for navigation, water quality, fish and wildlife, recreation, etc.

- flood control regulation

- storage releases for water supply, irrigation, navigation, downstream water temperature control, etc.

- daily and hourly discharge fluctuation limits to protect navigation, recreation, and fish and wildlife, and to prevent bank erosion

- maximum discharge limits to prevent flooding and bank erosion (due to power operation) and to facilitate upstream fish migration

- limitations on pool fluctuation to protect navigation, irrigation pumping, riparian vegetation, fish spawning, waterfowl nesting, recreational use of shorelands, etc.

- forced spill to enhance downstream fish migration or to improve water quality

- fixed release schedules to improve conditions for fishing or white water rafting

When power is being added at an existing non-power project, it is common to find that operating limits already exist. It is also possible to find that limits exist on open reaches where new projects are being considered. In other cases, however, limits may not exist at the time power studies are initiated, but would be implemented concurrently with the installation of the power facilities, in order to insure that environmental factors and non-power river uses are recognized in project operation.

b. Analysis of Constraints. Information relevant to existing operating limits and the possible need for new constraints can be obtained through environmental studies, public involvement, and agency coordination. When analyzing the implementation of new operating limits or when reexamining the validity of existing limits, the value of power benefits foregone by implementing the limits should be carefully weighed against the nonpower benefits achieved. Depending on the type of constraint being examined, either seasonal or hourly operation studies (or both) may be required to analyze the impacts of operating limits on both power operation and other river uses.

c. Seasonality of Operating Constraints. Many river uses and environmental considerations are seasonal in nature, and every effort should be made to insure that operating limits are imposed only during those times of year that they will achieve the desired results. The report Seasonality of River Use, (32) is an example of data gathered to identify seasonal variations in river use on a specific stream.

d. Soft Versus Hard Constraints. To provide additional flexibility, it is sometimes possible to classify operating constraints as either "hard" or "soft" constraints. Hard constraints are those which can never be violated, while soft constraints are those which are observed in normal operation but can be violated under some circumstances. For example, a daily tailwater fluctuation limit of four feet may be observed under normal conditions, but during occasional periods of severe power demand, fluctuations of up to six feet may be permitted.

e. Reregulating Dam. Some sites might be well suited to development of hydropower for peaking, but downstream minimum flow or fluctuation constraints may limit peaking operation. In these cases, it is sometimes possible to construct a small reregulating reservoir to impound peaking discharges from the powerplant and release them more uniformly, in order to meet downstream flow criteria. The use of reregulating reservoirs is discussed in more detail in Section 6-8c.

6-6. Selection of Alternative Power Installations.

a. Introduction. As discussed in Section 6-2c, a number of scoping variables may be involved at some sites, such as alternative dam heights, alternative storage volumes, and alternative operating plans. For each of these alternatives, a range of power installations could be considered. This section discusses how a range of plant sizes would be selected for detailed study and suggests some guidelines on selection of the appropriate number and size of units for a given plant size.

b. General Considerations.

(1) In reconnaissance level studies, only a single plant size need be studied, although it may be necessary to consider several installations in order to determine if a feasible plan exists.

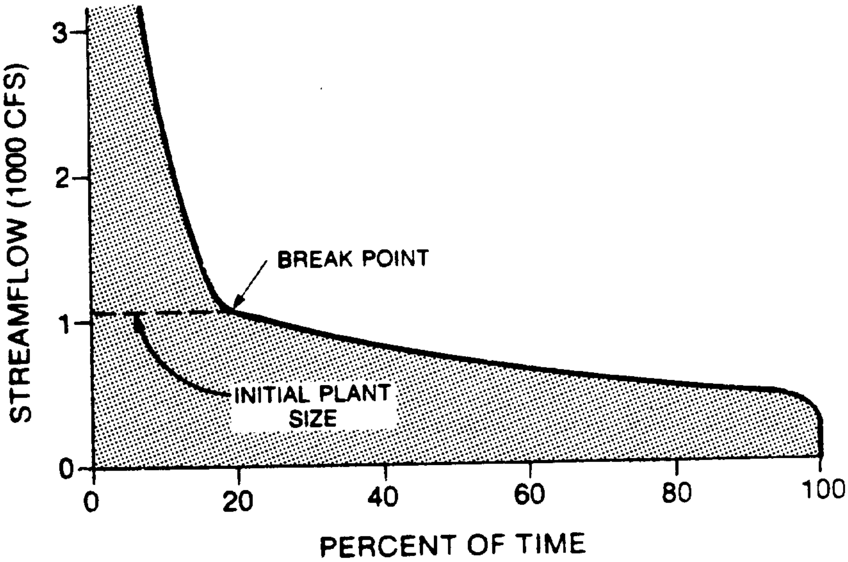


Figure 6-2. Flow-duration curve with break point

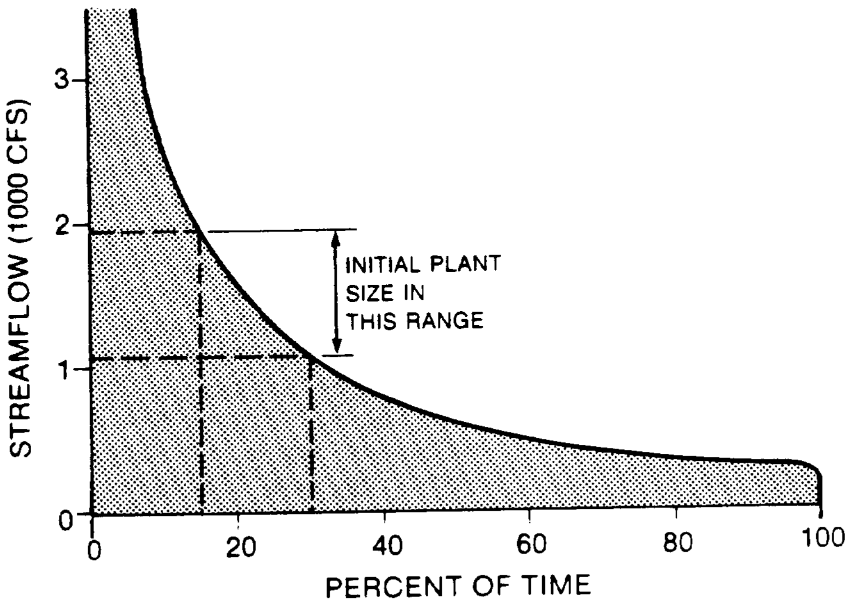


Figure 6-3. Uniform flow-duration curve

However, once a project reaches the feasibility stage, a range of plans, including alternative plant sizes, must be studied in order to determine the best development.

(2) For studies where plant size is the only variable, a minimum of three plant sizes must usually be examined in order to identify the economically optimum installation. The range of plant sizes to be studied is a function of power system requirements and the physical, environmental, and operational factors discussed in previous sections, as well as the characteristics of the project's energy output.

c. Run-of-River Projects.

(1) If no pondage or seasonal power storage is available to permit peaking or load following, or if operational considerations preclude such operation, selection of the range of plant sizes is simplified. The project would be operated in the run-of-river mode, limiting its use to base load operation or fuel displacement. An examination of the project flow-duration curve may suggest a plant size that will develop a substantial portion of the available energy (Figure 6-2). If the duration curve has no obvious break (Figure 6-3), an initial plant size can be selected based on the average annual flow or a point between 15 and 30 percent exceedance on the duration curve.

(2) Two additional plant sizes should be selected, one somewhat larger and one somewhat smaller than the initial plant size. The specific plant sizes selected will depend on the shape of the flow-duration curve, the initial plant size (selected as described in the previous paragraph), and the way the energy will be used. Small hydro installations typically optimize in the 40 to 60 percent plant factor range. Selecting plant sizes corresponding approximately to the 10 to 15, 20 to 25, and 35 to 40 percent exceedance points on the flow-duration curve will usually bracket a project in that plant factor range. If the duration curve has an unusual shape, somewhat different points might be selected. Finally, if the plant will be used to displace high cost energy from existing thermal plants (see Section 6-3b(10)), a wider range of installations should be considered. Projects with average annual plant factors as low as 20 to 40 percent will sometimes be feasible in these cases. Figure 6-4 illustrates a typical range of alternative plant sizes for a run-of-river plant which displaces new base load generation, and Figure 6-5 shows a range of sizes for a plant which displaces high cost generation from existing thermal plants.

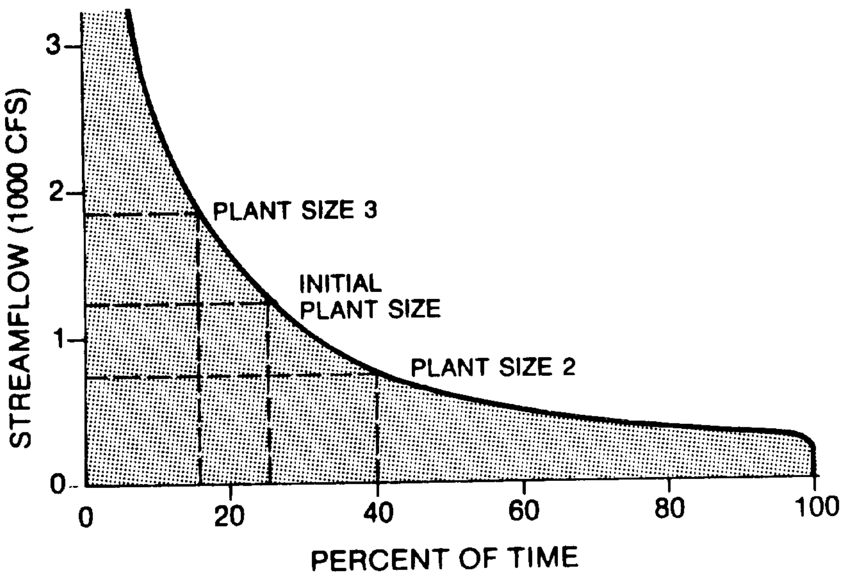


Figure 6-4. Range of plant sizes for run-of-river project used to generate base load power

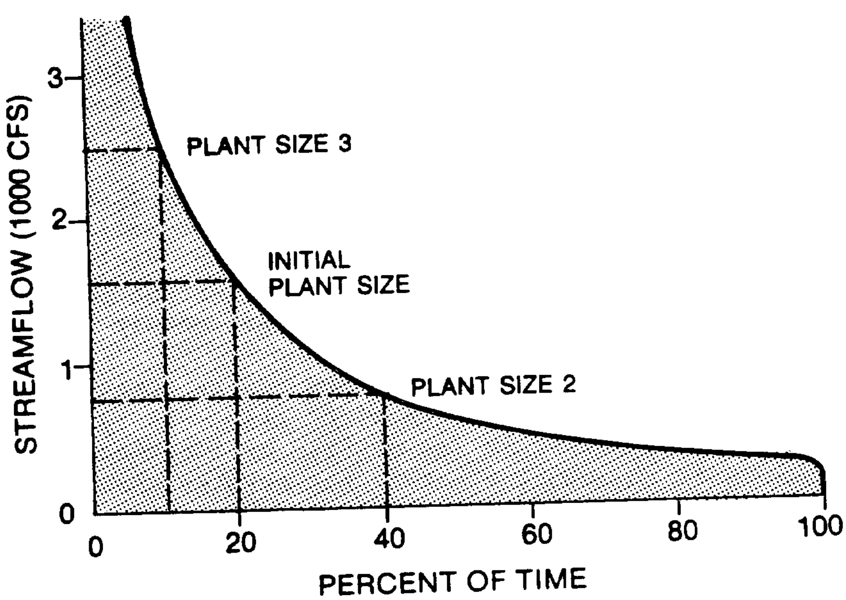


Figure 6-5. Range of plant sizes for run-of-river project used for fuel displacement

(3) The environmental impacts of adding a run-of-river powerplant to an existing dam are usually relatively minor. The only significant effect would be that water would pass through turbines instead of over a spillway or through a regulating outlet, thus possibly reducing the amount of oxygen entrained, or affecting the passage of downstream fish migrants. Likewise, run-of-river operation has little or no effect on non-power river uses and other project functions. Thus, environmental and non-power operating considerations seldom establish a limit on plant size. The construction of a new run-of-river plant would have more substantial impacts, but they would deal more with the issue of whether or not to construct the dam rather than with the size of plant to be installed.

d. Projects with Pondage or Storage.

(1) Both power marketability and impact on the environment and non-power river uses can have a major influence on the range of plant sizes that could be developed at a pondage or storage project. In the case of marketability, it is seldom practical to install more capacity than can be used effectively in the load. Likewise, operating constraints such as minimum flows and rate-of-change limits can limit the amount of capacity that can be used effectively.

(2) A preliminary indication of the maximum plant size to be considered can be obtained by doing some simplified hourly routings, based on an assumed hourly power loading and several representative weekly average flows. The hourly loadings would usually be developed in coordination with the regional PMA. If a limit exists on the amount of pondage that would be available, it should be accounted for in the routings. Cases 1 and 2 in Appendix N are examples of preliminary hand routings of this type. A computerized sequential routing model could also be used for these studies.

(3) If operating constraints such as minimum flows and a maximum rate of change of discharge exist, they should be reflected in the initial hourly studies. Power installations that violate constraints can be eliminated from further consideration (or the constraints should be examined to insure that they are not unduly restrictive).

(4) The type of service a hydro project is intended to perform usually dictates the lower limit on plant size. It is rare that a hydro plant intended primarily for peaking or intermediate load service would have an annual plant factor greater than 40 to 45 percent. However, plants intended for a combination of base load and peaking/intermediate operation could have plant factors as high as 60 percent.

(5) The considerations discussed above define the basic upper and lower limits of the range of plant sizes, and three or more plant sizes should then be selected within this range for further analysis. If the project is to be a large installation with a number of generating units, the alternative plant sizes should usually be based on multiples of a given unit size.

(6) The project described as Case 2 in Appendix N could be used to illustrate the process. It was determined that a project with a given amount of pondage is capable of a sustained peaking capacity of about 263 MW. This analysis establishes the upper limit on plant size, and it is assumed that turbine selection studies indicate that six 44 MW units would be the best installation for this plant size. From the seasonal routing studies, the average annual energy was found to be about 500,000 MWh. In this example, it will be assumed that the smallest plant size to be examined would be one based on an annual plant factor of about 45 percent, or 118.8 MW. The nearest multiple of 44 MW units would be a three-unit plant with an installed capacity of 132 MW. The third plant size would be somewhere between these two plant sizes, either a five-unit plant (220 MW), or a four-unit plant (176 MW).

(7) This example is intended only to illustrate the general approach. Different criteria may dictate the range of alternatives in different parts of the country. Selection of the range of alternatives is to some extent trial-and-error. Even when reasonable criteria are applied to identify the range, the point of maximum net benefits sometimes falls outside that range, and the analysis of an additional plant size is required.

(8) Sometimes it is necessary to select an approximate range of plant sizes early in the study, before data is available on load shapes and hourly operation studies, in order to permit initiation of preliminary project layouts and cost estimates. In these cases, it may be necessary to base the largest installation size on annual plant factor. As noted in Section 6-3b(6), some hydro peaking plants have been designed to operate at firm plant factors as low as 5 percent. However, at the present time, it is difficult for capital intensive hydro peaking projects to compete with combustion turbines in the very low plant factor range. Thus, in most parts of the country, a 10 percent firm annual plant factor would be a reasonable basis for the maximum plant size to be examined, although in the Pacific Northwest, 20 percent would be more appropriate.

e. Staged Installation. Detailed system studies may show that the role of hydropower may change substantially with time, perhaps due to a changing resource mix. For example, a hydro project may initially best be used as an intermediate load plant. Later, as loads increase and the resource mix changes, operation as a peaking plant might yield greater benefits. In such cases, staged installation should be considered, with enough capacity installed initially to handle intermediate load operation and additional units being installed at a later date to permit the project to operate in the peaking mode. In other systems, hydro may initially be scheduled for base load operation, and in later years shift to intermediate and peaking operation. Section 9-10f discusses how benefits are treated in the analysis of staged installations.

f. Size and Number of Units.

(1) In preliminary studies, it is often necessary to deal only with total plant size. However, in advanced stages of study, number and size(s) of units must be determined so that final design layout and cost estimates can be prepared and an accurate estimate of the project's energy output can be made.

(2) For a given plant size, capital costs usually increase with the number of units. Thus, the minimum number of units of the largest practicable size should result in the minimum powerhouse cost. However, identification of the best installation often requires consideration of many other factors.

(3) Following is a listing of general factors that should be considered when selecting the number of units for a given power installation.

- maximum unit size minimizes capital costs and (except for very large units) operation and maintenance costs.

- an installation consisting of units of equal size is less costly than a mix of unit sizes, in terms of both capital costs and maintenance costs.

- a mix of unit sizes may be useful where a wide range of streamflow is experienced.

- a minimum of two units may be desirable so that generation can be maintained (and energy loss minimized) when one unit is out of service.

- the number and size of units should be selected to insure that the plant will operate at a high efficiency as much of the time as possible.

- the largest turbine component that can be transported to the site using available modes sometimes establishes maximum unit size.

- cavitation considerations establish the minimum discharge at which a given turbine can operate (see Table 5-1). If a single unit is installed, considerable energy may be spilled under low flow conditions (see examples in Section 6-6g).

- the amount of space available for the powerplant may influence selection of size and number of units. This is particularly a problem when retrofitting existing dam structures.

- where a wide range of head exists, separate units to operate under different head ranges may be desirable. An alternative would be to use interchangeable turbine runners for different head ranges.

- poor foundation conditions may limit excavation depth, resulting in a larger number of smaller units.

- an even number of units sometimes permits more economical bus and auxiliary systems arrangements.

- in small power systems, large units may increase system forced outage requirements.

Some of these constraints are intended to minimize costs, and others are intended to maximize energy output or dependable capacity. Often it may be necessary to examine several combinations of numbers and sizes of units in order to determine the best choice for a given plant size.

(4) While it is important to consider all of these factors in the planning stage, it is often not possible to make the detailed studies required for selection of the optimum plant layout until the design memorandum stage.

g. Examples of Selecting Size and Number of Units.

(1) In order to illustrate some of the problems commonly encountered in selecting the best installation, a run-of-river project without pondage will be examined. For simplification, head is assumed to be constant and generation is directly proportional to flow. The plant will be designed for a hydraulic capacity of 230 cfs.

(2) Assume first that a single unit will be installed (Figure 6-6). Two points should be noted for this installation: (a) the 40 percent minimum discharge limit (92 cfs) results in a substantial amount of energy being spilled in the low flow range (the "lost energy" on Figure 6-6), and (b) energy will be spilled whenever the unit is out of service for scheduled maintenance or forced outages (about 5 percent of the time -- see Table O-1 in Appendix O).

(3) Figure 6-7 shows what would happen if two units of equal size were installed. About 15 percent more energy would be recovered in the low flow range, compared to the single unit installation, and the losses due to outages would be reduced to about 1.5 percent (5 percent of the energy output of the second unit). An additional increment of energy would be gained through an overall increase in efficiency.

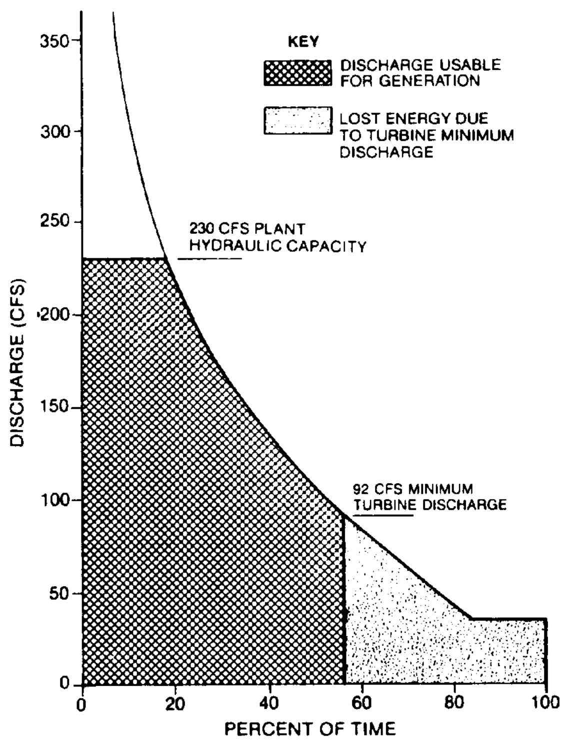


Figure 6-6. Flow-duration curve showing streamflow usable for generation: one 230 cfs unit

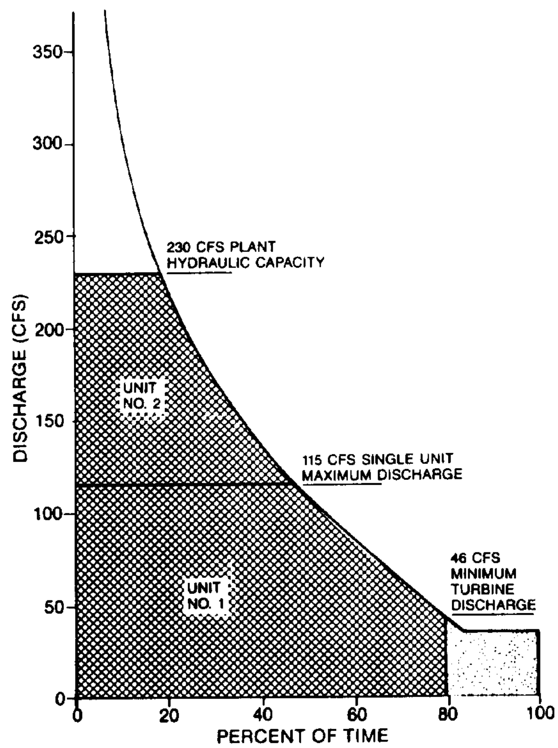


Figure 6-7. Flow-duration curve showing streamflow usable for generation: two 115 cfs units

(4) Figure 6-8 shows a two-unit plant where one unit is sized particularly to operate in the low-flow range. Energy output will be increased by an additional seven percent with this installation (compared to Figure 6-7). Losses due to forced outages will be approximately the same as Figure 6-7, but a slight increase in energy output due to increased efficiency will be realized.

(5) Figure 6-9 illustrates an installation with three units of equal size. It also will develop the full energy potential of the site at flows up to 230 cfs. Forced outage losses will be reduced to less than 1 percent, and a slight increase in overall efficiency will be obtained.

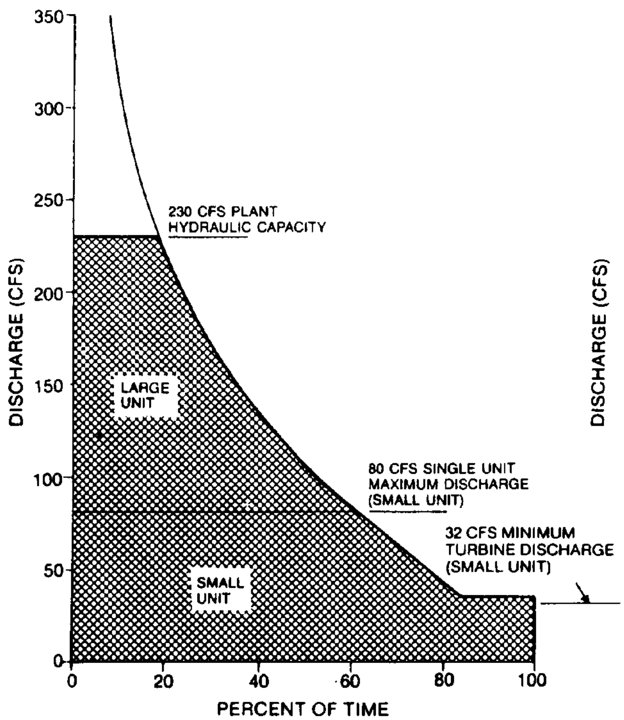


Figure 6-8. Flow-duration curve showing streamflow usable for generation: one 80 cfs unit and one 150 cfs unit

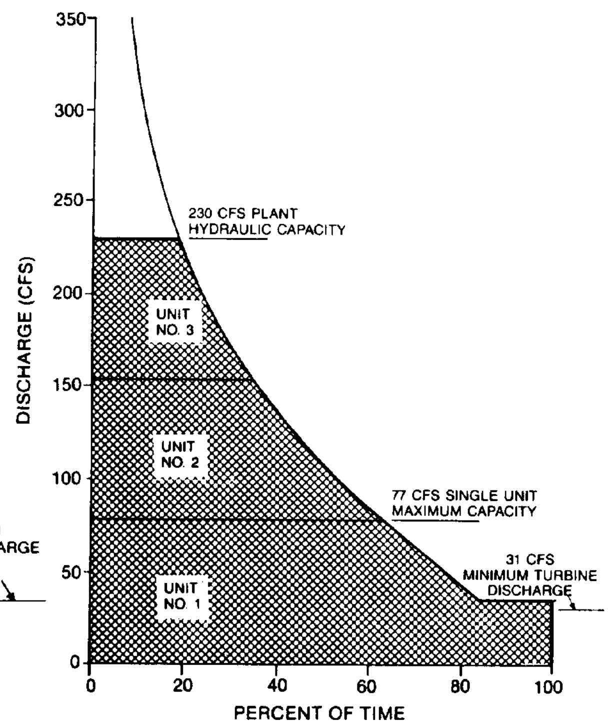


Figure 6-9. Flow-duration curve showing streamflow usable for generation: three 77 cfs units

(6) The percentage increases in energy output are, of course, specific to this particular project. However, the example does illustrate how energy output can be maximized through careful selection of sizes and numbers of units. It also shows that energy gains rapidly diminish in moving from one to two units, and from two to three units. Offsetting these gains will be a corresponding increase in powerhouse cost. Potential gains in energy output should be carefully weighed against increases in cost when selecting the final installation.

h. Turbine Selection. Selection of the proper type of turbine and runner design will also have a major effect on both energy output (through efficiency) and cost. Sections 2-6, 5-5, and 5-6i provide information on turbine types and selection criteria.

6-7. Dependable Capacity.

a. General.

(1) The traditional definition of dependable capacity is the load-carrying ability of a powerplant under adverse load and flow conditions. Although the term "dependable capacity" can be applied to thermal plants, it has been primarily used in connection with hydro plants and hydro-based power systems. Dependable capacity is used in load-resource analysis and in power sales contracts, but in the planning of hydro projects, its major use is in estimating a project's capacity benefits.

(2) The objective in estimating capacity benefits is to determine the capital cost of thermal plant capacity that would be displaced by the construction of the hydro plant (see Sections 9-3 and 9-5b). This requires an estimate of the amount of thermal plant capacity that is equivalent in peak load-carrying capability to the hydro plant. The traditional method of measuring dependable capacity does in some cases give a reasonable estimate of "equivalent thermal capacity" -- notably when evaluating hydro plants operating in hydro-based power systems. However, it has not proven satisfactory for other types of hydro projects, particularly those operating in thermal-based power systems.

(3) To offset these shortcomings, dependable capacity has been redefined in terms of equivalent thermal capacity, and a special procedure has been developed to estimate the dependable capacity of hydro projects operating in thermal-based power systems. The remainder of this section is devoted to explaining the concept of equivalent thermal capacity, describing the different methods for

measuring dependable capacity, suggesting where each method might be appropriate, and discussing several important factors related to estimating dependable capacity.

b. Basic Approach.

(1) For purposes of benefit analysis, dependable capacity is used to represent the amount of thermal capacity that would be displaced by the hydro plant. More specifically, it is intended to identify how much thermal capacity would be required to carry the same amount of system peak load as would be carried by the hydro plant. Because of differences in the way in which hydro and thermal plants perform, a kilowatt of hydroelectric capacity will seldom make exactly the same contribution to system peak load-carrying capability as a kilowatt of thermal powerplant capacity. A relationship which accounts for these differences must therefore be developed.

(2) Three factors must be considered when estimating equivalent thermal capacity:

- the relative mechanical reliabilities of the powerplants
- the relative flexibility characteristics
- the impact of hydrologic variations on hydro plant output

The Water and Energy Task Force addressed these parameters in reference (78) (see also Appendix 0 to this EM). Their findings can be summarized in the following equation for computing annual capacity benefits.

$$\text{Capacity benefit} = (CV)(DC)\,\frac{HMA}{TMA}\,(1 + F) \qquad \text{(Eq. 6-2)}$$

where: CV = unadjusted capacity value, \$/kW-yr
HMA = hydro plant mechanical availability
TMA = thermal plant mechanical availability
F = hydro plant flexibility adjustment
DC = hydro plant dependable capacity, in kilowatts

(3) The dependable capacity (DC) component should reflect all of the hydrologic factors which affect a hydro plant's ability to deliver capacity: (a) the variation of head with tailwater fluctuations and reservoir regulation, (b) the impact of operating constraints, and (c) the variability of streamflow. The derivation of HMA, TMA, and F are described in Appendix 0, and the derivation of the capacity value (the annualized unit capital cost of thermal plant capacity) is discussed in Section 9-5b.

(4) Removing the capacity value from the equation results in an equation which gives a measure of the amount of thermal capacity which is equivalent to the hydro plant capacity.

$$\text{Equivalent thermal capacity} = (DC)\frac{HMA}{TMA}(1 + F) \qquad \text{(Eq. 6-3)}$$

(5) Equivalent thermal capacity can be computed directly and applied to a capacity value which reflects only the costs of the alternative thermal plant. Normally, however, the capacity values provided by the Federal Energy Regulatory Commission include adjustments which account for HMA, TMA, and F (see Section 9-5c). Thus, in most cases, the Corps field office must compute only the dependable capacity (DC) component.

$$\text{Capacity benefit} = (DC)(\text{adjusted CV}) \qquad \text{(Eq. 6-4)}$$

c. Methods for Determining Dependable Capacity. The following sections describe the four basic methods that have been used within the Corps for estimating dependable capacity:

- the critical month method
- the firm plant factor method
- the specified availability method
- the average (or hydrologic) availability method.

d. Critical Month Method.

(1) The traditional definition of dependable capacity is based on the hydro project's load-carrying capability under conditions that are most adverse from the standpoint of both load and flow. Thus, a storage project's dependable capacity is based on its capability in a high demand month near the end of the reservoir drawdown cycle, when its capacity would be reduced due to reduced head. Interpreting this definition literally, the most adverse drawdown cycle would be the critical drawdown period (Section 5-10d). However, it is not always reasonable to use the most adverse peak load month in the period of record. For example, the most adverse month for the Pacific Northwest power system would be the January nearest the end of the 42-1/2 month historical critical period (January 1932). This month is estimated to have a hydrologic recurrence interval of about once in 200 years, which is too conservative for evaluating power system peak load reliability. It is seldom that a power customer is willing to pay for a system which is so reliable that it will fail to meet peak loads only once in 200 years. The region uses January 1937 instead. This month has a recurrence interval of once in 20 years, which is more consistent with regional peak load reliability criteria.

(2) When analyzing a system with multiple storage projects, the critical month would be based on system criteria, rather than defining the critical month for each project on an individual basis. The dependable capacity of a run-of-river project located downstream of a storage project would be based on the same critical month as the storage project (or the system critical month, if multiple storage projects are involved). For run-of-river projects with pondage, the available capacity may not be influenced by streamflow variations, and may be the same for all load months and water years. However, in some cases it may be necessary to apply sustained capacity criteria in estimating dependable capacity (see Section 6-7i). For run-of-river projects without pondage, it may be necessary to base dependable capacity on the average capacity available in the critical month.

(3) When a system critical month is used to define a project's dependable capacity, care should be taken to insure that the project receives credit for its contribution to increasing system dependable capacity. For example, a storage project may be added to a system, and, because of its location in the system, it may be the first to be drafted. As a result, it would have a very low peaking capability in the critical month (due to loss of head). However, its operation may have permitted other storage projects to maintain higher heads than before, thus increasing their dependable capacity. In this case, it would be appropriate to credit the new storage project with the net increase in dependable capacity of the system (or at least a share of the increased dependable capacity at the other projects). Appendix Q discusses allocation of benefits among projects in a system.

(4) For capacity to be dependable, energy must be available to support it. At projects with power storage, this is seldom a problem. However, at run-of-river projects and at projects with storage regulated for other purposes, there may not be sufficient energy during low flow periods to make the full capacity usable in the system load. When using the critical month method, the dependable capacity should be based on the amount of capacity that can be "sustained" in the load during that month, rather than the amount of generating capability (machine capability) that is available. Section 6-7i discusses how sustained capacity can be measured.

e. Firm Plant Factor Method.

(1) In some areas, dependable capacity has been based on the amount of firm energy required to make a kilowatt of hydro capacity marketable.

$$\text{Dependable capacity} = \frac{\text{(Firm energy output, kWh)}}{\text{(Firm energy requirement, kWh/kW)}} \qquad \text{(Eq. 6-5)}$$

(2) Because the firm energy requirement can be converted to a required plant factor, this method is sometimes known as the firm plant factor method. This requirement is also sometimes expressed in terms of the minimum required number of hours at full load capacity in the period of analysis. In this case, the equation would take a somewhat different form:

$$\text{Dependable capacity} = \frac{\text{(Firm energy output, kWh)}}{\text{(Required hours at peak output)}} \qquad \text{(Eq. 6-6)}$$

(3) In either case, the analysis is usually based on the peak demand months, although it could in some cases be based on the project's performance over the entire year. This type of dependability criteria is usually established by the regional Power Marketing Administration based on marketing considerations and may include a weekly or monthly energy distribution as well. This criteria is normally used to evaluate peaking plants operated in thermal-based power systems.

f. Specified Availability Method. In some screening studies and small hydro project analyses, dependable capacity has been based on the amount of capacity available for a specified percentage of the time. In these studies, the required availability was based on the average availability of the alternative thermal plant -- usually on the order of 85 percent. Thus, the dependable capacity is obtained from the 85 percent exceedence point on the generation-duration curve for the peak load months (Figure 6-10). This method provides a measure of equivalent thermal capacity rather than dependable capacity and should not be used with capacity values that already have reliability and flexibility adjustments (Section 9-5c). While useful for preliminary studies, this method has largely been replaced by the average availability method.

g. Average Availability Method.

(1) This procedure was originally developed by the Water and Energy Task Force for evaluating relatively small hydro projects in large, diverse power systems (78). Because this method was first applied to small run-of-river projects, where the capacity available at any given time is a direct function of streamflow, it was originally called the "hydrologic availability" method. However, because the method has subsequently been applied to other types of projects, the more general term, "average availability method" is considered to be a more appropriate name for this procedure. The basic approach will be briefly described in the following paragraphs, but for a more detailed discussion of the conceptual basis, reference should be made to Section O-2c of Appendix O.

(2) The average availability method is based on the assumption that variation of hydro plant generating capability due to variations in streamflow and reservoir elevation is equivalent to variation in thermal plant availability due to outages. Through the use of a system reliability model, it was found that variations in a hydro project's capability due to these hydrologic factors have the same effect on peak load-carrying capability as for thermal plant forced outages.

(3) The basic equation for equivalent thermal capacity (Equation 6-3) can be modified as follows:

$$\text{Equivalent thermal capacity} = (IC)(HA)\frac{HMA}{TMA}(1 + F) \qquad \text{(Eq. 6-7)}$$

where: IC = installed capacity, kW
HA = average availability factor (decimal)

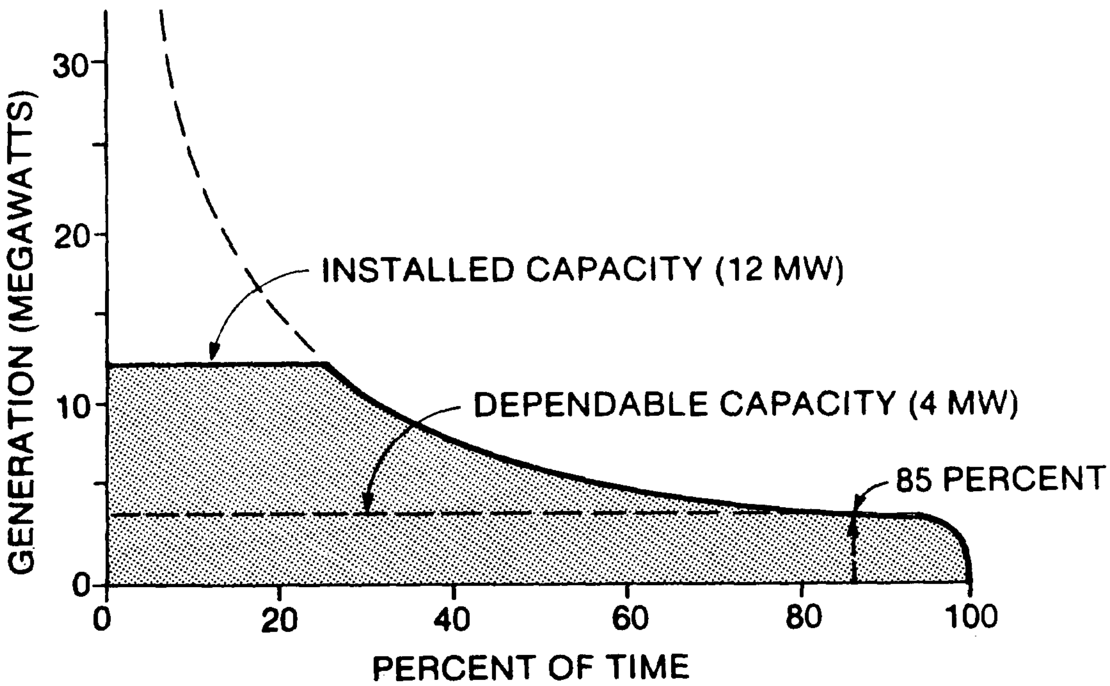


Figure 6-10. Determining dependable capacity using the specified availability method.

The average (or hydrologic) availability factor is the ratio of the average capacity available in the peak demand months (over the period of record) to the rated capacity:

$$\text{Average availability factor} = \frac{\text{Average capacity}}{\text{Rated capacity}} \qquad \text{(Eq. 6-8)}$$

(4) For run-of-river plants without pondage, the average capacity can be obtained by integrating the generation-duration curve for the peak demand month(s) (Figure 6-11). The product of the installed capacity and the hydrologic availability can, for purposes of benefit computation, be considered to be the project's dependable capacity.

$$\text{Dependable capacity} = \text{(HA)(Installed capacity)} \qquad \text{(Eq. 6-9)}$$

(5) A similar technique can be applied where the duration curve method is used to evaluate a project with pondage for daily load-shaping. Instead of using a generation-duration curve, the average

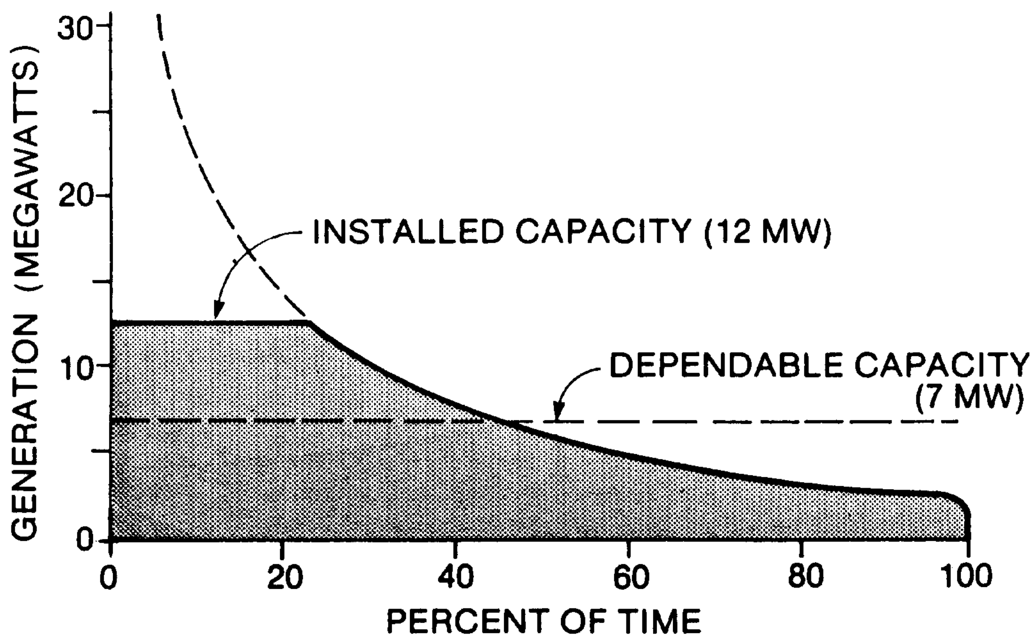


Figure 6-11. Determining dependable capacity using the average availability method

availability factor would be obtained from a capacity-duration curve, which shows the distribution of peaking capacity for the peak demand months over the period of record (see Section 5-71).

(6) The peak demand months are identified by examining power system load data. Usually, there is a two-month period where loads are substantially greater than other months (December-January in winter peaking systems and July-August in many summer peaking systems, for example). However, in some systems, the peak demand season may extend for three or four months. In other systems, the summer and winter peak loads may be very close, and it may be necessary to use both periods when evaluating dependable capacity. Identification of the peak load months should be made in consultation with the regional Power Marketing Administration, FERC, or the area utilities.

(7) The average availability method can also be applied to projects where energy has been estimated using sequential streamflow (SSR) routing. SSR models normally provide an estimate of the project's capacity, as well as energy, for each time increment in the period of record. The dependable capacity would then simply be the average of the capacity values for all of the peak demand months in the period of record (all of the July's and August's, for example). As is the case with the critical month method, the capacity values used to determine a project's dependable capacity must represent the amount of capacity that can be sustained in the load. Section 6-7i explains how sustained peaking capacity can be computed for each time increment, given the energy output and generating capacity for the time increment, the required load shape or amount of energy required to support each kilowatt of capacity, and minimum flow and other operating constraints.

(8) Tulsa District has developed a variation on the hydrologic availability method for evaluating capacity benefits at storage projects in the Arkansas-White River System (see Section 5-13d). Through analysis of historical operating data, a guide curve (Figure 5-50) has been developed which describes the daily plant factor at which a project would operate at each pool elevation. By applying this guide curve to a period-of-record daily streamflow routing, values of usable (or sustained) peaking capacity can be computed for each day in the period of record. The dependable capacity could then be computed by taking the average of the daily peaking capacity values for the peak demand months.

h. Selection of Method.

(1) The method selected for computing dependable capacity will depend on the type of project and type of power system in which the project will be operated.

(2) For projects which are located in large, thermal-based power systems, the average availability method should generally be used. For small projects, where the energy output is being derived with the duration curve or hybrid method, an average availability factor can be computed directly from the generation- or capacity-duration curve. Where the project is being analyzed with an SSR model, dependable capacity would be based on the average of the daily, weekly, or monthly capacity values for the peak demand months. To insure that the capacity values used reflect the amount of capacity which is usable in the load, it is sometimes necessary to convert them to sustained peaking capacity values.

(3) Where hydro comprises a substantial portion (one-third or more) of a system's generating capacity, it is usually necessary to use the critical month method. Here, too, the critical month peaking capacity should represent the project's sustained peaking capacity. The only case where the average availability method would be used in a hydro-based system would be to examine a small hydro project located in a basin with seasonal hydrologic characteristics that are different from the bulk of the hydro system.

(4) Regional power marketing requirements may in some cases suggest the use of the firm plant factor method. However, before this method is used, it should be confirmed that the project will actually be operated in accordance with the criteria upon which the firm plant factor is based (i.e., that the storage would actually be drafted to meet firm requirements in low water years). If not, this method could understate the capacity benefits.

(5) Another problem with the firm plant factor method is that the requirements for dependability are sometimes based on the specific needs of the PMA's customers, which, due to the PMA's particular rate structure, may be different from the needs of the region. Hence, the benefits derived using this method may not represent the NED hydropower benefits. The specific power needs of the PMA's customers and the effect of the PMA's rate structure on these needs should more properly be reflected in the PMA's marketability analysis rather than the NED benefit analysis. The marketability criteria criteria could, however, influence the selection of the recommended plan.

(6) Determining the dependable capacity of an off-stream pumped-storage project requires a somewhat different approach, which is described in Section 6-7j.

i. Sustained Capacity.

(1) Seasonal sequential routing studies provide daily, weekly, or monthly estimates of capacity. These values are a measure of the

plant's instantaneous peaking capability for each period. This is the maximum capacity the plant can carry, allowing for any loss of head due to reservoir drawdown and tailwater encroachment at high flows. However, this value does not always represent the amount of peak load that the project can carry effectively. Because of pondage limitations, low flows, and other operating limits, the amount of capacity that can actually be provided in the load may be less than the instantaneous peaking capability.

(2) The number of hours per day (or hours per weekday) that hydro capacity must be supplied for it to be usable can be determined by examining load curves and load-resource projections. This is usually done in coordination with entities such as the regional Power Marketing Administration, FERC, and the regional power pool. This criteria can be combined with minimum flow requirements and other operating criteria to develop a function that can be applied to the daily, weekly, or monthly energy output from the routing study to obtain the sustained peaking capacity for each period. The resulting values are a measure of the amount of capacity that is considered fully dependable in each period.

(3) For the reasons cited in Sections 6-7h(4) and (5) above, the sustained peaking criteria should usually be based on regional needs rather than on the specific needs of the PMA's customers. If the latter criteria is used, it must be demonstrated that benefits thus derived will provide a reasonable estimate of NED benefits.

(4) Figure 6-12 shows an equivalent load shape that has been applied to SSR studies of the Columbia River power system. This load shape can be reduced to the following equation, which can be applied to the energy output of individual projects, as obtained from the SSR study:

Sustained peaking capacity

$$= (\text{Min. cap.}) + \frac{(\text{Energy} - (168\text{ hrs})(\text{Min. cap.}))}{(0.5)(58\text{ hrs.}) + (20\text{ hrs.})} \qquad \text{(Eq. 6-10)}$$

where: Min. cap. = the capacity required to meet minimum flows, expressed in megawatts

Energy = energy available in that week or month, expressed in megawatt-hours

The sustained peaking capacity for a given time increment would of course be limited by the maximum plant capacity available during that period. Through use of an equation similar to Equation 6-10, the sustained peaking capacity computation can be incorporated in the SSR model used to do the energy analysis. At some projects, operating constraints are not a problem. In these cases, it is necessary to specify only the amount of energy required to support each megawatt of dependable capacity. Relationships similar to Figure 6-12 can be developed for other systems.

(5) As noted earlier, the method developed by Tulsa District for evaluating the Arkansas-White River system projects (Section 6-7g(8)), incorporates the sustained peaking capacity concept. If daily and hourly operating criteria are not too complex, a similar approach can be applied to the output of weekly or monthly sequential routing studies.

(6) Where storage is available at-site or upstream to supplement normal streamflows in emergency situations, the full peaking capability can sometimes be considered dependable, even though it cannot be sustained continuously in all time periods. Hourly operation models are often useful for evaluating sustained peaking capacity, particularly for systems of projects.

j. Dependable Capacity of Pumped-Storage Projects.

(1) The dependability of an off-stream pumped-storage project's capacity is a function of its storage volume and the desired load

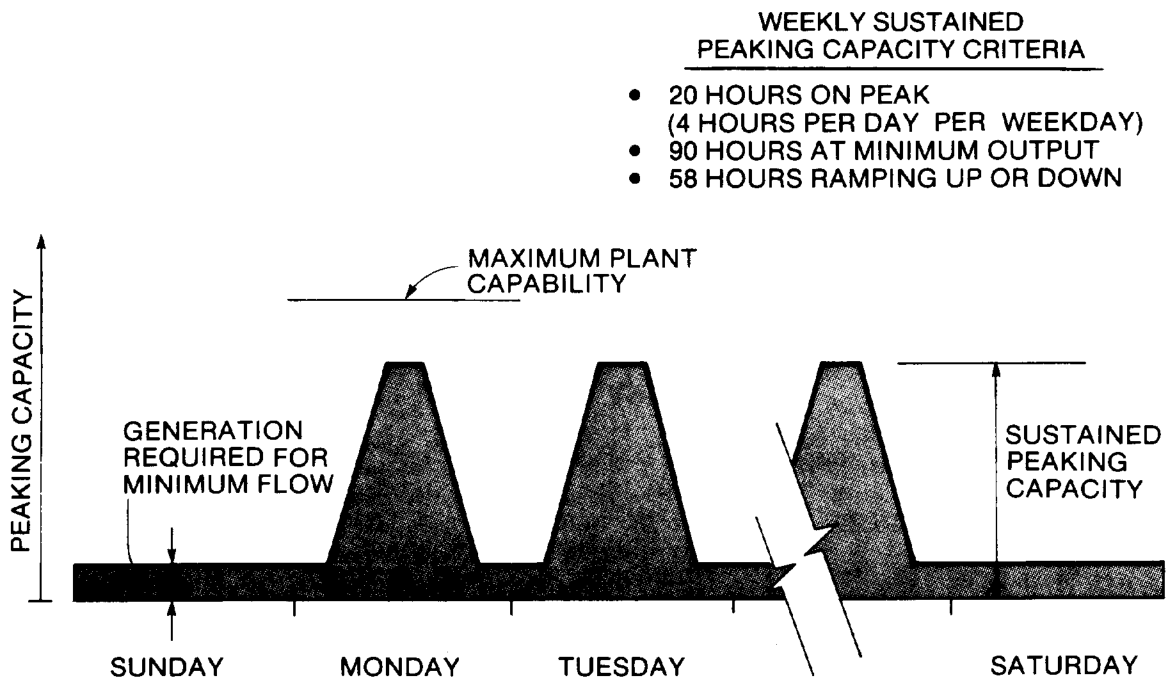


Figure 6-12. Example of sustained peaking capacity criteria

shape rather than hydrologic factors. Therefore, the dependable capacity of a pumped-storage project may be defined as the maximum capacity that can be provided for the required number of hours per day (or week) using available storage and off-peak pumping energy. The analysis should be based on conditions prevailing during the peak demand months.

(2) Where the generating units are rated at minimum head (see Section 7-2h), the full rated capacity will be dependable. In some cases, the units may be rated at a head greater than minimum head, and thus the available capacity may vary somewhat over the course of the day or week. In these cases, dependable capacity should be based on the average capacity available in the daily or weekly operating cycle.

(3) The mechanical reliability and flexibility components included in Equation 6-7 still apply when computing the equivalent thermal capacity for a pumped-storage project. In addition, the availability of pumping energy can affect the pumped-storage plant's capacity availability. Where availability of pumping energy is a problem, an availability factor should be estimated for the peak load months and applied to the dependable capacity. For example, during periods of high demand, the peak may sometimes be so broad that not enough night-time pumping hours are available to provide enough pumping energy to restore the upper reservoir to the desired level. This would in turn reduce the amount of capacity that could be sustained through the week. If extra reservoir storage is not provided to cover these situations, the dependable capacity should be adjusted accordingly. This could be done by applying an availability factor based on the ratio of the average number of hours that the week-night pumping energy is available (during the peak demand months) to the required number of hours as determined from the reservoir sizing study (Sections 7-2c and d).

(4) Other factors may also affect the availability of pumping energy, such as high night-time loads and forced outages on the thermal plants that provide the pumping energy. If the combined effect of these factors substantially reduces the pumped-storage project's dependability, consideration should be given to providing extra storage capacity in the upper reservoir to permit the project to maintain its dependable capacity during periods when sufficient off-peak pumping energy is not available.

k. Intermittent Capacity.

(1) Various references, including Section 2.5.8(4) of Principles and Guidelines (77), suggest that there is some value to capacity that does not meet the strict definition of dependable capacity, but which is available for a substantial portion of the time

during the peak demand months. This point is valid when the firm plant factor or specified availability methods are used to compute dependable capacity for a hydro project in a predominantly thermal power system.

(2) Several different approaches have been proposed for assigning credit to intermittent capacity, including giving half value to capacity which is available for "a substantial amount of the time" (see Section 15-26(2) of reference (37), and pp. 25-29 of reference (63)). However, these approaches have not generally been accepted because of the difficulty of quantifying the benefits derived from intermittent capacity. The only way in which intermittent capacity can be accounted for satisfactorily is by using the average availability method for computing dependable capacity (Section 6-7g). This method incorporates intermittent capacity directly in the dependable capacity computation.

(3) When it is not appropriate to use the average availability method, credit for intermittent capacity is not usually warranted. For example, in a hydro-based power system, the system must be designed to provide sufficient capacity to meet peak loads plus the desired reserve margin in the critical month. Additional capacity which is available in better than critical months may contribute to operating flexibility, but it does not save construction of an increment of thermal plant capacity. Therefore, no credit in the form of capacity benefits should be claimed.

l. Flexibility.

(1) Many hydro projects make contributions to system operation that are difficult to quantify. The most frequently mentioned attributes are fast-start capability, ability to respond quickly to changing loads, and ability to operate as a motor to improve the system power factor (Section 6-3b(12)). Some projects, because of their favorable location with respect to load centers, transmission lines, or other hydro projects, may make system contributions which cannot be readily quantified with conventional methods.

(2) Attempts should be made to quantify flexibility benefits if they appear substantial, or if they may affect project scoping. FERC presently gives a credit of up to five percent of the capacity value for flexibility (see Section 9-5c), and this factor is incorporated in the equivalent thermal capacity equation (Equation 6-3). However, the five percent value is admittedly a rough approximation. In cases where major flexibility benefits exist but cannot be accurately quantified, they should be discussed in support of selecting the recommended plan. Letters documenting the existence of these benefits from the regional Power Marketing Administration or power pool would

also be helpful. Flexibility credit is not usually given to projects with no pondage or storage, or to projects where operating constraints limit their ability to follow load.

(3) The Electric Power Research Institute is undertaking some research to quantify hydropower project flexibility benefits (68), and this effort should be monitored closely. Section 0-2e of Appendix 0 provides additional information on flexibility benefits.

6-8. Measures for Firming Up Peaking Capacity.

a. General. As discussed in Section 6-7, the installation of generating capacity does not in itself make it possible for a project to carry intermediate or peaking loads on a dependable basis. Three techniques are used to enable hydro projects to provide capacity when needed and within downstream operating constraints:

- pondage
- reregulating storage
- reversible units

These three techniques or measures are discussed in the following paragraphs. Section 6-9 describes how hourly sequential streamflow routing can be used to analyze these measures, and Appendix N contains example routings.

b. Pondage.

(1) If a hydro project is to follow hour-to-hour load fluctuations, it must be able to store inflow so that it can be released as

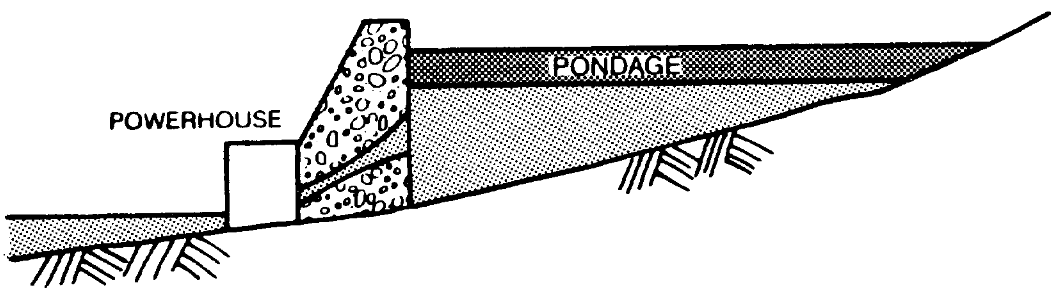


Figure 6-13. Run-of-river project with pondage

needed to meet power demands. Projects with seasonal power storage inherently have that capability, but to permit load-following at run-of-river projects, daily/weekly storage or "pondage" is sometimes provided (see Figure 6-13). When examining a new pondage project, a range of plant sizes are usually considered, so routing studies must be made to determine how much pondage is required to support each plant size. At existing projects, the amount of pondage may be fixed. In this case, the objective would be to determine either (a) how much capacity could be supported with the existing pondage, or (b) what type of operation can be supported with the pondage.

(2) Figure 6-14 shows a typical weekly operating cycle using pondage. In this example, the project is required to operate at or near maximum capability for 15 to 16 hours a day, five days a week, and at reduced output for the remainder of the time. A constant inflow is assumed. The pondage is gradually drawn down (or drafted) through the peak-load periods of the week and refilled at night and on weekends. Note that draft of pondage results in a gradual loss in available head through the course of the week, with a resulting loss of energy and sometimes even peaking capability (although power installations at pondage projects are often designed to maintain rated capacity through the normal pondage drawdown range).

(3) A number of factors influence the amount of peaking capacity that a project of a given installed capacity and pondage volume can deliver on a dependable basis:

- average reservoir inflow
- shape (time distribution) of reservoir inflow
- required generating pattern
- required minimum discharge
- reservoir elevation at start of weekly operating cycle
- downstream discharge or fluctuation limits
- reservoir fluctuation limits

(4) When evaluating the peaking capability of a given project, a range of weekly average inflows should be examined. Where inflows within the week are reasonably uniform, the lowest weekly average inflow often provides the most severe operating condition.

(5) The generating pattern dictates the schedule of releases required to meet loads. The weekly power release pattern is usually established in coordination with the regional Power Marketing Administration. If an upstream project is also operated for peaking, its operation may result in reservoir inflows being shaped. Depending on the travel time between projects and the amount of attenuation occurring in the process, the shape of the inflow may either increase

or decrease a hydro project's pondage requirements. The required minimum discharge is a flow that must be maintained downstream at all times (at some projects).

(6) The reservoir starting elevation also influences the amount of pondage required for a given project. If the project always begins the weekly cycle (or daily cycle) full, as shown in Figure 6-14,

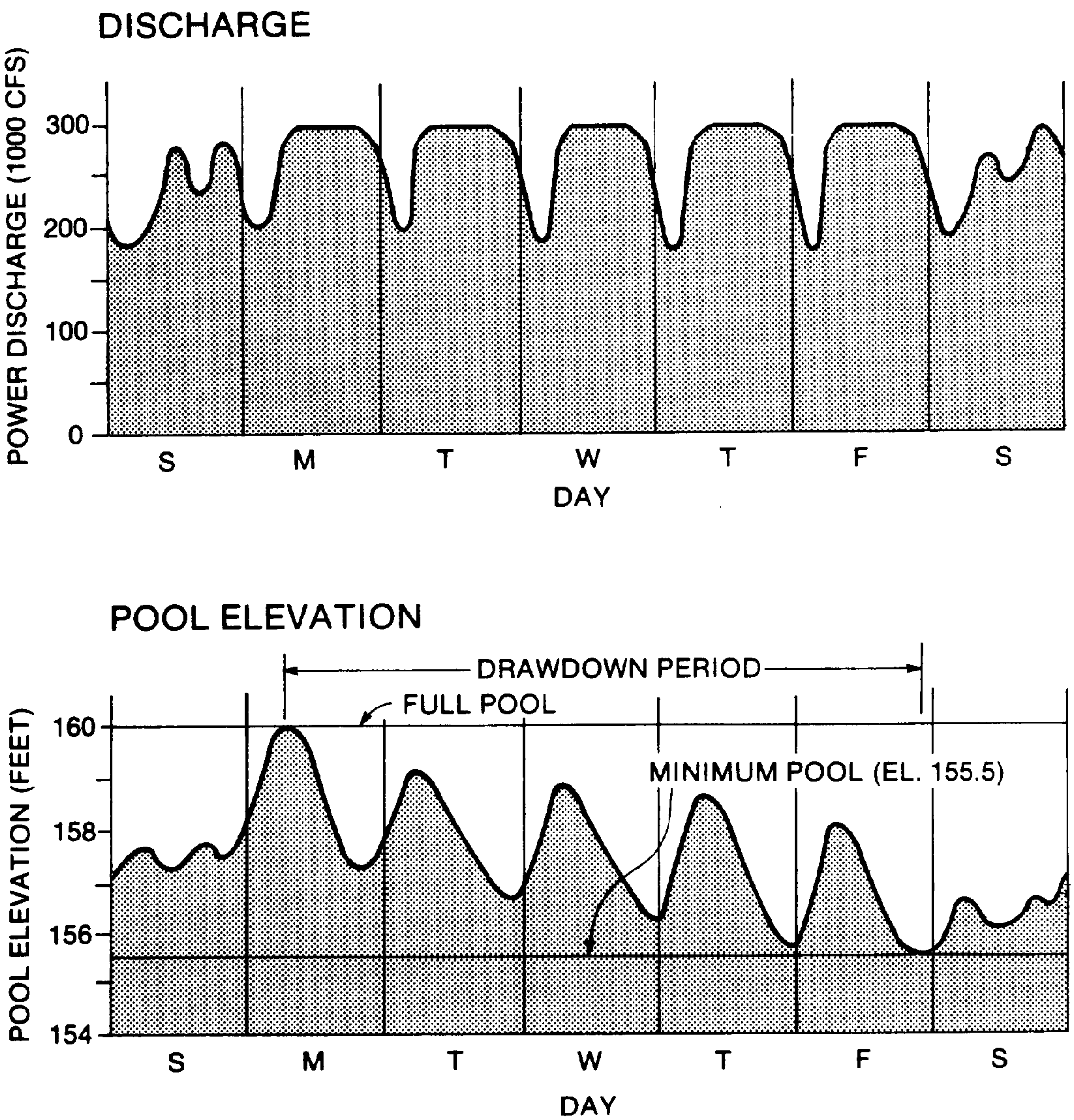


Figure 6-14. Regulation of a pondage project

pondage requirements will be minimized. However, if the reservoir does not always begin the week full, additional storage must be provided (Figure 6-15).

(7) Reservoir and downstream fluctuation limits, either hourly or daily, can limit the rate at which power loads can be picked up and can also limit the total amount of capacity that can be provided under some flow conditions. Hourly routing studies are required in order to evaluate the impact of these constraints on a project's peaking capability.

(8) At some projects the amount of pondage may be fixed, due to physical factors such as channel characteristics or non-power river uses such as minimum channel depth required for navigation. In these cases, the pondage volume is held constant and a range of plant sizes is tested, applying the expected range of inflow generating patterns and minimum flow conditions. Dependable capacities are derived for each installation, based on performance during the peak load months (Section 6-7i). When pondage volume is not fixed, an additional degree of freedom is added to the analysis, and the gain in dependable capacity resulting from added pondage is balanced against (a) the energy losses that usually result from a greater average drawdown, (b) possible increased dam and reservoir costs, and (c) the non-power impacts of increased reservoir drawdown.

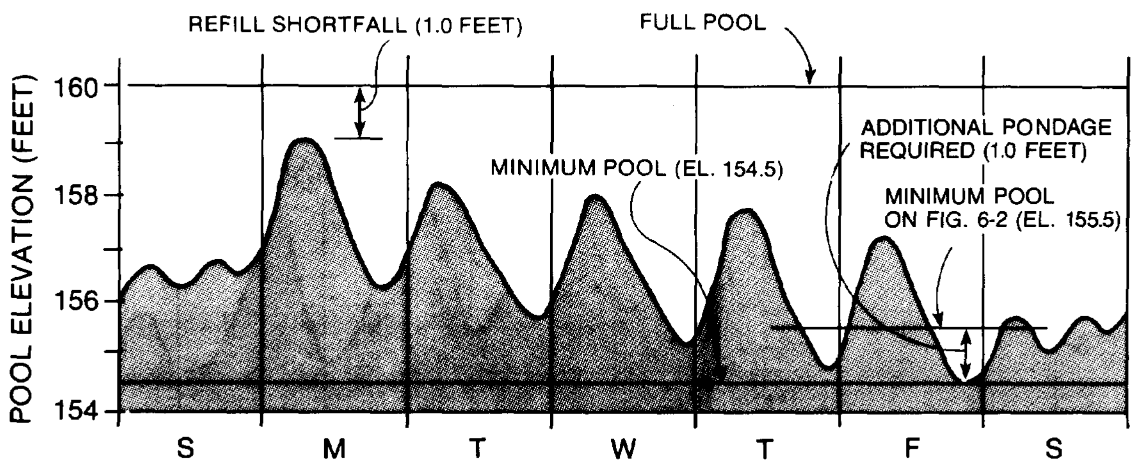


Figure 6-15. Regulation of a pondage project where the pool fails to refill by the start of the weekly operating cycle

(9) Case 1 in Appendix N is an example of an hourly routing for a pondage project.

c. Reregulating Dam.

(1) Where downstream operating limits constrain the peaking potential of the hydro site, a reregulating dam is sometimes provided to reshape peaking releases to provide the desired downstream flow conditions (Figures 2-19 and 6-16). Basically, the same concepts apply in designing a reregulating reservoir as in analyzing pondage, except that the objective is the opposite -- to smooth out rather than shape releases. For a given upstream power installation, a range of average flow conditions, inflow patterns, and required downstream conditions must be tested to determine the amount of storage needed for a reregulating reservoir.

(2) Figure 6-17 shows how a reregulating reservoir would operate on a daily cycle. Reregulating reservoirs are more typically required to operate on a weekly cycle. Sufficient storage must be provided to maintain minimum required downstream flows from the end of the Friday generating period through the start of generation on Monday morning (see Figure 6-24). The greatest storage demand at a weekly cycle reregulating reservoir usually occurs on a long holiday weekend, when the upstream powerplant would be shut down and minimum releases must be maintained over a period of 80 hours or more.

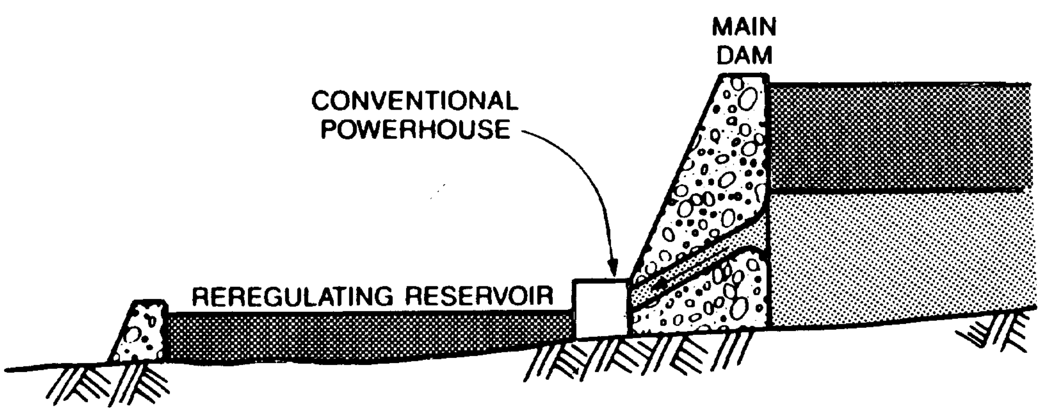


Figure 6-16. Peaking project with reregulating reservoir

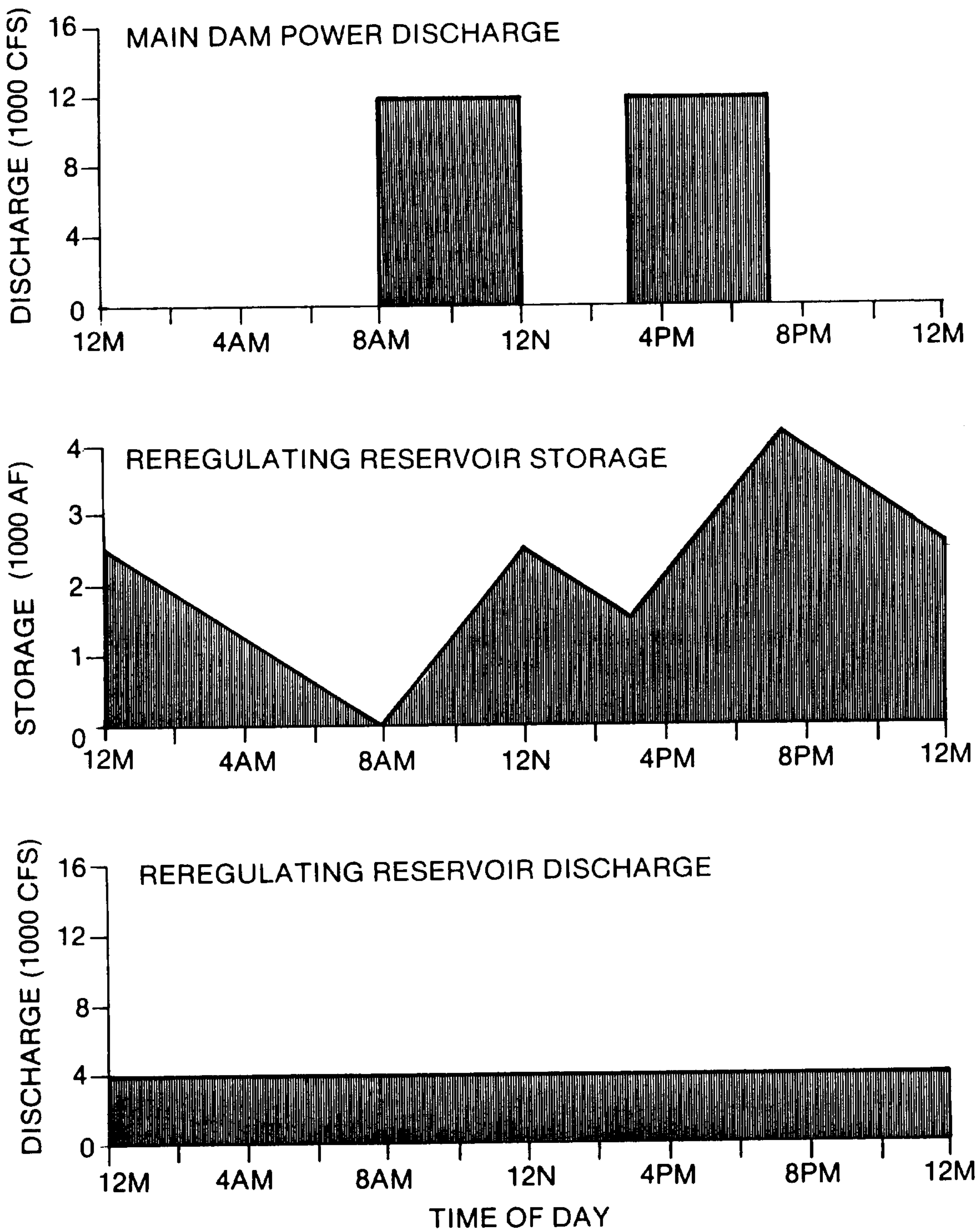


Figure 6-17. Reregulating reservoir daily operating cycle

(3) In Figure 6-17, a constant daily release of 4,000 cfs is being maintained by the reregulating reservoir. In many cases, some fluctuation in discharge level is permissible within the day. Taking advantage of this will reduce storage requirements. A gated outlet is required in order to maintain a fixed discharge schedule. Where some fluctuation in discharge can be accomodated, an ungated outlet can sometimes be used, with a substantial cost savings.

(4) Care must be taken in selecting the reregulating reservoir operating range. Minimizing dead storage will minimize construction costs, but could result in extensive areas of mud flats being exposed at minimum pool. On the other hand, if the reregulating reservoir encroaches on the upstream powerplant, generating head and hence energy production will be reduced at the main dam. If there is sufficient head, it may be desirable to install a powerplant at the reregulating dam.

(5) Case 2 in Appendix N is an example of an hourly routing for a peaking project with a reregulating reservoir.

d. Reversible Units.

(1) Some dam sites have the head potential and other qualifications suitable for large peaking installations, but low discharge levels may prevail over so much of the time that the plant's

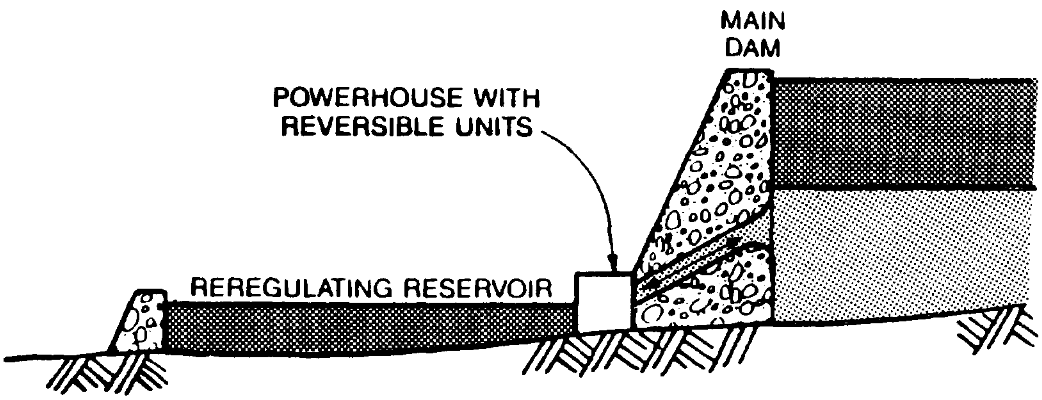


Figure 6-18. Pump-back project

capacity would not be dependable. Examples of situations like this would be (a) a large irrigation storage project where the release pattern does not coincide with the seasonal demand for power, and (b) a project where head is high but average discharges are low. In these situations, it is often possible to increase dependable capacity substantially through the use of reversible (pump/turbine) units.

(2) This concept is technically classified as integral or on-stream pumped-storage, but is frequently called simply "pump-back" operation. It consists of installing reversible units in a conventional powerhouse structure at the main dam and constructing a reregulating or "afterbay" reservoir just downstream (Figures 2-18 and 6-18). Water is released through the powerhouse during the peak load period, in order to generate power when it has its highest value, and this water is stored in the reregulating reservoir. A portion of the water is released downstream in accordance with minimum flow requirements and other operating criteria. The remainder is pumped back into the storage reservoir during off-peak hours. Figures 6-19 and 6-20 illustrate how the use of reversible units can increase peak power discharge during periods of low flow.

(3) Pump-back operation has some of the characteristics of both conventional hydro peaking operation and off-stream pumped-storage. When downstream releases from the main dam are adequate to meet peaking requirements, the project operates as a conventional hydro peaking plant with reregulating dam. When downstream releases are not adequate, the plant goes into a pump-back operation.

(4) The analysis of pump-back projects is discussed in more detail in Section 7-6.

6-9. Hourly Operation Studies.

a. General. Hourly operation studies are short-term sequential streamflow routing studies, performed primarily to evaluate the performance of hydro peaking projects, including pump-back and off-stream pumped-storage. The term "hourly studies" has been applied to this section as a matter of convenience; the approaches presented could be applied to multi-hour or fractional-hour time intervals as well as one-hour intervals. Following is a list of some of the studies where "hourly" analysis might be required:

- to determine how much capacity can be sustained under an assumed daily or weekly generation pattern (see Section 6-7i).

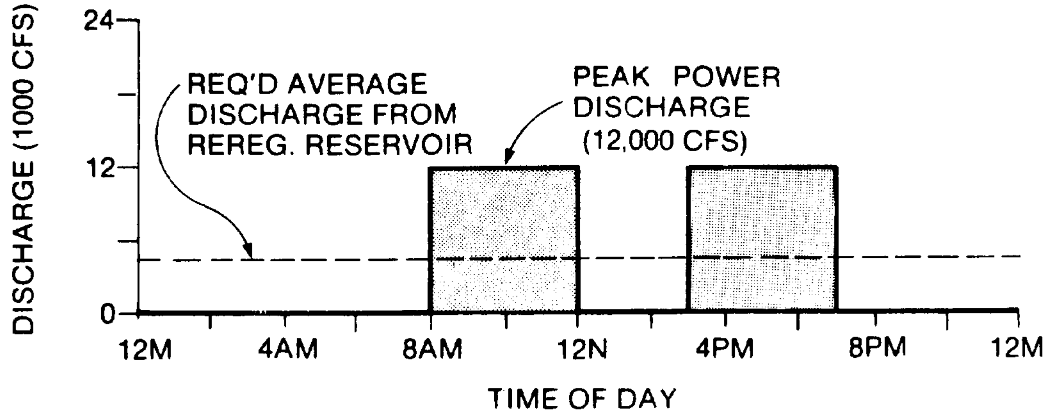


Figure 6-19. Power operation without reversible units

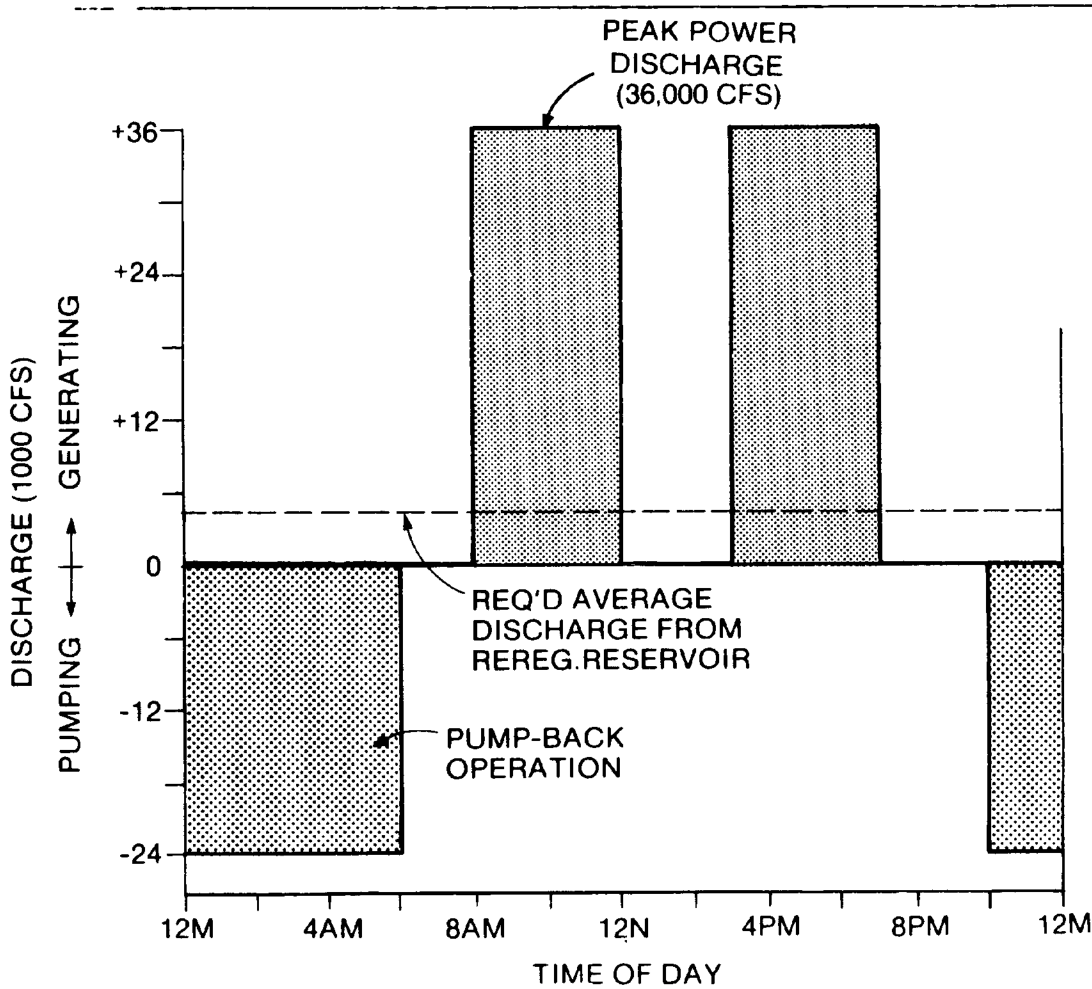


Figure 6-20. Power operation with reversible units

- to determine pondage requirements.
- to determine reregulating reservoir storage requirements.
- to determine upper and lower reservoir storage requirements for pump-back and off-stream pumped-storage projects.
- to determine the impact of peaking operation on adjacent projects (and vice versa).
- to define the pumped-storage operating cycle (pumping hours and generating hours).
- to evaluate the impact of the fluctuating discharges resulting from peaking operation on non-power river uses and the environment.
- to evaluate the impact of pool fluctuations resulting from peaking operation on other reservoir or river uses and the environment.
- to evaluate the impact of operating limits (such as minimum flows or rate-of-change constraints) on power operation.
- to evaluate the impact of expanding existing power projects (pondage requirements, environmental impacts, etc.)
- to determine the best operation for hydropower in the power system.
- to determine the best operation for a system of hydro peaking plants.

b. Data Requirements.

(1) General. Table 6-2 summarizes the basic assumptions and data required when applying the SSR method to hourly analysis. Further details on most of these parameters may be found in Section 5-6. However, there are several additional factors which must be considered in hourly analysis, and these are discussed in the following paragraphs.

(2) Hourly Load Shapes. Hourly load shapes must be provided in order to define the project's (or system's) operating pattern. The load shape may be (a) a prescheduled simple block load, (b) a prescheduled load which features some ramping (short-term change in output in response to changes in demand), or (c) an hour-by-hour load

TABLE 6-2
Summary of Data Requirements for SSR Method (Hourly)

Input Data	Paragraph 1/	Data Required
Routing interval	5-6b	hour, multi-hour, or fraction of an hour
Streamflow data	5-6c	historical records or output of weekly or monthly SSR models
Minimum length of record	5-6d	selected representative weeks
Streamflow losses		
Consumptive	5-6e	usually accounted for in streamflows
Nonconsumptive	5-6e	see Sections 4-5h(4) thru (10)
Reservoir characteristics	5-6f	storage-elevation curves or tables
Tailwater data	5-6g	tailwater curve with lag
Installed capacity	5-6h	specify
Turbine characteristics	5-6i	specify maximum and minimum discharges, minimum head, and in some cases maximum head
KW/cfs table	5-6j	optional
Efficiency	5-6k	see Section 5-6k
Head losses	5-6l	see Section 5-6l
Non-power operating criteria	5-6m	incorporate criteria directly in analysis
Channel routing	5-6n	incorporate if studying multiple projects
Generation requirements	5-6o	provide hourly loads or load shapes

1/ For more detailed information specific data requirements, refer to the paragraphs listed in this column.

shape which approximates the operation of a hydro project which is on automatic generation control (see Figure 6-21). A project on automatic generation control is one which is tied to the system automatic load dispatching equipment and which is used to follow the moment-by-moment fluctuations in system demand. Load shapes are usually developed in cooperation with the regional Power Marketing Administration, the local power pool, or FERC. Loads may vary seasonally and by day of the week. Pumping load shapes are also required for pumped-storage or pump-back projects. Where a minimum release is required, the hydro project's peaking load would be superimposed on the base load generation required to meet minimum flows (Figure 6-22). In some cases it may be desirable to test alternative load shapes to determine how the project could be used most effectively in the system load. When examining multi-project systems, some models require either (a) that an hour-by-hour load shape be specified for each project, or (b) that the same shape be applied to all projects. Other models allocate a specified total load among projects consistent with their operating characteristics.

(3) Period of Analysis. Because of the time and computer costs incurred, period-of-record studies are seldom made using hourly models. Normally, hourly studies are made for typical weeks, although periods longer than a week can be examined if necessary. When making hourly routings for design purposes, it is common to examine weeks which represent extreme cases, in terms of loads and streamflows. It may also be necessary to test different flow levels when examining dependability of capacity or environmental impact, and this may require that a range of flows be examined for several different seasons. Where a period of record analysis is required, a series of representative weeks could be examined and the results could be applied to the total period by statistical correlation.

(4) Operating Limits. Existing or proposed operating limits could impact hourly operation, and therefore they must be reflected in hourly studies. The more common limits are:

- minimum regulated discharge
- maximum regulated discharge
- maximum daily discharge range
- maximum hourly rate of change of discharge
- maximum hourly rate of change in water surface elevation
  - forebay
  - intermediate point on reservoir
  - tailwater
  - downstream control point
- maximum daily change of elevation (at any of the points listed above)
- minimum generation requirement

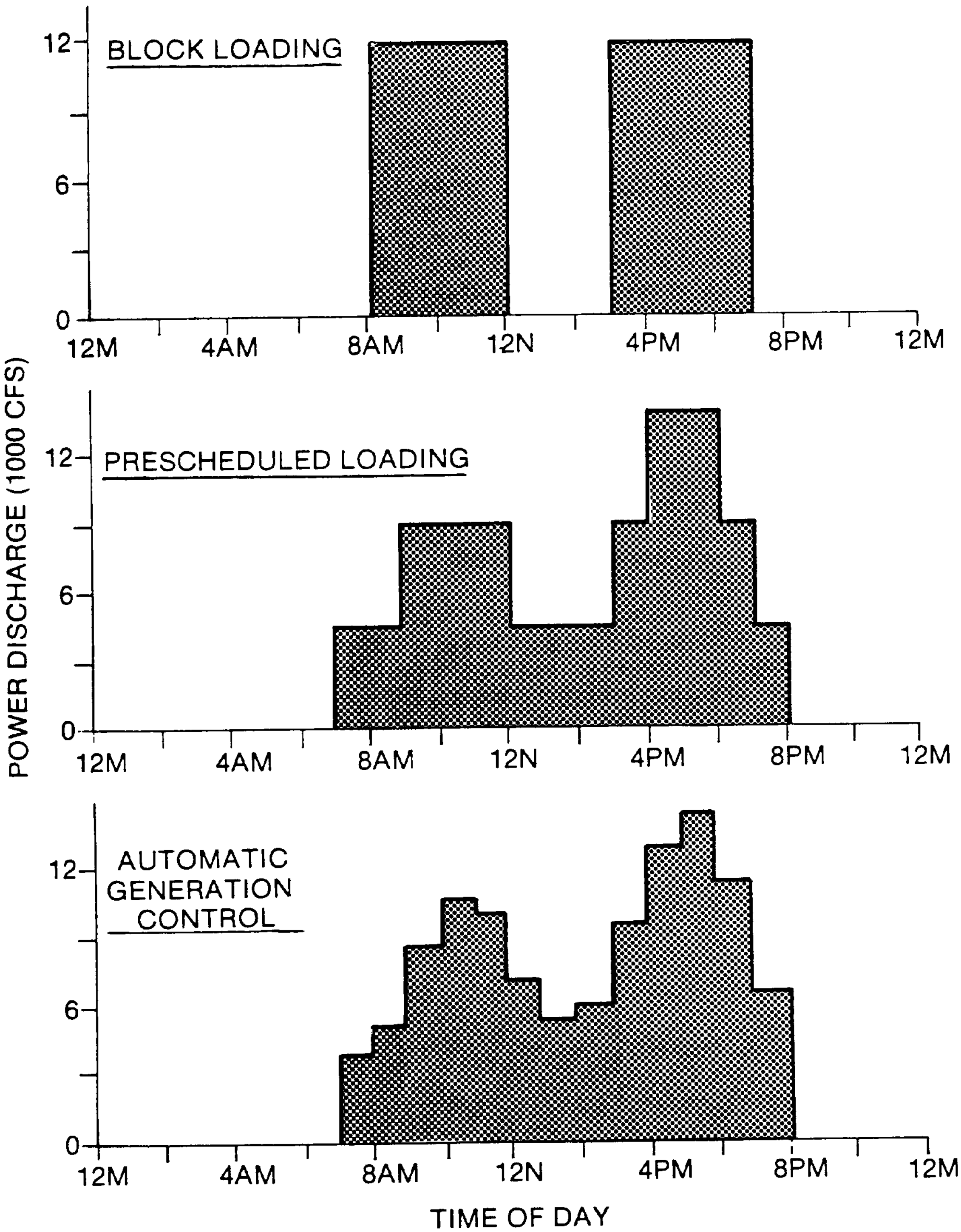


Figure 6-21. Alternative loading modes for peaking plant

These operating limits may vary seasonally or with average discharge (i.e., minimum discharge requirements may be a function of average weekly discharge).

c. Basic Approach.

(1) Types of Studies. Hourly operation studies fall into two general categories: (a) sequential routing studies, and (b) hydro-thermal system operation studies. Hydro-thermal operation studies consider the integrated operation of the total power system, and are generally beyond the scope of this manual. However, one model, POWRSYM, is discussed briefly (Section 6-9f) because of its usefulness in developing power values and in evaluating pumped storage projects. For further discussion on hydro-thermal system modeling and its application to hydro project planning, reference should be made to a report prepared by Systems Control, Inc. (33).

(2) Hourly SSR Studies. Hourly sequential routing studies are based on the same general principles as the longer term sequential streamflow routing studies described in Chapter 5. The following paragraphs discuss how these principles can be applied to hourly project analysis.

(3) The Objective of the Routing. Hourly routings differ from most seasonal routings in that meeting capacity requirements is the objective rather than maximizing energy production. In both cases, however, the objective is to meet specified loads (or a specified load

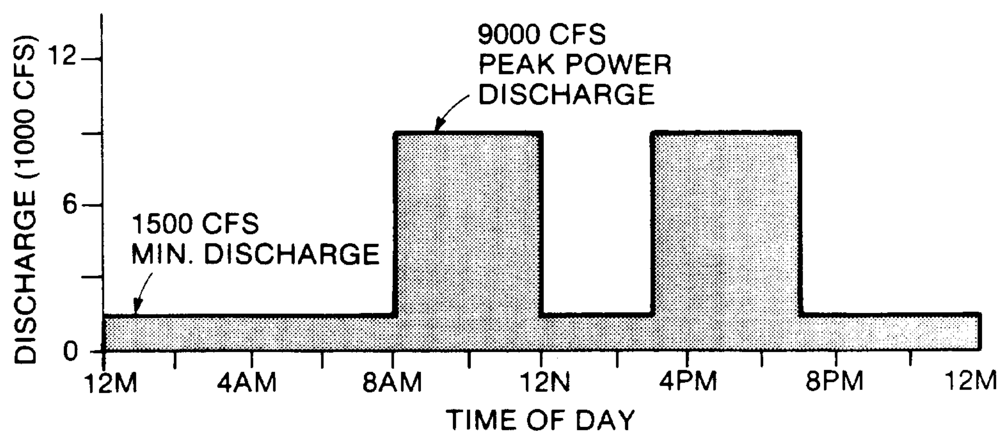


Figure 6-22. Peaking operation with minimum discharge

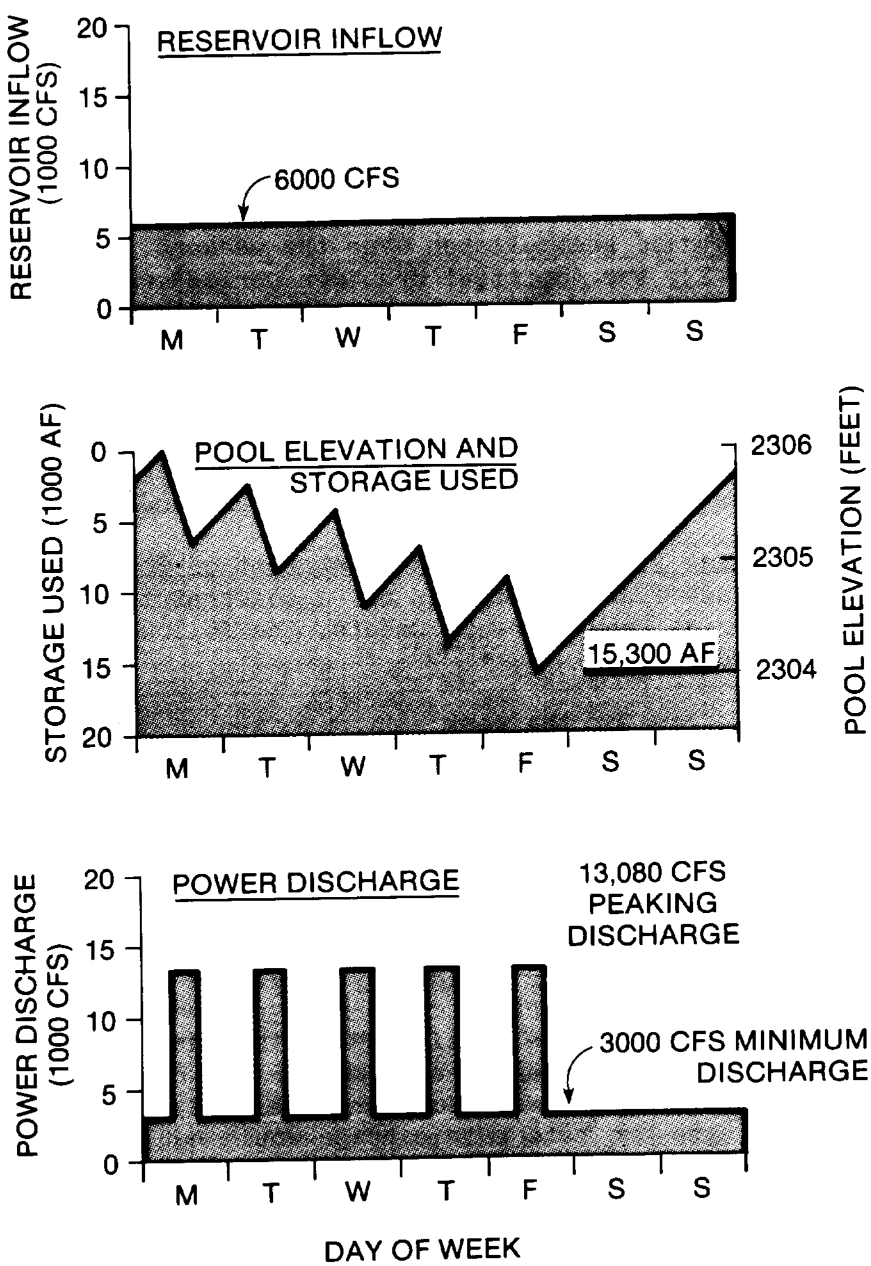


Figure 6-23. Graphical illustration of pondage analysis for peaking project

shape). In seasonal analyses, loads are generally based on system energy requirements, while in hourly analyses, loads are based on system peaking requirements.

(4) The Weekly Cycle. The "critical period" for hourly analysis is normally the week. A typical weekly loading on a hydro plant would consist of five weekdays with similar or identical loads, and Saturday and Sunday with reduced, minimum, or zero loads. Under this type of loading, the reservoir (pondage) would be at its highest level on Monday morning, just prior to assuming the normal weekday peak loads, and it would be at its lowest level on Friday evening (see Figure 6-23). Refill would be accomplished over the weekend. In the example shown on Figure 6-23, the "critical drawdown period" would extend from 7 am Monday to 5 pm Friday. In analyzing reregulating reservoirs, the weekend becomes the critical drawdown period (see Figure 6-24), and it is often desirable to use a three-day weekend for design purposes (see Section 6-8c). If the load were similar to that on Figure 6-24 except that Friday was a holiday, with only minimum generation being maintained, the critical drawdown period for the reregulating reservoir would extend from 5 pm Thursday to 7 am Monday.

(5) Evaluating Projects with No Constraint on Pondage. In evaluating a project where pondage is not a constraint or in making an analysis to determine pondage requirements, the following parameters would be specified.

- average flow for the week
- peaking capacity
- hour-by-hour load shape
- start-of-week reservoir elevation
- operating constraints

For a pondage project, the average flow for the week would be the average inflow. For a seasonal storage project, the average discharge would be used. The load shape would be a specified minimum number of hours at peak output (for block loading) or a prescheduled loading pattern (Figure 6-21). If the routing period begins with the first peakload hour on Monday morning, the reservoir can be assumed to be full. However, it is more common to start the analysis at midnight Sunday, in which case the reservoir pondage would not yet be full. A start-of-week elevation must therefore be specified for midnight Sunday which will permit the reservoir to be full at the start of the first peakload hour. Several iterations may be required to achieve a balanced reservoir at the end of the week (that is, the end-of-week reservoir elevation equals the start-of-week elevation). If the project has seasonal power storage, a storage draft may be acceptable, but at pondage projects, the pondage normally must be refilled by the following Monday morning. In the first iteration, the objective would

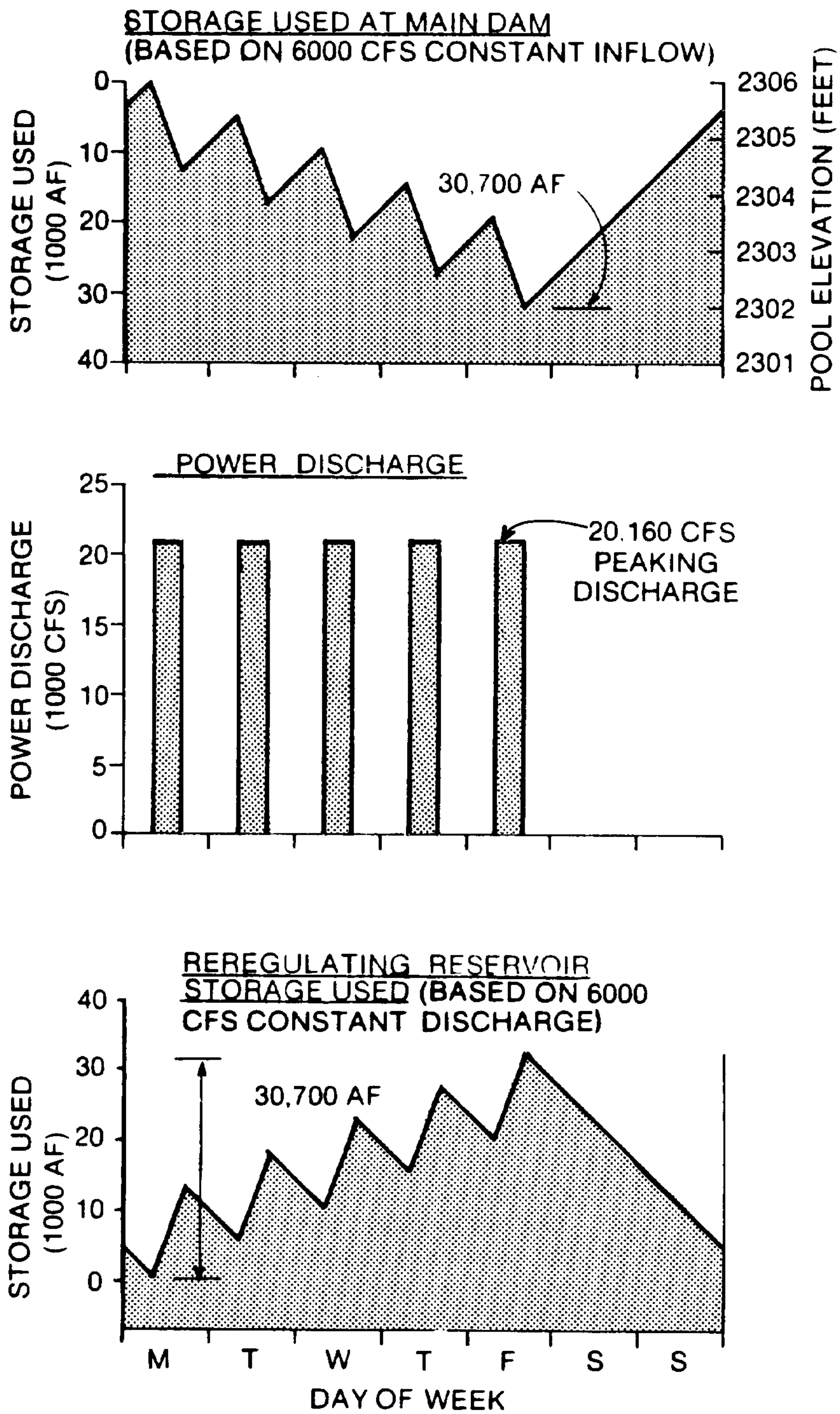


Figure 6-24. Graphical illustration of reregulating reservoir analysis

be to carry only the specified loads. If the pondage does not refill by Monday morning, this indicates that the specified load was too high to be supported by the available inflow. In subsequent iterations, either the load shape must be modified or the amount of capacity available for meeting load must be reduced, until a run is made in which the pondage exactly refills. If the pondage on Monday morning exceeds the initial elevation, then additional load can be carried. In subsequent iterations, the load shape would be modified, either by increasing the number of hours on peak or by increasing the minimum generation, until a run is made in which the pondage exactly refills.

(6) Evaluation of Projects with Limited Pondage. The analysis of projects with limited pondage would be similar to the procedure described in the previous paragraph, except that further iterations may be required in order to insure that the pondage constraint is not violated. Assume, for example, that a routing has been completed in which the pondage exactly refills, but more pondage is required than is available. The required power loading would have to be modified in subsequent routings until the pondage limitation is satisified, either by reducing the available peaking capacity, by broadening the load shape, or by increasing the minimum generation.

(7) Evaluating Reregulating Reservoirs. The evaluation of reregulating reservoirs would have to be coordinated with the pondage analysis described above. The first step would be to develop a satisfactory peaking operation which meets the pondage criteria. Then, the peaking operation would be imposed on the reregulating reservoir, in order to determine if downstream release criteria can be met within reregulating reservoir storage constraints. If the peaking operation requires more reregulating storage than is available, subsequent runs could be made with modified downstream release criteria (such as reduced weekend discharges), or increased weekend generation at the peaking plant.

(8) Treatment of Operating Limits. Section 6-9b(4) lists some of the operating constraints which may be imposed on peaking projects. Of these, minimum hourly discharge and generation constraints can be easily accommodated directly in the routing analysis. Hourly rate-of-change and daily range of fluctuation limits are more difficult to accommodate. In many cases, the most practical approach is to make a trial iteration to see if any constraints are violated. If so, subsequent iterations would be made with modified input parameters (load shape, available capacity, minimum generation, etc.) until a routing is made which does not violate any constraints. Where a computerized model is available, these constraints can sometimes be directly incorporated in the routing logic. But with complicated constraints or complex reservoir systems, it is usually more practical to do successive iterations.

(9) Selection of Weeks for Analysis. Some hourly studies are done for design purposes. The objective in these cases is to identify extreme, or "worst case" scenarios. Other studies are done to identify the range of expected operation conditions, and in these cases, a variety of conditions must be examined. In order to identify "worst case" situations, both loads and flows must be considered. It might be expected, for example, that the high demand months are the most critical, and the "worst case" scenario could then be identified by selecting the week (or month) in the peak demand season with the lowest average flow. This is often a correct assumption. However, in some cases, the highest loads may occur at a time of year when flows are high, so that a pondage project's reservoir capacity is not taxed. In other cases, the load shape during periods of very high demand is relatively flat, and thus pondage requirements are not severe. In addition, operating constraints may not be as severe in the peak demand months. Therefore, in order to identify the "worst case" scenario for purposes of analyzing the adequacy of pondage or reregulating reservoir capacity, or for analyzing the effects of operating constraints, it may be necessary to test low flow weeks at other times of the year as well. In some cases pondage requirements are not defined by the lowest flow conditions. Thus, it is often necessary to test a range of streamflows. When examining the full range of operating conditions, it is usually convenient to divide the year into several different "seasons", based on distinct load and streamflow conditions. For each of these seasons, studies would be made for a range of representative average flows.

d. Evaluation Tools.

(1) Hand Routings. Hand routings are sometimes useful for making preliminary analyses of pondage or reregulating reservoir requirements, or for evaluating single projects when extensive hourly studies are not required. Appendix N describes some examples of hourly hand routings. However, it should be obvious from the preceding paragraphs that for some projects, a number of different scenarios must be analyzed and that multiple iterations may be required for each scenario. The problem becomes even more complex if systems of projects are involved and/or conditions at other control points (downstream and at intermediate points on reservoirs, for example) must be considered. For these cases, the detailed analysis of a peaking project usually requires the use of a computerized SSR model.

(2) Hourly SSR Models. Three computerized SSR models have been used by the Corps of Engineers for hourly operation studies: HEC-5, HLDPA, and HYSYS. HEC-5 is useful for analyzing single projects or moderately complex systems, using time increments of either an hour, multiple hours, or a fraction of an hour. HLDPA can be used for

complex systems of projects and incorporates a routine for allocating a system load among the projects consistent with their operating characteristics. HLDPA is the most detailed hourly model and can be used for real time project analysis. These models are briefly described in Appendix C.

(3) Channel Routing Studies. It is often necessary to evaluate the hourly impact of power operations at intermediate points on reservoirs and at downstream locations. A number of models are available for making this type of analysis (see Section 5-6n). In some cases, they can be operated in direct conjunction with the model used to do the power routings, but in other cases it is necessary to transfer the hourly discharges and reservoir elevations from the power model to the channel routing model.

e. Examples of Hourly Studies. Sample hand routings have been prepared for three of the most commonly encountered hourly power studies:

- Case 1: determining the sustained peaking capacity of a pondage project (Figure 6-23)

- Case 2: sizing a reregulating reservoir (Figure 6-24)

- Case 3: sizing an upper reservoir for an off-stream pumped-storage project (Figure 6-25).

The back-up calculations are summarized in Appendix N.

f. POWRSYM Hydro-Thermal System Model.

(1) POWRSYM is an hourly system production cost model originally developed by the Tennessee Valley Authority to evaluate off-stream pumped-storage. TVA has subsequently adopted it for most of their system planning studies. The model operates on a weekly cycle over a period of one year. The driving function is to select the combination of generating resources (from a specified set of "existing" resources) which meets the load in each hour at the minimum system production (or operating) cost. Analysis of capital costs is handled outside of the model.

(2) The first resource dispatched is always hydro, because its production cost is essentially zero. Hydro capacity, hydro energy, and minimum (or continuous) hydro requirements are specified for each week. In its basic form, the model dispatches system hydro in two increments. First, sufficient hydro energy and capacity is allocated to meet any minimum generation (or minimum flow) requirements. The remainder of the hydro is dispatched as far up in the peak of the load

as possible within installed capacity and available energy constraints. Thermal plants are then dispatched by hour, generally in order of cost. Pumped-storage is dispatched either on a fixed (or "must-run") basis or on an economic dispatch basis. When dispatched on an economic dispatch basis, pumped-storage will operate only when the value of displaced thermal generation exceeds the cost of pumping energy. The probabilities of powerplant forced outages are computed for each hour and reserve generation is "dispatched" to cover these outages.

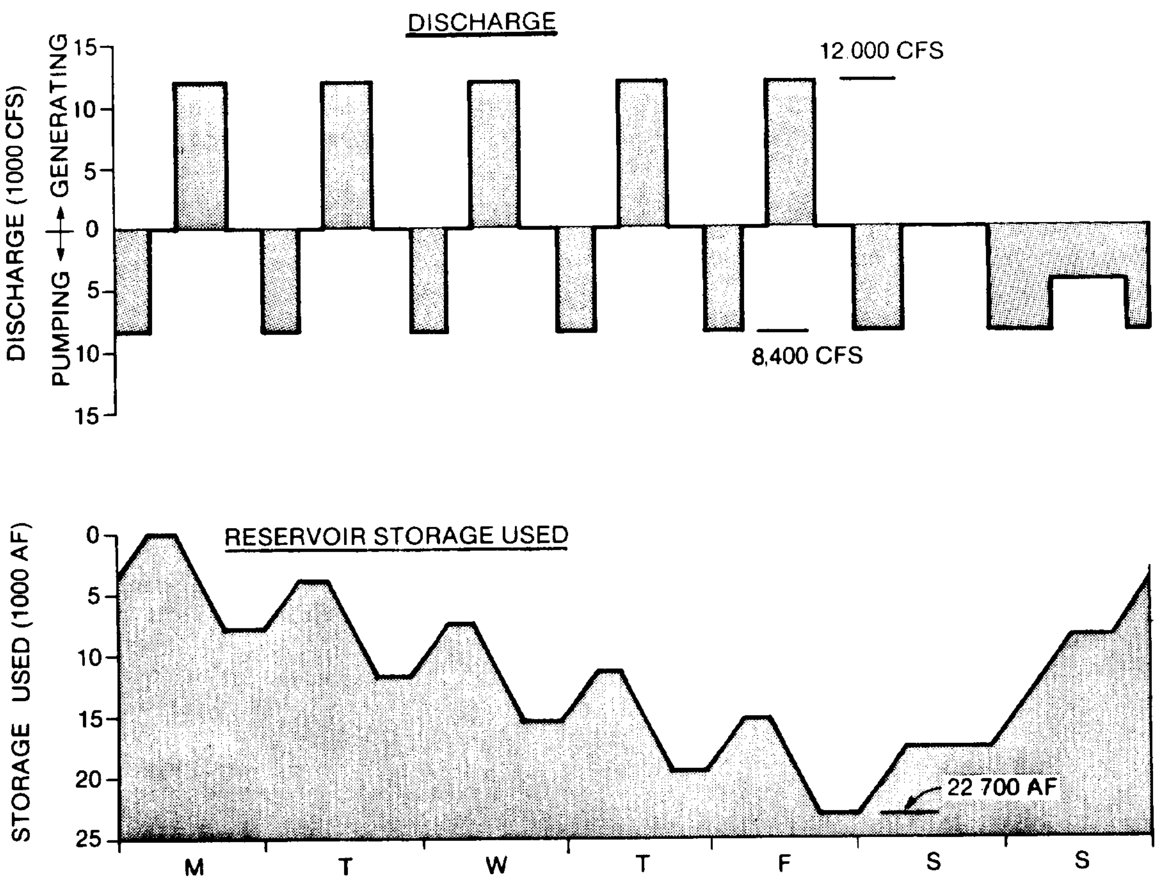


Figure 6-25. Sizing an upper reservoir for an off-stream pumped-storage project

(3) Total system operating costs are then computed and reported by hour, week, month, or year. POWRSYM can be used to estimate energy benefits for all types of hydro projects. It can also be used to help define the design operating schedule for pumped-storage and to determine its annual generation, pumping cost, and energy benefit (see Sections 7-5d through g and 7-6i). Energy benefits are computed by POWRSYM as follows: (a) the power system is operated for a representative year (or a series of years) with the proposed hydro plant in the system, (b) the system is run again with the hydro plant replaced by the most likely thermal alternative, and (c) the cost of operating the system with hydro is deducted from the cost of operating the system with the thermal alternative. The difference in cost is the hydro project's energy benefit. This energy benefit directly incorporates all system operation impacts, so no further "energy value adjustment" is required (see Section 9-5e).

(4) In its basic form, the model does not allocate loads among hydro projects and does not perform streamflow routing. Hence, the aggregate weekly dispatch of hydro should be examined in order to insure that it accurately represents the actual or expected operation of the hydro projects. Although no provision exists in the basic model for shifting energy from week to week within the year, North Pacific Division has made some changes to allow "borrowing" of energy from storage to permit the use of hydro to cover thermal plant forced outages. NPD has also modified the model to analyze pump-back projects in a thermal-based power system. Another user has modified the model to dispatch individual hydro plants or groups of plants (providing they are not hydraulically interconnected). TVA has adapted the model to compute "marginal" energy costs (the costs of the most expensive 100 MW of generation dispatched in any hour).

(5) To summarize, POWRSYM is perhaps the best available tool for evaluating pumped-storage operation and for computing power benefits. FERC uses this model for much of its power value work. A users manual is available (1).

CHAPTER 7

EVALUATING PUMPED-STORAGE HYDROPOWER

7-1. Introduction.

a. Purpose and Scope.

(1) Pumped-storage is a special type of hydropower development, in which pumped water rather than natural streamflow provides the source of energy. This chapter describes the general concepts of pumped-storage operation and outlines the planning studies required to evaluate a pumped-storage project.

(2) There are two basic types of pumped-storage projects:

- pure (or off-stream) pumped-storage projects, which rely entirely on water that has been pumped into an upper reservoir as their source of energy.

- combined pumped-storage projects, which use a combination of pumped water and natural streamflow to produce energy. These projects are also called pump-back projects, and the latter term will be used in this manual.

Both types of projects can be designed to operate on either a daily/weekly cycle (like a conventional hydro peaking plant with pondage) or on a seasonal cycle.

(3) This chapter deals primarily with surface type pumped-storage projects. However, it should be recognized that underground pumped-storage projects, where the powerhouse and lower reservoir are located below the surface, are sometimes viable alternatives for meeting peaking demands (see Section 7-7d). Evaluation procedures for underground projects are generally similar to those which would be followed in examining surface type projects.

(4) Pumped-storage operation can be best understood by examining an off-stream pumped-storage project which operates on a daily/weekly cycle (the most common type of pumped-storage development in the United States). The early sections of this chapter discuss the analysis of this type of project. Later sections are devoted to pump-back, seasonal pumped-storage, and other aspects of pumped-storage development.

(5) Following is an outline of the major topics covered in each of the sections in this chapter.

- 7-2: characteristics of daily/weekly cycle pumped-storage projects

- 7-3: overall procedure for evaluating daily/weekly cycle pumped-storage projects

- 7-4: routing studies required for daily/weekly cycle pumped-storage projects

- 7-5: economic analysis of daily/weekly cycle pumped-storage projects

- 7-6: analysis of pump-back projects

- 7-7: screening studies, seasonal pumped-storage, multiple-purpose pumped-storage, and special problems associated with pumped-storage development.

b. Basic Concept of Pumped-Storage.

(1) The basic idea behind pumped-storage is to convert relatively low-cost off-peak thermal generation from nuclear or coal-fired plants into high-value on-peak power. This is accomplished at a pumped-storage hydro plant by using the off-peak thermal energy to

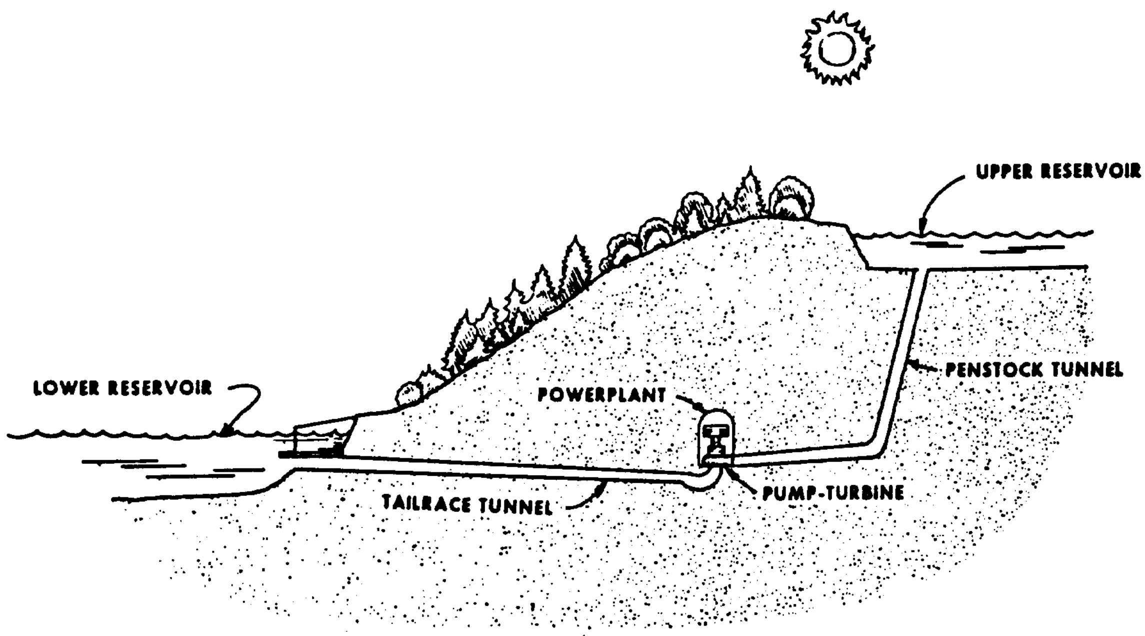


Figure 7-1. Diagram of an off-stream pumped-storage project

pump water from a lower reservoir to an upper reservoir (see Figure 7-1). The water is then released to generate power during peak demand periods.

(2) Most pumped-storage projects operate on either a daily or weekly cycle. At daily-cycle plants, the storage required to support each day's generation must be replenished by pumping the following night (Figure 7-2). In the case of weekly cycle plants, sufficient storage capacity is provided to permit a portion of the pumping to be accomplished on weekends (Figure 7-3). Pumped storage can also be

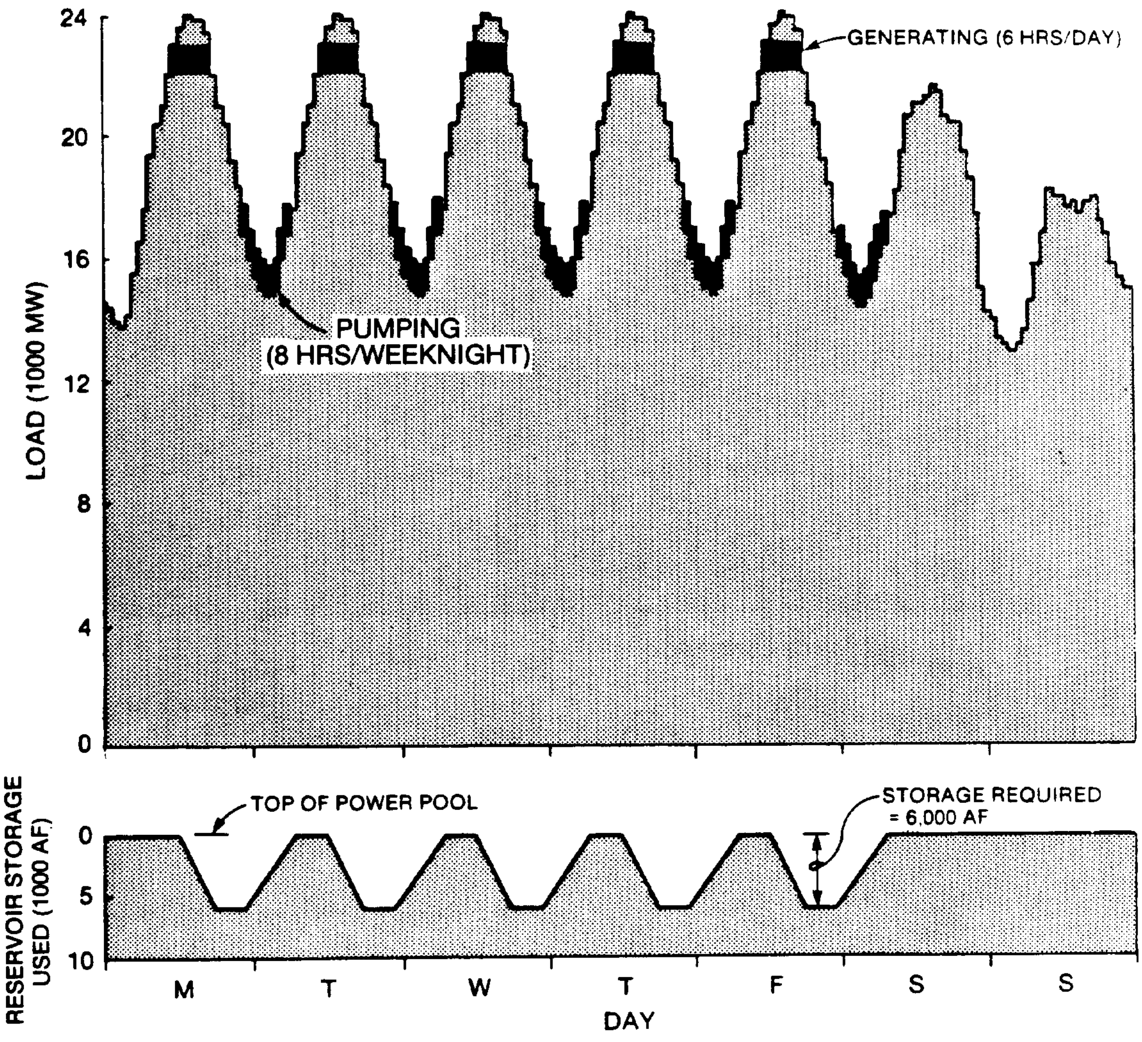


Figure 7-2. Operation of daily cycle pumped-storage project

used to store energy on a seasonal basis, but projects of this type usually store water for other purposes in addition to hydropower.

(3) Pump-back capability might be added at conventional hydro projects for two reasons: (a) to firm up peaking capacity during periods of low streamflow, or (b) to permit large peaking installations to be constructed at sites with relatively low natural flows. A pump-back project is basically a conventional hydro project

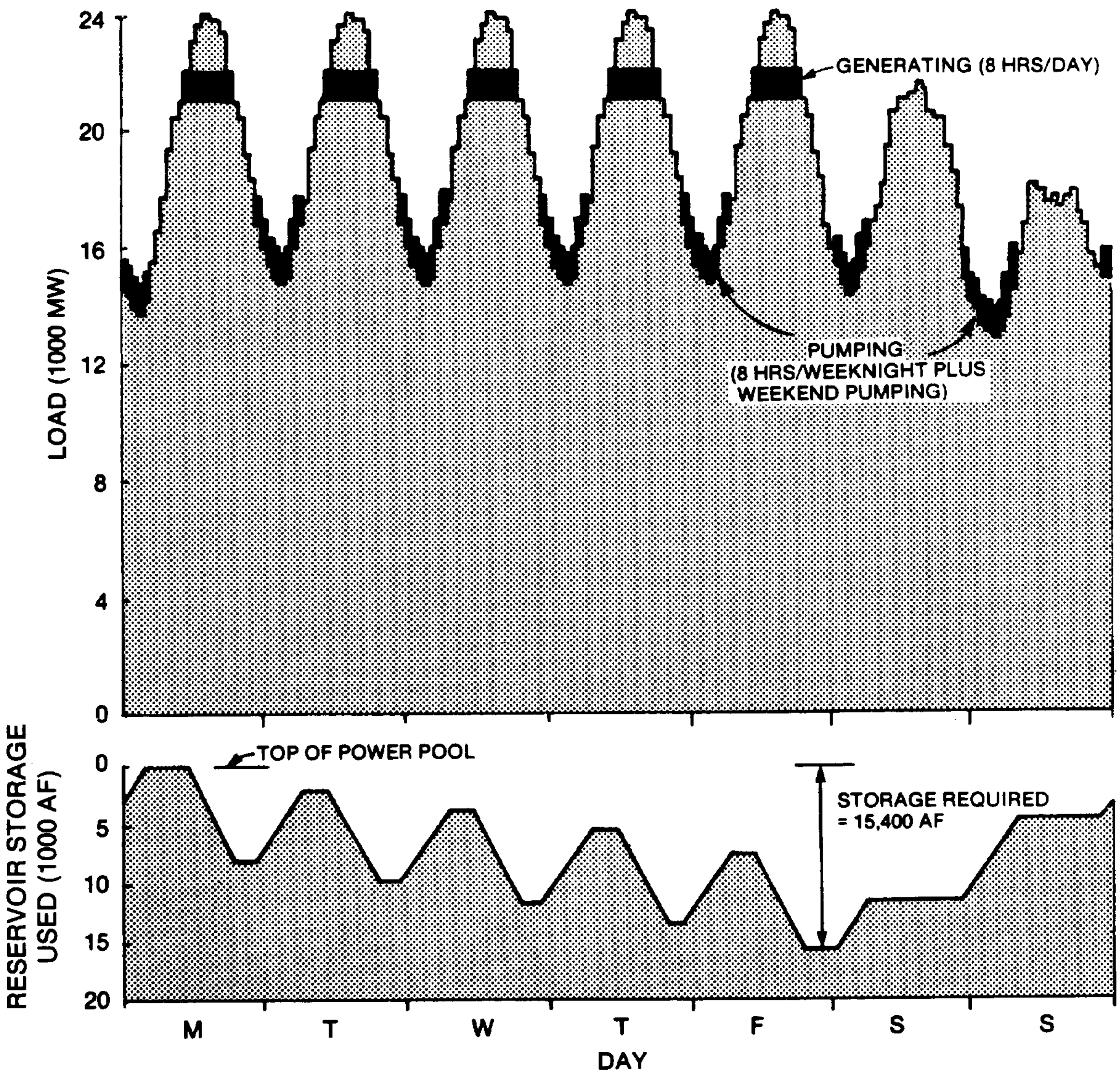


Figure 7-3. Operation of weekly cycle pumped-storage project

at which some or all of the generating units can also operate as pumps. Much of the time, natural flows (in combination with available pondage) may be sufficient to support the plant's peaking capacity. During low flow periods, however, a portion of the peaking discharge would be pumped back at night (or on weekends), to insure that sufficient water is available to meet peaking requirements on subsequent days. A reservoir must exist immediately downstream to capture these releases, and store them until pump-back can be accomplished.

(4) The concept of pumped-storage hydro has existed for many years, and pumped-storage projects were constructed in Europe as early as 1908. However, it was not until after reversible pump-turbines were perfected in the 1950's that pumped storage became an important source of peaking capacity in the United States.

c. Types of Pumped-Storage Projects.

(1) Introduction. Within the two broad categories of pumped-storage hydro, a number of different types of developments have evolved. Following are descriptions and examples of each of these different types. For details on the locations and characteristics of the example projects, refer to the tables in Section 7-1d.

(2) Off-Stream: Daily-Weekly Cycle (General). This type of development typically involves the use of a lower reservoir on a stream or other water body, which provides the source of water, and an upper reservoir located adjacent to the lower reservoir. The upper reservoir may also be located on a stream, but usually it is not. This type of development relies entirely on pumped water as a source of energy. At some projects, the upper reservoir is constructed on a mountain top, where there is little or no local inflow (Taum Sauk and Northfield Mountain are examples). Projects of this type have sufficient reservoir storage to permit operation on a daily or weekly cycle, which is typically sufficient to generate 6 to 20 hours continuously at full output.

(3) Offstream: Daily-Weekly Cycle (Types of Lower Reservoirs). Different types of water bodies have been used as lower reservoirs for off-stream projects. Ludington uses Lake Michigan, while the now-cancelled Cornwall project would have pumped from an open reach of the lower Hudson River. Salina and Seneca use existing multiple-purpose storage projects as lower reservoirs. Seneca (Figure 2-17) is of special interest because it uses a Corps of Engineers reservoir (Kinzua), and the powerhouse is designed to discharge to either the reservoir, or the river below Kinzua Dam, or both. In this way the head at Kinzua Dam, which has no powerhouse of its own, can be utilized also. TVA's Raccoon Mountain project pumps from the pool

behind Nickajack Dam, a navigation and run-of-river power project. Helms uses existing hydro projects as both upper and lower reservoirs. Most of the other off-stream pumped-storage projects use existing pondage projects or specially constructed lower reservoirs. The Corps of Engineers has investigated off-stream projects which would use the Fort Randall Reservoir on the Missouri River (Gregory County) and run-of-river navigation projects on the Arkansas River (Petit Jean-White Oak).

(4) Offstream: Seasonal. Rocky River was the first pumped-storage project to be constructed in the United States (1929). It was designed to pump water into a man-made lake during the high flow season, with releases being made during low flow periods to produce power at-site and firm up generation of a series of run-of-river projects located downstream on the Housatonic River. A number of other seasonal off-stream pumped-storage projects have been studied, but in most cases the primary objective has been to store water for purposes other than power. San Luis is the only large project of this type to have been constructed in this country. At San Luis, irrigation water is pumped into the reservoir during the winter months, when irrigation demands are low. During the winter, water is available in the lower Sacramento River, and the cost of pumping energy is relatively low. During the peak irrigation season, when energy has a higher value, water is released into the Delta-Mendota Canal and the California Aqueduct, producing power at both the San Luis and O'Neill powerplants (see Section M-3). The Corps of Engineers and other agencies have studied large off-stream reservoirs in the Columbia River basin, which is used to to supplement the power storage of the existing reservoir system. However, the relatively small gain in storage benefits that can be realized from additional storage, combined with the high cost of constructing large off-stream reservoirs, has thus far discouraged this type of development.

(5) Pump-Back: Single-Purpose Power Projects. Reversible units may be installed at on-stream hydro projects for one of two reasons: (a) to firm up peaking capacity during occasional periods of low flow, or (b) to permit large peaking installations at sites which are favorable for construction of hydro projects but where natural flows are too low to support such installations. Most single-purpose pump-back projects fall into the second category. At Jocassee and Smith Mountain, nearly 75% of the generation results from pumped-storage. At Horse Mesa and Mormon Flat, small conventional powerplants have been supplemented by large pump-turbine units, to increase the plant's peaking capabilities.

(6) Pump-Back: Multiple-Purpose Projects. Pump-turbines have also been installed at a number of multiple-purpose projects. One reason for this is that the seasonal discharge requirements of other

functions sometimes limit conventional power operation, and pump-back is required to firm up the peaking capacity. Oroville is a large seasonal reservoir which serves as the primary storage facility for the California Water Project. Most of the time, releases for water supply are sufficient to support the plant's installed capacity, but during low discharge periods, pump-back must be utilized to insure that peaking power committments are met. Truman, DeGray, and Cannon are Corps of Engineers projects having large flood control storage requirements. Power storage is limited, so pump-back capability was provided in order to firm up the peaking capacity during occasional low flow periods. In the system where DeGray is operated, there is at present no low-cost, off-peak energy available for pumping, so the plant has thus far been used only for conventional generation and spinning reserve. At Truman, unanticipated fish problems have precluded pumping to date. Carters (Figure 2-18) is another Corps of Engineers multiple-purpose storage project where pump-back has been used to support a large peaking installation, with half of the project's generation being supported by pumping. Richard B. Russell is a pondage project which develops the reach between two large storage projects on the Savannah River. The original power installation consisted of conventional peaking units, but the addition of reversible units made it possible to double the peaking capacity.

(7) Diversion Type: Single-Purpose Power. A diversion type project is one where water is diverted from one river basin to another. In such cases the pumping plant and generating plant would be separate installations. An example of a single-purpose hydropower diversion project would be where water is pumped into a storage reservoir located in an adjacent basin where the topography and other characteristics are more suitable for hydropower development. At some developments, the water thus diverted passes through a series of downstream generating plants, thereby realizing a large gain in generation in comparison with the pumping energy expended. No projects of this type are located in the United States, although some have been developed in Europe and South America.

(8) Diversion Type: Multiple-Purpose. Pumped-storage can also be incorporated in inter-basin diversion projects constructed to transport water for irrigation or municipal water supply. Frequently the power installations at projects of this type are designed only to recover as much of the pumping energy as possible, but in at least two cases reversible units have been installed to provide peaking power. Castaic is located at the terminus of West branch of the California Aqueduct, and it is designed primarily to recover energy from water conveyed over a mountainous segment of the Aqueduct. However, at times it operates as an off-stream pumped-storage peaking project.

Similarly, reversible units have been installed in the pumping plant constructed to pump water from Grand Coulee reservoir to Banks Lake, the equalizing reservoir for the Columbia Basin irrigation project. Normally these units function as pumps, but they can operate as generating units during the winter months, when pumping loads are minimal and power demand is high.

(9) Other Types of Projects. There are also several examples of pumped storage being used to provide pondage for conventional hydro plants. The most notable examples are the U.S. and Canadian power developments at Niagara Falls. Substantial flows must be maintained over the falls during the daylight hours, thus limiting the amount of water that can be diverted for power production during the hours when power demands are greatest. Tunnels have been constructed to divert water around the falls at night, and on the U.S. side this water is pumped into the Lewiston Reservoir. During the daylight hours, this water is released to produce power at both Lewiston and at the Robert Moses conventional generating plant, which discharges into the Niagara River below the falls. A similar development exists on the Canadian side of the river.

d. Existing Pumped-Storage Projects. Table 7-1 lists the major off-stream pumped-storage projects in the U.S. and their characteristics. Table 7-2 lists the major pump-back projects. Figure 7-4 shows the locations of these projects. The numbers on the map correspond to the project numbers on Tables 7-1 and 7-2. For further details on specific projects, Part 3 of reference (12) and Sections 2-2, 2-3, and Appendix B of reference (48j) should be consulted. Reference (22) contains an extensive bibliography of pumped-storage articles.

7-2. General Characteristics of Off-Stream Pumped-Storage Projects.

a. Introduction. This section describes the general characteristics of off-stream pumped-storage projects: desirable site characteristics, the operating cycle, storage requirements, plant size, head range, pump-turbine characteristics, rated capacity, plant operating characteristics, cycle efficiency, charge/discharge ratios, reliability and availability, plant factor, size and number of units, and other factors. Much of the material presented in this section has been drawn from Volume 3 of EPRI's Assessment of Energy Storage Systems Suitable for Use by Electric Utilities (12). References (22) and (48j) are also useful sources of information. For information on the characteristics of pump-back projects, see Section 7-6.

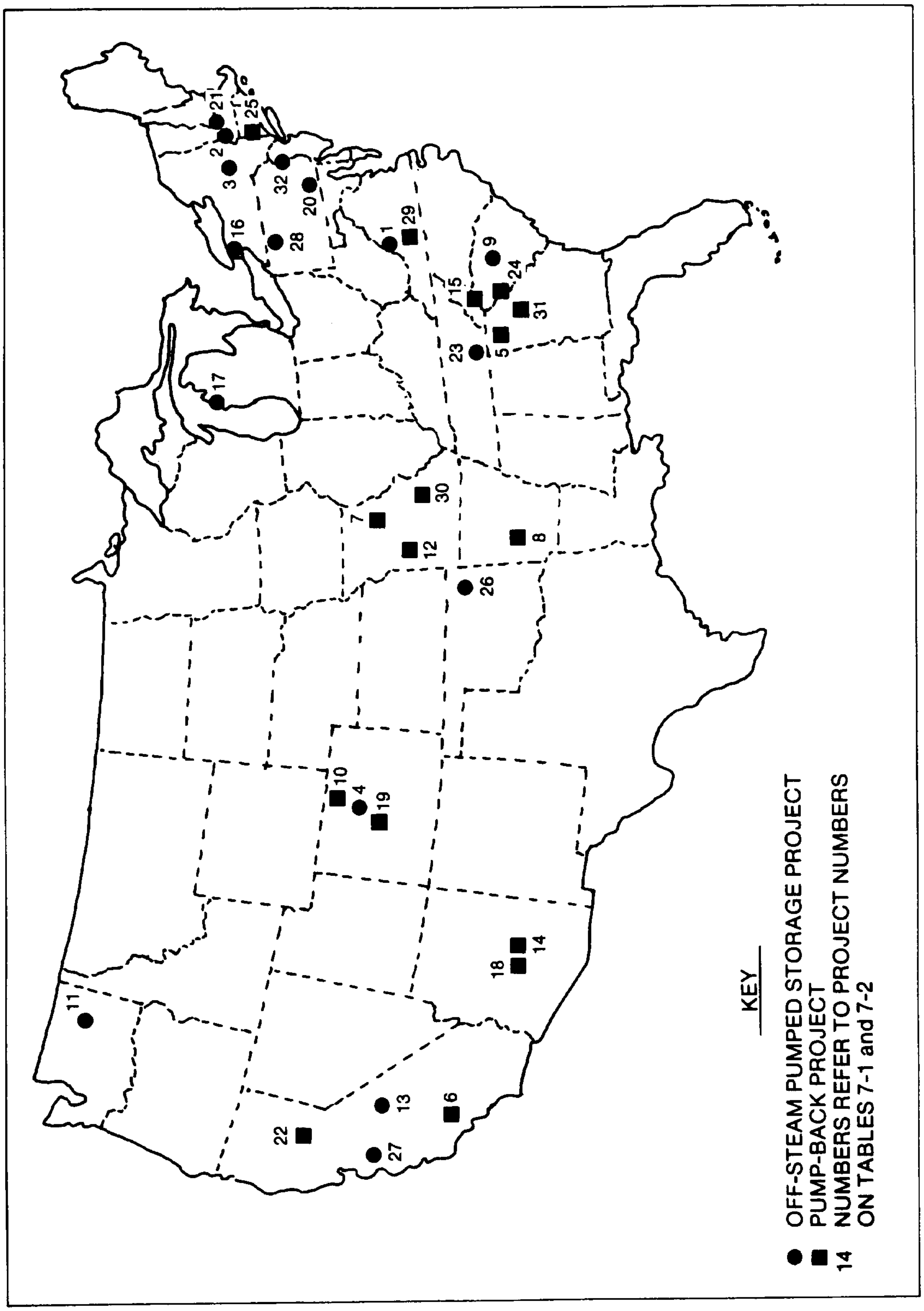


Figure 7-4. Major pumped-storage projects in the United States

TABLE 7-1. Major Off-Stream Pumped-Storage

Map No. 12/	Name of Project	State	Owner
1.	Bath County	VA	Virginia Power Company
2.	Bear Swamp	MA	New England Power Company
3.	Blenheim-Gilboa	NY	Power Authority, State of New York
4.	Cabin Creek	CO	Public Service Company of Colorado
9.	Fairfield	SC	South Carolina Electric and Gas Co.
11.	Grand Coulee 13/	WA	U.S. Bureau of Reclamation
13.	Helms	CA	Pacific Gas and Electric
16.	Lewiston-Niagara	NY	Power Authority, State of New York
17.	Ludington	MI	Consumers Power/Detroit Edison
20.	Muddy Run	PA	Philadelphia Electric Company
21.	Northfield Mountain	MA	CP&LCo./HE&LCo./WMECo. 4/
23.	Raccoon Mountain	TN	Tennessee Valley Authority
26.	Salina	OK	Grand River Dam Authority
27.	San Luis	CA	U.S. Bureau of Reclamation
28.	Seneca (Kinzua)	PA	CEICo./PECo. 6/
30.	Taum Sauk	MO	Union Electric Company
32.	Yards Creek	NJ	PSG&ECo./JCP&LCo. 8/

1/ rated generating capacity
2/ utilizes seasonal irrigation storage
3/ utilizes seasonal power storage
4/ Connecticut Power and Light Company/Hartford Electric and Light Company/Western Massachusetts Electric Company
5/ different units operate in different head ranges
6/ Cleveland Electric Illuminating Co./Pennsylvania Electric Co. (GPU)
7/ two 198 MW reversible units and one 26 MW conventional unit

Projects in the United States, 1 January 1985

On-Line Date	Units	Total Capacity (MW) 1/	Head Range (Feet)	Storage (Hours)	Map No. 12/
1985 11/	6	2100	1080 10/	11.3	1.
1974	2	600	660-750	5.6	2.
1973	4	1000	1001-1088	11.6	3.
1966	2	300	975-1190	5.8	4.
1979	8	511	155-169	8.0	9.
1973	6	314	262-358	2/	11.
1984	3	1050	1560 10/	3/	13.
1962	12	240	65-100	9/	16.
1973	6	1979	296-362	8.7	17.
1967	8	800	346-401	14.2	20.
1972	4	1000	700-815	8.5	21.
1979	4	1530	870-1017	24.0	23.
1968	6	260	223-243	19.0	26.
1968	8	424	114-316 5/	2/	27.
1970	3 7/	422	642-791	11.2	28.
1963	2	408	714-879	7.7	30.
1965	3	387	651-735	8.8	32.

8/ Public Service Gas & Electric Co./Jersey Central Power & Light Co.
9/ primary function of pumped-storage is to support large conventional hydro plants
10/ rated head (generating) of pumped-storage
11/ scheduled on-line date
12/ refers to location number on Figure 7-4; missing numbers are on Table 7-2
13/ Grand Coulee Pumping Plant

TABLE 7-2. Major Pump-Back

Map No. 1/	Name of Project	State	Owner
5.	Carters	GA	Corps of Engineers
6.	Castaic	CA	LADWP/CDWR 4/
7.	Clarence Cannon	MO	Corps of Engineers
8.	DeGray	AR	Corps of Engineers
10.	Flatiron	CO	Bureau of Reclamation
12.	Harry S. Truman 6/	MO	Corps of Engineers
14.	Horse Mesa	AZ	Salt River Project Authority
15.	Jocassee	NC/SC	Duke Power Co.
18.	Mormon Flat	AZ	Salt River Project Authority
19.	Mt. Elbert	CO	U.S. Bureau of Reclamation
22.	Oroville (Hyatt)	CA	California Dept. of Water Res.
24	Richard B. Russell	GA/SC	Corps of Engineers
25.	Rocky River	CT	Connecticut Power & Light Company
29.	Smith Mountain	VA	Appalachian Power Company
31.	Wallace	GA	Georgia Power Company

1/ number of reversible units/number of conventional units
2/ total reversible generating capacity/total conventional generating capacity
3/ at some plants, different units operate in different head ranges
4/ Los Angeles Department of Water & Power/California Department of Water Resources

Projects in the United States, 1 January 1985

On-Line Date	Units 1/	Total Capacity (MW) 2/	Head Range (Feet) 3/	Storage (Hours)	Map No. 7/
1975	2R/2C	250/250	320-427	44	5.
1973	6R/1C	1275/56	891-957	14.6	6.
1984	1R/1C	31/27	59-107	8	7.
1971	1R/1C	28/40	144-188	5/	8.
1954	8R/2C	480/63	140-290	4000 5/	10.
1981	6R/0C	160/0	41-79	19	12.
1972	1R/3C	100/30	151-259	8	14.
1974	4R/0C	610/0	276-331	192	15.
1971	1R/1C	49/9	100-138	11	18.
1981	2	200	400-475	13	19.
1968	3R/3C	293/351	500-675	5/	22.
1987 8/	4R/4C	475/346	135-163	26	24.
1929	2R/2C	7/24	190-219	830	25.
1965	3R/2C	236/300	174-195	5	29.
1980	4R/2C	216/108	94-97	42.9	31.

5/ utilizes multiple-purpose seasonal storage
6/ not currently operating in pumping mode due to fishery problems
7/ refers to location number on Figure 7-4; missing numbers are on Table 7-1
8/ scheduled on-line date for pump-back units, first conventional unit was placed in service in 1985.

b. Desirable Site Characteristics.

(1) General. In order to be cost-effective, an off-stream pumped storage site should have most or all of the following characteristics:

- geologic conditions should be suitable for water-tight reservoirs
- head should be as high as possible
- length of water conduit (intake tunnel, penstock, and discharge tunnel) should be as short as possible
- reservoir sites should require minimum excavation and embankment
- use existing reservoir for lower reservoir, if possible
- both reservoirs should have suitable drawdown characteristics
- site should be suitable for a large power installation
- site should be located reasonably close to load centers or transmission corridors
- source(s) of relatively low cost pumping energy should be available.

Note that these are all primarily engineering and economic characteristics. Environmental and socio-economic criteria are also important, and in many cases they may dominate the site selection process. However, this manual is limited to discussing engineering aspects of hydropower planning. References (12) and (22) and standard references on environmental impact evaluation give further information on the environmental aspects of pumped-storage development. The availability of relatively low-cost pumping energy is also a prerequisite to consideration of pumped-storage development, but this is addressed under the operational and economic studies, rather than under site evaluation.

(2) Head. Reservoir storage requirements are inversely proportional to head (Figure 7-5), so reservoir costs can be minimized by selecting a site with a high head. Hydraulic capacity is also inversely proportional to head, so penstock diameter, and hence penstock costs, can also be minimized by maximizing head. For a given plant capacity, powerhouse costs are lower for high head plants. This is because the units run at higher speeds and high-speed machines are

smaller than low-speed machines. Because smaller water volumes are required at high head plants, reservoir drawdowns are usually smaller at both reservoirs.

(3) Length of Water Conduits. Costs of water conduits (intake tunnels, penstocks, and discharge tunnels) can represent one-quarter or more of a pumped-storage project's costs, so sites should be sought which will require minimum penstock and discharge tunnel lengths.

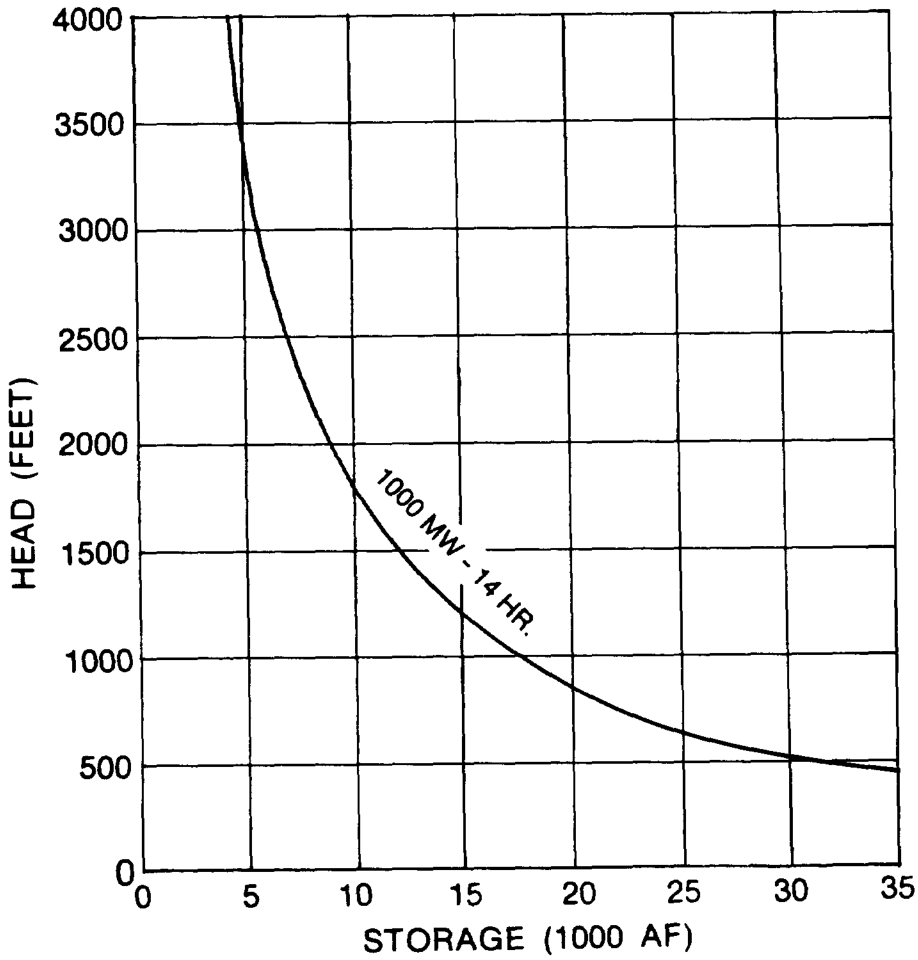


Figure 7-5. Reservoir storage required vs. head for 1000 MW plant with 14 hours of storage

This is particularly important at the lower head sites, because of the larger penstock and tunnel diameters involved. The economic limits to length of water conduits is a function of head and can be expressed in terms of horizontal length to head (L/H) ratios. Recent experience suggests that maximum acceptable L/H ratios range from 10 to 12 for high-head (1200-1500 ft.) projects down to 4 to 5 for low-head (500-600 ft.) sites.

(4) Upper Reservoirs. Upper reservoirs are usually constructed either with a dam across a natural valley or with an enclosure dike around a flat area, often on a hilltop. To minimize costs, sites should be sought where minimum excavation and embankment volumes are required, and sites having natural depressions are particularly desirable in this regard. Large drawdowns may cause slope instability, so sites with large, relatively shallow reservoirs are usually preferred to narrow, steep reservoirs. Slope treatment can sometimes alleviate this problem, but it can be expensive. Water-tight reservoirs are also essential, to minimize leakage losses (which in the case of the upper reservoir results in energy loss).

(5) Lower Reservoirs. Project costs can often be reduced by using existing reservoirs as lower reservoirs. However, care should be taken to insure that sufficient storage is available to handle fluctuations due to pumped-storage operation in addition to fluctuations resulting from existing reservoir operations. Because of the limited head range for efficient pump-turbine operation (Section 7-2f) and submergence requirements (Section 7-2q), caution should be exercised when considering the use of existing multiple-purpose reservoirs with large fluctuation ranges. When new lower reservoirs are required, sites with minimum embankments and relocation costs should be sought. Since new lower reservoirs are usually located on existing streams and are more generally accessible to the public, they should be designed to minimize daily and hourly fluctuations in order to insure public safety and to minimize environmental impact. Minimizing leakage losses is important here also, unless there is an abundant water supply.

(6) Plant Size. To minimize unit costs, most single-purpose off-stream pumped-storage plants are planned for relatively large capacities, with existing U.S. plants ranging in size from 300 MW to 2000 MW. Most recent plants have been in the 1000 MW or greater range. An additional factor encouraging large developments is the difficulty of obtaining site approval because of environmental and other factors. Total environmental impact (as well as study costs) can often be minimized by concentrating developments at one or two larger sites rather than many smaller sites.

(7) Geologic Conditions. It is beyond the scope of this manual to discuss geologic criteria for pumped-storage development, but it should be noted that geologic conditions are a key factor in evaluating the suitability of a site.

(8) Site Selection. It is seldom possible to locate sites which meet all of these criteria, in part because of the wide variations in topographic and geologic conditions around the country. As a result, trade-offs are usually required in the site selection process. It is because of these variations in conditions that specific ranges have not been recommended for head, length of water conduit, and plant size. For example, in some parts of the country, the topography is such that numerous sites are available with heads of 1000 feet or more. In such areas, plants of 1000 MW and larger can usually be constructed quite economically, and penstock/tunnel lengths of up to about two miles may be acceptable. In other areas, heads of 300-400 feet may be the highest obtainable. In such situations, short penstock lengths and reservoirs with minimum embankment and excavation requirements are much more important. The L/H ratios mentioned in paragraph (3) are helpful guidelines in estimating the maximum economical penstock and tunnel length for a given head. When heads are low, smaller plant sizes may also be necessary. At sites with low heads, the larger plant discharge and reservoir storage requirements per kilowatt of installed capacity will often dictate smaller installations than at high-head sites.

c. Operating Cycle.

(1) Paragraph 7-1b(2) and Figures 7-2 and 7-3 describe the two basic operating modes for off-stream pumped-storage projects, the daily and weekly cycles. The type of cycle utilized for a given project and the characteristics of that cycle are usually defined by the characteristics of the power system in which the plant will be operating: specifically, the number of off-peak pumping hours available each week-night and the number of on-peak generating hours required each weekday. In the following discussion, pumping and generating times are expressed in equivalent hours of full-load operation each day (at rated capacity in the generating mode). In actual operation, plants often operate at partial loadings part of the time, but equivalent hours of full-load pumping and generation are often used to simplify the analysis.

(2) Two different criteria may govern the operation of an off-stream pumped-storage project: economic dispatch and must-run operation. Normally, project operation is based on economic dispatch: i.e., the project is operated only if the value of the on-peak thermal energy that would be displaced by pumped-storage project generation exceeds the cost of the pumping energy. However, during periods of

high power demand and/or numerous plant outages, the project's capacity may be required so that the power system can meet its peak load requirements. In such cases, the project may be operated even though relatively high cost energy may be required to refill the reservoir during off-peak hours. This is sometimes called a "must-run" operation, as opposed to economic dispatch.

(3) The operating cycle required to perform the must-run operation helps to define a project's reservoir storage requirements and may serve as the basis for establishing its dependable capacity. The operating cycle, storage requirements, installed capacity, and project economics are all interrelated, and an iterative process is required to select the best plant size (see Section 7-3). However, one of the first steps in the analysis is to define a preliminary operating cycle. This is done through examination of the load shape and consultation with one or more of the entities familiar with the operation of the area power system: the regional Power Marketing Administration, FERC, and local utilities.

(4) Load shapes must be developed for typical peak demand weeks. Normally these shapes would be based on historical data, but they should be adjusted if necessary to meet expected changes in load shape. These changes could be caused by changes in the use pattern, changes in the customer mix, and the effects of load management. The analysis of the operating cycle should not be limited to the annual peak demand period. In some systems, the load shape is broader in off-peak periods, requiring more carry-over storage to support the capacity in the peak-demand weeks.

(5) Through examination of these load shapes, it should be possible to determine the maximum number of off-peak pumping hours available, which is normally in the 6 to 8 hour range on week-nights. In making this analysis, it should be kept in mind that pumping can be done in single-unit increments. In some off-peak hours, there may not be sufficient pumping energy to support the entire plant, but pumping could be accomplished with one or two units. This should be accounted for in estimating the equivalent number of full-load pumping hours available. Generally, the number of hours of available off-peak pumping energy is inversely related to the size of the pumped-storage plant in relation to the system load.

(6) The number of on-peak generating hours required is more difficult to define, because it is a function of the system generation mix and economics as well as load shape. Preliminary studies should consider a range of hourly generation requirements. If peaking capacity is required for an equivalent of only 4 to 6 hours at full capacity, the project can usually operate on a daily cycle (Figure 7-2). A daily cycle operation requires the minimum amount of

reservoir storage per kilowatt of installed capacity. However, a system often requires that peak output be maintained for more than 4 to 6 hours per day. To support this type of operation, a plant must be operated on a weekly cycle, with some of the pumping being accomplished on weekends (Figure 7-3). A reasonable range of alternatives for initial study might include a daily cycle and two or more weekly cycles, covering a range of equivalent full-load generation from 5 to 9 hours per weekday.

(7) It should also be mentioned that in most power systems, there are periods when system energy costs preclude the operation of pumped-storage: either the available off-peak energy is too costly, or the on-peak loads are already being carried with lower-cost generation. During these periods, the pumped-storage capacity is usually assigned to operating reserve, where its quick-start capability permits it to serve quite effectively.

d. Storage Requirements.

(1) For planning purposes, reservoir storage requirements are defined initially in terms of equivalent hours of full-load generation. This parameter is primarily a function of power system operation. Once this parameter has been defined, the volume storage requirements of specific sites can be determined by taking into consideration the site's head characteristics and the desired plant size.

(2) For a daily cycle plant, the number of hours of full-load generation that can be achieved each day (and hence the minimum reservoir storage requirements) is a function of the number of hours of off-peak pumping energy that are available each night, the overall cycle efficiency, and the charge/discharge ratio. The cycle efficiency, which is discussed in detail in Section 5-2j, accounts for machine efficiency and penstock losses in both the pumping and generating portions of the operating cycle. The charge/discharge ratio is the ratio of the unit's average pumping load to its rated generating capacity. This parameter is a characteristic of the pump-turbine runner design and how the unit is rated (see Section 5-2k).

(3) An example will illustrate how these parameters are related. Take for example a daily cycle plant with a cycle efficiency of 70 percent and a charge/discharge ratio of 1.1, operating in a system where seven hours of off-peak pumping energy is available each weeknight. Such a plant would require a reservoir with a minimum of (7.0 hours) x (0.70) x (1.1) = 5.4 hours of usable storage capacity.

(4) Similarly, the minimum storage requirements for a weekly cycle plant could be estimated using the following equation:

$$\text{Hours of Storage } (t_s) = 5(t_g) - 4(t_p)(E_c)(C_r) \qquad \text{(Eq. 7-1)}$$

where: t_g = equivalent hours of full-load generation per weekday
t_p = equivalent hours of pumping at full capacity per weeknight
E_c = overall cycle efficiency
C_r = charge/discharge ratio

(5) Figure 7-6 shows how storage requirements vary with number of hours of equivalent full-load generation per weekday for a project with the characteristics described in paragraph (2). It can be seen from both Equation 7-1 and Figure 7-6 that storage requirements increase by five hours for each additional hour of full-load generation. Note that the storage requirement values in Figure 7-6 are based on specific assumptions regarding pumping time, cycle efficiency, and charge/discharge ratio. Storage requirements can be reduced if (a) more night-time pumping is available, (b) a higher cycle efficiency can be obtained, (c) units with a higher charge/

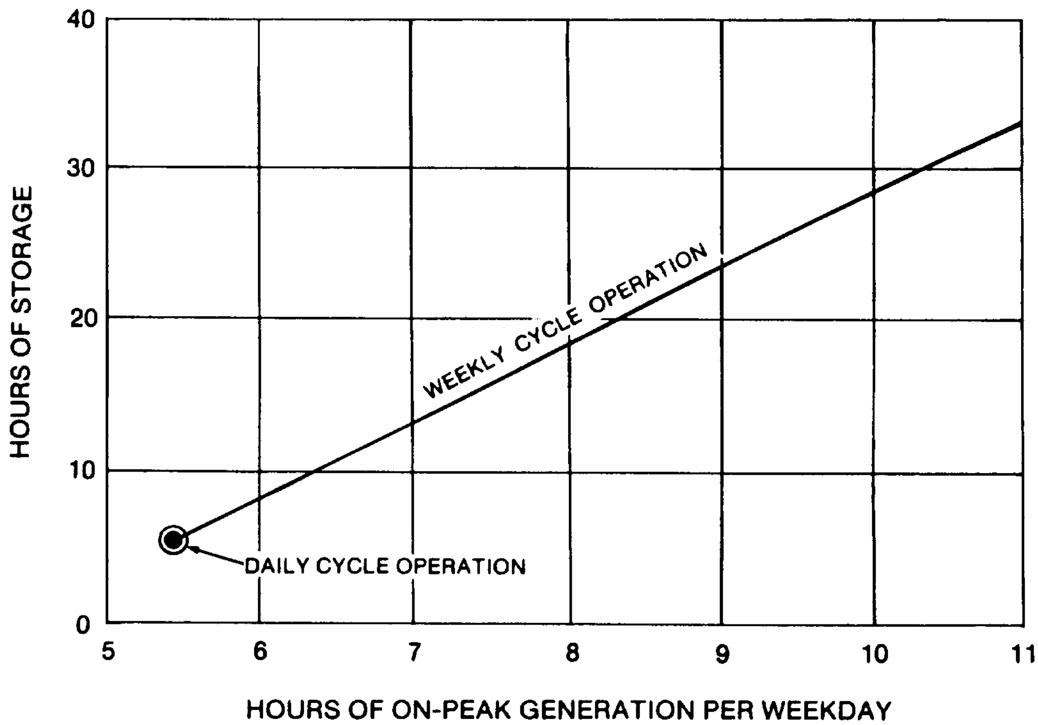


Figure 7-6. Reservoir storage requirements (in hours) versus hours of on-peak generation for plants operating in a system where seven hours of pumping can be done each week-night

discharge ratio are selected, or (d) the units are derated in the generating mode.

(6) Another key point is that the practical upper limit to the usable storage is established by the number of weekend hours available for pumping. If, in the case of the example project, a maximum of 20 hours of equivalent full-discharge pumping is available on weekends, it can be seen from Figure 7-6 that weekday generation will be limited to 8.3 hours per day.

(7) By estimating the number of night-time pumping hours and assuming an average cycle efficiency and charge/discharge ratio for the plant, preliminary storage requirements can be estimated for various weekday generation requirements. These storage requirements represent the minimum storage needed to follow the specified operating cycle. It is usually desirable to provide some additional storage to cover for evaporation losses and reservoir leakage, for reserve, and to provide operating flexibility (see Sections 6-7j(3) and (4)).

(8) Once the equivalent number of hours of full-load generation is established, the specific storage requirement (in acre-feet) for a given site can be estimated with the following adaptation of the water power equation:

$$\text{Storage (AF)} = \frac{976(MW)t_s}{He_g} \qquad \text{(Eq. 7-2)}$$

where: MW = plant capacity in megawatts
t_s = storage requirement in hours of equivalent full-load generation
H = average gross head in feet
e_g = generating efficiency, including head losses (see Section 7-2j)

Figure 7-5 shows the variation of reservoir storage requirements versus head based on a required capacity of 1000 MW, a 14 hour storage requirement, and an average generating efficiency of 83 percent. The storage requirements for a specific site can be defined more precisely using a sequential streamflow routing analysis (see Section 7-3c).

(9) The above analysis is intended only to develop preliminary storage requirements for a given plant size and operating cycle. The final determination of storage requirements will be based on economics and other factors, and would include testing of the plant's operation under a range of simulated system operating conditions (see Section 7-5). A range of reservoir sizes should be examined for each plant size. This analysis should be done very carefully, and allowance

should be made for unanticipated operating conditions. Operating experience with some of the earlier pumped-storage projects constructed in the United States suggests that storage requirements were estimated too conservatively, and that additional storage could have added significantly to the usability of the capacity.

e. Plant Size.

(1) System requirements and site economics are major factors influencing plant size. The general process outlined in Section 6-2 can serve for identifying a range of potential plant sizes. For the reasons outlined in Section 7-2b(6), off-stream pumped-storage installations are typically large, with many falling in the 1000 to 2000 MW range. Site characteristics (i.e. low heads or limited reservoir storage) and system requirements sometimes dictate smaller plants, but 300 MW appears to be the lower limit among plants of this type constructed in the United States in the past 20 years.

(2) Some of the early, smaller plants were constructed to meet the needs of individual utilities. More recently, it has been possible to take advantage of economy of scale by constructing plants to meet the joint requirements of several utilities, or even entire power pools. Selection of the appropriate range of plant sizes to be considered should be made in consultation with the regional PMA, FERC, and local utilities.

f. Heads.

(1) Pumped-storage projects have been constructed to develop heads ranging from less than 100 feet to more than 2000 feet, but most of the projects at the low end of this range are either multiple-purpose projects, pump-back projects, or special types of projects. The minimum practical head for an off-stream pumped-storage project using reversible units is generally around 300 feet, with higher heads being preferred.

(2) A variety of machine types are available for pumped-storage applications. The type used for a given installation is generally dictated by the available head. In the 300 to 1600 foot range (and perhaps up to 2000 feet), the single-stage reversible Francis pump-turbine is usually the best choice. Above this head range, multi-stage units, or separate pumps and turbines should be considered, although pump-turbine technology is advancing to the point where reversible single-stage Francis units may be able to accomodate heads of greater than 2000 feet. For low head installations, several types of reversible pump-turbine are available, including bulb, vertical Kaplan and propeller, and Francis, the effective ranges of each type

corresponding generally to those shown on Figure 2-35 for the corresponding turbine type.

(3) The design of a reversible pump-turbine represents a compromise between efficient pumping operation and efficient turbine operation. As a result, the head range in which a reversible unit can operate relatively efficiently as both a pump and a turbine is rather limited. Since a high cycle efficiency is usually required for pumped-storage to be cost-effective, pumped-storage projects are normally designed to operate over a relatively narrow head range. A survey of major U.S. off-stream pumped-storage projects shows that the ratio of minimum to maximum head falls in the range of 0.8 to 0.9 (and preferably 0.85 or greater). It is recommended that head fluctuations be limited to this range wherever possible.

(4) Wider head ranges are possible, and in fact may be required in the case of (a) multiple-purpose projects with pump-back and/or (b) off-stream pumped-storge projects that use multiple-purpose storage projects as lower reservoirs, but certain penalties must be accepted. At the high end of a wide operating head range, both pumping efficiency and pumping discharge capacity fall off substantially, reducing the amount of water that can be pumped back during the available off-peak pumping hours. At the low end of the head range, turbine output and turbine efficiency are reduced markedly, limiting the amount of power that can be produced. At both ends, the machinery will tend to run roughly, with all of the attendent vibration problems.

(5) At pump-back projects with relatively wide head ranges, operating conditions are often such that (a) pumping is not required during periods when the head is at the high end of the range (i.e., when the reservoir is full or nearly full), and (b) the project operates only infrequently in the low end of the range, where turbine output is limited. A satisfactory operation can sometimes be achieved if it is possible to obtain reversible units that will operate efficiently under these particular conditions. Installing a mix of reversible units and conventional turbines and/or units designed to operate at different head ranges also may help to effectively utilize the power potential of projects of this type.

(6) Because of the complexity of pump-turbine design characteristics, it is suggested that hydraulic machinery specialists from one of the Hydroelectric Design Centers (Section 1-7) be consulted at an early stage in the planning process to help determine what type of pump-turbine installation and what type of power operation is most suitable for a given site.

g. Pump-Turbine Performance.

(1) Reversible units operate somewhat differently from conventional turbines. Operating in the generating mode is similar to conventional turbine operation, in that output can be varied by varying the gate opening. However, as a practical matter, units are usually operated as close to the point of best efficiency as possible. In the pumping mode, the unit operates at the gate opening that allows the most efficient operation for a given head.

(2) Figure 7-7 shows some of the characteristics of a typical Francis pump-turbine design, adapted from data presented in Volume 3 of EPRI EM-304 (12). This design is shown as being applied to a project with an operating head range of 730-820 feet (a ratio of minimum to maximum head of 89 percent). It is assumed in this case that the unit will be rated at the minimum operating head (when generating) of 730 feet. The full-gate discharge at this head would be about 3580 cfs and the overall generating efficiency (e_g) would be about 82 percent. The rated generating capacity would therefore be

$$kW = \frac{QHe_g}{11.81} = \frac{(3580 \text{ cfs})(730 \text{ feet})(0.82)}{11.81} = 180 \text{ MW.}$$

(3) Note from the upper portion of Figure 7-7 that the pumping discharge at that head would be about 2930 cfs, substantially less than the generating discharge. The lower portion of Figure 7-7 shows that, at this head, the pumping efficiency (e_p) of about 87 percent is higher than the generating efficiency. However, since the pumping load requirements are inversely proportional to efficiency, the pump motor size at rated head will be somewhat larger than the generator requirement.

$$kW = \frac{QH}{11.81\ e_p} = \frac{(2930 \text{ cfs})(730 \text{ feet})}{(11.81)(0.87)} = 208 \text{ MW.}$$

(4) The application of this runner design to the 730-820 foot operating head represents a typical application for an off-stream pumped-storage project. The pump discharge is less than the generating discharge throughout the head range, and the pumping efficiency is somewhat greater than the generating efficiency. The pumping load requirements are greater than the generator output at most heads. Thus, the pumping requirements establish the size of the motor-generator. Note that because the motor-generator is sized to meet pumping requirements, the unit is capable of generating somewhat more than 208 MW in the high end of the operating head range, but the

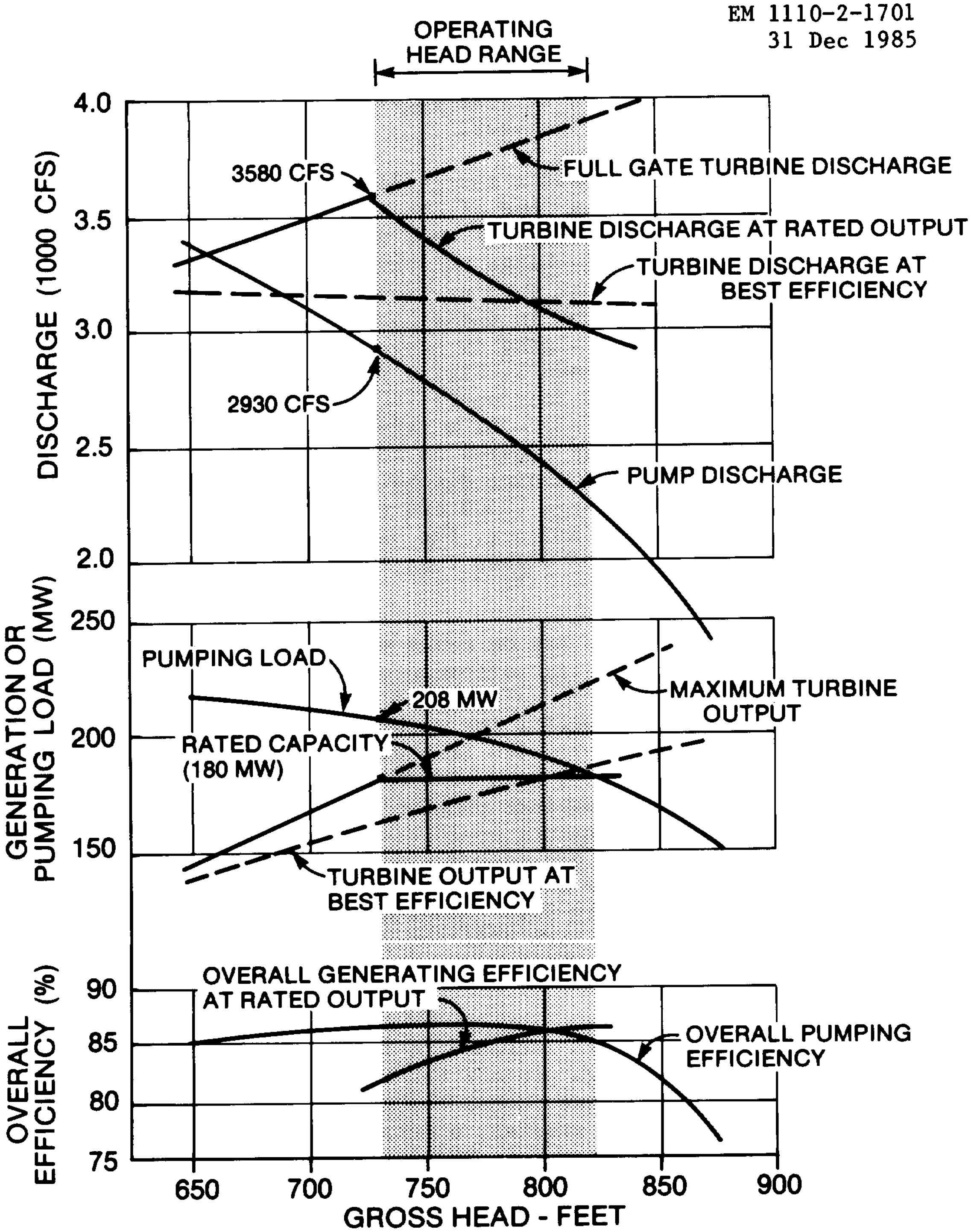


Figure 7-7. Performance curves for a typical pump-turbine runner showing application to a plant with an operating head range of 730-830 feet.

unit may in fact be operated at less than 208 MW in this head range in order to achieve best efficiency.

(5) This unit would have a charge/discharge ratio of about 1.1 (based on an average pumping load of about 200 MW and the rated generating capacity of 180 MW). At some projects, it may be important to have a higher pumping discharge relative to the generating discharge: i.e., where off-peak pumping time is limited and it is desired to move as much water in these hours as possible. In such cases, the unit would be designed to operate in the left-hand portion of the performance curve shown in Figure 7-7. Applying the same turbine design to a 650-730 foot operating head range would illustrate this approach (see Figure 7-8). At a rated head of 650 feet, the generating capacity would be limited to about 140 MW, but in the low end of the head range, the pumping discharge would equal or exceed the full gate generating discharge (3400 cfs versus 3300 cfs). However, to obtain this type of performance, the machine cost per kilowatt of generating capacity would be higher than for the original example (see Section 7-2k).

(6) Conversely, there may be cases where generating performance is more important than pumping performance. This might be the case at a pump-back project where the units would operate in the generating mode most of the time. Applying the turbine design in Figure 7-7 to an operating head range of 775-870 feet would achieve this objective (see Figure 7-9). At a rated head of 775 feet, the generator capacity (200 MW) would exceed the maximum pumping requirements (195 MW), and thus the generating requirements would dictate the size of the motor-generator. The generating efficiency would be somewhat higher than in the previous cases, and the machine costs per kilowatt of generating capacity would be relatively low. However, the pumping performance would be poor, in terms of both efficiency and pumping rate, and the unit would probably run roughly when pumping at the upper end of the head range.

(7) These examples are intended to illustrate how the performance of a pumped-storage project can be modified through the selection of the pump-turbine runner design and in rating that unit. As with conventional hydro studies, a detailed analysis of pump-turbine design is not necessary in the early stages of project planning. However, since pump-turbine selection can have a major impact on project performance and project economics, it is important to enlist the services of hydraulic machinery specialists once planning advances to the detailed analysis of a specific site. In order to permit selection of the proper unit, it will be necessary to define the operating characteristics of the project: (a) the operating cycle (required hours of generating and the available pumping hours), (b) the operating head range, and (c) any special

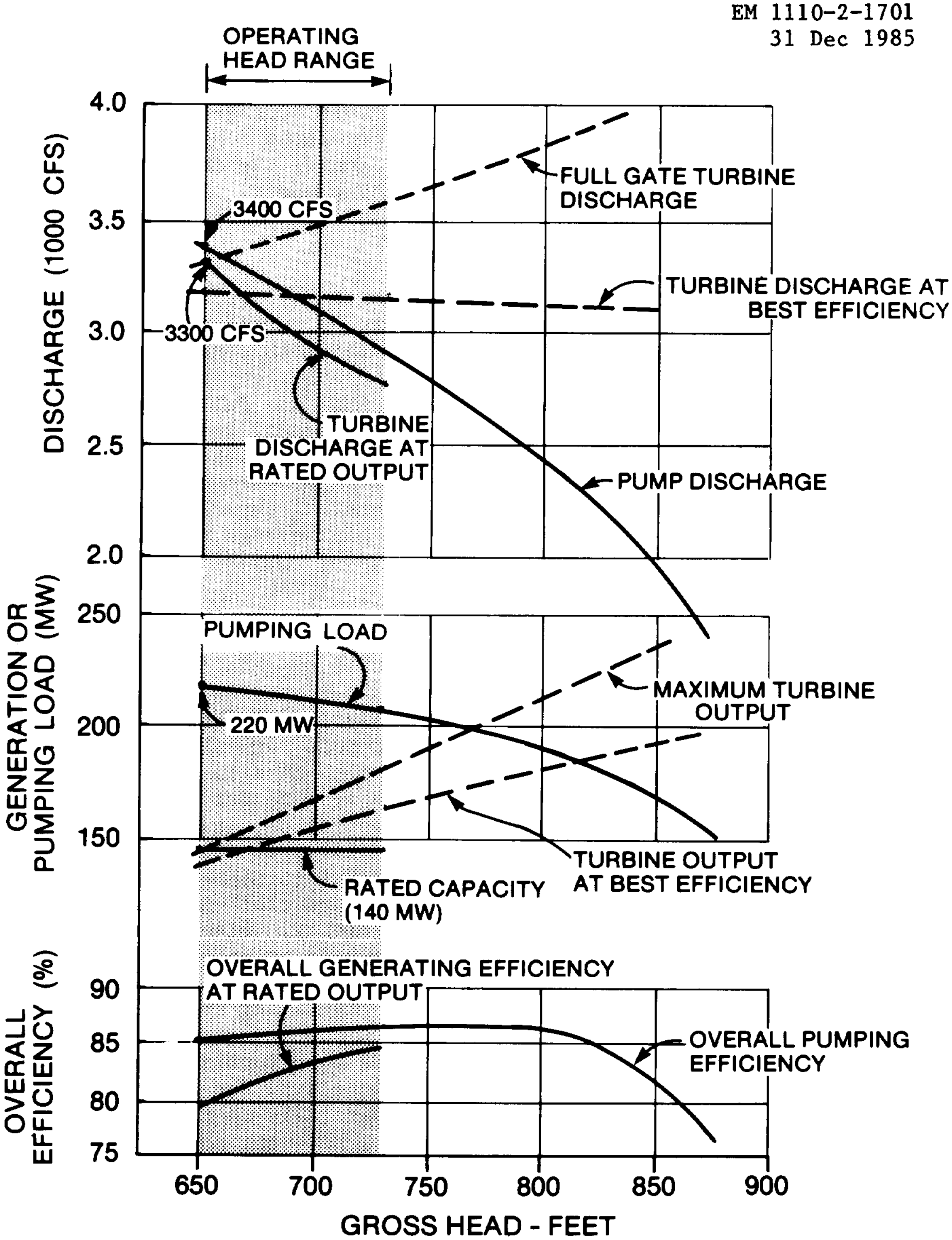


Figure 7-8. Application of pump-turbine shown in Figure 7-7 to a plant with an operating head range of 650-730 feet.

operating considerations. The special operating conditions could include limited pumping time, limited reservoir storage, operating characteristics of the lower reservoir if regulated for other purposes, and, in the case of pump-back projects, the relative amounts of time operated in the pumping and generating modes. Information should be provided for both design (must-run) and normal (economic dispatch) operating conditions.

h. Rated Capacity. A number of different approaches have been used to select the rated capacity of off-stream pumped-storage projects. However, for planning purposes, the most straightforward approach is to base the project's rated generating capacity on the normal minimum head. This helps to insure that the full rated capacity can be delivered by the plant regardless of pool elevation. In many cases, however, pumping requirements will dictate that a larger motor-generator be installed than would be needed to meet generating requirements. As a result, generating capacity may exceed the nominal rated capacity in the high end of the head range.

i. Plant Operating Characteristics.

(1) As noted in Section 7-2g(1), the output of reversible units operating in the generating mode can be varied by changing the wicket gate openings, thus varying the amount of water passing through the unit. Therefore, reversible units are physically capable of operating on automatic generation control in order to help regulate system loads. However, this type of operation results in a loss in efficiency (see Section 7-2j), and because water must be pumped using thermal plant generation to support this generation, the cost penalty for operating at reduced efficiency is not always acceptable. Operating to follow load also tends to increase maintainence requirements. Hence, most off-stream pumped-storage plants are block-loaded, operating at or near the point of best efficiency. Plant output can be adjusted to some degree by varying the number of units on line. There are, however, some systems where the resource mix is such that pumped-storage can be used effectively for regulating system loads.

(2) Starting and stopping a reversible pump-turbine when operating as a turbine is similar to the procedure used for a conventional unit. The unit is brought up to speed by partially opening the wicket gates. Starting the pump-turbine as a pump, however, poses special problems which must be examined in detail for each individual project. The more commonly considered starting methods include the following:

> full or reduced voltage across-the-line starting of the main unit as an induction motor: the starting current is obtained from the main transformers and damper windings which are built into the motor generator. This starting

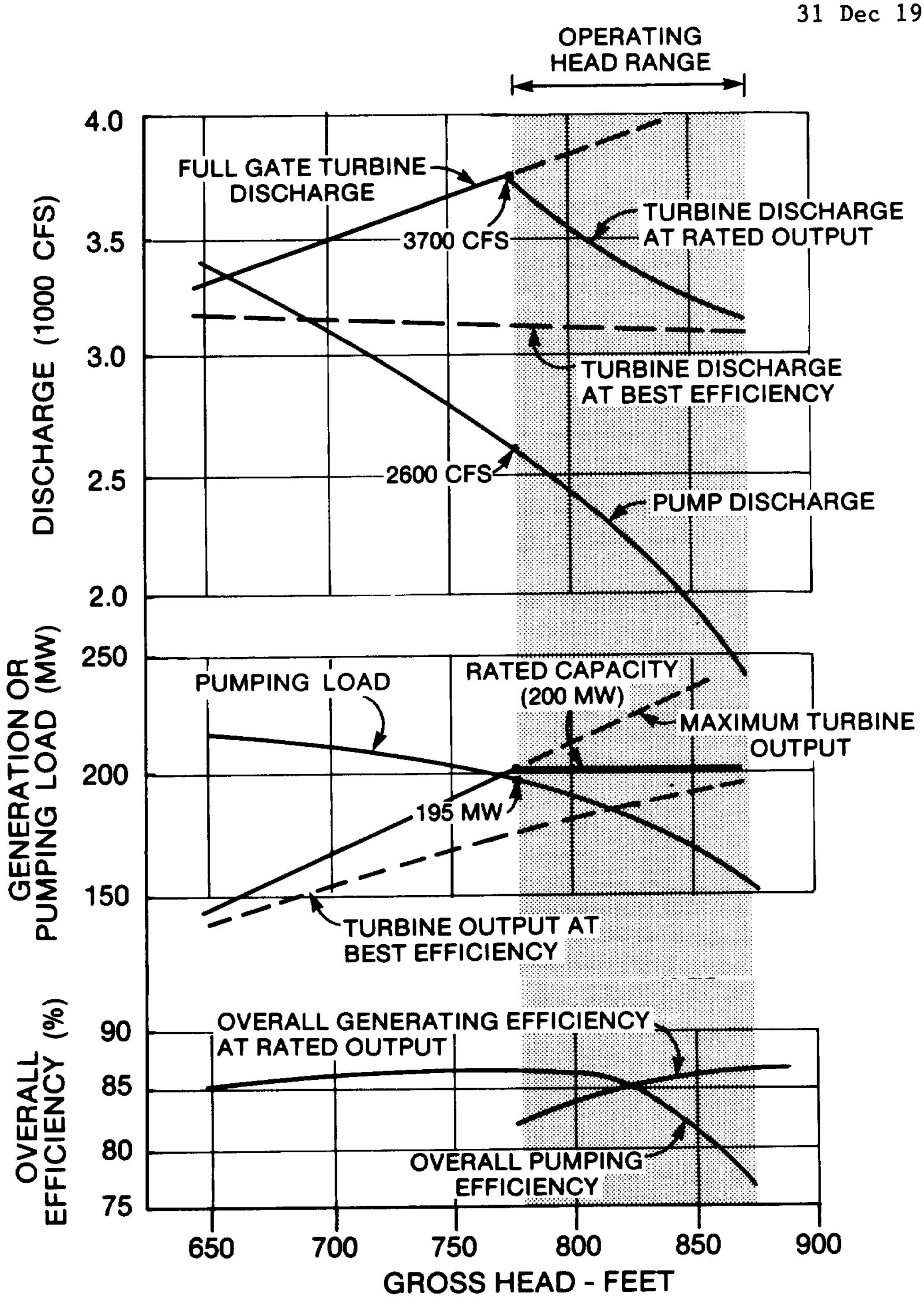


Figure 7-9. Application of pump-turbine shown in Figure 7-7 to a plant with an operating head range of 775-870 feet.

method can produce system disturbances due to the large kVA inrush. For this reason, it is normally limited to units of 30 MW or smaller for full-range starting and units up to 100 MW for reduced voltage starting.

synchronous or "back to back" starting: this requires that a separate prime mover (a turbine or another reversible unit) be connected electrically to the unit to be started. Both of these machines must be stopped and isolated from the system before starting. The prime mover is then started, and the pump turbine also starts in order to maintain an equal frequency. The speed of the prime mover is slowly increased until both units are at synchronous speed. Synchronous starting can also be accomplished with a small "pony" motor attached to the reversible unit shaft.

During starting as pump, the water level is normally depressed below the impeller to reduce starting torque.

(3) Typical turnaround and starting times for reversible units are as follows:

- from pumping to full-load generation . . . 2 to 20 minutes
- from generation to pumping . . . . 5 to 40 minutes
- from shut-down to full-load generation . . 1 to 5 minutes
- from shut-down to pumping . . . . 3 to 30 minutes

These times are to allow for deceleration of the unit, switching of electrical and mechanical circuits, and acceleration in the opposite direction. Because of limitations in control facilities or in the mechanical and electrical arrangement of the plant, it is frequently not possible to turn around more than one or two units at a time.

j. Cycle Efficiency.

(1) Cycle efficiency accounts for all losses in the operating cycle except transmission losses, and the reciprocal of the cycle efficiency represents the number of kilowatt-hours of pumping energy required to obtain one kilowatt-hour of generation. This value includes water passage head losses as well as pump, turbine, motor, generator, and transformer losses. In the past, a cycle efficiency of 67 percent has been used in planning studies. However, experience with plants constructed in the 1970's suggests that higher efficiencies can be achieved. In Volume 3 of EPRI EM-264 (12), representative ranges of cycle efficiency and their respective component efficiencies are presented (Table 7-3). The "high" values represent unconfirmed extrapolation of recent experience, but it is expected that overall cycle efficiencies as high as 75 percent can be

TABLE 7-3
Components of Cycle Efficiency

	Representative Ranges, %	
Pumping	Low	High
Motor and transformer	97.5	98.5
Pump	91.5	92.5
Water passages	96.5	98.5
Total	86.0	90.0
Generating		
Water passages	95.5	97.5
Turbine	89.0	92.5
Generator and transformer	97.5	98.5
Total	83.0	89.0
Allowance for Operation Under Other than Optimum Efficiency	92.0	98.0
Overall Cycle Efficiency	66.0	78.0

achieved in some cases. For planning purposes, it is suggested that a 70 percent cycle efficiency be used, which would be comprised of an overall pumping efficiency of 85 percent and an overall generating efficiency of 82 percent.

(2) The 70 percent cycle efficiency includes head loss allowances of about three percent for pumping and two percent for generating. Once the tentative penstock diameter has been established, more specific head loss values can be determined, and adjustments can be made to the overall efficiency values. In making sequential routing studies, it may be desirable to remove the head losses from the efficiency values and treat them separately.

(3) The pumping and generating efficiency values presented in the upper part of Table 7-3 represent operation at best efficiency. An "allowance for operation under other than optimum conditions" has also been included in the overall cycle efficiency to account for the

fact that the units must at times be operated under less than optimal loadings. For plants operated for load-following (see Section 7-2i), this component would be substantially lower. Existing plants operated in this mode exhibit overall cycle efficiencies on the order of 50 percent.

(4) The cycle efficiency values discussed above do not account for natural inflow to the upper reservoir or reservoir losses due to leakage or evaporation. In some cases, these quantities may be so small that they can be ignored, but they should be checked during the feasibility analysis and accounted for if necessary.

k. Charge/Discharge Ratio.

(1) The charge/discharge ratio for a pumped-storage unit is the ratio of the average pumping load (in megawatts) to the unit's rated capacity (see page C-4 of Volume 3 of reference (29)). Ratios for existing off-stream plants typically fall in the 0.9 to 1.3 range, with values as high as 1.4 being obtainable. A high value is achieved when a runner design is selected in which the average pumping discharge over the operating range is close to the average generating discharge. The charge/discharge ratio can be approximated by dividing (a) the ratio of average pumping discharge to the average generating discharge, by (b) the overall cycle efficiency. Thus, when the ratio of the average pumping discharge to the average generating discharge is 1.00, and the average cycle efficiency is 70 percent, the charge/discharge ratio will be (1.00)/(0.70) = 1.4.

(2) A high charge/discharge ratio is desirable because a maximum amount of water can be pumped during available off-peak hours, thus increasing on-peak generation time and/or reducing the carryover storage requirements (see Section 7-2d). However, this advantage comes at the expense of a slightly lower cycle efficiency and higher equipment costs (a larger runner and motor-generator will be required, compared to a unit having the same rated generating output but a lower charge/ discharge ratio). The average charge-to-discharge ratio for selected existing U.S. plants is about 1.1, and it is suggested that this value be used for planning studies. An exception might be where upper reservoir storage space is physically constrained or very costly, in which case a higher value could be assumed. Normally, detailed analysis of the charge/discharge ratio would be deferred until the project design stage.

l. Reliability and Availability.

(1) According to statistical data maintained by NERC, the forced outage rate for pumped-storage plants averages about 16 percent (27). However, this value is not suitable for computing an average annual

availability factor, because it is based on a relatively small number of operating hours per year. For purposes of developing an average annual availability factor (excluding maintenance) that is comparable with availability factors for non-peaking powerplants, an annual forced outage rate of seven percent was estimated (see Section 0-2d). This rate takes into consideration successful start ratios, number of outage hours per year, and other factors in addition to the NERC forced outage rate.

(2) The seven percent value is still higher than for conventional hydro plants, but this should be expected because pumped-storage units are more complex both electrically and mechanically, and they are typically involved in frequent start-ups and shutdowns, which put more stress on the equipment. Planned and other scheduled outages for maintenance typically require about five and a half weeks per year, which results in the following average availabilities:

- availability excluding maintenance outages - 93.0 percent
- availability including maintenance outages - 85.5 percent

m. Size and Number of Units. Whereas the size and number of units at a conventional hydro plant are often influenced by streamflow conditions (range of expected flows, minimum flow requirements, etc.), the size of the units at a pumped-storage plant is influenced predominantly by load conditions. Just as with conventional hydro plants, minimum plant costs are usually achieved for a plant of a given installed capacity with the minimum number of units of the largest practical size. However, offsetting the economy of scale are power system operating requirements. For maximum flexibility in dispatch of generation to meet loads, smaller units are desirable. Likewise, smaller units permit more flexibility in utilizing available low-cost pumping energy in the off-peak hours. Units for recent off-stream pumped-storage projects tend to be the largest size units that can effectively be used in the load, mostly falling in the 250 to 380 MW range.

n. Plant Factor.

(1) It is sometimes difficult to predict the plant factor of a pumped-storage project, because operation is a function of the generation mix, the relative fuel prices of the different types of projects in that mix, the load shape, and the reserve margin, all of which have been subject to change in recent years. In some cases, plants have operated at a higher plant factor than expected, while in other cases, the opposite has been true.

(2) Plant factor is also a function of reservoir storage, because the larger the amount of carryover storage, the larger the

theoretical maximum amount of generation that can be produced. The maximum plant factor (PF_{max}) for a weekly cycle off-stream pumped-storage project could be estimated by the following equation:

$$PF_{max} = \frac{t_s + 4\ t_p E_c C_t}{168} \qquad \text{(Eq. 7-3)}$$

where:
t_s = reservoir storage, in hours of equivalent full-load generation
t_p = equivalent hours of pumping at full capacity per weekend
E_c = overall cycle efficiency
C_t = charge/discharge ratio

For a daily cycle plant, the equation would be reduced to

$$PF_{max} = \frac{5 t_p E_c C_t}{168}.$$

These equations are based on the plant operating five days a week and all reservoir storage being restored over the weekend. However, the typical pumped-storage project does not normally operate at its maximum capacity throughout the year. Variations in the shape and magnitude of the daily load over the course of the year, the cost and availability of alternative peaking resources, and the cost of pumping energy all influence the amount of time a pumped-storage project is used. In addition, a portion of the plant is unavailable part of the time due to forced outages and scheduled maintenance outages.

(3) A survey of recent operating experience shows that most pumped-storage plants in this country operate at annual plant factors ranging from about 40 to 80 percent of the maximum plant factor, with some as low as 5 percent. This corresponds to annual plant factors of 6 to 16 percent for most plants, with two plants having plant factors on the order of one percent. This wide range illustrates the wide variety of system conditions under which these plants operate. Since the average annual plant factor is so strongly influenced by power system characteristics, it can be estimated accurately only by using system simulation studies (see Sections 7-5e through g). However, for very preliminary studies, an average plant factor of 60 percent of the theoretical maximum plant factor can be assumed for plants operating in most power systems. Operating experience in the WSCC reliability region, however, shows too much variation to permit use of a generalized value even in preliminary studies.

(4) Another point to consider when estimating plant factor is that a power system is dynamic. All of its characteristics change with time. Since a pumped-storage plant's operation is tied so closely to the system's characteristics, its plant factor could change considerably over its service life, in response to changing system characteristics. It is essential that these changes are accounted for in the project analyses (see Sections 7-5b and e).

o. <u>Lower Reservoir Characteristics.</u>

(1) A variety of water bodies can be used as lower reservoirs for pumped-storage projects:

- natural lakes
- open rivers
- existing pondage projects
- existing power storage projects
- existing multiple-purpose storage projects
- specially constructed lower reservoirs
- the ocean

In a few instances, natural lakes or open river reaches have been used as lower reservoirs (Ludington uses Lake Michigan, for example), but environmental and public use impacts often discourage consideration of natural lakes and open river reaches. New lower reservoirs can be designed specifically to meet the requirements of the pumped-storage operation. However, to avoid the environmental impact of constructing new reservoirs, siting pumped-storage projects adjacent to existing projects is often given serious consideration. Such projects must be examined carefully, because existing reservoirs do not always make suitable lower reservoirs for pumped-storage projects.

(2) At pondage projects, pumped-storage operation is superimposed on the existing pondage operation, and this may may in some cases increase pondage requirements above the existing reservoir capacity. To obtain the additional pondage, it may be necessary to raise the existing dam or otherwise modify the structure. In other cases, superimposing pumped-storage operation on the existing operation may reduce pondage requirements. Operation of the existing pondage project under flood flow conditions must also be examined, in order to determine if the operating head of the pumped-storage project is reduced significantly. Hourly sequential routing studies must be made in order to evaluate these operations (see Sections 7-3c and 7-4).

(3) Pondage requirements are not usually a problem where existing seasonal storage projects are used as lower reservoirs. Here, the major problem is usually the range of pool fluctuation. At

some storage projects, existing operations may require seasonal pool fluctuations of 100 feet or more. When combined with daily/weekly cycle fluctuations in the upper reservoir, the resulting head range may exceed the normal operating range for reversible units (Section 7-2f). A wide range of lower reservoir fluctuations may also require unacceptably low runner settings (see Section 7-2q(3)). In some cases, the latter problem can be alleviated by not pumping when the reservoir is at low elevations. However, this will impact the pumped-storage project's dependable capacity if low pool elevations occur frequently, or if they occur during the peak demand season.

p. Penstock Head Losses.

(1) Penstocks represent a significant portion of the costs of an off-stream pumped-storage project (10 to 30 percent), and detailed analyses must be made during the advanced stages of planning to determine the most cost-effective penstock design. However, in the initial stages of planning, some general guidelines can be applied to develop an approximate estimate of head loss. The rated generating discharge can be estimated using the water power equation:

$$\text{Generating discharge (cfs)} = \frac{11.81(\text{kW})}{He_g} \qquad \text{(Eq. 7-4)}$$

where: kW = installed capacity in kilowatts
H = gross head in feet
e_g = overall generating efficiency (including an estimated head loss)

(2) For pump-back projects, heads will generally be relatively low; the heads for most of the projects listed in Table 7-2 are less than 400 feet. For projects in this head range, the procedure outlined in Section 5-61 is satisfactory for developing a preliminary estimate of penstock size and head loss. Velocity (V) can be defined in terms of the generating discharge value (Q_g), which was computed using Equation 7-4, and penstock diameter (D), which is unknown:

$$V = \frac{4Q_g}{\pi D^2} \qquad \text{(Eq. 7-5)}$$

This value would then be substituted into Equations 5-6 and 5-7, and the two equations solved simultaneously to obtain the penstock diameter (D).

(3) Once the penstock diameter has been determined, the head loss would be estimated using Equation 5-6. If the resulting head

loss is substantially greater than that included in the overall generating efficiency in Equation 7-4, a second iteration could be made, incorporating the head loss value obtained in the first iteration in the overall generating efficiency.

(4) Off-stream pumped-storage projects tend to have considerably higher heads, ranging from 600 feet up to 2000 feet or more. For projects operating at these heads, the preliminary penstock size should be based on a maximum allowable head loss of three to five percent of the average gross head. The penstock diameter could then be estimated using the Scobey equation (Equation 5-6), the penstock length, the rated generating discharge from Equation 7-4, the average gross head, and the assumed maximum allowable percent head loss. The overall generating efficiency used in Equation 7-5 should be based on penstock head losses that are equal to the assumed maximum allowable percent head loss. For example, the 82 percent overall generating efficiency suggested in Section 7-2j incorporates a penstock head loss of about 3.5 percent. If a maximum allowable penstock loss of 5.0 percent is to be used for developing a preliminary estimate of penstock diameter, an overall pumping efficiency of (0.82) x (0.95/0.965) = 81 percent should be used in Equation 7-4.

(5) Typically, tunnel diameters would not exceed 40 feet, so multiple tunnels would be used for large discharges.

q. Other Factors.

(1) Transmission Costs and Losses. Just as with conventional hydro plants, transmission losses must be accounted for in the benefit analysis (see Sections 8-6 and 9-5g). An important difference, however, is the fact that transmission energy losses occur in both the pumping and the generating operations. Because the value of these losses can be substantial, particularly when pumping, and because of the high cost of constructing transmission lines to remote sites, off-stream pumped-storage projects located at a distance from load centers and/or the sources of pumping energy are seldom economically attractive.

(2) Reservoir Drawdown. An inherent characteristic of daily/weekly off-stream pumped-storage projects is that short-term reservoir fluctuations occur on a regular basis. During peak demand periods, it is not unusual for a large part of the reservoir storage to be drafted and then refilled during the course of the week (or within a 24-hour period in the case of daily cycle plants). Upper reservoirs often must be constructed in confined areas, and as a result, they have relatively steep storage-elevation characteristics. Fluctuation ranges are correspondingly larger, with some projects having normal

operating ranges of as much as 160 feet. Such wide fluctuation ranges can cause embankment and shoreline stability problems, as well as significant environmental and public safety impacts. In fact, it is often necessary to fence off upper reservoirs in the interest of public safety. Another problem with large fluctuations is that they may create a head range that exceeds the normal operating range for reversible pump-turbine units. Fluctuation ranges can be reduced by providing more dead storage, thus moving up to a flatter portion of the storage-elevation curve. However, the reduced fluctuations are usually achieved at the expense of increased embankment costs. Where possible, upper reservoirs should be designed such that weekly fluctuation ranges do not exceed 100 feet. Larger fluctuations may be permissible in some cases, but the impacts of such fluctuations must be carefully examined. Because lower reservoirs typically have larger surface areas, fluctuation ranges are usually smaller. However, because these reservoirs have larger shorelines and are usually more accessible to the public, the impacts of such fluctuations could be just as serious. Another consideration is the fact that lower reservoirs are often operated for other purposes in addition to pumped-storage operation. Superimposing the pumped-storage regulation on top of operation for other purposes could result in either larger or smaller fluctuation ranges (see Sections 7-3c(3) and 7-4c).

(3) Submergence. In order to avoid cavitation during pumping operations, reversible units must be set lower than conventional turbines. The distance the runner centerline must be set below normal minimum tailwater elevation is a function of head, rotational speed, and other factors. Submergence values for reversible units can range from 30 feet to 100 feet or more, depending on the site characteristics and the runner design. For preliminary planning purposes, a minimum of 50 feet can be assumed for high head off-stream projects. During advanced studies, specific submergence requirements should be determined in consultation with hydraulic machinery specialists from one of the Hydroelectric Design Centers. Submergence characteristics often make underground powerhouses more attractive than above-ground structures, because higher speed units with greater submergence requirements can be used. Higher speed units are physically smaller, requiring a smaller, less costly powerhouse structure.

7-3. Overall Study Procedure.

a. Introduction.

(1) Following is an outline of the overall procedure for analyzing an off-stream pumped-storage site. A study of a specific site often originates as a result of a screening study. System planning studies may indicate a need for a block of peaking power that

could be met with off-stream pumped storage. The first step would be to make a screening study to evaluate alternative sites in the area which might be capable of providing the required block of capacity (see Section 7-7b). The most promising site (or sites) would then be subjected to the analysis described below. In such an analysis, the approximate plant size would usually by given, although a limited range of alternative plant sizes would be tested to insure that the site is developed economically.

(2) A pumped-storage study could also be initiated to examine a specific promising site. Such a study might be made, for example, to determine if an off-stream pumped-storage project could be developed and operated in conjunction with an existing hydropower or multiple-purpose project, which would serve as the lower reservoir for the pumped-storage project. In such a study, a wide range of plant sizes might be examined in order to determine the optimum overall development.

(3) In the procedure outlined below, it is assumed for the sake of simplicity that the objective is to develop a site to meet a specific capacity requirement (1000 MW, for example). The same general procedure would be followed in a study to determine the optimum plant size for a given site, except that a wider range of alternatives would be carried through the economic analysis stage.

(4) As with other portions of this manual, emphasis has been placed on the power studies that are required to evaluate a pumped-storage project. Environmental, institutional, and socio-economic studies and analysis of other potential project purposes are equally important, and they must be closely coordinated with the power studies. The Planning Guidance Notebook (49) provides information on these aspects of the planning process and how to integrate the power studies in the overall project planning program. Geologic studies must also be undertaken in parallel with the power studies, in order to determine if the reservoirs can hold water and if the site is suitable for the construction of impoundment structures, tunnels, and either an underground or surface type powerhouse.

b. Define Site and Plant Characteristics.

(1) Develop Tentative Site Layout. Make a preliminary layout of the project, including upper and lower reservoir location, powerhouse location, and penstock and discharge tunnel alignments.

(2) Define Operating Cycle. Determine the number of off-peak pumping hours available each week-night and the minimum number of on-peak generating hours required each weekday for the capacity to be dependable (see Section 7-2c).

(3) Estimate Storage Requirements. Given the operating cycle and Equation 7-1, estimate the minimum number of hours of storage required (see Section 7-2d). For the initial estimate, an overall cycle efficiency of 70 percent and a charge/discharge ratio of 1.1 can be assumed (see Section 7-2j and k). Storage requirements should also be estimated for at least two larger reservoirs. For example, if the minimum number of on-peak generating hours is 5 hours per day, storage requirements might also be estimated for reservoirs capable of supporting 6 and 7 hours per day.

(4) Define Characteristics of Lower Reservoir. If an existing reservoir is to be used, the normal maximum and minimum pool elevations must be identified so that the pumped-storage project's operating head range can be assumed. Storage-elevation characteristics must also be identified, and reservoir inflow and reservoir regulation characteristics must be defined. If a new lower reservoir is to be constructed, a storage-elevation curve must be developed and reservoir inflows must be determined for a representative historical period of record.

(5) Define Characteristics of Upper Reservoir. A storage-elevation curve must be developed for the upper reservoir. Evaporation and leakage losses must also be estimated, and natural inflows (if any) must be estimated.

(6) Estimate Reservoir Volume and Pool Elevations. Estimating the required reservoir volume is an iterative process. The first step is to make a preliminary estimate using the desired plant size, the hours of storage determined above, and Equation 7-2 (Section 7-2d). For this calculation, estimate the average gross head and use a generating efficiency (including head losses) of 82 percent (see Section 7-2j). Apply this volume to the storage-elevation curve for the upper reservoir (allowing for a reasonable amount of dead storage and some reserve storage capacity, if desired (see Section 7-2d)). Identify maximum and minimum pool elevations. Check these elevations to insure that the drawdown range is not excessive (see Section 7-2q(2)). If a new reservoir is to be used for the lower reservoir, calculate preliminary maximum and minimum pool elevations in the same way. Head losses can also be estimated using the procedures outlined in Section 7-2p. With this information, estimate a new average head, and recompute the required storage volume using Equation 7-2. If head losses are computed separately, they would be included in the average head, and a somewhat higher generating efficiency should be used (84 to 85 percent). This revised reservoir volume, along with revised maximum and minimum pool elevations, could be used for making initial reservoir cost estimates. A more precise estimate of reservoir storage requirements will be required for the detailed layouts and

cost estimates prepared in the final stages of planning, and this value would be obtained from sequential streamflow routing studies.

c. Sequential Streamflow Routing and Related Studies.

(1) Define Worst Case Operating Cycle. In order to make final estimates of reservoir storage volumes, discharges, and reservoir fluctuations, a sequential routing analysis must be made for the operating situation that puts the greatest stress on the reservoir. This would normally be a week when the project is operating to meet the design operating cycle under must-run conditions (see Section 7-2c). When the lower reservoir is operated to serve other functions, the worst case often occurs when it is at the upper part of its elevation range (i.e., when the head on the pumped-storage project would be at its minimum).

(2) Perform Worst Case Sequential Routings. Perform hourly sequential streamflow routing studies based on the worst case operating conditions (see Section 7-4). This analysis would consider operation of both the upper and lower reservoirs.

(3) Perform Other Sequential Routings. Perform additional sequential routings for other operating conditions, in order to define the full range of conditions under which the project would be expected to operate, typical as well as extreme. Typical pumped-storage loadings could be obtained from the production cost studies (see Section 7-5g). A range of lower reservoir operating conditions should also be examined. If the lower reservoir is a pondage project, a variety of streamflow conditions and pondage operations should be examined, in order to insure that adequate pondage is available to support both the pumped-storage and pondage operation. Operation under flood flow conditions should also be examined. If the lower reservoir is a multiple-purpose storage project, examine the operation of the pumped-storage project under the full range of reservoir operating conditions. Data from the hourly sequential routing studies would be used in turbine selection studies, project design, environmental analyses, and in evaluating impacts on lower reservoir functions. If the reservoir is a new impoundment, designed to serve only as a lower reservoir for the pumped-storage project, operation under a range of typical flow conditions should be examined. Also, it may be desirable to test alternative maximum pool elevations in order to determine the relative magnitude of pool fluctuations.

(4) Select Pump-Turbine Design. Once sufficient sequential routing studies have been done to identify the normal and extreme operating conditions, a tentative pump-turbine design would be selected in consultation with hydraulic machinery specialists from one of the Hydroelectric Design Centers. Unit size would also be

selected, considering power system operating requirements, project operating conditions, and economics.

(5) Compute Energy Content of Reservoirs. Production cost models often require that upper reservoir storage be specified in terms of energy content. Since models of this type typically incorporate an efficiency loss adjustment, the gross energy content would normally be specified.

$$\text{Reservoir Energy Content (gWh)} = \frac{MWt_s}{1000e_g} \qquad \text{(Eq. 7-6)}$$

where: MW = installed capacity in megawatts
t_s = hours of storage (Section 7-2c)
e_g = overall generating efficiency, including head loss

(6) Compute Dependable Capacity. Compute dependable capacity as described in Section 6-7j.

d. Economic Analysis.

(1) General. Off-stream pumped-storage projects are typically large compared to system loads, so in accordance with Section 2.5.6 of Principles and Guidelines (77), a complete load-resource analysis must be performed in order to define the need for the capacity (see Chapter 3). However, because the economics of pumped storage are so closely related to the power system's load and resource characteristics, the economic analysis and load-resource analysis must be performed together. Since pumped-storage benefits are sensitive to changes in load shape, system generation mix, relative fuel costs, and other system-related factors, all of which are subject to change over time, this analysis should be performed for a period extending ten to twenty years beyond the expected project on-line date. Following is a summary of the major steps involved in a combined economic/load-resource analysis. The details of each of these analysis are described in Section 7-5.

(2) Define Without-Project Conditions. This step includes defining the power system to be analyzed (see Section 7-5b(2)). Loads and load shapes for the system must be projected for at least ten years beyond the expected project on-line date, and projections of the expected generating resources must be developed for each of these years. New (non-hydro) generating resources would be scheduled to come on-line as needed to insure that peak loads will be met while maintaining an adequate reserve margin (see Section 7-5b). Operating characteristics and fuel costs must also be defined for each of these resources.

(3) Compute System Operating Costs for Without-Project Scenario. System operating costs (mostly fuel costs) would be computed for each year using an hourly production cost model (see Section 7-5d).

(4) Define With-Project Scenario. The without-project conditions would be modified such that the pumped-storage project would be scheduled to come on-line in lieu of an increment of new thermal capacity (Section 7-5e). Several on-line dates should be tested, the first of which would be the first year in which the load-resource analysis shows that the new capacity would be needed.

(5) Compute Pumped-Storage Energy Benefits. System operating costs would be computed with pumped-storage replacing the increment of thermal capacity (Section 7-5g). The difference in system operating costs between the system without pumped-storage and the system with pumped-storage would be the net savings in energy costs due to pumped-storage operation. The pumping energy costs can also be identified using the production cost model, and the sum of the net savings in energy costs and the pumping energy costs would equal the energy benefits attributable to pumped-storage (Section 7-5h).

(6) Compute Capacity Benefits. The capacity benefits would be the annualized capital costs of the increment of capacity replaced by the pumped-storage project, and they would be computed in the same way as for conventional hydro projects (Section 7-5i).

(7) Alternative Configurations. In a typical pumped-storage site evaluation, a number of alternative developments might be considered, including the following:

- alternative reservoir sizes
- alternative plant sizes
- alternative pump-turbine sizes
- alternative penstock sizes
- underground vs. above-ground powerhouses

Benefit analyses would have to be performed to test each of these alternatives.

(8) Other Sensitivity Analyses. It is often desirable to do additional sensitivity studies, to test such variables as alternative on-line dates, alternative real fuel cost escalation rates, alternative load growth rates, and alternative load shapes.

7-4. Sequential Routing Studies.

a. General. The sequential streamflow routing (SSR) studies described in Section 7-3c would be made using an hourly (or multi-hourly) SSR model. Section 6-9 provides some general information on hourly SSR studies. Input data that would be required in addition to that described in Section 6-9b is listed below. The HEC-5 model includes a special routine that is capable of analyzing both pump-back and off-stream pumped-storage projects. Section K-5 describes how HEC-5 would be applied to pumped-storage analysis.

b. Data Requirements.

(1) General. Following is a list of additional data required for hourly SSR studies of pumped-storage projects.

(2) Hourly Generation. Generation requirements for the pumped-storage project must be specified by hour for each week being examined. These values can be obtained from either the design operating cycle (Section 7-2c) or from production cost studies (Section 7-5g), depending on the operating condition being examined.

(3) Hourly Pumping Loads. Available off-peak pumping energy is also specified by hour for each week. These values are also obtained from either the design operating cycle or from production cost studies.

(4) Efficiency Values. Efficiency values must be specified for both pumping and generating. Initial studies could be based on typical fixed efficiencies (see Section 7-2j), which might include an allowance for penstock head losses. Once pump-turbine selection has been completed, efficiency versus head curves could be used, with penstock losses treated separately (see below).

(5) Head Losses. Head losses can be important in the analysis of pumped-storage projects, and where possible, it should be represented as a function of flow rather than a fixed value (see Sections 5-6l and K-3c(5)).

(6) Pumping Capacity. The rated pumping capacity for a reversible unit is often different (usually larger) than the generating capacity. When operating in the pumping mode, the units typically operate at the gate opening that gives best efficiency. Hence, they might operate at rated capacity only at the low end of the normal operating head range (see Figure 7-7), and of reduced capacity at higher heads. Where possible, it is preferable to specify pumping capacity as a function of head. When this is not possible, an average pumping capacity rather than a rated capacity should be specified.

c. Analysis of Storage Requirements. The procedure outlined in Section 7-3b is intended to provide only an approximate "starting" value based on some generalized assumptions. Hourly sequential streamflow routing studies must be made for the worst-case week (see Section 7-3c(1)), in order to develop a more precise estimate of the projects's reservoir storage requirements. The sequential routing will account for (a) hour-by-hour variations in head due to changes in reservoir elevation, (b) reservoir storage-elevation characteristics, (c) the performance characteristics of the pump-turbine, and (d) other factors. It is often necessary to test a range of operating conditions to insure that the worst-case scenario has in fact been identified. It may also be desirable to examine a range of less severe operating conditions in order to define the project's normal performance characteristics.

d. Analysis of Lower Reservoirs.

(1) When existing projects are used as lower reservoirs, the pumped-storage operation must be superimposed on the operation of the existing reservoir (see Section 7-3c(3)). In most cases inflow, discharge, and basic reservoir elevation data describing the operation of the existing lower reservoir can be obtained from historical data or from existing period-of-record SSR studies.

(2) In the case of pondage projects, it may be desirable to test alternative operations of the pondage project to optimize the combined operation of the pondage project and the off-stream pumped-storage project. When the lower reservoir is a pondage project that is one of a series of projects, the analysis would be more complex. For further information on this type of analysis, reference should be made to studies of the Richard B. Russell project (Savannah District) and to studies of potential pumped-storage projects located adjacent to mainstream Columbia River projects (North Pacific Division).

(3) When an existing seasonal storage project is being used as the lower reservoir, either the historical operating record or a period-of-record sequential routing (or both) should be examined, in order to identify the range and distribution of pool elevations. This is required to help define the pumped-storage project's head characteristics.

(4) When a new lower reservoir is to be constructed, the lower reservoir often operates as a reregulating reservoir, and minimum discharge and rate-of-change-of-discharge criteria must be developed to govern operation of the reservoir. For flood control projects, existing pondage projects, and new lower reservoirs, flood flows must be routed through the reservoirs to determine their impact on pumped-

storage project operation. This is because in many cases, flood operation defines the project's minimum operating head.

e. Unsteady Flow Analysis. When a pumped-storage project discharges into a relatively shallow lower reservoir, full-load pumping or generating can have a major impact on flow conditions in the immediate vicinity of the intake/discharge. Unsteady flow studies must be made to determine velocity conditions and their impact on other reservoir uses (such as navigation, recreation, and fish and wildlife). Models such as RMA-2 (91) are suitable for this purpose.

7-5. Economic Analysis.

a. Introduction. Section 7-3d outlines the general procedures used in economic analyses of pumped-storage projects. This section describes these steps in more detail, as well as some of the tools that are available for these analyses.

b. Define Without-Project Conditions.

(1) General. This step basically consists of making a year-by-year load-resource analysis for the period extending from the present to ten to twenty years beyond the expected project on-line date. It is necessary to extend the analysis into the future because pumped-storage benefits are a function of factors such as load shapes, load growth rate, resource mix, relative fuel costs, reserve margin and other system-related factors, many of which may change significantly with time. The difficulty with doing this type of analysis is that uncertainty is associated with all of these factors. One practical approach is to make an analysis based on the best estimate of expected conditions and to make sensitivity studies to test the effect of alternative assumptions on project economics. As planning continues, project economics should be reexamined periodically to determine if changing conditions will affect the project's feasibility or on-line date.

(2) Identify System for Analysis. The system to be included in the analysis should include those power systems that would be impacted by operation of the pumped-storage project. This would often include adjacent systems, in addition to those systems where the power would actually be marketed. The selection of the area to be analyzed should be made in consultation with the regional Federal Power Marketing Administration, FERC, and in some cases, the local utilities or power pool.

(3) Load Forecast. Sources of load forecasts are described in Chapter 3. Often, however, it is necessary to project loads beyond the available data. It is common to extend forecasts using the load growth rate assumed for the last 5 to 10 years of the available forecast period.

(4) Hourly Load Shapes. Hourly load shapes must also be developed. Generally, the only hourly load data available is recent historical loads. This data can be used, but care should be taken to insure that it is representative. Production cost models such as POWRSYM require hourly loads for an entire year. When a full year of data is not available, a full year can be generated using several representative weeks, as described in EPRI report EM-285 (15). This report also contains some typical weekly load shapes. Consideration should be given to modifying these load shapes so that they reflect expected changes due to factors such as load shape management. Omaha District has developed a technique for modifying load shapes to account for load management in their Gregory County pumped-storage project studies.

(5) Existing and Planned Resources. Data on existing generating resources and scheduled additions and retirements is usually available from the Energy Information Agency (EIA) and from the NERC Regional Reliability Councils (see Section 3-5b). Unfortunately, this data usually covers only the next ten years, which in many cases would not extend even to the projected on-line date for the pumped-storage project being studied. This requires that additional resources be scheduled to insure that peak loads are met and that adequate reserves are provided for each year in the period of study.

(6) Determine Resource Deficits. Existing and planned resources are compared to projected loads in order to determine future deficits (see Sections 3-3b and 3-10d). In computing deficits, loads should be increased by reserve requirements (use a 20 percent reserve margin when more specific data is not available). Figure 7-10 shows an example of such an analysis. Note that the figure shows the total capacity of existing and scheduled generating resources decreasing with time. This is due to retirements. In estimating retirement dates, it has been common to assume that thermal plants have operating lives of 30 to 35 years, although the trend seems to be toward longer service lives.

(7) Project Additional Resources. In order to fully describe the without-project scenario, it is necessary to schedule additional resources to cover projected deficits. The most likely mix of new resources can be determined using a generation expansion model (see Section 9-4a(3) and reference (33)). However, when such a model is not available, the most likely resource mix can be estimated using the

production cost model (PCM) that will be used for the pumped-storage energy benefit analysis. Several alternative mixes (70 percent coal/30 percent combustion turbine, for example) could be scheduled to fill projected deficits through the end of the period of analysis (see Figure 7-11). System energy costs would be determined for each year using the PCM. The total present value of the capital costs of the new plants (as they occur) and the year-by-year system energy costs (from the PCM) would then be determined for each mix, and the mix with the lowest total present value cost would be identified (see Figure 7-12).

(8) Selection of Most Likely New Resource Mix. In many cases, the least costly resource mix would be used as the without-project scenario. However, in some systems, prevailing utility policies or other factors may suggest a somewhat different mix. For example, many utilities avoid installing a large amount of combustion turbine capacity because of uncertainty over fuel prices and fuel availability. They will instead invest in cycling steam plants and

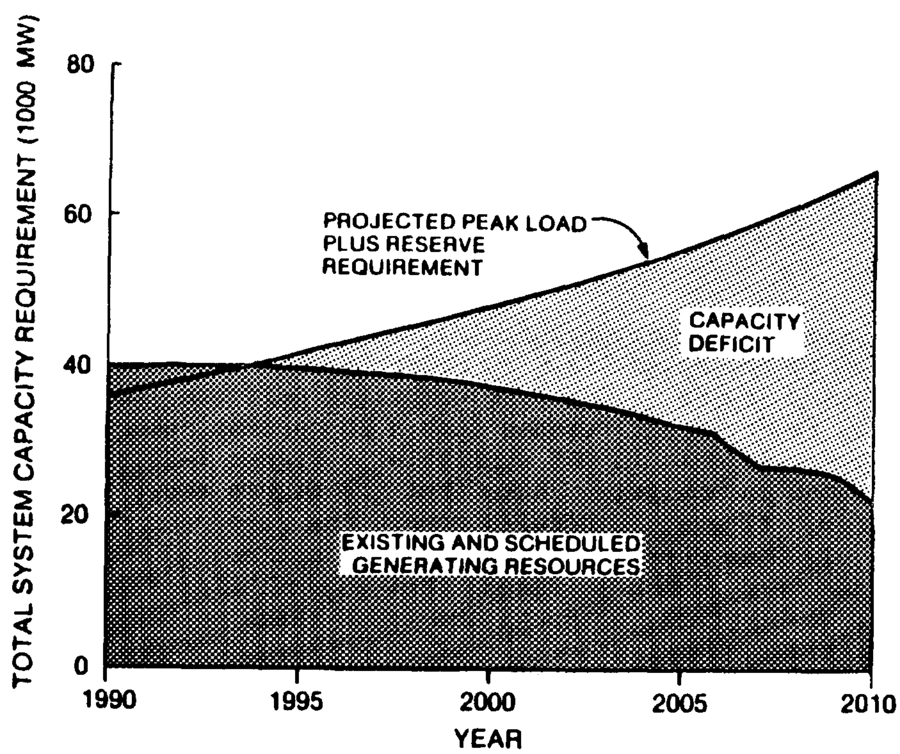


Figure 7-10. Projection of peak loads, resources, and capacity deficits

utilize older steam plants in order to meet reserve requirements. In the example based on Figure 7-12, the curve is relatively flat between 20 and 50 percent combustion turbines, indicating that costs are about the same for any mix in this range. To protect against fuel price escalation and fuel shortages, the regional policy might suggest that the most likely mix might be the mix in this range with the least amount of combustion turbine capacity (20 percent). While present value cost analysis should serve as the starting point in selecting the without-project resource mix, the regional PMA, FERC, and local utilities should also be consulted to insure that the mix approximates the most likely future condition as clearly as possible.

(9) Criteria for Analyzing Future Resource Mixes. Analyses of the type described above are typically done using an inflation-free discount rate of 3 to 4 percent. Note that this rate would be used only in the determination of the without-project resource mix; the current Federal interest rate would be used in the pumped-storage project benefit analysis. In order to avoid end effects, it is

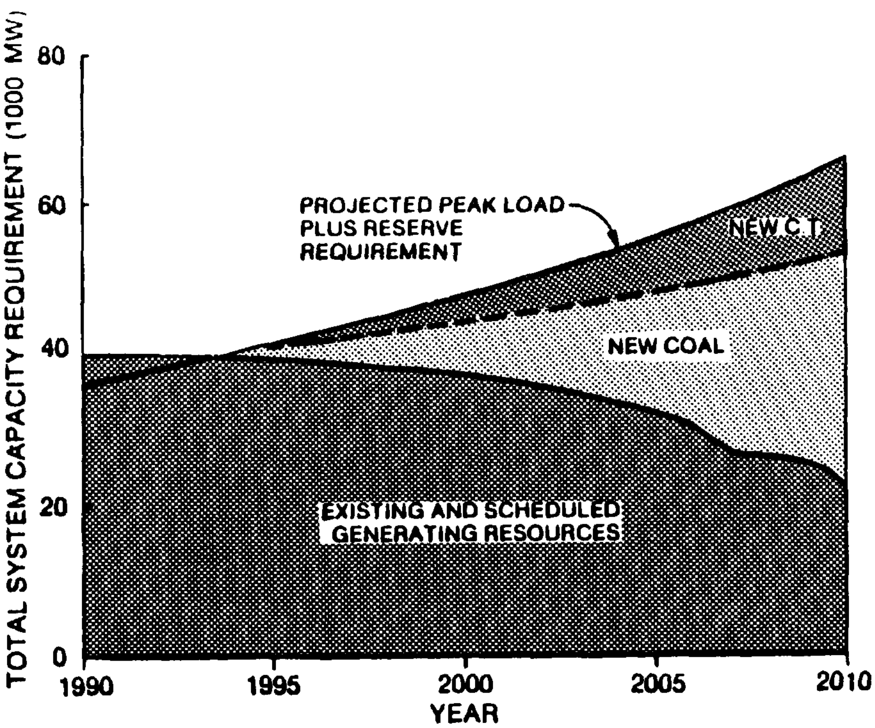


Figure 7-11. Mix of new resources to offset capacity deficits shown on Figure 7-10

suggested that the system energy cost analysis be extended 20 years beyond the end of the last date of the load-resource analysis. For these 20 additional years, only the present value of the system energy costs need to be included, and the costs for these years could be approximated by using those for the last year in the load-resource analysis (Figure 7-13).

c. Develop Plant and System Operating Characteristics. In the preceding section, loads, load shapes, and generating resources were projected through the period of analysis (project on-line date plus 10 to 20 years). Additional information is needed for the production cost analysis of system energy costs: data such as thermal plant heat

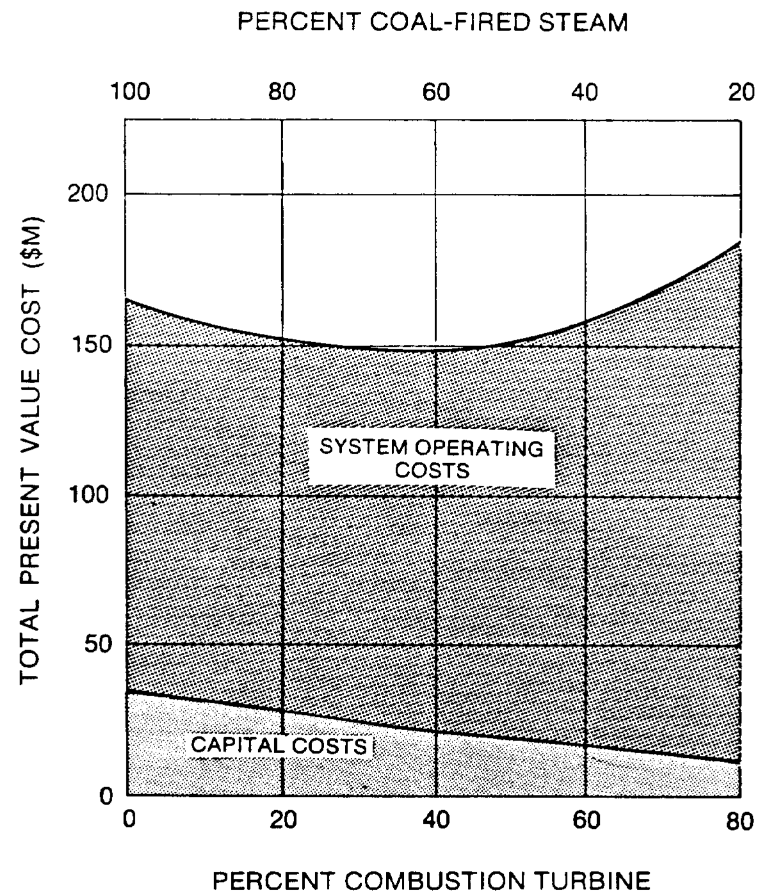


Figure 7-12. Present value cost versus new generating resource mix for hypothetical case described in paragraph 7-5b(7)

rates, maintenance schedules, forced outage rates, variable operation and maintenance costs, fuel types, plant operating modes, existing hydro system energy output, hydro minimum generation, hydro peaking capabilities, and fuel costs. For specific information on what is required, reference should be made to the user manual for the specific production cost model being used. Some of this data can be obtained from FERC, EIA, the regional Power Marketing Administration, or other standard references (15). Other data may be available only from the utilities or the NERC Regional Reliability Council. Fuel costs should reflect expected real fuel cost escalation (see Section 9-5f).

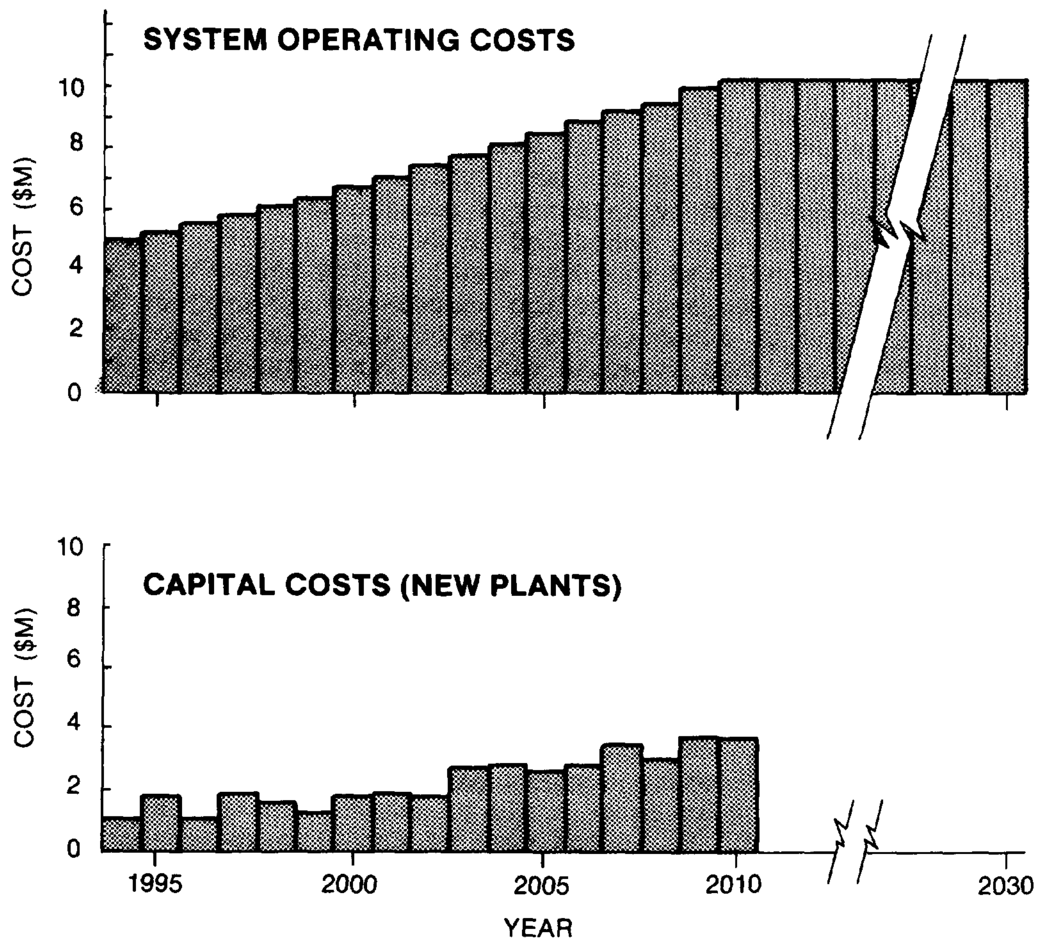


Figure 7-13. Example of cash flow for evaluating a possible new resource mix

d. Compute System Energy Costs. System energy costs would then be computed for each year in the period of analysis using an hourly production cost model such as POWRSYM (see Section 6-9f). The system energy (or production) costs include all of the variable costs associated with operating the power system (principally fuel costs, imported energy costs, and variable operation and maintenance costs). It is not usually necessary to run the model for each year in the period. Production costs could be computed for representative years (at five-year intervals, for example) and costs for intermediate years estimated by interpolation (see Figure 9-2).

e. Define With-Project Conditions.

(1) In most cases, the earliest possible on-line date for a pumped-storage project would be the first year in which a need for additional capacity exists (see Section 7-5b(6)). In some cases, however, the system resource mix may be such that the project could be economically justified earlier. In other cases, the optimum on-line date may be several years beyond the date when capacity deficits first occur. Thus, it is desirable to test several possible on-line dates. For on-line dates occuring after project deficits begin, the without-project scenario is modified by deleting a portion of the new generating resources that were scheduled in Section 7-5b(6). The block of new resources deleted would be equal to the capacity of the proposed pumped-storage project. If the pumped-storage project is large, its units might be scheduled to come on-line over a period of two or three years, and thus it would displace some capacity in each of these years.

(2) The type of capacity replaced could be determined in several ways. If a generation expansion model is available, the pumped-storage project could be entered as an existing resource as of the on-line date, and a new set of resources would be selected to fill in the remaining deficits. The new resource requirements in both the without-project and the with-project scenarios would then be compared, in order to identify the capacity replaced by the pumped-storage project. If such a model is not available, the new resource schedule identified in Section 7-5b(6) would have to be adjusted manually. When adding pumped-storage capacity, the least costly adjustment would usually be to replace combustion turbine capacity, although in some systems, replacing cycling steam or a mix of combustion turbine and steam might be considered. As in the case of the without-project scenario, the advice of the regional PMA, FERC, and local utilities should be sought to assist in developing the most likely with-project scenario.

f. Describe Pumped-Storage Project Characteristics.

(1) In a production cost model (PCM) such as POWRSYM, the pumped-storage project would be described by specifying the following characteristics:

- unit size (rated generating output) in megawatts
- average unit pumping load in megawatts
- number of units
- average generating efficiency (including penstock losses)
- average pumping efficiency (including penstock losses)
- usable reservoir storage, gWh (see Section 7-3c(5))
- start-of-week reservoir storage, gWh
- local reservoir inflow, gWh/hour
- forced-outage rate (see Section 7-21)
- maintenance outage rate or weeks out per year (see Section 7-21)

(2) An hourly PCM typically operates on a one-week cycle, beginning at midnight Sunday. A portion of the weekend pumping required to restore a weekly cycle plant's reservoir storage is typically done in the early hours of Monday morning (see Figures 7-3 and 7-14). Therefore, it is necessary to specify the start-of-week reservoir condition as somewhat less than full. The optimum starting storage is a function of the characteristics of the system being studied and can be determined only by trial-and-error. A start-of-week storage of 85 percent of total usable storage is usually a reasonable assumption for initial runs.

(3) Because pumping load can vary widely with head (Figure 7-7), an average pumping load should be assumed. For initial studies, which must be made prior to pump-turbine selection, it is usually satisfactory to assume an average pumping load equal to or slightly larger than the unit's rated generating output.

(4) Local reservoir inflow to the upper reservoir would represent the net result of local inflow (if any), evaporation, and reservoir precipitation. This is usually specified as an average annual inflow, although it can be specified by week if it is large and varies significantly within the year. In some cases, it may be so small that it can be ignored. At other projects, diversions may be made from the upper reservoir for irrigation or water supply. These diversions would be accounted for as negative inflows. The inflows would be expressed in terms of the gross energy potential of the inflow per hour:

$$\text{Reservoir inflow (gWh/hour)} = \frac{Q_i H_a}{3280} \qquad \text{(Eq. 7-7)}$$

where: Q_i = average weekly inflow, cfs
H_a = average gross head, feet

(5) Many PCM's can treat pumped-storage maintenance outages either by specifying that the units will be out of service for specific weeks, or by utilizing an average availability factor, which the model uses to derate the units week-by-week. If it is desired to examine weekly pumped-storage project operation in detail, it is recommended that the pumped-storage units be scheduled out of service for specific weeks if possible (although it is usually best to account for thermal plant maintenance using the derating method).

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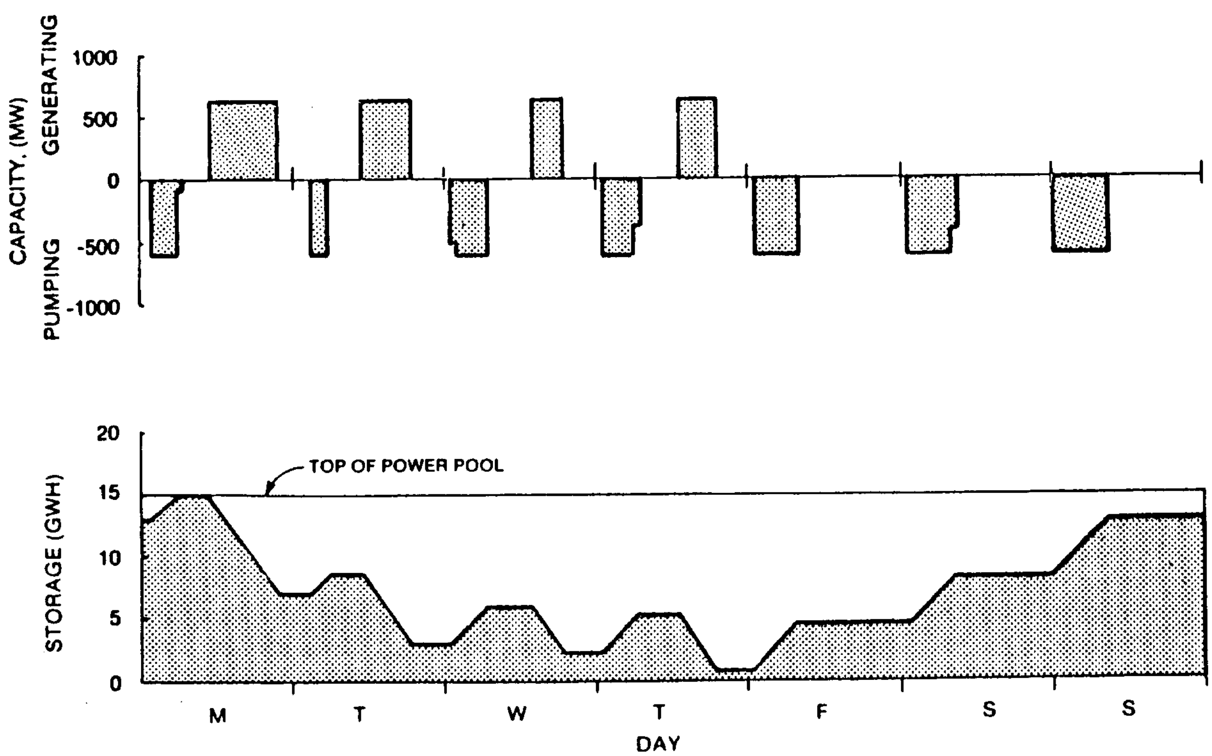

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Figure 7-14. Typical weekly operation for an off-stream pumped-storage project from a production cost model

g. Determine With-Project System Energy Costs.

(1) System energy costs would then be determined for each year in the period of analysis using the production cost model, in the same manner as was done for the without-project scenario (see Section 7-5d). A report of the system and pumped-storage plant performance (costs and generation) can be developed for each week and for each year.

(2) Hour-by-hour reports of pumped-storage plant operation can also be developed. Figure 7-14 shows an example of a weekly loading for a 634 MW off-stream pumped-storage project operating under economic dispatch. Reports of this type (and the resulting storage requirements) can be compared to the design operating cycle, and adjustments can be made to the design operating cycle or storage requirements if necessary. The hour-by-hour pumping and generating values from selected weeks can be used as input to an hourly SSR model, in order to make a detailed routing analysis for a range of expected operating conditions (see Section 7-3c(3)). Statistical data can also be developed to show average storage requirements, in order to evaluate the impact of reservoir fluctuations.

(3) In most production cost models, the pumped-storage plant would normally be operated only if the value of the on-peak energy exceeds the cost of the pumping energy (the economic dispatch mode, as described in Section 7-2c). Economic dispatch often requires considerable computer time, so, in order to save time, a certain amount of must-run pumped-storage operation can sometimes be specified. This value (which might be expressed in terms of gWh of generation per week) should be somewhat less than the generation that would be expected from economic dispatch, and it would be determined through experience in modeling the system under full economic dispatch. The must-run feature can also be used to test project operation under worst-case conditions or to model the operation of the project to meet specific operating conditions (such as operating the project to meet the week-by-week generation values specified by a proposed contract). The system costs developed using the latter type of operation should be used with caution, however, because the system may be forced to operate in a non-economic manner, and the resulting system energy benefit would not likely represent NED benefits.

h. Determine System Energy Benefits.

(1) The difference in total system operation costs between the without-project system (Section 7-5d), and the with-pumped-storage-project system is the net savings in system costs. This savings represents the difference between the value of the energy displaced and the cost of the pumping energy, and it accounts for any other

TABLE 7-4
Computation of System Energy Benefits for a Given Year
(all values in $1,000)

System energy costs without pumped storage	$5,917,720
System energy costs with pumped storage	$5,907,030
Net system energy cost savings	$10,690
Net system energy cost savings	$10,690
Pumping energy costs	$54,940
System energy benefits	$65,630

changes in system operating costs that result from replacing a specific increment of thermal generation with the pumped-storage capacity.

(2) In an NED benefit-cost analysis, the pumping energy cost should be included as a cost rather than as a negative benefit (Section 8-5e), so it must be removed from the net difference in system costs. The pumping energy cost can be computed as a part of the PCM analysis and included in the output reports. The sum of the net system energy cost and the pumping energy cost would be the system energy benefit attributable to the pumped-storage operation. Table 7-4 illustrates such a computation for a given year's operation.

(3) Similar calculations would be made for each year in the period of analysis. As noted earlier, PCM runs do not have to be made for each year in the period. Runs can be made for representative years and values for intermediate years determined by interpolation. Energy benefit values would have to be computed for each year of the project life, which would typically be 50 years in the case of an off-stream pumped-storage project (see Section 9-3c). Because of uncertainty and because of the limited effects of benefits for distant years on average annual benefits, production cost analysis would usually be limited to no more than the first 20 years following POL (see Section 7-3d). Energy benefits and pumping costs for subsequent years (year 21 through year 50, for example) can be represented by the values for the last year of the PCM analysis (year 20 in the example case). Given the values for all 50 years, average annual energy benefits and pumping costs can be computed by present-worthing all of

the annual values to the project on-line date and amortizing over the life of the pumped-storage project.

i. Determine Capacity Benefits. The type (or mix) of thermal capacity that would likely be displaced by the pumped-storage project was determined as described in Section 7-5e. Capacity benefits would be computed using the capital costs for these plants (see Sections 9-3b, 9-5a through 9-5c, and 9-8c(5)), and the pumped-storage project's dependable capacity (see Section 6-7j).

j. Flexibility Benefits.

(1) It is widely recognized that pumped storage has flexibility (or "dynamic") benefits that are not well quantified using present evaluation techniques, and the Electric Power Research Institute (EPRI) has research underway in this area (68). An adjustment is usually made to the capacity values in an attempt to account for the inherent flexibility of hydropower compared to thermal capacity (see Sections 9-5c and O-2e). However, the EPRI studies suggest that this adjustment (a five percent increase in the capacity value) underestimates the flexibility benefits for pumped storage. Prior to assigning flexibility credit to a specific pumped-storage project, the latest EPRI studies should be reviewed in order to determine if a better basis exists for assigning a value to flexibility. If not, the 5 percent flexibility credit described in Section O-2c can be used on an interim basis.

(2) Production cost models such as POWRSYM normally treat thermal plant outages probabilistically, by computing the costs of reserve capacity operation after the pumped-storage dispatch has been completed. Hence, the use of pumped-storage generation to help cover for thermal plant outages is not accounted for in the system cost analysis. An option is available in POWRYSM (and perhaps other PCM's) which treats forced outages on a Monte Carlo basis, and the use of this technique would give pumped-storage credit for this operation. The Monte Carlo technique requires considerably more computer time, but a sensitivity analysis could be made to give an estimate of the benefit gains to be realized, so that adjustments can be made to other PCM runs.

k. Sensitivity Analyses. Paragraphs 7-3d(7) and (8) list some of the variables that need to be considered in evaluating and scoping a pumped-storage project. It can be seen from the foregoing discussion that a proper economic analysis of an off-stream pumped-storage project is a relatively detailed and rigorous procedure. This is to be expected, because projects of this type are typically large, requiring sizable investments. However, treating all possible development alternatives and planning assumptions in detail would require excessive planning resources (time, manpower, and money). The analysis should be designed in such a way as to keep study costs as low as possible, while still producing an adequate level of accuracy and detail. One way to conserve both time and computer costs is to do a rigorous analysis of a few of the most likely alternative development plans and treat as many of the variables as possible in sensitivity studies, rather than doing a complete analysis of all of the possible alternative planning assumptions and development alternatives. Figure 7-15 shows, as an example, a sensitivity analysis that is intended to obtain a preliminary indication of the relative benefits of additional reservoir storage. A similar test could be applied in the final stages of project scoping to verify that the initial decision regarding reservoir storage was correct.

7-6. Analysis of Pump-Back Projects.

a. General. The operation of an on-stream or pump-back type pumped-storage project consists of a pumped-storage operation superimposed on a conventional hydro peaking operation, and the analysis of such a project requires a combination of the techniques used to evaluate both types of projects. This section describes how these various techniques would be used to perform such an analysis.

b. Objectives of Pump-Back Operation.

(1) Reversible units may be installed in conventional on-stream hydro projects either to increase the dependable capacity of a conventional power installation or to permit a larger power installation (or a combination of both). An example of the former would be a pondage project where streamflow is adequate to firm up the installed capacity most of the time, and pump-back would be used to help support the capacity only during occasional low flow periods. The reversible units at the Harry S. Truman project were installed to serve this purpose.

(2) The latter approach would be used to permit a large peaking installation at a site that has low streamflow, but is otherwise well-suited for a peaking development. Figures 6-19 and 6-20 in Section 6-8d graphically illustrate how pump-back can be used to increase plant capacity. The four pump-turbine units installed to expand the power installation at the Richard B. Russell project are an example of this type of philosophy. The initial (conventional) units at Russell fully developed the natural streamflow, so the additional units were designed to be supported most of the time with off-peak pumping energy. The location of the Russell project between two storage projects, which provide the necessary regulation and reregulation, made this type of installation attractive. At other projects,

reversible units may be installed to accomplish both purposes. Pump-back can be installed at pondage projects, projects with seasonal power storage, and multiple-purpose storage projects.

(3) Prior to considering pump-back, the power system must be examined in order to determine if low-cost off-peak pumping energy is available and if the on-peak generation that would be displaced is high-cost energy. If not, pump-back will not be feasible. This preliminary examination would be made in coordination with the regional PMA, FERC, or the local power utilities. This step is very important, and must be done carefully. There is no reason to expend effort on detailed studies of pump-back if it cannot operate economically in the power system.

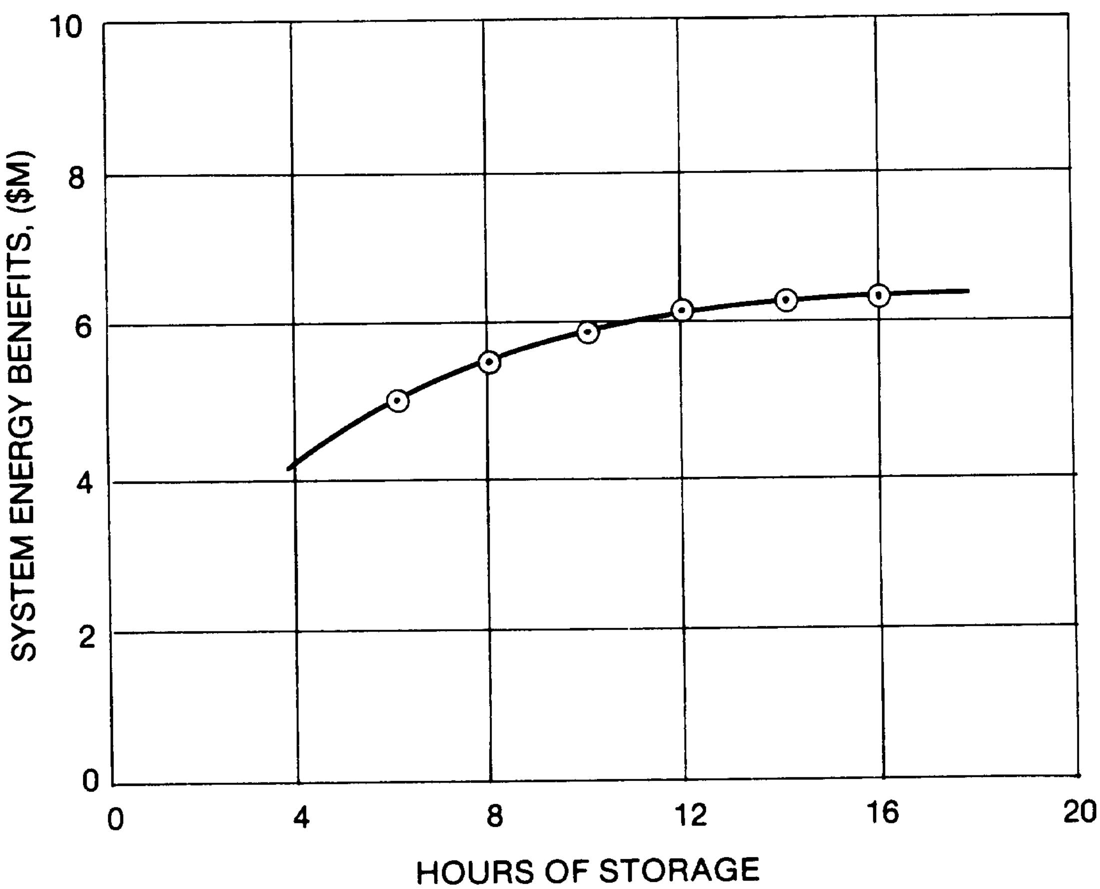

Figure 7-15. Sensitivity analysis showing the effect of reservoir size on system energy benefits

(4) Another requirement for pump-back is a downstream reservoir to serve as the lower reservoir for the pump-back operation and to regulate peaking discharges from the pump-back project to meet downstream flow requirements. This could be an existing reservoir or a specially constructed reregulating reservoir. Section 6-8c provides further information on reregulating reservoirs.

c. Basic Procedure.

(1) The analysis of a pump-back project requires that both period-of-record and hourly sequential streamflow analyses be made. A period-of-record routing must be made without pump-back in order to determine the conventional hydro energy potential of the project. Hourly studies are then made for selected weeks (or other suitable intervals) to determine the capacity that can be supported with a conventional pondage operation, and to identify the additional capacity that can be supported by adding pump-back. Additional period-of-record seqential routing studies are usually run with the pump-back installation in order to determine how often pump-back operation will be required.

(2) Following are the basic steps that would be followed in the analysis of a pump-back project:

- make a period-of-record routing to define the project's energy potential without pump-back.
- establish the on-peak generating pattern required for dependable capacity.
- select a range of possible plant sizes (the remaining steps are performed for each plant size).
- perform a series of hourly or multi-hourly routings in order to determine the dependable capacity without pump-back.
- identify the "worst case" week to serve as the basis for designing the pump-back installation.
- determine the hours when off-peak pumping energy is available.
- perform a preliminary routing for the worst-case week in order to to determine the pondage and reregulating reservoir requirements.

- select the appropriate mix of conventional and reversible units (or select several possible mixes).

- perform a series of hourly or multi-hourly routings to determine the dependable capacity and the maximum pumping requirements with pump-back.

- perform a system production cost analysis to determine whether pump-back is economical and to determine the average amount of pump-back operation that is required.

(3) At some pump-back projects, conventional hydro generation represents only a small portion of the energy output. In such cases, it is more appropriate to analyze the project as an off-stream pumped-storage project (as described in Sections 7-3 through 7-5), with conventional generation accounted for by specifying inflows to the upper reservoir (see Section 7-5f(4)).

d. <u>Base Period-of-Record SSR Analysis.</u>

(1) A base period-of-record sequential streamflow (SSR) routing is required in order to determine the project's energy output for each interval without pump-back. For storage projects, this routing would also serve to define the reservoir's seasonal operating pattern. The routing would be made generally as described in Chapter 5, following the procedures corresponding to the specific type of project being analyzed (i.e., pondage project, power storage project, multiple-purpose storage project, project operating as part of a system, etc.).

(2) In the case of projects with power storage, some modifications to the operating procedures can sometimes be made in order to take advantage of the pump-back capability. For example, it might be preferable to maintain a reservoir at an elevation such that rated capacity can be delivered at all times, rather than drafting the reservoir below that elevation to meet firm energy requirements (see Section 5-13c).

(3) When pump-back is being considered for addition to an existing project or for incorporation in a project already in the planning stage, it may be possible to utilize an existing routing as the base case analysis.

e. <u>Define Project's Dependable Capacity Without Pump-back.</u>

(1) The first step is to define the operating criteria that would make a project's peaking capacity dependable. Some systems require only that dependable capacity be supported either by (a) a specific minimum energy during the peak demand period, or (b) specific

minimum amounts of energy during each week or month of the year (see Section 6-7e). In other systems, the capacity must meet specific sustained capacity criteria, which reflect the number of hours on peak, minimum flows, and other factors (see Section 6-7i). The dependable capacity criteria are usually be established in coordination with the regional Power Marketing Administration.

(2) Whichever method is used, the dependable capacity criteria can be converted to a series of minimum energy requirements per week or month. These values would usually be expressed in terms of kilowatt-hours of energy required per kilowatt of firm peaking capacity. Separate values can be assigned for each week (or month) of the year, or just for each week (or month) during the peak demand period, depending on the criteria being followed.

(3) These values are then applied to the project's energy output from the period-of-record routing, in order to determine the amount of capacity that can be supported in each time interval without pump-back. If the average availability method is being used to measure dependable capacity (see Section 6-7g), one or more plant sizes can be assumed and the average capacity available during the peak demand months (over the period-of-record) can be computed for each. If the "firm plant factor" method is used (see Section 6-7e), the dependable capacity would be defined by the water year with the least amount of energy production during the peak demand months.

f. Define the Operating Cycle for Pump-Back Operation. The operating cycle for pump-back operation must be defined next. This is required in order to make the "worst-case" SSR routings which will establish the pondage and reregulating reservoir requirements for different plant sizes (or, if the available storage is fixed, which will determine the maximum installed capacity that should be considered). The operating cycle is defined in basically the same manner as for off-stream pumped-storage projects, in that the required number of hours of on-peak generation per weekday and the number of hours of off-peak pumping energy available per weeknight must be identified (see Section 7-2c). These values are normally established just for the peak demand months, but in some cases it may be necessary to define values for other periods as well.

g. Make Worst-Case Hourly SSR Routings.

(1) The "worst-case" week, which will serve as the basis for pump-back project design, will be the condition that puts the greatest stress on the project. It may be the historical peak demand week with the lowest average discharge, or it may be a week with an average flow having a recurrence interval that is consistent with the regional power system reliability criteria (once in ten years, for example).

(2) A range of potential plant sizes would then be selected as described in Section 6-2.

(3) Using the required on-peak generating pattern, the hours that off-peak pumping energy is available, and the downstream discharge requirements, an hourly routing must be performed for the "worst-case" week in order to determine the pondage and reregulating reservoir requirements for each plant size. As suggested in Section 6-8c(2), it may be desirable to base this analysis on a three-day weekend. If physical constraints limit the amount of pondage or reregulating reservoir capacity available, it may be possible at this stage to eliminate some of the proposed plant sizes.

(4) The routing study for the worst case week will also help identify the minimum amount of capacity that must be reversible. The most economical installation will usually be the mix with the minimum number of reversible units, but where the maximum pumping capacity and maximum flexibility is required, the choice may be all reversible units. It may be necessary to test several mixes in order to identify the combination that produces the maximum net benefits.

(5) This analysis would be done using an SSR model with hourly routing and pumped-storage evaluation capability, such as HEC-5 (see Sections 6-9 and K-5).

h. Compute Pump-Back Requirements for Period-of-Record.

(1) A period-of-record sequential routing must then be made for each plant size in order to determine how much pump-back will be required to meet dependable capacity criteria. A variety of different approaches can be taken to making this analysis, depending on the complexity of the system and the SSR model available.

(2) One approach is to use a daily routing interval. The first step in such an analysis would be to specify a minimum daily generation requirement, which would be based on the number of hours of on-peak generation required per day (this could vary by day of the week and by month, or by season). It will also be necessary to specify the maximum amount of energy that could be pumped with available pumping energy each weeknight and on weekends. Using a pondage project that is required to produce peaking power five days a week as an example, the generation from inflow is first computed for each weekday and compared with the minimum daily generation requirement. If the requirement is greater than generation from inflow, some pondage must be drafted. Pumping energy is then applied in an attempt to restore the reservoir that night. If the reservoir cannot be restored during the week-nights, it will gradually be drawn down until the weekend, when additional pumping energy becomes available. For a multiple-

purpose project, this operation would also have to accomodate releases to serve other project purposes.

(3) With this analysis, it is possible to determine the amount of pumping energy required to insure that the required on-peak power can be delivered throughout the period-of-record. However, the average annual generation and average annual pumping energy values obtained from these studies would not generally be used in the economic analysis, because they represent the maximum expected pump-back operation rather than the average pump-back operation. The economic analysis must account for the day-to-day (and hour-to-hour) variations in the value of on-peak power and off-peak pumping energy. A production cost analysis is normally used to define the average pump-back operation.

(4) For some projects, the use of pump-back will make the installed capacity fully dependable. At other projects, however, head loss due to reservoir drawdown or tailwater encroachment will result in reduced capacity during some periods. In such cases, the period-of-record daily routings can be used to estimate the average capacity available during the peak demand period (see Section 6-7g). The period-of-record routings can also be used to test alternative mixes of conventional and reversible units.

i. Economic Analysis.

(1) General. The procedure for evaluating the benefits for a pump-back project is generally similar to that for an off-stream pumped-storage project (see Section 7-5). Because pump-back projects are usually smaller and because they depend on pumping for only a part of their generation, the analysis can often be simplified. For example, if a project is relatively small compared to system loads and most of the generation is from natural inflow, it may be necessary to examine only one or two typical load years rather than a sequence ten to twenty years beyond the on-line date. However, for large plants, especially those where generation is mostly from pump-back, a more rigorous analysis would be required. If the detailed analysis is required, the procedure described in Section 7-5 should be followed, except that a production cost model capable of handling a pump-back project must be used (see paragraphs 7-6i(4) and (6)). The remainder of this section deals with the analysis of a smaller project.

(2) Define Base Conditions. The system for analysis should include the utilities where the power will be marketed and adjacent utilities whose system operation might be influenced by the pump-back project operation. For many pump-back projects, this will be a single power supply area. A load-resource analysis must be made to determine when new capacity would first be needed. If the pump-back

project is small and the system resource mix is not expected to change significantly with time, it may be sufficient to examine only a single representative year, typically within the first ten years after the project on-line date (POL). In other cases, it is best to analyze two different load years (five and ten years after POL, for example), and if studies show a major change in energy benefits between the two years, additional years should be examined and energy benefits should be determined for intervening years by interpolation (as in Figure 9-2).

(3) Define Without-Project Scenario. With the information on projected deficits obtained from the load-resource analysis, additional resources are be scheduled such that sufficient capacity will be available to meet projected peak loads with an adequate reserve margin in the load year (or load years) being examined. The new resource mix can be determined using optimized generation expansion techniques, as described in Section 7-5b(6) through (9)), or it can be projected based on discussions with the regional PMA and local utility planners. Plant data and hourly load shapes would be developed as described in Section 7-5c.

(4) Compute Without-Project System Energy Costs. System energy costs for the without-project case would be developed using an hourly production cost model as described in Section 7-5d. The POWRSYM model has been modified by North Pacific Division to handle pump-back projects, and it is recommended that this model be used for such analysis.

(5) Define With-Project Scenario. In this scenario, the pump-back project will replace an increment of the new capacity scheduled in step (3), above. The type of capacity replaced will be the most likely alternative, and since a pump-back project is usually a peaking project, the most likely alternative will normally be combustion turbine, cycling steam, or a mix of the two. It may be necessary to make several with-and-without project analyses in order to determine which alternative or mix of alternatives is most appropriate.

(6) Describe the Pump-Back Project. In POWRSYM, the pump-back project is modeled as a "pump-storage project". The same basic input data is required for a pump-back project as is required for an off-stream pumped-storage project (see Section 7-5f). In adapting POWRSYM to handle pump-back operation, the model was modified such that the following parameters can be specified by week:

- number of units available
- unit generating capacity, MW
- average unit pumping capacity, MW
- start-of-week reservoir elevation, gWh

- end-of-week reservoir elevation, gWh
- local reservoir inflow, gWh/hour

Reservoir inflow is modeled as "local inflow to the upper reservoir." Weekly average inflows are obtained from the period-of-record SSR routing and converted to potential energy, in gWh/hour (see Section 7-5f(5)). The number of units and the unit pumping capacity can be specified by week so that operating restrictions, such as limited or no pump-back during certain seasons, can be modeled. The model does not presently accomodate a mix of conventional and reversible units, but this type of installation could be approximated by assuming that all of the units are reversible and assigning a reduced equivalent pumping capacity to each of the units. This equivalent capacity value would be computed by dividing the total (average) pumping capacity of all reversible units by the total number of units, reversible and conventional. In this way, the total pumping capacity will never be exceeded, even though all units are in effect being modeled as reversible units. By specifying start-of-week and end-of-week reservoir elevations, it is possible to simulate the regulation of seasonal storage projects. Such values can be obtained from period-of-record SSR studies and converted to potential energy in gWh (see Section 7-3c(5)). In many cases, average annual energy benefits can be approximated by modeling only an average water year (i.e., specifying inflows and, in the case of storage projects, reservoir elevations for an average year from the period-of-record SSR analysis). However, when it is anticipated that the variations of inflows and reservoir elevations from year to year will have a significant effect on energy benefits, it may be necessary to model a range of representative water years. System energy benefits would then be based on a weighted average of those runs. If this is done, energy data for any existing conventional hydro in the system must also be adjusted to reflect the varying water conditions.

(7) Determine With-Project System Energy Costs. System energy costs are then computed with the production cost model for the system with the pump-back project. The model will produce output information similar to that for an off-stream pumped-storage project (see Section 7-5g). Figure 7-16 shows an example of a typical week's operation for a pondage project with pump-back. POWRSYM dispatches the project's generation from natural streamflows first, with pump-back normally being used only if it is economical (see Section 7-2c(2)).

(8) Determine System Energy Benefits. Average annual system energy benefits and average annual pumping costs for a pump-back project are computed in the same way as for an off-stream pumped-storage project (see Section 7-5h), except that in some cases they will be based on only one or two representative years.

(9) Determine Capacity Benefits. Capacity benefits are computed by applying unit capacity values (based on the capital costs of the thermal alternative replaced by the pump-back project) to the pump-back project's dependable capacity (see Sections 9-3b, and 9-5a thru 9-5c). Note that for some projects, the dependable capacity may be less than the installed capacity (see Section 7-6h(4)).

j. Additional Hours SSR Studies. It is often desirable to make additional hourly SSR studies, in order to examine pondage and drereguIation reservoir requirements and water surface fluctuation rates under other than worst-case conditions. Weekly generation and pumping schedules for making these analyses can be obtained from production cost model runs.

k. Unit Characteristics.

(1) As noted earlier, power installations at pump-back projects can be all reversiblae units or a mix of reversible and conventional

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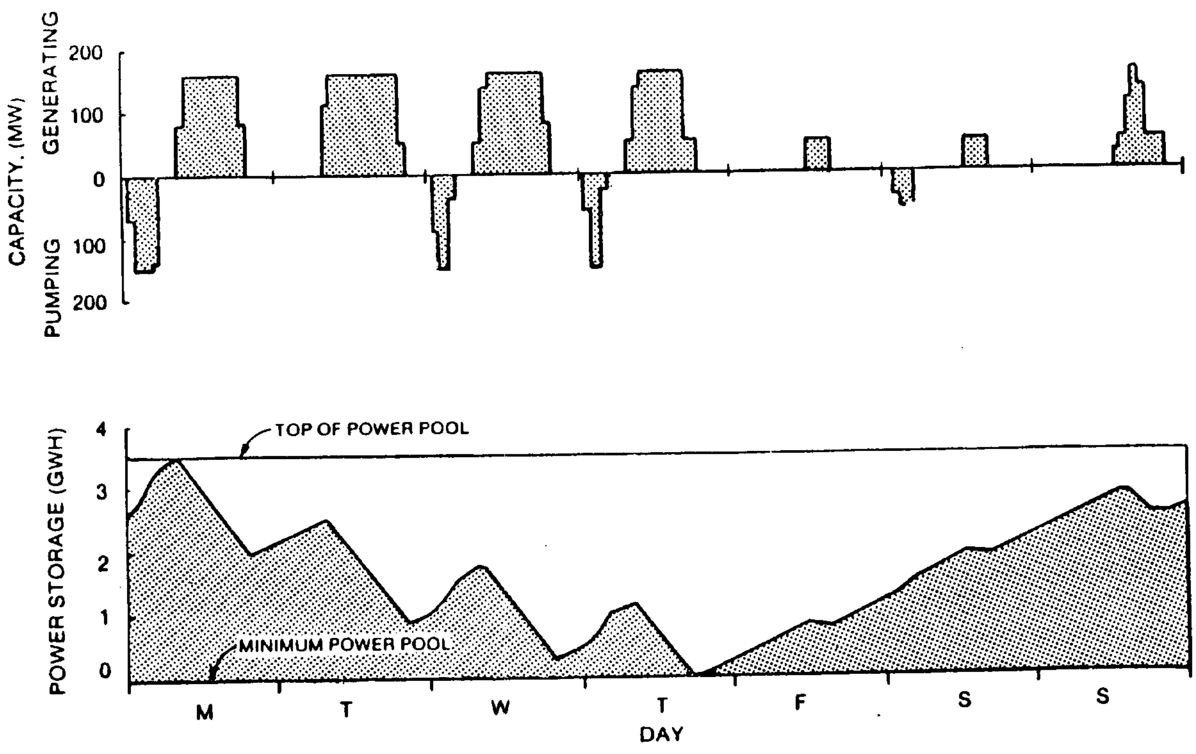

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Figure 7-16. Operation of a pump-back project for a typical week based on a production cost analysis.

units. The characteristics of conventional units are described in Section 5-5. The characteristics of reversible units for pump-back operations are generally as described in Section 7-2.

(2) Heads are usually smaller for pump-back projects than for off-stream pumped-storage plants. Hence, the head range for efficient operation becomes more of a consideration, particularly at multiple-purpose storage projects, where large reservoir fluctuations are required to serve other project functions. In some cases, it is necessary to limit the head range in which pumping can be accomplished. Where a mix of conventional and reversible units are installed, the two types of units can be designed for somewhat different operating head ranges to permit efficient operation over the full project head range. Submergence requirements can also be an important consideration, particularly at above-ground powerhouses.

l. Alternative Project Configurations and Sensitivity Studies. Some of the variables that might be considered at pump-back projects include alternative plant sizes, alternative unit sizes, alternative mixes of conventional and reversible units, alternative reservoir sizes, and alternative reregulating reservoir configurations. Sensitivity studies can also be made to test alternative on-line dates, alternative fuel cost escalation rates, alternative load growth rates, and alternative load shapes.

7-7. Special Problems.

a. General. This section briefly reviews some of the special types of pumped-storage projects and other special problems involved in the analysis of pumped-storage.

b. Screening Studies.

(1) The first step when considering the addition of off-stream pumped-storage to a system is often a comparative examination of alternative sites in the area. Such a study is usually conducted in stages. The first step is to identify all potential sites. Then, physical screening criteria can be applied to eliminate the most costly sites. Such criteria could include minimum head, maximum penstock and tunnel length, distance from load centers, and the minimum plant size that can be supported. Another screening can be done to eliminate those projects in environmental or politically sensitive areas. Those projects that survive these tests would then be costed out, with the best site or sites then being considered for a reconnaissance level analysis.

(2) A number of pumped-storage inventories and screening studies have been completed, and three of them are described in references (85) through (88). The Bureau of Reclamation has developed a screening procedure for comparative evaluation of water resource projects (63) which may be of some value to Corps of Engineers planners in evaluating pumped-storage projects.

c. Seasonal Pumped-Storage.

(1) Off-stream seasonal storage for power and other functions is sometimes attractive because it represents a possible means of obtaining storage without obstructing existing waterways. Section 7-1b(4) describes two existing U.S. seasonal pumped-storage projects. However, development of seasonal pumped-storage has not been extensive in the U.S. to date, because the high costs of embankment structures and pumping energy, together with the impacts of flooding large reservoir areas, have usually more than offset the benefits to be gained. However, there may yet be cases where the value of stored water, whether for power or for other purposes, will be great enough to warrant consideration of such developments.

(2) Such a project would inherently be a multiple-purpose project. For example, assume that an off-stream storage reservoir is needed for low flow augmentation. Water would be pumped into storage in the high runoff season, providing flood control benefits in some years and possibly using secondary energy which would otherwise be spilled for pumping. Where the water is released for low flow augmentation, relatively high value of energy may be produced. The upper reservoir could also provide reduced pumping head for irrigation of adjacent areas, and a daily/weekly cycle pumped-storage project operation could be superimposed on the seasonal operations.

(3) Analysis of the seasonal operation would be made using standard seasonal SSR techniques (Chapter 5), utilizing a SSR model with pumped-storage capabilities. The daily/weekly cycle pumped-storage operation would be evaluated as described in Section 7-2 through 7-5.

d. Underground Pumped-Storage.

(1) Underground pumped-storage is a variation of the daily/weekly cycle type of development in which the lower reservoir is underground. This type of development has the advantage of considerable flexibility in siting. Underground pumped-storage projects can be chosen which have relatively minor environmental and political impact, whereas sites which are suitable for above-ground

development almost inherently have significant impacts. Furthermore, both the upper and lower reservoirs can be considered off-stream reservoirs, so there will be relatively little impact on existing waterways.

(2) From the planning standpoint, underground projects are analyzed in basically the same manner as above-ground daily/weekly cycle off-stream pumped-storage projects. There are, however, additional design complexities, particularly in the areas of geology, construction, and machinery design. Both the U.S. Department of Energy and the Electric Power Research Institute have supported research on underground pumped-storage in recent years. Reference (90) and Section 3 of Volume III of Reference (12) should be consulted for further information in this area.

e. Multiple-Purpose Operation. At daily/weekly off-stream pumped-storage projects, the opportunities for multiple-purpose operations are limited, but some examples of incorporation of other functions do exist. A pumped-storage project could be used to pump water for local irrigation or water supply systems. Recreational facilities could be constructed on lower reservoirs if reservoir fluctuations are not too large. On the other hand, it is sometimes possible to add daily/weekly cycle pumped-storage operations to a facility that is designed primarily to convey or store water for other purposes. Examples are (a) the Castaic project, which is located on the West Branch of the California Aqueduct, (b) the Mt. Elbert project, which is located on one of the conduits of the Fryingpan-Arkansas inter-basin diversion project, and (c) the Grand Coulee pumping plant, which pumps water from the Grand Coulee Reservoir to Banks Lake, a key storage reservoir for the Columbia Basin Irrigation project. The multiple-purpose aspects of seasonal pumped-storage were discussed in Section 7-7c. Pump-back can also be readily incorporated in a project that serves multiple purposes.

f. Environmental Problems. While a detailed discussion of the environmental problems associated with pumped-storage is beyond the scope of this manual, two problems that are commonly encountered at pumped-storage projects are worthy of special mention: (a) intakes at lower reservoirs often must be screened to prevent fish from being drawn into the powerplant during the pumping operations, and (b) large daily/weekly reservoir fluctuations are often required, particularly at upper reservoirs. Additional information on environmental impacts of pumped-storage can be found in references (22), (48j), and (88).

TABLE 7-5
Maximum Pumped-Storage Development by Region
As Reported in the National Hydropower Study 1/

Northeast (NPCC & MAAC)	3,400 MW
Southeast (SERC)	18,600 MW
North Central (ECAR, MAIN & MAPP)	36,000 MW
South Central (SPP & ERCOT)	1,300 MW
West (WSCC)	600 MW
	59,900 MW

1/ base case projections, from Table 5-6 of reference (48j)

g. The National Hydropower Study.

(1) Dames and Moore has prepared An Assessment of Hydroelectric Pumped-Storage for the Corps of Engineers as a part of the National Hydroelectric Power Resources Study (48j). This report contains detailed information on most existing and planned U.S. pumped-storage projects (pump-back as well as off-stream). Included are case studies of several recently proposed projects and the problems associated with bringing these projects through the planning process and into production. The report also includes a discussion of the alternatives to pumped-storage hydro and a comparative assessment of pumped-storage hydro with these alternatives.

(2) An attempt was also made to assess the potential need for pumped-storage by region, using a generalized production cost model. This analysis tested a number of alternative planning assumptions with respect to load growth resource dispatch philosophy, powerplant retirement schedules, and load management. The study, which was generally based on NERC regions (Figure 3-1), showed that the largest potential need for pumped-storage would occur in the north central states (MAPP, MAIN, AND ECAR) and the southeastern states (SERC). Some need was also identified in the northeast (NPCC and MAAC) and in the south central states (SPP and ERCOT). Very little pumped-storage appeared to be required in the Western states (WSCC), largely due to the availability of conventional hydro for peaking service. Table 7-5 lists the maximum pumped-storage development projected using base case planning assumptions.

(3) These projections should be used with caution, because some of the planning assumptions are now dated, the model used for the analysis was of necessity somewhat simplistic, and the study was based on large, multi-region areas. However, they should give a general indication of the most promising areas for development. It is recommended that this analysis be carefully reviewed in the process of making any pumped-storage feasibility study.

CHAPTER 8

ESTIMATING POWERHOUSE COSTS

8-1. Introduction. Cost estimates for hydroelectric projects are generally similar to those for other types of projects. However, there are some special considerations, particularly with respect to sources of data. This chapter describes these considerations in the context of the standard cost estimating process. Specific topics addressed include types of estimates, construction costs, investment costs, O&M and replacement costs, transmission costs, and the indexing of costs to current price levels. A sample cost calculation is also included. The methodology and examples cited in this chapter represent a suggested approach. Variations may be appropriate in the case of specific projects. The sample computations shown in Section 8-8 include only powerhouse costs. When making the total estimate for a power project or a multiple-purpose project including power, other cost items would be included as well.

8-2. Types of Cost Estimates.

a. General. Cost estimates are made for all levels of hydropower investigations. Reconnaissance, feasibility, and project design reports each require cost estimates that are consistent with the level of detail presented in the study.

b. Reconnaissance Reports. The purpose of a reconnaissance report is to determine if a project has sufficient promise to warrant more detailed study. The intent of this report is to perform a preliminary economic analysis and appraise the critical issues, rather than to formulate detailed approaches or solutions. Cost information would be obtained from generalized cost curves or from data for similar projects. The report would contain a summary cost estimate for one or more schemes, and drawings would be limited to a cross-section of the powerhouse and a plan showing exterior dimensions of the structure.

c. Feasibility Reports. The purpose of a feasibility study is to determine whether a specific project (or other action) should be recommended for Congressional authorization. At this level of study, the primary objective is to formulate a project and to establish project feasibility. As the study progresses toward selection of the recommended plan, characteristics are defined, and costs for the major electrical and mechanical items, such as turbines and generators, may be obtained directly from the manufacturers. Costs for civil features, such as powerhouse structure, penstock, and intake and outlet works, are similarly refined. In the early stages of project formulation, a large number of alternative plans may be under consideration, and cost estimates may be similar to reconnaissance grade estimates. Once the number of alternatives has been screened down to the best candidates, more detailed cost estimates are prepared. Narrative descriptions of the major elements of the powerhouse are included, together with drawings describing the general location plan, powerhouse plan and section, and a one-line diagram of the electrical system.

d. Design Memoranda. This category includes General Design Memoranda (GDM), Feature Design Memoranda, and the Definite Project Reports (DPR). The DPR is prepared for smaller single-purpose hydro projects and serves as a combination GDM and Feature Design Memorandum. These reports are the last documents written prior to preparation of plans and specifications. At this stage of study, detailed cost estimates are based upon specific design studies for all powerhouse features.

8-3. Construction Costs.

a. Introduction. Powerhouse construction costs are usually defined to include turbines and generators, control systems, communication facilities, ground mats, transformers, high and low voltage switching equipment, buswork, and the service equipment essential for operation of the powerhouse, as well as the powerhouse structure itself. Following is a brief description of the major powerhouse components and the contingency allowances normally used in making powerhouse cost estimates.

b. Major Powerhouse Components.

(1) General. The powerhouse generally includes the items listed in Table 8-1. Intake works, gates, penstocks, and related features are generally not included in powerhouse cost estimates. These items are included in other civil feature cost accounts and will not be discussed here, since they are covered in other engineering manuals such as EM 1110-2-1301, Cost Estimates: Planning and Design Stages.

(2) Powerhouse Structure. This account includes all materials and work needed to construct the actual structure which encloses the powerplant equipment. For an existing structure, this account would include any remodeling or rehabilitation needed to bring the structure up to design specifications. Typical items included in this category

TABLE 8-1
Typical Powerhouse Cost Estimate

Price Level: January, 1981

	FEATURE	COST (DOLLARS)
7.1	POWERHOUSE STRUCTURE	
	a. Excavation	$ 9,240,000
	b. Reinforced concrete	11,070,000
	c. Miscellaneous building items	260,000
	d. Bulkhead, guides & structural steel	1,980,000
	Subtotal	$22,550,000
7.2	TURBINES AND GENERATORS	
	a. Turbines, generators, & governors	$17,130,000
	b. Cooling system	44,000
	Subtotal	$17,174,000
7.3	ACCESSORY ELECTRICAL EQUIPMENT	
	a. Switchgear, breakers & busses	$ 453,000
	b. Station service unit	85,000
	c. Control system	428,000
	d. Miscellaneous electrical systems	597,000
	Subtotal	$ 1,563,000
7.4	AUXILIARY SYSTEMS & EQUIPMENT	
	a. Heating and ventilating	$ 75,000
	b. Station, brake & governor air	50,000
	c. Dewatering & drainage systems	74,000
	d. Bridge crane	425,000
	e. Tailrace, gantry crane	350,000
	f. Miscellaneous mechanical systems	225,000
	Subtotal	$ 1,199,000
7.6	SWITCHYARD	
	a. Power transformer	$ 522,000
	b. High voltage equipment	200,000
	Subtotal	$ 722,000
7.7	SITE PREPARATION & SPECIAL ITEMS	
	a. Mobilization & preparation	$ 1,500,000
	TOTAL	$44,708,000

are excavation and foundation, concrete, structural steel, and architectural features.

(3) Turbine and Generators. This category includes the major equipment and systems needed to convert the available energy in water to electrical energy: the turbines, generators, governors, excitation equipment, and cooling systems.

(4) Accessory Electrical Equipment. These are items that control the generating unit and interconnect the generator with the switchyard. This account includes switchgear, circuit breakers, and station service and control systems.

(5) Auxiliary Systems and Equipment. This account includes supporting systems and equipment and items not included in other powerhouse categories, such as heating and ventilating systems; piping, dewatering, and drainage systems; cranes and hoists; fire protection systems; and machine shop (where appropriate).

(6) Switchyard. This equipment provides the power interface between the power plant and the transmission system. This account consists primarily of the power transformers and related high-voltage equipment.

(7) Site Preparation and Special Items. This account includes those costs associated with contractor setup and other mobilization and preparation items.

c. Contingencies. A contingency allowance is applied to the powerhouse construction cost in order to account for uncertainty in the cost estimate. The magnitude of the contingency allowance varies with the level of study; i.e., a smaller allowance is applied to a GDM estimate than a reconnaissance study estimate. In estimating powerhouse costs, it is sometimes desirable to apply different allowances to different cost components. For example, there is usually more uncertainty associated with foundation and excavation work than with major powerplant equipment such as turbines and generators. Cost estimates prepared by the Hydroelectric Design Centers include contingency allowances which reflect the variation of uncertainty of costs among components. General guidance on contingency allowances is contained in EM 1110-2-1301, and is summarized in Table 8-2.

d. Sources of Powerhouse Cost Data.

(1) General. The principal sources of data on powerhouse costs within the Corps of Engineers are the Hydroelectric Design Centers. For preliminary studies, rough estimates can also be developed using cost data from one of several reference publications.

TABLE 8-2
Contingency Allowances

Basis of Estimate	Contingency Allowances for Projects with Construction Cost of: More Than $10,000,000	Less Than $10,000,000
Survey and review	20%	25%
Phase I GDM	20%	25%
Phase II GDM	15%	20%
Completed plans and specs	10%	10%
Awarded contracts	5%	5%
Completed contracts	0%	0%

(2) Hydroelectric Design Centers. ER 10-1-41 and ETL 1110-2-272 require that all cost estimates for project studies beyond the feasibility stage be prepared or reviewed by one of the Hydroelectric Design Centers (see Section 1-7). These offices are also equipped to make reconnaissance and feasibility grade cost estimates, and Districts not having in-house capability are encouraged to consult the Centers for these estimates as well. The Centers utilize historical information, detailed cost curves, manufacturers' data, and design studies when making these estimates.

(3) Cost Estimating Reports. Three reports contain information which may be useful in making preliminary powerhouse cost estimates:

- Hydropower Cost Estimating Manual, prepared by North Pacific Division for the National Hydroelectric Power Resources Study, dated May, 1979 and revised July, 1981 (41).

- Feasibility Studies For Small Scale Hydropower Additions: A Guide Manual, prepared by the Hydrologic Engineering Center for the Department of Energy, dated July, 1979 (39).

- Reconnaissance Evaluation of Small, Low-Head Hydroelectric Installations, prepared by Tudor Engineering Company for the Bureau of Reclamation, dated July, 1980 (36).

The data contained in these reports was developed primarily from statistical studies of historical cost data and is presented in the form of curves and equations. The Hydropower Cost Estimating Manual, which is due to be updated in CY 1985, presents data on all sizes of powerplants, while the latter two reports deal primarily with small hydro projects. The data from these reports is not all-inclusive, and the user must index cost data to current price levels. It must be emphasized that these estimates are very general and are appropriate only for preliminary studies.

8-4. Investment Cost.

a. General. Investment cost is the total cost required to bring a project on-line and includes indirect costs such as engineering and design, supervision and administration, and interest during construction. The following paragraphs describe each of these items and the adjustments that must sometimes be applied to construction cost estimates in order to account for inflation during construction. More specific guidance on each of these elements is contained in EM 1110-2-1301.

b. Construction Costs. This is the total cost required to build the project, including both the structure and equipment (see Section 8-3).

c. Project Engineering and Design (E&D) Costs. The magnitude of these costs is influenced by many factors, including the type, size, and geographical location of the project. In the early stages of study, E&D costs are usually treated as a percentage of the construction cost, and the value used varies somewhat from District to District. A sampling of recent hydropower studies showed that most values fall in the 6 to 10 percent range, with 8 percent being most common. For very large projects, a value of less than 6 percent might be justified. As a project moves into the design memorandum stages, project-specific E&D costs are often computed.

d. Supervision and Administration (S&A) Costs. S&A costs include field office and inspection costs, construction management costs, and a percentage of the District's general overhead costs. These items are treated similarly to E&D costs. A percentage of construction costs is generally used in the pre-authorization studies, and project-specific cost estimates are often developed for design memoranda. A sampling of recent studies showed that S&A costs generally fall in the 5 to 7 percent range.

e. Interest During Construction.

(1) Interest during construction (IDC) accounts for the cost of capital during the construction period. ER 1105-2-40, which provides general guidance on the computation of IDC, states that it must be based on compound interest.

(2) IDC computations are based on the projected power on-line date. IDC is compounded on all expenditures preceding that date, and all expenditures incurred after that date are discounted from their expected expenditure date to the power on-line date. For very preliminary studies, a uniform distribution of costs over the period of construction can be assumed. However, for most reconnaissance and all feasibility studies, a year-by-year distribution of costs should be used.

(3) Figure 8-1 shows a typical distribution of costs for powerhouses (including the cost of procuring turbines and generators). Table 8-3 is based upon Figure 8-1 and shows the typical annual construction cost distribution for projects with construction periods ranging from 1 to 6 years. Interest during construction is applied to the total project cost (construction cost plus E&D and S&A), using the applicable Federal interest rate.

(4) IDC must be readjusted following completion of the cost allocation to reflect the power repayment interest rate of the Department of Energy. This is in accordance with the interagency agreement of 1 September 1983.

f. Investment Cost. The investment cost is the sum of the total project cost and interest during construction.

g. Inflation During Construction. A hydropower project is usually constructed over a period of several years. During this time, the price of the items necessary to build the project may escalate due to inflation. Contractors making bid estimates on projects are aware of these effects and increase their bid estimates accordingly. If the construction cost estimates are based upon past contractor bid prices, these inflated cost estimates must be adjusted to a base year for proper economic analysis. The inflation adjustment would be applied to the construction cost, thus providing an adjusted (inflation-free) construction cost for use in the economic analysis. If the cost estimates are based upon spot prices for work to be done or materials to be delivered immediately, the estimates need not be adjusted for inflation. Section 8-8d illustrates how an inflation adjustment could be made.

8-5. Annual Costs.

a. General. Benefits and costs must be reduced to the same time basis for valid economic comparison, and the preferred time basis is the equivalent annual value. Both the annual benefits and annual costs must be adjusted to the same base price level. The annual cost consists of the amortized investment cost plus yearly operation, maintenance, and interim replacement costs. For pumped-storage projects, pumping costs would be included as well.

b. <u>Interest and Amortization.</u> Amortization of investment cost is the process of spreading the project's cost over its economic life to determine an equivalent annual cost. This requires the computation

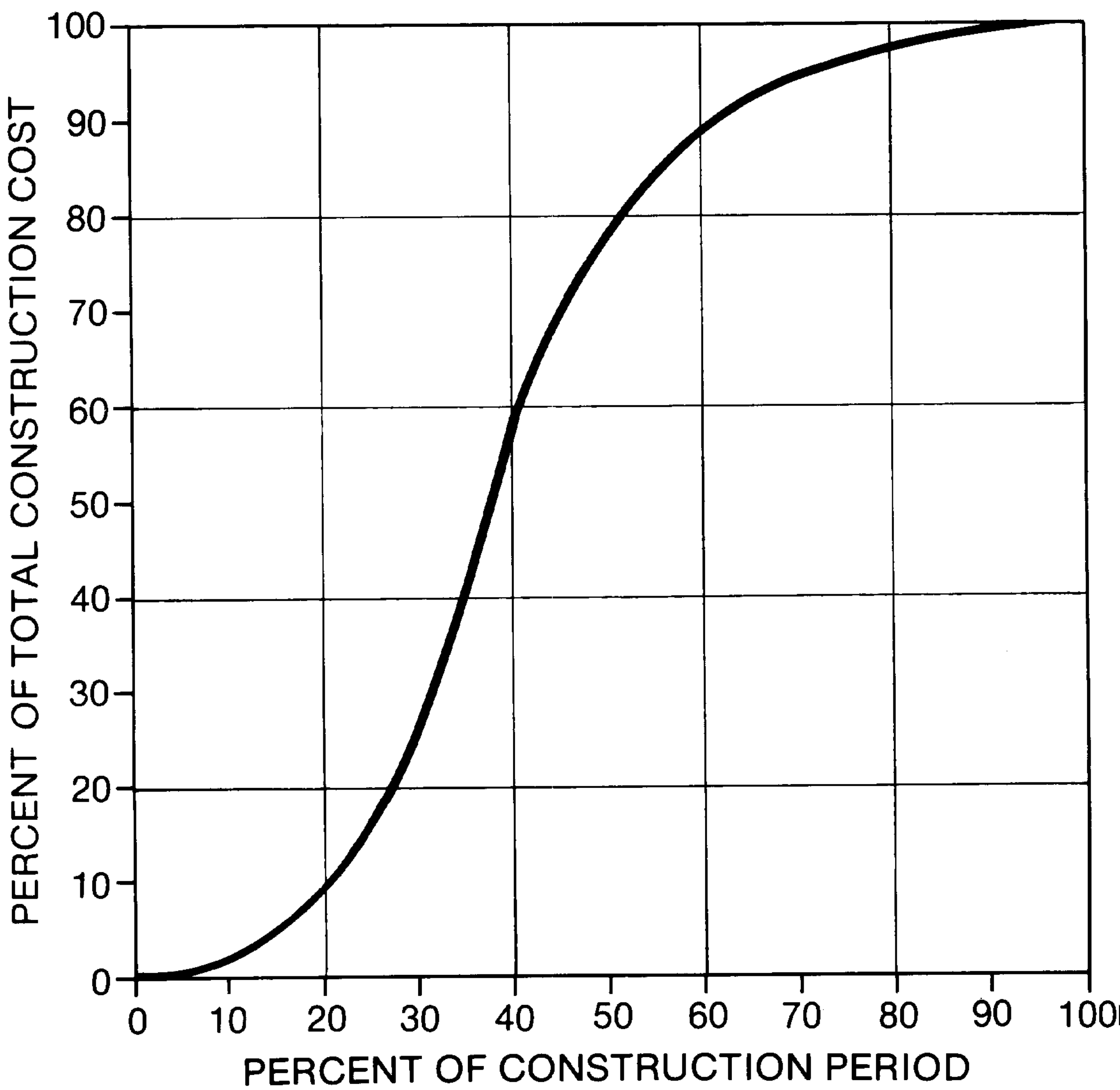


Figure 8-1. Distribution of powerhouse construction costs over construction period

TABLE 8-3
Powerhouse Construction Cost Distribution by Year for Various Construction Periods

Construction period	Percentage of total project costs expended during year: 1	2	3	4	5	6
1 Year	100	-	-	-	-	-
2 Years	77	23	-	-	-	-
3 Years	37	56	7	-	-	-
4 Years	16	62	18	4	-	-
5 Years	9	49	30	9	3	-
6 Years	6	31	40	15	6	2

of an amortization factor based upon the annual interest rate and economic life. The applicable interest rate is recomputed each year, and field offices are advised annually by HQ, USACE of these changes. The interest rate for a given project must be adjusted annually through the planning process, but once construction funds are appropriated, the project interest rate is fixed. The same interest rate is used for interest during construction calculations. Section 9-3c gives guidance on the economic life to be used in estimating annual costs for hydropower projects.

c. Operation and Maintenance.

(1) Operation and Maintenance (O&M) costs represent the average annual costs of maintaining the project at full operating efficiency throughout project life. This includes salaries of operating personnel; the cost of labor, plant, and supplies for ordinary maintenance and repairs; and applicable supervisory and overhead costs. Many Corps projects are multiple purpose installations that provide benefits and services other than power production. Some of the costs of operating multiple purpose projects are joint costs, which must be apportioned among all project functions, including hydropower. These joint O&M costs are allocated to project purposes on the same basis that joint construction costs are allocated, but the

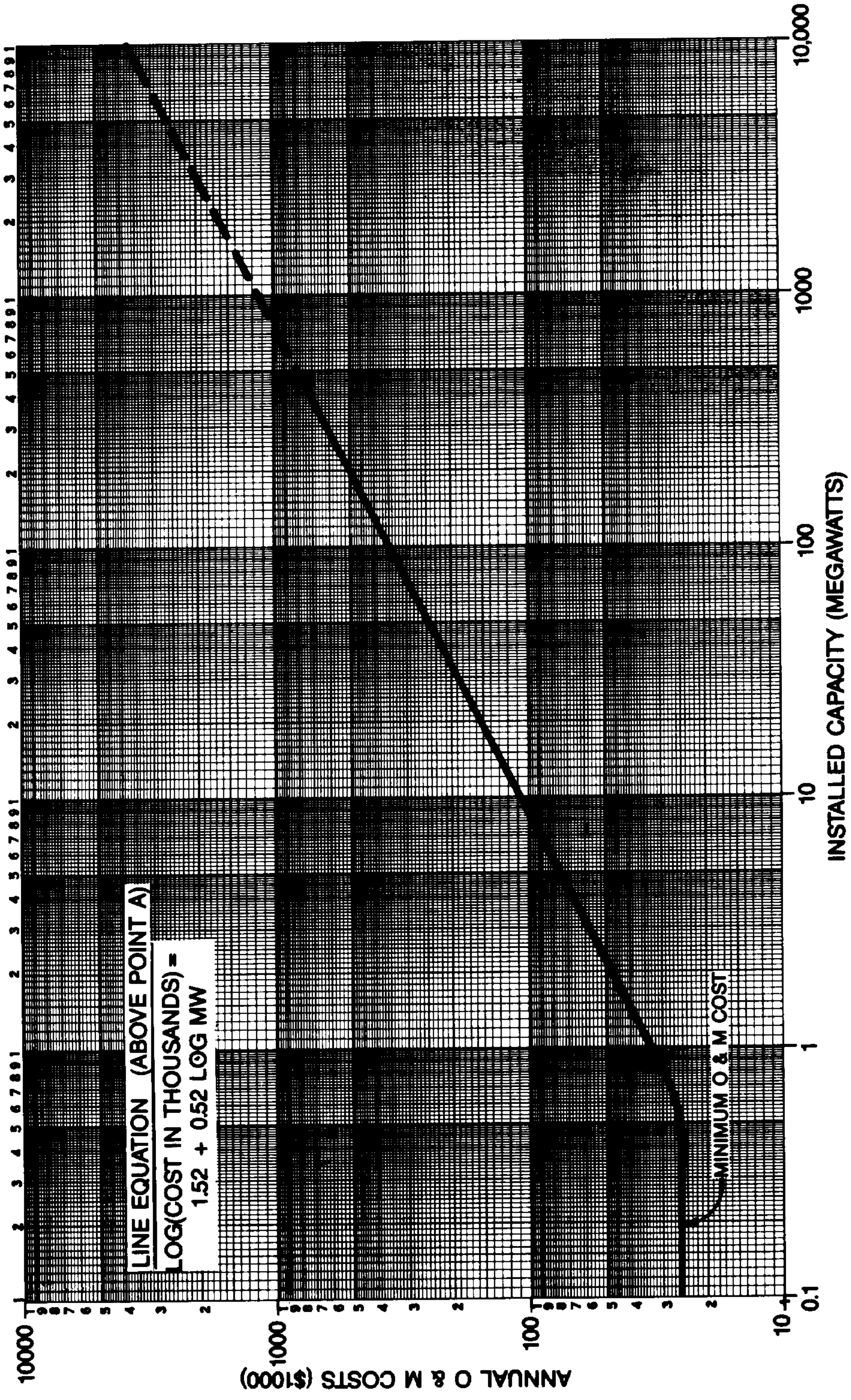


Figure 8-2. Annual operation and maintenance costs for remotely operated power plants (1983 prices)

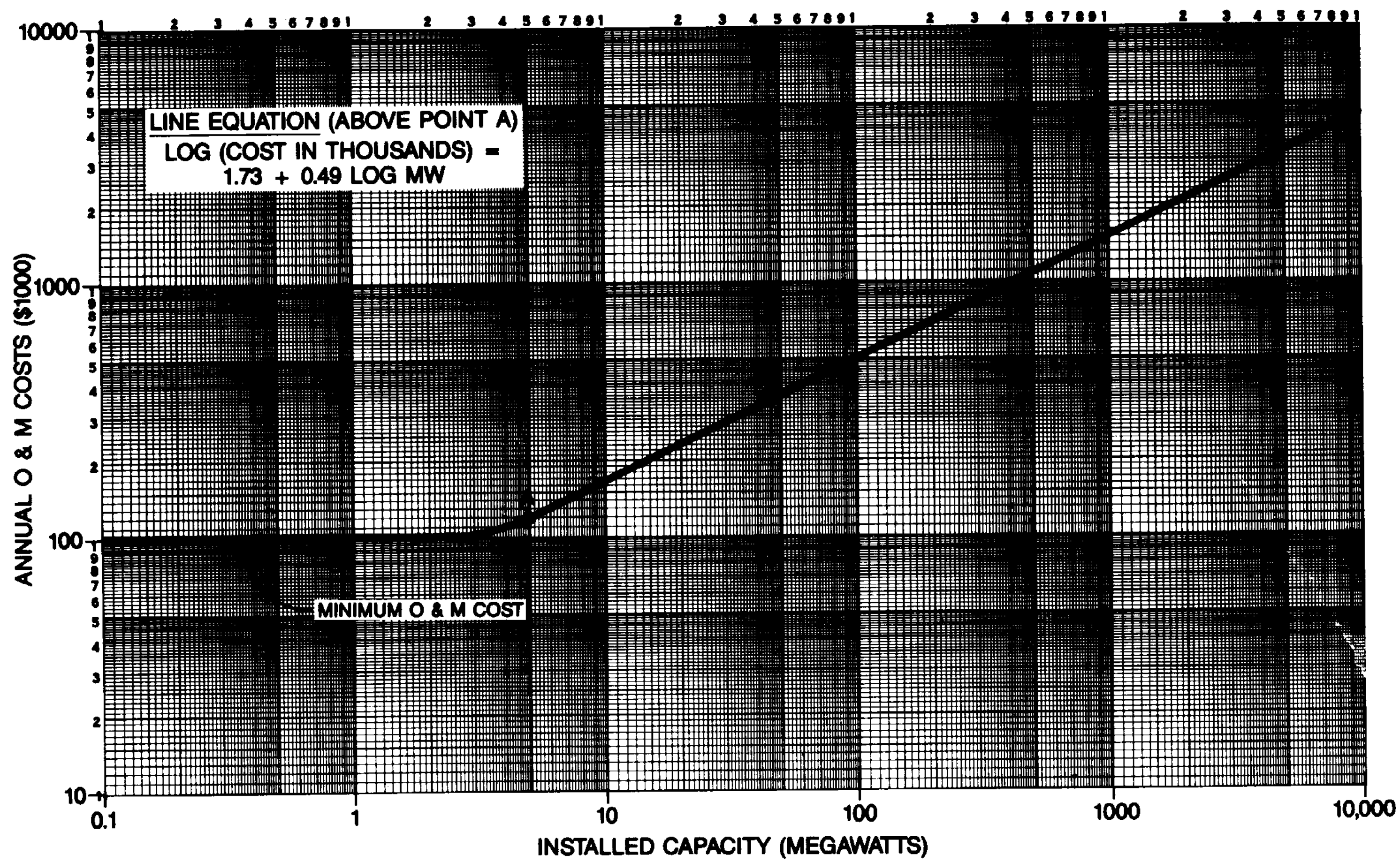


Figure 8-3. Annual operation and maintenance costs for locally operated power plants (1983 prices)

distribution percentages are not usually identical (refer to ER 1105-2-40 and EP 1105-2-45, which are part of the Planning Guidance Notebook).

(2) O&M costs are usually a function of installed capacity and type of operation. The operation of power projects is divided into two general categories: local and remote. Projects that are operated locally have operators on-station. Typical projects of this type are older power projects and new power projects where the location or the complexity of operation requires a manned station. Remote operation is performed by automated equipment, with operating instructions transmitted being from a centralized source. The complexity of the control equipment depends on plant size and location. When two or more plants are located in one area, it is often possible to operate them all from one location. In these cases, it is also common to perform maintenance at all projects with a single crew.

(3) Figures 8-2 and 8-3 show annual O&M costs as a function of project size for remote and local plant operation, respectively. These curves are based on historical O&M costs for a large number of projects throughout the country, adjusted to 1983 price levels. As Figures 8-2 and 8-3 show, total O&M costs generally decrease with plant size down to a fixed minimum level, which is necessary to cover minimum personnel and supply costs. These minimum levels are estimated to be $25,000 per year for remotely controlled projects and $100,000 per year for locally controlled projects (assuming that part of operator costs can be allocated to non-power project functions). The figures show a straight line relationship on the log-log grid. Equations for these lines are also shown on the figures, for convenience in preparing the O&M cost estimates. The curves are generalized and therefore do not reflect special conditions that can be unique to some projects. If better information is available, such as historical data from a similar project, it should be used in lieu of data from the curves. In design memoranda and other advanced studies, project-specific O&M costs based on expected staffing requirements and other costs should be developed.

d. Replacement Costs.

(1) Certain major components of a powerhouse require replacement before the end of the project life. Examples are generator windings, turbine runners, thrust bearings, pumps, air compressors, communications equipment, generator, voltage regulation and excitation equipment, and certain types of transformers. The replacement cost for a facility is the estimated future cost of such replacements, converted to an equivalent average annual value over the entire project life. ER 37-2-10, Accounting and Reporting Civil Works

Activities, provides guidance on the procedure to be used and lists the estimated service life for most of these components.

(2) The detailed procedure described in ER 37-2-10 should be used for post-authorization (design memoranda and beyond) cost estimates, and may also be used in the feasibility report. For pre-authorization studies, replacement costs can also be estimated from the construction cost estimate using an approximate procedure based on composite service lives. Detailed cost estimates were examined for a number of powerhouses of different types, and estimates were made of the percentage of each cost account that represents equipment that would require replacement at least once during project life. Service lives were then assigned to each piece of equipment requiring replacement, based on the data shown in ER 37-2-10, and composite service lives were developed for each cost account. In developing these composite service lives, the service life for each component (the generator windings, for example) was weighted by the cost of that component. Table 8-4 lists the percentages of each cost account that requires interim replacement and the corresponding composite service lives for both medium to large and small (smaller than 10 MW) hydro plants.

(3) The annual replacement cost for each cost account is estimated by (a) computing the portion of the construction cost (including contingencies) that requires replacement during the life of the project (using the percentages listed in Table 8-4), then (b) computing the present worth of that cost based on its composite service life and the project interest rate, and finally (c) amortizing the present worth amount over the composite service life. This procedure results in the determination of the amount required to be deposited annually in a sinking fund, earning interest at the project interest rate, in order to accumulate an amount equal to the estimated replacement cost. This analysis, of course, ignores future increases in replacement costs resulting from general inflation. Table 8-5 shows an example based on the construction costs from Tables 8-1 and 8-9. Note that replacement costs were not computed for the mobilization expenses. Also, to simplify the table, the present worth factor and annuity factor were combined into a single sinking fund factor.

(4) For reconnaissance studies where a detailed powerhouse cost breakdown is not available, the annual replacement costs can be approximated as 0.2 percent of the powerhouse cost estimate.

e. Pumping Costs.

(1) The cost of pumping energy is a part of the annual operating costs for both off-stream and integral pumped-storage projects. Estimates of the average annual pumping energy requirement can be

TABLE 8-4
Representative Composite Service Lives for Powerhouse Equipment Requiring Replacement During Project Life

	Med. to Large Plants 1/		Small Plants 2/	
	Percent 3/ Requiring Replacement	Composite Serv. Life (years)	Percent 3/ Requiring Replacement	Composite Serv. Life (years)
7.1 Powerhouse structure	1	38	-	0
7.2 Turbines, generators, and governors	24	38	18	39
7.3 Accessory electrical equipment	50	34	80	38
7.4 Auxiliary systems and equipment	7	24	20	35
7.5 Tailrace	-	-	0	-
7.6 Switchyard	43	36	53	38

1/ Plants larger than 10 megawatts installed capacity
2/ Plants of 10 megawatts installed capacity or smaller
3/ Percentage of total account cost which requires replacement at least once during project life.

obtained from sequential routing studies or from power system production cost studies. For integral (pump-back) projects, routing studies can be used to define the periods when streamflows are such that pumping is required to firm up capacity. Hourly production cost studies can be used to determine when pumped-storage operation is economical for both pump-back and off-stream projects, and they can also be used to estimate the average annual pumping requirement. The POWRSYM model (see Section 6-9f) is particularly well-suited to analysis of pumped-storage projects, and FERC, North Pacific Division, and Omaha District have used the model for studies of this type.

(2) To estimate pumping costs, the unit cost of pumping energy must also be determined. This value can be obtained from production cost models such as POWRSYM. The value should reflect the same base fuel costs, price levels, and real fuel cost assumptions as the power values used for estimating energy benefits. Pumping energy values are normally obtained from FERC and are generally requested at the same time as the power values (see Section 9-5k). Section 7-5h(2) provides

TABLE 8-5
Computation of Powerhouse Replacement Costs (Approximate Method)

	Cost Account	Cost of 1/ Replacements ($1000's)	Composite Serv. Life (years) 2/	Sinking Fund Factor 3/	Annuity
7.1	Powerhouse structure	$321	38	0.004401	$1,400
7.2	Turbines, generators, and governors	5,524	38	0.004401	24,300
7.3	Accessory electrical equipment	1,055	34	0.006137	6,500
7.4	Auxiliary systems and equipment	113	24	0.014720	1,700
7.5	Tailrace	4/	-	-	-
7.6	Switchyard	408	36	0.005193	2,100
				TOTAL	$36,000
				Rounded	$40,000

1/ Construction Cost (from Table 8-9) multiplied by Percent Requiring Replacement (from Table 8-4). For example, for cost account 7.1, Cost of Replacements = ($32,070,000)x(1%) = $321,000.
2/ From Table 8-4
3/ Based upon 8-1/8% interest rate and period equal to composite service life.
4/ In this example, tailrace costs are included in powerhouse costs.

additional information on estimating pumping energy requirements, and Section 9-10d describes how to treat the cost of pumping energy in the net benefit analysis.

8-6. Transmission Costs.

a. Transmission costs consist of the cost of the transmission line and substation equipment needed to transfer generated power to the regional transmission grid. Transmission costs vary depending on the location of the proposed project relative to the existing system and on the size of the project. For some projects, transmission requirements may be minor, because existing transmission facilities are nearby. In other cases, transmission costs can be a significant part of project costs, due to a remote site location, difficult topography, or right-of-way constraints.

b. For some projects, it is possible to clearly identify the increment of transmission facilities required for a proposed hydro project, but often the analysis is more complex. For example, the transmission facilities carrying the project's output to the load center(s) may also be used by other generating projects or may be required for system stability or reliability. In these instances, a portion of the transmission costs should be allocated to these other users. In cases where modification or replacement of existing transmission lines would be required, it is necessary to estimate transmission facility costs both with and without the proposed hydro project. The difference between these costs is the economic cost of transmission chargeable to the project.

c. In most cases, the responsibility for transmission facilities rests with entities other than the Corps of Engineers. In the western and south-central states, the regional Federal Power Marketing Administrations (PMA's) generally construct the required transmission facilities (see Section 3-12a and Figure 3-2). In other cases, utilities wheel the power to the load centers under contracts, administered in most cases by the PMA's. Thus, the primary source of information on transmission costs would usually be the PMA, and a request for transmission costs would be sent to the PMA once the project location and generating capacity are defined. The transmission costs should be based on the same interest rate and price level as the project costs and should include contingencies, IDC, operation and maintenance costs, and replacement costs where applicable. The transmission costs would be converted to an equivalent average annual cost in the same manner as for hydro project costs (see Section 8-5).

d. In the Pacific Northwest, the complexity of the regional transmission system is such that it is frequently difficult to isolate the transmission costs associated with given hydro projects. In these cases, the PMA (Bonneville Power Administration) has estimated average per kilowatt transmission costs. These costs are incorporated by FERC in the project capacity values, which then become "at-hydro site" capacity values rather than "at-market" values (see Section 9-5g). This approach should be applied only to projects where site-specific transmission costs cannot be identified.

8-7. Updating Cost Estimates.

a. General. Once a cost estimate has been made, it is frequently necessary to update the estimate to reflect current price levels and interest rates. Following is a discussion of cost indices available for updating powerhouse costs and procedures to be used for updating O&M and replacement costs.

b. Construction Cost Indexes.

(1) The Engineering News Record (ENR) Construction Cost Index and the Bureau of Reclamation (USBR) Construction Cost Trends are the two sources of information most often used to update hydro project construction cost prices.

(2) The ENR Construction Cost Index is a weighted aggregate cost index intended to reflect general cost trends in the construction industry as a whole. The index is derived from the costs of labor, steel, cement, and lumber, and is computed for twenty major U.S. cities. A twenty-city average is also computed. Separate indices are also developed for skilled labor, common labor, and building materials. The 20-city average indices are published weekly in Engineering News Record, and the regional indices are published quarterly. The first quarterly cost round-up for each year also includes a tabulation of historical indices. Many Corps offices rely heavily on ENR indices for updating construction costs.

(3) The USBR cost indices (see Table 8-6) are tailored more specifically to water resource projects and are more detailed. Separate indices are developed for various project components, including "Power Plant, Hydro". For example, the USBR powerhouse cost index is based on a mixture of labor, material, and equipment costs typical of a powerhouse. The individual components included in that index are periodically updated using the published index that applies to each component, and they are weighted according to each component's share of the total powerhouse cost. The Bureau of Reclamation's Construction Cost Trends are published quarterly by the Bureau's Division of Construction, located at the Engineering and Research Center, P.O. Box 25007, Denver, CO 80225. They are also included in Engineering News Record's quarterly cost round-ups. The USBR indices are particularly appropriate for indexing powerhouse costs, because they reflect the cost of major equipment (such as turbines and generators) in addition to labor and construction materials, and they are based on a mix of labor and materials that is characteristic of powerhouse construction.

c. Updating O&M Costs. Operation and maintenance costs consist of a mix of labor and materials costs. The materials cost represents supplies, tools, equipment, and minor replacement parts. Separate indices should be used for updating each, and in most cases indexing can be done with the annual price level adjustments developed by field offices for updating budgetary submittals. Where detailed O&M cost estimates have been made, segregating the labor and materials comp-

TABLE 8-6.
Example of USBR Construction Cost Trend Indices

BUREAU OF RECLAMATION CONSTRUCTION COST TRENDS
(BASE 1977 = 100 FOR INDEXING FIELD COSTS ONLY)

	1980				1981				1982				1983			
	JAN	APR	JUL	OCT	JAN	APR	JUL	OCT	JAN	APR	JUL	OCT	JAN	APR	JUL	OCT
CONSTRUCTION INDEXES																
EARTH DAMS	123	127	132	134	137	140	143	144	146	144	145	142	141	140	139	139
DAM STRUCTURE	119	122	124	127	132	135	137	138	141	139	140	135	135	134	132	131
SPILLWAY	128	134	140	143	143	147	149	150	151	148	149	147	146	146	144	144
OUTLET WORKS	128	132	139	141	141	145	148	150	151	150	151	151	151	151	152	152
CONCRETE DAMS	128	133	139	142	142	146	150	151	153	153	154	153	153	153	153	153
DIVERSION DAMS	125	128	133	136	137	140	144	147	149	150	152	152	151	151	152	153
PUMPING PLANTS	124	127	131	134	136	139	143	146	148	150	151	152	151	151	152	153
STRUCTURES AND IMPROVEMENTS	126	129	133	136	138	140	143	145	147	149	150	149	148	147	147	148
EQUIPMENT	122	124	129	133	135	138	143	147	150	151	154	156	156	157	158	160
PUMPS AND PRIME MOVERS	123	125	131	133	137	141	145	149	152	154	156	157	157	157	158	160
ACCESSORY ELECT + MISC. EQUIP.	121	123	128	131	132	134	139	144	146	148	151	153	155	155	158	160
POWERPLANTS	122	126	132	135	138	141	145	149	151	152	154	155	155	155	156	157
STRUCTURES AND IMPROVEMENTS	125	129	133	135	138	140	143	145	147	149	150	149	148	147	148	148
EQUIPMENT	120	125	132	136	138	142	147	151	152	154	157	157	158	158	159	160
TURBINES AND GENERATORS	120	125	133	137	139	144	148	152	154	156	158	159	160	160	161	162
ACCESSORY ELECT + MISC. EQUIP.	121	123	127	130	132	134	139	143	145	146	149	150	151	151	153	155
STEEL PIPELINES	124	127	130	135	137	139	145	149	152	154	158	158	158	158	161	161
CONCRETE PIPELINES	125	130	135	138	141	143	146	148	150	151	153	154	154	153	154	156
CANALS	123	127	130	134	137	139	142	144	147	147	148	146	144	144	144	144
CANAL EARTHWORK	122	125	128	133	138	141	143	146	147	146	147	144	143	143	143	143
CANAL STRUCTURES	125	129	132	135	137	139	142	144	146	149	150	149	148	147	147	148
TUNNELS	125	128	132	136	138	140	144	149	151	154	157	158	158	158	160	161
LATERALS AND DRAINS	122	126	129	133	135	137	140	142	145	146	146	144	143	142	141	142
LATERAL EARTHWORK	120	123	126	130	133	135	139	142	144	143	144	142	141	139	139	140
LATERAL STRUCTURES	123	127	130	134	136	138	140	142	145	147	148	146	145	144	143	144
DISTRIBUTION PIPELINES	124	129	133	136	139	141	144	147	148	149	152	152	152	152	153	154
SWITCHYARDS AND SUBSTATIONS	123	127	132	134	135	138	141	145	146	148	151	152	152	152	153	154
WOOD POLE TRANSMISSION LINES	129	132	133	134	136	138	141	142	142	141	142	141	141	141	144	146
POLES AND FIXTURES	132	132	132	132	130	131	132	133	132	130	130	130	129	129	133	136
OVERHEAD CONDUCTORS AND DEVICES	125	131	134	138	142	146	151	153	155	155	156	157	157	156	158	159
STEEL TOWER TRANSMISSION LINES	126	130	135	138	140	144	148	152	154	157	161	162	162	162	163	163
PRIMARY ROADS	131	137	142	144	146	148	150	151	152	153	154	154	153	152	153	154
SECONDARY ROADS	137	145	152	154	160	160	160	159	162	164	162	162	160	160	161	160
BRIDGES	126	129	134	137	140	141	144	147	160	153	155	155	154	153	154	154
GENERAL PROPERTY	127	127	131	133	133	136	139	143	144	144	147	148	149	149	152	155
LAND INDEXES																
ARIZONA	123	128	130	132	134	136	136	139	143	145	146	146	146	146	137	133
CALIFORNIA	158	165	169	173	176	206	209	214	218	219	223	227	228	229	225	225
COLORADO	149	153	157	160	162	166	167	172	174	176	176	176	176	176	164	161
IDAHO	135	138	141	143	144	145	146	149	152	153	154	155	156	156	144	140
KANSAS	129	132	134	136	138	138	138	139	141	142	142	142	142	142	130	126
MONTANA	135	142	145	148	150	150	150	152	154	155	158	160	161	162	150	146
NEBRASKA	133	137	139	143	145	149	150	153	155	157	156	155	154	153	135	129
NEVADA	126	129	131	132	133	137	139	141	142	144	145	145	145	146	137	133
NEW MEXICO	122	124	128	130	133	132	133	136	142	144	144	144	144	144	136	133
NORTH DAKOTA	124	134	138	141	142	145	147	149	151	153	153	154	154	154	145	142
OKLAHOMA	134	140	144	147	149	156	156	160	163	165	166	167	167	168	159	156
OREGON	121	121	125	129	131	140	141	143	144	147	147	148	148	149	141	138
SOUTH DAKOTA	141	147	151	155	157	157	157	159	163	165	160	160	160	160	145	140
TEXAS	136	142	145	149	150	157	158	161	165	167	174	180	185	187	198	191
UTAH	123	126	128	130	131	135	135	137	140	142	142	142	142	142	133	130
WASHINGTON	124	125	126	128	129	148	149	151	152	154	154	155	155	156	154	152
WYOMING	126	128	130	131	132	136	136	138	141	142	142	143	143	144	136	133
OTHER INDICATORS																
COMPOSITE TREND	124	128	132	135	137	140	144	146	148	149	152	152	151	151	152	153
MACHINERY AND EQUIPMENT (BLS)	129	133	136	140	143	148	152	154	158	160	162	162	163	164	165	166
FEDERAL SALARY	119	119	119	129	129	129	129	136	136	136	136	141	141	141	141	141

TABLE 8-7
Indices for Adjustment of Materials Cost Component to Reflect Interest Rate (Base Interest Rate = 2-1/2 percent)

Percent	0	1/8	1/4	3/8	1/2	5/8	3/4	7/8
2	-	-	-	-	1.000	0.936	0.886	0.842
3	0.800	0.760	0.722	0.688	0.656	0.626	0.599	0.574
4	0.550	0.526	0.503	0.481	0.460	0.440	0.421	0.404
5	0.388	0.372	0.357	0.343	0.329	0.316	0.303	0.291
6	0.279	0.267	0.255	0.243	0.232	0.221	0.211	0.203
7	0.194	0.186	0.177	0.169	0.161	0.153	0.146	0.139
8	0.132	0.126	0.120	0.115	0.110	0.104	0.099	0.093
9	0.088	0.083	0.079	0.076	0.073	0.070	0.067	0.064
10	0.061	0.058	0.055	0.053	0.051	0.048	0.045	0.043
11	0.041	0.038	0.036	0.034	0.032	0.031	0.030	0.028
12	0.026	0.025	0.024	0.023	0.022	0.021	0.020	0.019
13	0.019	0.018	0.018	0.017	0.017	0.016	0.016	0.015
14	0.014	0.013	0.013	0.012	0.011	0.011	0.010	0.010
15	0.009							

onents is a straightforward process. Where a breakdown is not available, powerhouse O&M costs can be roughly apportioned 80 percent to labor and 20 percent to materials.

d. Updating Replacement Costs. Replacement costs are essentially 100 percent materials costs and should be updated using an index which is representative of the mechanical and electrical equipment which would require replacement. In many cases, price level adjustments developed by field offices for updating budgetary submittals can be used. An alternative is the USBR index for "equipment," which is a sub-category under "Power Plants, Hydro" (see Table 8-6). Because replacement costs represent a sinking fund, they must be adjusted for changes in project interest rate. The most precise approach is to recompute the replacement cost as shown on Table 8-5, using updated construction costs and sinking fund factors. An alternative is to use the indices from Table 8-7. For example, in order to adjust the materials cost from a 7 percent project interest rate to 8 percent, an adjustment factor of (0.132/0.194) = 0.680 would be used.

TABLE 8-8
Adjustment of Costs for Price Level

Cost Account	Jan 1981 Costs	Oct 83 Index/ Jan 81 Index	Oct 1983 Costs
7.1 Powerhouse	$22,550,000	(157/138)	$25,655,000
7.2 Turbines & generators	17,174,000	(162/139)	20,016,000
7.3 Accessory electrical equip.	1,563,000	(155/132)	1,835,000
7.4 Auxiliary systems & equip.	1,199,000	(155/132)	1,408,000
7.6 Switchyard	722,000	(154/135)	824,000
7.7 Site prep. & special items	1,500,000	(155/133)	1,748,000

8-8. Example Powerhouse Cost Analysis.

a. Introduction. In order to illustrate the concepts presented in this chapter, an example calculation of annual costs for a power project is presented. This example includes only powerhouse costs.

Given:
- cost estimate breakdown presented in Table 8-1.
- USBR Construction Cost Trends presented in Table 8-6.
- project life: 100 years.
- Federal interest rate: 8-1/8%.
- price level: October 1983
- construction period: 4 years.

b. Price Level Adjustment. The costs presented in Table 8-1 are in January 1981 dollars and must be adjusted to represent October 1983 price levels. This is done by applying the USBR indices from Table 8-6 to each of the powerplant features (see Table 8-8).

c. Contingencies. The next step is to adjust for contingencies, so that the above figures will represent construction costs. Turbine and generator costs and other equipment costs can generally be estimated with greater precision than other costs. In this example, a 15 percent contingency allowance has been assumed for these items, and 25 percent is assumed for the remaining accounts (see Table 8-9).

d. Inflation Adjustment.

(1) It is assumed that the cost estimate shown in Figure 8-1 was developed from bid prices for similar projects. Since bid prices

TABLE 8-9
Contingency Adjustment

Cost Account	Oct 1983 Cost	Contingency Allowance	Construction Cost
7.1 Powerhouse	$25,655,000	25%	$32,070,000
7.2 Turbines & generators	20,016,000	15%	23,020,000
7.3 Accessory electrical equip.	1,835,000	15%	2,110,000
7.4 Auxilary systems & equip.	1,408,000	15%	1,620,000
7.6 Switchyard	824,000	15%	950,000
7.7 Site prep. & special items	1,748,000	25%	2,180,000
TOTAL			$61,950,000

incorporate the contractor's estimate of inflation over the construction period, the cost estimate must be adjusted to remove the estimated inflation during construction. It is further assumed that these estimates were taken from a project that had an identical construction payout schedule.

(2) For this example, it is assumed that the average inflation rate per year during this construction period was determined to be 6%. Powerhouse costs accounts 7.2 and 7.3 (turbines, generators, and electrical equipment) are not adjusted for inflation during construction because these cost estimates are based upon point in time delivery. Therefore, only the remaining features will be adjusted for inflation during construction effects. The cost to be adjusted would then be:

$$\$61,950,000 - (\$23,020,000 + 2,110,000) = \$36,820,000$$

(3) Since these construction costs are paid out over a series of years, inflation effects will vary for each year. The procedure to adjust for these effects consists of converting each year's payment to inflation-free costs. This is done by discounting each year's payment from the midpoint of that year to the start of construction by using the inflation rate as the discounting factor (see Table 8-10).

(4) The costs shown on line F of Table 8-10 represent the expected real cost distribution for features 7.1, 7.4, 7.6, and 7.7. To obtain total costs, the costs of features 7.2 and 7.3 must be added to this distribution, as shown in Table 8-11.

TABLE 8-10
Adjustments for Inflation During Construction

Total project cost to be adjusted: \$36,820,000 (from Section 8-8d(2)).

	Year 1	Year 2	Year 3	Year 4
A. Yearly percentage (Table 8-3)	15.7	61.7	18.6	4.0
B. Yearly cost 1/	\$5,780,000	22,720,000	6,850,000	1,470,000
C. Years from start of construction (n)	0.5	1.5	2.5	3.5
D. Interest rate (i), %	6.0	6.0	6.0	6.0
E. $(1+i)^n$	1.030	1.091	1.157	1.226
F. (B)/(E)	\$5,610,000	20,820,000	5,920,000	1,200,000

1/ (\$36,820,000)x(A)

TABLE 8-11
Adjusted Construction Costs

Cost of features 7.2 and 7.3; \$23,020,000 + \$2,110,000 = \$25,130,000

	Year 1	Year 2	Year 3	Year 4
A. Yearly percentage	15.7	61.7	18.6	4.0
B. Yearly cost of accts. 7.2 and 7.3 1/	\$3,950,000	15,510,000	4,670,000	1,000,000
C. Yearly cost of accts. 7.1,7.4,7.6,7.7 2/	\$5,610,000	20,820,000	5,920,000	1,200,000
D. Total cost for year (B)+(C)	\$9,560,000	36,330,000	10,590,000	2,200,000

E. Total powerplant cost = \$58,680,000

1/ (\$25,130,000)x(A)
2/ From line F of Table 8-10

TABLE 8-12
E&D and S&A Costs

	Year 1	Year 2	Year 3	Year 4
A. Construction expenditure	$9,560,000	36,330,000	10,590,000	2,200,000
B. E&D, (A)x(0.08)	760,000	2,910,000	850,000	180,000
C. S&A, (A)x(0.06)	570,000	2,180,000	640,000	130,000
D. Adjusted expenditure (A)x(B) - rounded	$10,890,000	41,420,000	12,080,000	2,510,000

Total adjusted expenditure = $66,900,000

e. Engineering and Design & Supervision and Administration (E&D and S&A). These costs are calculated by applying flat percentages to the construction costs from line D of Table 8-11 (see Table 8-12). Values of 8 percent for E&D and 6 percent for S&A are assumed (see Sections 8-4c and 8-4d).

f. Interest During Construction. In order to obtain total investment cost, including interest during construction, each expenditure is brought to the project on-line date by discounting with the Federal interest rate. These values are then summed to establish total investment cost. Table 8-13 shows these calculations.

g. Annual Cost.

(1) General. In order to calculate annual cost, the project's investment cost is amortized over its economic life and added to annual operation, maintenance, and replacement costs.

(2) Interest and Amortization. Interest and amortization is calculated by multiplying the investment cost by an amortization factor, which in this example is based upon a Federal interest rate of 8-1/8% and a project economic life of 100 years.

Interest and Amortization = $80,870,000 x 0.08129 = $6,570,000

(3) Operation and Maintenance. These costs are determined from Figure 8-2 for a remotely controlled site of 25 MW installed capacity.

O&M Cost = $180,000.

TABLE 8-13
Computation of Investment Cost

	Year 1	Year 2	Year 3	Year 4
A. Yearly expenditure (from Table 8-12)	$10,890,000	41,420,000	12,080,000	2,510,000
B. Years to on-line date (n)	3.5	2.5	1.5	0.5
C. $(1+i)^n$ 1/	1.314	1.216	1.124	1.040
D. Yearly investment cost, (A)x(C)	$14,310,000	50,370,000	13,580,000	2,610,000

Total IDC = $80,870,000 - 66,900,000 = $13,970,000

1/ (1+i) @ 8-1/8 % = 1.08125

Although the O&M cost from Figure 8-2 is in 1983 dollars, assume for purposes of illustration that it is in 1981 dollars and must be adjusted to reflect October 1983 costs. It is assumed that this cost consists of 80% material and 20% labor.

TABLE 8-14
Adjustment of O&M for Price Level

	Labor	Materials
A. O&M cost (Jan 1981) = $180,000		
B. Percentage breakdown	80%	20%
C. Cost breakdown (A)x(B)	$144,000	$36,000
D. USBR cost index (Oct 1983/Jan 1981)	141/129 1/	166/143 2/
E. Adjusted cost (C)x(D)	$160,000	$40,000

Total adjusted O&M cost (Oct 1983) = $160,000 + $40,000 = $200,000

1/ Federal salary index
2/ Machinery & equipment index

(4) Replacement Costs. Replacement costs are estimated as described in Table 8-5. This value is already based on an 8-1/8 percent interest rate and a 1983 price level so it requires no further adjustment. Annual replacement costs are $40,000.

(5) Total Annual Costs. This project's annual cost is the sum of the amortized investment cost, operation and maintenance costs, and interim replacement costs. Table 8-15 summarizes total annual costs.

TABLE 8-15
Summary of Project Costs

	Source	Cost
Construction cost	Table 8-11	$58,680,000
Engineering and design costs	Table 8-12	4,700,000
Supervision and administration costs	Table 8-12	3,520,000
Interest during construction	Table 8-13	13,970,000
Total investment cost	Table 8-13	$80,870,000
Annual interest & amortization	Para. 8-8g(2)	6,570,000
Annual O&M costs	Table 8-14	200,000
Annual replacement costs	Table 8-5	40,000
Total annual cost		$6,810,000

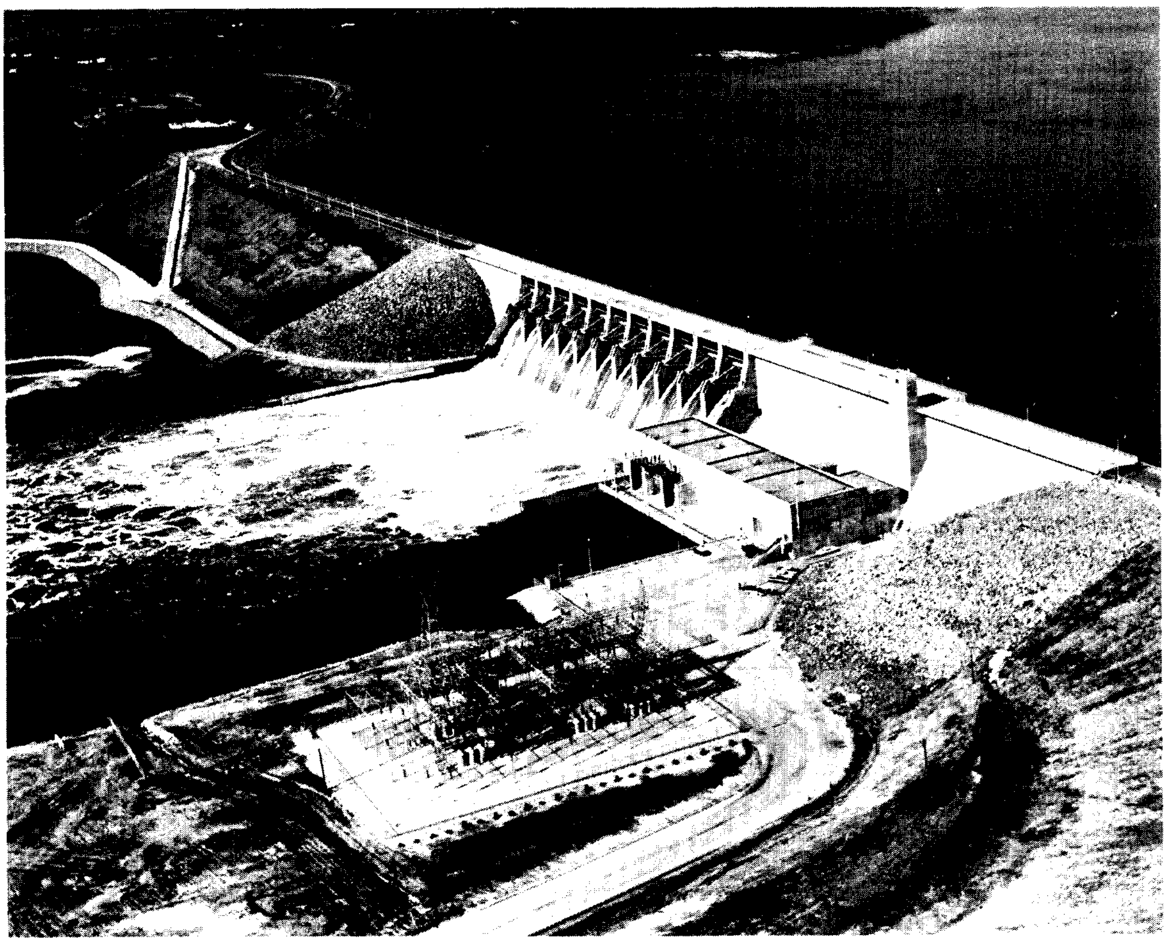


Figure 8-4. Eufaula Dam and Lake (Tulsa District)

CHAPTER 9

ECONOMIC EVALUATION OF HYDROPOWER PROJECTS

9-1. Introduction.

a. This chapter and supporting appendixes outline the procedures for computing hydropower benefits and discuss some of the economic evaluation problems relating to hydropower projects. Subjects covered include the conceptual basis for power benefits, definition of with-project and without-project conditions, computation of benefits using the alternative thermal plant and energy displacement methods, treatment of annual costs, scoping of hydro projects, financial feasibility studies, and special problems encountered in the economic analysis of hydro projects.

b. The basic approach to economic evaluation of water resources projects is contained in the Corps of Engineers' Planning Guidance Notebook (49). The Notebook includes the Water Resources Council document that serves as overall guidance for Federal water resources planning: Economic and Environmental Principles and Guidelines for Water and Related Land Resources Implementation Studies, dated March 10, 1983, which will be referenced simply as Principles and Guidelines (77).

c. This chapter discusses the concepts and procedures contained in the references mentioned above and generally covers analysis of only the power function. Analysis of hydropower as part of a multiple-purpose project is handled by incorporating the hydropower function in a multiple-purpose formulation analysis, with power benefits computed as described in this chapter.

9-2. Conceptual Basis for Hydropower Benefits.

a. Basis for Measuring Benefits.

(1) Section 1.7.2(b) of Principles and Guidelines states that the general measurement standard for estimating value is the willingness of users to pay for the project's output. It further suggests that it is not possible in most instances to measure willingness to pay directly. Four alternative techniques are proposed to obtain an estimate of the value of the project's output in lieu of direct measurement of willingness to pay. These are, in order of preference:

- actual or simulated market price
- change in net income
- cost of the most likely alternative
- administratively established values

(2) The first three measures stem from the willingness to pay criterion; the fourth, administratively set prices, relates to this criterion but also may reflect other social objectives and procedures. Only the first and third options can readily be applied to hydropower benefit evaluation, and these will be discussed in detail below.

(3) For a more detailed discussion of the conceptual basis of hydropower benefit evaluation, reference should be made to Volume VI of the National Hydroelectric Power Resources Study (48f).

b. Actual or Simulated Market Price.

(1) Where energy from electric powerplants is priced and sold at its marginal cost, where new powerplant additions are small compared to the system load, and where there is no likely private alternative to the proposed Federal hydropower project, actual or simulated market price can be used to calculate benefits. As a practical matter, market price is seldom used. There are two major reasons: (a) electric power is not normally priced at the marginal cost, and (b) the cost of the most likely alternative frequently puts a limit on the benefit value.

(2) Electric power at the retail level is normally priced at the average cost of generation (which includes costs of older powerplants as well as newer plants), rather than the marginal cost. Where this is the case, market price cannot be used for benefit calculations. PURPA rates and prices based on wholesale bulk power transactions among suppliers have been suggested as an indirect means of simulating market price. PURPA rates are the prices which utilities are required to pay developers for the output of small renewable power projects under the terms of the Public Utility Regulatory Policies Act of 1978 (PURPA). These rates, which are computed by the utilities and approved by state public utility commissions, are usually based on the utilities' long-run incremental power costs. The use of PURPA rates would be a valid method only (a) if these values are adjusted so that they would be comparable to the hydro plant costs in terms of evaluation criteria (discount rate, etc.), and (b) they are based upon the cost of new resources, rather than the cost of surplus power from existing resources. Because of the variations in the way PURPA rates are developed, and the difficulty in obtaining the backup data necessary to make these adjustments, the use of this approach is not encouraged.

(3) Perhaps a more basic reason that market price is not used is that there is usually a private alternative to the Federal hydropower project. If this is the case, the cost of the most likely alternative puts a limit on the benefit value. This can be illustrated with the following example. Assume that it is possible to measure power benefits directly with actual or simulated market prices and that the annual benefits attributable to a proposed Federal hydropower plant are $100,000. The annual cost of the hydropower plant is $70,000. Assume further that if the hydropower plant is not constructed, the increment of load to be carried by the proposed hydropower plant would be exactly met by a new utility-constructed thermal plant. In this case, the thermal plant would carry the same increment of load as the hydro plant, so it would also accrue annual benefits of $100,000. The annual cost of that thermal plant, based upon the same economic criteria used for the hydropower plant, is $80,000.

TABLE 9-1
Summary of Example Costs and Benefits

	Federal Hydro Project	Private Thermal Plant
Total annual benefit	$100,000	$100,000
Total annual cost	70,000	80,000
Annual net benefit	$30,000	$20,000

(4) Table 9-1 shows that the net benefit of the Federal hydropower plant would be $30,000. However, $20,000 of this would be reaped even if the hydro plant were not constructed, because the thermal plant would be constructed instead. In other words, the total benefits of $100,000 will be achieved whether or not the Federal hydropower plant is constructed, and the benefits of the Federal project are therefore limited to the resource savings of the alternative thermal plant, or ($80,000)-($70,000) = $10,000. Thus, the incremental effect upon the system of building the Federal project is not the achievement of the benefits, which will be realized in either case, but rather the avoidance of economic costs. Society's net willingness to pay for the Federal hydropower project is therefore the avoided cost of the alternative.

c. Cost of the Most Likely Thermal Alternative.

(1) Where a likely alternative to the Federal hydropower project exists (and whether or not total benefits are known), the appropriate form of evaluation is the alternative cost measure. Alternative costs can be measured in two ways:

- the cost of constructing and operating an alternative thermal plant or an increment thereof (the "alternative thermal plant" method)
- the value of generation (primarily fuel costs) from existing thermal plants that would be displaced by the output of the proposed hydro plant (the "energy displacement" method)

These methods are described in more detail in Sections 9-5 and 9-6, respectively. For some hydro projects, a combination of both methods would most accurately measure benefits. This would be handled by using the "alternative thermal plant" method and accounting for the displacement of existing generation through the energy value adjustment (Section 9-5e).

(2) Conservation measures, alternative hydropower projects, or other renewable resources may in some cases be viable alternatives to the hydro project under study. However, all of these options would be compared with the most likely thermal alternative in order to determine their relative economic merit. The treatment of conservation and alternative hydropower projects is discussed further in Sections 9-2e and 9-2f, respectively.

d. Need for Power.

(1) In order for any measure of benefits to be valid, there must be a need for the power (capacity or energy) that would be produced by the hydro plant during the period being considered. In most cases, therefore, it is necessary to either (a) demonstrate that there is a requirement for additional generating capacity within the service area of the system to which the hydro plant would be added, or (b) secure a statement of marketability from the regional Federal Power Marketing Administration (small projects only). Procedures for accomplishing both are described in Chapter 3.

(2) In some cases, a hydropower plant may be a cheaper source of energy than existing thermal generation. Since the project would not defer the need for new thermal capacity, a load-resource analysis of the type described in Chapter 3 would not be meaningful. Need would be established simply by demonstrating positive net benefits in an

analysis of energy benefits alone, using the "energy displacement" method described in Section 9-6.

(3) Export markets are sometimes a means of helping to support the need for a hydropower project. Although it would seldom be appropriate to base a substantial portion of the justification for a Federal hydropower project on extra-regional power markets, there may be some cases where benefits from export sales can be claimed. Examples would be (a) the sale of secondary energy which is surplus to the needs of the region, and (b) short-term sales of firm energy during periods of regional surplus. In these cases, benefits would be based upon the value of the power to the importing power system and not the price at which it would be sold to that system.

e. Nonstructural Alternative.

(1) Although this chapter primarily discusses benefits based upon the cost of the most likely thermal alternative, it is recognized that an NED plan may consist of "...a system of structural and/or nonstructural measures, strategies, or programs..." and that "Alternative plans should not be limited to those the Federal planning agency could implement directly under current authorities". (Principles and Guidelines, Sections 4.1.6.1(a) and (c). In addition, in some parts of the country (the Pacific Northwest, for example), state or regional policies may require that a specified cost advantage be credited to conservation in the analysis of alternative methods for meeting power demand. For these reasons, a nonstructural measure, such as conservation, may be a valid alternative. In general, nonstructural alternatives should be evaluated for projects which are not exempted from the requirements of Section V of Principles and Guidelines. Exempted projects are single-purpose, small scale projects of 25 megawatts or less, and projects of less than 80 megawatts that add power to existing Federal facilities.

(2) The term "nonstructural" as applied to hydropower is not limited to measures which are nonstructural in the engineering sense, but includes all measures which reduce the need for additional power generation resources. Thus, the term encompasses all measures, whether structural or nonstructural, which are commonly referred to as conservation. In general, conservation involves more efficient use, production, and generation of electricity. However, when evaluating conservation as an alternative (or set of alternatives) to a hydro project, it should be kept in mind that Principles and Guidelines requires that "...the without-project condition include the effects of implementing all reasonably expected nonstructural and conservation measures...". Thus, for a conservation measure to be an alternative, it must be one which is not already reflected in the power load forecast.

(3) In order to develop a meaningful analysis of a conservation measure, the costs and potential results of implementing the measure must be quantifiable. As a result, analyses of conservation options such as increased education of electricity consumers, legal restrictions on the use of electricity, and pricing should not be attempted unless an accurate measure of costs and results can be assumed. Within the foregoing constraints, there are a number of opportunities for conservation in all sectors (residential, commercial, and industrial), which include:

- insulation of existing buildings
- conservation standards for new buildings
- insulation of water heaters and hot water systems
- efficiency standards for household appliances
- load management
- changes in power plant operating schemes
- improvement of industrial process efficiencies
- power system interties

Specific measures to be considered for analysis for individual projects will vary according to the type of hydro project being studied (i.e., base load, peaking, or energy displacement), and which conservation programs are already in place in the study area.

(4) Because the electricity savings potential of each of the various possible conservation measures is technically and practically limited, economic comparisons between them and a hydropower project should be based upon cost-effectiveness (i.e., the option with the lowest cost, when computed on a comparable basis, is always the preferred option), rather than benefits as traditionally determined by the least-cost thermal alternative method. The cost-effectiveness approach permits the scheduling of a hydropower project in combination with less costly conservation measures which may not produce sufficient energy or capacity savings over the planning horizon to eliminate the long-term need for additional generation resources. The analysis of conservation should be done at the same level of detail as the analysis of the hydropower project and should include consideration of the following:

- identification of conservation measures expected to be implemented in the without-project condition.

- verification that the load forecast for the study area reflects implementation of expected conservation measures.

- identification of specific areas of electricity use where additional conservation is possible and potentially cost effective.

- determination of current levels of electricity use in each area identified above.

- determinations of the cost of each measure, including administrative costs.

- determination of economically feasible energy or capacity savings.

(5) The result of the study will be an array or supply curve of potential conservation measures from which specific measures may be selected for implementation in order of ascending cost. However, the analyst must insure that the aggregate savings of electricity, in terms of both capacity and energy, are accounted for such that the residual need for power generation resources is accurately shown. This analysis does not determine the economic feasibility of a proposed hydropower project, but establishes when it will be needed. In other words, it assumes that conservation measures available at a lower cost than the proposed hydropower project would be in place before the project would be constructed, presuming that the project is economically feasible (as determined, for example, by the most likely alternative method of computing power benefits).

(6) Additional information on the evaluation of nonstructural (conservation) measures may be found in Volume VI of the National Hydroelectric Power Resources Study (48f) and Volumes 1 and 2 of the Northwest Conservation and Electric Power Plan (29).

f. Use of Hydro as an Alternative. In cases where several candidate hydro plants exist, the most likely alternative to a given hydro plant may be one of the other hydro plants. In such cases, however, benefits attributable to the given hydropower plant would not be based on the cost of the alternative hydro plant. Instead, all of the candidate hydro plants would be evaluated and ranked to identify the best project. The benefits used in the ranking process would be based upon the cost of the most likely thermal alternative. This approach assures that the most cost-effective hydro plant is the first one to be considered for development.

9-3. Overall Approach in Computing Hydropower Benefits

a. Hydro Plant Output.

(1) Hydro plant output is measured in terms of both energy and capacity. Following are the most common ways in which output is measured:

- firm or primary energy
- secondary energy
- average annual energy (firm plus secondary energy)
- dependable capacity
- intermittent capacity

These values are obtained from power studies as described in Chapters 5, 6,and 7.

(2) In most cases, benefits are based on a project's average annual energy and dependable capacity. Where secondary energy has a substantially different value than firm energy, it may be necessary to evaluate the two energy components separately (see Section 9-10o).

(3) There are also cases where benefits may be based on energy output only. The energy-only approach would be applied primarily at hydro plants where (a) the energy displacement method is used (see Section 9-6), or (b) the project has no dependable capacity.

(4) In the past, credit has sometimes been given to intermittent capacity, but the development of procedures for basing dependable capacity on average availability (Sections 6-7b, g and k) has eliminated the need for evaluating intermittent capacity separately.

b. Computing Benefits. Power benefits are computed by applying unit "power values", representing the costs associated with the alternative thermal plant, to the capacity and energy output of the hydropower plant. For example:

Capacity benefit = (Dependable capacity, kW)(CV) (Eq. 9-1)

Energy benefit = (Avg. annual energy, kWh)(EV) (Eq. 9-2)

Total power benefit = (Capacity benefit) + (Energy benefit) (Eq. 9-3)

where: CV = Capacity value, $/kW-year
EV = Energy value, mills/kWh

The capacity value represents the per kilowatt annualized capital cost and other fixed costs associated with the thermal plant, and the energy value represents per kilowatt-hour fuel and variable O&M costs. The procedures for computing these power values are described in Sections 9-5 and 9-6.

c. Period of Analysis. Sections 1.4.12 and 2.1.2(c) of Principles and Guidelines specify the maximum period of analysis for water resources projects to be 100 years, and this period is normally used for new hydro projects. However, Principles and Guidelines further restricts the period of analysis to "...the period of time over which the project would serve a useful purpose." This results in a period of analysis of less than 100 years for certain types of hydro projects. For example, a 50-year project life is normally assumed for single-purpose off-stream pumped-storage projects, because the likelihood that changing technology will render a pumped-storage plant obsolete is considered to be greater than for conventional hydropower plants. Likewise, small single-purpose diversion type hydropower projects are sometimes designed for a 50-year rather than a 100-year service life. When adding a new powerhouse or additional units to an existing dam, an analysis must be made to determine the remaining useful life of the existing structure. The remaining life of the existing structure establishes the project life of the hydropower addition.

9-4. With- and Without-Project Conditions.

a. General.

(1) Careful definition of the with- and without-project conditions is essential to the proper evaluation of hydropower benefits. Sections 2.5.3, 2.5.5, and 2.5.6 of the Principles and Guidelines provide general guidance on definition of the with- and without-project conditions for hydropower with respect to existing resources, existing institutional arrangements, actions anticipated or underway, and treatment of conservation. The with- and without-project conditions must be examined somewhat differently, depending upon whether the alternative thermal plant method or the energy displacement method is used.

(2) As noted earlier, an important assumption underlies the alternative thermal plant method. That assumption is that the projected increment load growth will be met whether or not the proposed Federal hydropower project is constructed. Thus, the with-project plan describes how the system operates to meet anticipated power demand with the existing resources, the proposed new hydropower project, and, in some cases, some additional new generating resource. The without-project condition describes the operation of the system in meeting the same power demand with the same existing resources plus the mix of new resources that would be constructed in the absence of the proposed hydro plant.

(3) Theoretically, the addition of a hydro plant to a system could influence the timing and mix of new generation far into the future. The planner could evaluate this by using generation system expansion models, which select the most economic schedule of plants to

be installed to meet increasing power demands. These models consider both capital and operating costs in developing these plans. A model of this type could be applied alternatively to the with- and without-hydro project scenarios. The resulting difference in system costs would be the total benefit attributable to the hydropower plant. This approach should be considered when a proposed hydropower plant is large in relation to the size of the system that would incorporate it, because the plant will have a major long-term effect on system resource development. Section 7-5 describes how the without-project scenario might be developed for the analysis of a large off-stream pumped-storage plant.

(4) In most cases, however, the proposed hydro addition is small compared to the system and can be regarded as having only a short-term effect on the mix of thermal generation that will evolve. Thus, it is usually sufficient to identify a single thermal alternative and apply energy and capacity value adjustments to reflect system impacts.

(5) When the energy displacement method is used, it is assumed that the proposed hydro plant has no dependable capacity and will be used only for displacing generation at existing thermal plants. Thus, for small hydro projects, the addition of future resources will usually proceed in the same manner for both the with- and without-project scenarios. The only difference between the two scenarios would be in system operating costs (fuel plus O&M costs).

b. Identification of the System. The system is generally defined as the area where the power from the project will be used. Small hydro projects can frequently be analyzed in the context of a single utility. Larger projects may have to be analyzed in a multi-utility system or power pool area. Definition of the system should be made in consultation with the FERC regional office and the regional Federal Power Marketing Administration.

c. Individual Years to be Analyzed.

(1) The hydro project's economic life (Section 9-3c) establishes the period of analysis for benefit evaluation. The power system in which the hydro project would operate and the relative fuel prices of the plants operating in that system will change with time. In order to be theoretically correct, it would be necessary to examine the with- and without-project systems and compute benefits individually for each year of project life. However, this is often neither practical or necessary. Benefits are normally estimated either on the basis of a single "typical" load year or on a series of years representative of the system conditions that are expected to evolve over the life of the project.

(2) In most cases, a hydro plant reaches a relatively stable "mature" state of operation within a few years of its on-line date. Once a mature operation is achieved, the hydro project's impact on other plants in the system (and hence its benefits) can be assumed to be essentially constant through the end of project life. In cases where a hydro project is added to a large power system and where the resource mix is expected to remain relatively stable, it is sufficient to analyze a single year which would be representative of the project's long-term operation. The only time-oriented adjustment necessary would be to account for real fuel cost escalation (Section 9-5f) in computing costs for the alternative thermal plant. Most small hydro projects can be analyzed in this way.

(3) There are other cases where hydropower benefits would vary substantially with time, and in these cases, analyses would have to be made at intervals. Examples are:

- where the project is large and requires several years to be absorbed by the system load.
- where the resource mix is changing, and the hydro project's role changes with time.
- where the hydro project is constructed in stages.
- where the energy displacement method is used and the mix of displaced generation changes with time.
- where differential fuel price escalation changes system operation.

(4) The number of intervals to be analyzed depends upon the manner in which benefits vary with time. For example, if a large project requires several years to be absorbed in the load, benefits should be computed for each year until the project output is fully used (Figure 9-1). In most other cases, however, it is only necessary to examine a series of representative years that would be sufficient to describe how benefits change with time and interpolate to obtain benefits for intervening years (Figure 9-2). Because discounting minimizes the influence of benefits in distant years and system conditions are uncertain in those years, it is seldom necessary to examine system changes beyond project year 20.

d. Comparability.

(1) General. For a benefit analysis to be valid, project costs and benefits must be based on fully comparable economic criteria. The comparability requirement applies to comparison of alternative hydro

projects as well as to the comparison of the hydro project with the thermal alternative. The analyses must be comparable with respect to the following:

- discount rate
- price level
- treatment of inflation
- period of analysis
- treatment of insurance and taxes

(2) Discount Rate and Price Level. Section 1.4.11 of Principles and Guidelines states that the Federal discount rate published by the Water Resources Council shall be used to evaluate the economic feasibility of Federally financed projects. The costs of the hydropower project and the thermal plant must be based upon the same price level.

(3) Treatment of Inflation. Section 1.4.10 of Principles and Guidelines specifies that prices of goods and services used in economic analysis should be based on real exchange values (i.e., should exclude the effects of general inflation). The thermal plant

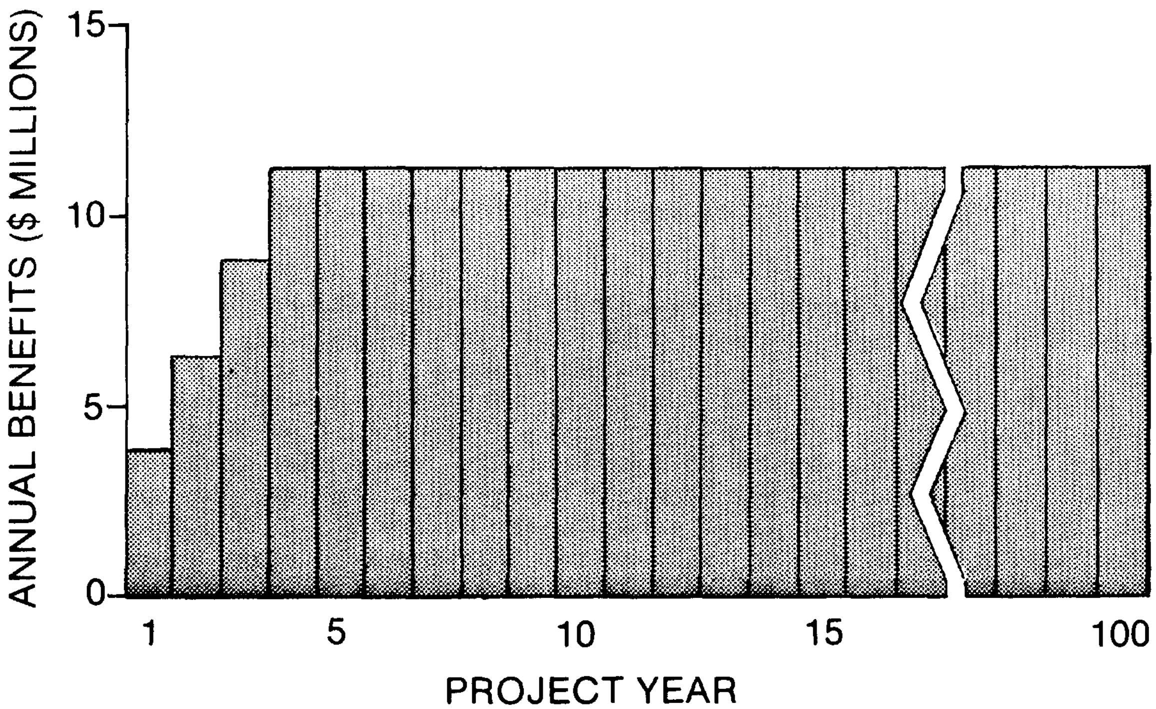


Figure 9-1. Plot of benefit stream for project requiring several years to be absorbed in system load

construction costs developed by FERC for computing power values are inflation-free costs. However, project costs developed by the Corps are frequently based on recent bid prices, which include an element of inflation. While suitable for budgetary purposes, these costs cannot be used for economic analysis until the inflation component has been removed, as specified in EM 1110-2-1306 (see also Sections 8-4g and 8-8d of this manual). Section 2.5.8(a)(5) of Principles and Guidelines gives guidance on relative price relationships, including the effects of real fuel cost escalation. That section also stipulates that fuel costs should reflect economic (market clearing) prices rather than regulated prices.

(4) Period of Analysis. It should be noted that the useful life of most thermal alternatives is 30 years, rather than the 50 to 100-year life assumed for the hydro plant. It is assumed that, should the alternative thermal plant be constructed, it would be replaced by an

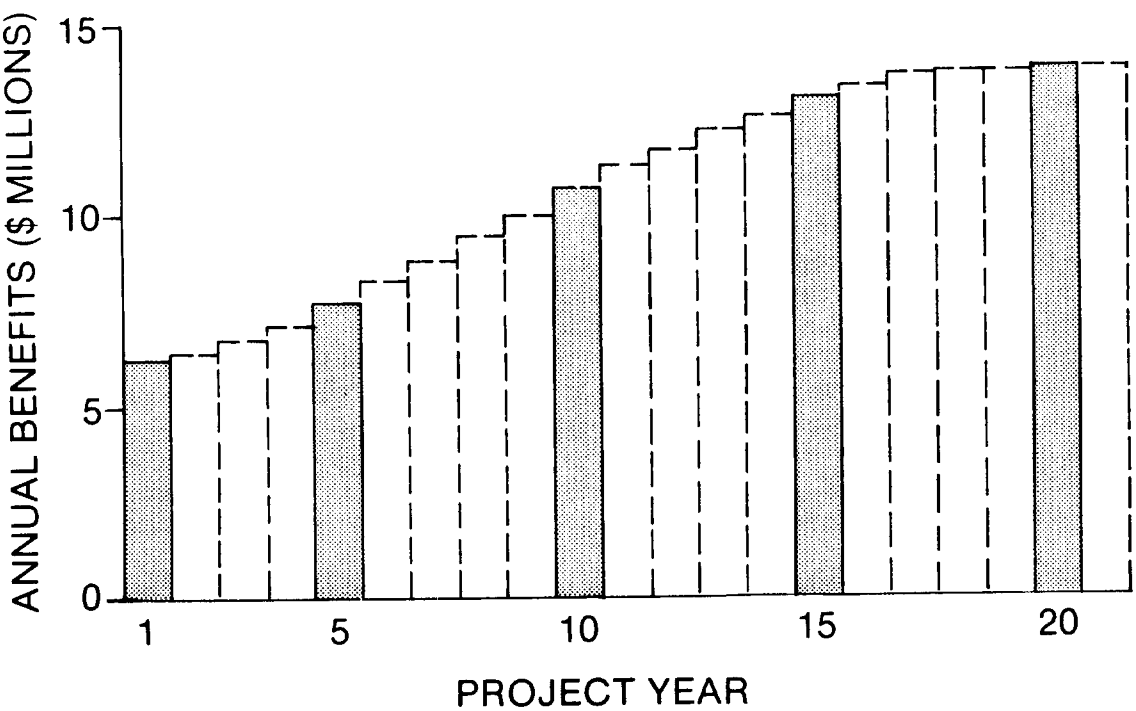


Figure 9-2. Plot of benefit stream for project where benefits vary with time
(NOTE: Benefits need be computed for the years shown as bars. Values for intervening years are obtained by interpolation).

identical plant at appropriate intervals through the hydro project's life (i.e., years 30, 60, and 90). As long as thermal plant cost increases over this period are limited to those resulting from general inflation, the amortized present value of the fixed costs for the series of identical thermal plants over 100 years (adjusted to remove the effects of general inflation) will be identical to the amortized present value of the initial thermal plant amortized over its 30-year life. As a result, power values are normally computed simply on the basis of the initial thermal plant's 30-year life. It is very likely that the replacement plants will not be identical to the initial plant, but it is difficult to predict 30 years in advance if the replacement plant will be more or less expensive (in today's dollars) than the initial plant. Because of the uncertainty about future inflation and because the present value of the future replacement plants is relatively small, basing power values on the initial thermal plant's service life is considered to be reasonable.

(5) Treatment of Insurance and Taxes. Section 2.5.8(a)(1) of Principles and Guidelines states that insurance and taxes shall be excluded from NED benefit analyses.

9-5. Alternative Thermal Plant Method

a. Basic Approach.

(1) The basic approach to computing power values when using the alternative thermal plant method is to identify all of the costs associated with the thermal plant and to segregate them into fixed cost (capacity cost) and variable cost (energy cost) categories. These costs are then converted to unit power values. In many cases, the hydro plant performs somewhat differently than the thermal alternative in a power system, and as a result, each has a somewhat different effect on the cost of operating the power system as a whole. This is accounted for by applying adjustments to the costs of the thermal alternative to reflect the differences in system costs.

(2) The general approach for computing alternative thermal plant costs has been developed by the Federal Energy Regulatory Commission (FERC), and it is described in detail in Hydroelectric Power Evaluation (72). A summary of this information follows in succeeding paragraphs. The main discussion applies to the development of power values for the alternative thermal plant method, where both energy and capacity values are required. A special section (9-6) is also included to describe how energy values are computed for use in the energy displacement method.

(3) FERC normally computes the power values used in the evaluation of power benefits at Corps projects (see Section 9-5k). However, the basis for deriving power values is described in this manual to give the planner the background necessary to apply these values.

b. Capacity Value. The capacity value is based on the fixed costs associated with the alternative thermal plant. The following cost components are included:

- construction cost
- interest during construction
- fuel inventory cost
- fixed O&M costs
- administrative and general expenses

These costs are amortized over the thermal plant's expected operating life (normally 30 years) at a fixed charge rate which includes the cost of money and depreciation. The resulting value is expressed in terms of dollars per kilowatt-year. Table 9-2 shows sample calculations deriving capacity values for coal-fired steam and combustion turbine power plants.

c. Capacity Value Adjustment.

(1) Operating experience has indicated that a hydro plant is normally more mechanically reliable than a thermal plant and, where operating limits do not restrict its operation, a hydro plant has more flexibility in terms of fast-start capability and quick response to changing loads. In order to reflect these characteristics, an adjustment is applied to increase the capacity value. This increase is applied because somewhat more thermal capacity is required than hydro capacity to reliably carry a given increment of peak load in a system. Recent studies by the Water and Energy Task Force resulted in the development of a method for evaluating these characteristics (78). This procedure is described in Sections 6-7 and O-2.

(2) Capacity values provided by FERC normally include a capacity value adjustment which reflects (a) the relative mechanical reliabilities of the hydro plant and its thermal alternative, and (b) a flexibility credit for hydro if appropriate. This capacity value adjustment can be described by the equation

TABLE 9-2
Unadjusted Power Values at Busbar 1/

	Coal-fired Steam	Combustion Turbine
Basic Data		
Plant size	500 MW	60 MW
Price level	July 1982	July 1982
Investment cost	$1360/kW	$268/kW
Fixed charge rate 2/	0.0878	0.0878
Plant life	30 years	30 years
Total O&M cost	$30/kW-year	$4.42/kW-year
Fuel cost	$1.68/million Btu	$7.41/million Btu
Heat rate	10,500 Btu/kWh	12,500 Btu/kWh
Annual plant factor	55 percent	7.5 percent
Capacity Value		
Amortized investment	$119.40/kW-year	$23.50/kW-year
Fuel inventory cost	1.40/kW-year	1.00/kW-year
Fixed O&M 3/	18.30/kW-year	0.00/kW/year
Administration and general expenses	5.20/kW-year	1.50/kW-year
Bus-bar cap. value	$144.30/kW-year	$26.00/kW-year
Energy Value		
Fuel cost	17.6 mills/kWh	93.0 mills/kWh
Variable O&M	2.4 mills/kWh	7.0 mills/kWh
Bus-bar energy value	20.0 mills/kWh	100.0 mills/kWh

1/ Busbar power values are at-thermal plant costs and do not include transmission costs and losses.
2/ Based upon interest rate of 7-7/8 percent and project life of 30 years.
3/ For coal-fired steam, 61 percent of operation and maintenance costs are assumed to be fixed and 39 percent are assumed to be variable. For combustion turbine, 100 percent of O&M costs are assumed to be variable.

TABLE 9-3
Adjusted Capacity Values at Load Center

	Coal-fired Steam	Combustion Turbine
At-market Capacity Costs		
Bus bar capacity value	$144.30/kW-year	$26.00/kW-year
Sending substation cost	1.30/kW-year	1.80/kW-year
Transmission line cost	7.50/kW-year	2.10/kW-year
Receiving substation cost	1.90/kW-year	0.30/kW-year
Total capacity cost	$155.00/kW-year	$30.20/kW-year
Transmission losses 1/	6.00/kW-year	0.50/kW-year
At-market capacity cost	$161.00/kW-year	$30.70/kW-year
Capacity Value Adjustment		
Hydro plant availability, HMA	0.98	0.98
Thermal plant availability, TMA	0.84	0.86
Flexibility adjustment, F	0.05	0.00
Capacity value adjustment 2/	0.22	0.14
Adjusted Capacity Value		
At-market capacity cost	$161.00/kW-year	$30.70/kW-year
Capacity value adjustment	35.40/kW-year	4.30/kW-year
At-market capacity value	$196.40/kW-year	$35.00/kW-year

1/ 3.9 percent for coal-fired steam and 1.7 percent for combustion turbine.
2/ Capacity value adjustment = ((HMA/TMA)x(1+F))-1

$$\text{Capacity value adjustment} = \frac{\text{HMA}}{\text{TMA}}(1 + F) - 1 \qquad \text{(Eq. 9-4)}$$

where: HMA = hydro plant mechanical availability
TMA = thermal plant mechanical availability
F = hydro plant flexibility adjustment

Table 0-1 lists representative values for HMA and TMA, and Section 0-2e discusses the flexibility adjustment. Table 9-3 shows the derivation of capacity value adjustments for the plants described in Table 9-2.

d. Energy Value. The energy value is based upon the variable cost associated with operation of the alternative thermal plant. This variable cost consists of the fuel costs and the variable portion of the O&M costs. Energy values are expressed in terms of mills/kWh. Table 9-2 shows the derivation of energy values for the example coal-fired steam and combustion turbine plants.

e. Energy Value Adjustment.

(1) The addition of a hydro plant to a system will often have a different effect on the operation of other powerplants in the system than if the thermal alternative were added instead. Some existing plants may be required to run more, and others may run less. The net result will be a difference in system operating cost, which must be accounted for when computing energy benefits.

(2) An example will illustrate why the proper accounting for system energy costs is important. This example is based on a 100 megawatt hydropower project having an average annual energy output of 175,000 MWh. Its average annual plant factor would be:

(175,000 MWh)/(100 MW X 8760 hours/year) = 20 percent.

The most likely alternative is assumed to be an oil-fired combustion turbine having an energy cost of 100 mills/kWh. Figure 9-3 shows how the power plants would be operated in the annual system load curve (a) with the hydropower project and (b) with the 100 MW combustion turbine alternative (the "without hydro" case). The operation of three existing power plants -- 100 MW of combined cycle (@ 70 mills/kWh), 100 MW of oil-fired steam (@ 55 mills/kWh), and 100 MW of gas-fired steam (@ 45 mills/kWh) -- are affected by which alternative is included in the system. The operation of other existing plants (those in the base load portion and in the extreme peak) are not affected and thus are not shown in the calculations.

(3) In the with-hydro system, the proposed hydro plant would operate at a 20 percent plant factor, while the combined cycle plant operates at 7 percent, the oil-fired steam at 11 percent, and the gas-fired steam at 16 percent. In the without-hydro system, the combustion turbine alternative is loaded above combined cycle, oil-fired steam, and gas-fired steam because it has a higher energy cost (100 mills/kWh). Thus, the energy alternative to the 20 percent plant factor hydro project is not a 100 MW, 20 percent plant factor combustion turbine, but 100 MW of combustion turbine operating at a 7 percent plant factor. The balance of the energy would come from running the three existing thermal plants at higher plant factors than in the with-hydro case.

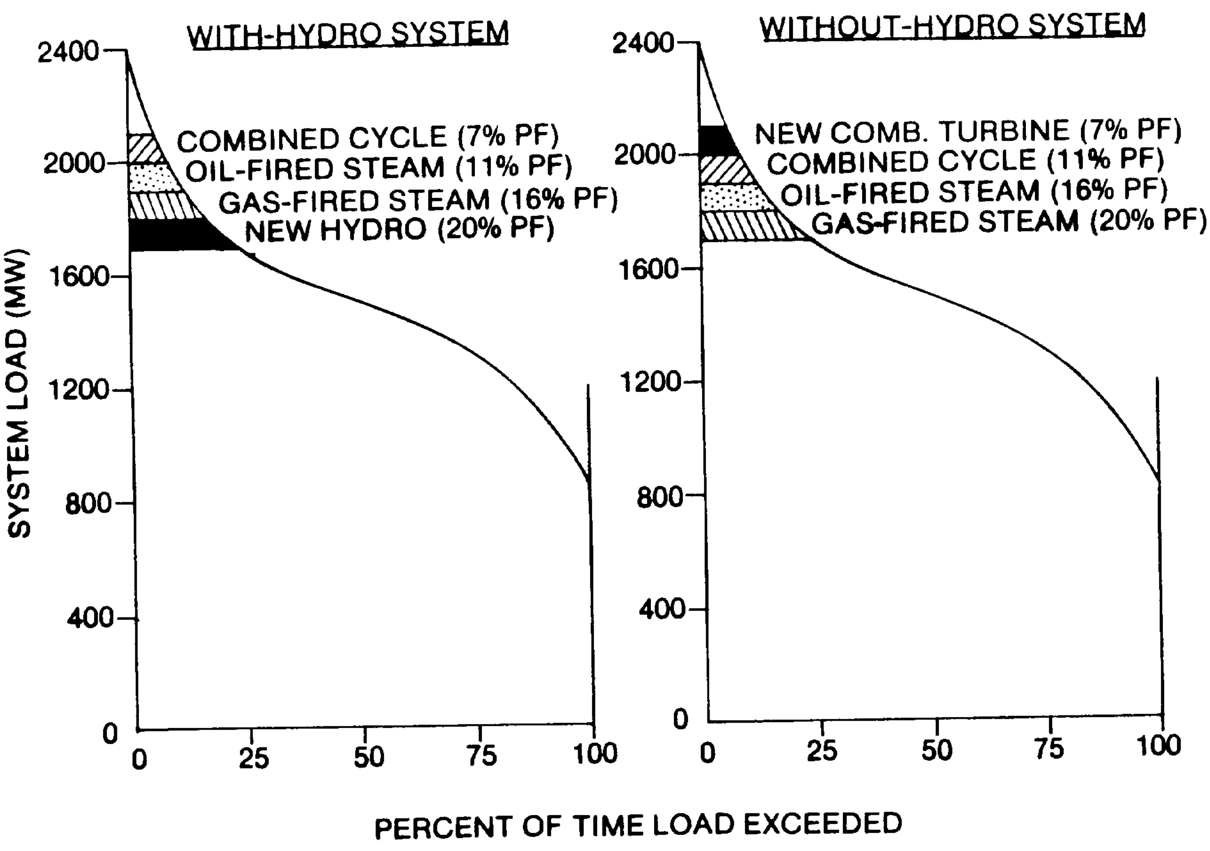


Figure 9-3. Differences in system operation which should be accounted for in making system energy value adjustment

(4) Thus, in order to determine the energy benefit of the hydro plant, it will be necessary to consider the operating costs of the three existing plants as well as the combustion turbine. Table 9-4 shows the computation of "system costs" for the two cases. In order to simplify the example, only the costs of the plants that operate differently in the two cases are shown. The total system cost would include the base load plants and plants operating in the peak as well. The difference in system cost is $12,500,000, and this is the net energy benefit that accrues to the hydro plant. The system energy benefit can be converted to a mills/kWh energy value by dividing it by the hydro plant's energy output:

Energy value = ($12,500,000)/(175,000 MW) = $71/MWh = 71 mills/kWh.

This system energy value is also known as the adjusted energy value. The difference between the 71 mill system energy value and the 100 mill combustion turbine energy value is the energy value adjustment, which in this case is a negative 29 mills/kWh. To select the combustion turbine as the thermal alternative but to ignore the energy value adjustment would have resulted in overstating the benefits by (175,000 MWh) x (100 mills/kWh - 71 mills/kWh) = $5,075,000.

(5) The energy value adjustment can be accounted for in two ways: (a) through the use of a simplified equation, and (b) through the use of a computer model which derives system production costs. The simplified or "short-cut" equation, which is discussed further in Section 0-3d of this manual and chapter 3 of reference (72), derives an energy value adjustment using average costs for thermal plants operating in the appropriate plant factor range: i.e., the average costs of those thermal plants that operate in the same general plant factor range as the hydro plant. For example, if the proposed hydro project has a plant factor of 30 percent (see Section 9-5h(6)), the average system energy cost might be based upon those thermal plants operating in the 30 percent plant factor range. The resulting energy value adjustment is deducted from the energy value of the thermal alternative to obtain the adjusted or system energy value. This approach provides an approximate value, which is satisfactory for preliminary studies. The sample energy value computations shown on Table 9-5 illustrate the use of the short-cut equation for computing the adjusted energy value. FERC uses the short-cut equation primarily for developing generalized power values for screening studies and where a system production cost model is not available.

(6) FERC uses a production cost model method for computation of most specific project power values. Computerized production cost models derive the system energy benefit directly, using the general procedure outlined in the example. This benefit can also be converted to a mills/kWh adjusted energy value if desired. The use of

TABLE 9-4
Computation of Difference in System Operating Costs

With-Hydro Project System

Combined cycle:
(100 MW)x(0.07)x(8760 hrs/yr)x(70 mills/kWh) = $4,300,000
Oil-fired steam:
(100 MW)x(0.11)x(8760 hrs/yr)x(55 mills/kWh) = $5,300,000
Gas-fired steam:
(100 MW)x(0.16)x(8760 hrs/yr)x(45 mills/kWh) = $6,300,000
Hydro:
(100 MW)x(0.20)x(8760 hrs/yr)x(0 mills/kWh) = $ 0

Total system cost = $15,900,000

Without-Hydro Project System

Combustion turbine:
(100 MW)x(0.07)x(8760 hrs/yr)x(100 mills/kWh)= $6,100,000
Combined cycle:
(100 MW)x(0.11)x(8760 hrs/yr)x(70 mills/kWh) = $6,700,000
Oil-fired steam:
(100 MW)x(0.16)x(8760 hrs/yr)x(55 mills/kWh) = $7,700,000
Gas-fired steam:
(100 MW)x(0.20)x(8760 hrs/yr)x(45 mills/kWh) = $7,900,000

Total System Cost = $28,400,000

Difference in system costs

$28,400,000 - 15,900,000 = $12,500,000

NOTE: Energy costs in this example do not include real fuel cost escalation.

TABLE 9-5
Adjusted and Escalated Energy Values at Load Center

	Coal-fired steam	Combustion turbine
Escalated Busbar Energy Cost		
Fuel cost	17.6 mills/kWh	93.0 mills/kWh
Fuel cost escal. factor 1/	1.88	2.08
Escalated fuel cost	33.1 mills/kWh	193.4 mills/kWh
Variable O&M cost	2.4 mills/kWh	5.2 mills/kWh
Escalated energy cost	35.5 mills/kWh	198.6 mills/kWh
At-Market Energy Cost		
Escalated energy cost	35.5 mills/kWh	198.6 mills/kWh
Transmission losses 2/	1.1 mills/kWh	1.2 mills/kWh
At-market energy cost, EC_t	36.6 mills/kWh	199.8 mills/kWh
Energy Value Adjustment		
Hydro project plant factor, PF_h	0.30	0.30
Thermal plant factor, PF_t	0.55	0.075
Avg. system energy cost, EC_d	60.0 mills/kWh	60.0 mills/kWh
Energy value adjustment 3/	19.5 mills/kWh	104.8 mills/kWh
Adjusted Energy Value		
At-market energy cost	36.6 mills/kWh	199.8 mills/kWh
Energy value adjustment	- 19.5 mills/kWh	- 104.8 mills/kWh
Adjusted energy value	17.1 mills/kWh	95.0 mills/kWh

1/ From Appendix P, Table P-5, for DOE Region 5, 1990 POL date.
2/ 3.0% for coal, 0.6% for combustion turbine
3/ Based on FERC short-cut equation:

$$\text{Energy value adjustment} = \frac{(PF_t - PF_h)(EC_d - EC_t)}{PF_h}$$

production cost models for power value work is discussed in a report prepared by Systems Control Inc. for the Corps of Engineers and the Bureau of Reclamation (33). Section 6-9f of this manual briefly describes the POWRSYM model, which is used by FERC for most of its power value work.

(7) It should be noted that where the hydro plant and its thermal alternative operate at markedly different plant factors, the energy value adjustment can be large, sometimes resulting in negative energy values (i.e., total system operating costs are higher with the proposed hydropower plant in the system than with the thermal alternative). However, energy value adjustments can be positive as well as negative, depending upon the nature of the effect on system operation. This is illustrated by Figure 9-4, which shows how adjusted energy values might vary with plant factor for a base load coal-fired steam alternative.

f. Real Fuel Cost Escalation.

(1) As discussed in Section 9-4d, NED costs and benefits are to be expressed in constant dollars: i.e., no accounting is to be made for future general price inflation. However, Principles and Guidelines (Section 2.5.8(a)(5)) does permit the escalation of fuel prices in real terms due to increasing scarcity and other factors.

(2) The Water and Energy Task Force has developed a procedure that accounts for real fuel cost escalation (78). This procedure is discussed in Appendix P to this manual. Generally, the Task Force recommends that escalation be limited to a maximum of 30 years from the present, although a shorter escalation period may be warranted in some cases due to limited availability of forecast data, uncertainty, or other factors. The Task Force further recommends that these future escalated costs be present-worthed to the project on-line date and then amortized to develop average annual energy values. Appendix P also describes a technique for developing multipliers that adjust base fuel prices directly to account for real fuel cost escalation.

(3) Real fuel cost escalation is applied only to the fuel component of the energy value, and not to the variable O&M cost. For example, a typical coal-fired energy value for DOE Region 5 would be 20.0 mills/kWh (in 1980 dollars), of which 17.6 mills/kWh represents the fuel cost and 2.4 mills/kWh variable O&M costs. If the proposed hydro plant is assumed to come on-line in 1990, the equivalent annual fuel cost multiplier would be 1.88 (Appendix P, Table P-5). The escalated energy value would then be

(17.6 mills/kWh) x (1.88) + 2.4 mills/kWh = 35.5 mills/kWh.

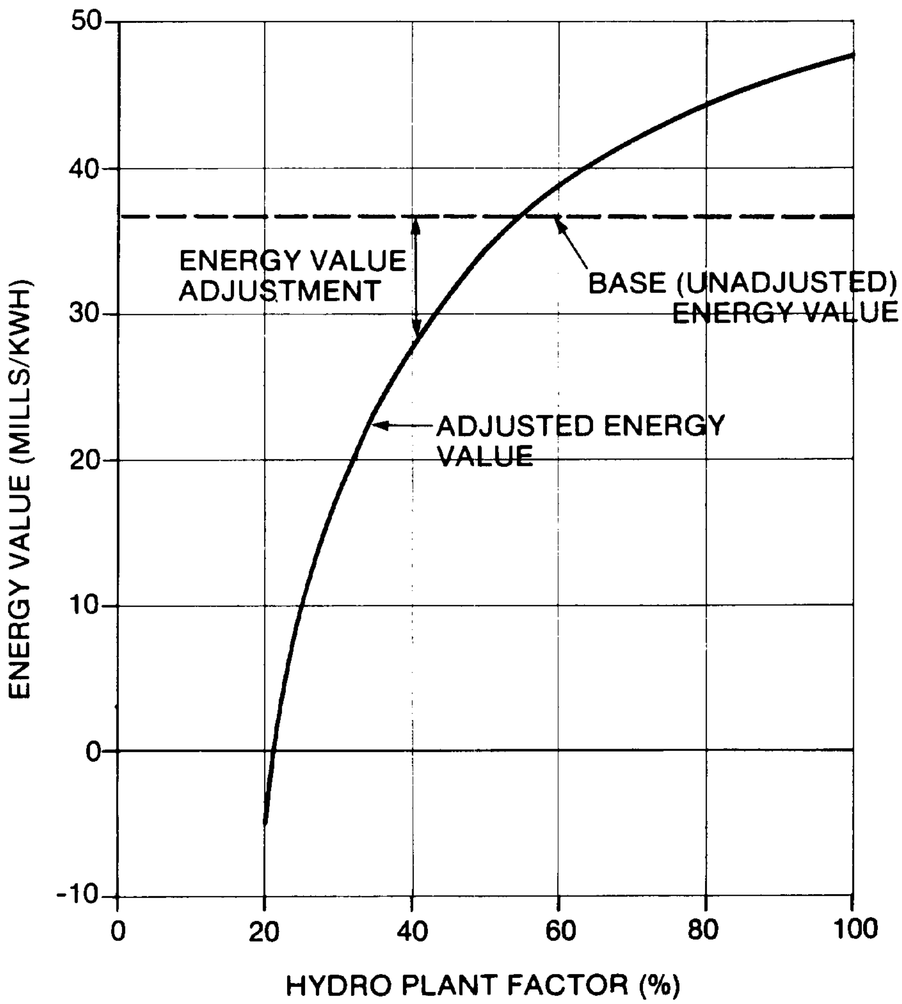


Figure 9-4. Example showing the effect of system energy value adjustment on energy values for base load coal-fired steam alternative.

Although real fuel price changes could have an effect upon operation and maintenance costs and other aspects of project evaluation, the effect is normally assumed to be small enough that it would not have any significant effect on the benefit analysis.

(4) The tables in Appendix P are for illustration purposes only. The most current fuel cost escalation rates available should be used. As noted in Appendix P, the Water and Energy Task Force suggests using Department of Energy (DOE) escalation rates when up-to-date estimates are available and their input assumptions are satisfactory. An alternative source of escalation data is the Data Resources, Inc. (DRI) Energy Review (4). The DRI projections are updated quarterly using current prices and other economic information; the regional data reflects local conditions more accurately than the DOE projections; and DRI provides specific information on fuel prices applicable to electric utilities. For these reasons, many Corps field offices elect to use the DRI escalation rates. Whichever rates are used, rationale should be provided for selecting those rates. FERC will normally use DOE escalation rates in their power value computations unless the Corps field office specifically requests that other rates be used.

(5) Power benefit computations should show the incremental effect of real fuel cost escalation on benefits. FERC provides supporting data with their power values (see Section 9-5k) to permit the computation of energy benefits with and without real fuel cost escalation so that Corps field offices can test alternative fuel cost escalation rates.

(6) Rising benefits resulting from real fuel cost escalation can have an effect upon the optimal on-line date for a hydropower project. For large projects especially, alternative on-line dates should be tested to determine if the first year that the project is needed (as determined from load-resource analyses) is in fact the date that yields the greatest net benefits. Chapter 9 of Volume VI of the National Hydroelectric Power Resources Study (48f) provides further information on the scheduling criterion.

g. Transmission Costs and Losses.

(1) Hydro project benefits and costs are normally compared at the "load center". Although a system's power demand is usually distributed over a wide area, for purposes of comparison it is usually possible to identify a single point of concentrated demand (such as a metropolitan area), which is designated as the load center. Transmission costs and losses associated with getting the power from the thermal plant to the load center must be computed and added to the capacity and energy values described above. Chapters 4, 10, and 11 of Hydroelectric Power Evaluation (72) describe techniques for accom-

plishing this. Tables 9-3 and 9-5 illustrate how these costs and losses are accounted for during the computation of typical power values. Transmission costs and losses must also be computed for the hydro plant (see Section 8-6). Figure 9-5 shows how the various cost components are accounted for in the normal "at-load center" benefit cost analysis.

(2) In the Pacific Northwest, it is sometimes difficult to isolate and assign specific segments of transmission line to individual hydro plants. In these cases, costs and benefits may be compared at the hydro site. This is done by applying generalized values for hydro plant transmission costs and losses to the "at-load center" energy and capacity values. Figure 9-6 shows how the cost components are accounted for in an "at-hydro site" benefit-cost analysis.

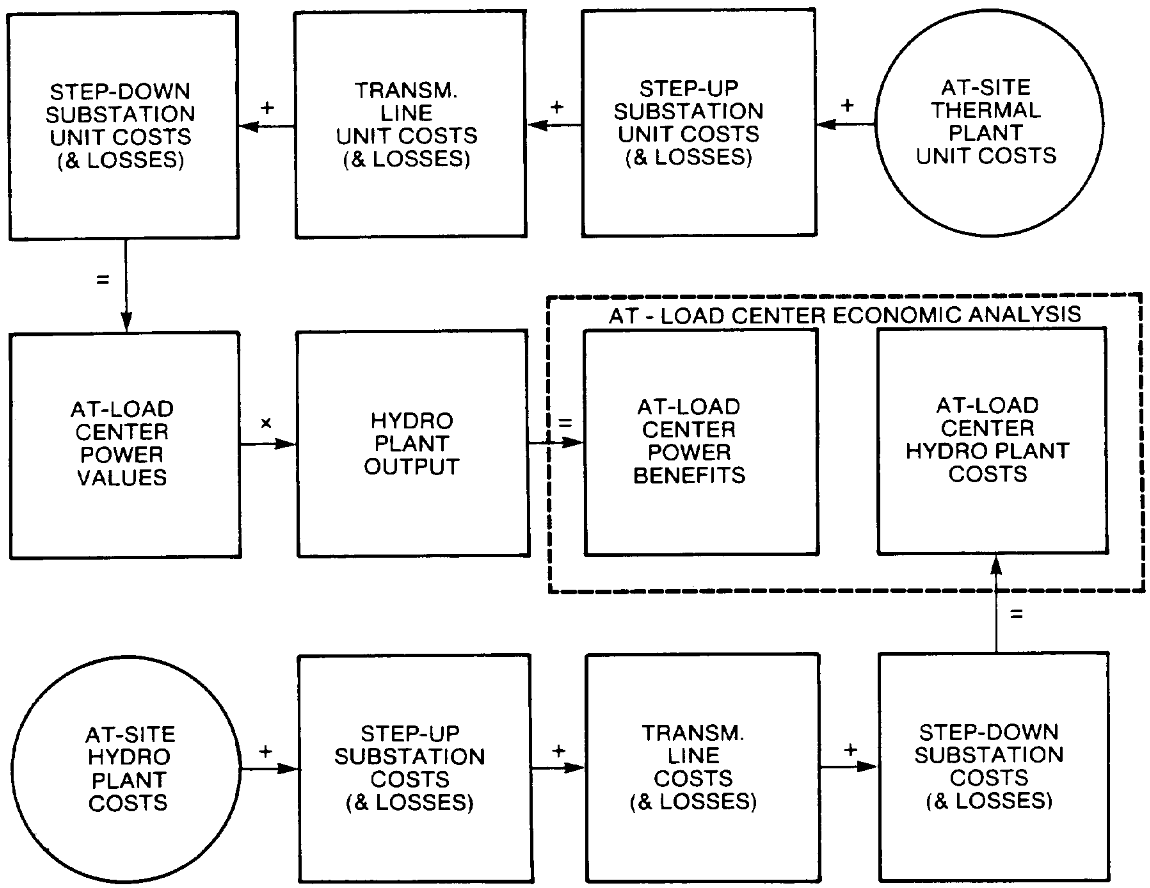


Figure 9-5. Schematic diagram showing accounting for transmission costs and losses in "at-load center" (at-market) economic analysis

h. <u>Selection of the Most Likely Alternative.</u>

(1) At the present time, five types of thermal power plants are being constructed by utilities in the contiguous United States, and these serve as the basis for power values. These plants, classified according to the type of load they serve, are as follows:

- base load: coal-fired steam and nuclear
- intermediate load: cycling coal-fired steam and combined cycle
- peaking: combustion turbine

In Alaska, Hawaii, Puerto Rico, and other isolated areas, oil-fired steam, gas- and oil-fired combustion turbines, or diesel may be the most likely thermal alternative for base load as well as intermediate and peaking service. Section 2-2d describes the general characteristics of the plants listed above.

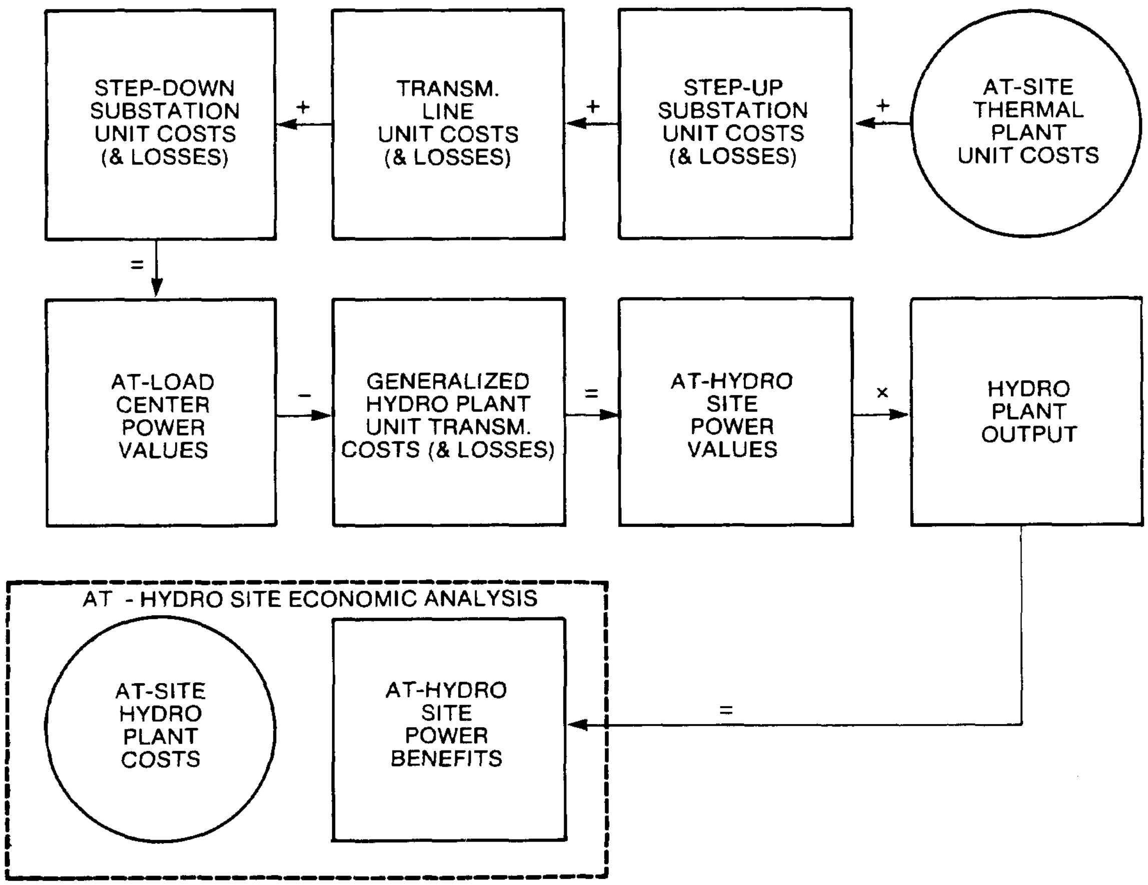


Figure 9-6. Schematic diagram showing accounting for transmission costs and losses in "at-hydro site" economic analysis

(2) To determine the least costly thermal alternative to a given hydro plant (with a given plant factor), several types of plants are usually considered. Capacity and energy values are computed for each. Selection of the appropriate alternative is accomplished as follows. In computing the energy values, energy value adjustments are applied as described in Section 9-5e. The energy value for each thermal plant is then converted to dollars per kilowatt-year and added to the corresponding capacity value to determine the total power value for each alternative. The plant with the lowest total power value is usually selected as the most likely thermal alternative. Table 9-6 shows power values for a 30 percent plant factor hydro plant based on three different thermal alternatives.

(3) Table 9-6 shows that coal-fired steam is the least costly alternative, and it would probably be used as the basis for the hydro project benefits. However, a distinction must be made between the "least costly" alternative and the "most likely" alternative. The least costly alternative is not always selected because there may be factors other than cost alone that dictate which thermal plants are viable alternatives. For example, combined-cycle plants may not be constructed in a given area due to an uncertain fuel supply, or nuclear plants may not be constructed because of siting restrictions. Thus, in some cases, the least costly alternative may not be selected as the most likely alternative because it is not implementable.

(4) Power values are frequently computed for specific hydroelectric plant installations, as shown in Table 9-6. Where scoping studies are being made to select plant size or where screening studies are being made to select the best sites, generalized power values may be developed for a range of hydro plant factors. They are usually presented in tabular form (see, for example, Table 9-7), but they can also be plotted in terms of hydro plant factor versus total power value in $/kW-yr.

(5) The graphic presentation is known as a screening curve and can be used to identify the appropriate alternative for each plant factor range. To be valid for use in hydropower project analysis, screening curves must reflect the capacity and energy value adjustments described in Sections 9-5c and 9-5e.

(6) It should be noted that the hydropower project plant factor enters into the computation of the total power values shown in Tables 9-6 and 9-7 and Figures 9-7 and 9-8, and in fact the screening curves are plotted using hydro plant factor as one of the variables. Hence, it is important that the proper hydro plant factor be used if the correct thermal alternative is to be selected. Since the hydro project's capacity benefits are based on dependable capacity (Sections 6-7 and 9-3), the hydro plant factor used for selecting the thermal

TABLE 9-6
Power Values for Thermal Alternatives to
30 Percent Plant Factor Hydro Project

	Combustion Turbine	Combined Cycle	Coal-fired Steam
Unadjusted energy value, mills/kWh	199.8	143.3	36.6
Energy value adjustment, mills/kWh	-104.8	- 13.9	-19.5
Adjusted energy value, mills/kWh	95.0	129.4	17.1
Adjusted energy value, $/kW-yr 1/	$249.70	$340.10	$ 44.90
Capacity value, $/kW-yr	35.00	75.40	196.40
Total power value, $/kW-yr	$284.70	$415.50	$241.30

1/ To convert energy value from mills/kWh to $/kW-year, multiply the energy value by the number of hours in a year and the hydro plant factor. For example, for the combustion turbine:

$$\frac{(95.0 \text{ mills/kWh})\text{x}(8760 \text{ hrs/yr})\text{x}(0.30)}{(1000 \text{ mills/\$})} = \$249.70/\text{kW-year}$$

alternative should also be based on the hydro project's dependable capacity. In most cases, the hydro plant factor should also be based on the project's average annual energy, although for power systems where secondary energy cannot be readily marketed, the hydro plant factor shoud be based on firm energy (see Section 9-10o). For most cases, the hydro plant factor used for selecting the thermal alternative should be computed as follows:

$$\text{Hydro project plant factor} = \frac{(\text{Average annual energy, MWh})}{(8760 \text{ hours})(\text{Dependable capacity, MW})} \qquad \text{(Eq. 9-5)}$$

(7) Figure 9-7 illustrates typical screening curves, where combustion turbine is the alternative at low (or peaking) plant factors and coal-fired steam is the alternative at high (or base load)

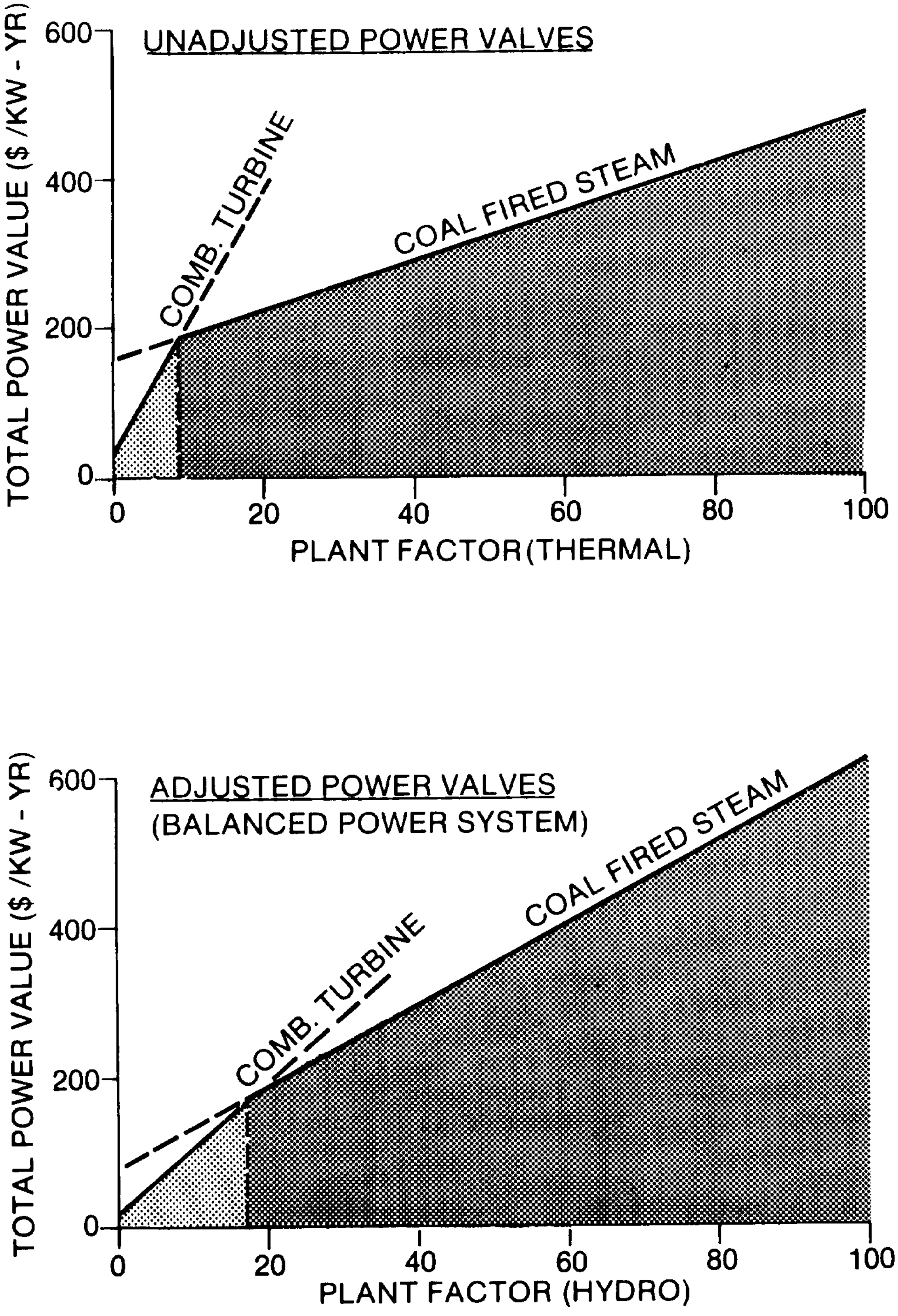


Figure 9-7. Comparison of screening curves based upon adjusted and unadjusted power values

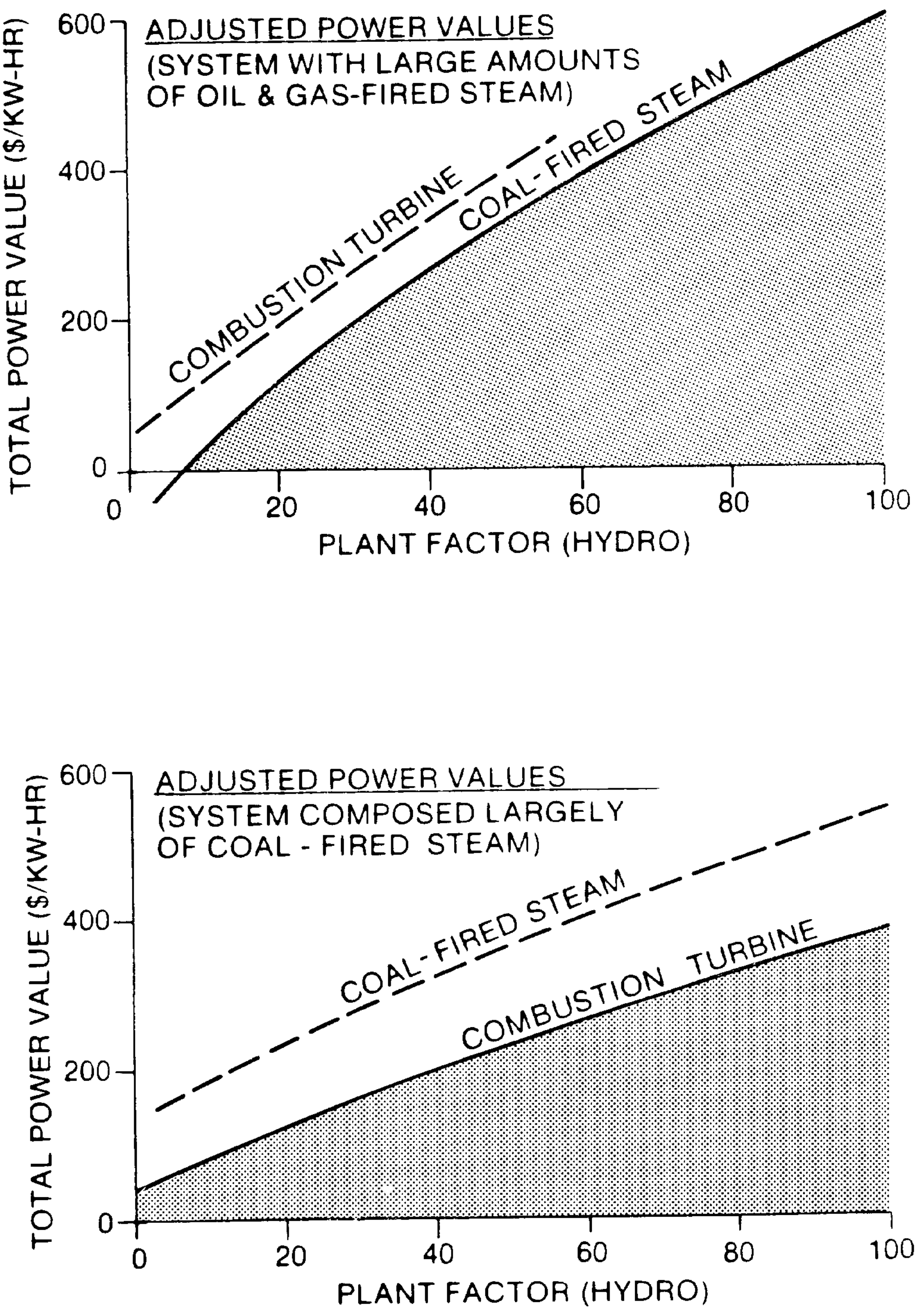


Figure 9-8. Screening curves based upon adjusted power values for two types of unbalanced power systems

TABLE 9-7
Generalized Power Values

Hydro Project Plant Factor (percent) 1/	Capacity Value ($/kW-year) 2/	Energy Value (mills/kWh) 3/	Total Power Value ($/kW-year) 4/
Combustion Turbine			
5	$35.00	269.7	$153
10	35.00	164.9	179
15	35.00	129.9	206
20	35.00	112.4	232
25	35.00	101.9	258
30	35.00	95.0	285
Coal-fired Steam			
10	$196.40	-68.7	$136
20	196.40	-4.4	189
30	196.40	17.1	241
40	196.40	27.8	294
50	196.40	34.3	347
60	196.40	38.6	399
70	196.40	41.6	451
80	196.40	43.9	504
90	196.40	45.7	557
100	196.40	47.1	609

1/ See Section 9-5h(6)
2/ These are adjusted capacity values, computed as shown on Table 9-3.
3/ These are adjusted energy values, computed as shown on Table 9-5.
4/ Total power value, $/kW-year =
(capacity value, $/kW-year) + (energy value, $/kW-year)

The energy value is converted from mills/kWh to $/kW-year as shown on Table 9-6.

plant factors. The upper curve is based on unadjusted thermal plant costs. A curve of this type might be used by utilities in determining the best mix of thermal resources. The lower curve is based on the same plant costs, but incorporates capacity and energy value adjustments (although not the same adjustments reflected in Table 9-7). Data from this curve would be used for developing power benefits. It can be seen from the lower curve that the break point between the combustion turbine and coal-fired steam alternatives would be a 17 percent plant factor. Compared to the unadjusted curve, the adjusted coal-fired curve has a steeper slope, and the total power values are higher at the high plant factors and lower at the low plant factors. The slope of the combustion turbine curve is flatter than the unadjusted curve, and the power values are lower at all but the lowest plant factors.

(8) The lower curve in Figure 9-7 illustrates power values for a system where a good balance of existing resources exists. A "good balance" refers to a mix of base load, intermediate, and peaking plants which is near optimum in terms of system operating costs. In some systems, changes in relative fuel prices, delays to planned new powerplants, or other factors may result in a "poor balance" (a mix of plants which is relatively expensive to operate).

(9) Where a poor balance exists, or where a system includes a large percentage of high-cost oil- or gas-fired steam generation, large energy value adjustments may result. In these situations, a screening curve may suggest a thermal alternative other than that which might be expected for a given plant factor, or the power values may be much higher or lower than expected on the basis of unadjusted thermal plant costs. For example, if a system has a disproportionate amount of peaking generation or high-cost steam generation, it would best be served by base load plants having low energy costs. The resulting power values (upper portion of Figure 9-8) would suggest that a hydro plant should be developed as a base load plant rather than as a peaking plant (i.e., the net benefit analysis would tend to favor the selection of a hydropower project having a higher plant factor than would have been selected for addition to a system having a good balance of existing resources). This is because the power values at the lower (peaking and intermediate) plant factors are substantially lower for this system compared to the balanced system, while the power values at the higher (base load) plant factors remain high. On the other hand, for a system having a large amount of low-cost base load generation, the adjusted power values (lower portion of Figure 9-8) would likely suggest the development of hydro for peaking.

i. Size of Thermal Alternative. Frequently, the size of a proposed hydro plant is much different than the normal size of the thermal alternative. For example, the least costly thermal alternative to a proposed 20 MW hydro plant as determined from the screening curve may be base load coal. The thermal alternative would not be a 20 MW coal-fired plant, but an increment of a standard-sized coal-fired plant (500 MW, for example). Thus, construction of the 20 MW hydro plant would defer but not replace the large coal-fired plant, or would make it possible to build a somewhat smaller coal-fired plant.

j. Combination of Alternatives.

(1) In some cases, the operation of a hydro plant may be such that it is not possible to select a single thermal alternative that is equivalent to the hydro plant, even through use of an energy value adjustment. An example would be a large hydro plant that provides some base load capacity and some peaking capacity. Another example might be a hydro plant that produces base load power for part of the year and peaking power for the rest of the year. In these cases, the least costly alternative that is nearly equivalent to the hydropower plant from an operational standpoint may be a mix of thermal plants.

(2) The following example illustrates how a mix of alternatives might be developed. Assume that minimum release requirements dictate that a portion of the capacity of a 100 MW, 40 percent plant factor hydro plant will be used for base load operation and the remainder will be used for peaking. The most likely alternative in this case may be a combination of coal-fired steam and combustion turbine capacity. By examining the operation of similar units in the power system, it may be found that new coal-fired steam plants operate at an average annual plant factor of 60 percent and combustion turbines operate at 10 percent. The mix would be computed by simultaneous solution of the following equations, where MW_c is the coal-fired capacity and MW_t is the combustion turbine capacity:

$$MW_c + MW_t = \text{Hydro plant capacity} = 100\ MW$$

$$(MW_c)x(60\%) + (MW_t)x(10\%) = (100MW)x(40\%)$$

$$MW_c = 60\ MW \qquad MW_t = 40\ MW$$

(3) In this example, construction of the hydro plant displaces the construction of a combination of thermal plants. A more common case is the situation where the hydro plant displaces the construction of a single thermal alternative, but in operation displaces a mix of thermal generation. Due to the hydrologic characteristics of the site, the hydro project may operate in the base load mode part of the year and in the peaking mode for the remainder of the year. The most effective way to deal with this problem is through the use of a system production cost model, such as POWRSYM (see Section 6-9f), which is able to model the day to day or week to week variations in hydro generation and thus properly identify the value of the energy displaced. Different thermal alternatives (or combinations of

alternatives) could be tested to determine which would be least costly, considering both capital costs (capacity values) and system operating costs from the POWRSYM model.

(4) Take for example a 200 MW hydro plant with a 30 percent annual plant factor that operates for peaking most of the time but as a base load plant during periods of high runoff. Three thermal alternatives might be considered: 200 MW of combustion turbine, 200 MW of coal-fired steam, and a combination of 100 MW of coal-fired steam and 100 MW of combustion turbine (other combinations could also be considered if necessary). Table 9-8 shows the computation of benefits for all three alternatives, the result being that the combustion turbine by itself is the least costly alternative in this case. Therefore, benefits should be based on these alternative costs. The hydro plant would replace the need for construction of 200 MW of combustion turbine capacity, and a portion of the hydro plant's energy output would provide peaking generation. The remainder of the hydro plant's output would displace some of the energy output of other plants in the system (base load thermal, etc.), but it would not eliminate the need for these plants.

(5) FERC can account for this type of operation in the development of the adjusted energy values. However, the Corps field office must provide FERC with week-by-week values of hydro project energy output for a typical year in order to permit them to properly model the project. Where capacity varies over the course of the year, it should be specified by week also. In determining what mixes of power output (base load and peaking, for example) should be considered, it is important to coordinate these studies closely with the regional Federal Power Marketing Administration to insure that the proposed operations produce power which is marketable in the area power system.

k. Sources of Power Values.

(1) In most cases, the power values used by the Corps of Engineers are developed by the Federal Energy Regulatory Commission. FERC has experience in power value work and has access to the basic cost and power system operation data necessary to derive accurate power values. Also, there are advantages in having the power values developed by an independent agency. However, there are occasionally cases where the Corps may find it desirable to become directly involved in power value work. One example would be where FERC staff limitations preclude timely development of power values. Another might be the case of a large or complex hydro development, where it is necessary for Corps planners to understand the mechanics of power system operation so that they can properly evaluate the projects. Working directly with system models is one of the best ways of gaining

TABLE 9-8
Alternatives to a 30 Percent Plant Factor Hydropower Plant Operating Part-time as a Peaking Plant and Part-time as a Base Load Plant

	Coal-fired Steam	50-50 Mix	Combustion Turbine
Combustion turbine capacity, MW	-	100	200
Combustion turbine capacity value, $/kW-year	-	35.00	35.00
Combustion turbine capacity benefit, $1000	-	3,500	7,000
Coal-fired steam capacity, MW	200	100	-
Coal capacity value, $/kW-year	196.40	196.40	-
Coal capacity benefit, $1000	39,300	19,600	-
Average annual energy, gWh	525.6	525.6	525.6
System energy value, mills/kWh 1/	20.05	46.78	74.17
Energy benefits, $1000	10,500	24,600	39,000
Total benefits, $1000	49,800	47,700	46,000

1/ System energy value obtained from POWRSYM analysis of Southwest Power Pool system, 1995 load year, DRI real fuel cost escalation rates, and 1990 power on-line date.

this knowledge. Finally, there may be studies where a large number of alternative plan's sensitivity analyses are being considered, and having the Corps do some of the power value work will expedite the process. However, where the Corps is directly involved, it is important for Corps personnel to work closely with FERC in developing the basic data and making the analyses.

(2) Where neither FERC nor Corps staff are available to develop power values, consulting firms which have experience in evaluation of power generation alternatives may be retained. In these cases, the consultant should follow the general procedures outlined in this manual and in FERC's Hydroelectric Power Evaluation (72).

(3) Table 3-4 lists the address of each FERC regional office and Figure 3-3 shows the geographical areas served by each. Letters requesting power values for specific projects should provide the following information:

- location of project
- expected on-line date
- discount rate and price level to be used in the analysis
- installed capacity
- average annual energy
- annual distribution of generation (by week or month)
- a discussion of the type of operation planned for the project (i.e., peaking or base load) and any operating criteria which may limit the use of the powerplant
- who is to perform the hydrologic availability adjustments

For generalized power values, it is necessary to specify only the first three items, although general information on the types of hydro plants being examined would also be useful. For pumped-storage projects, an estimate of the cost of pumping energy should be requested also. It may be desirable in some cases to request power values based on energy displacement (Section 9-6) as well as values based on the usual alternative thermal plant method.

(4) To permit adequate review of the power benefit analysis, the Corps has requested FERC to provide the following supporting information when they transmit their power values:

- name of model used in developing power values
- market area or system simulated
- basic cost of alternative power source (unadj. power values)
- values of the adjustments applied to the base power values, including:
  - hydrologic availability factor (if applied by FERC)
  - flexibility adjustment
  - mechanical availability adjustment
  - energy value adjustment
- price level and discount rate
- cost and nature of transmission facilities and transmission losses included in power values
- real fuel cost assumptions, including:
  - escalation rates
  - source of escalation rates
  - escalation period
  - beginning and ending unit fuel prices
  - incremental effect of real fuel cost escalation on power values

l. Cost-indexing Power Values. It is sometimes necessary to cost-index FERC power values to make them consistent with the cost base established for the hydro project analysis. Capacity values may be indexed with the standard construction cost index used by the Corps field office or with the Whitman-Requardt Electric Utility Construction Cost Index, which is published in Engineering News Record's "Quarterly Cost Roundups." Energy values may be updated using an index based upon fuel prices obtained from DOE/Energy Information Administration's Electric Power Monthly (83). Information on fuel prices for peaking plants can be found in Electric Power Quarterly (84). These reports normally lag the dates upon which the fuel prices are based by several months. More recent values for both types of plants can be obtained directly from the Energy Information Administration's National Energy Information Center. Another source of data for indexing fuel prices is the DRI Quarterly Energy Review (4). Where the power values are a year or more out of date, updated power values should be requested from FERC.

9-6. Energy Displacement Method.

a. General. In some systems, the best use of a hydro project's energy output is displacement of generation (energy) from existing power plants rather than displacement of the construction of an increment of a new thermal powerplant. The energy displacement method should be considered for the evaluation of small hydro plants having little or no dependable capacity and for the assessment of hydro plants to be constructed in power systems having a high proportion of expensive oil- or gas-fired generation. This method computes only energy values. The value is based on the hydro plant displacing the most expensive generation on-line at any given time, and this will vary with time of day, time of week, and time of year.

b. Computerized Production Cost Model. The "energy displacement" energy value represents the system's marginal operating cost and can be estimated most accurately using a computerized hourly production cost model (Section 6-9f). The same general techniques used for developing energy values for the alternative thermal plant method (Sections 9-5d through 9-5g) apply to this method as well. The system marginal operating cost is a system cost and requires no further energy value adjustment. Real fuel cost escalation should be applied to all components when developing this system cost.

c. Manual Load-Duration Curve. Approximate energy values can be obtained manually from annual load duration curves. In order to provide an accurate estimate of the amount of time each type of generation is operating at the margin, the system load-duration curve must be adjusted to account for forced outages. This will cause the load duration to more closely represent a system generation-duration curve. Figure 9-9 and Table 9-9 show a simplified example of an energy value estimate performed using an annual load-duration curve. The upper portion of Table 9-9 shows the computation of the average energy value of 44 mills/kWh for the load year 1980.

d. Time-Related Factors. When the generation mix changes substantially with time, it is necessary to make energy value estimates at intervals during the first 10 to 20 years of project life. Real fuel cost escalation can be accounted for at the same time. Energy values can be computed for intervening years by interpolation, and an equivalent annual value can be derived by present-worthing techniques. Power benefits would then be computed simply by applying the equivalent annual energy value to the hydro project's energy output. Table 9-9 illustrates how the energy value might vary with time in response to changes in system mix and fuel cost escalation for the simplified system illustrated in Figure 9-9. Figure 9-10 and Table 9-10 show the computation of an equivalent annual energy value which reflects these changes.

e. Selection of Approach. The computerized production cost model models the impact of system costs and relative fuel costs most accurately and should be used when developing energy displacement values for feasibility level studies. Most FERC offices have the capability of doing this type of analysis. Where the energy value is developed using a production cost model, the hydro plant's energy output should be specified by week or month. Where a production cost model is not available, the manual load-duration curve method must be used. An annual curve can be used for reconnaissance level studies, but seasonal curves must be developed for more advanced studies. This is because generation at hydro plants usually varies seasonally and the mix of generation that would be displaced may vary seasonally as well.

f. Comparison with Alternative Thermal Plant Method.

(1) When using the energy displacement method, it is usually desirable to analyze benefits using the alternative thermal plant method as well, in order to verify that the fuel displacement method reflects the best use of the hydro project. The upper portion of Table 9-11 is an example of this comparison.

(2) When using the fuel displacement method for computing benefits, it is also necessary to show that the proposed hydro plant is the least costly way of achieving the benefits. The lower part of Table 9-11 shows that when both the hydropower plant and the thermal alternative (coal-fired steam) are compared using benefits based upon fuel displacement, the hydropower plant, since it is cheaper, accrues

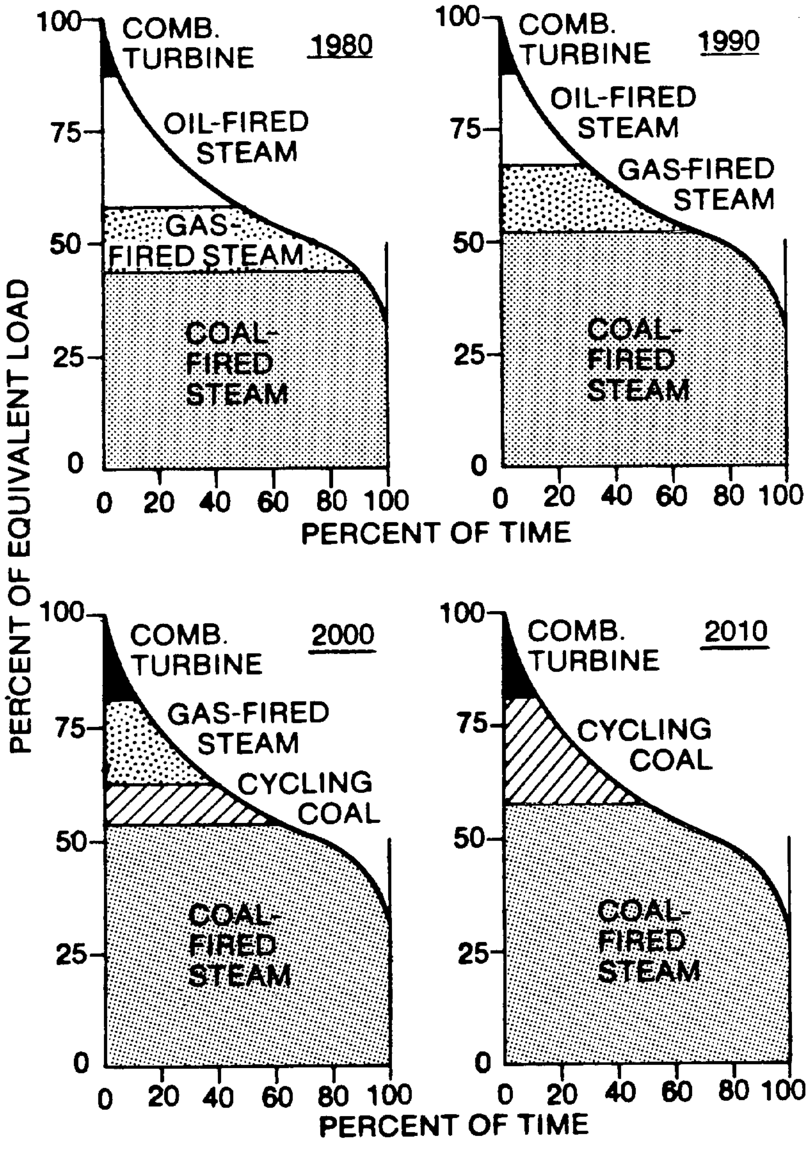


Figure 9-9. Example of variation in system generation mix with time: 1980-2010

TABLE 9-9
Variation of Average System Marginal Cost with Time

	Percent of Time on Margin Max.	Min.	Net.	Energy Value mills/kWh	Weighted Energy Value mills/kWh 1/
1980					
Combustion turbine	5	0	5	100	5
Oil-fired steam	50	5	45	55	25
Gas-fired steam	90	50	40	30	12
Coal-fired steam	100	90	10	20	2
System average			100		44
1990					
Combustion turbine	5	0	5	158	8
Oil-fired steam	30	5	25	90	22
Gas-fired steam	70	30	40	84	34
Coal-fired steam	100	70	30	32	10
System average			100		74
2000					
Combustion turbine	10	0	10	211	21
Oil-fired steam	40	10	30	125	38
Coal cycling plant	60	40	20	42	8
Coal-fired steam	100	60	40	36	14
System average			100		81
2010					
Combustion turbine	10	0	10	263	26
Coal cycling plant	50	10	40	46	18
Coal-fired steam	100	50	50	39	20
System average			100		64

1/ (Weighted energy value) =
(Energy value) x (Net percent of time on margin)

greater net benefits. Table 9-12 shows a case where the hydro plant again accrues greater net benefits when benefits are based on the fuel displacement method than when benefits are based on the coal-fired steam alternative, but here the coal-fired steam plant is less costly than the hydropower plant. Therefore, in this case, the plan with the greatest net benefits (+$40,000) is to construct the coal-fired steam plant for energy displacement. If the coal-fired plant is truly implementable and can be considered within the same time frame as the hydro plant, then the hydro plant should not be recommended, even though it is justified using the energy displacement method.

g. Combination of Methods. In some systems, there may be opportunities in the near term for displacement of high cost energy from existing thermal plants, but, in the long run, these thermal plants would be retired or replaced with other types of generation.

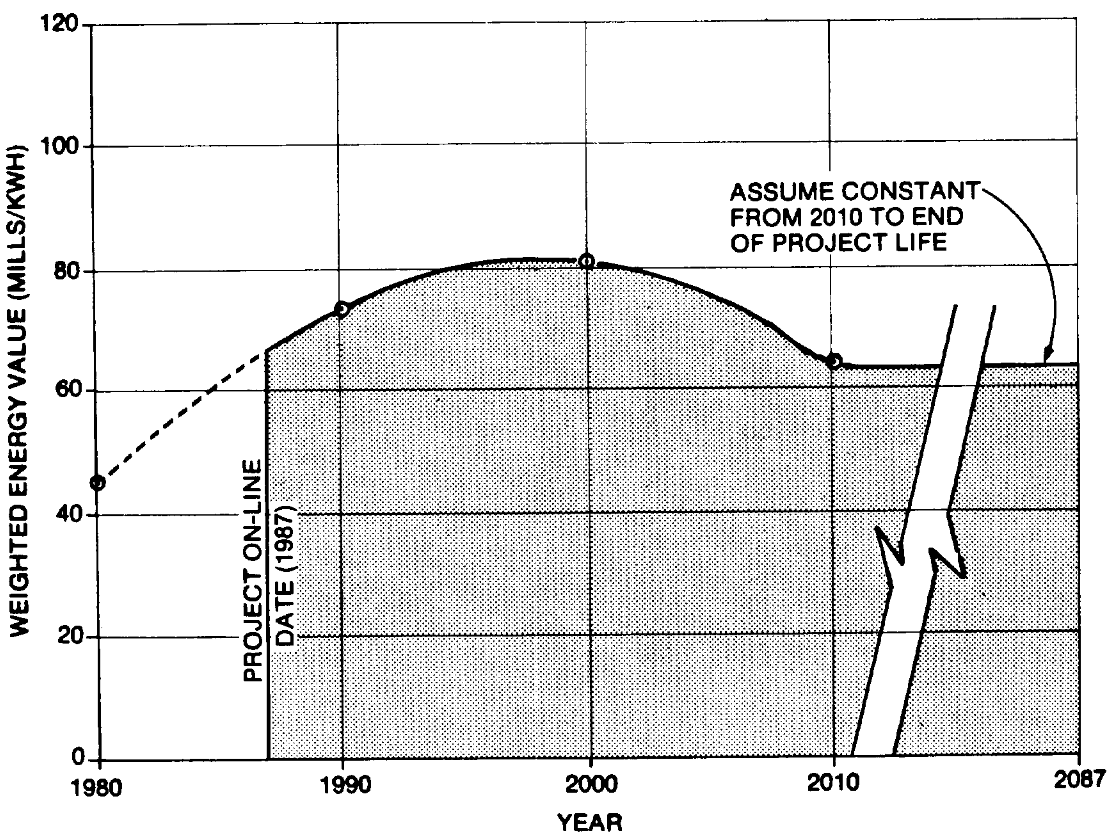


Figure 9-10. Variation of energy value with time due to fuel cost escalation and changes in system energy mix

TABLE 9-10
Equivalent Annual Energy Value Reflecting Real
Fuel Cost Escalation and Changes in System Generation Mix

Year	Years after POL	Fuel cost 1/ (mills/kWh)	Discount factor at 7-7/8%	Present worth (mills/kWh)
1980	-	44.0	-	-
1987	POL	67.8	-	-
1988	1	69.9	0.9270	64.8
1989	2	71.9	0.8593	61.8
.	.	.	.	.
.	.	.	.	.
2009	22	66.9	0.1887	12.6
2010	23	64.0	0.1749	11.2

Sum of present worth (years 1-23, growth period) = 799.3
Sum of present worth (years 23-100, constant fuel price) 2/ = 141.4
940.7

Adjusted Energy Value 3/

Equivalent annual fuel cost, mills/kWh =
(940.7)x(A/P, 7-7/8%, 100 years) = (940.7)x(0.0788) = 74.1
Variable O&M cost, mills/kWh 4/ = 3.2
Total energy cost at bus bar, mills/kWh 5/ 77.3

1/ Values from Figure 9-10

2/ (64.0 mills/kWh)x(P/A, 7-7/8%, 100 yrs - P/A, 7-7/8%, 23 yrs) = (64.0 mills/kWh)x(12.69 - 10.48) = 141.4 mills/kWh.

3/

$$\frac{A}{P} = \frac{i}{1 - \frac{1}{(1+i)^n}} \qquad \text{and} \qquad \frac{P}{A} = \frac{1 - \frac{1}{(1+i)^n}}{i}$$

where: A/P = interest and amortization factor
P/A = present worth factor for equal annual payments
n = number of years
i = interest rate expressed as a decimal fraction

4/ Weighted combination of operation and maintenance costs for combustion turbine and coal-fired steam plants.

5/ Does not include transmission costs or losses.

TABLE 9-11
Comparison of Energy Displacement
and Alternative Thermal Plant Methods (Case A)

Cost of Hydropower Project Compared to Benefits Based on Energy Displacement and Coal-fired Steam

	Benefits Based on Energy Displacement	Benefits Based on Coal-fired Steam
Benefits, $1000	120 1/	100 2/
Costs, $1000 3/	80	80
Net benefits, $1000	40	20

Energy Displacement Benefits Compared to Cost of Coal-fired Steam and Hydropower Project

	Coal-fired Steam	Hydropower Project
Benefits, $1000 1/	120	120
Costs, $1000	100 4/	80 3/
Net benefits, $1000	20	40

1/ Benefits based upon energy displacement
2/ Benefits based upon alternative coal-fired steam plant
3/ Cost of hydropower project
4/ Cost of alternative coal-fired steam (same as 2/)

In the example shown on Figure 9-9, gas-fired steam is phased out by the year 2000 and oil-fired steam is phased out by 2010. Thus, in some cases, the hydro plant might best be used to displace generation from existing plants during the early years of project life, and replace an increment of new thermal generation during the remainder of its life. An analysis of this type would involve using both the energy displacement method and the most likely thermal alternative method. Each method would be applied to the appropriate portion of the project life, and present-worthing techniques would be used to derive an equivalent average annual benefit.

TABLE 9-12
Comparison of Energy Displacement
and Alternative Thermal Plant Methods (Case B)

Cost of Hydropower Project Compared to Benefits Based on Energy Displacement and Coal-Fired Steam

	Benefits Based on Energy Displacement	Benefits Based on Coal-Fired Steam
Benefits, $1000	120 1/	80 2/
Costs, $1000 3/	100	100
Net benefits, $1000	20	-20

Energy Displacement Benefits Compared to Cost of Coal-Fired Steam and Hydropower Project

	Coal-Fired Steam	Hydropower Project
Benefits, $1000 1/	120	120
Costs, $1000	80 4/	100 3/
Net benefits, $1000	40	20

1/ Benefits based upon energy displacement
2/ Benefits based upon alternative coal-fired steam plant
3/ Cost of hydropower project
4/ Cost of alternative coal-fired steam plant (same as 2/)

9-7. Annual Costs. Standard Corps of Engineers cost-estimating procedures are to be used for developing hydro project annual costs. Data should be developed for amortized annual investment costs, interim replacement costs, and operation and maintenance costs. For pumped-storage plants, estimated annual pumping costs should also be included. Costs and benefits are usually compared at the load center, and the transmission costs associated with the hydro plant must be included (see Section 9-5g). Further information on computing hydro plant costs is provided in Chapter 8, including an example of a typical annual cost computation.

9-8. Scoping of Hydro Projects.

a. General. A number of alternative plans are usually considered when determining the best plan for developing a new dam site or modifying an existing project. This section lists some of the types of alternative developments that may be considered at hydro plants, illustrates several typical plant-sizing exercises, and discusses some of the scoping considerations unique to hydropower.

b. Types of Alternative Plans. Following is a list of some of the common alternatives that could be considered in selecting the proper development at hydro projects:

- alternative dam sites
- alternative project configurations
- alternative dam heights
- provision of seasonal power storage
- alternative seasonal power storage volumes
- provision of daily/weekly pondage (to firm peaking capacity)
- alternative plant sizes
- alternative sizes and numbers of units

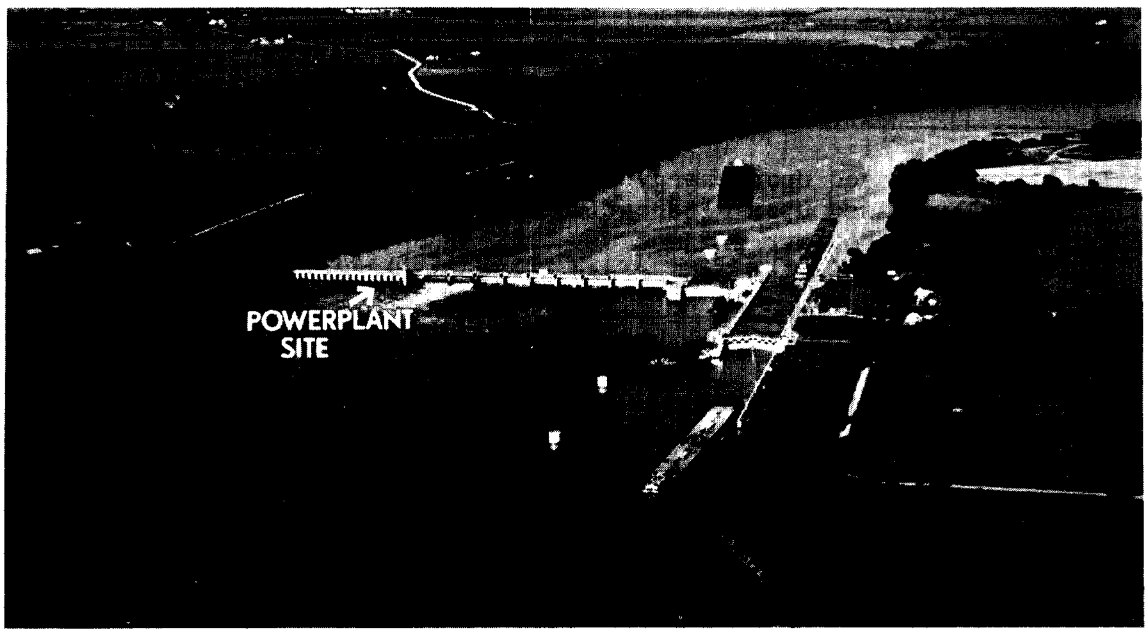


Figure 9-11. Potential small-scale hydropower installation at Dresden Island Lock and Dam. This is the same type of project as is illustrated in Table 9-14. (Rock Island District)

- alternative types of plant operation (peaking vs. base load, etc.)
- provision of reregulating dam (to firm up peaking capacity)
- installation of reversible units (to firm up peaking capacity)
- alternative development schemes (for multiple-project system)
- benefits based upon alternative thermal plant vs. energy displacement method
- use of hydro to provide system spinning reserve.

Obviously, not all of these alternatives need to be examined in detail for each project. Some apply only to new projects, some apply only to storage projects, and some apply only where operating and physical conditions permit use of hydro for peaking. Non-power operating limits and the needs of the power system, for example, may limit the range of alternatives that need to be examined in detail. The parameters listed above are, for the most part, single-purpose power considerations. Multiple purpose project planning adds another dimension to the scoping process. However, detailed examination of a wide range of alternatives is both expensive and time-consuming. Every effort should be made to reduce the range of alternatives to a reasonable number early in the planning process.

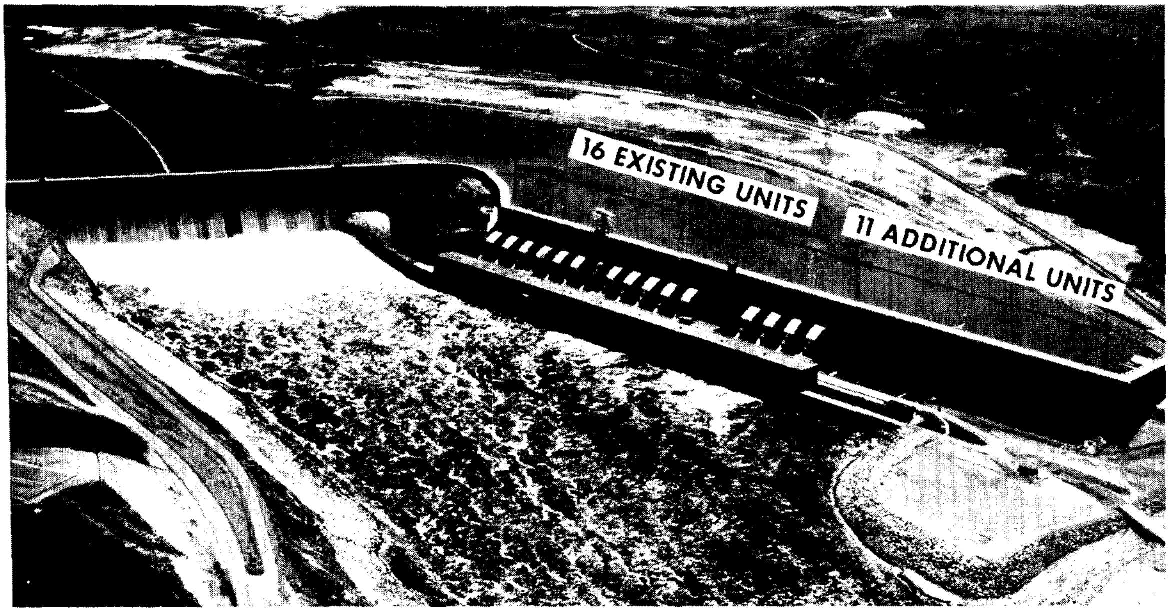


Figure 9-12. Powerplant expansion for peaking at Chief Joseph Dam. This is the same type of project as is illustrated in Table 9-15. (Seattle District)

c. Examples of Plant Sizing.

(1) General. One of the most common exercises relating to hydropower planning is plant sizing, and Chapter 6 describes the details involved in selecting a range of plant sizes. Tables 9-13 through 9-16 and Figures 9-13 through 9-16 illustrate some typical plant-sizing situations, including:

- single-purpose hydro project with storage
- small scale run-of-river hydro plant
- expansion of existing powerplant for peaking
- off-stream pumped-storage project

(2) High Head Storage Project. Note that in the case of the first example (Table 9-13 and Figure 9-13), storage as well as plant size is a variable (storage increases with pool elevation). Plant sizes based upon three different plant factors were tested for each pool elevation. This is a screening analysis, so generalized power values from Table 9-7 were used. The analysis shows that the higher pool elevations and firm plant factors in the 40 to 60 percent range yield the greatest net benefits, and these combinations would then be studied in greater detail.

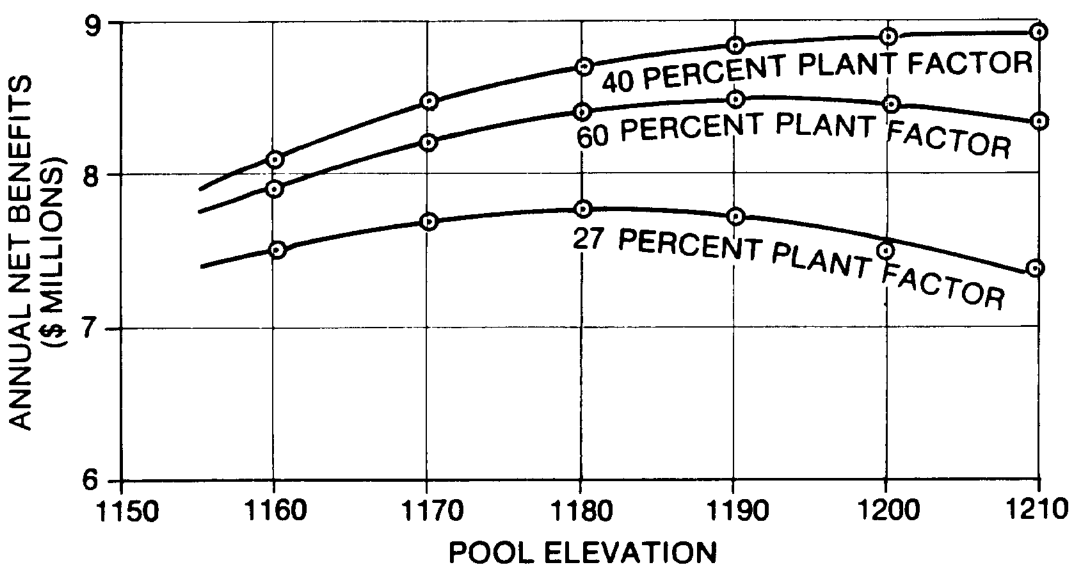


Figure 9-13. Net benefit analysis for high head storage project

TABLE 9-13
Net Benefit Analysis - High Head Storage Project

Pool Elevation	Installed Capacity (MW)	Dependable Capacity (MW)	Capacity Value 1/ ($/kW-yr)	Capacity Benefit ($1000)	Avg. Ann. Energy (gWh)
60% P. F.					
El. 1160	57.9	57.9	196.4	11,400	330.6
El. 1180	61.8	61.8	196.4	12,100	342.6
El. 1200	65.7	65.7	196.4	12,900	353.9
40% P. F.					
El. 1160	86.8	86.8	196.4	17,000	345.9
El. 1180	92.8	92.8	196.4	18,200	354.3
El. 1200	98.5	98.5	196.4	19,400	361.5
27% P. F.					
El. 1160	132.5	132.5	196.4	26,000	357.9
El. 1180	137.2	137.2	196.4	26,900	363.4
El. 1200	141.7	141.7	196.4	27,800	366.5

	Energy Value 1/ (mills/kWh)	Energy Benefit ($1000)	Total Benefit ($1000)	Annual Cost ($1000)	Net Benefit ($1000)
60% P. F.					
El. 1160	38.6	12,800	24,200	16,300	7,900
El. 1180	38.6	13,200	25,300	17,000	8,300
El. 1200	38.6	13,700	26,600	18,200	8,400
40% P. F.					
El. 1160	27.8	9,600	26,600	18,600	8,000
El. 1180	27.8	9,800	28,000	19,300	8,700
El. 1200	27.8	10,000	29,400	20,500	8,900
27% P. F.					
El. 1160	12.8	4,600	30,600	23,100	7,500
El. 1180	12.8	4,700	31,600	23,800	7,800
El. 1200	12.8	4,700	32,500	25,100	7,400

1/ Power Values From Table 9-7

(3) Small Run-of-River Project. In the case of the run-of-river project (Table 9-14 and Figure 9-14), dependable capacity is based on the average availability method (Section 6-7g). Since the project will be operated base load at plant factors in the 40 to 90 percent range, coal-fired steam was used as the alternative. Because of the variable seasonal distribution of the hydro energy output, energy benefits were based on values developed using a system production cost model (such as POWRSYM, see Section 6-9f).

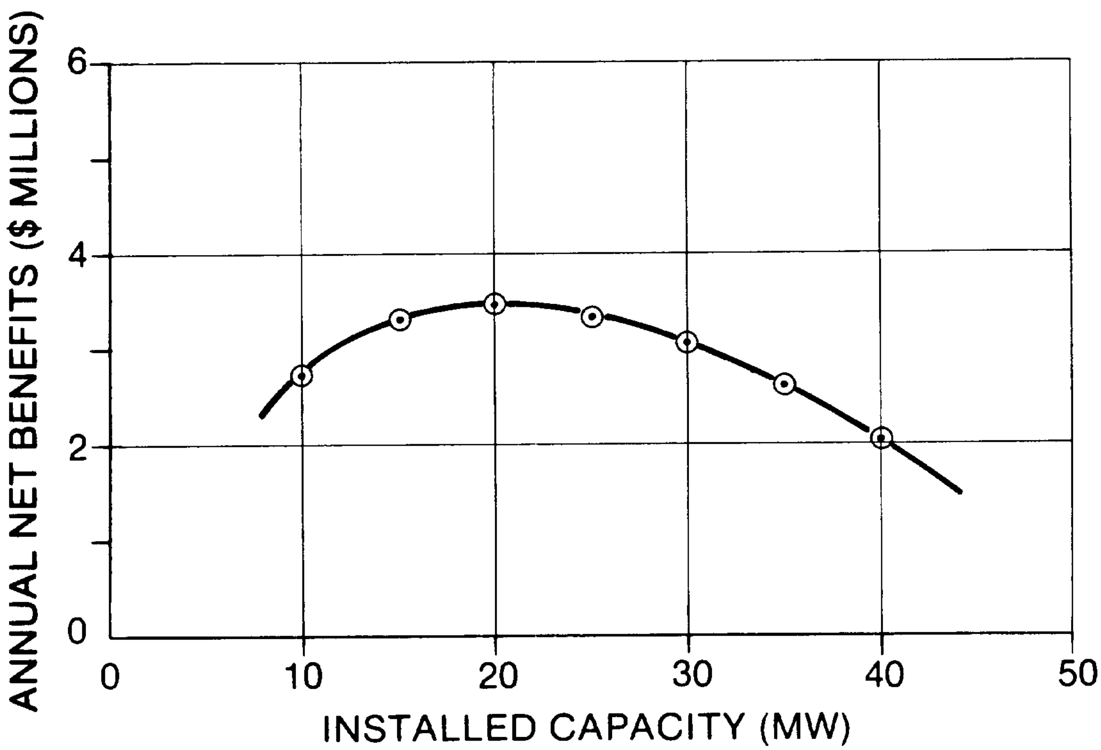


Figure 9-14. Net benefit analysis for small run-of-river project

TABLE 9-14
Net Benefit Analysis - Small Scale Run-of-river Project

Installed Capacity (MW)	Hydrologic Availability (percent)	Dependable Capacity (MW)	Capacity Value ($/kW)	Capacity Benefit ($1000)
10.0	98.9	9.9	$196.40	1940
15.0	91.1	13.7	196.40	2690
20.0	78.1	15.6	196.40	3060
25.0	66.7	16.7	196.40	3280
30.0	57.3	17.2	196.40	3380
35.0	50.5	17.7	196.40	3480
40.0	45.0	18.0	196.40	3540

Installed Capacity (MW)	Average Energy (gWh)	Energy Value 1/ (mills/kWh)	Energy Benefits ($1000)	Total Benefits ($1000)	Annual Costs ($1000)	Net Benefit ($1000)
10.0	78.0	43.7	3410	5350	2590	2760
15.0	97.5	41.9	4080	6770	3430	3340
20.0	111.5	42.0	4680	7740	4270	3470
25.0	122.4	42.5	5200	8480	5110	3370
30.0	130.7	43.2	5650	9030	5960	3070
35.0	137.3	43.5	5970	9450	6800	2650
40.0	142.1	43.7	6210	9750	7640	2110

1/ Energy values from system analysis model, based on an alternative thermal plant having an installed capacity equivalent to the hydro plant (Equation 6-7).

(4) Powerhouse Expansion. In the case of the powerhouse expansion (Table 9-15 and Figure 9-15), the purpose of the added units is for peaking, so the combustion turbine was used as the thermal alternative ($35/kW-yr). The added hydro units pick up some energy that was previously being spilled, but this energy is generated in the off-peak months, so its value is limited to displacement of coal-fired steam generation from existing plants (36.6 mills/kWh). The major benefit attributable to the added units is the reshaping of the existing daily generation pattern. The larger plant capacity will permit water presently being spilled at night and on weekends to be stored for release during peak demand hours, when energy has a higher value. This increase in the value of existing generation is called the system energy benefit and is derived using a production cost model analysis. The benefits attributable to both the recovered spill and the reshaped existing generation are included in the energy benefits obtained from the production cost analysis.

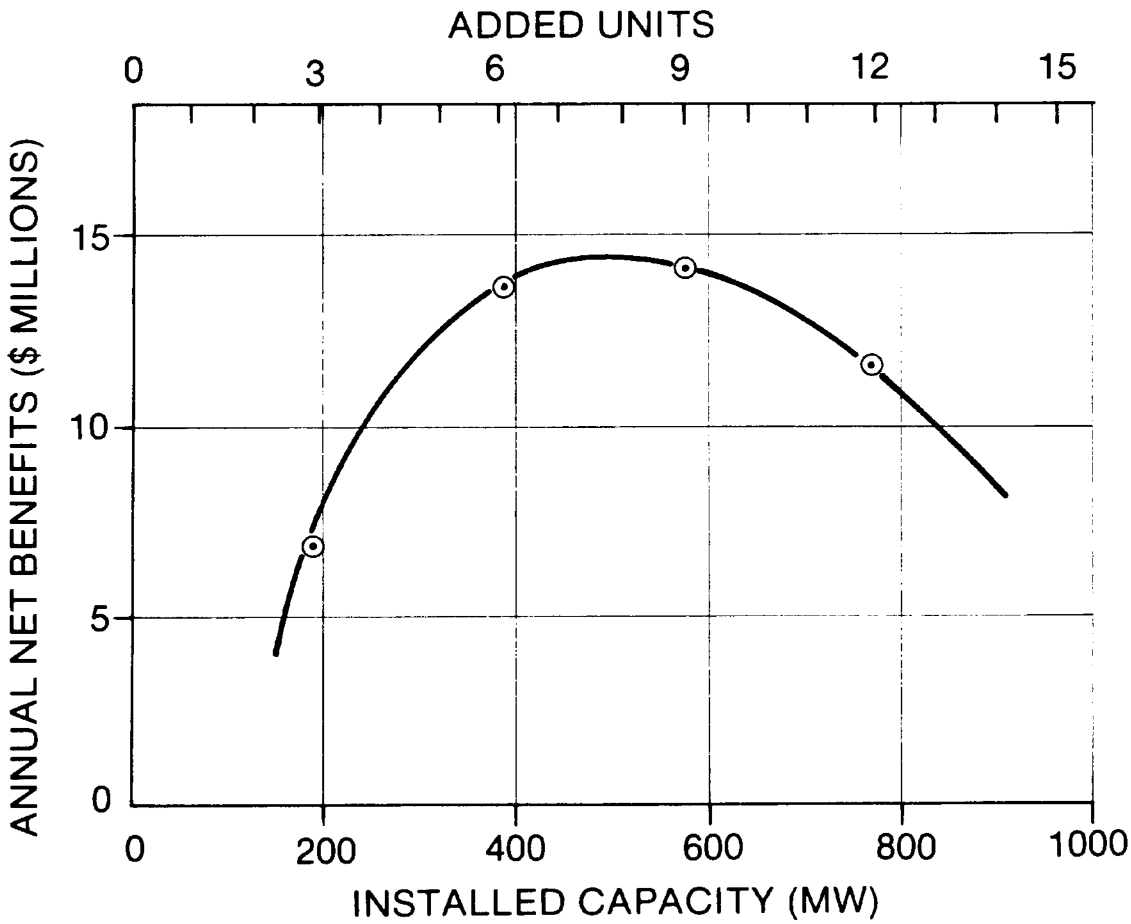


Figure 9-15. Net benefit analysis for powerhouse expansion for peaking

TABLE 9-15
Net Benefit Analysis - Powerhouse Expansion for Peaking Plant

Number of added units	3	6	9	12
Installed capacity, MW	192	384	576	768
Capacity Benefit				
Dependable capacity, MW	192	371	525	662
Capacity value, $/kW-yr 1/	35	35	35	35
Capacity benefit, $1000	6,700	13,000	18,400	23,200
Energy Benefit				
System energy benefit, $1000 2/	20,600	29,600	33,700	34,600
Net Benefits				
Total benefits, $1000	27,300	42,600	52,100	57,800
Average annual costs, $1000	20,400	29,000	37,400	46,200
Annual net benefits, $1000	6,900	13,600	14,700	11,600

1/ From Table 9-3
2/ From production cost model analysis

(5) Off-Stream Pumped Storage Project. For the off-stream pumped-storage project (Table 9-16 and Figure 9-16), it is assumed that the daily/weekly storage volume is fixed and that the variable is the number of hours of equivalent full-load generation that the project could produce each weekday with that storage volume. The 4.9 hour installation (405 MW) would be a daily cycle plant, while the other plants would have weekly cycle operations (Section 7-2d describes how a pumped-storage project's installed capacity can be determined, given the reservoir storage volume and the operating cycle). The net benefit analysis shows the 4.9 hour daily cycle plant to have the greatest net benefits, but a marketability analysis may show that the minimum number of daily hours of on-peak generation that power users are willing to purchase may be greater than 4.9 hours. Capacity benefits are based upon the combustion turbine peaking alternative, and energy benefits and average pumping cost values were obtained from production cost model analyses.

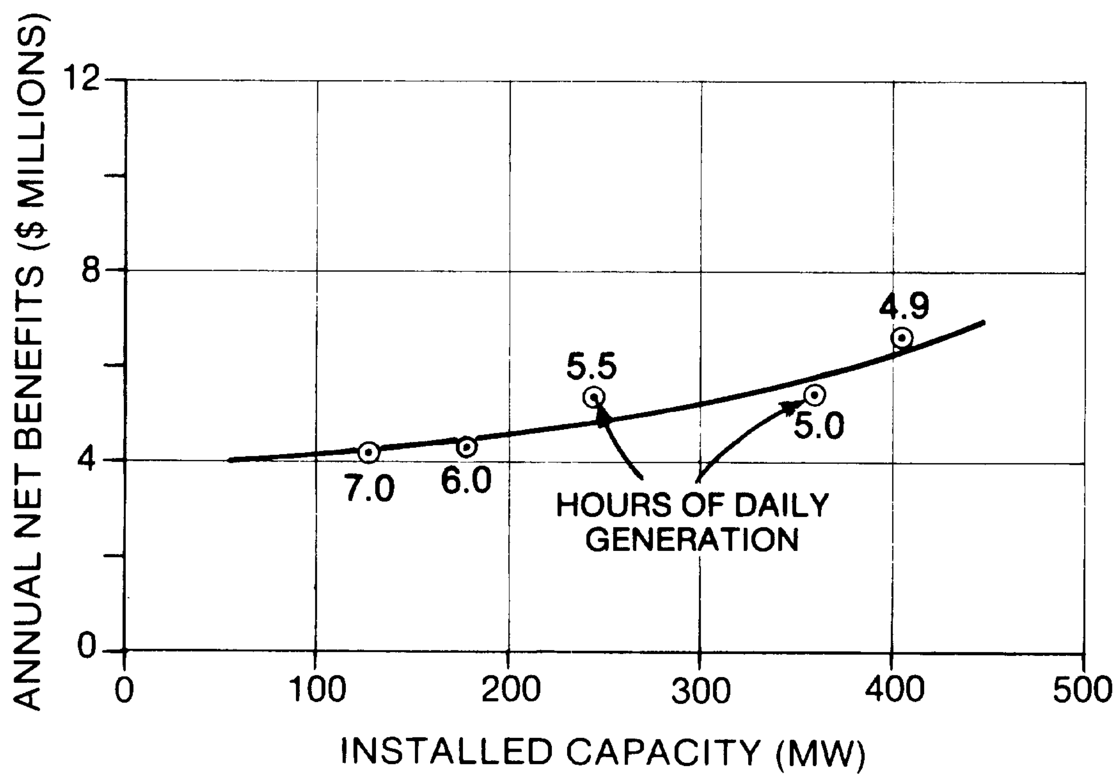


Figure 9-16. Net benefit analysis for off-stream pumped-storage project

TABLE 9-16
Net Benefit Analysis - Pumped-Storage Project

Hrs. of Daily Gen.	Installed Capacity (MW)	Plant Factor 1/ (percent)	Capacity Benefit 2/ ($1000)	Average Energy (gWh)	Energy Benefit 1/ ($1000)	Energy Value 3/ (mills/kWh)
4.9	405	6.2	14,200	220	21,100	96.0
5.0	359	6.8	12,600	213	19,800	92.9
5.5	246	10.5	8,600	226	19,500	86.3
6.0	183	12.5	6,400	200	16,400	82.0
7.0	128	16.0	4,500	179	14,000	78.2

Installed Capacity (MW)	Annual Project Costs ($1000)	Annual Pumping Cost 3/ ($1000)	Pumping Energy Value 4/ (mills/kWh)	Total Annual Costs ($1000)	Total 5/ Annual Benefits ($1000)	Annual Net Benefits ($1000)
405	16,700	12,000	38.2	28,700	35,300	6,600
359	15,500	11,500	37.8	27,000	32,400	5,400
246	11,300	11,400	35.3	22,700	28,100	5,400
183	8,700	9,800	34.3	18,500	22,800	4,300
128	5,800	8,300	32.4	14,100	18,500	4,400

1/ From production cost model analysis
2/ (Capacity benefit) = (Installed capacity) x ($35/kW). Installed capacity at this project is fully dependable.
3/ Energy value = (Energy benefit)/(Average annual energy)

4/ Pumping energy value = $\dfrac{\text{(Annual pumping cost)}}{\text{(Average energy)/(70\% cycle efficiency)}}$

5/ (Total annual benefit) = (Energy benefits) + (Capacity benefits)

d. Selection of Recommended Plan.

(1) Current Corps procedures and policies are to be followed in selecting the recommended plan. A key element in these policies consists of developing an NED plan. The NED plan is that plan which maximizes either net economic benefits or net NED benefits and is generally the plan which must be recommended for implementation. Special care must be taken in the formulation process to insure that (a) the recommended project's power operation is compatible with non-power river uses and other project functions, and (b) the project output can be used effectively in the power system and is readily marketable by the regional Federal Power Marketing Administration (PMA). To insure that this is done, close coordination with the PMA should be maintained throughout the planning process. Another important consideration is that the recommended plan must be a complete plan: i.e., all costs required to realize the project's benefits should be included. For example, if the project is to be a peaking facility, the cost of a reregulating dam or measures to protect the downstream channel and adjacent streambanks should be included.

(2) For some hydro projects, the NED plan may underdevelop the energy potential of the site. Recommending a plan which departs from the NED plan because it would more fully develop the site's potential is sometimes permitted, but such recommendations would have to be consistent with current Corps policy. Factors which have been be considered in the past for supporting a larger plant size include (a) reducing use of non-renewable resources, (b) reducing the adverse environmental impacts associated with thermal generation, (c) reducing dependence on foreign oil imports and the attendant economic and national security problems, and (d) enhancing project reliability and flexibility. Inflation-free analyses can also be used as sensitivity studies to assist in the selection of the proper plant size, and testing of alternative project on-line dates may also serve to identify a plan which yields greater net benefits. Another strategy which could ultimately permit full development of a site's potential would be to design the project for staged development. The initial installation could be based upon the current NED plan, but provision would be made for expansion in case additional generation should become economically feasible in the future. Such a design could include structural provisions for future units (Section 9-10b), or it could simply consist of allowing space for such an installation.

9-9. Financial Feasibility.

a. Section 5 of the Flood Control Act of 1944 (PL 78-534), as amended by the Department of Energy Reorganization Act of 1977 (PL

95-91), provides that electric power generated at Corps of Engineers reservoir projects that is not required in the operation of such projects shall be delivered to the Department of Energy for marketing. Rates for sale of such power are established to insure that the cost of producing and transmitting that power (including repayment of the Federal investment with interest) shall be recovered in a reasonable period. Fifty years has been established by law and administrative practice as the repayment period. The Act further specifies that preference in the sale of power shall be given to public bodies and cooperatives. Responsibility for marketing has been assigned to five regional Power Marketing Administrations (PMA's) within the Department of Energy.

b. To insure that the requirements of these Acts are met, the Corps includes in each feasibility report a statement from the appropriate regional PMA indicating that power from the project can be marketed and that project costs allocated to power can be repaid with interest in 50 years. Statements of this type should also be included in General Design Memoranda to confirm that the project continues to be financially feasible.

c. The discount rate and period of analysis used in a repayment study for a given project frequently differs from the discount rate and period of analysis used in the economic analysis. This is because different laws and procedures govern the repayment process analysis than govern Federal water resources planning. Primarily because of these differences, some projects that are economically feasible may not pass the financial feasibility test and vice versa.

d. Power from most Corps projects is marketed on a system basis, through one of several regional or river basin marketing arrangements. Power from these projects is marketed at average system rates, which reflect the costs associated with older, relatively inexpensive projects having low interest rates as well as the higher costs associated with newer projects. A project usually passes the financial feasibility test, because these average rates are substantially lower than would be required to amortize the costs of new alternative sources of power. Where generation is marketed on an individual project basis, financial feasibility is much more difficult to achieve.

e. The addresses and service areas of the regional PMA's are shown on Table 3-3. Requests for marketability and financial feasibility studies for projects located outside of the service areas of established PMA's should be addressed to:

Office of Power Marketing Coordination
Department of Energy
Room 6B-104, Forrestal Building
Washington, DC 20585

f. Letters of request to regional PMA's should include the following information:

- location of project
- installed capacity
- average annual energy output and seasonal distribution of generation
- anticipated power on-line date
- investment costs allocated to power
- annual OM&R costs allocated to power
- price level (year) of costs
- project life and interest rate
- description of expected power operation and any operating constraints which might restrict the use of the power.

g. The procedures and policies described above have been in effect since 1944. However, it should be noted that national water resources development policies continue to evolve. Care should be taken to insure that the latest policies and procedures are followed.

9-10. Special Problems.

a. Introduction. Because of the wide variety in potential hydro developments, and the wide variety and dynamic nature of power systems in which the hydro projects might be operated, it is not possible in a manual of this type to describe all of the types of analysis that might be encountered. However, some of the most commonly encountered special analysis problems are discussed in this section.

b. Minimum Provisions for Future Power Installations.

(1) At some projects, installation of power may not prove feasible at the time planning or design is initiated, but the addition of generation at a later date may be attractive. In other instances, increases in the value of power following authorization may render a previously unfavorable hydro installation feasible, but this finding may come too late in the design process to incorporate the powerplant in the initial construction phase. These situations are covered by

the Flood Control Act of 1938 and subsequent Flood Control and River and Harbor Acts, which state that:

> "Penstocks and other similar facilities adapted to possible future use in the development of hydroelectric power shall be installed in any dam authorized in this Act for construction of the Department of the Army when approved by the Secretary of the Army on the recommendation of the Chief of Engineers and the Federal Power Commission."

The Federal Power Commission is now the Federal Energy Regulatory Commission.

(2) Guidance for this type of analysis is contained in ER 1110-2-1, Provision for Future Hydroelectric Installation at Corps of Engineers Projects, which states that hydroelectric power potential must be investigated, where feasible, in conjunction with all Corps of Engineers water resources feasibility reports and/or design memoranda. In view of the increased value of energy, a number of Corps projects which are in planning and engineering or construction stages may support minimum provisions for future hydropower facilities. To obtain approval of the Secretary of the Army for incorporating minimum power provisions in these projects, a letter report or supplement to an applicable design memorandum should be forwarded to DAEN-ECE for review and OCE/HQ recommendation, and to the Secretary of the Army for approval. Minimum facilities should be those necessary to avoid major reconstruction and/or interruption to other project purposes should full power facilities be installed at some future date. The format and content of the required letter reports are discussed in ER 1110-2-1. The hydropower benefits would be computed in the same manner as for other types of hydropower studies.

(3) ER 1110-2-1 applies primarily to projects where minimum hydropower provisions were not installed in the initial construction stage. The same type of analysis must be applied where skeleton bays or other minimum provision for future units are included as a part of the installation. The incremental cost of these minimum provisions for additional units must in most cases be carried by the expected benefits accruing to those units. In these cases, coordination with FERC on the future units is usually handled as a part of the analysis of the initial installation.

c. Expansion of Existing Powerplants.

(1) Existing powerplants may be expanded to capture energy now being spilled, to increase a project's peaking capability, or for both reasons. Analysis of projects which are being expanded to capture spilled energy is relatively simple. Power benefits are based upon

the incremental increase in dependable capacity and average energy creditable to the added units. This type of analysis would be based upon either the displaced energy method or the alternative thermal plant method, using the least costly thermal alternative which is consistent with the type of operation planned for the added unit. For example, if the incremental plant factor were greater than 40 percent and the units would be operated in the run-of-river mode, the thermal alternative would probably be coal-fired steam. For lower plant factors, it may be necessary to test several alternatives to determine which is least costly.

(2) Analysis of added units for peaking is more complex. In most cases, the operation of the existing installation is changed in the process. Water originally passing through the existing units during off-peak hours would be shifted to the new units during the peak demand hours. The project would then be credited with (a) an increase in the value of some (or all) of the existing generation, (b) the dependable capacity credited to the added units, and (c) possibly some captured spill. Figure 9-17 illustrates how the daily generation pattern might be modified by plant expansion. The capacity benefits accruing to the added units will usually be based on combustion turbines, which have relatively low capital costs. Therefore, the bulk of the benefits from added units will usually come from the increased value of existing energy output. This increased value would be reflected in the system energy cost computations described in Section 9-5e. Section 9-8c(4) illustrates an example of a benefit analysis of added units for peaking.

(3) Evaluations of this type can be made with accuracy only by using hourly system production cost models. In requesting power values for this type of project, it is necessary to specify both energy and peaking capability by week or month, as well as the generation required to meet minimum flow requirements and any other operating constraints which might affect peaking operation.

(4) Development of a meaningful unit energy value is difficult during evaluation of added units for peaking, because many peaking additions result in the addition of little or no energy (in some cases, there may even be a net energy loss). If the units do capture additional energy, this energy is usually secondary energy produced in high flow periods rather than peaking energy. Two approaches can be taken to present energy benefits in lieu of the usual procedure of developing a unit energy value to be applied to the incremental energy output of the added units. Regardless of which approach is taken, it is important to keep in mind that the energy benefit would be a system energy benefit: i.e., the difference in total power system operating cost between the system with the added units and the system with the

thermal alternative. The first (and preferred) way to display this benefit would be to simply show the net system benefit, in dollars, as obtained from the system production cost studies.

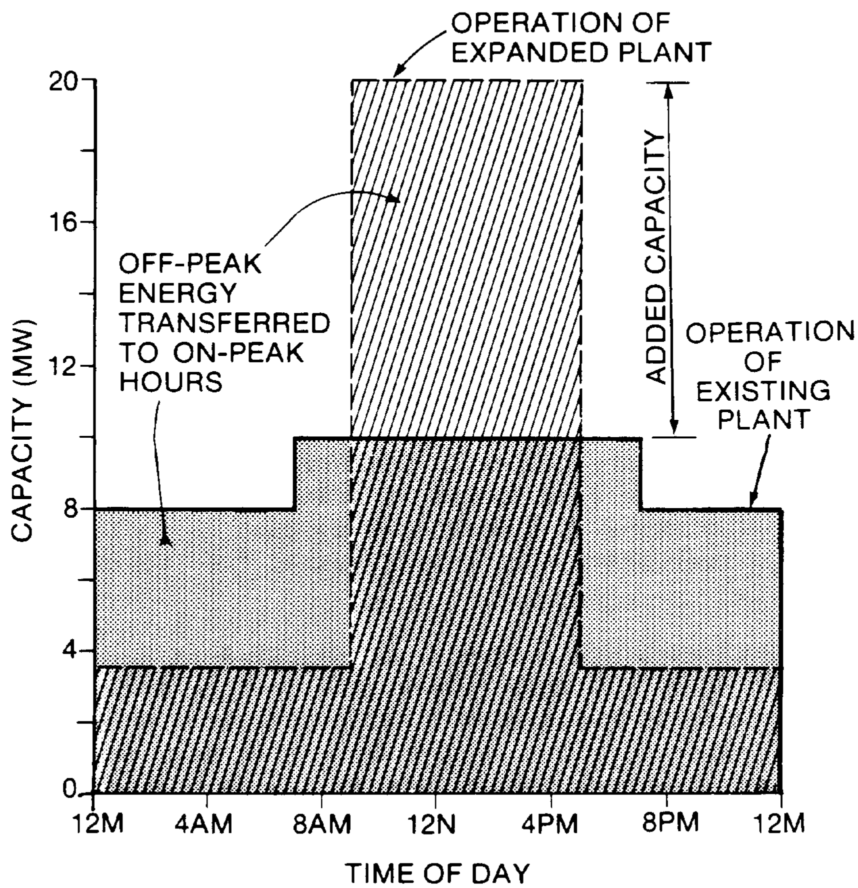


Figure 9-17. Modification of project operation resulting from plant expansion

(5) The second approach would be to combine the energy benefit with the capacity value to develop an "energy adjusted" capacity value. This approach is sometimes used by FERC. For example, a 200 MW peaking addition might produce a net annual system energy cost savings of $10,000,000, compared to a system including an equivalent amount of combustion turbine capacity. Assume that the $35.00/kW-yr capacity value developed in Table 9-3 applies here. The net system energy savings could then be applied as a unit value to the capacity value, as follows:

$$\text{Total capacity value} = \$35.00/\text{kW-yr} + \frac{(\$10{,}000{,}000/\text{yr})}{(200{,}000\ \text{kW})} = \$85.00/\text{kW-yr.}$$

d. Off-Stream Pumped-Storage Projects.

(1) Analysis of off-stream pumped-storage projects is in many ways similar to the analysis of added units for peaking. Energy benefits are based on conversion of low-value energy produced in off-peak hours to high value on-peak energy. In the process, the system loses energy due to inefficiencies in pumping, generating, and transmission. Capacity benefits are usually (but not always) based on combustion turbines. The net energy benefits are best computed by using an hourly system production cost model (Section 7-5). The energy benefits attributable to pumped-storage project operation can be presented in two ways: (a) the net system energy savings, which would be the difference in system operating costs with and without the pumped-storage project, and (b) the system energy benefits, which would have the pumping costs removed. However, because the value of the generation must be included on the benefit side of the benefit-cost equation and the value of pumping energy must be included on the cost side, the two components must be segregated (see Sections 7-5h, 8-5e, and 9-8c(5)).

(2) Most pumped-storage projects are operated on an economic dispatch (Section 7-2c). In these cases, the average annual energy and annual pumping energy requirements can be obtained only from the hourly production cost analysis. Where the system generation mix and/or the relative values of pumping energy and on-peak energy change with time, it will be necessary to make energy benefit analyses for a series of representative years covering the first 10 to 20 years of project life. Analysis of the benefits at intervals in the early years of project life is important because a pumped-storage project's value to the system frequently increases with time (see Section 7-3d).

(3) The analysis of a pumped-storage project is heavily dependent upon assumptions with respect to operating cycle and reservoir storage. These subjects are also treated in Chapter 7.

e. Reservoir System Power Benefits. One of the potential reasons for constructing a headwater storage project is to increase the power output of downstream projects. Downstream power benefits are very important, because the economic feasibility of the relatively expensive headwater storage projects often hinges on these benefits. Likewise, the feasibility of a downstream project is sometimes dependent on the availability of headwater storage regulation. System analysis is required to properly evaluate situations like these, where the benefits that accrue at one project are dependent on the operation of another project. Although the analysis of reservoir power system benefits is simple in concept, the application can be rather complex, especially if more than one reservoir is involved. Appendix Q describes how system power benefits are computed and allocated among the projects that make up a system.

f. Staging of Hydropower Projects.

(1) Most of the examples of power benefit analysis discussed in previous sections are based upon all of the hydro project's generating capacity coming on-line in a single year. At some projects, the capacity may be scheduled to come on-line in stages. Two types of staging situations may be encountered: (a) the absorption of a large project into the system load over a period of years and (b) the staging of various units over a period of time. In both cases, present-worthing techniques are used to convert the benefits, which vary in the early years of project life, to an average annual equivalent.

(2) In the first case, the major effect of staging will be on capacity benefits. A peak load-resource analysis would be made to determine the amount of capacity that is usable (and for which benefits can be claimed) year by year until the project is fully usable in the load. In some cases, there may be an effect upon energy benefits as well. For example, when a hydro project is added to a very small system, several years may be required to absorb the project's energy output. Table 9-17 illustrates benefit computations for a project of this type. The data on load and capacity requirements was obtained from a load-resource analysis of the type described in Sections 3-3 and 3-10. In most cases, however, the full energy output of a hydropower project can be used from the start. That energy which is not used to meet the increase in power demand would be used to displace existing generation.

(3) The second situation is where units are scheduled to come on-line at intervals over a period of years. Here, benefits are computed as they are realized and present-worthed to determine the average annual equivalent benefit. Care must be taken to insure that interest during construction (IDC) is properly accounted for on the

TABLE 9-17
Annual Benefits for Project Which Requires Several Years for its Output to Become Fully Usable

	1990	1991	1992	1993	1994	1995
System peak load, MW	99	102	105	108	111	115
Reserve requirement, MW	20	20	21	22	22	23
Total capacity required, MW	119	122	126	130	133	138
Existing capacity, MW	115	115	110	110	110	110
New capacity requirements, MW	4	7	16	20	23	28
Hydro project dependable capacity, MW	10	20	20	20	20	20
Useable dependable capacity, MW 1/	4	7	16	20	23	28
Capacity value, $/kW-yr	80	80	80	80	80	80
Capacity benefit, $1000	320	560	1280	1600	1600	1600
Hydro project average energy, gWh	75 2/	87.6	87.6	87.6	87.6	87.6
Energy value, mills/kWh 3/	60	60	60	60	60	60
Energy benefit, $1000 4/	4500	5260	5260	5260	5260	5260
Total benefit, $1000	4820	5820	6540	6860	6860	6860

1/ As limited by new capacity requirements
2/ Because only 10 of the new project's 20 MW of capacity is available during the first year (1990), the full 87.6 gWh of average energy cannot be utilized.
3/ No real fuel cost escalation is included in this example.
4/ It is assumed that the project's full energy output will be useable right from the project on-line date for displacing existing thermal generation.

delayed units. Where a high discount rate must be used, the IDC component may become substantial, and careful study must be made to insure that spreading out the on-line dates is justified.

(4) A variation of the second situation would be the case where a hydro plant is constructed initially as a base load plant and is later expanded to serve as a peaking plant. Present-worthing techniques would be used for determining average annual benefits here, also. However, if the project's operation changes markedly when it is expanded, the most likely alternative may change as well, and thus energy and capacity values used for computing benefits will also change. For example, the most likely alternative may switch from a base load thermal plant to either a mix of base load thermal and combustion turbines or combustion turbines alone. Where this is the case, the with-project scenario must include provisions for replacing any base load generation formerly carried by the hydro plant.

(5) In evaluating staged projects, it is important to test alternative on-line dates in order to determine the schedule which yields the optimum net benefits (see Chapter 9 of reference (48f)).

g. Reallocation of Storage. Because of the increasing cost of electrical energy, it may be desirable to examine the feasibility of reallocating unused or marginally valuable non-power storage or flood control storage space to power (or vice versa if the relative value of storage for non-power purposes increases markedly). For the case where additional storage is allocated to power, incremental power benefits would be computed based on the additional power output gained, which could include:

- additional capacity and energy resulting from increased head
- additional at-site and downstream energy and capacity gains resulting from increased seasonal power storage
- additional dependable capacity resulting from provision of daily/weekly storage (pondage)

Power benefits would be based on the general procedures described previously in this chapter. To determine whether the reallocation is economically feasible, the gain in power benefits resulting from the reallocation would be compared with the sum of (a) the incremental loss in benefits to those functions from which storage was transferred and (b) the cost of any required project modifications. A similar analysis would be made when storage is transferred from power to another function. Care should be taken in these analyses to insure that existing water rights are properly accounted for and that compensation is allowed for any water rights which must be purchased to permit the reallocation of storage.

h. Use of Falling Water Charges. Where a non-Federal entity constructs a powerplant at a Corps project, a falling-water charge is assigned to the developer so that he will assume an equitable share of the cost of the structure that provides the benefits he is realizing. These charges are mandated by Section 10(e) of the Federal Power Act (16 USC 803(e)(1976)) and are evaluated by the Federal Energy Regulatory Commission. The Corps of Engineers is not normally involved in this process. The FERC regulation for this purpose is published in the Federal Register, Vol. 49, no. 107, Section 11.2, dated 1 June 1984.

i. Design Analyses.

(1) Estimates of the value of power are sometimes used as the basis of power project design decisions, such as sizing of penstocks, design of transformers, etc. The value of power should be based on the same basic power values that were used in analyzing the power project in the planning stage. They should, however, be updated if necessary to reflect the same price level as the design costs. For some types of analysis (penstock design, for example), both energy and capacity values are involved. In these cases it is sometimes easier to use a total power value expressed in mills/kWh. This value can be computed as follows:

$$\text{Total power value (mills/kWh)} = EV + \frac{(CV) \times (PF)}{(8760 \text{ hours/year})} \qquad \text{(Eq. 9-6)}$$

where: CV = capacity value, \$/kW-yr
PF = hydro project plant factor, decimal fraction
EV = energy value, mills/kWh

(2) Some equipment, such as transformers, produce only an energy loss. However, if that loss is a firm energy loss, an increment of thermal capacity as well as energy will be required to replace it. Hence, analyses of this type of equipment should be based on the total power value, rather than the energy value alone.

(3) Other types of equipment (spare transformers, for example) are intended to improve the reliability of the hydro plant. For multi-unit plants, a change in reliability would affect primarily the capacity benefits. An estimate of the benefits achieved by an improvement in reliability can be estimated using the following equation:

TABLE 9-18
Reduction in Energy Loss Due to
Improvement in Equipment Reliability

Units Available	Energy (gWh)	Initial Conditions FOR	Initial Conditions Loss (gWh)	With Improvements FOR	With Improvements Loss (gWh)	Reduction in Loss (gWh)
1	51	$(0.03)^3$	0.001	$(0.02)^3$	0.000	0.001
2	32	$(0.03)^2$	0.029	$(0.02)^2$	0.013	0.016
3	16	0.03	0.480	0.02	0.320	0.160
Totals	99		0.510		0.333	0.177

$$\text{Benefit} = (IC)x(CV)x \frac{(\Delta \text{ Avail})}{100\%} \qquad \text{(Eq. 9-7)}$$

where: Δ Avail = the change in overall plant availability, in percent.
IC = installed capacity, kW

Alternatively, Δ Avail could be replaced in the equation by (Δ FOR), which is the change in overall plant forced outage rate, in percent.

(4) A change in reliability may also affect the energy output of the hydro plant, especially if it has only a few units. In computing the energy loss, each unit must be treated separately. Table 9-18 illustrates how the energy losses would be reduced at a three-unit plant where the overall forced outage rate is reduced from three percent to two percent. The incremental energy production per unit is obtained from routing studies or from generation-duration curves. The expected average energy losses due to outages would be based upon the sum of the probabilities that one, two, and three units would be out of service. The summation would be obtained from the equation

$$\text{Combined probability} = (FOR)^1 + (FOR)^2 + \dots + (FOR)^n \qquad \text{(Eq. 9-8)}$$

where: n = total number of units in the powerplant.
FOR = unit forced outage rate

Since the incremental energy output of each unit is different, the individual outage probability components must be applied to the corresponding energy values: i.e., $(FOR)^1$ would have to be applied to the incremental energy output of Unit 3, $(FOR)^2$ to Unit 2, and $(FOR)^3$ to Unit 1. In the example shown in Table 9-18, the expected average annual energy loss would be reduced by 0.177 gWh. The current energy value applicable to the hydro project would be applied to determine the average annual benefits attributable to the improvement of equipment reliability. Using the coal-fired energy value from Table 9-5, the annual benefit would be

Annual benefit = (0.177 gWh) x (36.6 mills/kWh) = $6,500.

(5) The revenue rates charged by the regional Power Marketing Administration for power produced by the hydro plant should not be used as the basis of design decisions because they do not represent the economic worth of the power.

j. Delays to On-line Dates.

(1) Occasionally it is necessary to estimate the cost of delays to on-line dates for a powerplant or individual generating units that are already under construction. The only impact on the project's benefits would be an adjustment to account for real fuel cost escalation. Other than that, the delay would only result in slightly deferring the time period in which the benefits would be realized. However, there are two economic consequences which could have an impact on project costs. The first would be an increase in the interest during construction applicable to the costs allocated to power (either for the total plant or to specific generating units, depending upon the nature of the delay). The second would be the cost to the system of purchasing replacement power to meet loads during the period of the delay. A with- and without- analysis must be made to determine any increase in energy costs that would occur to the system because of the delay. This type of information can usually be obtained from the regional Federal Power Marketing Administration (PMA) that would market the power.

(2) The computation of the cost of delays can best be illustrated by an example. Assume that the project on-line date for a 10 MW single purpose power project will be delayed three months, causing it to be unavailable during the peak demand season. During these three months, the plant would have produced peak power at a 20 percent plant factor. In order to meet contractual obligations, the regional PMA has to purchase replacement power at an average cost of 80 mills/kWh. The project, which has a construction cost of

$10,000,000, is 99 percent complete, and the applicable project interest rate is 7-7/8 percent. The cost of the delay would be computed as follows:

Cost of replacement power
= (10,000 kW)(0.20)(92 days)(24 hrs)(80 mills/kWh) = $350,000

Interest during construction
= ($10,000,000)(0.99)(0.07875/yr)(0.25 yr) = $190,000

Total cost of delay = $350,000 + $190,000 = $540,000

(3) Lost revenues are normally not used for this type of analysis. The reasons for not using lost revenues are (a) there will be no loss in the project's lifetime power output, only a deferral of that output, and (b) revenues do not reflect economic values. A case where lost revenue might be used would be in litigation relative to the cost of delays, where it may be necessary to identify the cost to the Government. In these cases, the analysis should be based on lost revenues.

k. Cost of Hydro Plant Outages. Sometimes it is necessary to shut down an existing powerplant (or generating unit) for an extended period of time to modify equipment or the dam structure, or for special operational reasons. When this occurs, a cost is incurred as a result of lost generation, and this cost should be included in the analysis of the outage. The cost assigned to the lost generation should be based on the cost of replacement power, generally as described in the preceding section. The cost of replacement power may vary substantially from season to season, and therefore it may be desirable to schedule the outage for a season when the cost of replacement power is lowest. Where peaking capacity is involved, the outage should be scheduled outside of the peak demand period if possible.

l. Conservation.

(1) ETL 1110-2-216, Energy Conservation for Civil Works, provides guidelines for evaluating potential energy-saving measures at Corps installations, including hydroelectric projects. A savings in electrical energy use at a hydro plant makes that energy available to the power system. Where the measure is long-term or permanent, it will result in an incremental increase in the project's firm energy output. The value of this output would be based on the power values used in evaluating the total hydro project (updated to current price levels and interest rate). These values could be used most readily by converting them to a total energy value in mills/kWh, as described in paragraph 9-10i(1).

(2) It is frequently possible to implement an energy-saving measure relatively quickly. In these cases, it may be preferable to base the value of energy on the cost of displaced energy (Section 9-6) for the first few years (until the date that the long-term power source, the alternative thermal plant, would come on-line). For the remainder of the period of analysis, power values would be based upon the alternative thermal plant.

m. Plants Smaller than 25 MW. Section 2.5.4(b) of Principles and Guidelines states that "...for purposes of ensuring efficiency in the use of planning resources, simplifications of the procedures set forth in Section V are encouraged in the case of single purpose, small scale hydropower projects (25 MW or less), if these simplifications lead to reasonable approximations of benefits and costs." It should be noted, however, that the basic procedure for computing hydropower benefits is relatively straightforward, and where power values are provided in a timely manner by FERC, computation of benefits can be accomplished quite readily. Power value computations can be simplified by basing them on a single representative year (Section 9-4c) and using simplified techniques for estimating system energy value adjustments (Section 9-5e). Reducing the number of alternative hydro plans to a minimum early in the study will also help to keep study costs in line. Other simplifications may be used, depending upon the situation. For example, a marketability analysis may be substituted for a demand analysis in some cases (see Section 3-3). However, it should not be implied from Section 2.5.4(b) of Principles and Guidelines that a marketability analysis can be substituted for the economic evaluation.

n. Non-Federally Financed Projects.

(1) Federal policies being implemented at the time this manual was being prepared encourage the financing of power facilities at Federal Water Resources projects by non-Federal entities. A non-Federal entity planning to construct and operate the hydro plant will require a FERC license. Corps of Engineers involvement in this process relates primarily to technical issues, and not economic analysis.

(2) However, where the non-Federal entity provides funds and the Corps is authorized to construct and operate the plant, the Corps must prepare a feasibility report which would include an economic analysis. Section 2.5.10 of Principles and Guidelines permits an alternative hydropower benefit evaluation procedure that may be used for evaluating "...single purpose projects that are to be 100 percent non-Federally financed, provided that there are no significant incidental costs." In essence, the procedure permits evaluation using the non-Federal entity's financial criteria. However, the formulation of

alternative plans is still subject to the other provisions of Principles and Guidelines, including evaluation of incidental benefits and costs, compliance with environmental laws, and inclusion of appropriate mitigation. Through this process, the most financially attractive plan would be identified. Because benefits and costs of all alternative plans would be evaluated in a consistent way, the most financially attractive plan can be considered a surrogate for the NED plan.

(3) In developing this analysis, Corps planners should work closely with the non-Federal entity in order to select financial evaluation criteria which properly reflect that entity's situation, and to identify those alternative power sources which are actually available to that entity. It should be kept in mind that future revenue streams are more important than power "benefits" in the analysis of non-Federally financed projects. Assistance in developing evaluation criteria can also be provided by the appropriate regional Federal Power Marketing Administration.

(4) Section 2.5.10(b) of Principles and Guidelines suggests basing benefits on industry long-run wholesale prices as one approach. Where this approach is used, it must be carefully applied to insure that the long term contract prices reflect the energy and capacity characteristics of the proposed hydropower project. Another approach would be to do a conventional benefit analysis, using the cost of the most likely thermal alternative, but based on the non-Federal entity's financial criteria.

(5) It should be noted that as of the date of this manual, for the Corps to construct a project and a sponsoring non-Federal entity to receive the power output would require legislative exemption from that portion of the 1944 Flood Control Act which requires that project-produced power be delivered to the Department of Energy for marketing. (see Section 9-9).

o. Firm and Secondary Energy.

(1) In thermal-based power systems, both firm and secondary hydro energy are equally usable in the system load, and there is seldom any need to distinguish between the two (except, in some cases, for marketing purposes). Thus, the energy values developed as described in Sections 9-5 and 9-6 can be applied directly to the project's average annual energy to obtain energy benefits.

(2) However, it is sometimes necessary in hydro-based power systems to evaluate firm and secondary energy separately. If there is normally thermal energy in the system which can be displaced by the hydro secondary energy and the energy values incorporate a system

energy value adjustment (see Section 9-5e), it is usually not necessary to assign separate values to firm and secondary energy. There are at least three situations where separate energy would be required. The first would be in an isolated system, such as in Alaska, where there may be only a limited market for the secondary energy. The second would be in systems where a secondary market normally exists, but in periods of high runoff secondary energy production exceeds the market for such power. The third would be where an export market exists for secondary energy, and where the value of energy to the importing system is different than the value of secondary energy in the system in which the hydro plant is located.

(3) In such cases, firm energy benefits would be based on the energy values defined as described in Section 9-5, and the secondary energy would be evaluated based on an estimate of the amount that would be marketable and the value of the thermal energy that would be displaced by that which is marketable. For example, at a project in Alaska it may be found that, on the average, only about half of the secondary energy is marketable and that this energy could be used to displace existing oil-fired diesel generation. The value of this energy would then be based upon the cost of the diesel generation displaced, computed as described in Section 9-6, and the remainder of the secondary energy would have no value. FERC and the regional Federal Power Marketing Administrations can offer assistance in making this type of analysis.

APPENDIX A

POWER STUDY CHECKLIST

A-1. Introduction. To permit ready review of the power portion of a feasibility study and to ensure proper documentation, enough information must be presented to allow the report to stand on its own. The feasibility report itself normally includes only a brief summary of data and procedures, so the details of the power studies would be presented in a technical appendix.

A-2. Checklist. Following is an outline of the material that should be included in such an appendix. The degree of detail included in each report depends on the type and size of the project. Large or controversial projects may require a more detailed presentation than smaller projects. Those subjects noted with asterisks (*) are items that apply only to certain types of projects or analyses. In the case of "Need For Power," alternative data requirements are presented for both large and small plants (see Section 3-3a). Certain types of projects or studies may require additional data not listed below. For example, pumped-storage studies should present supporting data on selection of the operating cycle and on cost and availability of pumping energy.

1. Project Description
    a. General description of the proposed project
    b. Description of how it fits in existing water control system *
    c. History of power development at the project *

2. Need for Power (for "small" project)
    a. Statement from regional PMA or other sponsoring entities indicating that power is needed

2.1 Need for Power (for "large" project)
    a. Brief description of local economy
    b. Historical power demand
    c. Load forecast
        (1) source of forecast
        (2) forecast methodology
        (3) forecast assumptions
        (4) discussion of forecast uncertainty and alternative scenarios considered
        (5) load forecast by year

(6) reserve requirements
(7) additional power requirements (if any)

d. Resource forecast
(1) description of with-project and without-project conditions
(2) resource projections
(3) discussion of resource uncertainty

e. Load-resource analysis
(1) tabular or graphical comparisons of loads and resources
(2) identification of dates when project output may be needed
(3) impact of alternative load and resource assumptions on need for and timing of project.

3. Hydrology

a. Source of streamflow data, type of data (interval), and length of record

b. Analysis of streamflow record for adequacy

c. Adjustments to streamflow data to modify record
(1) to extend record
(2) to adjust record for upstream regulation, diversions, etc.
(3) to adjust gage data to reflect drainage area at damsite
(4) other adjustments

d. Project operating criteria
(1) description of proposed project operation
(2) downstream channel capacity constraints
(3) list of operating constraints

e. Project characteristics
(1) tailwater curve or tailwater assumptions
(2) storage-elevation curve *
(3) downstream flow requirements
(4) range of expected heads and streamflows

f. Flow unavailable for generation
(1) reservoir diversions *
(2) project water requirements *
(3) leakage and losses

g. Duration curve
(1) flow-duration curves (annual and monthly) *
(2) head-duration curves *

4. Energy Analysis

a. Type of analysis (duration curve vs. sequential routing method)

b. Identification of model used (and brief description if not a standard Corps model).

c. Summary of procedure followed in computing energy output

d. Input assumptions (in addition to those described under hydrology)
   (1) alternative power installations studied (refer also to 5d)
   (2) turbine characteristics
   (3) hydraulic capacity
   (4) efficiency
   (5) head loss
   (6) channel routing assumptions
   (7) generation requirements *
e. Power operation criteria including basis for selection of criteria (where alternative criteria were tested, describe each).
   (1) maximize firm energy vs. maximize average energy vs. maximize dependable capacity, etc.
   (2) base load vs. peaking
   (3) other alternative operations
f. Output (for duration curve analysis)
   (1) total energy potential for the site
   (2) average annual energy
   (3) annual generation-duration curve
   (4) generation-duration curve for peak demand months
   (5) monthly distribution of generation
   (6) monthly generation-duration curves (optional) *
f.1 Output (for sequential routing analysis)
   (1) identification of critical period, including basis for selection *
   (2) total energy potential (for the site)
   (3) average annual energy (for each plant size)
   (4) firm annual energy *
   (5) monthly distribution of generation (firm * and average)
   (6) month by month generation for period of record
   (7) impact on operation of other projects (system benefits, encroachment on adjacent projects, etc.) *
g. Transmission losses

5. Capacity Analysis
   a. Marketability (types of power needed in system)
   b. Physical constraints
   c. Environmental and operating constraints
   d. Selection of range of alternatives considered
      (1) alternative operating modes *
      (2) range of alternative plant sizes
      (3) alternative methods considered for firming up peaking capacity *
      (4) reregulating dam *
      (5) other variables considered *

e. Dependable capacity
    (1) method used and basis for selecting method
    (2) dependable capacity for each alternative
f. Transmission losses *

6. Powerplant Features
    a. General description
    b. Alternative powerhouse sites considered *
    c. Turbines
    d. Generators
    e. Governors
    f. Auxiliary equipment
    g. Connection to load
    h. Control equipment

7. Project Costs and Schedule
    a. Summary of construction cost estimate by feature
    b. Construction schedule
    c. Interest during construction
    d. Investment cost
    e. Transmission costs, including basis for costs
    f. Annual costs
        (1) project interest rate
        (2) project life, including basis for assumed life
        (3) interest and amortization
        (4) operating and maintenance costs, including basis for costs
        (5) interim replacement costs, including basis for costs
        (6) pumping energy costs, including basis for costs (for pumped-storage projects only) *

8. Power Benefits
    a. Method for computing benefits
    b. Description of with-project and without-project system
    c. Power values and required supporting data
    d. Adjustments made to power values and basis for adjustment *
    e. Calculation of benefits

9. Marketability Statement (statement from regional PMA that power is marketable and that costs can be repaid with interest in 50 years).

APPENDIX B

LOAD FORECASTING METHODS

B-1. General.

a. A model is a mathematical description of how the complex elements of a real-life situation or problem might interplay at some future date. In projecting electricity demand, a modeler uses data on electricity prices, income, population, the economy, and the growth rates for each and then varies the mix according to varying sets of assumptions. Different assumptions produce different outcomes. The relationships between electricity demand and the multitude of factors that influence or affect electricity demand are expressed in mathematical equations called functions. A model is a collection of functions. A function, in turn, is made up of variables - those factors which change or can be changed. Independent variables are those factors which influence the demand for electricity, and the dependent variable is electricity demand itself. In other words, the demand for electricity depends on population, income, prices, etc. Finally, elasticities describe how much the dependent variable (electricity demand) changes in response to small changes in the independent variables. Elasticities are what the modeler uses to measure consumer behavior.

b. Energy planners often speak of scenarios - hypothetical pictures of the future based on different assumptions about economic or political events. They make different projections for each scenario. For example, a low-growth scenario might assume high energy prices and slow population growth, while a high-growth scenario would assume the opposite. These scenarios allow planners to see how electricity demand might change if the different assumed economic and political events actually occur. All of the forecasting methods are capable of looking at different scenarios and do so by changing their basic assumptions.

B-2. Types of Models.

a. Introduction. The three types of electricity demand forecasting methods (or models) are: trend analysis, end-use analysis, and econometrics. Each of the three forecasting methods uses a different approach to determine electricity demand during a specific year in a particular place. Each forecasting method is distinctive in its handling of the four basic forecast ingredients: (a) the mathematical expressions of the relationship between electricity demand and the factors which influence or affect it - the functions; (b) the factors which actually influence electricity demand (population, income, prices, etc.) - the independent variables; (c) electricity demand itself - the dependent variable; and (d) how much electricity demand changes in response to population, income, price, etc., changes - the elasticities.

b. Trend Analysis.

(1) Trend analysis (trending) extends past growth rates of electricity demand into the future, using techniques that range from hand-drawn straight lines to complex computer-produced curves. These extensions constitute the forecast. Trend analysis focuses on past changes or movements in electricity demand and uses them to predict future changes in electricity demand. Usually, there is not much explanation of why demand acts as it does, in the past or in the future. Trending is frequently modified by informed judgement, wherein utility forecasters modify their forecasts based on their knowledge of future developments which might make future electricity demand behave differently than it has in the past.

(2) The advantage of trend analysis is that it is simple, quick and inexpensive to perform. It is useful when there is not enough data to use more sophisticated methods or when time and funding do not allow for a more elaborate approach.

(3) The disadvantage of a trend forecast is that it produces only one result - future electricity demand. It does not help analyze why electricity demand behaves the way it does, and it provides no means to accurately measure how changes in energy prices or government policies (for instance) influence electricity demand. Because the assumptions used to make the forecast (informed judgements) are usually not spelled out, there is often no way to measure the impact of a change in one of the assumptions. Another shortcoming of trend analysis is that it relies on past patterns of electricity demand to project future patterns of electricity demand. This simplified view of electrical energy could lead to inaccurate forecasts in times of change, especially when new concepts such as conservation and load management must be included in the analysis.

c. End-Use Analysis.

(1) The basic idea of end-use analysis is that the demand for electricity depends on what it is used for (the end-use). For instance, by studying historical data to find out how much electricity is used for individual electrical appliances in homes, then multiplying that number by the projected number of appliances in each home and multiplying again by the projected number of homes, an estimate of how

much electricity will be needed to run all household appliances in a geographical area during any particular year in the future can be determined. Using similar techniques for electricity used in business and industry, then adding up the totals for residential, commercial, and industrial sectors, a total forecast of electricity demand can be derived. The advantages of end-use analysis is that it identifies exactly where electricity goes, how much is used for each purpose, and the potential for additional conservation for each end-use. End-use analysis provides specific information on how energy requirements can be reduced over time from conservation measures such as improved insulation levels, increased use of storm windows, building code changes, or improved appliance efficiencies. An end-use model also breaks down electricity into residential, commercial and industrial demands. Such a model can be used to forecast load changes caused by changes within one sector (residential, for example) and load changes resulting indirectly from changes in the other two sectors. Commercial sector end-use models currently being developed have the capability of making energy demand forecasts by end-uses as specific as type of business and type of building. This is a major improvement over projecting only sector-wide energy consumption and using economic and demographic data for large geographical areas.

(2) The disadvantage of end-use analysis is that most end-use models assume a constant relationship between electricity and end-use (electricity per appliance, or electricity used per dollar of industrial output). This might hold true over a few years, but over a 10- or 20-year period, energy savings technology or energy prices will undoubtedly change, and the relationships will not remain constant. End-use analysis also requires extensive data, since all relationships between electric load and all the many end-uses must be calculated as precisely as possible. Data on the existing stock of energy-consuming capital (buildings, machinery, etc.) in many cases is very limited. Also, if the data needed for end-use analysis is not current, it may not accurately reflect either present or future conditions, and this can affect the accuracy of the forecast. Finally, end-use analysis, without an econometric component (discussed next), does not take price changes (elasticity of demand) in electricity or other competing fuels into consideration.

d. Econometrics.

(1) Econometrics uses economics, mathematics, and statistics to forecast electricity demand. Econometrics is a combination of trend analysis and end-use analysis, but it does not make the trend-analyst's assumption that future electricity demand can be projected based on past demand. Moreover, unlike many end-use models, econometrics can allow for variations in the relationship between electricity input and end-use.

(2) Econometrics uses complex mathematical equations to show past relationships between electricity demand and the factors which influence that demand. For instance, an equation can show how electricity demand in the past reacted to population growth, price changes, etc. For each influencing factor, the equation can show whether the factor caused an increase or decrease in electricity demand, as well as the size (in percent) of the increase or decrease. For price changes, the equation can also show how long it took consumers to respond to the changes. The equation is then tested and fine tuned to make sure that it is as reliable a representation as possible of the past relationships. Once this is done, projected values of demand-influencing factors (population, income, prices) are put into the equation to make the forecast. A similar procedure is followed for all of the equations in the model.

(3) The advantages of econometrics are that it provides detailed information on future levels of electricity demand, why future electricity demand increases or decreases, and how electricity demand is affected by all the various factors discussed in this section. In addition, it provides separate load forecasts for residential, commercial, and industrial sectors. Because the econometric model is defined in terms of a multitude of factors (policy factors, price factors, end-use factors), it is flexible and useful for analyzing load growth under different scenarios.

(4) A disadvantage of econometric forecasting is that in order for an econometric forecast to be accurate, the changes in electricity demand caused by changes in the factors influencing that demand must remain the same in the forecast period as in the past. This assumption (which is called constant elasticities) may be hard to justify, especially where very large electricity price changes (as opposed to small, gradual changes) make consumers more sensitive to electricity prices.

(5) Also, the econometric load forecast can only be as accurate as the forecasts of factors which influence demand. Because the future is not known, projections of very important demand-influencing factors such as electricity, natural gas, or oil prices over a 10- or 20-year period are, at best, educated guesses. Finally, many of the demand-influencing factors which may be treated and projected individually in the mathematical equations could actually depend on each other, and it is difficult to determine the nature of these interrelationships. For example, higher industrial electricity rates may decrease industrial employment, and projecting both of them to increase at the same time may be incorrect. A model which treats projected industrial electricity rates and industrial employment separately would not show this fact.

(6) Econometric models work best when forecasting at national, regional, or state levels. For smaller geographical areas, meeting the extensive data needs of the model can be a problem. This is because most utilities have oddly shaped service areas for which there is no published economic or demographic data.

B-3. Forecasting Accuracy. The only way to determine the accuracy of any load forecast is to wait until the forecast year has ended and then compare the actual load to the forecast load. Even though the whole idea of forecasts is accuracy, nothing was said in the comparison of the three forecasting methods about which method produces the most accurate forecasts. The only thing certain about any long-range forecast is that it can never be absolutely precise. Forecasting accuracy depends on the quality and quantity of the historical data used, the validity of the forecaster's basic assumptions, and the accuracy of the forecasts of the demand-influencing factors (population, income, price, etc.). None of these is ever perfect. Consequently, regional load forecasts are reviewed continually, and some are revised yearly. Even so, there is simply no assurance that electricity demand will be exactly as forecast, no matter what method is used or who makes the forecast.

APPENDIX C

COMPUTER MODELS FOR POWER STUDIES

C-1. Introduction.

a. This appendix briefly describes some of the computer models being generally used for power studies within the Corps of Engineers at the present time. While many models have been developed and used within the Corps over the years, not all are included here. Some are tailored to the specific needs of individual field offices. Others are almost identical to more commonly used models, and still others are now obsolete. However, examples of all of the major types of models have been included. The following models are described:

- Flow-duration models (Section C-2)
  - HYDUR
  - NAVOP
- Sequential streamflow routing models (Section C-3)
  - HEC-5
  - SUPER
  - HYSSR
  - RESOP
  - HLDPA (hourly)
  - HYSYS (hourly)
- Hybrid models (Section C-4)
  - DURAPLOT

b. The descriptions of the models and their capabilities are based on their status at the time of this manual's publication. Most of these models were designed with flexibility in mind, and they are being modified or expanded from time to time as needed to handle new types of problems. Hence, if special needs develop which appear to be beyond the capabilities of a given model, it is suggested that the office responsible for maintaining that model be contacted in order to determine the current state of the model and to determine whether the model could be adapted to meet those needs.

C-2. Flow-Duration Models.

a. General.

(1) The basic concepts of flow-duration energy analyses are relatively simple, and as a result, a number of models have been

developed at different Corps field offices. While all of these models are generally similar, each is tailored to the specific data base which is being utilized for streamflows, the degree of detail required, and the type of output desired. For example, while most models utilize USGS streamflow records, both Little Rock District and Southwestern Division have developed models which utilize daily flows generated by the SUPER Model (Section C-3(o)). Little Rock's model was designed to examine alternative turbine types, and thus reflects the variation of efficiency with discharge. Southwestern Division's model can automatically load alternative combinations of units to select the combination that produces maximum energy at each flow level, based on operating for peaking whenever conditions permit.

(2) Space does not permit a detailed discussion of each of the existing models. However, two models which have more general applicability will be briefly described: HEC's HYDUR model and Ohio River Division's NAVOP model.

(3) Another useful general model is North Pacific Division's DURAPLOT model. DURAPLOT can examine projects where head varies independently of streamflow. It is designed to compute power from sequential streamflow and reservoir elevation records prior to developing the duration curves, so it must be classified as a hybrid model rather than a true flow-duration model. DURAPLOT is described in Section C-4.

b. HYDUR.

(1) HYDUR is a standard flow-duration model with various options that permit it to address a variety of energy analyses. Some of the model's options are listed as follows:

- can derive annual, seasonal, or monthly data
- can input flow-duration curve or develop curve from user-specified data files
- can utilize GETUSGS technique for evaluating ungaged sites
- will account for upstream diversions or flow losses at dam
- can input tailwater curve or fixed average tailwater
- can input fixed average forebay elevation or forebay elevation vs. discharge curve
- can input fixed average efficiency or efficiency vs. discharge curve
- can specify maximum penstock discharge
- can adjust flow-duration curve to reflect effects of power storage (see Section 5-7m)
- can analyze either run-of-river or peaking (block load) operation (see Section 5-6g)

- will compute dependable capacity based on specified availability (Section 6-7f)
- will compute average annual energy or average energy by month or season
- will compute firm energy based on specified minimum plant factor or energy available at dependable capacity

(2) The model can also compute power benefits, estimate project costs, and select the plant size that provides maximum net benefits. The cost data and procedures used for doing these analyses were developed for the National Hydropower Study and as such should be considered applicable only to screening analyses.

(3) Documentation for the model is contained in HYDUR, Hydropower Analysis Using Streamflow Duration Procedures: Users Manual, (45). Copies of the manual and further information on using the model can be obtained from the Corps of Engineer's Hydrologic Engineering Center, 609 Second Street, Davis, CA 95616.

c. NAVOP.

(1) NAVOP is a standard flow-duration model which evaluates the viability of low head hydro installations. The program is particularly applicable to for the analysis of addition of hydropower to existing low head dams. Two modes of operation may be specified: (a) run-of-river operation, where the inflow equals the turbine discharge plus the spill, leakage loss and navigation releases, or (b) limited peaking operation, where the pool is allowed to draw down during a specified length of time each day. The required data needed to run the model either in run-of-river or peaking mode are listed below:

- flow-duration curves for each month (based on either daily or mean monthly flows)
- turbine characteristics, including number of turbines
- maximum, minimum, and rated heads for the turbine
- efficiency of the turbine and generator
- minimum turbine discharge
- headwater and tailwater rating curves
- outage rate expressed as the fraction of time that the plant is shut down due to forced outages
- number of peaking hours per day
- maximum and minimum allowable pool elevations
- maximum allowable difference in tailwater fluctuation
- minimum required releases each month

(2) The model may be used to determine average monthly and annual energy available at a particular site. The program output consists of monthly duration curves of head, spill, turbine discharge, and plant capacity, for either run-of-river or peaking operation. A summary of monthly energy production, dependable capacity (based on a specified availability), intermittent capacity, and average capacity is also shown in the output. In addition, a summary of these parameters can also be provided to describe operation in the peaking mode.

(3) The model can also compute headwater elevations when only spillway discharge, crest elevation, and crest length are given. Several user-specified options are also included in the model. These options include controls for executing another simulation using the same data but varying the number and/or capacity of turbines during multiple runs.

(4) A user manual is available. For further information, contact the Plan Formulation Branch, Ohio River Division, PO Box 1159, Cincinnati, Ohio 45201.

C-3. Sequential Streamflow Routing Models.

a. General.

(1) Hand routing can sometimes be used for examination of single storage projects where non-power operation is well defined, but where non-power operating functions are complex, when storage operation is to be optimized, or where the project is to be operated as a part of a system, computerized SSR models must be used. A wide variety of seasonal SSR models have been developed over the years for estimating power potential in conjunction with other functions. Some of these models are generalized, and others have been developed to meet the needs and characteristics of a specific basin.

(2) Following are brief descriptiona of several of the most extensively used seasonal regulation models in the Corps: the Hydrologic Engineering Center's HEC-5, Southwestern Division's SUPER model, North Pacific Division's HYSSR model, and Ohio River Division's RESOP model. Other models have also been used in the Corps, including HEC-3 and models developed by the Alaska and Fort Worth Districts.

(3) Several models also address hourly problems, including, in addition to HEC-5, North Pacific Division's HLDPA model and the HYSYS model. These models are also described below.

(4) Sources of background information on the system aspects of reservoir modeling are references (19), (23), and (34). A number of modeling techniques and applications to different types of basins are described in these publications. Other information can be found in the proceedings of the American Society of Civil Engineers and the Institute of Electrical and Electronic Engineers.

b. HEC-5.

(1) General. HEC-5 is a general-purpose reservoir simulation model developed by the Hydrologic Engineering Center to evaluate a wide variety of flood control and conservation storage projects, including hydropower analysis. The program can be used efficiently for single reservoirs or for complete reservoir systems on either critical period or period of record studies.

(2) Driving Functions. The model is designed to simultaneously meet flood control criteria and conservation requirements within other operating constraints. Conservation requirements can be expressed in terms of seasonal flow requirements or seasonal generation requirements, at specific reservoirs or as seasonal flow requirements at downstream control points. Each demand may be served by one or more upstream reservoirs based upon input data. System operations are performed for flood control, water supply, and hydropower, where more than one reservoir is operated for a common location.

(3) Number of Projects. The model is presently designed to handle a total of 35 reservoirs and 55 control points, but arrays can easily be increased or decreased.

(4) Routing Interval. The model can use multi-hourly, daily, weekly, or monthly intervals. Continuous simulations can also be made using a combination of these intervals. For instance, weekly or monthly intervals can be used for non-flood periods and daily (or shorter) intervals can be used during flood periods.

(5) Channel Routing Methods. Six channel routing procedures are presently available: Muskingum, Modified Puls, Working R & D, Tatum, Straddle-Stagger, and Lag. For daily (or shorter) routing intervals, flows may be routed throughout the system in downstream sequence. Diversions may also be routed using a different routing network.

(6) Flood Control Operations. Flood control operation of projects having either gated or uncontrolled outlets is a fundamental part of the model. Reservoirs with gated outlets are operated for each time period to prevent downstream flooding and to evacuate flood control storage as quickly as possible without exceeding maximum flow levels at one or more downstream control points. Emergency gate

regulation criteria can be specified to override flood control releases for downstream locations, which are based upon seasonal balancing of input storage target levels.

(7) Power Operations. The model is designed to make power releases to meet user-specified firm energy requirements (often expressed as monthly plant factors) within non-power operating constraints. This criteria results in full use of power storage in critical water years, but in good water years, it generally maintains the reservoir as close to the top of the power pool as possible. Not specifying firm energy requirements provides an alternative strategy that will maximize the average annual energy output. Period-by-period (monthly, daily, and hourly) energy requirements can be specified, or the model can be run in an optimization mode, to automatically select the critical period and determine the maximum amount of firm energy that can be produced. Seasonal rule curve operation can be accomplished where energy requirements vary with elevation in the power pool. Pumped-storage projects can also be simulated.

(8) System Operation. Reservoirs are drafted proportionally to meet user-defined reservoir storage balancing levels to the extent possible within power and non-power operating constraints in order to meet user-specified system energy requirements for up to two different hydropower systems. Thermal loads are not simulated by the model, so they must be subtracted from the input hydropower system loads. Water supply and flood control system operation are also made based upon balancing reservoir storage levels.

(9) Documentation. A users manual, entitled HEC-5, Simulation of Flood Control and Conservation Systems, (40) is available. HEC Training Document No. 12, Application of the HEC-5 Hydropower Routines (included as Appendix K to this manual) provides additional details on the use of HEC-5 for hydropower analysis. Regularly scheduled training courses and video tapes are available from the HEC to provide instruction in the use of HEC-5. For additional information, contact the Hydrologic Engineering Center, 609 Second Street, Davis, CA 95616.

(10) Applicability. HEC-5 is well-suited to examining the power potential of single storage projects or systems of reservoirs, where the projects are operated for hydropower alone or for flood control and other conservation purposes in addition to power. The model has been applied to many systems throughout the U.S. and overseas where hydropower is one of the project or system purposes.

c. SUPER.

(1) General. SUPER is a system of computer programs developed by Southwestern Division to simulate the daily sequential regulation of a multiple-purpose system of reservoirs and the corresponding hydrologic and economic impacts. The simulation is based on a specific plan of regulation, specific economic parameters, and a long period of daily hydrologic input. The model provides a way to compare alternative system regulation plans by providing hydrologic and economic results for each simulation.

(2) Driving Functions. The model is designed to simultaneously meet flood control objectives and conservation storage requirements within the specified operating constraints. Water supply requirements are expressed as seasonal pipeline system demands and seasonal streamflow requirements to be maintained at downstream control points. Eaoh demand may be served by one or more reservoirs as specified. Generation requirements are based on seasonal system load requirements and thermal purchase criteria as a function of system state. The daily generation schedule may be provided seasonally as a function of system or individual reservoir state.

(3) Number of Projects. The model is designed to handle any number of reservoir projects within the limitations of the computer system. Presently the maximum number of reservoirs included in a single model has been 40.

(4) Routing Interval. The model uses a one-day routing interval. However, the system power load filling routine is based on an hourly load requirement.

(5) Channel Routing Methods. The model uses the Muskingum Method to route reservoir releases downstream. The basic discharge hydrograph data input is total uncontrolled area flow at each stream control point and at each reservoir inflow point. These total uncontrolled area flows are developed by use of the Modified Puls streamflow routing procedure.

(6) Flood Control Operations. Reservoirs are regulated on a daily basis to stay within downstream maximum flow levels. These flow levels are expressed as a function of season and system or reservoir state. Priority of releases among reservoirs is based on seasonal balance levels which subdivide the flood control storage. On each day of the simulation, a tentative schedule of flood releases is developed for the next several days. This schedule takes into account downstream maximum flow levels, system balance and maximum allowable daily rate of release change.

(7) Power Operation. Power is produced for multiple system loads. Each particular reservoir, however, is assigned to a specific system. System loads are expressed seasonally, according to system state. Mandatory flood control and low flow releases are the first categories of flow used to generate power. Any excess energy above system local requirements is counted as dump energy. The necessity for thermal purchase as a function of system state and season is then determined. The remaindar of the load is then satisfied, if possible, taking into account available power storage, generating capacity and remaining available channel capacity. Any deficiencies are accounted for as additional thermal purchase. The daily operation factor may be expressed seasonally as a function of reservoir or system state as an option separate from the seasonal system load and thermal purchase option.

(8) System Operation. Reservoirs are operated within operating constraints as much as possible, in order to maintain seasonal reservoir balance in each system for both the flood control and the conservation storage zones.

(9) Documentation. Users manuals are available from the SWD for data base development, operation of the model, and display of the simulation and evaluation results. For further information, contact the Water Management Branch, Southwestern Division, 1114 Commerce St., Dallas, Texas, 75242.

(10) Applicability. The model is suited to the overall evaluation of multiple-purpose regulation objectives for large reservoir systems. The model's planning mode can also be used to evaluate various alternative power plants at a single reservoir by interfacing each reservoir model with the output from the total system model. The data required at the interface is the period of record daily inflows and flood pool balance levels for the reservoir being evaluated. The model thus provides an economical way to make period of record routings for the single reservoir with various power plants while maintaining flood control operations very close to those which would be obtained if the total system model had been utilized. The Tulsa District's Production Cost Avoidance (PCA) hydropower evaluation method (see Section 5-13d(3)) is incorporated in this model to develop both the hydrologic operation and the economic value of a specific hydropower alternative in a single computer run. This model requires extensive training and data base development. However, once a modeled system is established, it is relatively easy to make hydropower evaluations for various alternatives for any reservoir in the system.

d. HYSSR.

(1) General. HYSSR is a monthly sequential routing model that is designed to analyze the operation of a large reservoir system primarily for power and snowmelt flood control. The model was originally developed by North Pacific Division as a planning tool to examine alternative reservoir systems in the Columbia River Basin, and it is now being used in addition for operational planning. HYSSR has also been used in other basins as well, including the Mekong River Basin of Southeast Asia, where floods are of the monsoon type, and elsewhere.

(2) Driving Functions. This model is designed to meet a residual system power load (total system power load less expected thermal plant output) within the constraints of other project functions. These constraints include flood control, minimum in-stream flows for fish passage at downstream control points, minimum releases from individual projects for fish and wildlife and other purposes, and desired reservoir elevations for fish spawning, at-site recreation, and irrigation pumping.

(3) Number of Projects. The model currently handles a total of 150 projects, including 50 seasonal reservoirs.

(4) Routing Interval. The model normally uses a monthly interval. although half-month intervals can be used in months where reservoir operation changes in mid-month.

(5) Channel Routing Method. Because a monthly interval is used, detailed channel routing is not required.

(6) Flood Control Operation. Flood control operation is designed to simulate forecastable seasonal snowmelt floods. The actual day-by-day routing of each annual flood in the period of record is accomplished outside of HYSSR using the NPD's SSARR model (56). The results of the flood control regulation are translated into monthly guide curves and release schedules, which are provided as input to the HYSSR model. These curves and release schedules reflect the progressively decreasing uncertainty associated with a snowmelt type flood. Unless the flood control operating criteria are modified, it is not necessary to change the flood operation input from run to run.

(7) Power Operation. The objective of the power operation is to maximize firm energy load carrying capability. Rule curves are based on operation in a multi-year critical period. Because of the large size of the system and the large number of operating constraints,

optimization is done manually. The details of the Pacific Northwest power operation upon which the model is based are described more fully in Appendix L.

(8) System Operation. The major requirements which the Columbia River Basin projects must meet (power generation, flood control, navigation, fish flows, etc.) are for the most part system requirements, so the HYSSR model has been designed such that the reservoirs are operated to meet system requirements. The general objective is to proportionally draft headwater storage projects within non-power operating constraints in order to maintain head and thus maximize power production. Downstream storage projects are not usually drafted until required for flood control operation. The model is designed to handle operation of both annual and cyclical (multi-year) storage projects simultaneously.

(9) Documentation. The user's manual is entitled HYSSR (Hydro System Seasonal Regulation); Program User's Manual (46). For additional information, contact Power Section, North Pacific Division, PO Box 2870, Portland, Oregon, 97208.

(10) Applicability. HYSSR is best suited to the analysis of medium to large systems of projects where hydropower is a major function and flood control operation is well defined seasonally, such as with snowmelt and monsoon type floods. HYSSR is used in conjunction with SSARR to simulate flood control operation and with HLDPA (discussed below) to simulate hourly power operation.

e. RESOP.

(1) General. RESOP is a sequential routing model that was developed by Ohio River Division for examining the energy potential of an individual reservoir (either a storage project or a run-of-river project).

(2) Driving Function. The model is designed to operate a project to meet non-power requirements and operating constraints and, from the resulting regulation, determine the amount of power that could be produced. The simulation is based on rule curves, maximum reservoir elevation constraints defined by the flow regimes, and meeting any combination of the following operating parameters and constraints:

- reservoir surface evaporation
- minimum discharge requirements
- minimum power releases
- releases to meet non-power water requirements
- consumptive withdrawals from the reservoir
- powerplant characteristics

- tailwater constraints
- reservoir elevation constraints
- oil displacement parameters (for on-peak power)
- peaking time in hours per day

(3) Number of Projects. The model is designed to examine single projects.

(4) Routing Interval. Separate versions of the model use daily and monthly routing intervals.

(5) Channel Routing Method. Downstream effects are not considered.

(6) Flood Control Operation. For flood control projects the model follows the established (or specified) flood regulation procedures.

(7) Power Operation. The model is designed essentially to produce power while meeting non-power requirements and other operating constraints. There is no provision for seasonal regulation of conservation storage to maximize power production. However, one option evaluates the potential for peaking operation. This is done by specifying the number of on-peak hours per day in which generation is desired. The model then determines the amount of capacity that can be supported in each day given the daily average power discharge and the various operating constraints. When operating in the peaking mode, energy produced in the off-peak hours is classified as secondary energy. Dependable capacity is computed based on a specified availability (normally 90 percent) in the peak load months. Another option computes power benefits using specified regional power values.

(8) System Operation. Because the model is designed for examining single projects, system operation capability is unnecessary.

(9) Documentation. A user manual is available. For further information, contact the Plan Formulation Branch, Ohio River Division, PO Box 1159, Cincinnati, Ohio 45201.

f. HLDPA.

(1) General. North Pacific Division developed the Hourly Load Distribution and Pondage Analysis Program (HLDPA) as a planning tool to address such problems as optimum installed capacity, adequacy of pondage for peaking operation, and impact of hourly operation on non-power river uses.

(2) Driving Function. This model efficiently allocates a residual hourly power load to hydro projects in a system while meeting non-power operating constraints.

(3) Number of Projects. HLDPA is designed to handle a total of 50 projects, including both run-of-river and storage projects.

(4) Routing Interval. The model uses an hourly interval and examines one week at a time.

(5) Channel Routing Method. A simplified channel routing technique routes streamflow from project to projects. A more sophisticated model, such as SSARR (56) or SOCH (Simulation of Open Channel Hydraulics) should be used to examine water surface fluctuation at intermediate points on a reservoir or at downstream points. Hourly project discharges from HLDPA are used as input.

(6) Flood Control Operation. HLDPA uses monthly average project discharges and reservoir elevations from HYSSR (or another seasonal model) as input data, and these values reflect seasonal operation for flood control as well as seasonal storage regulation for power and other conservation functions.

(7) Power Operation. (See paragraph (2), Driving Function, above). The residual load to be met is the difference between total system hourly load and the expected load to be carried by thermal generation. This results in hydro normally being assigned to carry the peaking portion of the load. Pumped-storage can be included as a specific project.

(8) System Operation. Hourly loads are allocated among projects in accordance with plant generating capability, hydraulic capacity, operating constraints, and characteristics of adjacent plants.

(9) Documentation. A user's manual for the Hourly Load Distribution and Pondage Analysis Program, commonly known as the "Pondage Program," is available from NPD (42). For further information, contact Power Section, North Pacific Division, PO Box 2870, Portland, Oregon, 97208.

(10) Applicability. HLDPA is a planning tool and is best suited to examining hourly operation of peaking projects as a part of a system. It would normally be used in conjunction with a seasonal routing model such as HYSSR or HEC-5. The seasonal model would be used to develop the basic regulation using a weekly or monthly time interval, and HLDPA would be used to examine selected weeks in detail.

g. HYSYS.

(1) General. The Hydropower System Regulation Analysis (HYSYS) computer program was originally developed by the North Pacific Division, Corps of Engineers. The program is generalized so that it can be adapted for use on most hydropower systems where simulation of real-time conditions are desired. The program performs sequential river and reservoir routings that simulate reservoir regulation to meet a system power load. Emphasis is given to the evaluation of short-term projections, such as hourly generation determinations. While it was developed primarily as an operational tool, it can also be used in project planning in situations where detailed hourly simulations are required.

(2) Driving Functions. This program is designed to meet a residual system power load (total system power load less expected thermal plan output) within the constraints of non-power project functions. These constraints include flood control, minimum instream flows for fish passage and navigation, minimum releases from individual projects for fish and wildlife, and desired reservoir elevations for fish spawning, at-site recreation, and irrigation pumping. Given the projected system power load, fixed thermal generation schedule, and projected inflows, the program simulates the allocation of power to the individual projects Some projects may be constrained by specific schedules of releases or elevations, while others operate on power load control to meet the remaining system load. The program is also capable of simulating predetermined regulation schedules at all projects in order to provide the resultant system generation. The program does not contain optimization procedures, but optimal or desired regulation ranges are specified to the program and the program operates within the desired ranges to best meet the system load.

(3) Number of Projects. The program handles a total of 30 control points. A control point can be either a river station or a project.

(4) Routing Interval. The routing interval for projects can be as short as one hour or as long as 24 hours. Routing intervals for river reaches can be as short as one minute, but intervals of one hour or longer must be multiples of 60 minutes. This feature allows the program to more closely simulate the dynamic process in channel flow by placing emphasis on determining the tailwater elevations for detailed generation analysis. The program is capable of routing up to 168 periods. Therefore, the program can simulate a full week of hourly regulation. Using routing intervals of one day, a total of 168 days can be simulated.

(5) Channel Routing Method. The program uses the channel storage routing procedure to simulate river and flow/stage characteristics. Channel routing is accomplished as a series of incremental river reaches described in terms of storage/stage vs. discharge.

(6) Flood Control Operation. The model does not in itself perform flood control regulation, but uses as input data streamflows which already reflect flood regulation.

(7) Power Operation. The basic power operation procedure is described above, under paragraph (2), Driving Functions. Individual generating unit characteristics are described in the program, and units are loaded to take advantage of the best operating efficiency. By doing so, the program determines the optimum number of units required to meet various loads.

(8) System Operation. The program can operate in two different modes: (a) a system load is provided and generation is allocated to individual projects, or (b) a scheduled discharge, generation, or pool elevation pattern is provided and the resulting system generation is computed. The general objective of the system load mode is to proportionally draft or fill headwater storage projects to meet desired system generation targets. At the same time, pool fluctuations are minimized at pondage projects to maximize power production. The same general approach is followed in mode (b), except that pre-specified project operating data constrains the operation.

(9) Documentation. The user manual is entitled Hydropower System Regulation Analysis. For additional information, contact Chuck Abraham, Central Valley Operations Office, Bureau of Reclamation, 2800 Cottage Way, Sacramento, CA 95825.

(10) Applicability. For planning purposes, HYSYS is best suited for detailed hourly examination of individual power projects or groups of projects under varying operational assumptions. For example, the project or projects could be tested under different power loadings to determine adequacy of pondage, impact on tailwater elevation, etc. HYSYS requires more detailed input data than HLDPA, and is thus more cumbersome to use, but it has the advantage of being able to examine the impacts of specified project operations. HYSYS has also been used in planning day-to-day project operation.

C-4. Hybrid Method.

a. General. North Pacific Division's DURAPLOT is the only specifically designed hybrid model currently being used in the Corps.

It was developed primarily to examine the installation of power at existing non-power storage projects but has also been used for run-of-river projects. Similar routines could also be added to system regulation models such as HEC-5 and SUPER to access the output files from the system studies. These could be used in conjunction with output files for detailed examination of single projects, and thus it would not be necessary to rerun the entire system model for each alternate power installation.

b. DURAPLOT.

(1) Description. DURAPLOT is used to estimate the generation potential of a specific plant. Given the appropriate input data, the program uses the power equation,

$$P = \frac{QHe}{11.81} \qquad \text{(Eq. 5-2)}$$

to compute the average plant generation for each day in the period of record. The resulting daily generation data is then used to produce power-duration curve plots and tables, which summarize the plant capacity and energy potential. The program allows the user to place separate minimum and maximum head and flow constraints on each turbine-generator unit. Thus, the user is able to study, with minimal effort, any number of possible unit configurations using daily hydrologic data.

(2) Options. DURAPLOT normally accesses historical streamflow records, although any user-supplied streamflow and reservoir elevation data could be utilized. Options are listed below:

- can do analysis of total year, months, or a user-specified multiple-month peak demand season.
- will account for upstream diversions or losses at the dam.
- can input tailwater curve, fixed average tailwater elevation, or can input historical tailwater data if the elevation varies independently of flow.
- can input fixed average efficiency or efficiency as a function of head.
- will compute average annual energy or average energy by month or season.

- can define head loss either as a fixed value or as a function of flow.

- dependable capacity computed as average power output in peak demand season (average availability method, Section 6-7g).

- can use a fixed average forebay elevation or a seasonally varying forebay elevation (to reflect the seasonal use of flashboards at run-at-river projects).

- can specify the use of multiple units with varying head ranges.

- can examine projects where the reservoir fluctuation range exceeds the operating range of a single turbine.

(3) Input Data. Input data would be essentially the same as for the flow-duration curve method except that daily values of reservoir elevation must be provided in addition to daily streamflow values. This data could be obtained from USGS records, project operating records, or from system regulation models such as SUPER. As with the flow-duration method, daily data would be used in most cases.

(4) Output. Monthly, seasonal, and annual power-duration (Figure 5-60), flow-duration, and head-duration plots are available, as well as a bar chart showing monthly distribution of energy production (Figure C-1). The flow-duration and head-duration curves are useful in selecting turbines, and the monthly energy distribution chart is helpful in assessing marketability of the power.

(5) Sources of Information. Further information on DURAPLOT can be obtained from Power Section, North Pacific Division, PO Box 2870, Portland, Oregon, 97208.

(6) Applicability. The Corps of Engineers has used the DURAPLOT program primarily to study the feasibility of installing power at already existing non-power projects. These include both non-power storage projects and run-of-river projects. The power-duration feature of the program makes it particularly useful when studying a project that experiences a large range of head.

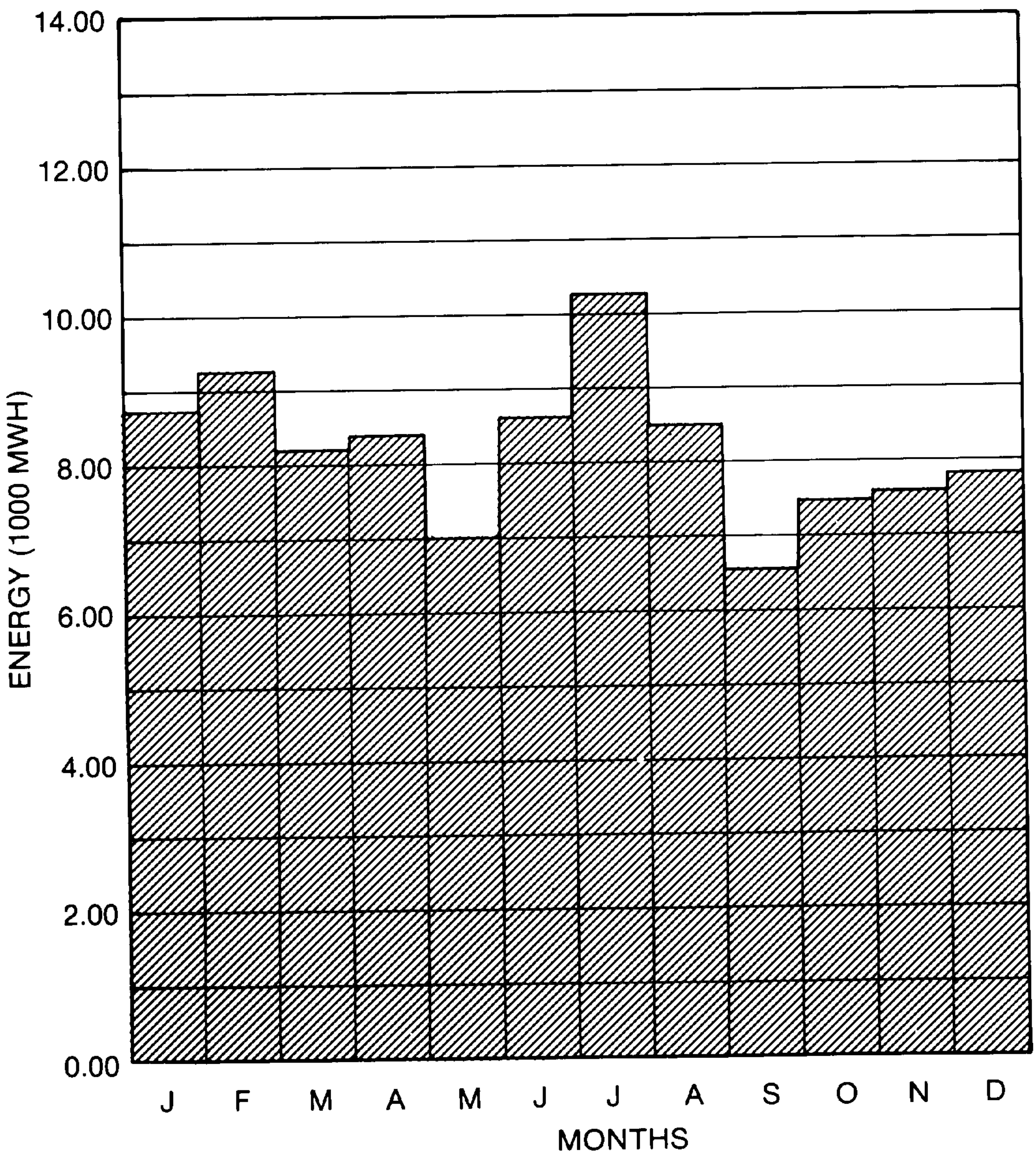


Figure C-1. Average monthly energy output from DURAPLOT model

APPENDIX D

CALCULATIONS FOR FLOW-DURATION METHOD EXAMPLE

D-1. General. This appendix includes the backup calculations used in deriving the figures which illustrate the example described in Section 5-7 (computing energy using the flow-duration method). Data is presented only for a sufficient number of points to define the curves.

D-2. Total Energy Potential.

a. Table D-1 summarizes the calculations used to derive the total energy potential curves shown as dashed lines on Figures 5-20 and 5-21 and described in Section 5-7i. Generation was computed for 100 percent exceedance (60 cfs), minimum discharge (155 cfs), discharge at rated head (400 cfs), discharge at minimum head (1450 cfs), and several additional points. Power output at each discharge level was computed using the water power equation, as described in Section 5-7i. Net head values were obtained from Figures 5-16 and 5-17, and percent exceedance values were taken from Figure 5-15, with both values based on total discharge. The net discharge value is equal to the total discharge minus the 20 cfs loss (Section 5-7e). A fixed overall efficiency of 85 percent was assumed for all discharge levels. It should be noted that the total energy curves on Figures 5-20 and 5-21 do not represent gross theoretical energy potential, but the total developable potential, which reflects friction head losses, flow losses due to leakage, and turbine-generator efficiency losses.

b. The dashed line on Figure D-1 (and Figure 5-21) is a plot of the data shown on Table D-1. It should be noted that this figure is not a true generation-duration curve, because the generation drops off at exceedance levels greater than eight percent. This is because of the low heads that occur at high discharge levels. In plotting Figure 5-20, the data shown on Figure D-1 was rearranged in true duration curve format.

D-3. Usable Generation. Table D-2 summarizes the calculations used for describing the usable generation curve, which is the curve enclosing the shaded area on Figure D-1. Figure 5-20 shows the same data plotted in true duration curve format (see also Section 5-7i). These curves describe that portion of the total energy that could be developed by a single tubular turbine with a rated head of 31.0 feet and a rated discharge of 380 cfs. The calculations are identical to

TABLE D-1
Total Energy Potential

Total Discharge (cfs)	Net Head (feet)	Net Discharge (cfs)	Efficiency (percent)	Power Output (kW)	Percent Exceedance
60	35.0	40	85	100	100
155	34.0	135	85	330	77
250	33.0	230	85	550	49
400	31.0	380	85	850	32
600	28.0	580	85	1170	22
1000	21.0	980	85	1480	11
1200	16.7	1180	85	1420	8
1450	11.0	1430	85	1130	5
1750	5.2	1730	85	650	4
2000	1.7	1980	85	240	3
2100	0.8	2080	85	120	2

TABLE D-2
Usable Generation Using Approximate Method

Total Discharge (cfs)	Net Head (feet)	Net Discharge (cfs)	Efficiency (percent)	Power (kW)	Percent Exceedance
60	35.0	40 1/	85	0 1/	100
155	34.0	135	85	330	77
250	33.0	230	85	550	49
400	31.0	380	85	850	32
600	28.0	380 2/	85	760	22
1000	21.0	380 2/	85	570	11
1200	16.7	380 2/	85	460	8
1450	11.0	380 2/	85	300	5
1500	10.0 3/	380 2/	85	0 3/	5

1/ Net discharge is less than 135 cfs minimum discharge.
2/ Limited by 380 cfs full gate turbine discharge (see Section D-4).
3/ Net head is less than 11.0 ft. minimum.

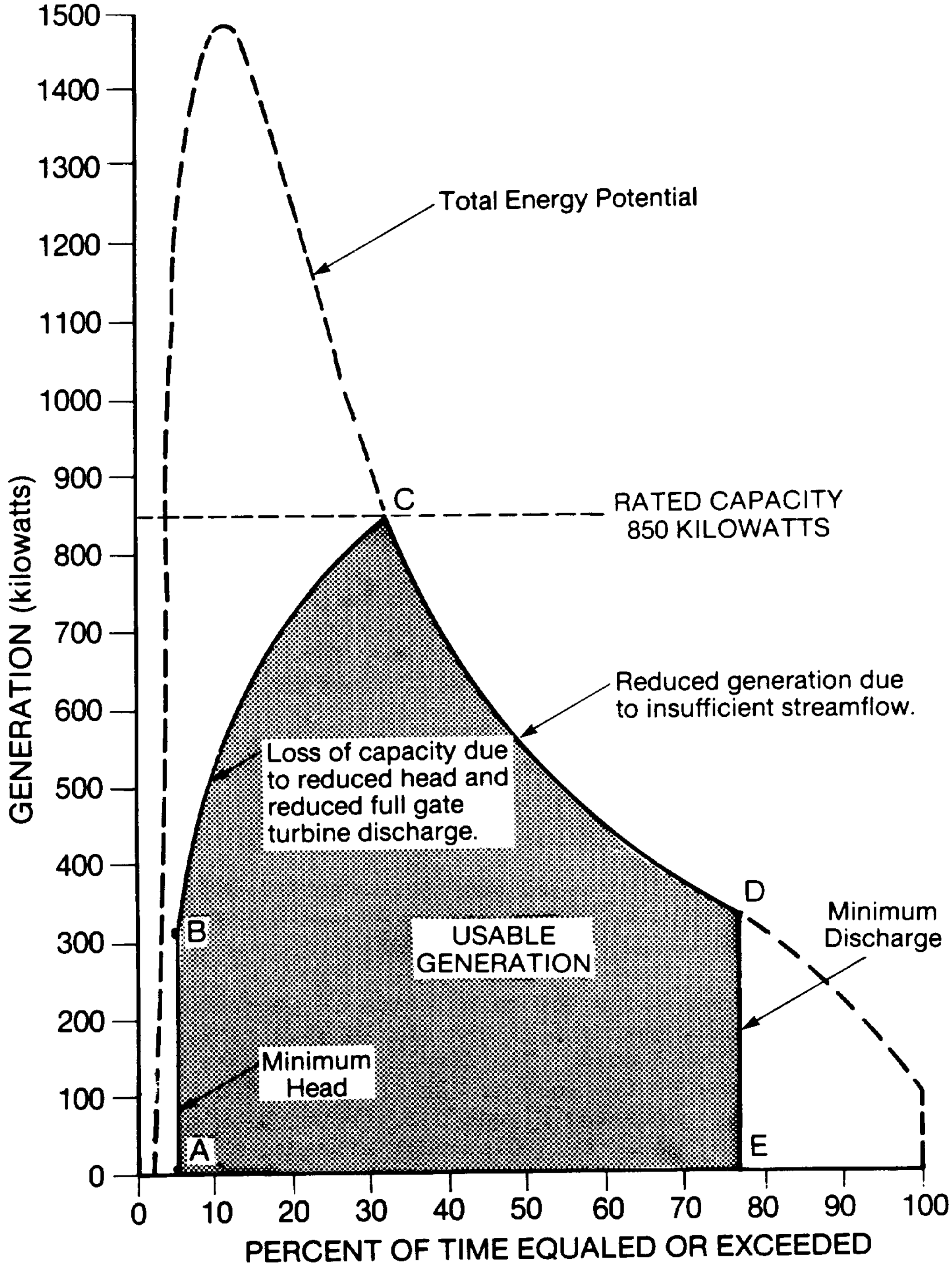


Figure D-1. Usable generation

those shown in Table D-1 except that discharge is limited by the 135 cfs minimum turbine discharge (to the right of line D-E on Figure D-1), the 380 cfs turbine full gate discharge (above line B-C), and the 11.0 foot minimum head (to the left of line A-B).

D-4. Effect of Fixed Overall Efficiency and Fixed Full Gate Discharge Assumptions.

a. The calculations described in Sections D-2 and D-3 are based on a fixed overall efficiency of 85 percent and the assumption that the full gate discharge at heads below rated head is equal to the rated discharge (380 cfs). In reality, turbine efficiency may vary considerably over the unit's operating range, and full gate discharge is always less than rated discharge at heads less than rated head. These factors can be accounted for by using a turbine performance curve in making power calculations.

b. In this section, the example project will be reevaluated using a sample performance curve for an adjustable blade turbine (Figure 39) from Bureau of Reclamation Engineering Monograph No. 20 (64), included here as Figure D-2. This curve shows only the turbine efficiency. The overall unit efficiency for each condition will be computed by applying a generator efficiency of 98 percent.

c. Figure D-2 shows a turbine efficiency of just over 88 percent when operating at rated head and rated discharge, for an overall efficiency of 86 percent. Applying the water power equation, the unit's rated output would then be

$$\text{Rated Capacity} = \frac{(380 \text{ cfs})(31.0 \text{ feet})(0.86)}{11.81} = 858 \text{ kW.}$$

d. Table D-3 shows the computation of generation using Figure D-2. For example, the head at 250 cfs is 33.0 feet, which is 106 percent of the rated head. The discharge available for generation is 250 cfs minus the 20 cfs loss or 230 cfs, which is 60 percent of the rated discharge. Entering Figure D-2, the turbine efficiency corresponding to a head of 106 percent of rated head and a discharge of 60 percent of rated discharge would be about 92.0 percent. The overall efficiency would be (0.92)(0.98) = 90.2 percent. The generation would be

$$\text{Generation} = \frac{(230 \text{ cfs})(33.0 \text{ feet})(0.902)}{11.81} = 580 \text{ kW.}$$

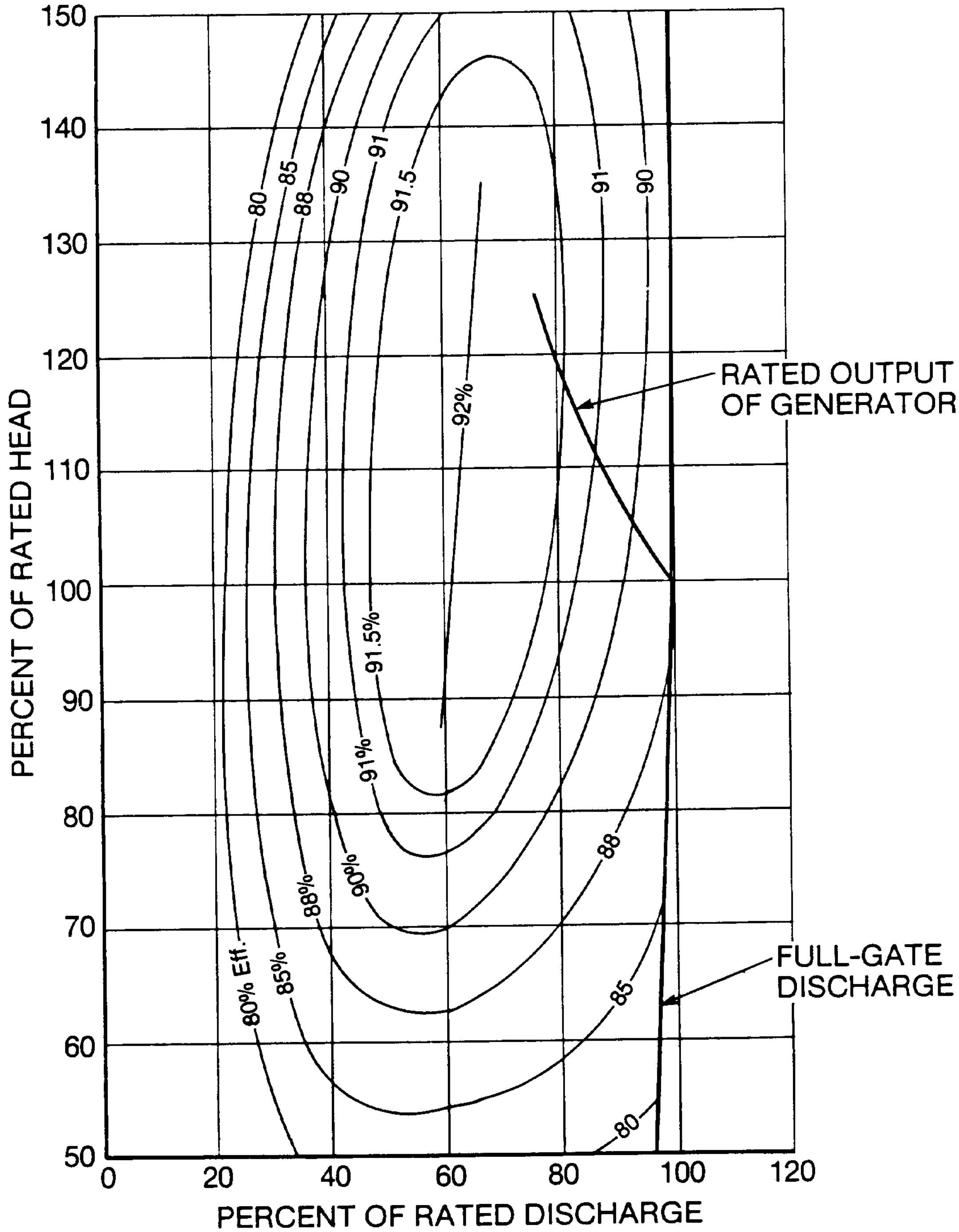


Figure D-2. Turbine performance curve-adjustable blade propeller turbine (Courtesy of U.S. Bureau of Reclamation)

TABLE D-3
Calculation of Usable Generation Using Turbine Performance Curve

Total Discharge (cfs)	Net Head (feet)	Percent Rated Head	Power Discharge (cfs)	Percent Rated Discharge	Overall Efficiency (percent) 1/	Power (kW)
60	35.0	113	40	10 2/	-	0
155	34.0	110	135	35	87.8	341
250	33.0	106	230	60	90.2	580
400	31.0	100	380	100	86.1	858
600	28.0	90	376 3/	99 3/	85.3	760
1000	21.0	68	367 3/	97 3/	82.8	540
1200	16.7	54	365 3/	96 3/	78.4	404
1450	11.0	35	357 3/	94 3/	68.9	229
1500	10.0	32 4/	-	-	-	0

1/ The product of the turbine efficiency from Figure D-2 and an assumed generator efficiency of 98 percent.
2/ Discharge below minimum discharge of 35 percent of rated discharge (135 cfs).
3/ Unit operating at full gate discharge below rated head (see paragraph D-4e).
4/ Head below minimum head (33 percent of maximum head, or 11.0 feet).

e. Similar computations would be made at other discharges. At heads of less than rated head, the full gate discharge curve would limit output. For example, the head corresponding to a discharge of 1200 cfs would be 16.7 feet, or 54 percent of rated head. Entering Figure D-2, the full gate discharge corresponding to 54 percent of rated head would be 96 percent of rated discharge, or (0.96)(380 cfs) = 365 cfs. The turbine efficiency at that point is 80.0 percent, giving an overall efficiency of 78.4 percent. The power output at that discharge would be

$$\text{Generation} = \frac{(365\ \text{cfs})(16.7\ \text{feet})(0.784)}{11.81} = 404\ \text{kW.}$$

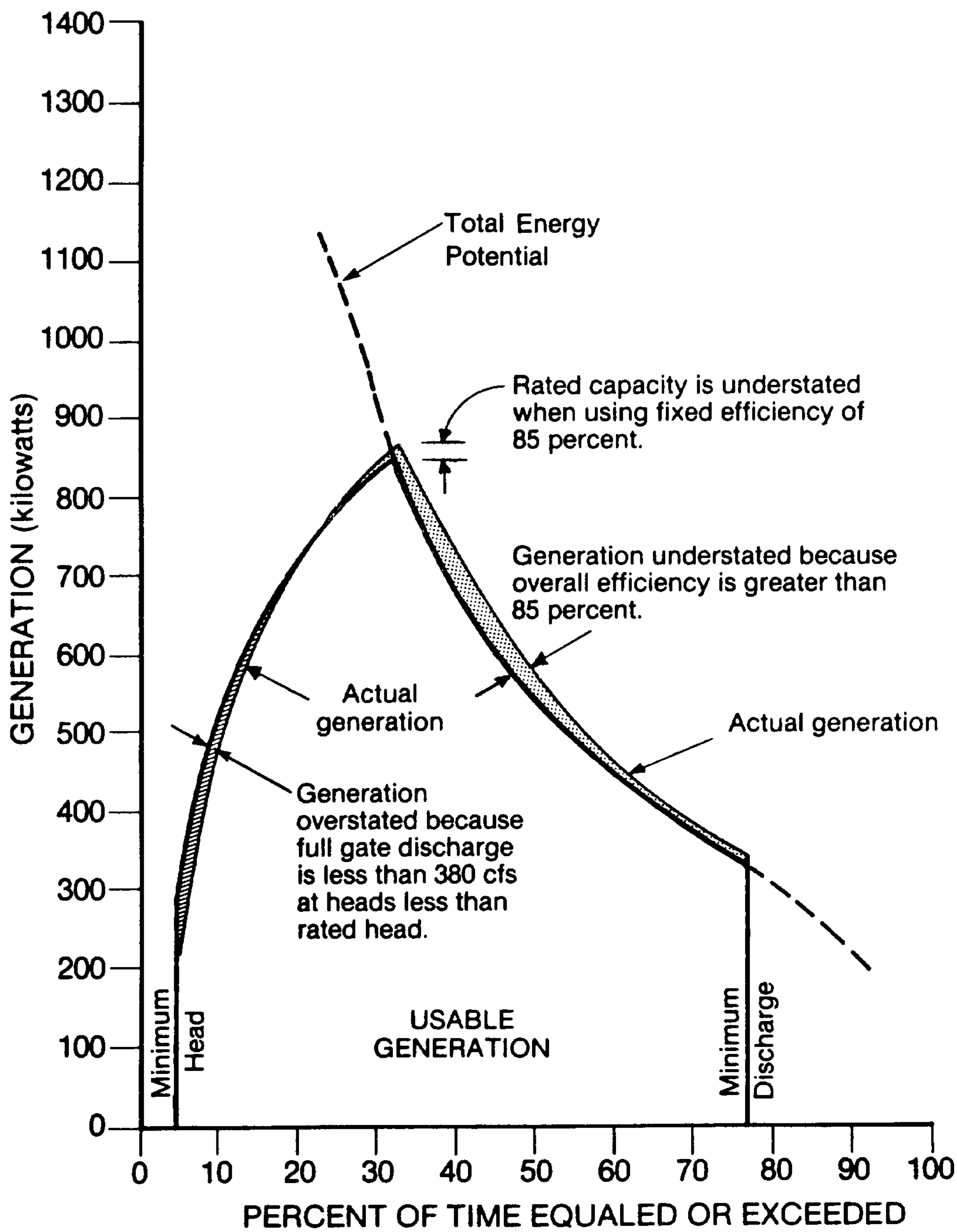


Figure D-3. Effect of using fixed efficiency of 85 percent instead of using turbine rating curve -- tubular turbine with movable blades

f. Figure D-3 shows a comparison of the generation using the performance curve (solid line) compared to that obtained using the simplified assumptions (dotted line). Note that in this example, using the simplified assumptions understates generation at discharges of less than 22 percent exceedance (600 cfs) because the actual efficiency in this range is greater than the assumed fixed efficiency of 85 percent and because the actual rated output is somewhat greater when the efficiency from the performance curve is used. At higher discharges, the simplified assumptions overestimated the generation, because the analysis fails to recognize that full gate discharge is less than rated discharge at heads less than rated head, and because the actual efficiency is less than 85 percent over most of this range.

g. In this example, the use of the simplified assumptions underestimates the average annual generation of the project by about two percent. However, this illustrates only one type of installation. Figure D-4 illustrates a similar analysis for a single Francis unit. In this case, the generation is overestimated by about two percent using the simplified assumptions. In other situations, the discrepancy could be less or it could be even greater. However, it is obvious that using the simplified assumptions is satisfactory for reconnaissance and preliminary feasibility study analyses. Note that the Francis turbine was selected for comparsion only to illustrate that the characteristics of different turbines vary. In reality, the operating head range of 11.0 to 33.9 feet is below the head range where Francis units are normally applied.

h. It should be noted that the above analysis is applicable only to the evaluation of a project where discharge is proportional to head. Refer to Sections 5-5e and 5-6k for a discussion of how to analyze projects where head is independent of discharge.

D-5. Peaking Flow-Duration Curve.

a. Sections D-5 and D-6 provide the backup for Section 5-71 and Figures 5-24 and 5-25. The peaking flow duration curve shown on Figure 5-24 was derived using the usable flow duration curve shown on the same figure and the peaking discharge pattern shown on Figure 5-23. A required minimum continuous discharge of 150 cfs is assumed, part of which will be met by the 20 cfs leakage loss. Any remaining flow above the 150 cfs minimum will be available for peaking.

b. Figure 5-23 shows that the peaking discharge is to be provided for a minimum of eight hours per day. To define the peaking flow-duration curve, a series of calculations were done at various

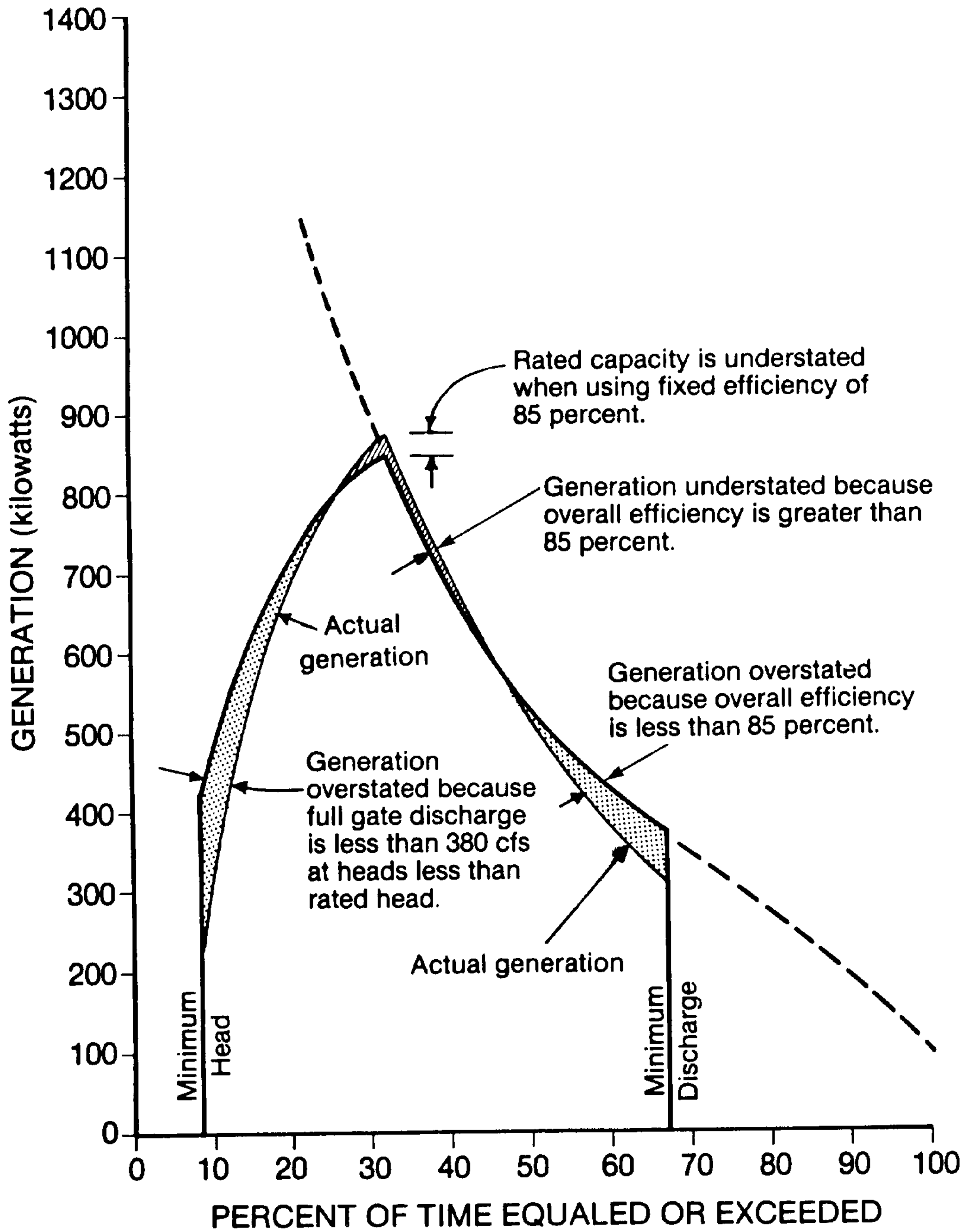


Figure D-4. Effect of using fixed efficiency of 85 percent instead of using turbine rating curve -- Francis turbine average discharge levels. For example, for an average daily discharge of 180 cfs, the peaking discharge would be computed as follows.

Total average daily discharge = 180 cfs

Average net discharge available for generation =
(180 cfs - 20 cfs) = 160 cfs

The minimum discharge that must be maintained at all times is 150 cfs, of which 20 cfs would be supplied from the leakage losses. This leaves 130 cfs which must be met from the 160 cfs average net discharge available for power generation. If 130 cfs is allocated to maintaining the minimum discharge, the remaining (160 cfs - 130 cfs) = 30 cfs daily average discharge is available to be used for peaking, and this is to be released if possible in the 8-hour peak demand period. The 30 cfs daily average discharge, when concentrated in the peak demand period, would equate to a peaking discharge of

(30 cfs)(24 hours)/(8 hours) = 90 cfs.

The total discharge available for generation would then be (130 cfs + 90 cfs) = 220 cfs during the eight peak demand hours and 130 cfs during the remainder of the day. Adding in the 20 cfs loss, the total project discharge would then be 240 cfs in the peak demand hours and 150 cfs during the remainder of the day.

c. At a total discharge of 233 cfs, the plant will be capable of operating at the total rated capacity of 380 cfs for eight hours per day, while maintaining the minimum discharge the remainder of the time. At higher discharges, the number of hours the plant can operate at rated capacity will increase, up to the maximum of 24 hours per day at 400 cfs (380 cfs rated discharge plus 20 cfs loss). At flows greater than 400 cfs, the peaking flow-duration curve would be identical to the average daily flow-duration curve.

d. Table D-4 summarizes these calculations.

D-6. Peaking Capacity-Duration Curve.

a. For pure run-of-river projects, the peaking capacity-duration curve would be identical to the generation-duration curve for the peak demand months, and dependable capacity would be computed as described in Section 5-7k.

b. If pondage were added to the example project, the capacity-duration curve would be modified to reflect the regulation of the project for peaking. Section D-5 describes the computation of

TABLE D-4
Total Discharge When Peaking

Percent Exceedance	Average Daily Discharge: Total (cfs) 6/	Average Daily Discharge: Avail. for Generation (cfs) 1/	Avail. for Peaking (cfs) 2/	Hours on Peak	Discharge in Peak Hours: Peaking (cfs) 3/	Discharge in Peak Hours: Total (cfs) 4/
70	152	132	2	8.0	6	155
65	155	135	5	8.0	15	165
60	160	140	10	8.0	30	180
50	180	160	30	8.0	90	240
40	225	205	75	8.0	225	375
38.5	233	213	83	8.0	250	400
30	300	280	150	14.4	250 5/	400
22	400	380	250	24.0	250 5/	400

1/ Total average daily discharge minus 20 cfs loss.
2/ Total average daily discharge minus 150 cfs minimum discharge.
3/ (Average daily discharge available for peaking x 24 hours) divided by number of hours on peak.
4/ Peaking discharge plus 150 cfs minimum discharge.
5/ Limited to 250 cfs by the 380 cfs hydraulic capacity.
6/ From Figure 5-24 (the average daily flow-duration curve).

discharge in the peak load hours, based on the daily operating pattern shown on Figure 5-23. Figure 5-24 (incorporating the solid line between 22 and 70 percent plant factors) shows the resulting peaking flow-duration curve. Using the data from this curve, the peaking capacity would be computed for a series of exceedance levels in the same manner as was described in Sections D-2 and D-3. The calculations for the example problem are shown in Table D-5, and the resulting curve is plotted as Figure 5-25. In order to simplify the example, a constant efficiency of 85 percent was assumed for all discharge levels and no adjustment was made for reduced full gate discharge at heads less than rated head (see Sections 5-7n and D-4).

c. When pondage is used for peaking, there is a loss of head when the pondage is drafted. It is assumed that two feet of pondage is available at the example project between El. 266.0 feet and El. 268.0 feet (normal full pool). When the pondage is being used, the amount of drawdown varies over the course of the day. Referring to Figure 5-23, the reservoir would be full when peaking starts at 8 am, and there would be no loss of head. At 4 pm, when the peaking cycle is complete, the reservoir would be at its minimum level. Between 4 pm and 8 am the next morning, the reservoir would fill again. Precise estimates of the amount of head loss due to reservoir drawdown could be made for each average daily discharge level by doing hourly reservoir routings (see Section 6-9). However, an approximate estimate can be made by assuming an average drawdown of 30 percent over the discharge range where the pondage would be used (between 22 and 70 percent exceedance in the case of the example problem (see Figure 5-24)). The 30 percent average drawdown accounts for the fact that the average daily drawdown would vary from zero at 22 percent exceedance (because the plant is operating at full hydraulic capacity 24 hours per day) to one foot at 40 percent exceedance (when the plant is using the full two feet of pondage) and back to zero at 70 percent (when the plant is receiving the 150 cfs minimum discharge for 24 hours per day). The computations shown on Table D-5 reflect an average drawdown of 30 percent, or (0.30 x 2.0 ft.) = 0.6 ft.

d. Note that peaking capacity drops off at total discharges greater than 400 cfs (22.0 percent exceedance) due to falling head. As a result, plotting peaking capacity versus the percent exceedance values from Table D-5 would not produce a true duration curve. In plotting Figure 5-25, however, the data was converted to true duration curve format (see Section D-2b).

D-7. Turbine Efficiency.

a. This section provides the backup for Section 5-7n. Table D-6 summarizes the calculations required to derive the turbine efficiency-discharge curve shown in Figure 5-27. Turbine discharges and corresponding heads are obtained from the flow-duration curve (Figure 5-15) and the head-discharge curve (Figure 5-16). These figures are converted to percent of rated discharge (Q_R) and percent of rated head (H_R) values. In this example, a corresponding value of turbine efficiency is taken from the movable blade propeller turbine performance curve (Figure D-2). The overall efficiency is computed by applying a generator efficiency of 98 percent. The resulting efficiencies are plotted as Figure 5-27 (see Sections 5-7n(4) and (5)).

b. At heads less than the rated head of 31.0 feet, the net turbine discharge is limited by the full gate discharge (see Section D-4). The turbine efficiencies in this range can be determined from Figure D-2 by reading the efficiency values on the full gate discharge line corresponding to the respective percent of rated head values.

TABLE D-5
Peaking Capacity

Percent Exceedance	Total Discharge in Peak Hours (cfs) 6/	Net Head 1/ (feet)	Net Peak Discharge (cfs) 2/	Efficiency (%)	Peaking Capacity (kW)
100.0	110	34.2	90 3/	85	0 3/
70.0	155	33.4	135	85	320
65.0	165	33.2	145	85	350
60.0	180	33.1	160	85	380
50.0	240	32.6	220	85	520
40.0	375	30.9	355	85	790
38.5	400	30.4	380 4/	85	830
30.0	400	30.4	380 4/	85	830
22.0	400	31.0	380 4/	85	850
14.0	600	28.0	380 4/	85	770
9.0	800	24.7	380 4/	85	680
1.5	1450	11.0	380 4/	85	300
1.0	1600	9.0 5/	380 4/	85	0 5/

1/ Head between 22 and 70 percent exceedance incorporates an average head loss of 0.6 feet to account for pondage drawdown (see Section D-6c).
2/ Total discharge in peak hours minus 20 cfs losses.
3/ Net discharge is less than the 135 cfs minimum turbine discharge.
4/ Output limited by the 380 cfs turbine full gate discharge.
5/ Net head is less than the 11.0 foot minimum head.
6/ From Figure 5-24 (peaking flow-duration curve).

For example, for a total discharge of 1000 cfs, the net head is equal to 21.0 feet, or 0.68 H_R. From Figure D-2, turbine efficiency at 0.68 H_R would be 84.5 percent, and the overall efficiency would be (0.845)(0.98) = 82.8 percent.

TABLE D-6
Turbine Efficiency Curve Calculations

Total Discharge (cfs)	Net Head (feet)	Percent of Rated Head	Net Turbine Discharge (cfs) 1/	Percent of Rated Discharge	Turbine Efficiency (percent)	Overall Efficiency (percent) 3/
60	35.0	113	40	- 2/	-	-
155	34.0	110	135	35	89.6	87.8
250	33.0	106	230	61	92.0	90.2
400	31.0	100	380	100	88.0	86.2
500	29.2	94	376	99	88.0	86.2
600	28.0	90	376	99	87.6	85.8
800	24.7	80	372	98	86.8	85.1
1000	21.0	68	367	97	84.5	82.8
1200	16.7	54	365	96	80.0	78.4
1450	11.0	35	361	95	70.3	68.9
1600	8.1	26 4/	-	-	-	-

1/ Total discharge minus 20 cfs loss; limited by full gate turbine discharge (see Section D-7b).
2/ Net flow less than the 135 cfs minimum turbine discharge.
3/ (Turbine efficiency) x (98 percent generator efficiency).
4/ Head is less than the minimum turbine operating head of 11.0 feet.

APPENDIX E

DAILY SEQUENTIAL ROUTING

E-1. General. This appendix illustrates the daily sequential routing of a project that is operated primarily for flood control and non-power conservation storage. The project operates at minimum pool during the winter months for flood control and begins refill on February 1. The refill rule curve is based on providing flood control storage space consistent with the gradually diminishing flood risk while attempting to refill the conservation storage by June 1. Figure E-1 shows the annual rule curve for the project.

E-2. Basic Data. Following is a list of project characteristics:

Maximum pool elevation:	El. 1540.0
Minimum pool elevation:	El. 1450.0
Average pool elevation:	El. 1490.0
Minimum discharge:	100 cfs
Storage-elevation characteristics:	Figure E-2 (partial)
Tailwater characteristics:	Figure E-5
Head loss in penstock and trashracks:	3.0 feet
Rule curve elevations:	Table E-1 (partial)

TABLE E-1
Rule Curve Elevations for March

Day	Elevation	Day	Elevation	Day	Elevation
1	1499.0	11	1505.2	21	1511.2
2	1499.6	12	1505.8	22	1511.8
3	1500.2	13	1506.4	23	1512.4
4	1500.9	14	1507.0	24	1513.0
5	1501.5	15	1507.6	25	1513.6
6	1502.1	16	1508.2	26	1514.2
7	1502.7	17	1508.8	27	1514.8
8	1503.5	18	1509.4	28	1515.3
9	1504.0	19	1510.0	29	1515.9
10	1504.6	20	1510.6	30	1516.5
				31	1517.1

E-3. Powerplant Characteristics.

a. General. Assume that it is desired to have a two-unit powerplant with a total rated discharge of 1000 cfs. Assume further that the plant will operate in a "block-loading" mode, in that each day the plant will be operated at full load for as many hours as water permits and it will be shut down for the remainder of the day.

b. Head Range. For block-loaded operation, the tailwater elevation would normally correspond to a discharge of about 1000 cfs, or El. 1225.0 (see Figure E-5).

Head at full pool = El. 1540.0 - El. 1225.0 - 3.0 feet = 312 ft.
Head at min. pool = El. 1450.0 - El. 1225.0 - 3.0 feet = 222 ft.

With this head range, a Francis turbine would be most appropriate (see Figure 2-35). The ratio of minimum head to maximum head is (222 feet/312 feet) = 0.71, which is within the allowable head ratio for this type of unit (0.50, see Section 5-6i).

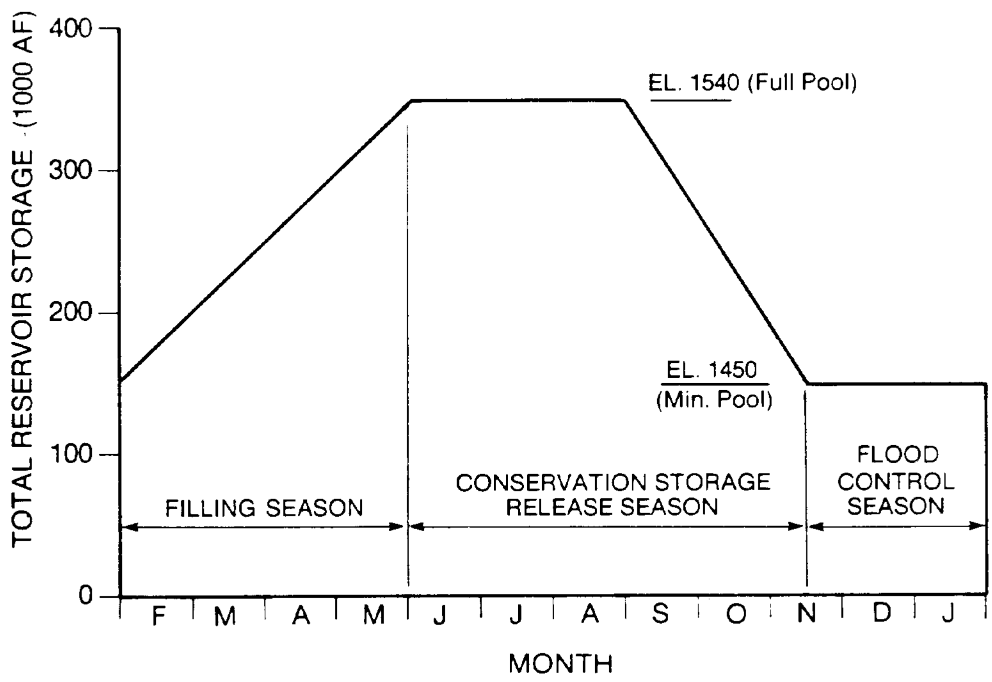


Figure E-1. Reservoir rule curve for example project

c. Rated Capacity. As noted above, the powerplant rated discharge or hydraulic capacity will be 1000 cfs. The unit will be rated at average head, which is the head corresponding to the average pool elevation of 1490.0 feet.

Rated head = El. 1490.0 - El 1225.0 - 3.0 feet = 262.0 feet.

Assuming an overall efficiency of 88 percent at rated output and using the water power equation (Eq. 5-2),

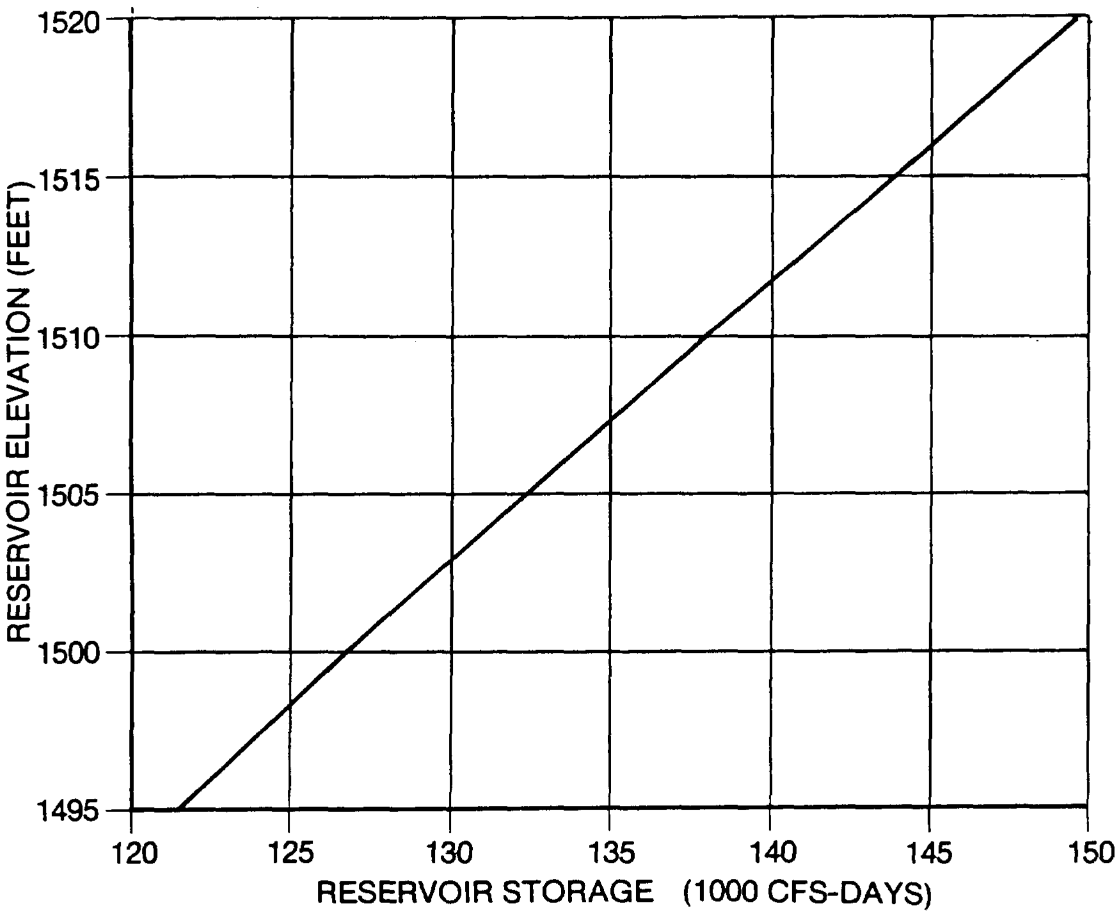


Figure E-2. Partial reservoir storage-elevation curve

$$\text{Rated capacity} = \frac{Q_R H_R e}{11.81} = \frac{(1000\text{ cfs})(262.0\text{ ft})(0.88)}{11.81} = 19{,}500\text{ kW.}$$

where: Q_R = rated discharge, cfs
H_R = rated head, feet

d. Hydraulic Capacity and Efficiency vs. Head. For preliminary studies, the variation of hydraulic capacity (full gate discharge) and overall unit efficiency with head can be ignored. However, in this example, these variables will be accounted for. Where this is done, calculation of energy for a large number of time increments can be expedited by using hydraulic capacity versus head and efficiency versus head curves. Turbine characteristics will be based on the generalized performance curve for a Francis turbine, Figure 2-39. Because the unit will be block-loaded, the unit performance is defined by the full gate discharge line at heads up to rated head and by the generator rated capacity line at heads greater than rated head. Table E-2 was compiled by assuming a series of heads (expressed as ratios of head to rated head) and reading corresponding values of percent of rated discharge (Q_R) and percent of rated capacity (P_R) from the full gate discharge and rated capacity lines on Figure 2-39. The actual values of head, discharge, and capacity shown on the table are based on the percent values from Figure 2-39 and the rated discharge of 1000

TABLE E-2
Computation of Powerplant Characteristics

H_R	Head (feet)	Percent of Q_R	Hydraulic Capacity (cfs)	Percent of P_R	Capacity (kW)	Efficiency (percent)
0.65	170.3	92	920	55	10,725	0.81
0.75	196.5	94	940	67	13,065	0.84
0.85	222.7	97	970	83	16,185	0.89
1.00	262.0	100	1000	100	19,500	0.88
1.15	301.3	88	880	100	19,500	0.87
1.30	340.6	77	770	100	19,500	0.88
1.40	366.8	70	700	100	19,500	0.90

1/ Ratio of head to rated head

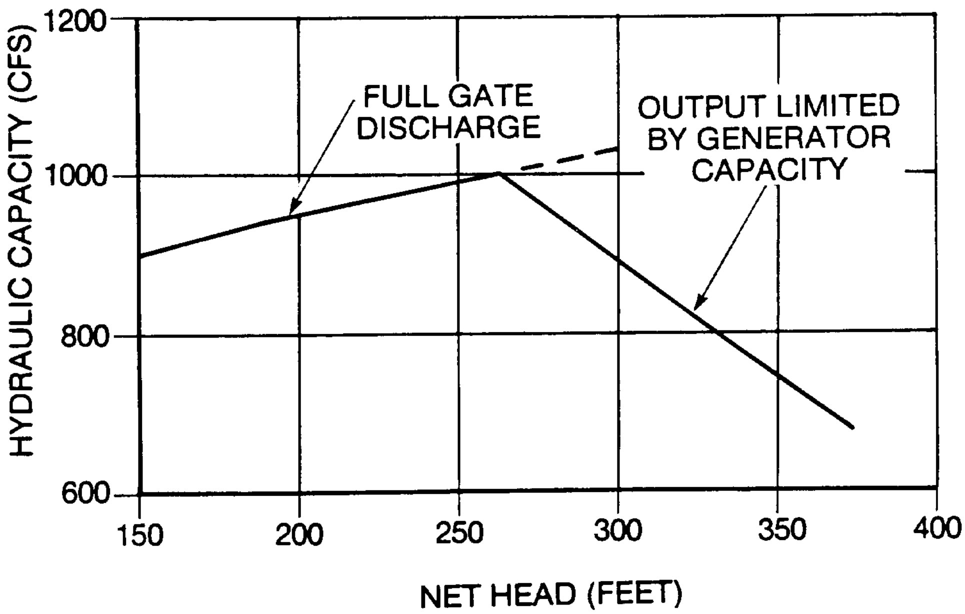


Figure E-3. Hydraulic capacity vs. head

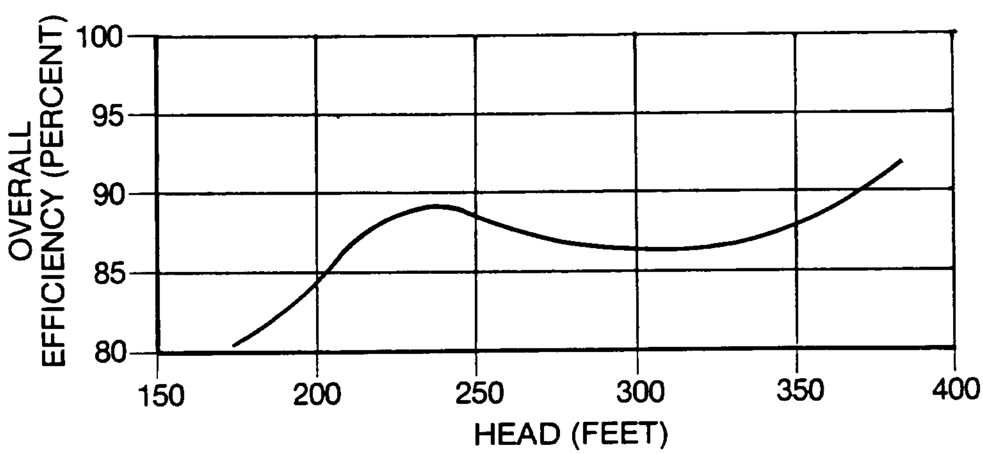


Figure E-4. Efficiency vs. head

cfs, the rated head of 262 feet, and the rated output of 19,500 kW. Efficiency was computed for each head using the water power equation,

$$\text{Efficiency} = \frac{11.81(\text{kW})}{QH} \qquad \text{(Eq. E-1)}$$

Figure E-3 shows the resulting plot of hydraulic capacity versus head, and Figure E-4 shows the plot of efficiency versus head.

E-4. Computation of Energy Output.

a. General. Table E-3 summarizes the computation of energy for each day using regulated flows for the month of March 1982. Table E-4 shows how each value was determined, by column. Figure E-6 shows a plot of actual reservoir elevation by day compared to the rule curve elevations.

b. Rules for Selection of Daily Discharge.

(1) During flood control operation, project discharge is reduced to zero when flood flows are being stored. During evacuation of flood storage, the objective is to empty the flood control space as rapidly as possible, but project discharge is limited to 4000 cfs in order to avoid exceeding bankfull conditions downstream.

(2) During the filling of conservation storage (1 February to 1 June), the daily discharge is generally equal to inflow minus water required to be added to storage to reach the end-of-day rule curve elevation. However, a minimum daily discharge of 100 cfs must be maintained at all times for downstream uses. Some deviation from the rule curve elevation is permissible to avoid spilling energy (days 5 and 6, for example).

(3) During the conservation season (1 June to 15 November), discharge is generally based on downstream requirements. However, larger releases may be scheduled to keep the reservoir from exceeding the rule curve elevation. Small deviations above the rule curve may be permitted here also in order to avoid spill.

c. Routing for March 1982. The daily routing shown on Table E-3 and Figure E-6 is for the month of March, which is midway through the refill phase. This routing is based upon actual regulation of a similar project during calendar year 1982. Flood regulation occured during the last few days of February. During the first five days of March, the reservoir was being drawn back down to the rule curve elevation. During these five days, the required draft rate caused the powerplant hydraulic capacity to be exceeded, and some water was spilled.

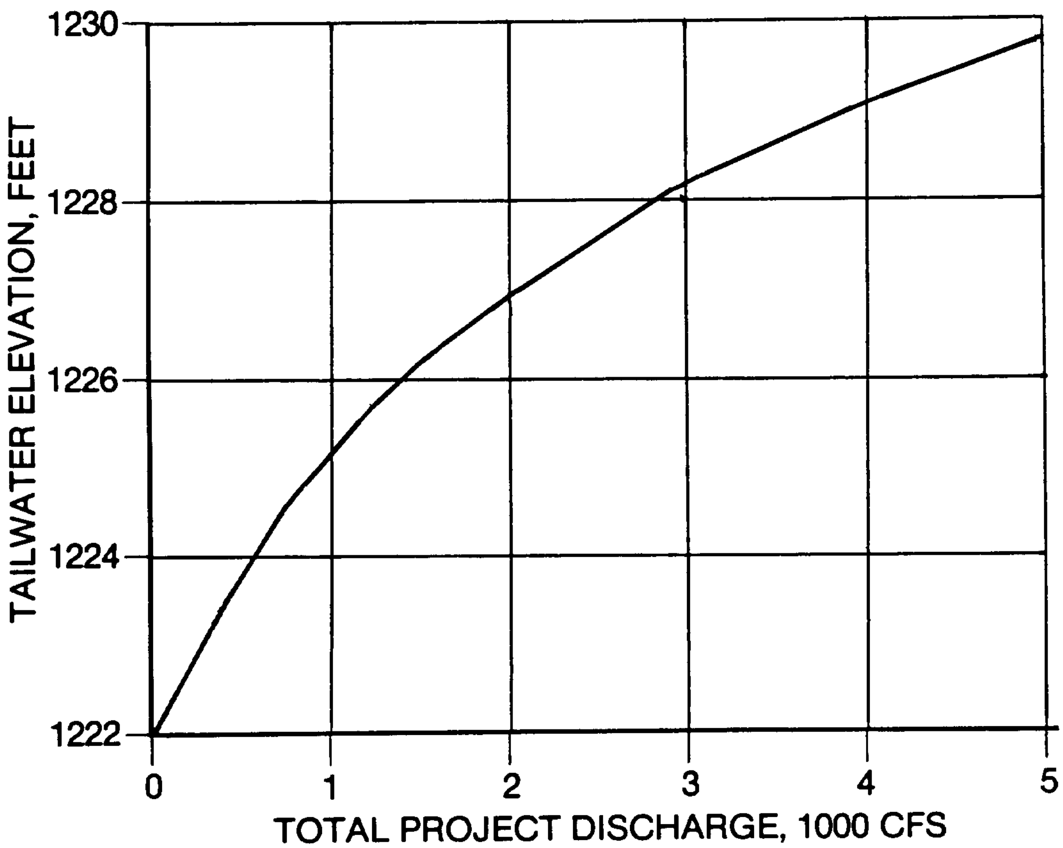


Figure E-5. Tailwater rating curve

TABLE E-3. Energy Calculation for Project Without Power

(1) Day of Month	(2) Reservoir Inflow (CFS)	(3) Starting Reservoir Elevation (Ft., MSL)	(4) Starting Reservoir Storage (KSFD)	(5) Rule Curve Elevation (ft., MSL)	(6) Rule Curve Storage (KSFD)	(7) Target Storage Change (CFS)	(8) Discharge Required to Meet Target (CFS)	(9) Maximum Flood Control Discharge (CFS)	(10) Approx. Hydraulic Capacity (CFS)	(11) Average Actual Discharge (CFS)
1	2670	1506.5	134.1	1499.0	125.8	-8300	10970	4000	1000	4000
2	2580	1505.3	132.8	1499.6	126.5	-6300	8880	4000	965	4000
3	2260	1504.0	131.3	1500.2	127.2	-4100	6360	4000	970	4000
4	2180	1502.4	129.6	1500.9	127.9	-1800	3980	4000	970	3980
5	1940	1500.8	127.8	1501.5	128.6	800	1140	4000	980	980
6	1730	1501.7	128.8	1502.1	129.2	400	1330	4000	970	970
7	1580	1503.2	129.6	1502.7	129.9	300	1280	4000	970	970
8	1480	1502.9	120.2	1503.5	130.8	600	880	4000	960	880
9	1570	1503.5	130.8	1504.0	131.3	500	1070	4000	960	960
10	1600	1504.1	131.4	1504.6	132.0	600	1000	4000	960	960
11	2070	1504.7	132.1	1505.2	132.7	600	1470	4000	955	955
12	1860	1505.7	133.2	1505.8	133.4	200	1660	4000	960	960
13	1660	1506.5	134.1	1506.4	134.0	-100	1760	4000	955	955
14	1560	1507.1	134.8	1507.0	134.7	-100	1660	4000	950	950
15	1430	1507.6	135.4	1507.6	135.4	0	1430	4000	950	950
16	1280	1508.1	135.9	1508.2	136.1	200	1080	4000	945	945
17	1180	1508.3	136.2	1508.8	136.7	500	680	4000	945	680
18	1150	1508.8	136.7	1509.4	137.4	700	450	4000	940	450
19	1050	1509.4	137.4	1510.0	138.1	700	350	4000	940	350
20	1000	1510.0	138.1	1510.6	138.8	700	300	4000	940	300
21	940	1510.6	138.8	1511.2	139.5	700	240	4000	935	240
22	900	1511.2	139.5	1511.8	140.2	700	200	4000	935	200
23	880	1511.8	140.2	1512.4	140.9	700	180	4000	935	180
24	920	1512.4	140.9	1513.0	141.6	700	220	4000	930	220
25	1010	1513.0	141.6	1513.6	142.3	700	310	4000	925	310
26	1150	1513.6	142.3	1514.2	143.0	700	450	4000	925	450
27	1190	1514.2	143.0	1514.8	143.7	700	490	4000	925	490
28	1270	1514.8	143.7	1515.3	144.2	500	770	4000	920	770
29	1070	1515.3	144.2	1515.9	144.9	700	370	4000	920	370
30	1010	1515.9	144.9	1516.5	145.6	700	310	4000	920	310
31	1090	1516.5	145.6	1517.1	146.4	800	290	4000	915	290

Storage Using Sequential Streamflow Routing Method.

(12) Change in Storage (CFS)	(13) End of Period Storage (KSFD)	(14) End of Period Elevation (Ft., MSL)	(15) Tailwater Elevation (Ft., MSL)	(16) Average Head (Feet)	(17) Efficiency (Percent)	(18) Actual Hydraulic Capacity (CFS)	(19) Power Discharge (CFS)	(20) Spill (CFS)	(21) Energy (MWh)
-1330	132.8	1505.3	1229.1	273.8	87.4	965	965	3035	469
-1420	131.3	1504.0	1229.1	272.6	87.4	970	970	3030	470
-1740	129.6	1502.4	1229.1	271.1	87.5	970	970	3030	468
-1800	127.8	1500.8	1229.0	269.6	87.5	980	980	3000	470
960	128.8	1501.7	1225.0	273.3	87.4	970	980	0	476
770	129.6	1503.2	1225.0	274.5	87.3	965	970	0	472
610	120.2	1502.9	1225.0	275.0	87.2	960	970	0	473
600	130.8	1503.5	1224.9	275.2	87.2	960	880	0	429
610	131.4	1504.1	1225.0	275.8	87.2	960	960	0	469
660	132.1	1504.7	1225.0	276.4	87.2	955	960	0	470
1115	133.2	1505.7	1225.0	277.2	87.2	960	955	0	469
900	134.1	1506.5	1225.0	278.1	87.2	955	960	0	473
705	134.8	1507.1	1225.0	278.8	87.1	950	955	0	471
610	135.4	1507.6	1225.0	279.4	87.1	950	950	0	470
480	135.9	1508.1	1225.0	279.9	87.0	945	950	0	470
335	136.2	1508.3	1225.0	270.2	87.0	945	945	0	468
500	136.7	1508.8	1224.3	281.2	86.9	940	680	0	289
700	137.4	1509.4	1223.7	282.4	86.9	940	450	0	223
700	138.1	1510.0	1223.6	283.1	86.9	940	350	0	175
700	138.8	1510.6	1223.5	283.8	86.8	935	300	0	150
700	139.5	1511.2	1223.0	284.9	86.7	935	240	0	120
700	140.2	1511.8	1222.9	285.6	86.7	935	200	0	101
700	140.9	1512.4	1222.9	286.2	86.7	930	180	0	91
700	141.6	1513.0	1223.0	286.7	86.6	930	220	0	110
700	142.3	1513.6	1223.5	286.8	86.6	925	310	0	157
700	143.0	1514.2	1223.7	287.2	86.6	925	450	0	227
700	143.7	1514.8	1223.8	287.7	86.6	925	490	0	247
500	144.2	1515.3	1224.7	290.3	86.5	920	770	0	389
700	144.9	1515.9	1223.6	289.1	86.5	920	370	0	188
700	145.6	1516.5	1223.5	289.7	86.4	920	310	0	158
800	146.4	1517.1	1223.4	290.4	86.4	915	290	0	148

TABLE E-4
Key to Calculations Shown on Table E-3

Column	Explanation
1	Given.
2	Given.
3	Given for day 1; for all other days, obtain from Column 14 of previous day.
4	On first day, value from storage-elevation curve (Figure E-2) corresponding to elevation in Column 3; for all other days, obtain from Column 13 of previous day.
5	From rule curve (Table E-1).
6	Value from storage-elevation curve (Figure E-2) corresponding to elevation in Column 5.
7	Change in storage required to reach rule curve elevation by end of day, expressed in average cfs: (Column 6 - Column 4)x(1000)
8	(Column 2) - (Column 7).
9	Given (see Section E-4b(1)).
10	Approximate value only. For day 1, use rated discharge; for other days, use Column 18 value for previous day.
11	See Section E-4b.
12	(Column 2) - (Column 11).
13	(Column 4) + (Column 12/1000)
14	Value from storage-elevation curve (Figure E-2) corresponding to value in Column 13.
15	Value from tailwater curve (Figure E-5) corresponding to discharge in Column 11.
16	(0.5)(Column 3 + Column 14) - (Column 15) - (3.0 foot head loss).
17	Value from Figure E-4 corresponding to head in Column 16.
18	Value from Figure E-3 corresponding to head in Column 16.
19	The smaller of Column 11 or Column 18. Note that for those days, where the actual discharge (Column 11) is based on the powerplant hydraulic capacity, Column 11 would actually be based on Column 18 instead of Column 10. Hence, Columns 18, 19 and 11 would all be equal.
20	Column 11 - Column 18.
21	$\text{MWh} = \frac{\text{QHe}}{11{,}810} \times 24 \text{ hours} = \frac{(\text{Col. }19)(\text{Col. }16)(\text{Col. }17)}{11{,}810} \times 24 \text{ hours}$

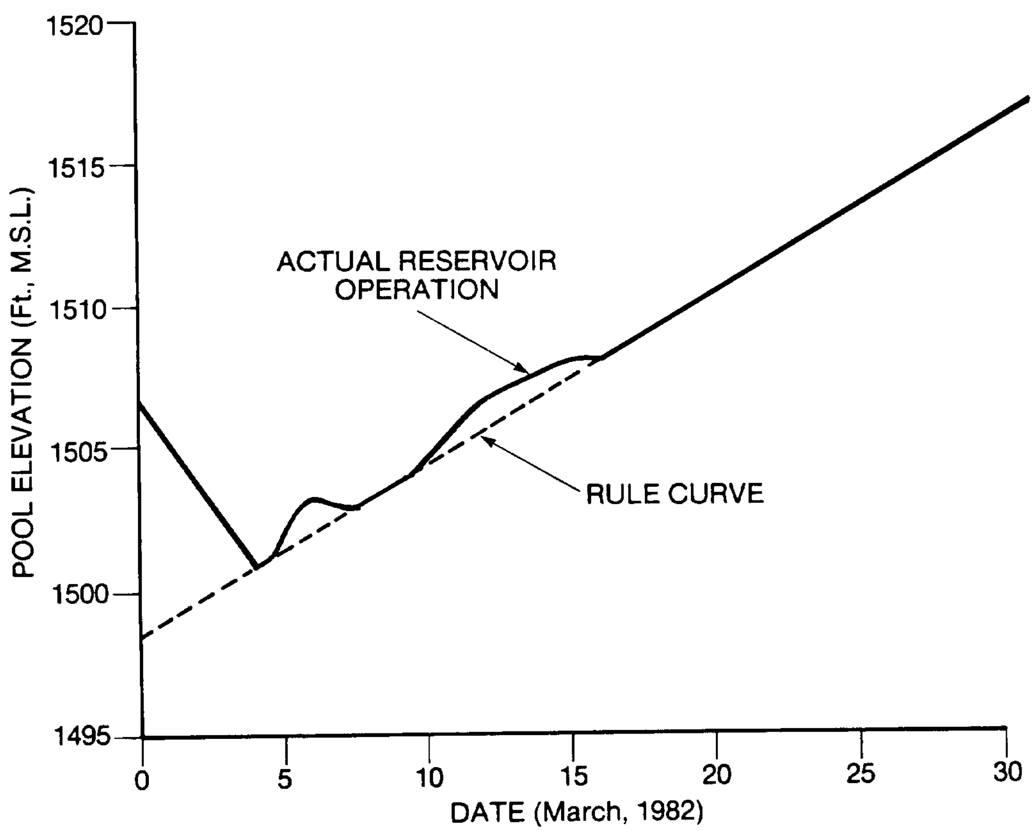


Figure E-6. Rule curve vs. March 1982 daily reservoir routing

APPENDIX F

USE OF THE MASS CURVE METHOD TO IDENTIFY THE CRITICAL PERIOD

F-1. General.

a. The mass curve method is a manual, graphical procedure that is used to identify the critical period and the firm yield (in terms of average sustainable streamflow) for a reservoir of a given storage capacity, or conversely, to identify the storage required to support a given firm yield. Firm yield is maximized by fully drafting available reservoir storage to supplement natural streamflows at some point in time during the most adverse sequence of streamflows. This adverse streamflow period, (the critical period) is identified by examining the historical streamflow record.

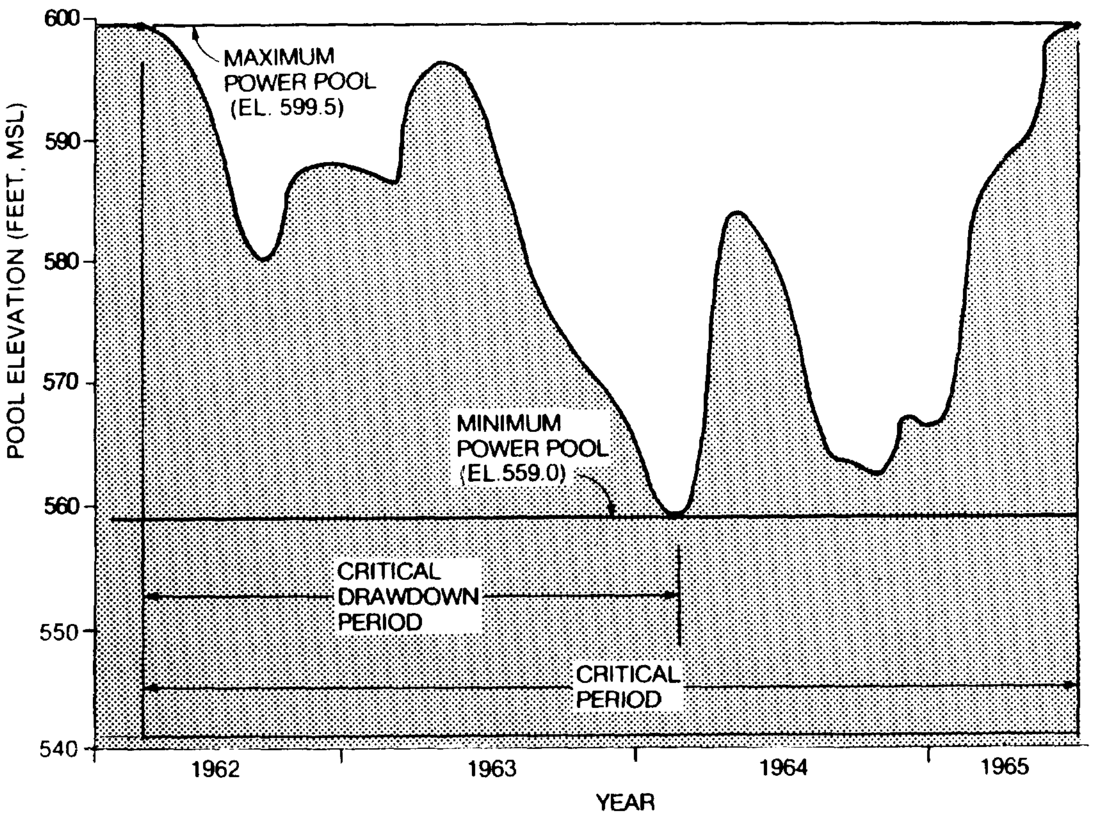


Figure F-1. Critical period and critical drawdown period

b. As noted in Section 5-10d, a critical period always begins at the end of a preceding high flow period which leaves the reservoir full. The end of the critical period is identified as the point when the reservoir has refilled after the drought period. The period beginning with the reservoir full and ending with the reservoir empty is called the critical drawdown period (See Figure F-1).

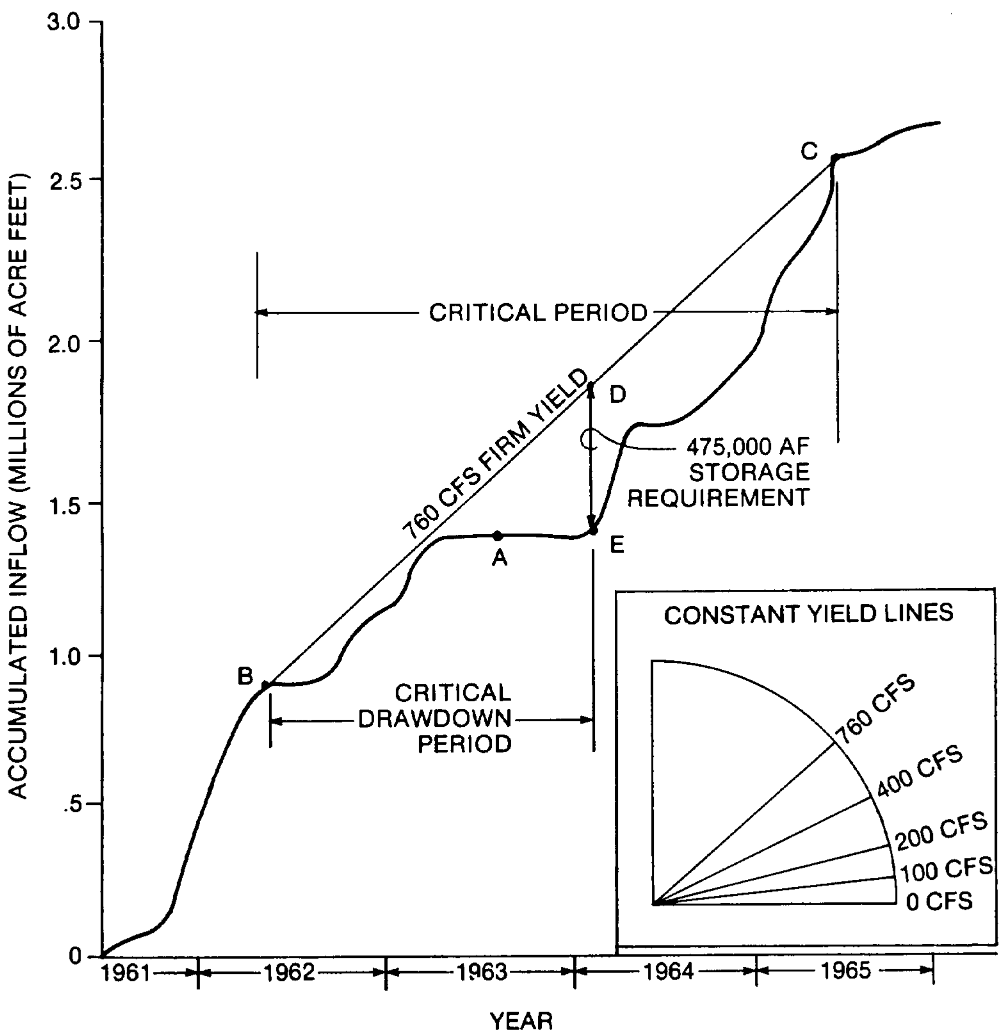


Figure F-2. Mass curve and constant yield lines

F-2. The Mass Curve.

a. A mass curve is a cumulative plotting of reservoir inflow (in acre-feet) over a period of years (Figure F-2). The entire period of record can be plotted, but it is often possible to limit the scope of the study by analyzing only those periods containing the more obvious low flow sequences.

b. The slope of the mass curve at any point in time represents the inflow rate at that time. Demand lines based on a constant yield can also be plotted, and they would have a slope equal to the desired demand rate. A family of yield lines is plotted in the inset to Figure G-2. The firm yield of an unregulated stream occurs at the point on the mass curve having the flattest slope (in the case of Figure F-2, zero cfs at point A).

F-3. Procedure and Example.

a. The procedure for using a mass curve can best be illustrated by examining how the mass curve could be used to determine the storage required to support a given firm yield. Assume for example that the objective of a study is to determine the feasibility of increasing the firm flow of an unregulated stream to 760 cfs (see the 760 cfs constant yield line on the inset, Figure F-2). The 760 cfs firm yield curve is applied to a positive point of tangency on the mass curve (Point B) and is extended to the point where it again intersects the mass curve (Point C). Period B-C thus describes a complete storage draft-refill cycle (which corresponds to the critical period on Figure F-1). The length of the vertical coordinate between the 760 cfs yield curve and the mass diagram represents the amount of storage drafted from the reservoir, at any point in time, and the point where this ordinate is at its maximum length (Point D) represents the total amount of reservoir storage required to maintain a firm flow of 760 cfs during this particular flow period.

b. This same procedure is applied to other low flow periods, and the period requiring the largest reservoir draft is identified as the critical period. Assuming that the period B-C is the most adverse sequence of flows in the period of record, a volume of 475,000 acre-feet is required to assure a firm yield of 760 cfs at the project. The low flow period that is most adverse (the critical period) may extend over several years, and such a multi-year critical period is illustrated by Figure F-2. The period B-E defines the critical drawdown period and B-C defines the total critical period.

F-4. <u>Firm Yield Curve.</u> Alternative firm yields could be tested, and a firm yield versus storage capacity curve could be developed (Figure F-3). A curve of this type would be useful in defining the range of storage volumes to be considered at a reservoir site. It should again be noted that as the available storage volume increases, the length of the critical period will often increase, or the critical period may at some point shift to an entirely different sequence of historical flows.

F-5. <u>Maximum Firm Yield for Given Storage Volume.</u> Another typical problem would be to identify the maximum firm yield that could be obtained for a given storage volume. Figure F-4 illustrates how firm yield is determined for three low-flow periods for a project having 150,000 AF of storage. The 1963-64 sequence produces the lowest firm yield (280 cfs) and hence identifies the critical period for the 150,000 AF project.

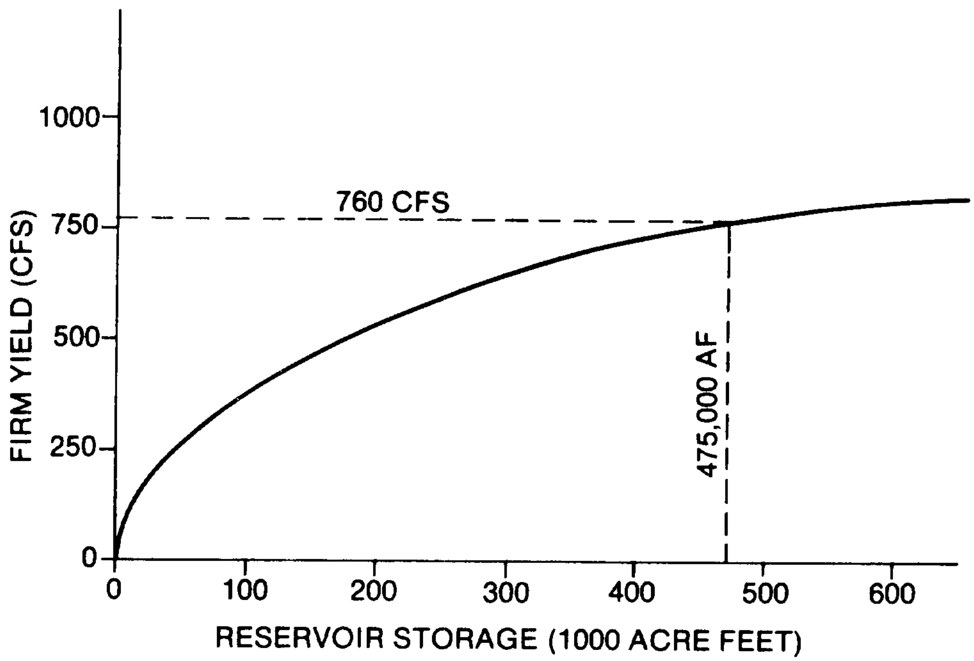


Figure F-3. Firm yield vs. storage capacity curve

F-6. Use of the Mass Curve to Estimate Firm Energy. The mass curve method described above deals with flows and storage volumes. This method could conceivably be adapted to determine a project's firm energy output. However, the procedure would be complicated by the fact that power demand is not constant the year around, but varies from month to month. Furthermore, the head at a storage project varies through the storage regulation cycle, making direct computation of energy impractical. Hence, the mass curve is used primarily to identify the critical period and make a preliminary estimate of the average firm discharge for a project of a given storage volume. This data could be used to make a preliminary estimate of firm energy, which would be followed by a sequential streamflow routing analysis to determine the project's exact firm energy capability (see Appendix H).

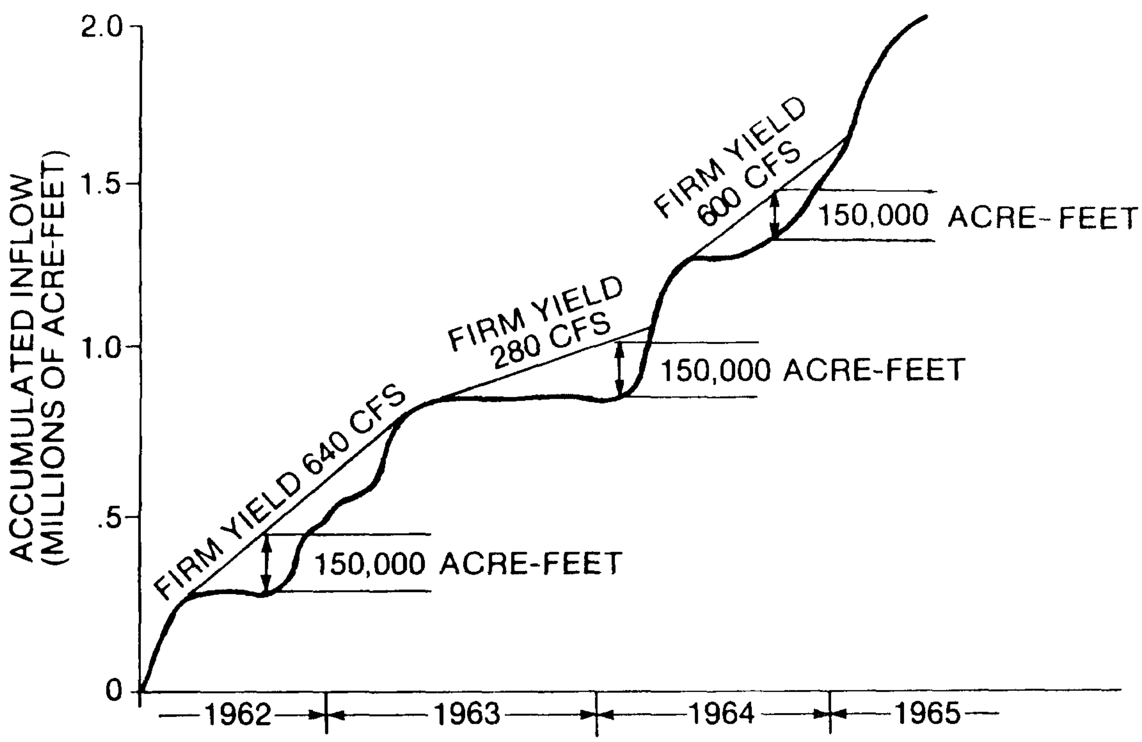


Figure F-4. Firm yield determination with mass curve

APPENDIX G

KW/CFS CURVE COMPUTATION

G-1. Introduction.

a. Curves (or tables) specifying the amount of power that can be obtained per cfs of powerplant discharge versus head or reservoir elevation were originally developed to simplify hand SSR power routings. This data is also required by some SSR models and can be provided as an option in others. The simple kW/cfs vs. head curve reflects efficiency and the necessary conversion factors to yield power in kilowatts, given the discharge and the operating head, while the kW/cfs vs. reservoir elevation curve accounts for tailwater elevation and head losses as well.

b. The kW/cfs curve reflects only the effects of head on plant performance, but not the effects of discharge. Therefore, certain assumptions must be made with respect to plant loading in order to select proper efficiency values and tailwater elevations. The example shown in this appendix is based on a "block loaded" operation, where the plant is assumed to operate at full output when it is running and to be shut down the remainder of the time. The number of hours that the plant operates per day would be a function of the available water. With this type of operation, the efficiency values would be based on operation at full gate discharge for heads below rated head, and at rated capacity for heads above rated head. The tailwater elevation would be based on corresponding discharge values. Alternative plant loadings may be assumed, and methods for treating several of the more common loadings are discussed in Section G-3.

G-2. Example.

a. Assumptions. Assume a power installation at a storage project that will be block loaded. Preliminary studies indicate that the average flow available for power generation is 628 cfs, so the hydraulic capacity, based on an assumed average annual plant factor of 20 percent, would be 3,140 cfs. The estimated average pool elevation, based on 25 percent storage drawdown, would be El. 592.3. It is assumed that the rated head will be 95 percent of the average or design head (see Section 5-5b(8)). The head range suggests the use of Francis units, and for the initial kW/cfs curve, the generalized turbine performance curve for Francis units (Figure 2-39) will be used. Eighty-eight percent is a typical value for overall efficiency at rated head, and that value is assumed for this case. Friction head losses are assumed to total 1.0 feet.

b. Procedure for Developing kW/cfs vs. Head Curve.

(1) The kW/cfs versus head curve will be examined first. The first step is to determine the rated head. From the tailwater rating curve, it is found that the tailwater elevation at the desired hydraulic capacity of 3140 cfs is El. 404.3. The design head (head at average reservoir elevation) would be (El. 592.3 - El. 404.3 - 1.0 feet head loss) = 187.0 feet. The rated head is assumed to be 95 percent of design head, or (187.0 x 0.95) = 177.6 feet.

(2) The rated discharge of the plant would be equal to the desired hydraulic capacity. and the efficiency at rated output was assumed to be 88 percent. Based on this data, the rated capacity is computed as follows:

$$kW = \frac{QHe}{11.81} = \frac{(3140\ cfs)(177.6\ ft)(0.88)}{11.81} = 41{,}600\ kW$$

The kW/cfs for that head would be (41.600 kW/3140 cfs) = 13.2.

(3) Referring to Figure 2-39. values would be computed for additional heads, following the 100 percent rated capacity line above rated head and the full gate discharge line below rated head. For example, at a head of 130 percent of rated head, the discharge would be 76 percent of rated discharge (hydraulic capacity).

$$Head = (1.30)(177.6\ ft) = 230.9\ ft.$$

$$kW/cfs = \frac{41{,}600\ kW}{(0.76)(3140\ cfs)} = 17.4$$

At a head of 85 percent of rated head, Figure 2-39 shows the maximum output to be 83 percent of rated output and the full gate discharge to be 95 percent of rated discharge.

$$Head = (0.85)(177.6\ ft.) = 151.0\ ft.$$

$$kW/cfs = \frac{(0.83)(41{,}600\ kW)}{(0.95)(3140\ cfs)} = 11.6$$

(4) Similar computations would be made for different heads until sufficient points are developed to describe the expected range of heads. Figure G-1 shows the resulting kW/cfs curve.

c. Procedure for Developing kW/cfs vs. Reservoir Elev. Curve.

(1) In some cases it is more convenient to use a kW/cfs versus reservoir elevation curve. Values of kW/cfs would be computed for various heads, as described above, and the head values would be converted to reservoir elevations by adding tailwater elevations and head losses.

(2) For a head equal to 130 percent of rated head (230.9 ft), the kW/cfs value was computed to be 17.4. The discharge at that head would be 76 percent of rated discharge, or (0.76 x 3140 cfs) = 2390 cfs. The tailwater elevation for that discharge (obtained from a tailwater rating curve) is found to be El. 403.5. The reservoir elevation corresponding to 130 percent of rated head is therefore equal to El. 403.5 + 230.9 ft. + 1.0 ft. = El. 635.4.

(3) Similar computations would be made for different heads and a kW/cfs versus reservoir elevation curve would be plotted. Figure G-1

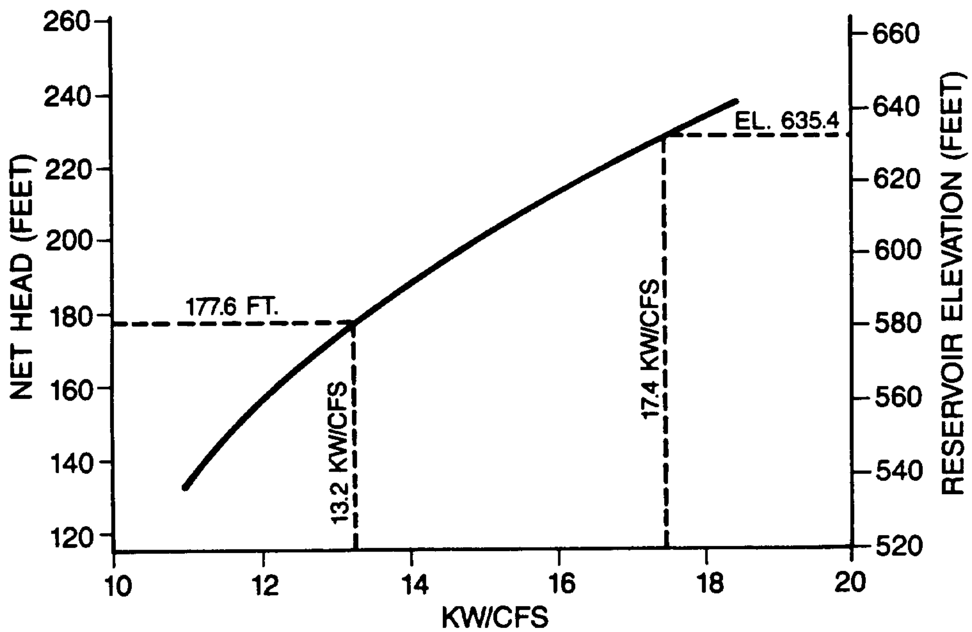


Figure G-1. KW/cfs curve

also includes a scale for determining kW/cfs versus reservoir elevation for the example project.

(4) Figure G-2 shows the KW/cfs versus reservoir elevation curve that was used in the example routings in Appendices H and I.

G-3. Treatment of Alternative Plant Loadings.

a. Assuming that a plant will be operated at full output (block-loaded) may be appropriate for projects that are operated in systems where on-peak energy has a very high value. However, this is not always the case, and alternative approaches may be required. Following are suggested approaches for deriving kW/cfs curves for several different situations.

b. For preliminary studies, a fixed efficiency value of 80 to 85 percent can be assumed (Section 5-5e(2)), and a kW/cfs versus head curve can be constructed based on that value. For higher head projects where variations in tailwater elevation have very little effect on net head, a fixed tailwater elevation can be derived based on a typical plant loading. A kW/cfs versus reservoir elevation curve could then be constructed using the fixed tailwater elevation, a fixed efficiency value, and an estimated head loss value.

c. For more detailed studies, where it is desired to reflect variation of efficiency with head but the project is not block-loaded, an alternative approach must be used. For a project with multiple units, it can often be assumed that sufficient units will be placed on line that the plant will operate at or near best efficiency most of the time. To reflect this operation, it will be necessary to obtain a more detailed turbine performance curve, such as Figure 5-8. The generalized performance curves (Figures 2-39 through 2-45) would not be suitable. Using Figure 5-8 as an example, the unit would operate at best efficiency at about 65 percent gate. Efficiency values can be estimated from the figure for various heads, and a kW/cfs versus head curve can be constructed. Care should be taken to be sure that a generator efficiency loss of about two percent is included in the analysis (turbine performance curves frequently do not reflect generator efficiency losses).

d. During high flow periods, a plant must often be loaded at full output, and thus the "best efficiency" assumption would not be valid. This could be handled by using a curve based on full output during the high runoff season and a curve based on best efficiency operation during the remainder of the year. Or, a single composite curve can be constructed that is intermediate between a block-loading curve and a best-efficiency curve. The latter approach might be particularly useful where plant operation varies widely from period to period or where it is not possible to precisely identify a high-runoff season. A composite curve could also be used for plants with a small number of units, where the "best efficiency" assumptions would not be appropriate.

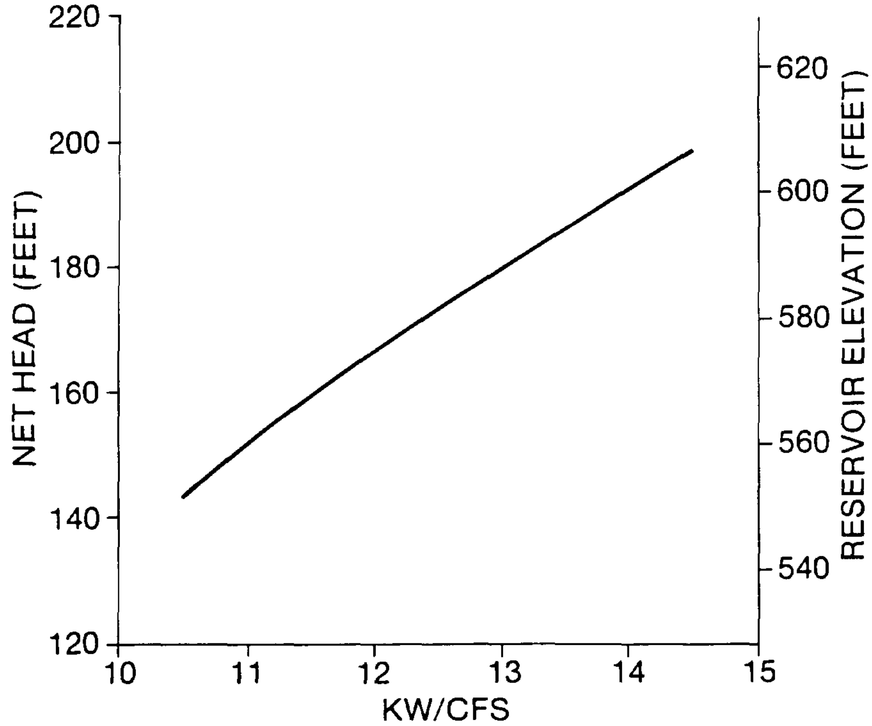


Figure G-2. KW/cfs versus reservoir elevation curve for Broken Bow Reservoir, Oklahoma.

APPENDIX H

FIRM ENERGY ESTIMATE FOR A STORAGE PROJECT

H-1. Introduction.

a. General. This appendix presents an example of how firm energy is estimated for a storage project having power storage. Section H-2 shows how a preliminary firm energy estimate is made. Section H-3 describes an initial hand routing using the sequential streamflow routing method, Section H-4 explains how the initial hand routing can be modified to obtain the final firm energy estimate, and Section H-5 summarizes the final firm energy estimate.

b. Project Characteristics. The example project used in this appendix (and in Appendices I and J) is Broken Bow Lake, a multiple-purpose storage project located on the Mountain Fork of the Red River in Oklahoma. Following are the major project characteristics:

Top of flood control pool:	El. 627.5 (1,368,800 AF)
Top of conservation pool:	El. 599.5 (918,800 AF)
Bottom of conservation pool:	El. 559.0 (448,700 AF)
Storage-elevation curve:	Figure 4-8
Area-elevation curve:	Figure 4-8
Tailwater curve:	Figure H-1
Reservoir withdrawals:	Table H-1
Evaporation losses:	Table H-1
Losses through dam (leakage):	Table H-1
Minimum flow requirements:	Table H-1
Monthly energy requirements:	Table H-1
Powerplant hydraulic capacity:	2000 cfs
Penstock and related head losses:	0.5 feet
Powerplant operation:	Block loading at full capacity

H-2. Computation of Preliminary Firm Energy Output.

a. Procedure. The preliminary firm energy estimate is made by assuming average head and streamflow conditions over the length of the critical period, as follows:

- identify critical period (see Section 5-10d)
- compute average streamflow (in cfs) over the length of the critical period

- estimate average evaporation and other losses and deduct from average critical period streamflow to obtain net streamflow available for generation
- estimate average reservoir pool elevation
- estimate average tailwater elevation
- compute average net head
- assume an average overall efficiency of 85 percent
- compute firm energy output using the water power equation

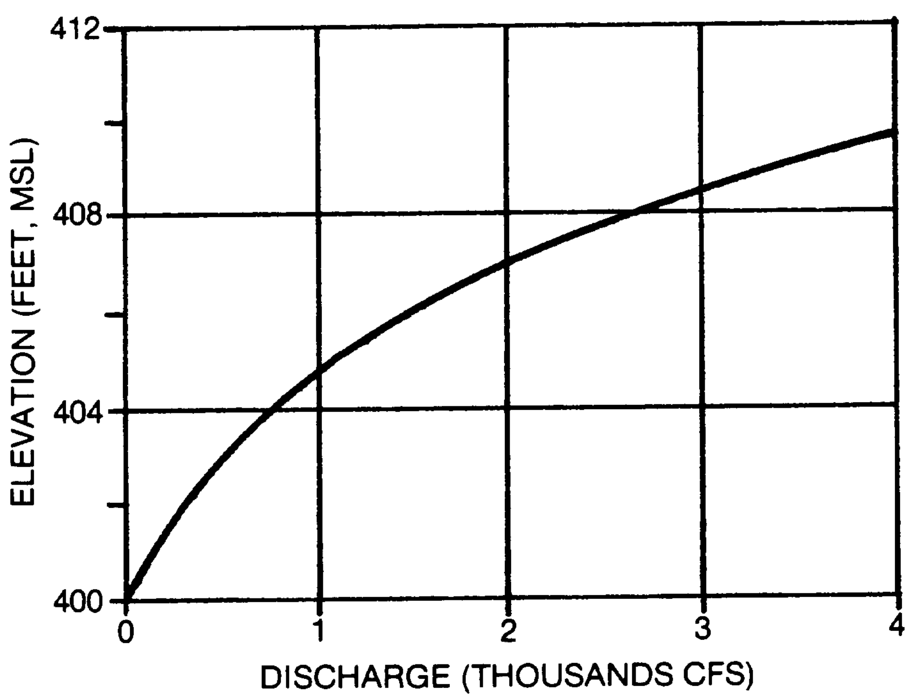


Figure H-1. Tailwater rating curve for Broken Bow Reservoir, Oklahoma

TABLE H-1
Monthly hydrologic and operations data,
Broken Bow Reservoir, Oklahoma

Month	Net Evaporation (inches)1/	Withdrawals (CFS)	Leakage Losses (CFS)	Minimum Flow Req. (CFS)	Percent Firm Energy Requirement
January	-2.42	24	10	118	8.33
February	-1.57	26	10	90	5.00
March	-1.10	27	10	86	5.00
April	-0.64	37	10	86	5.00
May	-1.53	55	10	88	8.33
June	1.87	95	10	90	8.33
July	3.10	94	10	120	16.67
August	3.15	94	10	173	16.67
September	1.41	66	10	314	8.33
October	0.15	33	10	320	5.00
November	-1.63	25	10	320	5.00
December	-2.41	24	10	235	8.33
22-mo. tot. 2/	-1.50	1136	220		190.00
22-mo. avg. 2/	-0.07	52 cfs	10 cfs		

1/ A negative number means that precipitation exceeds evaporation for the month.

2/ The 22-month period corresponding to the critical drawdown period (May of the first year through February of the third year). Totals shown in cfs-months.

b. Example.

(1) Identify Critical Period. Assume that the critical drawdown period has been determined to be the period May 1962 through February 1964 (see Figure F-2). The length of the critical drawdown period would be 22 months, or 670 days.

(2) Calculate Average Streamflow. From the flow records, the natural streamflow into Broken Bow Reservoir during the critical drawdown period was found to be 517,500 acre-feet. This amount, added to the total conservation storage volume of 470,100 acre-feet, shows

that 987,600 acre-feet of water is available for all purposes during the 670-day long critical drawdown period. This amount converts to an average available flow during the critical period of 744 cfs (which is slightly less than the 760 cfs firm yield estimated in Appendix F).

(3) Account for Consumptive Losses. The hydrologic data on Table H-1 shows that the total evaporation over the drawdown period is negative, which means that more water fell onto the reservoir surface as precipitation than evaporated from it. From Figure 4-8, the reservoir surface area at the average assumed average pool elevation of El. 581.4 (see Section H-2b(4)) is found to be 11,800 acres, so the total water gain in storage from the net negative evaporation is estimated to be

$$\frac{(1.50 \text{ inches})(11.800 \text{ acres})}{(12 \text{ in./foot})} = 1,475 \text{ AF}$$

which, over the critical drawdown period, is equivalent to 1.1 cfs. The total flow available for power generation is therefore:

	744 cfs	inflow
+	1 cfs	net evaporation
-	52 cfs	withdrawals/diversions
-	10 cfs	losses
	683 cfs	total

(4) Estimate Average Pool Elevation. The reservoir elevation over the critical drawdown period can be approximated by the elevation with 50 percent of the usable storage remaining. The storage at the top of conservation pool is 918,800 AF and the storage at the bottom of the conservation pool is 448,700 AF, so the total reservoir storage at 50 percent usable storage remaining would be

$$\frac{(918.800 \text{ AF} + 448,700 \text{ AF})}{2} = 683,800 \text{ AF}.$$

Referring to the storage-elevation curve (Figure 4-8), the pool elevation at 50 percent usable storage remaining is found to be El. 581.4.

(5) Estimate Average Tailwater Elevation. If the powerplant were operated at a constant output, the average tailwater elevation could be approximated as the tailwater elevation at the average flow during the critical drawdown period. However, the project will be operated for peaking and will be block-loaded at full capacity.

Hence, the average tailwater elevation would be equal to the tailwater elevation at the powerplant hydraulic capacity (2000 cfs), or El. 407.4 (see Figure H-1).

(6) Compute Average Head. The average head for the critical period would be the average pool elevation minus the average tailwater elevation minus the estimated average head loss or

Average Head = El. 581.4 - El. 407.4 - 0.5 feet = 173.5 feet.

(7) Compute Energy for Critical Drawdown Period. Using the water power equation (Eq. 5-4) and the average streamflow (683 cfs), the average head (173.5 feet), and an assumed average overall efficiency of 85 percent, the preliminary energy estimate for the critical drawdown period is

$$\text{Energy} = \frac{(683\ \text{cfs})(173.5\ \text{feet})(0.85)(670\ \text{days})(24\ \text{hours/day})}{(11.81)}$$

$$= 137{,}000{,}000\ \text{kWh.}$$

(8) Calculate Annual Firm Energy Requirement. The next step is to calculate how much of this power is generated during a 12-month span of time during the period of critical drawdown. By adding up the 22 monthly firm energy values for the critical drawdown period (May 1962 to February 1964. inclusive -- see Table H-1 for monthly percentages), it can be seen that the generation requirements during the entire critical drawdown period are equal to 190 percent of the annual generation requirements. Therefore, the generation for a 12-month period would be:

$$(137.000.000\ \text{kWh}) \times \frac{100\%}{190\%} = 72{,}000{,}000\ \text{kWh.}$$

(9) Find Monthly Firm Energy Requirements. The final step is to allocate this annual firm energy figure among the twelve months of the year. Table H-2 shows the resulting monthly generation allocation.

H-3. Initial Critical Period Hand Routing.

a. General.

(1) This section describes an initial hand routing of the Broken Bow project over the critical drawdown period. The project is regulated to meet the preliminary monthly firm energy requirements

TABLE H-2
Preliminary Allocation of Firm Energy by Month

Month	Percent of Annual Firm Energy Requirement	Firm Energy Allocation (kWh)
January	8.33	6,000,000
February	5.00	3,600,000
March	5.00	3,600,000
April	5.00	3,600,000
May	8.33	6,000,000
June	8.33	6,000,000
July	16.67	12,000,000
August	16.67	12,000,000
September	8.33	6,000,000
October	5.00	3,600,000
November	5.00	3,600,000
December	8.33	6,000,000
Total	100.00	72,000,000

developed in Section H-2. using the procedures described in Section 5-10f. Minimum discharge requirements must also be maintained for water quality. The only other factors that must be accounted for in the analysis other than power requirements are reservoir withdrawals, reservoir evaporation, and leakage through the dam.

(2) The computations are summarized in Table H-3. Section H-3b illustrates sample calculations for the first month in the critical period. As described in Section H-3b(3), at least two iterations are required in order to accurately solve the continuity equation for most months. Both iterations are shown on Table H-3 for the first four months, but only the final iteration is shown for subsequent months.

(3) It will be noted that the reservoir does not draft to the bottom of the conservation pool (El. 559.0) at the end of the drawdown period, but reaches only El. 561.9. To fully utilize the storage, the firm energy requirements must be adjusted and the regulation must be redone. Section H-4 describes this procedure.

b. Example Calculation.

(1) Following is an example calculation illustrating how the values shown on Table H-3 for May, 1962 were derived.

(2) Determine Net Inflow. Given are reservoir inflow (I, Column 3), evaporation rate (Table H-1), and reservoir withdrawals (W, Column 5). Reservoir evaporation is in inches per month and can be converted to average cfs over the month as follows:

$$E = \frac{(0.042)(EVAP)(A)}{(t)}$$

where: EVAP = evaporation rate, inches/month
A = reservoir surface area, acres
t = number of days in month

For preliminary studies, the surface area at average pool elevation (see Section H-2b(4)) and 30 days per month can be used for all months. For more detailed studies, the approximate reservoir surface area for a given period can be obtained from an area-elevation curve or table, using the reservoir elevation at the end of the previous period. The more detailed calculation is used in this example. The end-of-month reservoir elevation is obtained from Figure 4-8 and is entered in Column 17. For May, 1962, the evaporation is -1.53 inches and the surface area of the reservoir at the end of April 1962 (El. 599.5) is 14,200 acres. The evaporation in cfs would be:

$$E = \frac{(0.042)(-1.53 \text{ in./mo.})(14{,}200 \text{ acres})}{(31 \text{ days/month})} = -29 \text{ cfs.}$$

The net reservoir inflow for the same period is

$$\text{Net inflow} = I - E - W$$

$$= 389 \text{ cfs} -(-29 \text{ cfs}) - 55 \text{ cfs} = 363 \text{ cfs.}$$

This value would be inserted in Column 6.

(3) Determine Required Power Discharge. From Table H-2, the firm energy requirement for May, 1962 was found to be 6,000,000 kWh. A previously prepared kW/cfs curve will be used to account for the efficiency and net head calculations (see Appendix G). The kW/cfs value used for a given month should be based on the average reservoir elevation for that month. However, since the average elevation is a

function of the end-of-month elevation and this elevation is not known initially, two or more iterations must be made for some periods in order to achieve a correct solution (see Section 5-10f(7)). For the first iteration, the initial kW/cfs value can be based on the start-of-month reservoir elevation. For May, 1962, the start-of-month elevation is El. 599.5 and from Figure G-2, the kW/cfs would be 14.0. The required power discharge would be computed as follows;

$$Q_P = \frac{(6{,}000{,}000 \text{ kWh/month})}{(744 \text{ hours/month})(14.0 \text{ kW/cfs})} = 576 \text{ cfs.}$$

This value would be inserted in Column 10.

(4) Compute Required Total Discharge. The total required discharge would be the sum of the power discharge needed to meet firm energy requirements (Q, Column 11) plus estimated leakage losses (Q_L), Table H-1), and non-power discharge requirements (Table H-1). Column 10 lists the minimum discharge required for water quality. If this value exceeds the required power discharge plus losses, it would serve as the total discharge requirement. For this month, the minimum discharge requirement is 88 cfs, which is less than $(Q + Q_L)$ = (576 cfs + 10 cfs) = 586 cfs, so the power discharge requirement establishes the total discharge requirement (Column 12).

(5) Compute Change in Storage. The change in reservoir storage would be a function of net inflow (Column 6), total discharge requirements (Column 12), and the start-of-month reaservoir elevation (Column 16 for the previous month). The difference between the net reservoir inflow and the total discharge requirement would establish whether the reservoir would draft, fill, or maintain the same elevation. This computation represents the solution of the continuity equation (Eq. 5-13), which, when rearranged, would be as follows;

$$\Delta S = (I - E - W) - (Q_P + Q_L)$$

For May, 1962,

$$\Delta S = (363 \text{ cfs}) - (586 \text{ cfs}) = (-223 \text{ cfs}).$$

The ΔS value would be converted to acre-feet using the discharge-to-storage conversion factor (C_S) for a 31-day month, from Table 5-5. Thus,

$$\Delta S = (-223 \text{ cfs})(61.49 \text{ AF/cfs-month}) = (-13{,}700 \text{ AF}).$$

These values would be inserted in Columns 13 and 14. For those months where net inflow exceeds total discharge requirements, the reservoir would store the difference unless it is already at the top of conservation pool. If the reservoir is full, the full net inflow (minus losses) would be discharged through the powerhouse, if possible. Any generation above the firm energy requirement (Column 7) would be classified as secondary energy.

(6) Compute End-of-Month Reservoir Status. The change in storage, ΔS, can also be expressed as follows:

$$\Delta S = S_2 - S_1$$

where: S_1 = start-of-period storage volume
S_2 = end-of-period storage volume

The change in reservoir storage computed in step (5) would be applied to the start-of-month storage volume (Column 15 of preceding month) to determine the end-of-month storage volume. The end-of-month reservoir elevation would then be obtained from the storage-elevation curve or tables. For May, 1962;

$$S_2 = S_1 + \Delta S = 918{,}800 \text{ AF} + (-13{,}700 \text{ AF}) = 905{,}100 \text{ AF.}$$

From Figure 4-8, the end-of-month reservoir elevation is found to be El. 598.5.

(7) Adjust Power Discharge Requirement. In step (3), it was noted that a second iteration may be required in order to account for the change in reservoir elevation (head) during the month. For the second iteration, a new kW/cfs factor is obtained from Figure G-1, based on the average of the start-of-month elevation (El. 599.5) and the end-of-month elevation from the first iteration (El. 598.5). The average pool elevation would be (El. 599.5 + El. 598.5)/2 = El. 599.0. In this case, the actual average pool elevation is very close to the El. 599.5 value assumed in the first iteration, so the kW/cfs value of 14.0 still applies. As a result, the values computed for Columns 10 through 16 remain the same as for the first iteration. However, for some of the subsequent months, the second iteration produces a substantially different end-of-month storage. In Table H-3, both iterations are shown for the first four months. For subsequent months, only the second iteration is listed.

(8) Compute Total Generation. During the critical period, generation will be limited to meeting firm energy requirements. The generation would be computed by applying the kW/cfs factor (Column 9) to the greater of the required power discharge or the water quality

requirement (Column 11) minus 10 cfs losses. For May, 1962, the generation would be

(576 cfs)(14.0 kW/cfs)(744 hours/month) = 6,000,000 kWh,

which is, of course, equal to the firm energy requirement. In many months,

surplus water may be available for producing secondary energy (see step (5)). The second routing (Table H-4) extends beyond the end of the critical period, and secondary energy is produced in June of 1965. In this month, the net inflow is 1,643 cfs. 242 cfs is required to fill the reservoir (Column 13), which leaves a total of 1,643 cfs minus the 242 cfs placed in storage, or 1,401 cfs available for power generation. This exceeds the 615 cfs firm energy requirement (Column 10) (plus the 10 cfs leakage loss) by 776 cfs. The 1,401 cfs is entered in Column 12, instead of the greater of (a) the required power discharge plus losses or (b) the minimum discharge requirement from Column 10. The total generation for the month can be computed by deducting the 10 cfs losses and applying the kW/cfs factor. Thus, the generation for June, 1965 would be

(1,401-10 cfs)(14.0 kW/cfs)(720 hours/month) = 14,020,000 kWh.

The power discharge must not exceed the powerplant hydraulic capacity, which in this case is 2,000 cfs. Note that hydraulic capacity varies with head (see Section E-3d), and in some studies it may be desirable to account for this variation.

H-4. Adjustment of Firm Energy Output.

a. Introduction. In the initial routing (Table H-3), the storage remaining at the end of the critical period was 475,800 AF, which means that (475,800 AF - 448,700 AF) = 27,100 AF of power storage remained unused. As described in Section 5-10g, the firm energy estimate must be adjusted and the routing must be done again if the project fails to utilize all of the storage in the critical drawdown period. Following is a summary of the procedure used to make this adjustment and an example showing the adjustment of the firm energy estimate used in Table H-3.

b. Procedure. The following steps are required to develop a revised firm energy estimate where a reservoir fails to completely use its power storage during the critical drawdown period.

- convert the storage remaining at the end of the critical drawdown period to average cfs in order to determine the additional average flow that could be used during the critical drawdown period.

- divide the initial energy output for the critical drawdown period by the number of hours to determine the average power in kilowatts.

- determine the average power discharge for the critical drawdown period from the routing data.

- divide the average power output by the average power discharge to determine the average kW/cfs for the critical drawdown period.

- multiply the additional average flow from the first step by the average kW/cfs and the number of hours in the critical drawdown period to determine the approximate amount of additional energy that could be produced during the critical drawdown period.

- convert the additional energy to a monthly distribution as described in Section H-2b(9) and add to the monthly power requirements.

c. Example of Firm Energy Output Recalculation.

(1) The 27,100 acre-feet of storage remaining at the end of the critical drawdown period corresponds to:

$$\frac{(27{,}100\ \text{AF})(43{,}560\ \text{ft}^3/\text{AF})}{(670\ \text{days})(24\ \text{hrs/day})(3600\ \text{sec/hr})} = 20.4\ \text{cfs.}$$

(2) The total output for the critical drawdown period is the sum of the values in Column 18, or 136,800,000 kWh. The average power output during the initial hand regulation was:

$$\frac{(136{,}800{,}000\ \text{kWh})}{(670\ \text{days})(24\ \text{hrs/day})} = 8{,}510\ \text{kW.}$$

(3) The average power discharge, obtained from Column 10 of Table H-3, was 654 cfs. Therefore, average kW/cfs was:

$$\frac{8510\ \text{kW}}{654\ \text{cfs}} = 13.0\ \text{kW/cfs.}$$

TABLE H-3. Initial Critical period SSR routing

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Routing Period Month	Year	Inflow 'I' (CFS)	Evaporation 'E' (CFS)	Withdrawals 'W' (CFS)	Net Inflow (CFS)	Energy Required (MWh)	Average Pool Elev. (Feet)	kW Per CFS	Required Power Discharge 'Q_p' (CFS)
Apr	1962	-	-	-	-	-	-	-	-
- - - - -	- - - - -	- - - - -	- - - - -	- - - - -	- - - - -	- - - - -	- - - - -	- - -	Start of
May	1962	389	-29	55	363	6,000	599.5	14.0	576
		"	"	"	"	"	599.0	14.0	576
Jun	1962	230	37	95	98	6,000	598.5	13.9	600
		"	"	"	"	"	597.4	13.8	604
Jul	1962	21	58	94	-131	12,000	596.3	13.8	1,169
		"	"	"	"	"	593.4	13.6	1,186
Aug	1962	46	55	94	-103	12,000	590.2	13.3	1,213
		"	"	"	"	"	586.9	13.1	1,231
Sep	1962	182	24	66	92	6,000	582.2	12.7	656
Oct	1962	1,731	2	33	1,696	3,600	584.1	12.8	378
Nov	1962	697	-29	25	701	3,600	588.1	13.1	382
Dec	1962	465	-42	24	483	6,000	588.5	13.2	611
Jan	1963	633	-42	24	651	6,000	588.1	13.1	616
Feb	1963	182	-30	26	186	3,600	587.7	13.1	409
Mar	1963	2,109	-19	27	2,101	3,600	591.2	13.4	361
Apr	1963	913	-12	37	888	3,600	596.4	13.8	362
May	1963	396	-29	55	370	6,000	597.0	13.8	584
Jun	1963	36	36	95	-95	6,000	595.0	13.7	608
Jul	1963	65	56	94	-85	12,000	590.3	13.3	1,213
Aug	1963	43	54	94	-105	12,000	583.8	12.8	1,260
Sep	1963	19	23	66	-70	6,000	578.4	12.4	672
Oct	1963	0	2	33	-35	3,600	575.2	12.2	397
Nov	1963	0	-25	25	0	3,600	572.8	12.0	417
Dec	1963	15	-35	24	26	6,000	569.5	11.8	684
Jan	1964	15	-33	24	24	6,000	565.0	11.4	707
Feb	1964	338	-22	26	334	3,600	562.3	11.2	462
- - - - -	- - - - -	- - - - -	- - - - -	- - - - -	- - - - -	- - - - -	- - - - -	End of	Critical

for Broken Bow Reservoir, Oklahoma

(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
Required Minimum Discharge (CFS)	Required Total Discharge (CFS)	Change in Storage, Δ S (CFS)	(AF)	End of Period Reservoir Status (AF)	(Elev.)	Reservoir Surface Area (Acres)	Total Power Generation (MWh)
-	-	-	-	918,800	599.5	14,200	-
Critical Period -							
88	586	-223	-13.700	905,100	598.5	-	-
88	586	-223	-13,700	905,100	598.5	14,100	6,000
90	610	-512	-30,500	874,600	596.3	-	-
90	614	-516	-30,700	874,400	596.3	13,800	6,000
120	1,179	-1,310	-80.600	793.800	590.4	-	-
120	1,196	-1,327	-81,600	792,800	590.2	13,000	12,000
175	1.223	-1,326	-81,500	711,300	583.7	-	-
175	1,241	-1,343	-82,600	710,200	583.6	12,200	12,000
314	666	-574	-34,200	676,000	580.8	11,800	6,000
320	388	1,308	80,400	756,400	587.5	12,600	3,600
320	392	309	18,400	774,800	588.8	12,800	3,600
235	621	-138	-8,500	766,300	588.1	12,700	6,000
118	626	25	1,500	767,800	588.2	12,700	6,000
90	419	-233	-12,900	754,900	587.2	12,600	3,600
86	371	1,730	106,400	861,300	595.3	13,600	3,600
86	372	516	30,700	892,000	597.5	13,900	3,600
88	594	-224	-13.800	878,200	596.6	13,800	6,000
90	618	-713	-42,400	835,800	593.4	13,400	6,000
120	1,223	-1,308	-80.400	755,400	587.2	12,600	12,000
173	1.270	-1,375	-84,500	670,900	580.3	11,700	12,000
314	682	-752	-44,700	626,200	576.4	11,200	6,000
320	407	-442	-27.200	599,000	574.0	10,900	3,600
320	427	-427	-25,400	573,600	571.6	10,600	3,600
235	694	-720	-44,300	529,300	567.4	10,100	6,000
118	717	-741	-45,600	483,700	562.7	9,600	6,000
90	472	-138	-7,900	475,800	561.9	9,500	3,600
Drawdown Period -							

TABLE H-4. Second Critical period SSR routing

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Routing Period Month	Year	Inflow 'I' (CFS)	Evapo-ration 'E' (CFS)	With-drawals 'W' (CFS)	Net Inflow (CFS)	Energy Required (MWh)	Avg. Pool Elevation (Ft., MSL)	kW Per CFS	Required Power Discharge (CFS)
Apr	1962								
									Start
May	1962	389	-29	55	363	6,200	599.5	14.0	595
		"	"	"	"	"	599.0	14.0	595
Jun	1962	230	37	95	98	6,200	598.4	13.9	620
		"	"	"	"	"	597.3	13.8	624
Jul	1962	21	58	94	-131	12,350	596.1	13.8	1,212
		"	"	"	"	"	593.0	13.6	1,230
Aug	1962	46	55	94	-103	12,350	589.8	13.3	1,248
		"	"	"	"	"	586.5	13.1	1,277
Sep	1962	182	24	66	92	6,200	581.5	12.7	684
Oct	1962	1,731	2	33	1,696	3,700	583.2	12.8	389
Nov	1962	697	-29	25	701	3,700	587.3	13.1	392
Dec	1962	465	-41	24	482	6,200	587.6	13.2	636
Jan	1963	633	-41	24	650	6,200	587.2	13.1	636
Feb	1963	182	-30	26	186	3,700	586.7	13.1	424
Mar	1963	2,109	-18	27	2,100	3,700	590.1	13.4	374
Apr	1963	913	-12	37	888	3,700	595.3	13.8	375
May	1963	396	-29	55	370	6,200	595.8	13.8	608
Jun	1963	36	36	95	-95	6,200	593.7	13.7	633
Jul	1963	65	55	94	-84	12,350	588.8	13.3	1,258
Aug	1963	43	52	94	-103	12,350	581.9	12.8	1,307
Sep	1963	19	22	66	-69	6,200	576.1	12.4	700
Oct	1963	0	2	33	-35	3,700	572.8	12.2	414
Nov	1963	0	-24	25	-1	3,700	570.1	12.0	436
Dec	1963	15	-34	24	25	6,200	566.7	11.8	725
Jan	1964	15	-32	24	23	6,200	562.2	11.4	744
Feb	1964	338	-21	26	333	3,700	559.3	11.2	483
									End of
Mar	1964	2,438	-14	27	2,424	3,700	559.3	11.27	436
Apr	1964	2,851	-9	37	2,823	3,700	577.6	12.36	414
May	1964	457	-25	55	427	6,200	583.4	12.77	651
Jun	1964	46	31	95	-80	6,200	580.9	12.67	683
Jul	1964	2	48	94	-140	12,350	574.7	12.17	1,372
Aug	1964	501	45	94	362	12,350	567.1	11.72	1,431
Sep	1964	796	19	66	711	6,200	563.6	11.31	762
Oct	1964	316	2	33	281	3,700	562.8	11.26	444
Nov	1964	1,225	-22	25	1,222	3,700	564.6	11.31	451
Dec	1964	589	-33	24	598	6,200	566.5	11.50	725
Jan	1965	1,200	-33	24	1,199	6,200	567.5	11.57	718
Feb	1965	3,579	-24	26	3,577	3,700	576.6	12.17	448
Mar	1965	1,208	-18	27	1,199	3,700	586.3	13.03	383
Apr	1965	774	-11	37	748	3,700	589.1	13.21	389
May	1965	2,567	-27	55	2,539	6,200	594.3	13.51	613
Jun	1965	1,775	37	95	1,643	6,200	599.0	13.97	615
									End of Critical

for Broken Bow Reservoir. Oklahoma

(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
Required Minimum Discharge (CFS)	Required Total Discharge (CFS)	Change in Storage, ΔS (CFS)	(AF)	End of Period Reservoir Status (AF)	(Elev.)	Reservoir Surface Area (Acres)	Total Power Generation (MWh)
				918,800	599.5	14,200	
Critical Period							
88	605	-242	-14,900	903,900	598.4		
	605	-242	-14,900	903,900	598.4	14,000	6,200
90	630	-532	-31,700	872,200	596.2		
	634	-536	-31,900	872,000	596.1	13,700	6,200
120	1,222	-1,353	-83,200	788,800	588.9		
	1,240	-1,371	-84,300	787,700	589.8	12,900	12,350
173	1,258	-1,361	-83,700	704,000	583.1		
	1,287	-1,390	-85,500	702,200	583.0	12,000	12,350
314	694	-602	-35,800	666,400	579.9	11,600	6,200
320	399	1,297	79,800	746,200	586.6	12,500	3,700
320	402	299	17,800	764,000	588.0	12,700	3,700
235	646	-164	-10,100	753,900	587.2	12,600	6,200
118	646	4	200	754,100	587.2	12,600	6,200
90	434	-248	-13,800	740,300	586.1	12,400	3,700
86	384	1,716	105,500	845,800	594.2	13,500	3,700
86	385	503	29,900	875,700	596.4	13,800	3,700
88	618	-248	-15,200	860,500	595.3	13,600	6,200
90	643	-738	-43,900	816,600	592.0	13,200	6,200
120	1,268	-1,352	-83,100	733,500	585.5	12,300	12,350
173	1,317	-1,420	-87,300	646,200	578.2	11,400	12,350
314	710	-779	-46,300	599,900	574.1	10,900	6,200
320	424	-459	-28,200	571,700	571.4	10,600	3,700
320	446	-447	-26,600	545,100	568.9	10,300	3,700
235	735	-710	-43,700	501,400	564.5	9,800	6,200
118	754	-731	-44,900	456,500	559.8	9,300	6,200
90	493	-160	-9,200	447,300	558.8	9,200	3,700
Critical Drawdown Period							
86	446	1,978	121,600	568,900	571.2	10,600	3,700
86	424	2,399	142,700	711,600	583.8	12,200	3,700
88	661	-234	-14,400	697,200	582.6	12,000	6,200
90	693	-773	-46,000	651,200	578.7	11,500	6,200
120	1,382	-1,522	-93,600	557,600	570.1	10,500	12,350
173	1,441	-1,079	-66,300	491,300	563.6	9,700	12,350
314	772	-61	-3,600	487,700	563.3	9,700	6,200
320	454	-173	-10,600	477,100	562.2	9,500	3,700
320	461	761	45,300	522,400	566.7	10,100	3,700
235	735	-137	-8,400	514,000	565.9	10,000	6,200
118	728	471	29,000	543,000	568.7	10,300	6,200
90	458	3,119	173,200	716,200	584.1	12,200	3,700
86	393	806	49,600	765,800	588.1	12,700	3,700
86	399	349	20,800	786,600	589.7	12,900	3,700
88	623	1,916	117,800	904,400	598.5	14,100	6,200
90	1,401	242	14,400	918,800	599.5	14,200	14,020
Period							

(4) The additional energy that could be generated during the critical drawdown period from the 19.9 cfs of "unused" flow calculated in Step (1) would be approximately equal to

(20.4 cfs)x(13.0 kW/cfs)x(670 days)x(24 hours/day) = 4,300,000 kWh.

(5) The new firm energy estimate for the critical drawdown period at Broken Bow Reservoir would be

(136,800,000 kWh + 4,300.000 kWh) = 141,100.000 kWh.

Using the procedure described in Section H-2b(8), the annual firm energy generation would be:

$$(141{,}100{,}000 \text{ kWh}) \times \frac{(100\%)}{(190\%)} = 74{,}200{,}000 \text{ kWh.}$$

(6) Each month's firm energy requirement must now be recalculated using the monthly percentages shown in Table H-1. The resulting firm energy requirements are as follows;

January	6,200.000 kWh	July	12,350,000 kWh
February	3.700.000 kWh	August	12,350,000 kWh
March	3,700,000 kWh	September	6,200.000 kWh
April	3,700.000 kWh	October	3,700,000 kWh
May	6,200.000 kWh	November	3,700,000 kWh
June	6,200.000 kWh	December	6,200,000 kWh

H-5. Final Firm Energy Estimate. The second hand routing for Broken Bow Reservoir. using the recalculated monthly firm energy requirements, is shown on Table H-4. In this routing, Broken Bow Reservoir is drafted to 1,400 acre-feet below the bottom of its power pool in February 1964. This means that firm energy was slightly overestimated (by 0.16%). A further regulation could be made to eliminate this error, but 0.16 percent is well within the accuracy required for planning studies.

APPENDIX I

SSR REGULATION USING ALTERNATIVE OPERATING STRATEGIES

I-1. Introduction.

a. This appendix shows the effects of various operating strategies on power generation at Broken Bow Reservoir, Oklahoma, during operating year June 1965-May 1966. This year was selected for routing because its total runoff most closely approximates the average annual runoff for the period of record. The project characteristics are the same as described in Section H-1b of Appendix H. and the project firm energy requirements are those developed in Section H-4.

b. Except as noted, the routings follow the basic procedure outlined in Sections 5-10f and H-3. Tables summarizing the routings are presented for each case, and these tables follow the general format prescribed as Table 5-6 and described on Table 5-7. Although two or more iterations were required in order to achieve balance in some months, only the final iteration is shown in the supporting tables.

c. In the routings, the total discharge in any given period would be defined by one of the following parameters:

- power discharge required to meet firm energy requirements (Column 10) plus 10 cfs leakage losses
- water quality discharge requirements (Column 11)
- net inflow (Column 6), when reservoir is at the top of the conservation pool
- net inflow plus or minus Column 13, the storage draft required to meet end-of-period rule curve elevation
- powerplant hydraulic capacity (2000 cfs) plus 10 cfs
- power discharges required to meet other specified power requirements (Column 10) plus 10 cfs. This applies only to Cases 4 and 5.

In order to make it easier to follow the routings on the tables, the parameter controlling the total discharge for each monthly interval is designated with an asterisk. It should be noted that in some months more than one parameter is involved in establishing the discharge requirement.

d. Energy benefits were computed for the six cases using the energy values shown on Figure I-1. The energy benefit calculations are shown on Table I-9. Table I-1 compares various parameters for the six cases.

I-2. Case 1: Routing to Protect Firm Energy Capability.

a. The primary objective of this routing, which is discussed in Section 5-10h, is to meet firm energy requirements. Hence, storage will be drafted only to meet these requirements. Secondary energy will be generated only when the reservoir is full and the net inflow exceeds the firm energy discharge requirements. This routing strategy will give the maximum assurance that firm energy requirements will be met, but it lacks the flexibility to utilize excess streamflow effectively in good water years.

b. The routing is summarized on Table I-2 and is plotted as Figure 5-35. Heavy runoff in June allowed a large amount of secondary energy to be generated without drafting the power pool. The reservoir was operated essentially as a run-of-river project during this period.

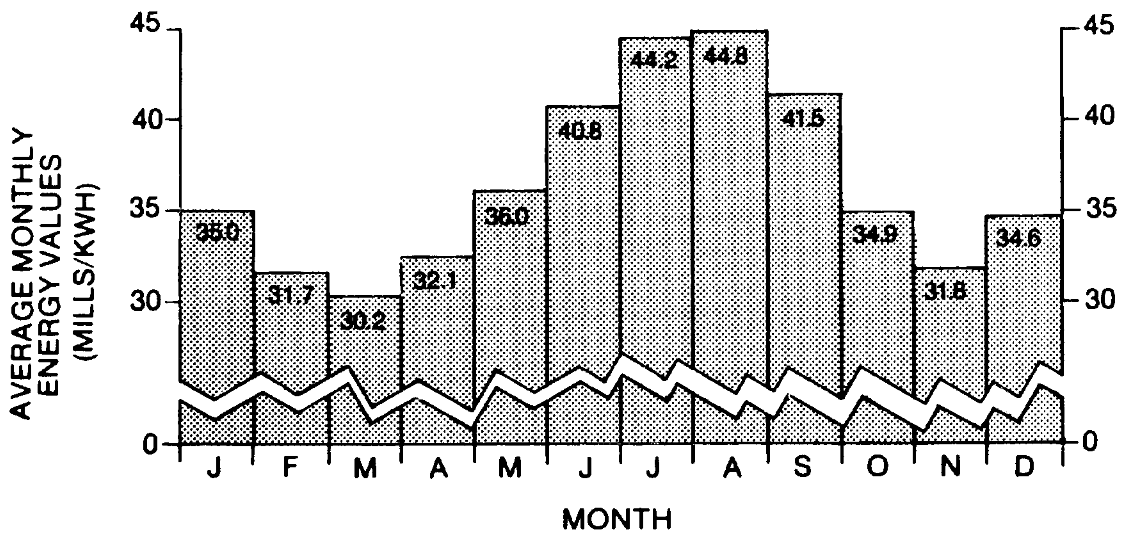


Figure I-1. Monthly energy values

TABLE I-1
Comparisons of Various Parameters for Cases 1 Through 6
for an Average Water Year (1965-66)

	Case 1	Case 2	Case 3
Average inflow (cfs)	855	855	855
Average evaporation (cfs)	-2	0	1
Average withdrawals (cfs)	52	52	52
Average losses (cfs)	10	10	10
Average power discharge (cfs)	796	811	757
Average pool elev. (Ft, MSL)	589.4	585.0	578.6
Average kW/cfs	13.44	13.16	12.35
Annual generation (MWh)	93,710	91,850	82,050
Generation, percent of Case 1	100.0	98.0	87.6
Spill (AF)	0	0	38,300
Annual energy benefit, $1000 1/	$3,610	$3,590	$2,930
Average energy value, mills/kWh	38.52	39.85	35.72

	Case 4	Case 5	Case 6
Average inflow (cfs)	855	855	855
Average evaporation (cfs)	-2	-1	-2
Average withdrawals (cfs)	52	52	52
Average losses (cfs)	10	10	10
Average power discharge (cfs)	782	796	796
Average pool elev. (Ft, MSL)	598.1	585.0	594.6
Average kW/cfs	13.93	13.31	13.81
Annual generation (MWh)	95,460	92,820	96,270
Generation, percent of Case 1	101.9	99.1	102.7
Spill (AF)	11,300	0	0
Annual energy benefit, $1000 1/	$3,350	$3,770	$3,560
Average energy value, mills/kWh	35.11	40.62	36.94

1/ From Table I-9.

From July through January, demands on the reservoir exceeded available inflow, and the pool was drafted to an elevation of 579.9 feet. Heavy inflow in February, April. and May allowed the power pool to refill to maximum elevation, and a total of 9,250 MWh of secondary energy was generated during May. The annual generation for the operating year 1965-66 is 93,710 MWh.

I-3. Case 2: Rule Curve Routing.

a. For this routing, which is described in Section 5-11c, the rule curve derived in Appendix J was used to guide reservoir regulation as follows:

- for each month, the end-of-month rule curve elevations will be met whenever possible.
- the reservoir can be drafted below the rule curve only to meet firm energy requirements.
- the reservoir can be allowed to fill above the rule curve only to avoid spill (i.e., when following the rule curve results in discharges in excess of the powerplant's 2000 cfs hydraulic capacity).

b. The routing is summarized on Table I-3 and is plotted as Figure 5-37. The rule curve is shown as a dashed line on the figure. The reservoir was drafted in June at the powerplant's full 2000 cfs hydraulic capacity. but because of high reservoir inflows, it was not possible to meet the end-of-month rule curve elevation. The rule curve was reached at the end of July. but the reservoir had to be drafted below rule curve from September through January in order to meet firm energy requirements. Refill began in February, but the reservoir was just able to refill by the end of May. It should be noted that the storage will not be completely refilled in every year. However. as long as generation is limited to firm energy requirements whenever the reservoir falls below the rule curve, the reservoir will always be able to meet firm energy requirements without violating the the minimum power pool.

c. The average annual energy output for this case is 91,850 MWh, which is somewhat less than Case 1. However. because more energy is generated in the peak demand months of June and July. when the energy has a higher value, the energy benefits are somewhat higher (see Table I-9).

I-4. Case 3: Routing With Joint Use Storage.

a. Storage Allocation. In this example, which is discussed in Section 5-12e(4), the Broken Bow storage will be divided into three zones, which are primarily defined by the flood control rule curve (Figure 5-40).

Top of flood control pool:	El. 604.1 (985.900 AF)
Top of joint-use zone:	El. 595.0 (856,400 AF)
Bottom of joint-use zone:	El. 568.0 (535.900 AF)
Bottom of conservation pool:	El. 559.0 (448,700 AF)

The project provides 450.000 AF of flood control space, the same as the previous example (see Appendix H), but the full 450.000 AF is provided only in the winter months. During the summer months, it is assumed that only 129,500 AF of flood control space is required, so the remaining (856,400 - 535.900) = 320.500 AF of storage space between El. 595.0 and El. 568.0 (the joint use storage zone) would be available for hydropower regulation. To insure that firm energy requirements are met in the winter months in dry years and to help assure refill in dry years, an additional 87,200 AF of space between El. 559.0 and El. 568.0 is allocated to exclusive power storage.

b. Firm Energy Output. With such a large amount of storage being allocated to winter flood control, very little carry-over of conservation storage is possible. Thus, the project's firm yield will be defined by the single year with the most adverse sequence of flows, instead of the multi-year critical period 1962-65. An examination of the mass diagram (Figure F-2) shows that May 1963-April 1964 is the most adverse water year. and that approximately 256,000 AF is the maximum amount of conservation storage that can be used effectively in that year. However. the flood control rule curve imposes a constraint on refill. By testing alternative firm power storage volumes, it was found that the flood control rule curve limits usable firm power storage to about 218,000 AF (El. 580.0). Thus it is refilled in the previous water year (1962-63), rather than runoff in the critical water year (1963-64), that establishes the firm power storage in this example. Alternative routings for the 1963 refill season are plotted on Figure I-2 to illustrate how the spring flood control rule curve limits the amount of storage that can be counted on as being available by the first of June, 1963. Without the rule curve limit, the reservoir would refill to El. 582.0, and 242,000 AF of firm power storage would be available on June first.

c. Monthly Firm Energy Requirements. A firm energy routing was then made for the 1963-64 critical period, using 218,000 AF of firm power storage and following the procedure outlined in Appendix H. Following are the resulting monthly firm energy requirements.

January	2,980 MWh	July	5,960 MWh
February	1,790 MWh	August	5,960 MWh
March	1,790 MWh	September	2,980 MWh
April	1,790 MWh	October	1,790 MWh
May	2,980 MWh	November	1,790 MWh
June	2,980 MWh	December	2,980 MWh

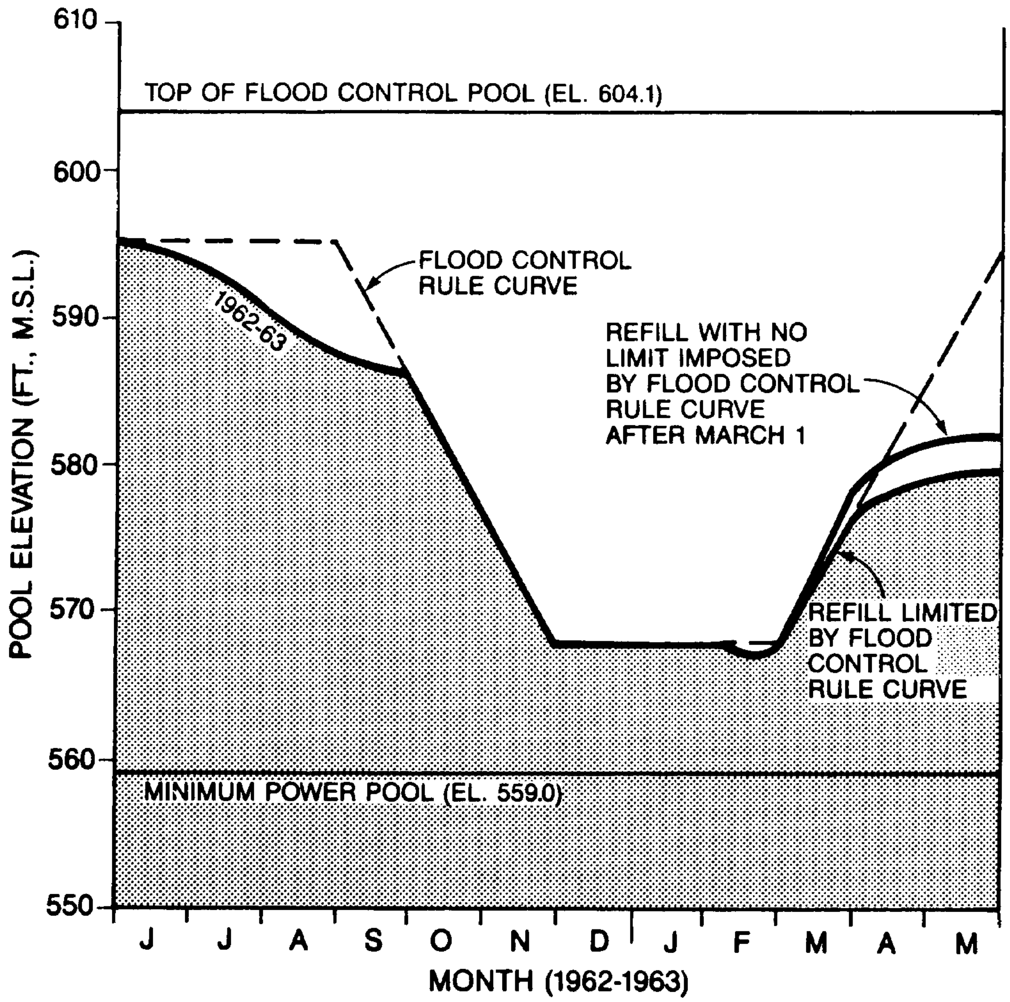


Figure I-2. Routings for 1962-63 water year illustrating impact of spring flood control rule curve on refill

The project would then be routed through the entire period of record using these firm energy requirements and the mandatory flood control rule curve.

d. Operation in an Average Water Year. The routing for 1965-66 is summarized in Table I-4 and plotted as Figure 5-42. In this example, the objective is to meet firm energy requirements, producing secondary energy only when drafts are required to follow the flood control rule curve. The combination of low spring runoff and the constraints imposed by the flood control rule curve resulted in the joint use storage not being completely filled as of the first of June, 1965. Some additional filling was accomplished in June, but the low summer inflows and high firm power discharge requirements resulted in storage drafts to meet firm energy requirements in July. August, and September. In October and November. the flood control rule curve governed drawdown, and secondary energy was produced. In December, energy production was limited to firm requirements, and the reservoir was drafted below the flood control rule curve. In January. moderate inflows permitted regaining the rule curve and allowed generating a small amount of secondary energy. Inflows were high in February, but some water had to be spilled in order to stay on the rule curve. In the spring of 1966, runoff was again insufficient to completely refill the joint use storage, although the firm power storage (El. 580.0) was refilled. The annual energy production would be 82.050 MWh, and the energy benefits would be $2.931.000.

e. Shifting Secondary Energy to Peak Demand Months. In the months of October and November. firm power discharge requirements are low. but large drafts are often required in order to stay on the flood control rule curve. Thus, in most years secondary energy would be produced in these months. Since energy has a substantially higher value in July and August, a preferred operating strategy would be to shift at least part of the secondary energy production to these months. This could be accomplished by discharging as much of the joint use storage in July and August as is possible without jeopardizing firm energy production in subsequent months. Although it would be possible to draft down to the firm energy rule curve, in some years this strategy may result in not refilling the firm power storage in the following spring. A more conservative approach would be to retain enough storage to meet firm energy requirements in September, October. and November. while just reaching the flood control rule curve on December first. The resulting "power rule curve" is shown on Figure I-3. Figure I-4 shows reservoir regulation for the summer and fall of 1965 based on this strategy. and it can be seen how the "power rule curve" sets a limit on the draft in these months. Energy benefits for the year would be $3,200.000. an increase of almost ten percent compared to the routing described in the preceding paragraph. The annual energy production would be reduced slightly due to a lower head in the fall months.

f. Use of Secondary Conservation Storage. The maximum conservation storage space available in the summer months is the storage between the top of the joint use pool (El. 595.0) and the minimum power pool (El. 559.0), or 407,700 AF. Of this, 218,000 AF is reserved for firm power storage (Section I-4b). This leaves (407,700 - 218,000) = 189,700 AF of space available for secondary conservation

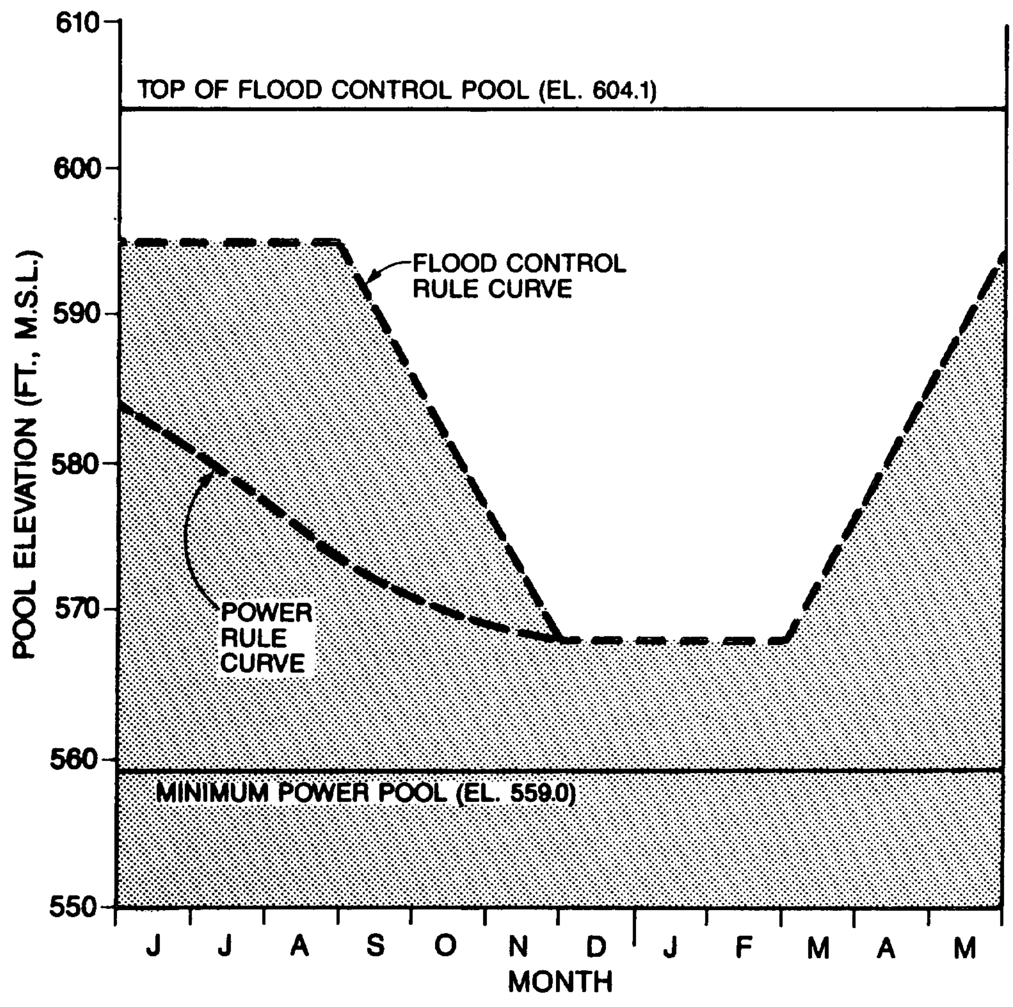


Figure I-3. Power rule curve to limit drawdown in summer months storage (see Figure 5-41). Note that in the example (Table I-4), only 179,400 AF of the 189,700 AF of secondary conservation storage was utilized in this operating year. and only 88,900 AF was available at the start of the next operating year. In Section 5-12e, it was pointed out that the secondary conservation storage space must be filled a reasonably high percentage of the years for it to be economically attractive. By examining the performance of the secondary conservation storage over the entire period of record, it is possible to determine how much space should be allocated to this function. In the case of the example project, it may be determined,

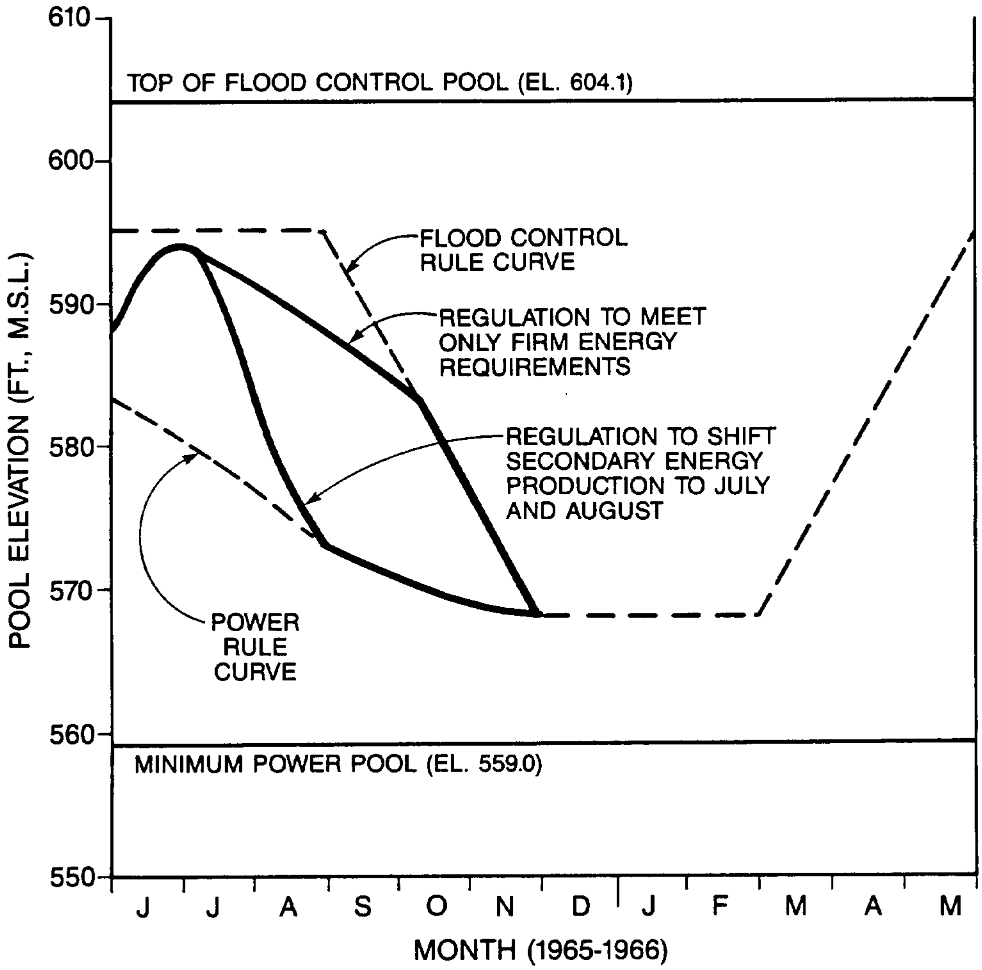


Figure I-4. Regulation in an average water year to shift secondary energy production to the months of July and August, when energy has its highest value for instance, that only 120,000 AF of secondary conservation storage can be used effectively. The top of the joint use pool would then be El. 589.8, and the remaining storage space (between El. 589.8 and El. 599.5) would be allocated to summer flood control.

g. At-Site Recreation. Another consideration is at-site recreation. In most parts of this country, the most satisfactory operation for recreation would be to maintain a constant reservoir elevation between Memorial Day and Labor Day (essentially from June through August). To most closely meet this criteria, the desired power operation would to be to set the top of the conservation pool on the basis of a storage volume that has a high probability of refilling, and to limit energy production in the summer months to firm energy requirements. Also, the modified regulation to increase energy benefits (Section I-4e) would conflict with the objective of maintaining a relatively constant summer pool elevation.

h. Multiple-Purpose Rule Curves. It should be obvious that in order to develop a satisfactory rule curve for regulating joint use storage for flood control, power generation, reservoir recreation, and perhaps other purposes, a careful balancing process is required. It may be necessary to test a large number of alternative operations in order to develop the rule curve which best meets the requirements of all purposes. This would involve testing alternative reservoir sizes and storage allocations as well as rule curve shapes.

I-5. Case 4: Routing to Maximize Average Energy.

a. In this case, which is discussed in Section 5-13b, the objective is to maximize energy output, and this is accomplished by holding the pool at its maximum possible elevation at all times. Thus, it operates essentially as a run-of-river plant. There is no attempt to meet a firm energy requirement, and drafts are made only to meet water quality discharge requirements.

b. The routing is summarized in Table I-5 and is plotted on Figure 5-46. Compared to the base case (Case 1), a higher head is available in most months, with a resulting energy gain. However, this gain is offset by spill in February, so the net energy gain is only 1,750 MWh, or about two percent. Another undesirable feature of this regulation is that only three percent of the energy output for this year occurs in the peak demand months of July and August, while in Case 1, 26 percent of the energy was produced in these months. The average annual generation, at 95.460.000 KWh, is the second highest of the six cases, but the energy benefits, at $3,350,000, are the second lowest (see Table I-1). Note that Case 6, which is designed to maximize dependable capacity, actually produces the maximum energy for this water year.

I-6. Case 5: Routing to Maximize Energy Benefits.

a. The purpose of this routing, which is also discussed in Section 5-13b, is to maximize dollar benefits, and this is accomplished by concentrating as much generation as possible into the peak demand months of June through September. Figure I-1 shows that the value of energy is substantially higher in these months than in other months. It is assumed, for the purposes of this routing, that environmental or recreational considerations would not preclude a large drawdown of the power pool in the summer months.

b. As with the previous routings (except Case 3), it is assumed that the power pool will normally be full at the end of May. During June, the powerplant will be operated at 1000 cfs (fifty percent of the powerplant's hydraulic capacity) or inflow, whichever is greater. During July and August, it is operated at full hydraulic capacity (2000 cfs), and during September, the powerplant backs off again to 1000 cfs. Through the remainder of the year, releases are limited to the water quality discharge requirements, and surplus inflow is used to refill the power storage. An analysis of the most adverse water year (1963-64) shows that the high power discharges can be maintained during the summer months without jeopardizing water quality discharge requirements in later months. However, to insure that problems do not occur in other water years, a rule curve was developed for the low flow discharge requirements by doing a reverse routing starting with the reservoir empty at the end of January 1964 (see Section J-2 of Appendix J). In making the drafts for hydropower in the summer months, the reservoir elevation will not be permitted to fall below that rule curve.

c. The routing for the 1965-66 water year is summarized on Table I-6 and is plotted on Figure 5-46. It can be seen that 63 percent of the usable storage is drafted in the summer months. The annual generation is 92,800 MWh, which is three percent lower than the case to maximize average energy (Case 4), largely due to a lower average head, but the energy benefits, at $3,770,000, are twelve percent higher than for Case 4 (see Table I-1).

I-7. Case 6: Maximize Dependable Capacity.

a. The objective of this routing, which is discussed in Section 5-13c, is to maintain the reservoir at or above the elevation corresponding to the powerplant's rated head. This will insure that the plant's full installed capacity is available at all times. However. just maintaining the pool at or above that elevation is not sufficient. For the capacity to be usable, it must be supported by energy. Therefore, a critical period routing was made based on the power storage above critical head in order to determine the firm energy available for supporting this capacity.

b. It is assumed that Case 6 is a reanalysis of an existing reservoir that was originally designed as described in Appendix H (i.e., where the full storage between El. 559.0 (448,700 AF) and El. 599.5 (918,800 AF) was to be available for hydropower regulation and the objective was to maximize firm energy). It is assumed that the power system resource mix has changed and the hydro project would now serve the system best by providing its full dependable capacity at all times. As originally designed, the units would probably have been rated to provide full capacity down to a head corresponding to (or slightly below) the reservoir elevation with 50 percent of the power storage remaining (see Section 5-5c(8)). Elevation 580.0 (667,000 AF) would therefore be a reasonable assumption for the rated head.

c. Using the storage available between El.580.0 and El. 559.5. monthly preliminary firm energy estimates were derived as described in Section H-2. With only 251,800 AF of power storage available instead of 470,100 AF, it was assumed that the critical period would be one year long, and Figure F-2 shows that 1963-64 is the most adverse single year.

d. Table I-7 shows the final regulation for this period. The generation for the critical drawdown period (June 1963 - January 1964), was 36,460 MWh. of which only 35,000 MWh is considered firm (see below). Using the percentages from Table H-1, the annual firm energy would be (100%/76.7%) x (35,000 MWh) = 45,700 MWh. The corresponding monthly firm energy requirements would be as follows:

January (8.33%)	3,800 MWh	July (16.67%)	7,600 MWh
February (5.0%)	2,300 MWh	August (16.67%)	7,600 MWh
March (5.0%)	2,300 MWh	September (8.33%)	3,800 MWh
April (5.0%)	2,300 MWh	October (5.0%)	2,300 MWh
May (8.33%)	3,800 MWh	November (5.0%)	2,300 MWh
June (8.33%)	3,800 MWh	December (8.33%)	3,800 MWh

e. Note that the actual generation shown in Table I-7 for October and November exceeded the 2,300 MWh firm energy requirement, because higher discharges were necessary to meet the water quality discharge requirements. In a sense, the full 3,090 MWh generated in October and the 2,970 MWh produced in November are firm, because they can be produced even in the most adverse year. However, since they exceed the 5.0 percent allocated for those months, firm energy credit is limited in this example to the generation corresponding to the 5.0 percent allocation, or 2,300 MWh. In many power systems, there is enough flexibility in the operation of other generating resources to accomodate the deviation from the monthly percentage allocations, and the full generation for these months could be considered firm.

f. A routing was also made for operating year 1965-66 using the firm energy requirements listed above. Storage was drafted only to meet firm energy requirements, so the reservoir remained at the top of power pool during the months of June, 1965 and March through May, 1966. The routing is summarized on Table I-8, and both the critical year routing and 1965-66 routings are plotted as Figure 5-47. The annual generation for 1965-66 is 96,270 MWh.

g. It can be seen that this generation actually exceeds the 95,460 MWh for the case which was intended to maximize average energy (Case 4). This is because the energy that was spilled in February in Case 4 (because of a full reservoir and net inflow in excess of the plant's hydraulic capacity) is converted to usable energy in Case 6. Hence, the regulation strategy followed in Case 6 may prove to be the one that maximizes average energy, rather than Case 4, but the entire period of record would have to be analyzed in order to verify this.

TABLE I-2. Case 1: Routing to Protect

(1) Routing Interval Month	(2) Year	(3) Inflow 'I' (cfs)	(4) Evaporation 'E' (cfs)	(5) Withdrawals 'W' (cfs)	(6) Net Inflow (cfs)	(7) Energy Requirement (MWh)	(8) Average Pool Elevation (feet)	(9) Net Head or kW/cfs
May	1965	-	-	-	-	-	-	-
Jun	1965	1,775	37	95	1,643*	6,200	599.5	14.0
Jul	1965	139	60	94	-15	12,350	596.8	13.8
Aug	1965	13	58	94	-139	12,350	590.8	13.4
Sep	1965	394	13	66	315	6,200	586.7	13.1
Oct	1965	189	3	33	153	3,700	585.2	12.9
Nov	1965	102	-28	25	105	3,700	583.8	12.8
Dec	1965	195	-40	24	211	6,200	581.9	12.7
Jan	1966	504	-38	24	518	6,200	580.3	12.6
Feb	1966	2,701	-27	26	2,702	3,700	585.0	12.9
Mar	1966	499	-19	27	491	3,700	590.3	13.3
Apr	1966	1,930	-12	37	1,905	3,700	594.0	13.6
May	1966	2,021	-29	55	1,995*	6,200	598.4	13.9

* Parameter controlling total discharge for month

Firm Energy Capability

(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
REQUIRED DISCHARGES								
Power 'Q$_p$' (cfs)	Non-power (cfs)	Total (cfs)	Δ STORAGE, $S_1 - S_2$ (cfs)	(AF)	END OF PERIOD RESERVOIR STATUS (AF)	(elev.)	(acres)	Total Energy (MWh)
-	-	-	-	-	-	599.5	14,200	-
615	90	1,643	0	0	918,800	599.5	14,200	16,460
1,203*	120	1,213	-1,228	-75,500	843,300	594.0	13,500	12,350
1,239*	173	1,249	-1,388	-85,300	758,000	587.5	12,600	12,350
657*	314	667	-352	-21,000	737,000	585.8	12,400	6,200
386*	320	396	-243	-14,900	722,100	584.6	12,200	3,700
401*	320	411	-306	-18,800	703,300	583.1	12,100	3,700
656*	235	666	-455	-28,000	675,300	580.7	11,700	6,200
661*	118	671	-153	-9,400	665,900	579.9	11,600	6,200
427*	90	437	2,265	125,800	791,700	590.1	12,900	3,700
374*	86	384	107	6,600	798,300	590.6	13,000	3,700
378*	86	388	1,517	90,300	888,600	597.3	13,900	3,700
600	88	1,504	491*	30,200	918,800	599.5	14,200	15,450

TABLE I-3. Case 2:

(1) Routing Interval Month	(2) Year	(3) Inflow 'I' (cfs)	(4) Evapo-ration 'E' (cfs)	(5) With-drawals 'W' (cfs)	(6) Net Inflow (cfs)	(7) Energy Require-ment (MWh)	(8) Average Pool Elevation (feet)	(9) Net Head or kW/cfs
May	1965	-	-	-	-	-	-	-
Jun	1965	1,775	36	95	1,644	6,200	598.7	13.9
Jul	1965	139	59	94	-14	12,350	594.2	13.6
Aug	1965	13	55	94	-136	12,350	587.1	13.1
Sep	1965	394	24	66	304	6,200	582.7	12.7
Oct	1965	189	2	33	154	3,700	581.1	12.6
Nov	1965	102	-26	25	103	3,700	579.7	12.5
Dec	1965	195	-37	24	208	6,200	577.5	12.4
Jan	1966	504	-36	24	516	6,200	575.8	12.2
Feb	1966	2,701	-26	26	2,701	3,700	580.7	12.6
Mar	1966	499	-18	27	490	3,700	586.2	13.0
Apr	1966	1,930	-11	37	1,904	3,700	589.9	13.3
May	1966	2,021	-28	55	1,994	6,200	596.5	13.8

1/ Draft limited by powerplant hydraulic capacity (2000 cfs).
* Parameter controlling total discharge for month

Power Rule Curve Routing

(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
REQUIRED DISCHARGES			Δ STORAGE,		END OF PERIOD			
Power	Non-		$S_1 - S_2$		RESERVOIR STATUS			Total
'Q_p' (cfs)	power (cfs)	Total (cfs)	(cfs)	(AF)	(AF)	(elev.)	(acres)	Energy (MWh)
-	-	-	-	-	918,800	599.5	14,200	-
620	90	2,010 1/	-366	-21,800	897,000	597.9	14,000	20,020
1,221	120	1,599	-1,613	-99,200	797,800	590.6*	13,000	16,180
1,267*	173	1,277	-1,413	-86,900	710,300	583.6	12,100	12,350
678*	314	688	-384	-22,900	688,000	581.8	11,900	6,200
395*	320	405	-251	-15,400	672,600	580.5	11,700	3,700
411*	320	421	-318	-18,900	653,700	578.8	11,500	3,700
673*	235	683	-475	-29,200	624,500	576.3	11,200	6,200
683*	118	693	-177	-10,900	613,600	575.3	11,100	6,200
437*	90	447	2,254	125,200	738,800	586.0	12,500	3,700
383*	86	393	97	6,000	744,800	586.4	12,400	3,700
386*	86	396	1,508	89,800	834,600	593.4	13,200	3,700
604	88	625	1,369	84,200	918,800*	599.5	14,100	6,200

TABLE I-4. Case 3: Routing

(1) Routing Interval Month	(2) Year	(3) Inflow 'I' (cfs)	(4) Evapo-ration 'E' (cfs)	(5) With-drawals 'W' (cfs)	(6) Net Inflow (cfs)	(7) Energy Require-ment (MWh)	(8) Average Pool Elevation (feet)	(9) Net Head or kW/cfs
May	1965	-	-	-	-	-	-	-
Jun	1965	1,775	33	95	1713	2,980	591.1	13.4
Jul	1965	139	57	94	-12	5,960	592.8	13.5
Aug	1965	13	57	94	-138	5,960	589.6	13.3
Sep	1965	394	25	66	303	2,980	586.9	13.1
Oct	1965	189	2	33	154	1,790	581.5	12.7
Nov	1965	102	-26	25	103	1,790	572.5	12.0
Dec	1965	195	-33	24	204	2,980	567.5	11.6
Jan	1966	504	-33	24	513	2,980	567.5	11.6
Feb	1966	2,701	-24	26	2,699*	1,790	568.0	11.6
Mar	1966	499	-15	27	487	1,790	568.5	11.7
Apr	1966	1,930	-9	37	1,902	1,790	574.2	12.1
May	1966	2,021	-24	55	1,990	2,980	583.1	12.8

1/ This discharge is required in order to stay on the rule curve. Generation is limited to the 2000 cfs hydraulic capacity, so the balance is spilled.

* Parameter controlling total discharge for month

With Joint Use Storage

(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
REQUIRED DISCHARGES			Δ STORAGE,		END OF PERIOD RESERVOIR STATUS			Total
Power 'Q_p' (cfs)	Non-power (cfs)	Total (cfs)	$S_1 - S_2$ (cfs)	(AF)	(AF)	(elev.)	(acres)	Energy (MWh)
-	-	-	-	-	763,100	587.9	12,700	-
309*	90	319	1,394	83,000	846,100	594.2	13,500	2,980
593*	120	603	-615	-37,800	808,300	591.4	13,400	5,960
602*	173	612	-750	-46,100	762,200	587.8	12,600	5,960
316	314	688	-385	-22,900	739,300	586.0*	12,400	6,390
189	320	1,889	-1,735	-106,700	632,600	577.0*	11,300	17,750
207	320	1,727	-1,624	-96,700	535,900	568.0*	10,200	14,840
345*	235	355	-151	-9,300	526,600	567.1	10,100	2,980
345	118	362	151	9,300	535,900	568.0*	10,200	3,040
230	90	2,699 1/	0	0	535,900	568.0	10,200	15,590
206*	86	216	271	16,700	552,600	569.6	10,400	1,790
205*	86	215	1,687	100,500	653,100	578.8	11,500	1,790
313*	88	323	1,667	102,500	755,600	587.3	12,500	2,980

TABLE I-5. Case 4: Routing to

(1) Routing Interval Month	(2) Year	(3) Inflow 'I' (cfs)	(4) Evaporation 'E' (cfs)	(5) Withdrawals 'W' (cfs)	(6) Net Inflow (cfs)	(7) Energy Requirement (MWh)	(8) Average Pool Elevation (feet)	(9) Net Head or kW/cfs
May	1965	-	-	-	-	-	-	-
Jun	1965	1,775	37	95	1,643*	-	599.5	14.0
Jul	1965	139	60	94	-15	-	599.2	14.0
Aug	1965	13	60	94	-141	-	598.2	13.9
Sep	1965	394	27	66	301	-	597.5	13.8
Oct	1965	189	3	33	153	-	597.1	13.8
Nov	1965	102	-31	25	108	-	596.2	13.7
Dec	1965	195	-45	24	216	-	595.7	13.7
Jan	1966	504	-45	24	525	-	596.6	13.8
Feb	1966	2,701	-33	26	2,708*	-	598.5	13.9
Mar	1966	499	-21	27	493*	-	599.5	14.0
Apr	1966	1,930	-13	37	1,906*	-	599.5	14.0
May	1966	2,021	-29	55	1,995*	-	599.5	14.0

1/ The required discharge exceeded the powerplant hydraulic capacity, so 213 cfs of spill was required.
* Parameter controlling total discharge for month

Maximize Average Energy

(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
REQUIRED DISCHARGES								
Power 'Q$_p$' (cfs)	Non-power (cfs)	Total (cfs)	Δ STORAGE, $S_1 - S_2$ (cfs)	(AF)	END OF PERIOD RESERVOIR STATUS (AF)	(elev.)	(acres)	Total Energy (MWh)
-	-	-	-	-	918,800	599.5	14,200	-
-	90	1,643	0	0	918,800	599.5	14,200	16,460
-	120*	120	-135	- 8,300	910,500	598.9	14,100	1,150
-	173*	173	-314	-19,300	891,200	597.5	13,900	1,690
-	314*	314	-13	-800	890,400	597.5	13,900	3,020
-	320*	320	-167	-10,300	880,100	596.7	13,800	3,180
-	320*	320	-212	-12,600	867,500	595.8	13,700	3,060
-	235*	235	-19	-1,200	866,300	595.7	13,700	2,290
-	118*	118	407	25,000	891,300	597.5	13,900	1,110
-	90	2,213 1/	495*	27,500	918,800	599.5	14,200	18,680
-	86	493	0	0	918,800	599.5	14,200	5,030
-	86	1,906	0	0	918,800	599.5	14,200	19,110
-	88	1,995	0	0	918,800	599.5	14,200	20,680

TABLE I-6. Case 5:

(1) Routing Interval Month	(2) Year	(3) Inflow 'I' (cfs)	(4) Evaporation 'E' (cfs)	(5) Withdrawals 'W' (cfs)	(6) Net Inflow (cfs)	(7) Energy Requirement (MWh)	(8) Average Pool Elevation (feet)	(9) Net Head or kW/cfs
May	1965	-	-	-	-	-	-	-
Jun	1965	1,775	37	95	1,643*	-	599.5	14.0
Jul	1965	139	59	94	-14	-	594.9	13.6
Aug	1965	13	49	94	-130	-	585.0	12.9
Sep	1965	394	23	66	305	-	577.8	12.4
Oct	1965	189	2	33	154	-	575.5	12.2
Nov	1965	102	-25	25	102	-	574.4	12.1
Dec	1965	195	-36	24	207	-	573.8	12.1
Jan	1966	504	-36	24	516	-	574.8	12.2
Feb	1966	2,701	-26	26	2,701	-	582.0	12.7
Mar	1966	499	-19	27	491	-	589.1	13.2
Apr	1966	1,930	-12	37	1,905	-	594.1	13.6
May	1966	2,021	-29	55	1,995*	-	598.8	13.9

* Parameter controlling total discharge for month

Routing to Maximize Energy Benefits

(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
REQUIRED DISCHARGES								
Power 'Q$_p$' (cfs)	Non-power (cfs)	Total (cfs)	Δ STORAGE, $S_1 - S_2$ (cfs)	(AF)	END OF PERIOD RESERVOIR STATUS (AF)	(elev.)	(acres)	Total Energy (MWh)
-	-	-	-	-	918,800	599.5	14,200	-
1,000	90	1643	0	0	918,800	599.5	14,200	16,460
2,000*	120	2010	-2,024	-124,500	794,300	590.3	13,000	20,240
2,000*	173	2010	-2,140	-131,600	662,700	579.6	11,600	19,200
1,000*	314	1010	-705	-42,000	620,700	575.9	11,100	8,930
-	320*	320	-166	-10,200	610,500	575.0	11,000	2,810
-	320*	320	-218	-13,000	597,500	573.8	10,900	2,700
-	235*	235	-28	-1,700	595,800	573.7	10,900	2,030
-	118*	118	398	24,500	620,300	575.9	11,100	980
-	90*	90	2,611	145,000	765,300	588.1	12,700	680
-	86*	86	4052	24,900	790,200	590.0	12,900	750
-	86*	86	1,819	108,300	898,500	598.1	14,000	740
-	88	1,665	330*	20,300	918,800	599.5	14,200	17,120

TABLE I-7. Case 6: Routing to Maximize

(1) Routing Interval Month	(2) Year	(3) Inflow 'I' (cfs)	(4) Evapo-ration 'E' (cfs)	(5) With-drawals 'W' (cfs)	(6) Net Inflow (cfs)	(7) Energy Require-ment (MWh)	(8) Average Pool Elevation (feet)	(9) Net Head or kW/cfs
May	1963	-	-	-	-	-	-	-
Jun	1963	36	37	95	-96	3,800	598.5	13.9
Jul	1963	65	58	94	-87	7,600	595.5	13.7
Aug	1963	43	57	94	-108	7,600	591.6	13.4
Sep	1963	19	25	66	-72	3,800	588.4	13.2
Oct	1963	0	2	33	-35	2,300	586.4	13.0
Nov	1963	0	-29	25	4	2,300	584.8	12.9
Dec	1963	15	-39	24	30	3,800	583.0	12.8
Jan	1964	15	-38	24	29	3,800	581.0	12.6
Feb	1964	338	-28	26	340	2,300	580.2	12.5
Mar	1964	2,436	-17	27	2,426	2,300	585.7	13.0
Apr	1964	2,851	-12	37	2,828*	2,300	595.3	13.7
May	1964	457	-29	55	431*	3,800	599.5	14.0

* Parameter controlling total discharge for month

Dependable Capacity (Critical Year Routing)

(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
REQUIRED DISCHARGES								
Power 'Q$_p$' (cfs)	Non-power (cfs)	Total (cfs)	Δ STORAGE, $S_1 - S_2$ (cfs)	(AF)	END OF PERIOD RESERVOIR STATUS (AF)	(elev.)	(acres)	Total Energy (MWh)
-	-	-	-	-	918,800	599.5	14,200	-
380*	90	390	-486	-28,900	889,600	597.4	13,900	3,800
746*	120	756	-843	-51,800	837,800	593.6	13,900	7,600
762*	173	772	-880	-54,100	783,700	589.5	12,900	7,600
400*	314	410	-482	-28,700	755,000	587.3	12,600	3,800
238	320*	320	-355	-21,800	733,200	585.5	12,300	3,090
248	320*	320	-316	-18,800	714,400	584.0	12,200	2,970
399*	235	409	-379	-23,300	691,100	582.0	11,900	3,800
405*	118	415	-386	-23,700	667,400	580.0	11,700	3,800
274*	90	284	56	3,100	670,500	580.3	11,700	2,300
238*	86	248	2,178	133,900	804,400	591.1	13,100	2,300
233	86	907	1,921*	114,400	918,800	599.5	14,200	8,950
365	88	431	0	0	918,800	599.5	14,200	4,490

TABLE I-8. Case 6: Routing to Maximize

(1) Routing Interval Month	(2) Year	(3) Inflow 'I' (cfs)	(4) Evapo-ration 'E' (cfs)	(5) With-drawals 'W' (cfs)	(6) Net Inflow (cfs)	(7) Energy Require-ment (MWh)	(8) Average Pool Elevation (feet)	(9) Net Head or kW/cfs
May	1965	-	-	-	-	-	-	-
Jun	1965	1,775	37	95	1,643*	3,800	599.5	14.0
Jul	1965	139	60	94	-15	7,600	597.0	13.8
Aug	1965	13	58	94	-139	7,600	594.0	13.6
Sep	1965	394	26	66	302	3,800	591.8	13.4
Oct	1965	189	2	33	154	2,300	591.2	13.4
Nov	1965	102	-30	25	107	2,300	590.3	13.3
Dec	1965	195	-42	24	213	3,800	589.4	13.2
Jan	1966	504	-42	24	522	3,800	589.2	13.2
Feb	1966	2,701	-30	26	2,705*	2,300	594.5	13.6
Mar	1966	499	-21	27	496*	2,300	599.5	14.0
Apr	1966	1,930	-13	37	1,906*	2,300	599.5	14.0
May	1966	2,021	-29	55	1,995*	3,800	599.5	14.0

* Parameter controlling total discharge for month

Dependable Capacity (Average Year Routing)

(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
REQUIRED DISCHARGES								
Power 'Q$_p$' (cfs)	Non-power (cfs)	Total (cfs)	Δ STORAGE, $S_1 - S_2$ (cfs)	(AF)	END OF PERIOD RESERVOIR STATUS (AF)	(elev.)	(acres)	Total Energy (MWh)
-	-	-	-	-	918,800	599.5	14,200	-
377	90	1,643	0	0	918,800	599.5	14,200	16,460
741*	120	751	-766	-47,100	871,700	596.1	13,700	7,600
751*	173	761	-900	-55,300	816,400	592.0	13,200	7,600
394*	314	404	-102	- 6,100	810,300	591.6	13,100	3,800
231	320*	320	-166	-10,200	800,100	590.8	13,000	3,090
240	320*	320	-213	-12,700	787,400	589.8	12,900	2,970
387*	235	397	-184	-11,300	776,100	588.9	12,800	3,800
387*	118	397	125	7,700	783,800	589.5	12,900	3,800
252	90	262	2,431*	135,000	918,800	599.5	14,200	2,300
221	86	496	0	0	918,800	599.5	14,200	5,060
228	86	1,906	0	0	918,800	599.5	14,200	19,110
365	88	1,995	0	0	918,800	599.5*	14,200	20,680

TABLE I-9. Summary of Monthly Energy

Routing Interval	Monthly Energy Value (Mills/kWh)	Case 1 Energy (MWh)	Case 1 Energy Benefit ($)	Case 2 Energy (MWh)	Case 2 Energy Benefit ($)
June 1965	40.80	16,460	671,600	20,020	816,800
July 1965	44.20	12,350	545,900	16,180	715,200
Aug. 1965	44.80	12,350	553,300	12,350	553,300
Sep. 1965	41.50	6,200	257,300	6,200	257,300
Oct. 1965	34.90	3,700	129,100	3,700	129,100
Nov. 1965	31.80	3,700	117,700	3,700	117,700
Dec. 1965	34.60	6,200	214,500	6,200	214,500
Jan. 1966	35.00	6,200	217,000	6,200	217,000
Feb. 1966	31.70	3,700	117,300	3,700	117,300
Mar. 1966	30.20	3,700	111,700	3,700	111,700
Apr. 1966	32.10	3,700	118,800	3,700	118,800
May 1966	36.00	15,450	556,200	6,200	223,200
Annual Totals		93,710	3,610,400	91,850	3,591,900

Outputs and Benefits: Cases 1 through 6

Case 3		Case 4		Case 5		Case 6	
Energy (MWh)	Energy Benefits ($)	Energy (MWh)	Energy Benefit ($)	Energy (MWh)	Energy Benefit ($)	Energy (MWh)	Energy Benefit ($)
2,980	121,600	16,460	671,600	16,460	671,600	16,460	671,600
5,960	263,400	1,150	50,800	20,240	894,600	7,600	335,900
5,960	267,000	1,690	75,700	19,200	860,200	7,600	340,500
6,390	265,200	3,020	125,300	8,930	370,600	3,800	157,700
17,750	619,500	3,180	111,000	2,810	98,100	3,090	107,800
14,840	471,900	3,060	97,300	2,700	85,900	2,970	94,400
2,980	103,100	2,290	79,200	2,030	70,200	3,800	131,500
3,040	106,400	1,110	38,900	980	34,300	3,800	133,000
15,590	494,200	18,680	592,200	680	21,600	2,300	72,900
1,790	54,100	5,030	151,900	750	22,700	5,060	152,800
1,790	57,500	19,110	613,400	7,400	23,800	19,110	613,400
2,980	107,300	20,680	744,500	17,120	616,300	20,680	744,500
82,050	2,931,200	95,460	3,351,800	92,820	3,769,900	96,270	3,556,000

APPENDIX J

CONSTRUCTION OF A RULE CURVE FOR SINGLE-PLANT POWER OPERATION

J-1. General. As discussed in Section 5-11a, a rule curve describes how much storage must be maintained in a reservoir at different times in the year to insure that firm discharge requirements can always be met. The rule curve is usually defined by the reservoir operation during the critical period, but it is also necessary to test other adverse streamflow periods to make sure that they do not control during certain periods of the year. To illustrate the development of rule curves, two examples will be described: (a) a simple single-year rule curve describing the storage required to meet the water quality discharges listed in Table H-1, and (b) a multi-year hydropower rule curve that will be used as the basis for Case 2 in Appendix I.

J-2. Single-Year Rule Curve.

a. This rule curve will be based on meeting the water quality requirements for the Broken Bow Reservoir, as listed in Table H-1, and it will be used as a possible constraint in the solution of Case 5 in Appendix I. An examination of the mass curve (Figure F-2) shows that the 1963-64 operating year is the most adverse single year, and the critical drawdown period could extend from the first of May through the end of February. However, since the water quality requirements for May and February (88 cfs and 90 cfs, respectively) are considerably less than the inflow for those months (396 cfs and 338 cfs), the critical drawdown period would not include May and February in this case.

b. The rule curve will be developed by doing a reverse routing, beginning with the reservoir empty at the end of the critical drawdown period (end of January, 1964). The routing continues through the point when the maximum pool elevation is reached (the start of the critical drawdown period, the end of May, 1963), and on until the reservoir is empty once more. The same basic procedures are followed as for a normal sequential power routing, except that the routing is done in reverse chronological order, starting with the reservoir empty. In addition, since the objective in this example is simply to meet monthly flow requirements, power calculations do not have to be made.

c. Table J-1 summarizes the calculations, and Figure J-1 shows the resulting rule curve. As long as the reservoir elevation stays above this rule curve and a flow sequence drier than 1963-64 does not occur, the water quality discharge requirements will always be met. In Case 5 in Appendix I, the objective is to maximize generation in the summer months, when energy has its highest value. There are no firm energy requirements to be met during the remainder of the year. Therefore, to insure that water quality requirements will be met in all months, summer drafts for power generation will not be permitted to fall below the water quality rule curve.

d. In this example, a reverse routing was done only for the 1963-64 operating year, because an examination of available streamflow records showed that it was the driest year on record. No other years approached that year in severity. However, if the records showed other comparably dry water years, reverse routings would be done for those years as well. and the rule curve would be constructed as an envelope curve, enclosing all of these curves. An example of how this would be accomplished is described in the next section.

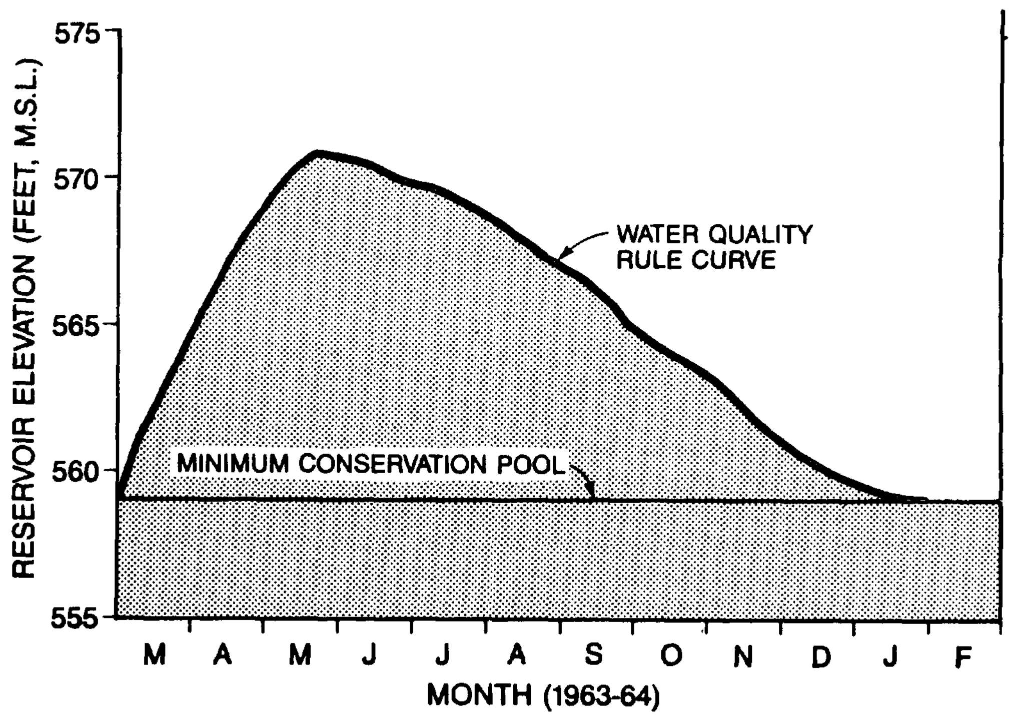


Figure J-1. Single-year water quality rule curve

J-3. Rule Curve Based on Multi-Year Critical Period.

a. The first step in developing a rule curve for the Broken Bow project is to do a reverse routing for the multi-year critical drawdown period, May 1962 through February 1964. Sinoe only firm energy requirements are to be met, this routing would be identical to the critical drawdown period routing described in Appendix H. The reverse routing is then extended from May 1962, meeting only firm energy requirements, until the reservoir is once again empty (the first of November, 1961). This routing defines the lowest reservoir elevations that could be maintained month by month during the winter and spring of 1961-62, while still insuring that the reservoir fills by the first of May.

b. Note that this leg of the reverse routing does not necessarily define the actual routing that would be followed during the period November 1961 through April 1962, because the historical streamflow sequence prior to November 1961 would have probably left the reservoir well above the bottom of the power pool on the first of November. It only serves as a possible adverse combination of streamflows and reservoir elevations, which will help define the refill leg of the power rule curve. The reverse routing for the entire period, November 1961 through February 1964, is shown on Figure J-2.

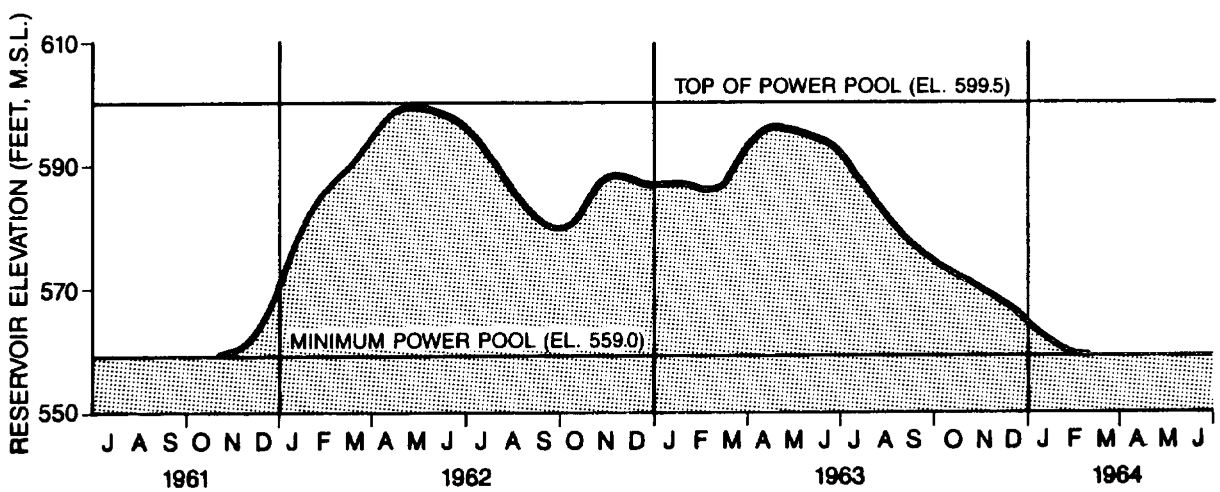


Figure J-2. Reverse routing for 1962-64 critical drawdown period

c. In addition to the most severe drought of record, several other periods of low inflow should be analyzed in order to determine whether combinations of demand and hydrologic conditions other than those experienced in the critical period might affect the location of the rule curve. Reverse routings would be made for each of these sequences, starting with the reservoir empty at the end of the period. Power discharges would be limited to firm energy requirements and the routing would continue forward in time until the reservoir is once again empty. Figure J-3 shows reverse routings for three additional low flow periods.

d. The final step is to plot the routings for all of the significant low-flow periods on a single-year time base, as shown in Figure J-4. Since an envelope of these hydrographs represents the pool levels required to provide adequate storage at the beginning of the four significant low-flow periods of record, a curve which envelops all hydrograph plots represents the pool elevations required at all times of the year to assure firm energy generation through all droughts of the period of record. The power operating rule curve (the enveloping curve) is also shown on Figure J-4. The rule curve insures that firm energy demands will always be met, providing no drought more severe than the critical period drought occurs during the project life.

e. However, if a more severe drought should occur, the reservoir power storage would be completely drafted and a firm energy shortfall would occur. In order to minimize the probability of such an event taking place, the period of record used for analyzing the project should be as long as possible (Section 5-6d). If there is some question about the adequacy of the record, streamflow data for adjacent basins and rainfall records should be examined in order to determine if there have been other periods that might have been more severe than the most adverse sequence in the existing period of record.

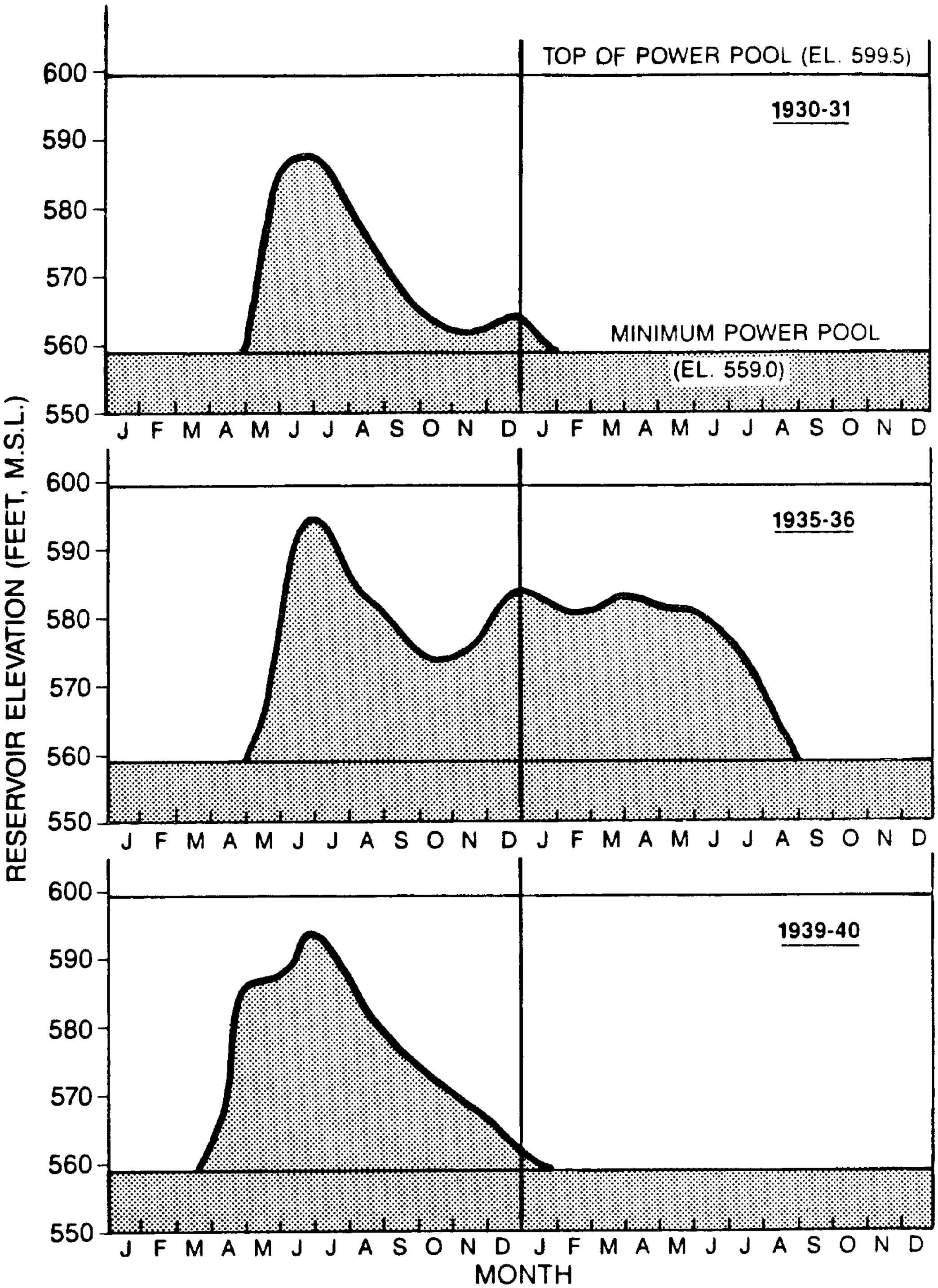


Figure J-3. Reverse routings for three additional historical low flow periods

TABLE J-1. Reverse Routing

Routing Interval Month	Year	Inflow 'I' (CFS)	Evapo-ration 'E' (CFS)	With-drawals 'W' (CFS)	Net Inflow (CFS)	Water Quality Discharge (CFS)
Feb	1964					
Jan	1964	15	-30	24	21	118
Dec	1963	15	-30	24	21	235
Nov	1963	0	-21	25	-3	320
Oct	1963	0	2	33	-31	320
Sep	1963	19	19	66	-66	314
Aug	1963	43	43	94	-94	173
Jul	1963	65	43	94	-72	120
Jun	1963	36	27	95	-86	90
May	1963	396	-22	55	363	88
Apr	1963	913	-9	37	885	86
Mar	1963	2,109	-15	27	2,097	86

for Water Quality Rule Curve

Required Total Discharge (CFS)	Change in Storage, $S_2 - S_1$ (CFS)	Change in Storage, $S_2 - S_1$ (AF)	Start of Period Reservoir Status (AF)	Start of Period Reservoir Status (Elev.)	Start of Period Reservoir Status (Acres)
			448,700	559.0	9,170
118	-97	-6,000	454,700	559.6	9,240
235	-214	-13,200	467,900	561.0	9,400
320	-323	-14,300	482,200	563.2	9,650
320	-351	-21,600	503,800	564.8	9,840
314	-380	-22,600	526,400	567.1	10,090
173	-267	-16,400	542,800	568.7	10,270
120	-192	-11,800	554,600	569.8	10,400
90	-176	-10,500	565,100	570.8	10,530
88	275	16,900	548,200	569.2	10,330
86	799	47,500	500,600	564.5	9,810
1,253	844	51,900	448,700	559.0	9,170

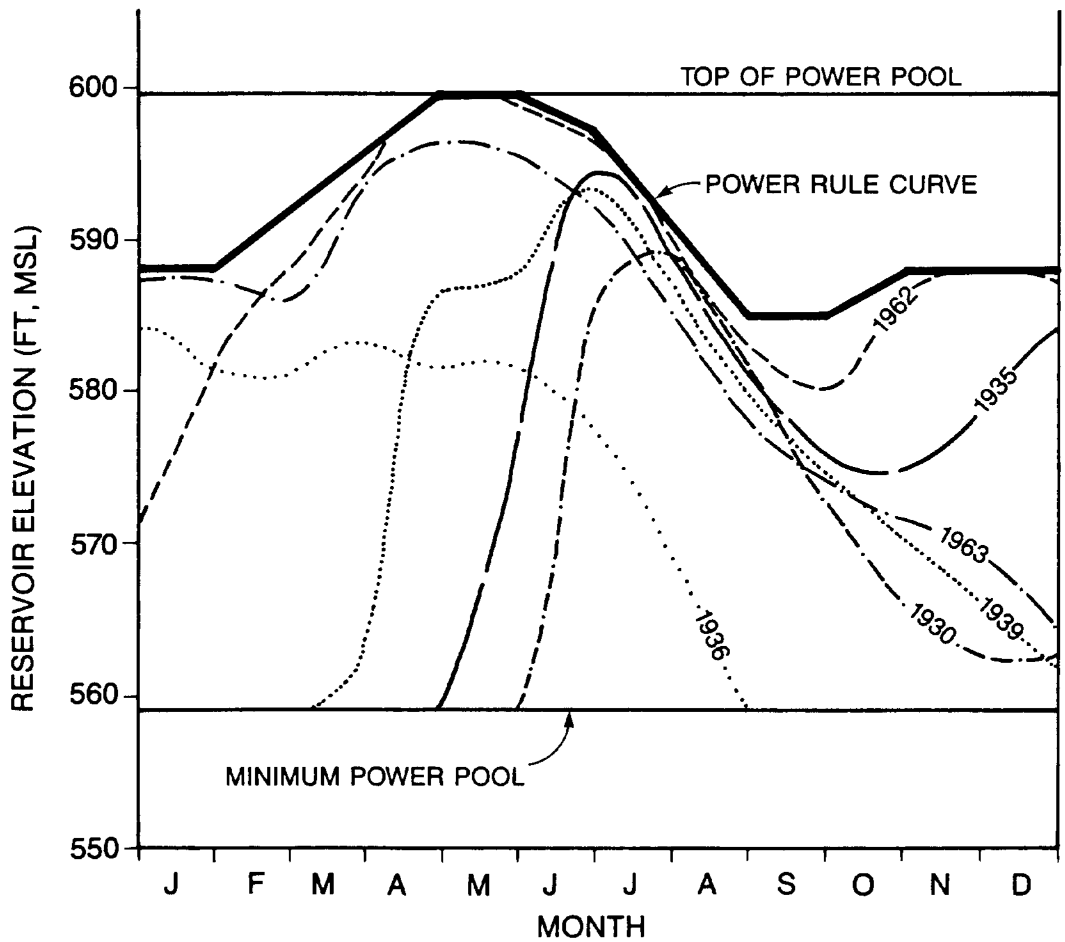


Figure J-4. Power operating rule curve (enveloping rule curve)

APPENDIX K

APPLICATION OF THE HEC-5 HYDROPOWER ROUTINES

K-1. Introduction.

a. Purpose and Scope. This training document is intended to assist engineers in the application of the computer program HEC-5, Simulation of Flood Control and Conservation Systems, to hydropower problems. While the general capabilities of the program are described, the emphasis is on hydropower simulation. The data requirements, program operation, and types of output available are described for all of the available hydropower routines. Strategies for using the program and program availability are also presented. Detailed instruction on the use of the program and input specifications can be obtained from the User's Manual (40).

b. Program Purpose. The HEC-5 program was developed primarily for planning studies to determine the hydrologic and economic consequences of existing and proposed reservoirs in a system. The program was initially (1973) designed for flood control operation studies; however. extensive capability to simulate hydropower operation and other conservation purposes has been added to provide project and system simulation capabilities for most project purposes (earlier program versions were labeled HEC-5C to identify the conservation capability). The program is useful in simulating the operation of a single reservoir or system of reservoirs operating for the typical "at-site" and "system" demands, within specified constraints. Sizing reservoir storage, determining reservoir yield (or firm energy) or evaluating operation schemes are typical ways the program is used. The program was designed so that preparation of input to the model is an easy task. For simple jobs, little input is required, yet complex simulations can be accomplished by supplying more data.

c. Program Documentation.

(1) The primary documentation for HEC-5 is the User's Manual (40). The manual describes the program capabilities, input requirements, and output. To use the program, one would need a user's manual, as this appendix does not give details on many program features or on input formats. The manual is available through the Hydrologic Engineering Center, 609 Second Street, Davis, California 95616 (FTS 448-2105)

(2) Application of the program to flood control planning and operation problems is described in references (7), (8), (9), (10), and (11). "The Analysis of Structural and Nonstructural Flood Control Measures Using Computer Program HEC-5C" (21) demonstrates the use of the program's flood damage evaluation capability. Application of the model to a three-reservoir power system with pumped storage is described in reference (25). These publications can also be obtained from the Hydrologic Engineering Center.

K-2. <u>Program Capabilities and Limitations.</u>

a. <u>Introduction.</u> The April 1982 version of HEC-5 is the basis for this description. The full capabilities described are based on the program as used on the HEC maintained files (Lawrence Berkeley CDC 7600, Control Data CYBER 175 and Harris 500). The library version of the program, distributed to others, is scaled down to fit the "typical" large computer. Though it has the same general capabilities, the library version may not be able to simulate as many reservoirs, powerplants, etc., as described here.

b. <u>Reservoir System Description.</u>

(1) Generally, any reservoir system configuration can be used as long as the dimension limits are not exceeded. In many cases, those limits can be readily changed to meet a particular job requirement. The library version is set with 15 control points, 10 reservoirs, and 5 powerplants. The dimension limits for the HEC maintained files are as follows:

- control points (including reservoirs): 55
- reservoirs: 35
- diversions: 11
- powerplants: 9
- power systems: 2

There is no limit to the number of time periods that can be run, although the program processes a fixed number of periods per cycle.

(2) The conceptual model of a reservoir system is a branching network with a reservoir at the start of every branch. The reservoir and nonreservoir control points are linked to each other by routing criteria. The whole system cascades downstream and converges to a final control point. Reservoirs and control points are the only locations where flows, constraints, and demands are evaluated by the program. Diversions may be used to route flows to other locations in or out of the basin.

c. Reservoir Description. Each reservoir is described by the cumulative storage for each target level (see Section K-2e) and a starting storage. A rating table of storage vs. maximum outlet capacity defines the upper limit for reservoir releases. The reservoir operates for its demands and the demands at specified downstream locations. Additional data on reservoir areas, elevation, diversions, and minimum flows can be given as a function of reservoir storage. Each reservoir is also considered a control point and requires control point description. The required control point description includes a maximum channel capacity, an identifying name and number, and the routing criteria that links it with the next location.

d. Reservoir Purposes.

(1) The program can simulate reservoir operation for most of the typical operating purposes. Conservation operation can be specified by minimum flow requirements at the reservoir and at downstream control points. Flows can be diverted from a reservoir or control point and all or a portion of the diverted flow can return to the system at some other downstream location. Hydropower requirements are defined by energy demands for which the program determines the necessary release. All of these requirements can be varied monthly and the minimum flow and energy requirements can be specified for each period of the simulation.

(2) There is no explicit recreation purpose; however, recreation use may be the basis for minimum flow requirements. Also, the minimum pool level (inactive) may be specified to maintain a full pool during the recreation season.

(3) The flood control operation is based on the specified channel capacity at each control point. Those reservoirs with flood control storage will be operated to maintain flows within those channel capacities at each downstream control point for which the reservoirs are operated.

(4) The priority among purposes in the program can be changed, to some extent, by input specification. When flooding occurs at a downstream location, the program's default operation is flood protection. However, the program user may specify that the power releases and/or minimum flow releases be made during flood events.

e. Reservoir Operation.

(1) The reservoir operation is primarily defined by the allocation of reservoir storage. The program has provisions for four basic storage zones; (a) inactive, (b) conservation, (c) flood

control, and (d), surcharge. There is also provision for subdividing the conservation storage into two zones with a buffer level.

(2) No releases are made from the inactive pool. The only loss of water would come from evaporation, if defined.

(3) In the conservation pool, the goal is to release the minimum amount of water necessary to meet specified requirements. If the buffer level is being used, then two levels of minimum flows, termed desired and required flow, are used. Above the buffer pool level, the reservoir operates to meet all conservation demands, which includes the higher minimum flow (desired flow). When water in storage drops below the buffer level, some conservation purposes may not be met (i.e., hydropower and reservoir diversions) and the lower minimum flow (required flow) would be met. Whether reservoir diversions or hydropower operates in the buffer pool can be specified by the program user. The normal priority is just to provide for minimum required flows.

(4) The program tries to keep the flood control storage empty, if possible. The ideal state for a reservoir would be a full conservation pool and an empty flood control pool. The only reason for storing in the flood control pool would be to limit flows to channel capacity at specified downstream control points. The program also has provisions to limit the rate of change on reservoir outflow to provide for a reasonable transition for increasing and decreasing reservoir releases. The maximum outlet capacity would be another constraint on reservoir flood release. The program also has two options for making emergency flood control releases when it is apparent that the flood control storage will be exceeded.

(5) Above the top of the flood control pool lies the surcharge storage. In this zone, the reservoir is operating uncontrolled and only the outlet capacity vs. storage relationship and the reservoir inflow determine the reservoir outflow. The program would spill the inflow up to the outlet capacity. Inflow above the outlet capacity would be stored to the point of continuity balance. The storage-outflow relationship can be used to model an induced surcharge envelope curve.

(6) Many of the operation decisions are based on reservoir requirements; however. when there is a choice among several reservoirs, the program uses index levels to determine priorities. If two or more reservoirs are operating for a common control point, the program will try to balance the index levels among the projects when making the release determination. The balancing would only occur (for conservation operation) when the sum of the releases for individual project requirements is less than the target flow at the downstream

location. Exhibit 3 of the Users Manual describes how index levels can be used to set priorities among projects.

(7) Balancing index levels can also be used with tandem reservoirs. If the upstream reservoir is operating for a downstream reservoir, the program will attempt to keep the two reservoirs balanced (at the same index level). As the lower reservoir makes releases, the upper reservoir will make a release so that the two will draw down together. If the upper reservoir should only operate for specified demands, and not operate for the lower reservoir, the two tandem reservoirs can be operated independently by not indicating that the upper reservoir operates for the lower one.

(8) The basis for a reservoir release determined by the program is shown in the output variable case. The variable is printed for every time period at every reservoir in the normal sequential output and it can be requested in the user designed output. Table K-1 lists the reasons for a reservoir release and the corresponding case values. The table also represents the demands and operational constraints the program considers in reservoir operation. The order of the list does not correspond to priority.

f. Time Interval and Duration.

(1) The program is capable of operating on a time interval as small as one hour and as large as one month. For conservation purposes, many of the input parameters can vary by the month (e.g., evaporation, flow requirements, storage allocation) and therefore certain monthly time interval data is included with the basic reservoir model. The basic reservoir model then can be used with any time interval. The program's date routine keeps track of time and provides for the capability to use time series data for any time interval (e.g., one or more hours, one day, one week, or one month).

(2) When flood flows are a concern, short interval routing is necessary to simulate rapidly changing conditions. The program has the capability to change between two different time intervals during a simulation. Therefore, monthly conservation routing could be used until a flood starts, at which time the model could shift to a shorter time interval. Then, after the flood sequence, the time interval could return to monthly. As before, the flow data input to the model would provide for the time interval used in the model.

(3) The duration for simulation studies is often the period-of-record. The program has provision for continuous simulation, even though only a finite number of flow periods can be stored in core memory. When the number of periods simulated exceeds the dimension limit, the program will automatically subdivide the data into sets of

TABLE K-1
Reservoir Release Case Values

Reservoir releases can be based on:	Case
a. Maximum reservoir release (channel capacity at the reservoir)	.01
b. Rate of change of release for flood control releases	.02
c. Not exceeding the top of conservation pool	.03
d. Not exceeding top of flood control pool (including prerelease options) (1) prerelease up to channel capacity if top of flood pool will be exceeded (2) prerelease, which may be greater than the channel capacity, to just fill flood pool (3) Gate regulation operation	.04
e. Keeping tandem reservoirs in balance using target levels	.05
f. Maximum outlet capacity for given pool elevation (surcharge routing)	.06
g. Not drawing reservoir empty (below inactive pool level)	.07
h. Minimum *required* flow	.08
i. Releases to draw reservoir down to top of buffer pool	.09
j. Power demand	.10
k. Minimum flow until fullest reservoir can release (scheduling option)	.11
l. System power requirements	.12
m. Release given on QA card	.99
n. Minimum	.00
o. Filling downstream channel at location X and time period Y for flood control or conservation operation	X.Y

"floods" that can be processed. The subdivision of flow data by the program is transparent to the user, and the input and output are continuous.

(4) There is a provision in the program to "window in" on a portion of the flow data. For instance, if a long period of flow data was input to the model, it would be fairly expensive to run repeatedly through the data for testing or evaluating a proposal. By isolating a critical period, the cost of analysis could be reduced by the percent reduction in flow data processed. Then, once the decisions were made, the entire flow data set could be processed.

g. Operation Parameters.

(1) There are several operation parameters that play a role in the program's simulation of the reservoir operation. The priorities between competing purposes can be specified by input data as previously discussed in Section K-2d. The index level was discussed in Section K-2e. This section presents what might be called control parameters.

(2) For short-interval simulation (i.e., hourly or daily) with routing effects, there is a time delay between the time a reservoir makes a release and when it arrives downstream. Under those conditions, the program needs to look several periods into the future (foresight) to determine the effect of reservoir releases. There should be a practical limit on the foresight (such as 24 hours) because in the real world we cannot accurately forecast flows too far into the future. In simulation, we can and should limit foresight in the model to provide a realistic operation.

(3) In a similar vein, the future flows in the real world are not known with the certainty of the given flow data in the model. Therefore, it is unrealistic to simulate reservoir releases using the observed flows as forecasted inflows. In the program, a contingency factor can be used to temporarily adjust control point flow data when making a release determination. That way, the releases will be more conservative than those computed using exactly known flow data. A contingency factor of 1.2 is frequently used, thus providing for a 20 percent "error" in uncontrolled local flow forecasts.

(4) Another constraint to reservoir operation for flood control is the rate at which reservoir releases can be increased or decreased (rate of change). For short-interval routings, the rate of change parameter prevents the reservoir releases from being changed too rapidly. The rate of change per time period can be expressed as a ratio of the reservoir's channel capacity or in absolute discharge units. There is also provision for having a different rate of change

for increasing and decreasing releases as well as different values for each reservoir.

h. Data Requirements.

(1) The data requirements for any job are dependent on the objectives and the level of the study. Often the changing data requirements reflect a need for more detailed analysis which comes from shorter time intervals and more detailed input, rather than using average values for the month.

(2) Reservoirs are defined by a series of relationships based on reservoir storage. The storage-maximum outflow relationship is required. For conservation studies, reservoir areas are needed for evaporation computations and elevations are needed for hydropower computations. Both area and elevation are given as functions of storage.

(3) Net evaporation data (evaporation minus precipitation) can be specified as an average monthly value (inches or millimeters) applicable for all reservoirs in the system or can be specified differently at any reservoir in the system. Evaporation defined as 12 monthly values would be used repeatedly throughout a multi-year simulation. For more detailed analysis, the evaporation data can be defined for every period of the simulation in the same way flow data is provided. Given evaporation data, the program computes the net evaporation volume for each time period based on the average reservoir area during the time interval.

(4) Flow data probably takes the most effort to develop. Flow data is usually based on historical flow, but can be used on stochastic flows from monthly models such as HEC-4, Monthly Streamflow Simulation (53). Daily and monthly flows can be obtained from the USGS WATSTORE system (see the section on program availability). The HEC-5 program operates with average incremental local flows for the duration of the simulation. Incremental local flows are the flows from the incremental area between adjacent locations in the model. The program can accept three types of flow data: natural, regulated, or incremental local.

(5) If natural flow data is given, the program computes incremental local flows by routing the flow at each location down to the next location, where it computes the difference between the routed upstream hydrograph and the given downstream hydrograph. The difference is then used as the incremental local flow. If regulated flows are given, then reservoir releases must also be given so that the program can compute incremental local flows. If incremental flows

are given, they would be used as given. If end-of-period flow data is indicated, the program averages the flows before using them.

(6) If flow data is not available at some locations, the program has provisions for computing flows as a ratio of the flow at another location in the model. The flow computed can also be lagged (forward or backward) an even number of time periods to adjust travel time. Only one location can be used to compute flow for another location. More complicated relationships must be computed outside the program. If flow data is not defined, the program assumes zero inflow.

(7) Control point data is given at each reservoir and non-reservoir location. Required input is limited to a name, a control point number. a channel capacity, and the routing criteria to the next location. Control point data can also include stage-discharge relationships, discharge-damage relationships, minimum flow requirements, and diversions.

(8) As discussed in Section K-2d, two levels of minimum flows can be specified: Desired and Required. The minimum flows can be constant, vary monthly. or vary with each time period, like flow data.

(9) Diversions can be specified from reservoirs or control points. Typically. a monthly diversion schedule is given: however, diversions can be related to reservoir storage or channel discharge. If a portion of the diverted flow returns to the channel system, routing criteria and the ratio of diverted flow returning is required data.

(10) Channel routing between adjacent locations is modeled by hydrologic routing techniques. The available techniques are the Modified Puls, Muskingum, progressive average-lag (straddle-stagger), successive average-lag (Tatum), and working R&D methods. These methods are described in Engineering Manual 1110-2-1408, Routing of Floods Through River Channels (54). The program user should set the time interval below which the given routing criteria are used (the program's default value is 24 hours). When the time interval for simulation is above that value, the routing coefficients are set to one, and no routing will be used. If monthly or weekly simulation is performed, a "no route" criterion is usually used.

i. Storage and Yield Optimization. For a single reservoir, the program can automatically determine the conservation storage necessary to meet specified demands or determine the yield for a specified storage. The yield can be optimized for energy requirements, minimum desired or required flow, diversions, or for all of the requirements. Yield optimization for energy will be discussed in detail in the section on Hydropower Application. The Users Manual provides a description of the procedure under "Optimization of Conservation Storage." Basically, the procedure uses an iterative search technique with the safe yield concept. The optimized storage or yield is determined when all of the conservation storage is used to supply the conservation demands, during the most critical drawdown period.

j. Economic Capabilities.

(1) The HEC-5 program has economic routines for flood damage assessment. Damages can be computed based on peak discharges at control points for up to nine damage categories. Provisions have also been made for a single flood event, or a number of events can be used to compute the expected average value of annual damages. The data required, methods used, and output for the flood damage outlines are given in the Users Manual.

(2) The only other economic capability in the program is the energy benefits computation. Based on input primary and secondary energy values, the program will compute energy benefits. There is also provision for computing a purchase cost for shortages in primary energy. The benefits for energy are provided in a standard summary table.

K-3. Application to Analysis of a Single Hydropower Project.

a. General. The application of the HEC-5 program to hydropower problems is presented here based on the program's capabilities in July 1983. The sections are presented as separate program features. However, they are all dependent on the same basic power data. The basic power data is presented in Section K-3c. The sections on Hydropower Systems (Section K-4), Pumped-Storage (Section K-5), and Firm Energy Optimization (Section K-6), all build on the basic capabilities described below.

b. Power Reservoirs. This section describes the additional data required to model a hydropower reservoir. It also tells how the program uses the data and what type of output is provided. The data required for a basic reservoir model were presented in Section K-2h and include the total storage at each operating level, the downstream control points for which the reservoir is operated, and a storage-outflow relationship indicating the maximum outlet capacity. For hydropower, both reservoir areas and elevations are provided as functions of reservoir storage. The areas are needed for evaporation computations and the elevations for head determination. Standard Test

5 in Exhibit 6 of the program Users Manual shows both input and output for a single power reservoir.

c. Data Requirements.

(1) Power data is input with reservoir data at each hydropower reservoir. The data requirements include an overload ratio, the installed capacity. a blockloading tailwater elevation, an efficiency, and the monthly energy requirements (kWh or plant factors).

(2) An overload ratio is used by the program, in addition to the installed capacity, to determine the maximum energy the powerplant can produce in a time interval. The maximum production would then be a limit on how much dump energy could be generated during periods of surplus water. The program assumes a value of 1.15 if none is given. For new plants, the current Corps policy is to make the installed capacity large enough so that the overload factor is 1.0.

(3) The terms "installed capacity" and "nameplate capacity" are used interchangeably. In some situations, the full overload peaking capability may not always be available due to head loss resulting from reservoir drawdown or tailwater encroachment during periods of high discharge. If the data is available, a variable peaking capability can be defined as a function of reservoir storage, reservoir outflow, or powerplant head.

(4) The tailwater elevation is normally specified as a constant value associated with full nameplate rating operation (block loading tailwater). Higher tailwater elevation can also be defined for flood operations as a function of reservoir releases. The average reservoir release for the routing interval is used to determine this tailwater elevation. If a downstream lake elevation could affect the tailwater elevation, the program can check that elevation to see if it is higher than the block loading tailwater elevation or the tailwater rating curve. If it is, then the downstream lake elevation would be used. When two or more methods are used to describe the tailwater, the higher tailwater value is used.

(5) Head loss can be defined a a constant or as a function of flow. If defined, the loss will be subtracted from the computed head (reservoir average elevation minus tailwater elevation) to determine the net head for power.

(6) Powerplant efficiency is the total efficiency of the powerplant (including generators and turbines). No other energy loss is computed by the program. The efficiency can be a constant value (the program assumes 0.86 if none is given) or it can vary with head. An alternative to using efficiency directly is the kilowatt per

discharge (kW/cfs) coefficient as a function of reservoir storage. Often older power studies, done by hand, used kW/cfs vs. elevation as an aid to computation. These relationships, with efficiency and tailwater elevations built into them, can be used directly in the program by relating reservoir storage to elevation.

(7) Firm energy requirements can be defined for each hydropower plant using 12 monthly values, or by using an energy requirement for every time period of the study. For most planning studies, the 12 monthly values are used. The monthly energy values can be given in megawatts-hours (MWh) or as plant factors. Plant factors are ratios indicating the portion of time (per month) that the plant is generating. If plant factors are given, the program computes the monthly firm energy requirement by multiplying the plant factor times the installed capacity times the hours in the month; the product is megawatt-hours for each month.

(8) If the time interval used is less than a month, daily ratios can be given to show how the firm energy requirement is distributed over the seven days of the week. The sum of the daily ratios provided must add up to 1.0. The program computes the weekly energy requirement from the given monthly requirement and then distributes the weekly total using the daily ratios. If no distribution is given, the program will use a uniform distribution. If daily ratios are used, the day of the week at the start of the simulation should be given. The program will assume Sunday if no starting day is given.

(9) If the time interval is less than one day, a distribution within the day can be given. The daily distribution should provide at least as many values as there are time intervals (t) in a day (24 hrs/t) The daily distribution can be as many as 24 hourly values. If 24 values are given, and the time interval is greater than hourly, the program will sum the hourly values to compute the value for the given time interval. As with the daily ratio, the values should sum to 1.0 and if no distribution is given, a uniform distribution is used.

(10) An alternative method of operation to the firm energy method discussed above is based on an individual project rule curve relating plant factor to percent of conservation storage. This method can produce more near-firm energy, but may have a few months where no energy is produced at all.

(11) Another rule curve type of operation is available using the firm energy method previously discussed. This method of operation is exactly the same as the firm energy operation except that the input firm energy requirements are used only when the reservoir is below some user specified storage index level (normally the buffer pool). When the reservoir (for the previous time period) exceeds the seasonal

rule curve storage, the input firm energy requirement is multiplied by a user supplied factor.

d. Program Operation.

(1) For hydropower operation, the program computes the energy requirements for each time period of operation. The monthly energy requirements and given distributions or the given period-by-period energy requirements are used for this purpose.

(2) The program cycles through the simulation one interval at a time. For the hydropower reservoirs, the following logic is used to determine a power release:

- Estimate average storage for the time interval. (Reservoir elevation and evaporation are both dependent on average storage.) Use end of previous period's storage (S_1) initially and then in subsequent iterations use the average of S_1, and the computed end-of-period storage for the current time interval (S_2).

- Estimate tailwater elevation. Use highest elevation from block loading tailwater. or tailwater rating curve, or downstream reservoir or channel elevation.

- Compute net head by subtracting tailwater and head loss from reservoir elevation corresponding to estimated average storage.

- Compute reservoir release to meet energy requirement.

$$Q = \frac{Ec}{eHt} \qquad \text{(Eq. K-1)}$$

where: E = required energy (kWh)
c = conversion factor (11.815 English or 0.102 metric)
e = plant efficiency
H = gross head (feet or meters)
t = time (hours)
Q = reservoir release

- Compute reservoir evaporation (EVAP) using reservoir area based on average reservoir storage.

- Solve the ending storage (S_1) using continuity equation:

$$S_2 = S_1 - \text{EVAP} + (\text{INFLOW} - \text{OUTFLOW}) \times \text{CQS} \qquad \text{(Eq. K-2)}$$

where: S_1 = End-of-period storage for previous period
EVAP = Evaporation during time interval
OUTFLOW = Power release and leakage
CQS = Discharge to storage conversion

- On the first cycle, use the new S_2 and return to the first step. On subsequent cycles, check the computed power release with the previous value for a difference of less than 0.0001 cfs. Use up to five cycles to obtain a balance.

- Check maximum energy that could be produced during time interval using overload factor and installed or variable peaking capacity.

- Check maximum penstock discharge capacity, if given. Reduce power release to penstock capacity if computed release exceeds capacity.

- Check maximum and minimum head and/or flow, if given. Do not generate power if the head and/or flow are not within defined operation range.

(3) The program will determine if there is sufficient water in storage to make the power release. The buffer pool is the default minimum storage level for power. However, the user can define the inactive pool as the minimum power pool. If there is not sufficient water in storage, the program will reduce the release to just arrive at the minimum pool level. If there is sufficient water, the power release for the reservoir establishes a minimum flow at that site. The program will evaluate every reservoir and control point in the system one time interval at a time. For conservation operation, it will determine if additional reservoir releases are required for some downstream requirement. If not, then the power release holds. If additional water is needed for non-power uses, then the release will be increased. Credit for the additional energy generated by the larger release will be given to the Secondary Energy account. The Primary Energy account only shows the energy generated to meet the specified demand.

(4) During flood control operation, the power release may add to downstream flooding. A user specified priority determines whether the program cuts back the release to prevent downstream flooding (the program shorts power under default priority). If the program cuts back on the power release, there will be an energy shortage for that time period and the shortage is shown in output as Energy Shortage. A program output variable "Case" will show the program basis for release determination. If priority is given to hydropower, then the power release will hold and some flooding due to reservoir release will occur.

e. Program Output.

(1) A description of the available output from the program is provided in the Users Manual. This section describes the power output and provides some suggestions on how to check the program's results. There are 38 variables pertaining to the flow data, reservoir and control point status, and energy production. The normal sequential output provides tables of the applicable variables for each location in the system, or a user can define tables for just the variables and locations desired. The variables that deal specifically with the power reservoir are: energy required, energy generated, energy shortage, peaking capability and plant factor. Summary tables also provide primary and secondary energy, shortages of energy, and energy benefits.

(2) Energy Required lists the given energy requirements for the reservoir. Energy Generated shows the computed energy based on the reservoir release, and Energy Shortage lists the deficiencies in generated Energy. If the Energy Generated equals the Energy Required, then the Case variable should equal 10 for that time interval, showing that the reservoir release was for hydropower. If generated Energy was less than required, the Case variable code may show the reason (e.g., insufficient storage or flood control operation). If Energy Generated was greater than Energy Required, the program Case should indicate either a release of surplus water, or that the required flow at another control point required a larger release.

(3) Variable peaking capability data, if provided, is based on Reservoir Storage, Reservoir Outflow or Reservoir Operating head. Given one of the peaking capability relationships, the program computes the peaking capability for each time period of the simulation. This information can be used in conjunction with peak demand information to determine the critical peaking capability for dependable capacity. If no peaking capability function is given, the program uses the installed capacity times overload factor for all periods.

(4) In the summary tables for energy, the total energy generated is divided into Primary and Secondary Energy. The Primary Energy represents energy generated to meet the primary energy demand. The Secondary Energy is all of the surplus generated energy (dump energy). Shortage is the shortage in the firm energy for the powerplant. The summary results are shown for each hydropower reservoir and for the total of all hydropower reservoirs in the system.

(5) The Energy Benefits Summary Table provides the dollar value for Primary and Secondary Energy and the Purchase Cost based on Shortages. The benefits are computed using input unit values for the

three categories. The Net Energy Value reflects the sum of primary and Secondary less Purchases. A capacity value is computed based on the installed capacity.

K-4. Analysis of Hydropower Systems.

a. General. Up to nine hydropower reservoirs can be modeled as individual power projects as described in the previous section. If some of the reservoirs are delivering power into a common system, system operation might be able to produce more energy than the sum of the individual projects operating independently. By allocating the system load dynamically (for each time period) based on each project's ability to produce power, the projects could help each other during periods, of low flows. This section describes the added input, program operation, and output associated with the System Power capability. Everything described in Section K-3 also applies to system analysis. Standard Test 8 in Exhibit 6 of the program Users Manual shows input and output for a three-reservoir power system.

b. Data Requirements.

(1) Additional data required for the system power routine consists of System Energy Requirements and an indication at each hydropower plant if it is in the system. One or two power systems can be used and some plants may just operate independently.

(2) System Energy requirements are provided as 12 monthly values in MW-hrs or ratios of the annual demand. The system energy requirement represents a demand on all projects in hydropower system one. If a second set of system energy demands are given, then they represent a demand on all projects in system two. The monthly energy requirements data starts with the same month used with all the other monthly varying data. The monthly system energy requirements are distributed in the same manner as the at-site energy requirements. Seven daily ratios define the total weekly energy, and multi-hourly ratios define the fluctuation within each day.

(3) At each hydropower reservoir in the model, all of the power data previously described is still provided, plus the indication if the powerplant is in the power system and the maximum plant factor the project can produce which will be useable in meeting the system load. The indicator is zero if a powerplant is not to be used for system power. A value of 1 indicates system 1, and 2 indicates that the plant is in a second system. The system plant factor is used to limit the extent (or percent of time) each powerplant can operate to meet system load. Generation rates greater than the system plant factor are allowed when excess water is available, but only the proportion up

to the specified plant factor can be credited as meeting the system load.

(4) The monthly at-site energy requirements at each powerplant should be reduced to some minimum value to provide the necessary operational flexibility of shifting load between projects. If the at-site requirements are not reduced, each plant will operate for the at-site requirements, reducing the possibility of system flexibility. Often some low plant factor is defined for at-site requirements at system power reservoirs just to ensure their operation. However, if there are some high priority at-site energy requirements for a particular project, they should be given and the other projects' minimum plant factors should be very small, allowing the maximum flexibility in those projects.

c. Program Operation.

(1) Given the system energy requirements, the program will allocate power demand to all of the projects designated in the power system. The allocation is performed at the beginning of each time step of operation, using data derived by determining the energy that can be produced by all system reservoirs releasing down to common levels. The program temporarily subdivides the conservation storage at all projects into a number of levels and then computes the energy that could be produced by releasing down to each level. Then, by using the total system demand, the program can determine by interpolation the system level and the project releases that will meet the system load and will keep the system balanced as much as possible. The program has provisions for checking minimum flow constraints to ensure the allocated release will also meet the reservoir's minimum flow requirements. Also, if a significant at-site requirement is given, the routine will ensure the at-site requirement is met within the total system generation. Once the allocation is made, the remaining operation for the program is the same as previously described.

(2) The reservoir release values, based on the interpolation described above, may not actually produce the required system energy due to the nonlinearity of the relationship. If the sum of the project's energy production does not match the system requirements within a specified tolerance, the program will cycle through the allocation routine up to two more times in an attempt to get the generated energy to within one percent of the requirement. If that is not close enough, the user can change the tolerance and the number of iterations to provide a closer check. For most applications increasing the cycles is not warranted.

(3) The input system energy requirements are presently limited to 12 monthly values. Also, the system energy allocation routine does not provide for routing between tandem reservoirs. This means that release from the upper reservoir is assumed available at the lower reservoir in the same time period. For short-interval routings with considerable travel time between tandem power reservoirs, the tandem project will not remain balanced and the actual energy generated may be lower than the system routine had computed during the allocation period.

d. Program Output.

(1) All of the previously described output would be available plus: System Energy Required, System Energy Usable, System Energy Generated and System Energy Shortage. The system energy variables are displayed for each time period for the first reservoir in the system. This output is available in either normal sequential output or user designed output tables.

(2) System Energy Required is the given input requirement. System Energy Usable is the sum of the energy generated from all projects in the system to meet the system demand, within each individual project's maximum plant factor for system power generation. System Energy Generated is the total generation of all projects in the system and System Energy Shortage is the deficiency in Usable System Energy.

(3) The Case code for system power is .12. When a project release is based on the allocation from the system power routine, a value of .12 will be reported. When the at-site power requirement controls, a value of .10 will still be reported.

K-5. Analysis of Pumped-Storage Projects.

a. General. The previous information on power reservoirs (Section K-3) applies to the pumped-storage model. This section describes the additional data required, the program operation, and the type of output available for pump-back operation. The pumped-storage capability is applicable to either an adjacent (offstream) or integral (pump-back) configuration. Routing intervals used with pumped-storage evaluation are usually daily or multihourly. Standard Test 8 in Exhibit 6 of the Users Manual shows input and output for a daily pumped-storage operation (see reservoir 99).

b. Data Requirements.

(1) To model a pump in a hydropower system, a dummy reservoir is added just upstream from the upper reservoir to input the pumping capabilities. The basic reservoir and power data described previously are required for the dummy location. For the power data, a negative installed capacity is used to tell the program that this is a pump and not a generator. The specified efficiency for the dummy reservoir is for the pump while the upstream reservoir specifies the generating efficiency. The tailwater elevation for the pump is usually based on the elevation of the lower reservoir, and the specified energy requirement data for the pump reflects energy available for pumping. Pumping energy is usually input to the program as plant factors based on the number of hours per day that energy is available and should be used for pumping.

(2) Added data includes a maximum pump-back pool level and a diversion card to convey the pump-back discharge into the upper reservoir. The program will pump water to the upper reservoir using all the available energy during the time periods specified. However, it will stop pumping if the upstream pool reaches the top-of-conservation level or if the lower pool draws down below the buffer pool. The maximum pump-back level can be set to a lower level than the top-of-conservation pool by defining an intermediate pump-back level. The diversion card defines the source of the pump-back water. The input would indicate a diversion from the dummy location to the lower reservoir, and the type of diversion would be -3 for pump-back simulation. The computed pump-back discharges are carried by the program as diversions from the lower reservoir to the dummy reservoir. Those diversions are then routed into the upper reservoir based on unlimited outlet capacity and a zero lag routing criterion from the dummy reservoir. Figure K-1 shows the model arrangement for an on-stream system, and a similar approach can be applied to an off-stream system.

c. Program Operation.

(1) The estimate of the pump-back discharge is based on the available pumping energy specified as input. The tailwater elevation will be based on the higher of the block loading tailwater elevation or the lower reservoir level. The upper reservoir elevation is used in computing the head. If pump leakage is specified, that discharge is subtracted from the pump-back discharge. If the minimum penstock capacity is defined, the program checks to see that value is not exceeded.

(2) The pump discharge based on available pumping energy is reduced, if necessary, to prevent the lower reservoir from being drawn

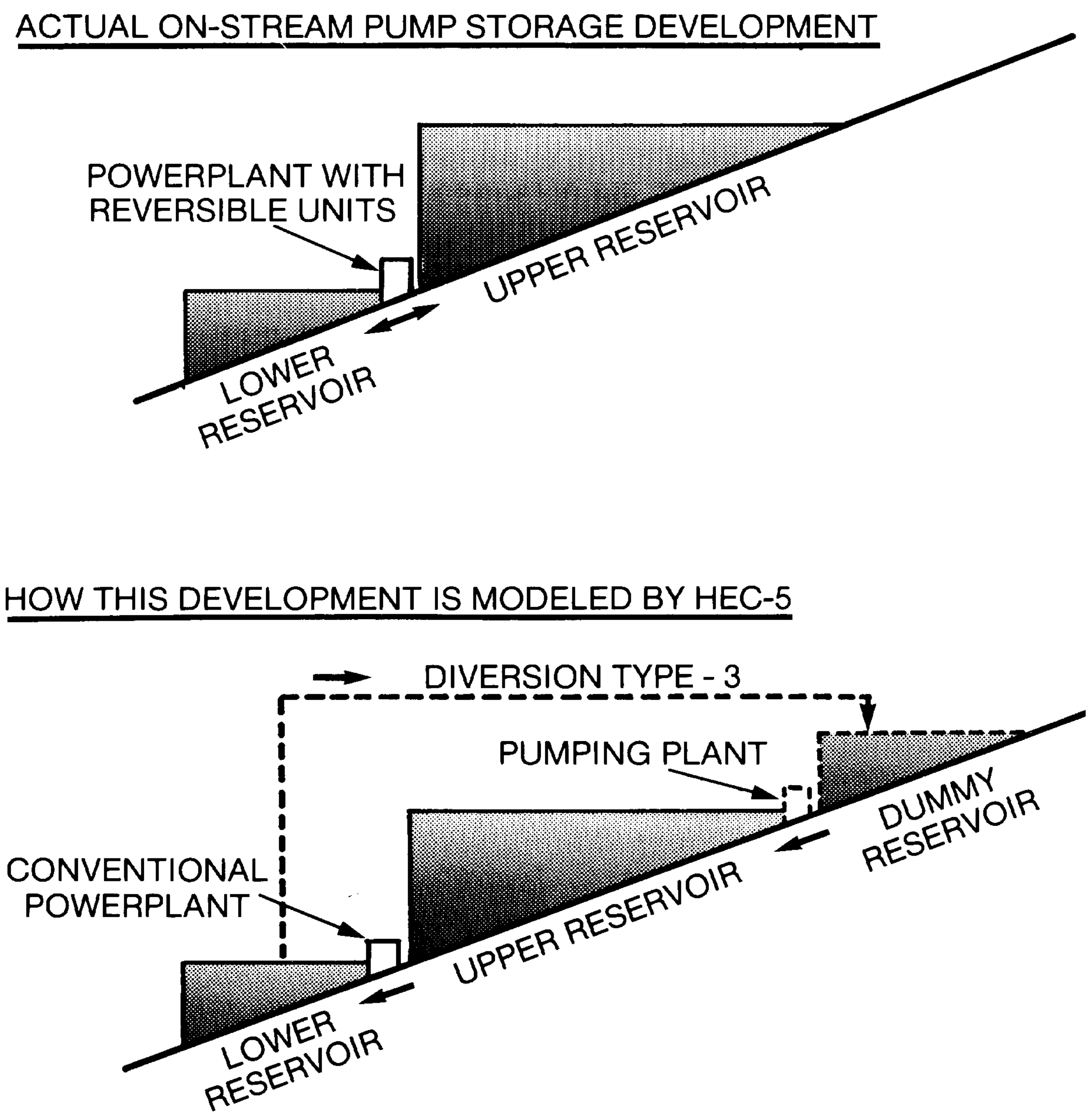


Figure K-1. Modeling of on-stream pumped-storage (pump-back) project below the buffer level. The program also prevents the pump-back discharge from exceeding the storage capacity of the upper project at the top of conservation pool or top of the pump-back pool if specified. The top of the pump-back pool can be set to a lower level to reduce the amount of pumping energy used. The pump would only be used to maintain a minimum pool level rather than full pool.

d. Program Output. No new output data has been provided for pump-back operation. The discharge values for pumping are displayed as diversions at the dummy reservoir (negative values) and at the lower reservoir (positive values). The pumping energy values are reported at the dummy reservoir. The Energy Required values reported for the dummy plant represent the Available Energy for pumping, and Shortage represents Available Energy that was not used for pumping. Energy Generated values represent energy used for pumping.

K-6. Firm Energy Optimization.

a. General. Energy is one of the conservation purposes the program's optimization can maximize using the firm yield concept. The previous discussions describe the use of HEC-5 for meeting specified energy requirements. In many planning studies, the objective is to determine how much firm energy a reservoir of a given size can produce or how much storage is required to produce a given amount of energy. The optimization routine can determine firm energy for up to nine independent reservoirs given a fixed conservation storage, or determine the required conservation storage to provide for a given at-site energy demand. Paragraph 10 of the Users Manual describes the optimization capabilities of the program. Standard Test 7 in Exhibit 6 shows input and output for an energy optimization problem. This section describes the additional input requirements, the program's operation, and the type of output provided.

b. Data Requirements.

(1) The basic power reservoir model previously described would be used for the optimization routine. Job card (J7) requests the optimization routine and tells the program which reservoirs to use and the option selected. The input values for the parameters to be optimized (e.g., storage or monthly energy) are used by the program as the initial values. In the case of energy optimization, a special capability has been developed to make the initial estimate of energy and capacity. The estimate is based on the power which could be produced from the power storage and the available flow during the estimated critical drawdown period. The length of the critical drawdown period is estimated by a routine based on an empirical

relationship between drawdown duration (in months) and the ratio of power storage to mean annual flow.

(2) The optimization routine only works with average monthly flow data. Unless otherwise requested, the program will simulate the project operation for the duration of the given inflow data. If 29 years of monthly data is available and 4 or 5 iterations are required to obtain the desired results, a considerable amount of computation will be required. By using the critical period option (J7.8), the program will identify the starting and ending points of the critical period by finding the minimum flow volume for the specified length of duration. Only the isolated critical period data would then be used for each of the iterative routings. However if the critical period does not start at the beginning of the year (as specified by ISTMO J1.2), the starting period will be automatically shifted back to the start of that year. The critical period can also be defined by specifying a starting and ending period.

c. Program Operation. The program operates the power reservoirs through a complete simulation as previously described. However. at the end of the simulation, the program checks to see if all of the power storage has been used in the routing. If not, a new estimate of the monthly energy requirements is made based on the minimum storage content during the routing to provide for all fixed purposes, plus the at-site energy requirements. The iterative search procedure uses the entire inflow data set for each cycle unless the critical period option is used to limit the simulation. The allowable error in storage can be set by the user, or the default value of 100 acre-foot negative error and one percent positive error are assumed. When all demands are met and the minimum storage at the reservoir is within the allowable error, the solution is obtained.

d. Program Output.

(1) The output options previously described would normally be used with the optimization routine. For each iteration, a special table of results is provided. Program HEC-5 is actually two separate programs (HEC5A and HEC5B) normally connected together by job control cards to appear as one program. For most applications of the optimization routine, it may be desirable to just run the first half of the program HEC5A, and not get the sequential routing output displays from HEC5B for each trial. Sufficient output displays of the optimization results are provided in HEC5A. The results can be used in a complete routing (using both program parts) to obtain final output displays for the sequential routing.

(2) For program determined critical periods, an additional table can be printed that will show, for each assumed critical drawdown

duration of 1-60 months, the minimum flow volume for each duration, the starting and ending periods of the minimum flow volume, and the initial estimate of dependable capacity. The estimated value of dependable capacity is based on the minimum flow volume plus the reservoir power storage released uniformly over the number of drawdown months. The capacity value is used by the routine for the initial estimate of the dependable capacity unless input specifies (J7.7) that the P1 card capacity value should be used.

K-7. Strategies for Using the HEC-5 Progam for Power Studies.

a. General. Strategies for using HEC-5 for project studies are similar to strategies for performing sequential routings by manual methods. The objective is to perform only those routings which are necessary to determine the amount of reservoir storage required to accomplish the desired objectives or to determine the reservoir accomplishment possible from a given amount of reservoir storage. The relatively low cost of computer solutions compared to manual methods makes it more economical to perform more routings. However, it is easy to spend too much money in evaluating "nice to know" conditions. It is, therefore, still important to restrict the number of routings to those essential to the success of the study. The following comments may help in deciding which combination of routings is required for different types of projects.

b. Large Storage Projects.

(1) In many cases, flow data is available near the project for long periods of time. In order to minimize computer time, it is usually desirable to initially limit the duration of the routings to the critical period and to use monthly flows in the analysis. Since the critical period-of-record can change as the demands on the system change, the full period of flow record should later be used to verify that the assumed yield or firm energy can be maintained throughout the entire historical record.

(2) The optimization routine in HEC-5 will determine the approximate critical period (or allow the user to specify the critical period) and will perform sequential routings using that critical period to automatically determine either:

- the storage required for a specified annual firm energy and reservoir yield, or
- the annual firm energy and/or reservoir yield that can be obtained from the specified reservoir storage.

(3) The optimization routine can also use the entire period of flow record to determine the storage or firm annual energy. The difference in computer costs between using the flows for the entire period of record versus the critical period only is approximately proportional to the number of months used in the routings. For 30 years of flow data and a 6-year critical period, the ratio of costs approaches 5 to 1. In general, it is less expensive to optimize on the critical period of record and then to verify the answer on the period of record than to optimize on the period of record.

(4) Once the conservation operation has been satisfactorily determined for a range of power storages and minimum power heads using monthly flow, the effect of the selected project on other project purposes should be determined. If flood control is a project purpose, the program can be set up to either (a) perform monthly routings during nonflood periods and daily or multihourly routings during major flood events, or (b) perform period-of-record routings for one fixed interval such as daily flows. It is particularly important to see how the proposed hour-by-hour operation affects both the power and the flood control operations. Test simulations of selected flood events using small time intervals should be made to evaluate performance. Runs should also be made to test for the desirability of using seasonally varying storage allocations (rule curves operation).

(5) Once a satisfactory operation for a single multipurpose reservoir is obtained, the data should be expanded to include other reservoirs whose operation might affect the reservoir under study. In order to determine if a system operation for flood control or power is necessary or desirable, studies should be made comparing the effectiveness of the system with and without the system rules.

c. Pumped-Storage Projects. While pumped-storage projects can be evaluated using some of the ideas mentioned above, the primary routings will have to be made using both daily flows and hourly or multihourly operations for selected periods. Monthly routings for pumped-storage operation would, in most cases, not be meaningful. While period-of-record runs using daily flows might be warranted for pump-back operation, most off-stream pumped-storage projects would require hour-by-hour operation during critical weeks to evaluate performance.

d. Run-of-River Projects. While run-of-river projects can be operated with other reservoirs in the system, studies using flow duration techniques are preferable to monthly sequential routings because short-duration high flows are important and cannot be captured by sequential analysis without going to daily operation. A daily flow sequential routing for the selected project would be desirable after the project characteristics have been established using daily flow-duration techniques. The HEC has developed a flow-duration program, HYDUR (45), which is available through the same sources as HEC-5 (see Program Availability).

K-8. Program Availability.

a. Introduction. The HEC-5 program, as well as other HEC programs, is available through the Hydrologic Engineering Center (FTS 448-2105). The source can be obtained from the Center or the program can be accessed by one of several commercial computing companies. The following section describes how one can gain access to the program.

b. Program Distribution.

(1) The program will be distributed without charge to Corps offices. For all others, a computer program order form must be completed and returned to the Center, together with a check payable to "FAO-USAED, SACRAMENTO", to cover handling costs. The appropriate form and information on the current handling charge can be obtained from the Center.

(2) The requested source code for the program is mailed, along with test data on magnetic tapes, either 7-tract BCD or 9-tract EBCDIC. The HEC-5 program is actually two programs which are executed together in sequence (HEC5A and HEC5B). Some applications, such as conservation optimization, only require the execution of the first program (HEC5A). Core storage requirements are 115,000 words (60 bits) and the program uses nine scratch units. The dimensions of the distributed program are set at 10 reservoirs, 15 control points, 11 diversions, and 5 powerplants.

c. HEC Maintained Files.

(1) The Center maintains a complete library of its programs at the Control Data Cybernet (CDC) System. Programs at this site are updated and supported by Center personnel. Corps offices and others with access to this site can use the following job control cards to execute the HEC-5 program.

CDC

```
Your Job Card.
USER Card.
GET,HEC5A/UN=CECELB.
HEC5A.
GET,HEC5B/UN=CECELB.
HEC5B.
```

End of Record Card.
Data.
End of Information Card.

(2) The HEC5A program reads the data and performs the simulation. Results are written to scratch files which are read by the second program. HEC5B reads the scratch files and provides output tables and economic calculations.

d. Program Support.

(1) The Center makes every effort to support its programs. If users experience difficulty in coding input, executing the program, or interpreting output, they can call the Center to request assistance. Every effort is made to provide timely assistance.

(2) The Center maintains a video tape library of lectures on the application of many of its programs. For new program users, the tapes can be helpful by explaining program capabilities, input requirements or output analysis. A video tape catalog can be obtained by calling the Center. Most of the tapes are 3/4" U-Matic Cartridges (Sony).

APPENDIX L

CALCULATIONS FOR STORAGE EFFECTIVENESS ANALYSIS

L-1. Introduction.

This appendix summarizes the calculations used to develop the storage effectiveness indices for the example reservoir systems discussed in Section 5-14f. Figure L-1 shows the storage-elevation curves for the various reservoirs. Note that the reservoir elevations on Figure L-1 are expressed in terms of net head in order to simplify the examples. The other data assumptions are summarized in Table L-1. In each case, the monthly firm energy requirement is assumed to be constant at 14,800 MWh and the critical drawdown period is eight months in length.

TABLE L-1
Characteristics of Storage Projects

	Reservoirs A, B, and C	Reservoir D	Reservoir E	Reservoir F
Total Storage at full pool, 1000 AF	280	280	280	280
Power storage, 1000 AF	200	200	200	200
Head at full pool, ft.	100	100	150	50
Head at minimum pool, ft.	60	60	90	30
Average inflow, cfs 1/	1,000	1,000 2/	1,000	1,000

1/ Assumed to be constant for all eight months
2/ 500 cfs for Case 4

L-2. Case 1: Upstream Reservoir in Tandem.

a. General. Paragraphs 5-14f(3) through (6) describe the computation of the storage effectiveness index for drafting from the the downstream reservoir (Reservoir A) in the example of two identical reservoirs located in tandem (Figure 5-53). Following are the computations for drafting the required storage from the upstream reservoir (Reservoir B).

b. Draft of Reservoir B.

(1) Energy Shortfall. Drafting storage from Reservoir B to meet the shortfall would be analyzed in the same way as drafting Reservoir A. Since no draft is required in this case from Reservoir A, the full 100 feet of head would be available for generating with inflow, and the resulting generation in the first month would be

$$\text{kWh} = \frac{(1000 \text{ cfs})(100 \text{ feet})(0.85)(720 \text{ hours})}{(11.81)} = 5{,}200 \text{ MWh.}$$

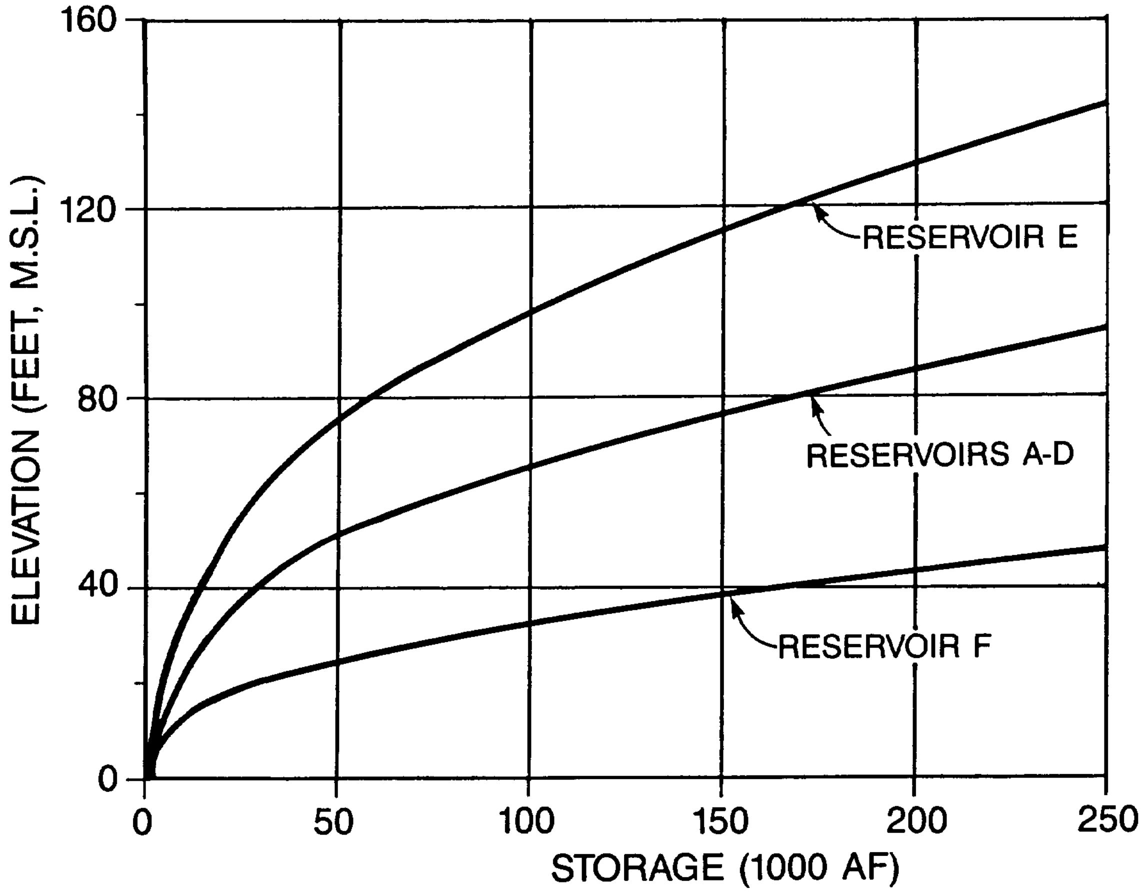


Figure L-1. Reservoir storage-elevation curves

Since storage drafts from Reservoir B pass through both powerplants, less storage would have to be drafted to make up the shortfall than was required from Reservoir A. Hence, an average head of 98 feet is assumed. The generation from inflow at Reservoir B would therefore be

$$\text{kWh} = \frac{(1000 \text{ cfs})(98 \text{ feet})(0.85)(72 \text{ hours})}{11.81} = 5{,}100 \text{ MWh.}$$

The resulting energy shortfall would be

$$(14{,}800 - 5{,}200 - 5{,}100) = 4{,}500 \text{ MWh.}$$

(2) <u>Required Draft.</u>

The average flow required to produce this generation would be

$$Q = \frac{(4{,}500{,}000 \text{ kWh})(11.81)}{(198 \text{ feet})(0.85)(720 \text{ hours})} = 439 \text{ cfs.}$$

Note that since this flow passes through both powerplants, the effective head is (100 + 98) = 198 feet. The 439 cfs corresponds to a storage draft of (439 cfs)(59.5 AF/cfs) = 26,100 AF. The end-of-period storage would be (280,000 - 26,100) = 253,900 AF, which corresponds to an end-of-period head of 96 feet (see Figure L-1). The average head would be (0.50)(100 + 96) = 98 feet (which verifies the initial assumption), and the head loss in subsequent months would be 4 feet.

(3) <u>Subsequent Energy Loss.</u> The resulting generation loss in subsequent months would be

At-site unregulated inflow = 1000 cfs

$$\text{Releases from Reservoir B} = \frac{(200{,}000 - 26{,}100 \text{ AF})}{(59.5 \text{ AF/cfs})(7 \text{ months})} = 417 \text{ cfs}$$

Storage releases from Reservoir A would not pass through Reservoir B, so the four foot head loss would apply only to the at-site unregulated inflow plus the storage releases from Reservoir A, which would be an average discharge of (1000 + 417) = 1,417 cfs. The resulting generation loss would be

$$\text{kWh} = \frac{(1{,}417 \text{ cfs})(4 \text{ ft})(0.85)(7 \times 720 \text{ hours})}{11.81} = 2{,}100 \text{ MWh.}$$

(4) Storage Effectiveness Index. The storage effectiveness index for Reservoir B would be

$$\frac{2{,}100 \text{ MWh}}{4{,}500 \text{ MWh}} = 0.47.$$

L-3. Case 2: Two Identical Reservoirs in Parallel.

a. General. Reservoirs C and D are identical (Figure 5-55), and inflows to both are the same, so both reservoirs would be drafted equally (see also Section 5-14f(10)).

b. Energy Shortfall. The generation from inflow would be computed as follows:

$$\text{kWh} = \frac{\text{QHet}}{11.81} = \frac{(\text{Avg. inflow})(\text{Avg. head})(0.85)(720 \text{ hours})}{11.81}$$

	Reservoir C	Reservoir D
Average inflow	1,000 cfs	1,000 cfs
Est. avg. head	98 feet	98 feet
Generation	5,100 MWh	5,100 MWh

The energy shortfall to be met from storage draft would be (14,800 - 5,100 - 5,100) = 4,600 MWh, or 2,300 MWh from each reservoir.

c. Required Storage Draft. The discharge required from each reservoir to meet the energy shortfall would be computed as follows:

$$Q = \frac{11.81(\text{kWh})}{\text{Het}} = \frac{11.81(2{,}300{,}000 \text{ kWh})}{(98 \text{ feet})(0.85)(720 \text{ hours})} = 453 \text{ cfs.}$$

This corresponds to a storage draft of (453 cfs)(59.5 AF/cfs) = 26,900 AF.

End-of-period storage = 280,000 AF - 26,900 AF = 253,100 AF
End-of-period head = 96 feet (From Figure L-1)
Average head over period = (0.5)(100 + 96) = 98 feet 1/
Loss in head = (100 - 96) = 4 feet.

1/ This agrees with the initial assumption

d. Subsequent Energy Loss. The subsequent energy loss at each reservoir during the remaining months in the critical drawdown period would be computed as follows:

Remaining storage = (200,000 AF - 26,900 AF) = 173,100 AF

$$\text{Average cfs from storage} = \frac{(173{,}100\ \text{AF})}{(7\ \text{months})(59.5\ \text{AF/cfs})} = 416\ \text{cfs}$$

Average inflow = 1,000 cfs
Total average discharge = (1,000 cfs + 416 cfs) = 1,416 cfs
Head loss = 4.0 feet

$$\text{kWh} = \frac{(1{,}416\ \text{cfs})(4\ \text{feet})(0.85)(720\ \text{hours})(7\ \text{months})}{11.81} = 2{,}100\ \text{MWh}$$

e. Storage Effectiveness Index. The storage effectiveness index would be the ratio of the subsequent energy loss to the generation from storage in the given period, or

$$\frac{(2{,}100\ \text{MWh})}{(2{,}300\ \text{MWh})} = 0.91$$

L-4. Case 3: Parallel Reservoirs, One with Downstream Powerplant.

a. General. Reservoirs C and D are identical, but a run-of-river plant with 30 feet of head is located downstream of Reservoir D (Figure 5-56 and Section 5-14f(11)).

b. Draft Reservoir C.

(1) Energy Shortfall. The generation from inflow would be computed as follows:

$$\text{kWh} = \frac{\text{QHet}}{11.81} = \frac{(\text{Avg. inflow})(\text{Avg. head})(0.85)(720 \text{ hours})}{11.81}$$

	Reservoir C	Reservoir D
Average inflow	1,000 cfs	1,000 cfs
Est. avg. head	97 feet	130 ft. 1/
Generation	5,000 MWh	6,700 MWh

1/ 100 feet at Reservoir D plus 30 feet at run-of-river plant

The energy shortfall to be met from storage draft would be (14,800 - 5,000 - 6,700) = 3,100 MWh.

(2) Required Storage Draft. The discharge required from Reservoir C to meet the energy shortfall would be computed as follows:

$$Q = \frac{11.81(\text{kWh})}{\text{Het}} = \frac{11.81(3{,}100{,}000 \text{ kWh})}{(97 \text{ feet})(0.85)(720 \text{ hours})} = 617 \text{ cfs.}$$

This corresponds to a storage draft of (617 cfs)(59.5 AF/cfs) = 36,700 AF.

End-of-period storage = 280,000 AF - 36,700 AF = 243,300 AF
End-of-period head = 94 feet (From Figure L-1)
Average head over period = (0.5)(100 + 94) = 97 feet 1/
Loss in head = (100 - 94) = 6 feet.

1/ This agrees with the initial assumption

(3) Subsequent Energy Loss. The subsequent energy loss at Reservoir C during the remaining months in the critical drawdown period would be computed as follows:

Remaining storage = (200,000 AF - 36,700 AF) = 163,300 AF

$$\text{Average cfs from storage} = \frac{(163{,}300 \text{ AF})}{(7 \text{ months})(59.5 \text{ AF/cfs})} = 392 \text{ cfs}$$

Average inflow = 1,000 cfs
Total average discharge = (1,000 cfs + 392 cfs) = 1,392 cfs
Head loss = 6 feet.

$$\text{kWh} = \frac{(1{,}392\ \text{cfs})(6\ \text{feet})(0.85)(720\ \text{hours})(7\ \text{months})}{11.81} = 3{,}000\ \text{MWh.}$$

(4) Storage Effectiveness Index. The storage effectiveness index for Reservoir C would be the ratio of the subsequent energy loss to the generation from storage in the given period, or

$$\frac{(3{,}000\ \text{MWh})}{(3{,}100\ \text{MWh})} = 0.97$$

c. Draft Reservoir D.

(1) Energy Shortfall. The generation from inflow would be computed as follows:

$$\text{kWh} = \frac{\text{QHet}}{11.81} = \frac{(\text{Avg. inflow})(\text{Avg. head})(0.85)(720\ \text{hours})}{11.81}$$

	Reservoir C	Reservoir D
Average inflow	1,000 cfs	1,000 cfs
Est. avg. head	100 feet	98 + 30 feet
Generation	5,200 MWh	6,600 MWh

The energy shortfall to be met from storage draft would be (14,800 - 5,200 - 6,600) = 3,000 MWh.

(2) Required Storage Draft. The discharge required from Reservoir D to meet the energy shortfall would be computed as follows:

$$Q = \frac{11.81(\text{kWh})}{\text{Het}} = \frac{11.81(3{,}000{,}000\ \text{kWh})}{(98 + 30)(0.85)(720\ \text{hours})} = 452\ \text{cfs.}$$

This corresponds to a storage draft of (452 cfs)(59.5 AF/cfs) = 26,900 AF.

End-of-period storage = 280,000 AF - 26,900 AF = 253,100 AF
End-of-period head = 96 feet (From Figure L-1)
Average head over period = (0.5)(100 + 96) = 98 feet 1/
Loss in head = (100 - 96) = 4 feet.

1/ This agrees with the initial assumption

(3) Subsequent Energy Loss. The subsequent energy loss at Reservoir D during the remaining months in the critical drawdown period would be computed as follows:

Remaining storage = (200,000 AF - 26,900 AF) = 173,100 AF

$$\text{Average cfs from storage} = \frac{(173{,}100 \text{ AF})}{(7 \text{ months})(59.5 \text{ AF/cfs})} = 416 \text{ cfs}$$

Average inflow = 1,000 cfs
Total average discharge = (1,000 cfs + 416 cfs) = 1,416 cfs
Head loss =

$$\text{kWh} = \frac{(1{,}416 \text{ cfs})(4 \text{ feet})(0.85)(720 \text{ hours})(7 \text{ months})}{11.81} = 2{,}100 \text{ MWh.}$$

(4) Storage Effectiveness Index. The storage effectiveness index for Reservoir D would be the ratio of the subsequent energy loss to the generation from storage in the given period, or

$$\frac{(2{,}100 \text{ MWh})}{(3{,}000 \text{ MWh})} = 0.70$$

L-5. Case 4: Parallel Reservoirs with Unequal Flow.

a. General. Reservoirs C and D are identical, but Reservoir D has an inflow equal to half of the inflow at Reservoir C (Figure 5-58 and Section 5-14f(13)).

b. Draft Reservoir C.

(1) Energy Shortfall. The generation from inflow would be computed as follows:

$$\text{kWh} = \frac{\text{QHet}}{11.81} = \frac{(\text{Avg. inflow})(\text{Avg. head})(0.85)(720 \text{ hours})}{11.81}$$

	Reservoir C	Reservoir D
Average inflow	1,000 cfs	500 cfs
Est. avg. head	92 feet	100 feet
Generation	4,800 MWh	2,600 MWh

The energy shortfall to be met from storage draft would be (14,800 - 4,800 - 2,600) = 7,400 MWh.

(2) Required Storage Draft. The discharge required from Reservoir C to meet the energy shortfall would be computed as follows:

$$Q = \frac{11.81(\text{kWh})}{\text{Het}} = \frac{11.81(7,400,00 \text{ kWh})}{(92)(0.85)(720 \text{ hours})} = 1,552 \text{ cfs.}$$

This corresponds to a storage draft of (1,552 cfs)(59.5 AF/cfs) = 92,400 AF.

End-of-period storage = 280,000 AF - 92,400 AF = 187,600 AF
End-of-period head = 84 feet (From Figure L-1)
Average head over period = (0.5)(100 + 84) = 92 feet 1/
Loss in head = (100 - 84) = 16 feet.

1/ This agrees with the initial assumption

(3) Subsequent Energy Loss. The subsequent energy loss at Reservoir C during the remaining months in the critical drawdown period would be computed as follows:

Remaining storage = (200,000 AF - 92,400 AF) = 107,600 AF

$$\text{Average cfs from storage} = \frac{(107,600 \text{ AF})}{(7 \text{ months})(59.5 \text{ AF/cfs})} = 259 \text{ cfs}$$

Average inflow = 1,000 cfs
Total average discharge = (1,000 cfs + 259 cfs) = 1,259 cfs
Head loss = 16 feet

$$\text{kWh} = \frac{(1{,}259 \text{ cfs})(16 \text{ feet})(0.85)(720 \text{ hours})(7 \text{ months})}{11.81} = 7{,}300 \text{ MWh}$$

(4) Storage Effectiveness Index. The storage effectiveness index for Reservoir C would be the ratio of the subsequent energy loss to the generation from storage in the given period, or

$$\frac{(7{,}300 \text{ MWh})}{(7{,}400 \text{ MWh})} = 0.99$$

c. Draft Reservoir D.

(1) Energy Shortfall. The energy shortfall would be the same as for drafting Reservoir C, or 7,400 MWh.

(2) Required Storage Draft. The required storage draft from Reservoir D would be the same as from Reservoir C, or 187,600 AF. The loss in head would also be 16 feet.

(3) Subsequent Energy Loss. The subsequent energy loss at Reservoir D during the remaining months in the critical drawdown period would be computed as follows:

Remaining storage = (200.000 AF - 92.400 AF) = 107,600 AF

$$\text{Average cfs from storage} = \frac{(107{,}600 \text{ AF})}{(7 \text{ months})(59.5 \text{ AF/cfs})} = 259 \text{ cfs}$$

Average inflow = 500 cfs
Total average discharge = (500 cfs + 259 cfs) = 759 cfs
Head loss = 16 feet

$$\text{kWh} = \frac{(759 \text{ cfs})(16 \text{ feet})(0.85)(720 \text{ hours})(7 \text{ months})}{11.81} = 4{,}400 \text{ MWh}$$

(4) Storage Effectiveness Index. The storage effectiveness index for Reservoir D would be the ratio of the subsequent energy loss to the generation from storage in the given period, or

$$\frac{(4{,}400 \text{ MWh})}{(7{,}400 \text{ MWh})} = 0.59$$

L-6. Case 5: Parallel Reservoirs of Unequal Slope.

a. General. Reservoirs E and F are of equal capacity, but Reservoir E has a head when full of 150 feet and Reservoir F has a head when full of 50 feet (Figure 5-59 and Section 5-14f(14)). The storage-elevation curves are shown on Figure L-1.

b. Draft Only Reservoir E.

(1) Energy Shortfall. The generation from inflow would be computed as follows:

$$\text{kWh} = \frac{\text{QHet}}{11.81} = \frac{(\text{Avg. inflow})(\text{Avg. head})(0.85)(720 \text{ hours})}{11.81}$$

	Reservoir E	Reservoir F
Average inflow	1,000 cfs	1,000 cfs
Est. avg. head	145 feet	50 feet
Generation	7,500 MWh	2,600 MWh

The energy shortfall to be met from storage draft would be (14,800 - 7,500 - 2,600) = 4,700 MWh.

(2) Required Storage Draft. The discharge required from Reservoir E to meet the energy shortfall would be computed as follows:

$$Q = \frac{11.81(\text{kWh})}{\text{Het}} = \frac{11.81(4{,}700{,}000 \text{ kWh})}{(145)(0.85)(720 \text{ hours})} = 626 \text{ cfs.}$$

This corresponds to a storage draft of (626 cfs)(59.5 AF/cfs) = 37,200 AF.

End-of-period storage = 280,000 AF - 37,200 AF = 242,800 AF
End-of-period head = 141 feet (From Figure L-1)
Average head over period = (0.5)(150 + 141) = 145 feet 1/
Loss in head = (150 - 141) = 9 feet.

1/ This agrees with the initial assumption

(3) Subsequent Energy Loss. The subsequent energy loss at Reservoir E during the remaining months in the critical drawdown period would be computed as follows:

Remaining storage = (200.000 AF - 37,200 AF) = 162.800 AF

$$\text{Average cfs from storage} = \frac{(162{,}800\ \text{AF})}{(7\ \text{months})(59.5\ \text{AF/cfs})} = 391\ \text{cfs}$$

Average inflow = 1,000 cfs
Total average discharge = (1,000 cfs + 391 cfs) = 1,391 cfs
Head loss = 9 feet

$$\text{kWh} = \frac{(1{,}391\ \text{cfs})(9\ \text{feet})(0.85)(720\ \text{hours})(7\ \text{months})}{11.81} = 4{,}500\ \text{MWh}$$

(4) Storage Effectiveness Index. The storage effectiveness index for Reservoir E would be the ratio of the subsequent energy loss to the generation from storage in the given period, or

$$\frac{(4{,}500\ \text{MWh})}{(4{,}700\ \text{MWh})} = 0.96$$

c. Draft Reservoir F.

(1) Energy Shortfall. The generation from inflow would be computed as follows:

$$\text{kWh} = \frac{\text{QHet}}{11.81} = \frac{(\text{Avg. inflow})(\text{Avg. head})(0.85)(720\ \text{hours})}{11.81}$$

	Reservoir E	Reservoir F
Average inflow	1,000 cfs	1,000 cfs
Est. avg. head	150 feet	45 feet
Generation	7,800 MWh	2,300 MWh

The energy shortfall to be met from storage draft would be (14,800 - 7,800 - 2,300) = 4,700 MWh.

(2) Required Storage Draft. The discharge required from Reservoir F to meet the energy shortfall would be computed as follows:

$$Q = \frac{11.81(\text{kWh})}{\text{Het}} = \frac{11.81(4{,}700{,}000\ \text{kWh})}{(45)(0.85)(720\ \text{hours})} = 2{,}016\ \text{cfs.}$$

This corresponds to a storage draft of (2,016 cfs)(59.5 AF/cfs) = 120,000 AF.

End-of-period storage = 280,000 AF - 120,000 AF = 160,000 AF
End-of-period head = 40 feet (From Figure L-1)
Average head over period = (0.5)(50 + 40) = 45 feet 1/
Loss in head = (50 - 40) = 10 feet.

1/ This agrees with the initial assumption

(3) Subsequent Energy Loss. The subsequent energy loss at Reservoir F during the remaining months in the critical drawdown period would be computed as follows:

Remaining storage = (200,000 AF - 120,000 AF) = 80,000 AF

$$\text{Average cfs from storage} = \frac{(80{,}000\ \text{AF})}{(7\ \text{months})(59.5\ \text{AF/cfs})} = 192\ \text{cfs}$$

Average inflow = 1,000 cfs
Total average discharge = (1,000 cfs + 192 cfs) = 1,192 cfs
Head loss =

$$\text{kWh} = \frac{(1{,}192\ \text{cfs})(10\ \text{feet})(0.85)(720\ \text{hours})(7\ \text{months})}{11.81} = 4{,}300\ \text{MWh}$$

(4) Storage Effectiveness Index. The storage effectiveness index for Reservoir F would be the ratio of the subsequent energy loss to the generation from storage in the given period, or

$$\frac{(4{,}300\ \text{MWh})}{(4{,}700\ \text{MWh})} = 0.91.$$

APPENDIX M

EXISTING MULTIPLE-PURPOSE SYSTEMS IN THE UNITED STATES

M-1. Introduction.

a. This appendix briefly describes seven of the major reservoir systems in the United States which include hydropower as a major function. These systems are:

- Cumberland River System
- Tennessee River System
- Arkansas River System
- Missouri River System
- Colorado River System
- Central Valley Project
- Columbia River System

This appendix illustrates the role that hydropower plays in different systems and some of the ways in which the power operation has been adapted to coexist with other operating objectives. These operating descriptions are intended to provide only a general overview of the respective system operations. For detailed information, the agency responsible for management of the system should be contacted.

b. The description of the operation of each system includes a table listing the operating characteristics of the projects in that system. The reservoir function listings generally include all existing functions, not just those included in the project authorizing legislation. For example, many projects were authorized before recreation was recognized as a Federal project function, but recreation has since developed into an important reservoir use at most of these projects. Unless otherwise noted, the tables list the project's conservation storage capacity, which usually represents the storage that can be used for power generation. This includes multiple-use conservation storage, exclusive power storage, and joint-use flood control/conservation storage, but does not include exclusive flood control storage. The installed capacity noted on the tables is the nameplate capacity of all generating units at the projects.

M-2. Cumberland River Basin System.

a. General.

(1) The Cumberland River is a tributary of the Ohio River, which runs in a general east-to-west direction, straddling the Kentucky-Tennessee border. Runoff, which is primarily from rainfall, is heaviest in the winter and spring months (Figure M-1). The Cumberland River is controlled by a multiple-purpose reservoir system consisting of five storage projects and four run-of-river navigation projects, all with power (Table M-1 and Figure M-2). The system was constructed by the Corps of Engineers, and the functions served by the projects include flood control, navigation, hydropower, and recreation.

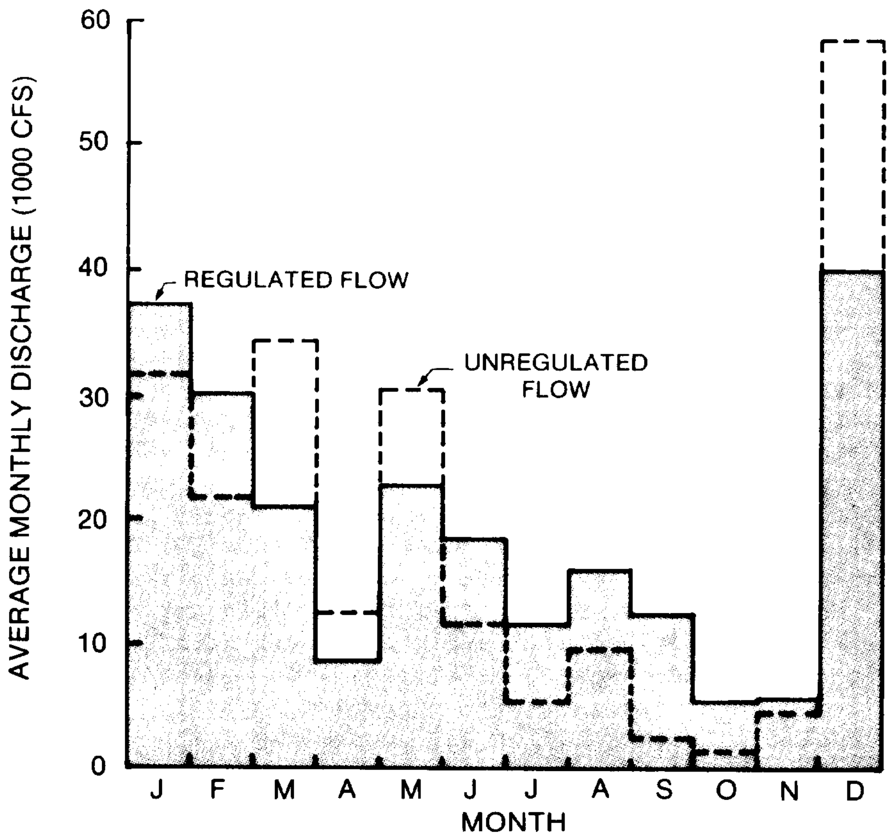


Figure M-1. Average monthly discharge of the Cumberland River at Old Hickory Dam, regulated and unregulated, for a typical year (1978)

(2) Power produced by the projects is marketed by the Southeastern Power Administration (SEPA). Prior to 1984, the power was marketed primarily to the Tennessee Valley Authority (TVA), and the Cumberland River powerplants were operated as part of the TVA system. Since that date, a large portion of the capacity has been marketed to preference customers outside of the TVA service area, and the power operating criteria of the Cumberland projects have been modified to accomodate the requirements of the outside-TVA customers.

b. System Operation.

(1) The primary functions of the Cumberland system are flood control, navigation, and hydropower. The storage projects are regulated primarily for flood control and hydropower, and releases for power generation are generally sufficient to meet the instream flow requirements for navigation and other river uses. Reservoir recreation is heavy at these projects, and efforts are made to maintain the reservoirs as high as practicable during the summer months, within the constraints of power requirements. At J. Percy Priest and Cordell Hull, the authorizing legislation specifies that summer pool elevations be maintained for recreation.

(2) Three of the five storage projects in the system provide the bulk of the control: Wolf Creek, Dale Hollow, and Center Hill. Laurel, the project that is furthest upstream, has power storage only and, since its output goes to a single customer, it is operated independently from the rest of the system. J. Percy Priest is located on the outskirts of Nashville, and its primary functions include flood control, hydropower, and recreation. The project operates in accordance with a fixed seasonal rule curve designed to keep the reservoir elevation high in the summer for recreation and low in the winter for flood control. Power generation is limited to what can be produced within these operating constraints, with most of the generation being produced in the winter and spring months.

(3) At Wolf Creek, Dale Hollow, and Center Hill, the storage is divided into two zones: an exclusive flood control zone on top and a conservation (power) storage zone on the bottom (Figure M-3). Because of the risk of large floods occurring at any time during the winter and the spring refill season, joint-use storage for both flood control and power is not practical. Regulation of the power storage follows a seasonal pattern, beginning with the reservoirs near the top of the power pool about the first of June. Storage is then gradually drafted through the low flow, high demand summer season, and the reservoir is usually at its lowest level in the late fall and early winter months. Refill takes place during the late winter and spring months.

TABLE M-1
Major Hydropower Projects in the Cumberland
River Multiple-Purpose Reservoir System

Dam	River	Owner or Operator	Reservoir Functions	Conservation Storage (1000 AF)	Installed Capacity (MW)
Laurel	Laurel	Corps	PR 1/	185	61
Wolf Creek	Cumberland	Corps	FPR	2,142	270
Dale Hollow	Obey	Corps	FPR	496	54
Cordell Hull	Cumberland	Corps	NPR	pondage	100
Center Hill	Caney Fork	Corps	FPR	492	135
Old Hickory	Cumberland	Corps	NPR	pondage	100
J. Percy Priest	Stones	Corps	FPRW	124	28
Cheatham	Cumberland	Corps	NPR	pondage	36
Barkley	Cumberland	Corps	FNPR	259 2/	130
Totals				3,698	914

1/ reservoir purposes:
F - flood control
I - irrigation
N - navigation
P - hydropower
R - recreation
W - fish and wildlife
S - water supply

2/ storage between normal full pool and winter flood control pool

(4) Figure M-3 also shows the regulation of Wolf Creek in a representative year (1978). The calendar year began with the reservoir relatively high, due to higher than average inflow in the preceding months. Some drafts were made in January and February, but they were partially offset by a storm in late January. Refill began in March, with most of the refill occurring in March and May. In late May, a storm caused the reservoir to rise into the flood control zone for a short time. Substantial drafts were made from June through November to meet power requirements, but a storm in early December refilled a large portion of the power storage. Drafting for power generation resumed shortly thereafter. Figure M-1 shows the effect of this regulation on the monthly average flow pattern.

(5) Like TVA's main river projects (Section M-3d), Barkley has a seasonally varying flood control pool with a rule curve similar to that shown for Chickamauga (Figure M-8). Within the limits imposed by the flood control rule curve, Barkley operates basically as a run-of-river project with pondage. Barkley Reservoir is connected to Kentucky Reservoir via an open canal, and the two projects are operated in unison.

(6) Because the Cumberland River system consists of multiple storage projects with downstream run-of-river projects, the power storage must be regulated as a system in order to maximize generation at both the reservoir powerplants and the run-of-river projects. Since the three main storage projects are situated in an essentially parallel configuration (Chapter 5, Section 5-14f, Case 2), storage is drafted proportionately; i.e., all of the reservoirs are maintained at approximately the same percent of power storage remaining. Variations in inflow patterns among the projects do cause some deviation from this objective, however.

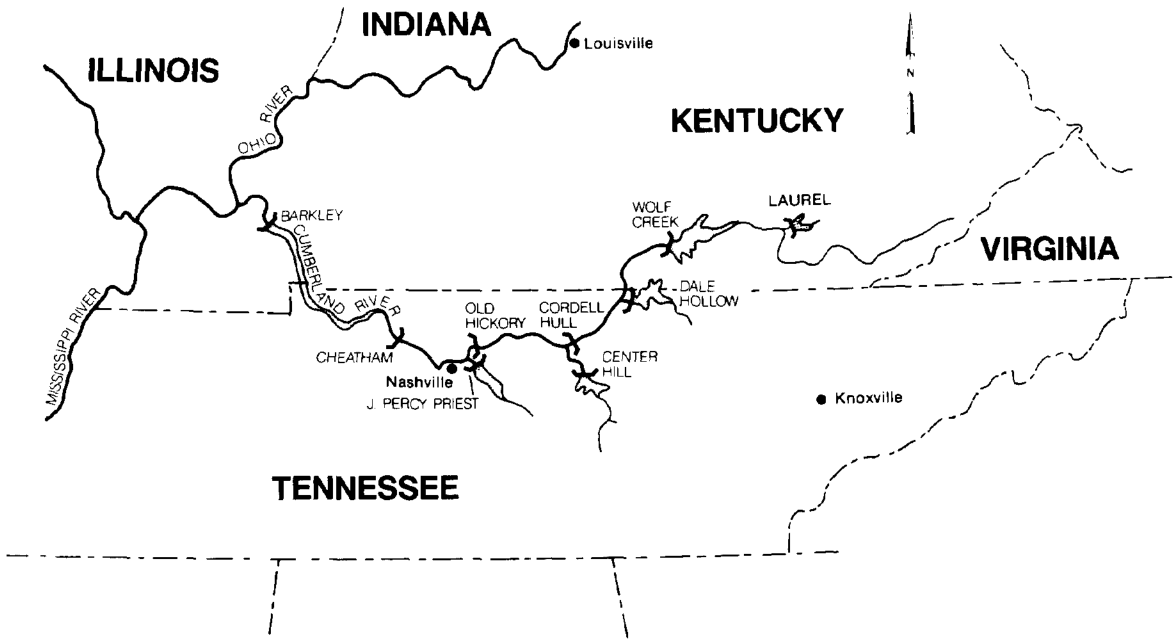


Figure M-2. Projects of the Cumberland River system

(7) The power from the Cumberland River system is marketed primarily as peaking power, so the powerplants at the storage project are operated at intermediate and peaking plant factors, except when high inflows and/or evacuation of flood control storage space permits higher generation levels. At the run-of-river projects, some pondage is provided to permit peaking operation, although this pondage is reduced or eliminated during the flood season by the need to provide surcharge space to replace lost valley storage. Minimum flows and maximum rate-of-change requirements are imposed at some projects in order to protect navigation.

c. SEPA Rule Curve Operation.

(1) Prior to 1984, the Cumberland River powerplants were generally dispatched as a part of the TVA system. Since 1984, a portion of the capacity has been marketed to outside-TVA customers. This in turn resulted in a new contract between TVA and SEPA, which imposed somewhat stricter operating constraints on the system. As a

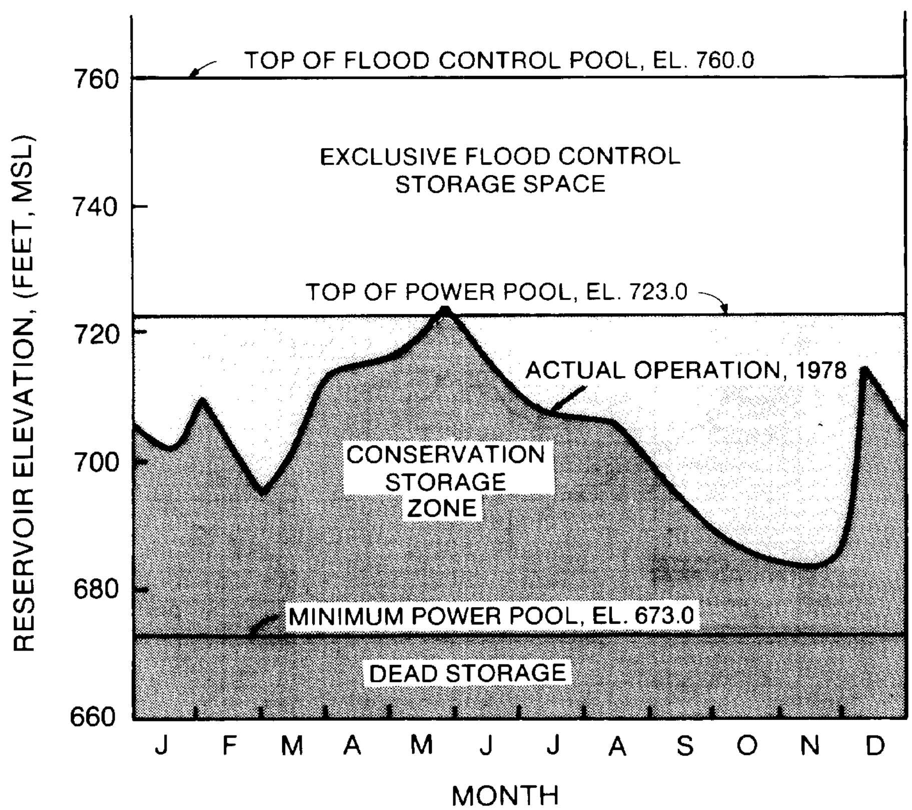


Figure M-3. Storage allocation at Wolf Creek Reservoir, showing actual operation in 1978 part of this contract, SEPA developed rule curves to define more specifically the seasonal regulation of the storage projects (Figure M-4). The power storage in each reservoir is subdivided into three zones. These zones are defined by two seasonally varying curves: the SEPA Rule Curve and the Bottom Operating Curve. The two curves are based primarily on the normal range of operation that has been experienced at the project, with some adjustments to protect capacity and to accomodate the requirements of the outside-TVA customers.

(2) As far as the outside-TVA customers are concerned, the operating objective is to meet specified weekly energy and capacity requirements. This type of operation would suggest operating against a single rule curve based on firm energy requirements. TVA prefers to use its share on more of a discretionary basis, with the amount of power used at any given time being a function of the needs of their system at that time. The use of two rule curves defining a zone of normal operation meets the requirements of both entities. The rule

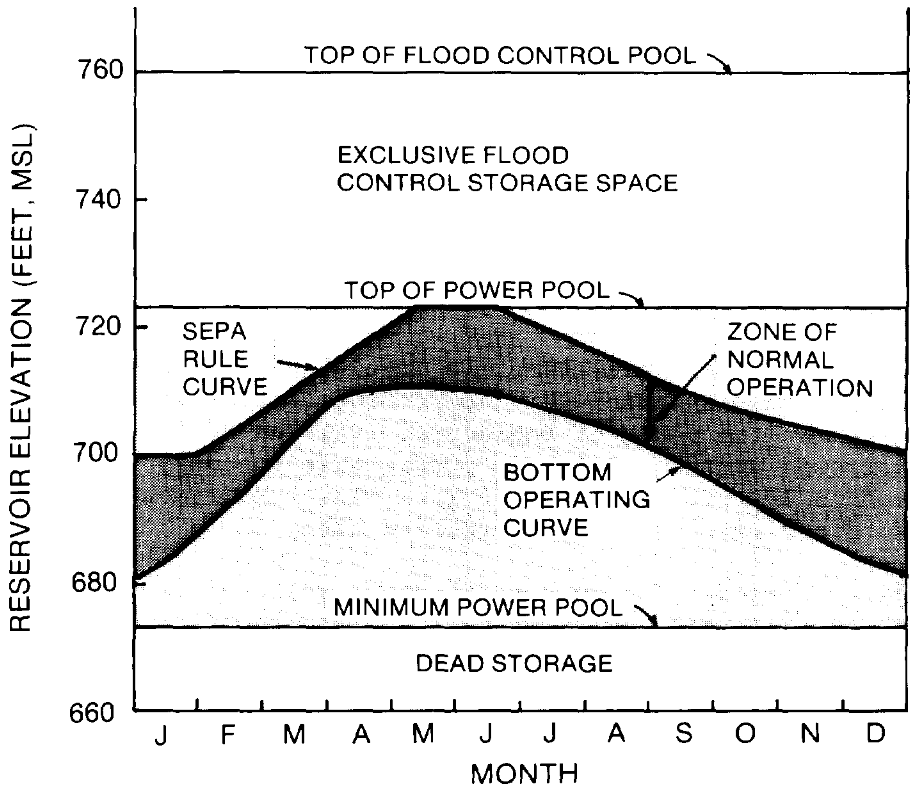


Figure M-4. Power rule curves for Wolf Creek Reservoir curves protect the weekly energy and capacity requirements of the outside-TVA customers, while the zone of normal operation permits TVA some flexibility in day-to-day operations.

(3) Typically, the projects are operated in the upper portion of the zone of normal operation. If TVA has the need for additional power, due to forced outages or unusually high loads, it may draft below this level. Later, if conditions permit, TVA may reduce its demands to permit the reservoir to approach the SEPA rule curve once again. During periods of high runoff, the reservoir may fill above the SEPA Rule Curve. In such cases, discharges will usually be increased above firm requirements in an effort to draw the reservoir back to the rule curve. If the reservoir fills into the flood control zone, that zone will be evacuated as soon as possible without violating bankfull conditions downstream, and the powerplant may be operated at full discharge, and supplemented by spill if necessary.

(4) Drafts below the Bottom Operating Curve would occur under unusually severe power situations, but any energy "borrowed" from below the zone of normal operation must be restored as soon as possible. The Bottom Operating Curve represents the minimum elevations required to insure that reservoirs will have sufficient remaining storage to meet future energy requirements.

(5) Deviations from the SEPA Rule Curve are permitted during the refill season. In a dry spring, the reservoir would be allowed to exceed the rule curve elevation in order to improve the probability of refill. In a wet spring, deviations below the rule curve might be permitted to reduce the liklihood of the reservoir filling into the flood control zone.

(6) Drafts for power generation are scheduled on a weekly basis, and the implementation of this operation requires daily coordination between the Corps of Engineers, TVA, and SEPA. The schedule of releases must be tested to insure that not only firm power requirements are met, but that minimum flow requirements for navigation and other river uses are satisfied also.

d. Critical Period. The Cumberland River reservoir system is operated on an annual cycle, with the critical period being defined as the eight-month sequence, May 1980 through January 1981.

e. Management of the System. The Cumberland River system is operated by the Nashville District, Corps of Engineers, PO Box 1070, Nashville, TN 37202. The power operation is closely coordinated with TVA and SEPA.

f. Summary. The reservoir storage in the Cumberland River system is divided into exclusive flood control and conservation storage zones. The conservation storage is regulated primarily for power on an annual cycle following rule curves. Releases for power generation are normally sufficient to meet navigation and other instream flow requirements. With the exception of Laurel, the projects are operated as a system.

M-3. Tennessee River System.

a. General.

(1) The Tennessee River drains about 41,000 square miles of seven southeastern states. Rainfall averages 52 inches over the basin and is well-distributed throughout the year. Average annual snowfall is eight inches, but it does not create a snowpack and is therefore not a significant factor in system operations. Average flow of the Tennessee River at its mouth is about 66,000 cfs. Figure M-5 shows the seasonal distribution of this flow.

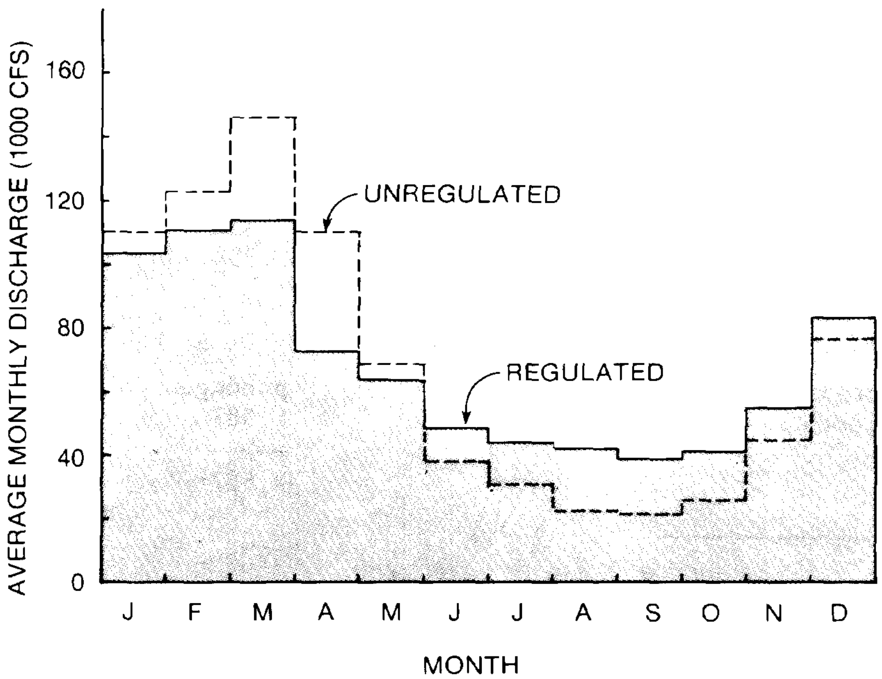


Figure M-5. Average monthly discharge of the Tennessee River at Kentucky Dam, regulated and unregulated, 1953-1980

TABLE M-2
Major Hydropower Projects in the Tennessee River Basin 2/

Project	River	Project Function 1/	Conservation Storage (1000 AF)	Installed Capacity (MW)
		Main River Projects		
Kentucky	Tennessee	FNP	721 3/	175
Pickwick Landing	"	FNP	239 3/	224
Wilson	"	NP	pondage	630
Wheeler	"	FNP	328 3/	375
Guntersville	"	FNP	132 3/	115
Nickajack	"	NP	pondage	104
Chickamauga	"	FNP	221 3/	120
Watts Bar	"	FNP	214 3/	167
Fort Loudon	"	FNP	79 3/	139
		Major Tributary Storage Projects		
Hiwassee	Hiwassee	FNP	306	117
Norris	Clinch	FNP	1,922	101
Fontana	Little Tenn.	FNP	946	239
Douglas	French Broad	FNP	1,252	121
Cherokee	Holston	FNP	1,148	135
South Holston	S. Fork Holston	FNP	438	35
Watauga	Watauga	FNP	354	58
		Other Projects		
Raccoon Mountain	4/	P	pondage	1,530
Smaller projects	-	-	1,387	423
Totals			9,687	4,808

1/ reservoir purposes: F - flood control
N - navigation
P - hydropower

2/ all projects listed are owned by the Tennessee Valley Authority

3/ storage between normal full pool and winter flood control pool

4/ off-stream pumped-storage project

(2) The water resource development of the Tennessee River Basin is managed by the Tennessee Valley Authority (TVA). The TVA operates or controls 50 dams and reservoirs in the Tennessee River Basin, 33 of which have power facilities. Total reservoir storage is 13.8 million acre-feet, or about 30 percent of the average annual runoff. Table M-2 lists the major characteristics of the main river projects, the major tributary storage reservoirs, and the Raccoon Mountain pumped-storage project. Figure M-6 shows the locations of these projects.

b. System Operation.

(1) The primary operating objectives of TVA's river control plan are flood control, navigation, and power generation, although recreation, fish and wildlife, water quality, water supply, and vector control are also important. Unregulated streamflows are at a maximum during the winter months and at minimum levels during the summer and fall. The objective of the reservoir operating plan is to

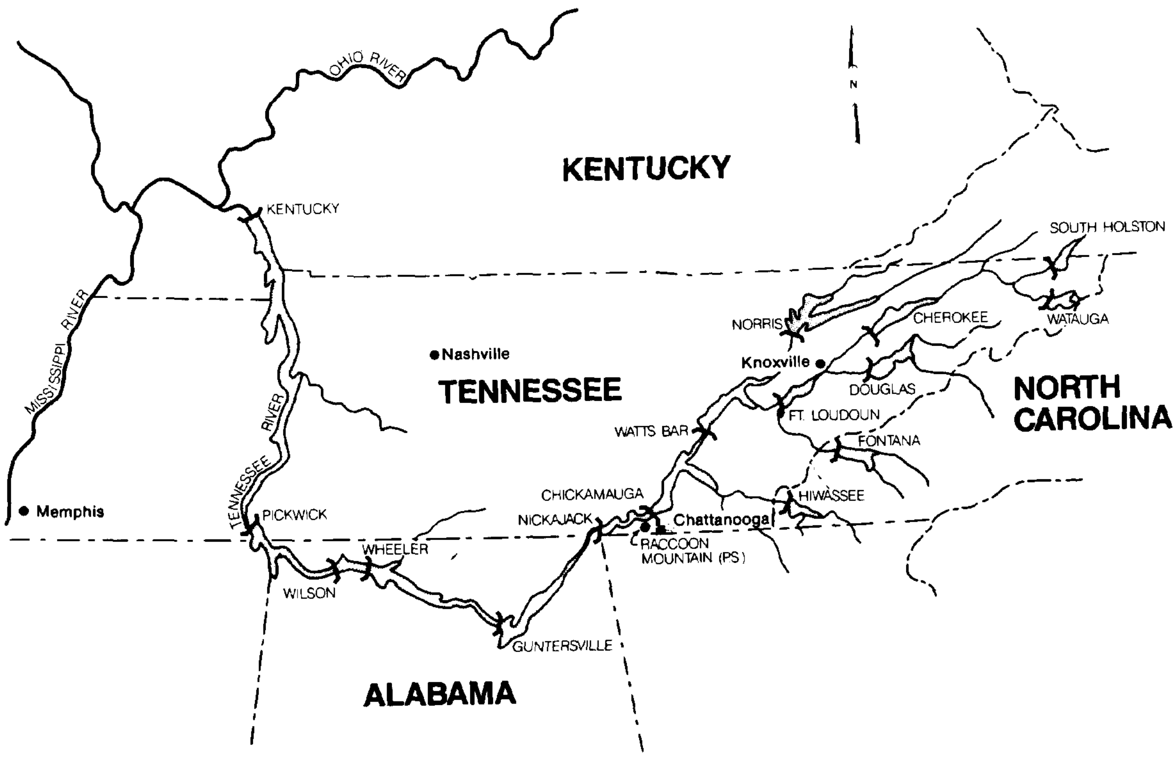


Figure M-6. Major projects of the Tennessee River system provide flood control, primarily in the winter months, and to augment streamflows in the summer and fall months for navigation, power generation, and other purposes.

(2) Power demand in the TVA service area is at its maximum in the winter months, but summer peak loads can be almost as high. TVA's hydro system was originally designed to carry the bulk of the system power demand, so most of the projects have relatively high average annual plant factors (40-70 percent). However, now that TVA has evolved into a thermal-based power system, the hydro plants are used primarily for carrying intermediate and peak loads. The 1530 MW Raccoon Mountain off-stream pumped-storage project was placed in service in 1979 to help carry peak loads.

(3) TVA's projects with seasonal regulating capability fall into two categories: (a) the tributary (or headwater) storage projects, and (b) the main river projects. Although the seasonal regulation pattern is basically the same in both cases, the details of the operations differ somewhat because of the differences in reservoir configuration, degree of control provided, and functions served.

c. Regulation of Tributary Storage Projects.

(1) The tributary storage projects are normally at or near maximum pool elevation about the first of June. A small amount of flood detention space is reserved through the summer months in order to control runoff from intense local storms. Storage draft begins in early summer and accelerates during the dry fall months to provide additional flows downstream for navigation, power generation, and low flow augmentation.

(2) The overall objective of the drawdown schedule is to have the storage drafted by the first of January in order to meet winter flood control requirements, but power generation requirements usually control the rate of draft. A basic power rule curve has been developed for each period in order to insure that firm power requirements are met (see Figure M-7). However, in most years reservoir and streamflow conditions are such that considerable flexibility exists as to how the storage would be drafted.

(3) Although the TVA has a substantial amount of hydropower capacity, it is now a thermal-based power system, so it uses its hydro generation to minimize system fuel costs. A set of intermediate guide curves is developed to govern storage draft (Chapter 5, Figure 5-49), and these curves are based on the expected value of hydroelectric generation over the course of the drawdown period. The decision to draft storage at any point in time is based on the amount

of reservoir storage available in the system and the cost of the most expensive (or marginal) thermal plant generation that would have to be operated in the absence of storage draft. If on any day the marginal cost of thermal generation exceeds the guide curve value corresponding to the reservoir storage available on that day, storage would be drafted and marginal thermal generation would be reduced or shut down. If the marginal cost of thermal generation is less than the guide curve value, storage drafts would be limited or water would be stored.

(4) The sequence of draft from the various tributary storage projects is based generally on optimizing system power generation and balancing relative storage among the projects. This objective is tempered by minimum discharge requirements for non-power purposes and the desirability of maintaining reservoirs as high as practicable during the summer months in the interest of reservoir recreation (within constraints imposed by the three primary operating objectives). The reservoir system configuration is a combination of series and parallel projects, with run-of-river and pondage projects interspersed among and downstream from the storage projects, so a system sequential streamflow routing model has been used to develop the system regulation plan.

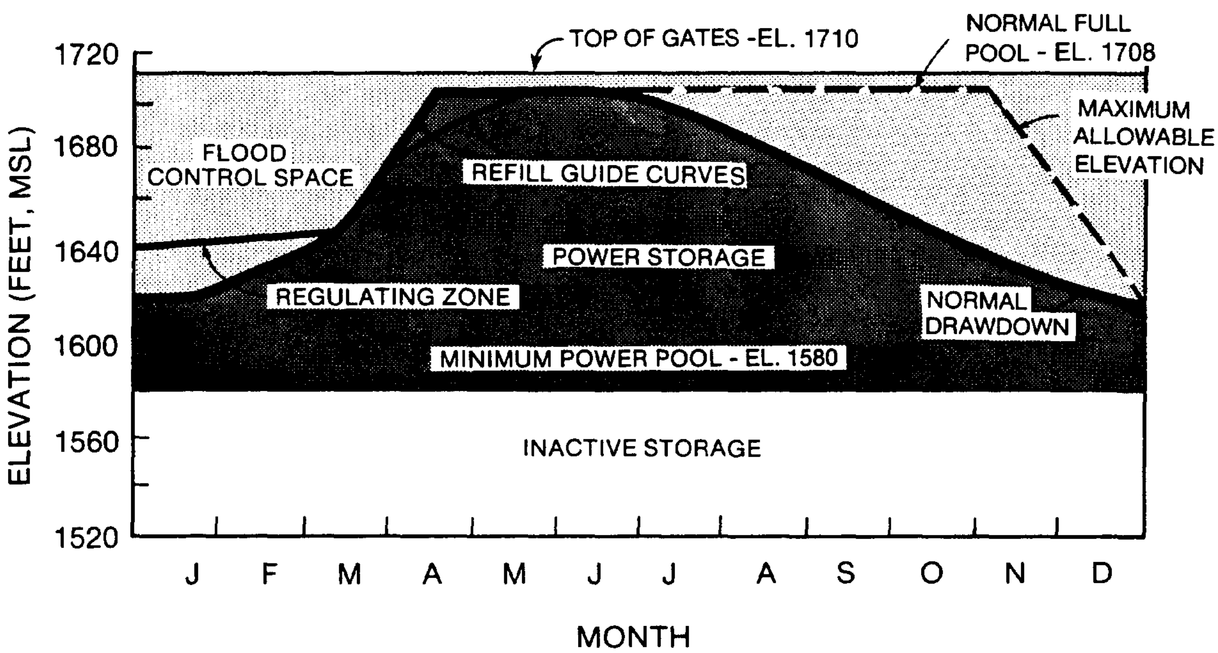


Figure M-7. Rule curve for Fontana Reservoir, a typical tributary storage project in the Tennessee River system

(5) The major flood control season includes the months of January, February, and March. Since there is no snowpack, these floods result from rainfall runoff. A specified amount of flood control storage space must be provided at each reservoir on March 15 to regulate floods at Chattanooga, a critical downstream location. The rule curve requires that additional storage space be available prior to March 15 in order to insure that earlier floods can be controlled without jeopardizing the March 15 requirement.

(6) The refill curve is based on balancing the diminishing flood control requirement with a reasonable probability of refilling the conservation storage. Operating procedures permit most reservoirs to be filled to the normal full pool level after the flood season. However, in some years, they do not refill completely.

d. Regulation of Main River Projects.

(1) The "main river projects" are the nine moderately low head (40 to 90 feet) projects that develop the hydro potential of the main stem of the Tennessee River from Knoxville to its confluence with the Ohio River, a distance of 625 miles. All of these projects have navigation locks, permitting barge traffic to be maintained through this reach. Wilson and Nickajack are run-of-river projects with pondage, but the remaining eight projects provide seasonal storage for flood control.

(2) Compared to the tributary storage projects, the main river projects have a relatively small amount of storage capacity in terms of inches of runoff (1.8 inches compared to 6.4 inches for the tributary reservoirs). However, these projects are useful in accelerating pre-flood flows downstream and in reducing the crest of the flood. Like the tributary projects, the main river reservoirs are required to be at their minimum elevations by 1 January (see Figure M-8). However, the total flood control space is reserved through the end of March, except when regulating floods. The winter flood control pool elevation is high enough to maintain adequate depth for navigation.

(3) Because of the relatively high ratio of runoff to storage space, these reservoirs are usually full by mid-April. Once the conservation storage is filled, the reservoirs are allowed to rise briefly into the summer flood control zone in order to strand floating debris. Storage drafts are scheduled through the summer and fall months for power production and other purposes to insure that the reservoirs will be at their winter flood control pool elevations by January 1. Because these projects are downstream reservoirs with relatively high streamflows, they are typically drafted later than the tributary projects, so that higher heads (and the resulting

higher power production) can be maintained as late as possible (see Chapter 5, Section 5-14). During the summer season, the main river projects are also operated on a weekly fluctuation cycle in order to control lake-breeding mosquitoes.

e. Critical Period. The 1939-41 critical drought period is used to establish the hydro system's basic power rule curve (Chapter 5, Figure 5-49). Because the TVA power system is an interconnected hydrothermal power system, the requirements for hydro firm energy and dependable capacity vary as a function of power loads, thermal plant performance, and purchase power availability. Because there is normally enough steam, combustion turbine, and import power available to meet hydro energy shortfalls caused by droughts, it is not necessary to reserve a large portion of the power storage for meeting firm energy requirements. This allows considerable flexibility in the use of this storage. As a result, resource allocation for the hydro system is based on expected output from an 82-year hydrologic record rather than protecting against the single worst drought of record. The overall operating strategy for hydropower is to minimize

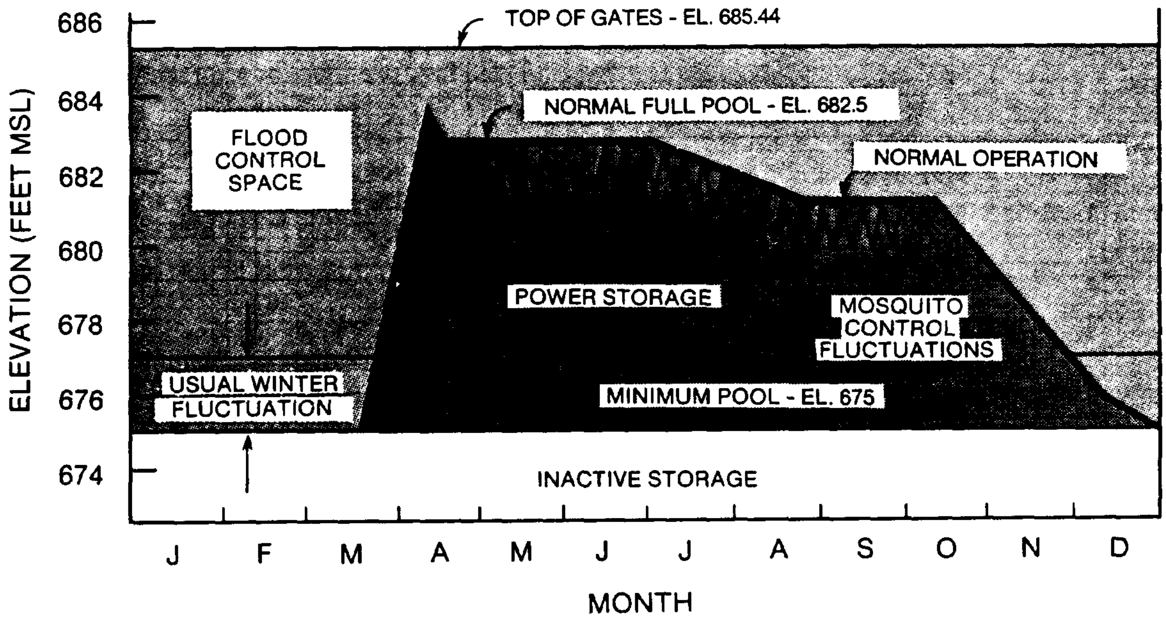


Figure M-8. Rule curve for Chickamauga Reservoir, a typical main river project in the Tennessee River system total system operating costs rather than maximizing firm energy output, so the classical critical period approach to reservoir regulation does not apply to the TVA system.

f. System Management. Operation of the Tennessee River reservoir system is managed by the Tennessee Valley Authority, Knoxville, TN 37902.

g. Summary. The TVA reservoir system is operated primarily to control winter floods and to provide conservation storage for power, navigation, and other river uses. Hydropower is used primarily to carry intermediate and peaking loads. The two operating features of the TVA system that are of special interest are: (a) that the relatively low-head main river reservoirs were designed to provide some seasonal storage capability, and (b) that storage drafts for power are based on the current value of the hydro energy for displacing thermal generation.

M-4. Arkansas River Basin System.

a. General.

(1) The Arkansas River drains 160,000 square miles of seven southwestern states and empties into the Mississippi River about 100 miles south of Memphis, Tennessee. Precipitation in the basin varies from 15 inches annually in its western reaches to more than 50 inches annually near the river's mouth. The majority of the precipitation occurs in May and June in the western portion of the basin and from March through May in the eastern section. Figure M-9 shows the seasonal runoff pattern for the Arkansas River at Van Buren, Arkansas, just downstream of the Oklahoma border.

(2) The Corps of Engineers and the Bureau of Reclamation have constructed 32 reservoirs in the basin, along with 17 locks and dams which permit shallow-draft navigation from the mouth of the Arkansas to Catoosa, near Tulsa, Oklahoma. This section describes the operation of the system of projects in the central part of the basin, which are regulated on a coordinated basis to meet the requirements of flood control, navigation, water supply, hydropower, recreation, water quality, and fish and wildlife. The major projects in this system are shown on Figure M-10, and their principal characteristics are listed on Table M-3. Ten of these projects have power facilities. The Grand River Dam Authority also operates three projects on one of the major tributaries, and two of these projects provide flood control storage, which is operated in coordination with the Federal projects.

b. Basic Reservoir Regulation.

(1) Reservoir space at most projects is divided into two zones: (a) an exclusive flood control zone on top, and (b) a conservation storage zone on the bottom (see Figure M-11). The seasons in which floods and droughts could occur overlap, so that it is not practical to provide a joint-use zone, such as that described in Section 5-12e of Chapter 5, in order to serve the needs of both flood control and conservation storage.

(2) Floods in the Arkansas River Basin are typically flashy, resulting from relatively short periods of intense rainfall. As originally designed, the flood control zone was intended to be evacuated as rapidly as possible following flood regulations. Conservation storage was to have been regulated to meet firm energy and water supply requirements. It was expected that regulation for flood control, power, and water supply would provide satisfactory conditions for navigation, except on the Verdigris River reach. A portion of the conservation storage at Oologah has been allocated to maintain navigation depth on the Verdigris during periods of drought.

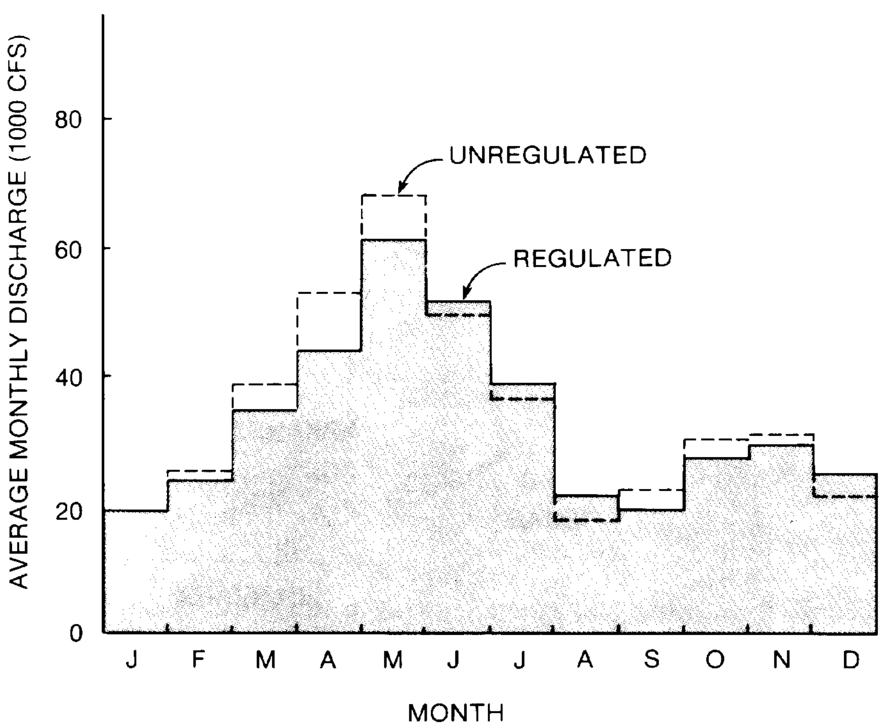


Figure M-9. Average monthly discharge of the Arkansas River at Van Buren, Arkansas, regulated and unregulated, 1940-1974

(3) The typical reservoir operating year begins in the late spring, with the reservoirs at their highest levels. Conservation storage drafts are normally made during the low flow summer months to meet power and water supply requirements, and these drafts can extend through the fall and winter months in many years. Conservation storage usually refills in the spring. Most of the major floods occur in the spring months, but high flows can be experienced at almost any time of the year.

(4) The power from the Corps' Arkansas River basin hydro projects is marketed by Southwestern Power Administration (SPA) as a system, together with projects in the adjacent White River basin. SPA serves a summer-peaking power system, with June, July, August, and September being the peak demand months. The original plan for regulating the conservation storage was based on maximizing firm energy production (while also maintaining water supply and minimum flow requirements).

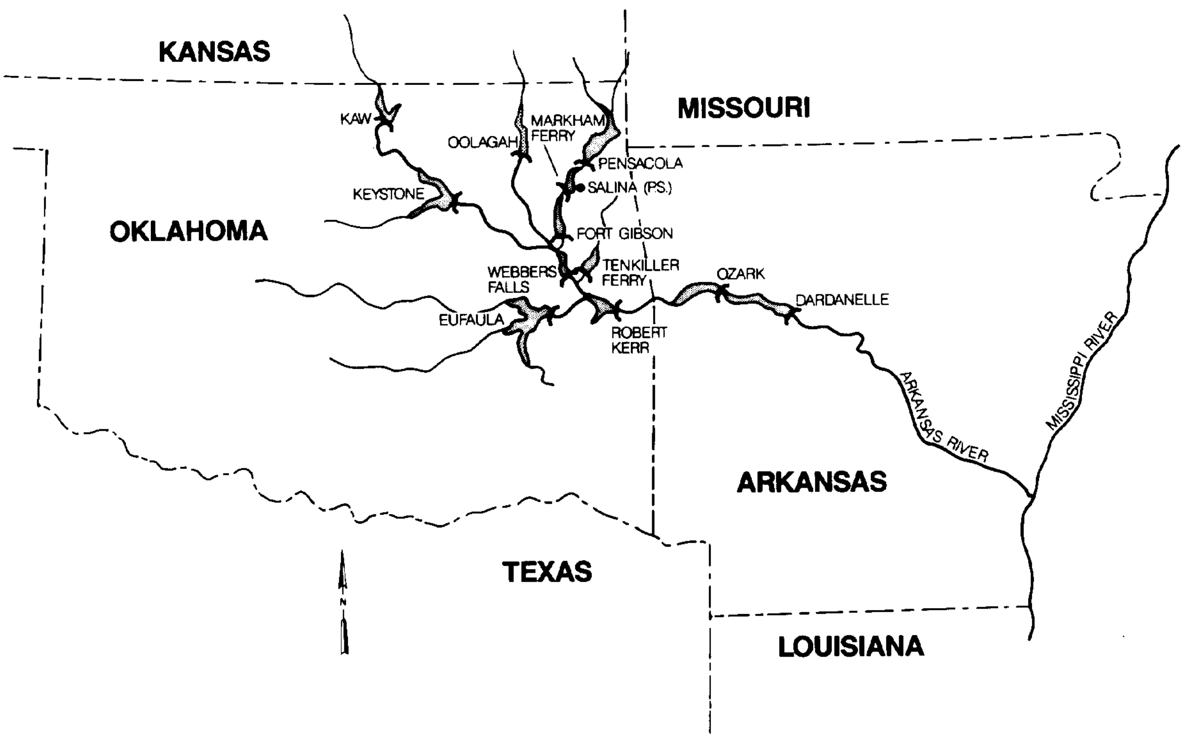


Figure M-10. Major hydroelectric projects in the Arkansas River Basin

TABLE M-3
Major Hydropower Projects in the Arkansas River Basin

Dam	River	Owner or Operator	Reservoir Functions	Conservation Storage (1000 AF)	Installed Capacity (MW)
Kaw	Arkansas	Corps	FRWSQ 1/	344	--3/
Keystone	Arkansas	Corps	FNPWS 4/	351	70
Oolagah	Verdigris	Corps	FNWS	544	--
Pensacola	Neosho	GRDA 2/	FP	586	86
Markham Ferry	Neosho	GRDA 2/	FP	pondage	108
Salina	off-stream	GRDA 2/	FP	p-storage	260
Fort Gibson	Neosho	Corps	FP	pondage	45
Webbers Falls	Arkansas	Corps	NP	pondage	60
Tenkiller Fy.	Illinois	Corps	FPS	371	37
Eufaula	Canadian	Corps	FNPRWS	1,481	90
Robt. S. Kerr	Arkansas	Corps	NPR	pondage	110
Ozark	Arkansas	Corps	NPRW	pondage	100
Dardanelle	Arkansas	Corps	NPRW	pondage	124
Totals				3,677	1,090

1/ reservoir purposes: F - flood control
I - irrigation
N - navigation
P - hydropower
R - recreation
W - fish and wildlife
S - water supply
Q - water quality

2/ Grand River Dam Authority

3/ in 1984 KAMO Electric Coop received a FERC license to install a powerplant at the Kaw project (final plant size not yet available)

4/ while many of the projects do not have recreation as an authorized project purpose, it is a major concern in developing operating plans for most of these projects.

(5) It was assumed that the full amount of reservoir storage allocated to power would be available for draft in order to meet firm power requirements. In the Southwestern states, hydropower is most valuable when used for peaking. Hence, most of the Arkansas and Red River basin hydro projects were designed to operate at firm plant factors in the low plant factor range. SPA's power sales contracts are essentially peaking capacity contracts, with each kilowatt of capacity being supported by a specified amount of firm energy. During periods of drought, the hydro system cannot fully meet these requirements, so thermal energy is obtained from local utilities under purchase and exchange agreements to make up the shortfall.

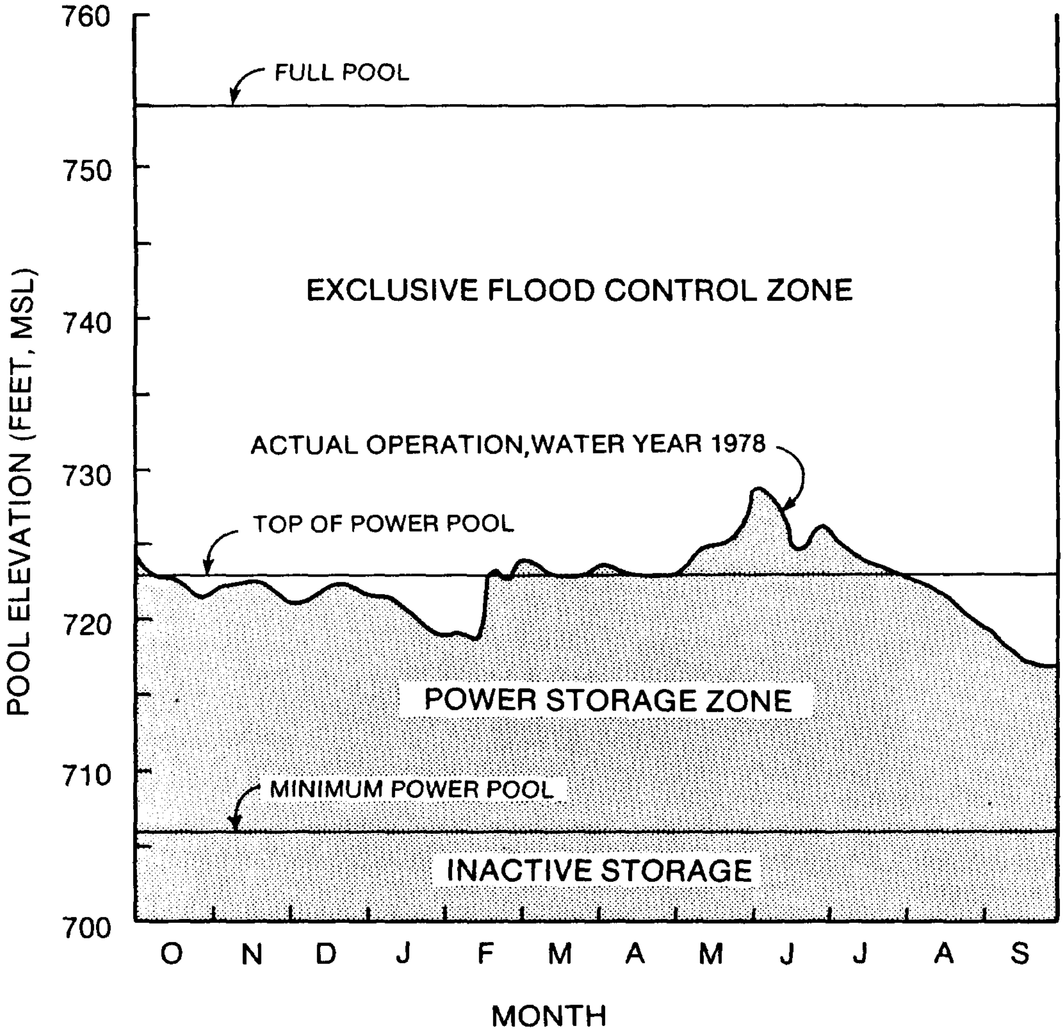


Figure M-11. Keystone Reservoir storage zones, showing actual operation in water year 1979

(6) When the reservoirs are operating in the flood control zone, the powerplants are generally operated at hydraulic capacity, and secondary energy is produced. Secondary energy could also be produced when operating in the conservation pool, depending on reservoir inflow, the time of year, and the power marketing situation.

(7) Operational experience has dictated two major changes to the operating plan: one when operating in the flood control zone and one when operating in the conservation storage zone. A description of these changes follows.

c. Modifications to Operation in Flood Control Zone.

(1) The rapid evacuation of the flood control space following flood events resulted in channel flows at or near bankfull capacity until evacuation was complete. At that point flows were reduced to those required to meet hydropower and water supply requirements. The sudden reduction in discharge would result in a corresponding sudden loss in river sediment transport capacity, leaving high shoals and blocked navigation channels in a number of reaches on the river. Furthermore, the discharges required to meet the rapid evacuation criteria exceeded the hydraulic capacities of the hydro plants, resulting in spilled energy. On the other hand, rapid evacuation of the flood control space left the storage space available as soon as possible for controlling subsequent flood events, thus maximizing flood control benefits. Rapid evacuation also brought the reservoirs down to the levels required for best reservoir recreation most rapidly.

(2) Because navigation is the dominant system function in terms of dollar benefits realized (more than 50 percent), a series of studies was made to develop a regulating plan which would improve navigation conditions during the post-flood evacuation period without significantly reducing flood protection. The result is a schedule of releases which is designed to provide a discharge level which is reduced gradually (or "tapered") as the flood control space is evacuated.

(3) The gage at Van Buren, Arkansas, near the Oklahoma-Arkansas border, is the control point upon which the regulation is based. When 40 percent or more of the basin flood control storage is filled, releases are scheduled at a rate such that flows at Van Buren do not exceed 150,000 cfs, which is the level at which structural flood damage occurs. When flood control storage is evacuated to the 40 percent level, releases are gradually reduced, so that by the time storage levels are in the 10-16 percent range, releases are at 105,000 cfs, the limit of agricultural flood damage. As the

remaining flood control space is evacuated, flows are maintained in the 20,000 to 40,000 cfs range, with 40,000 cfs being the level that corresponds to all power plants operating at hydraulic capacity.

d. Modifications to Operation in the Conservation Storage Zone.

(1) If the strategy of regulating the conservation storage to maximize firm energy production were to be followed rigorously, large storage drafts would be required on a regular basis. This would minimize SPA's purchases of supplemental thermal energy. On the other hand, the reservoirs would be frequently drafted to elevations that reduce (or threaten to reduce) generating capability below rated capacity. SPA has determined that maximizing dependable capacity is more valuable to their system than minimizing thermal energy purchases. Hence they prefer to purchase additional thermal energy in order to maintain the reservoir levels high enough to protect their dependable capacity.

(2) The power guide curves developed by Tulsa District illustrate this operation (see Chapter 5, Section 5-13d(3)). During periods of low flow, storage is drafted to support the capacity, but as the reservoir level drops, the hydro plant factor is gradually reduced. As the plant factor is reduced, increasing amounts of thermal energy must be purchased to meet SPA's energy requirements. During this type of operation, drafts must still be made for water supply and required downstream minimum flows, however.

e. Critical Period.

(1) The firm energy output of the Arkansas-White River hydro system is based on the 1952-56 critical period. The original studies assumed that the full amount of reservoir storage allocated to hydropower would be drafted during that period. At the present time, however, SPA regulates only the storage above rated head (see Chapter 5, Section 5-13c), so that rated capacity will be available at all times. The power storage below rated head is used to maintain head, rather than to increase firm energy output.

(2) While firm energy output is based on a multiple-year critical period, the reservoirs operate on an annual cycle. This is because of the relatively small amount of storage available compared to runoff. The multiple-year regulation serves primarily to identify the amount of thermal energy required to support the hydro generation in a critical year.

f. System Management. Operation of the majority of the Arkansas River reservoir system is managed by the Tulsa District, Corps of Engineers (PO Box 61, Tulsa, OK 74121). Little Rock

District (PO Box 867, Little Rock, AR 72203) is responsible for the portion of the basin located in Arkansas.

g. Summary.

(1) The Arkansas River reservoir system is operated primarily for flood control, hydropower, water supply, and navigation. The storage projects provide separate zones for flood control and conservation storage. Flood control storage is regulated to control flashy rainfall floods. The rate of evacuation of the flood control zone is based on a balance of three major considerations: (a) evacuating flood control space as soon as possible to provide space for controlling potential subsequent floods, (b) maintaining downstream rivers within bankfull capacities, and (c) minimizing sediment deposit by tapering the releases near the end of the evacuation period.

(2) Conservation storage is regulated primarily for power and water supply, and releases for these purposes are usually sufficient to meet navigation requirements. Only Oolagah has storage allocated for navigation. The conservation storage available in the system is equal to less than one-quarter of the basin's average annual runoff at Van Buren, so the degree of control is smaller than for some other basins. However, the storage does provide important benefits through the annual low flow period. Although the power storage was originally intended to be operated to maximize firm energy, present operation is oriented more toward maximizing dependable capacity. While recreation is not an authorized function at most of the storage projects, the lakes are heavily used for recreation, with the result that recreation does influence reservoir operation.

M-5. Missouri River Basin.

a. General.

(1) The Missouri River drains 520,000 square miles of ten midwestern states and about 10,000 square miles of Canada. Average annual precipitation over the basin ranges from 8 inches just east of the Rockies to about 40 inches in the southeastern portion of the basin and in parts of the Rockies. Normal seasonal maximum precipitation occurs throughout the basin during the period April-June. Snowfall in northern and central portions of the basin ranges from 20 inches in the lower basin to more than 100 inches in high elevation Rocky Mountain locations. High streamflows on the Missouri River are caused by plains snowmelt and rainfall during March and April and by mountain snowmelt and rainfall during the period May through July (see Figure M-12).

(2) In the 1930's and 1940's, a comprehensive plan for development of the water resources of the Missouri River Basin, the "Pick-Sloan Plan," was formulated by the Corps of Engineers and the Bureau of Reclamation. A number of the projects proposed in this plan have now been completed, including the six large reservoirs constructed by the Corps of Engineers on the Missouri River in Montana, North Dakota, and South Dakota (see Figure M-13). Sufficient usable storage space is available in these reservoirs to retain nearly two and one-half times the average annual flow of the Missouri River at Sioux City, Iowa. More than 90 percent of this storage is provided at Garrison (Lake Sakakawea, 18.9 MAF), Oahe (17.9 MAF), and Fort Peck (14.6 MAF), which are respectively the third, fourth, and fifth largest storage projects in the United States. Fort Randall (Lake Francis Case), like the large upstream reservoirs, also contains multiple-use carryover storage. Big Bend (Lake Sharpe) and Gavins Point (Lewis and Clark Lake) are pondage projects. Table M-4 summarizes the major operating characteristics of these projects.

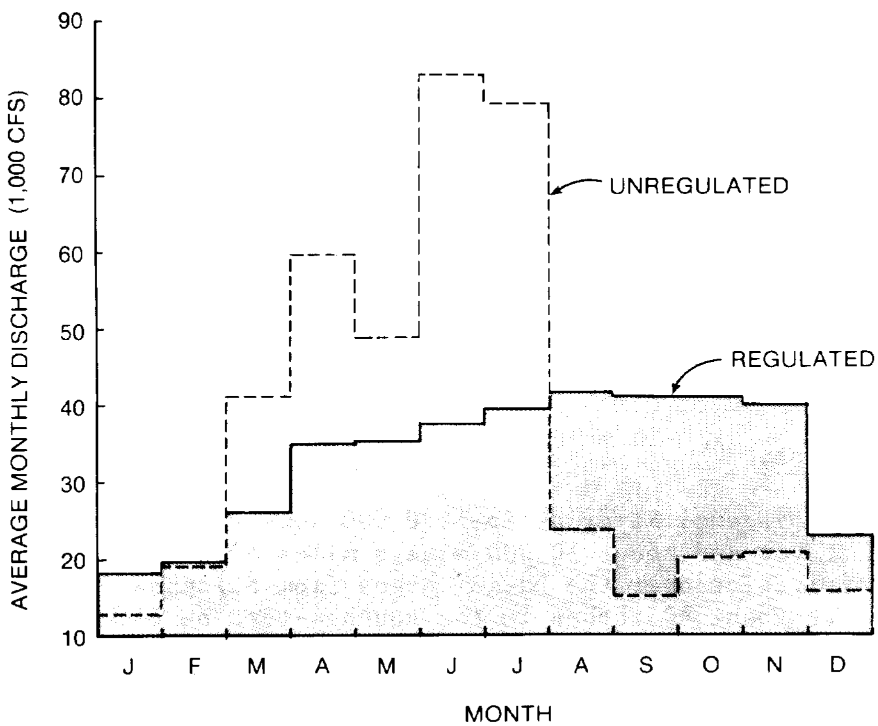


Figure M-12. Average monthly discharge of the Missouri River at Sioux City, Iowa, regulated and unregulated, 1967-1984

(3) This section describes the operation of the six mainstem projects, which are operated on a coordinated basis for flood control, navigation (on the mainstem Missouri River below Sioux City, Iowa), irrigation, hydroelectric power, municipal and industrial water supply, water quality control, recreation, and fish and wildlife.

b. Reservoir Regulation.

(1) Because of the reservoir system's large storage capacity and the basin's widely varying hydrologic conditions, the reservoirs must be regulated based on the projected long term future water supply as well as current conditions. The first system priority is to insure adequate flood protection. Second priority is to maintain enough seasonal storage to supply consumptive uses (irrigation and water supply) during anticipated future low flow periods. The consumptive use requirement totals about 20 percent of the total runoff at Sioux City and occurs primarily as pumping from the reservoirs or from the open reaches between the reservoirs. The remaining water is used to support navigation, generate hydropower, and to maintain suitable reservoir levels and outflows for recreation and fish and wildlife.

(2) Usable storage space at each of the four seasonal storage projects is divided into three zones (see Figure M-14). The uppermost zone is designated exclusive flood control storage space, which is reserved to control major floods. The next lower zone is designated as an annual flood control and multiple-use zone, which is regulated for seasonal flood control and to serve conservation requirements. Between the annual joint use zone and the dead storage zone is a carryover storage zone, which is used to support all project purposes during periods of extended drought.

(3) Releases for navigation are made to insure that adequate depths are maintained in the Missouri River between Sioux City and the confluence with the Mississippi River during the navigation season, which extends from about the first of April to the first of December. This typically requires releases from Gavins Point in the 28,000 to 35,000 cfs range. During the winter, ice bridges form on the river, precluding navigation. This ice could create local flood conditions if flows were maintained at the relatively high levels required for navigation. A discharge of 17,000 cfs is maintained from Gavins Point throughout the winter months for water quality and power production when water supply is adequate. Winter releases could be reduced to 6,000 cfs during extended drought periods.

(4) The firm power output of the projects, which is based on drought conditions (see Section M-5d), is marketed by the Western Area Power Administration to preference customers. This power is a mix of base load, intermediate, and peaking power. Energy is supplied on a two-step rate based on the customer's load factor. The standard rate applies so long as the customer's monthly load factor is 60 percent or less, and a higher rate is imposed if the load factor exceeds 60 percent. The higher rate is to cover thermal energy purchases that may be required to supplement the hydro at higher load factors. Energy in excess of preference customer requirements is marketed by WAPA to the area utilities at large. Excess energy is marketed primarily under two different rate schedules. Maintenance energy, which is typically available for a week or more, is sold at a fixed rate. Replacement energy, which has

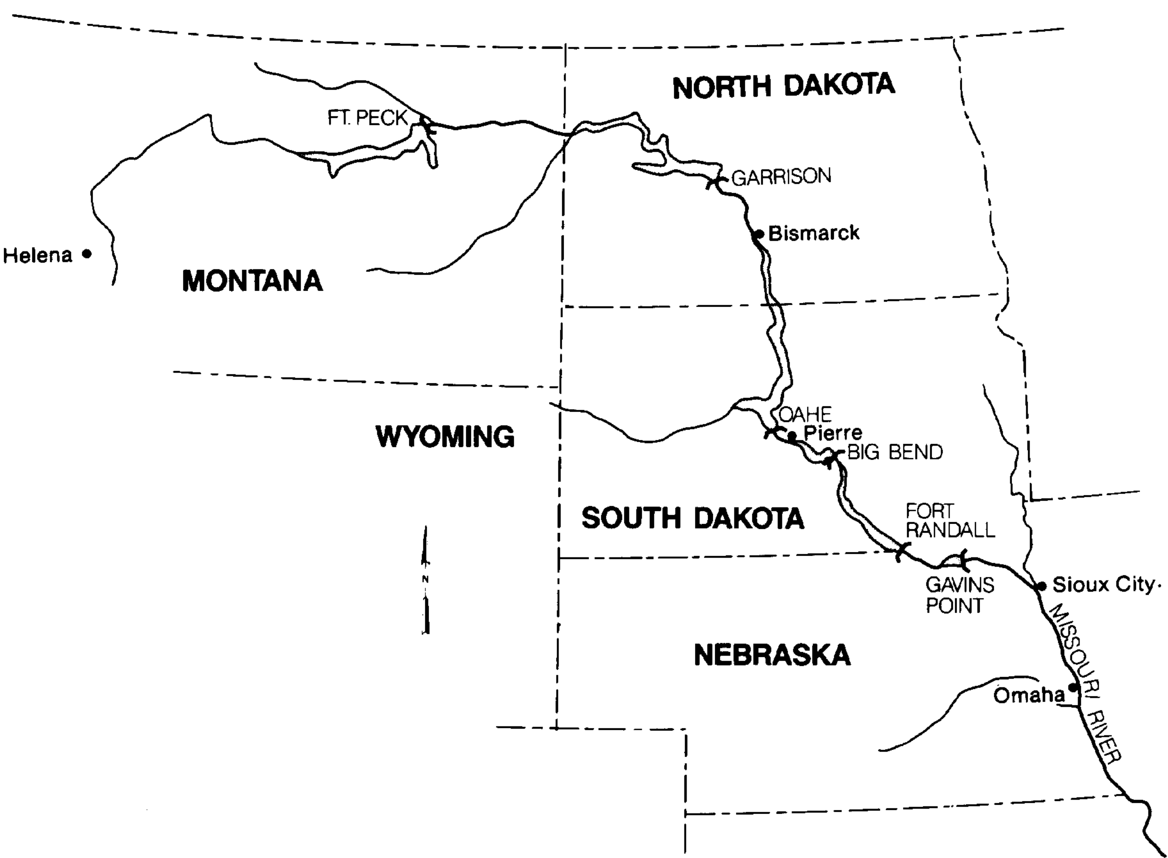


Figure M-13. Projects of the mainstem Missouri River reservoir system

TABLE M-4
Projects of the Mainstem Missouri River Reservoir System

Dam	River	Owner or Operator	Reservoir Functions	Usable Storage 2/ (1000 AF)	Installed Capacity (MW)
Fort Peck	Missouri	Corps	FINPRWS 1/	14,600	165
Garrison	Missouri	Corps	FINPRWS	18,900	400
Oahe	Missouri	Corps	FINPRWS	17,900	595
Big Bend	Missouri	Corps	FINPRWS	185	468
Fort Randall	Missouri	Corps	FINPRWS	4,000	320
Gavins Point	Missouri	Corps	FINPRWS	156	100
Totals				55,741	2,048

1/ reservoir purposes:
F - flood control
I - irrigation
N - navigation
P - hydropower
R - recreation
W - fish and wildlife
S - water supply

2/ storage at the major storage projects is allocated as follows (in million acre feet):

	Ft. Peck	Garrison	Oahe	Ft.Randall
Annual flood control and multiple-use	2.7	4.2	3.2	1.3
Carry-over multiple-use	10.9	13.2	13.6	1.7
Total conservation storage	13.6	17.4	16.8	3.0
Exclusive flood control	1.0	1.5	1.1	1.0
Total usable storage	14.6	18.9	17.9	4.0

shorter term availability, is marketed at a cost based on the value of the thermal plant fuel saved. The peak power demand occurs between mid-December and mid-February in the north portion of the marketing area due to home heating, and between mid-June and mid-August in the south due to air conditioning loads.

(5) The operating year begins with the reservoirs typically at their highest levels in July, following the spring snowmelt and early summer rains. The first step in the drawdown process is to evacuate the exclusive flood control zone if that space was required to control the spring runoff. Subsequent releases are made as required

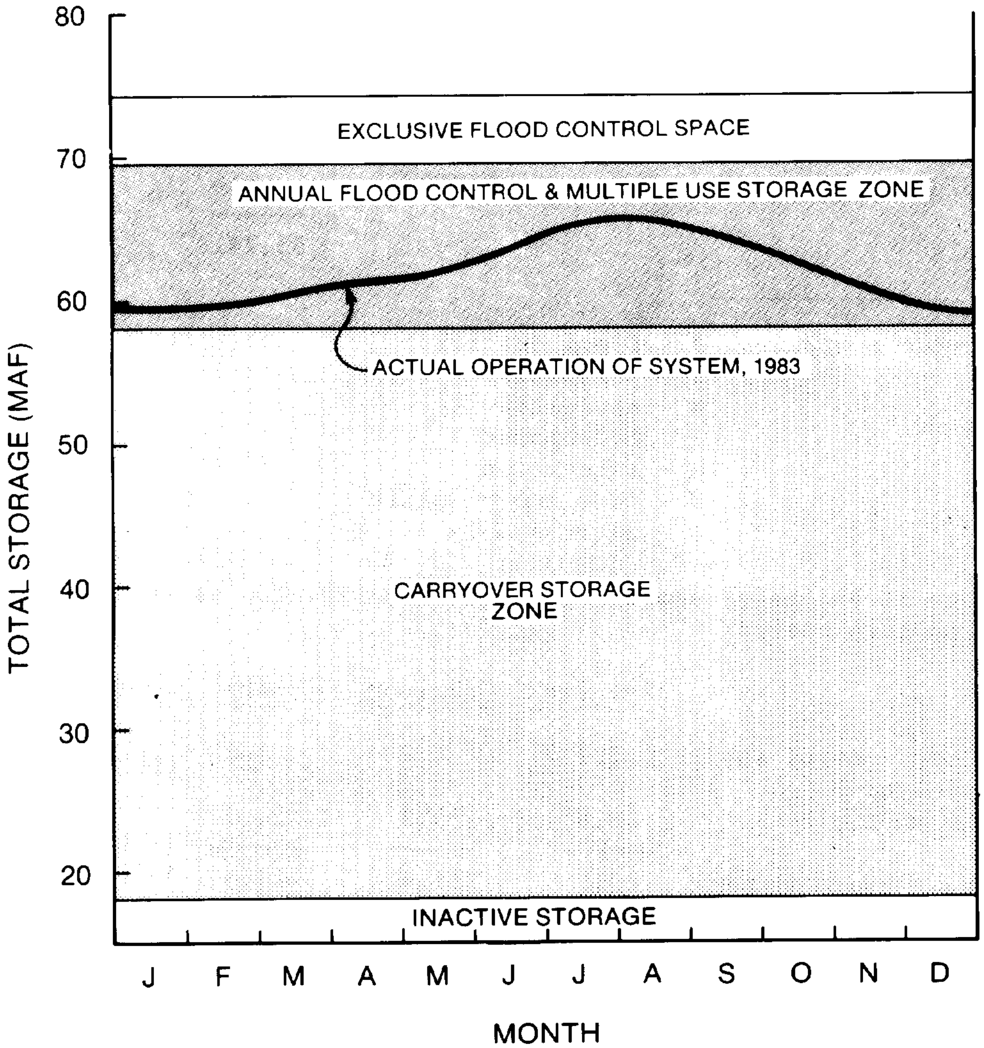


Figure M-14. Allocation of storage, mainstem Missouri River projects, showing actual operation in 1983 in order to maintain navigation flows on the mainstream Missouri through the remainder of the navigation season and to meet power requirements. In years of high runoff, it may be necessary to schedule releases in excess of that needed for navigation in order to evacuate storage to the desired level prior to the next flood season. The river freezes over and is closed to navigation in the winter months, and reservoir releases are at their lowest levels during these months. The river opens for navigation about the first of April, and releases are scheduled to meet these requirements. Further drafts may be scheduled in the early spring if the runoff forecast indicates that additional flood control storage is required. The refill period generally extends from early March until late July.

(6) In years of high runoff, the exclusive flood control zone may be used at some or all reservoirs. Because of the danger of floods resulting from summer rainstorms, this storage is evacuated as rapidly as possible within downstream channel capacity constraints. Releases in excess of powerplant capacities are scheduled when necessary. The flood control and multiple-purpose storage zone is regulated on an annual cycle. In normal or above-average runoff water years, this zone is filled during the refill season. On the average, approximately three-fourths of this zone is occupied at the time of maximum storage. Approximately one-half of this storage zone is needed to meet full service navigation requirements and average annual energy production through the drawdown season. The annual storage has only totally filled once in the first 18 years since the system reached normal operating levels. In most years it is almost completely drafted at the beginning of the upcoming flood season.

(7) In years when the annual storage does not reach the levels needed to maintain full service support to navigation, full support is continued only if a minor draft of the carryover storage is to be made. If a drought intensifies and more significant storage drafts would result, service to navigation is reduced by either shortening the eight month season or by reducing the river flows. Only once in the 18 years since the system first filled has less than full service to navigation been provided. In 1981, the season was shortened by three weeks.

(8) If two or more adverse water years occur in a row, the draft continues to be made in the carryover storage zone, and releases will be reduced to levels required to meet minimum navigation flow requirements. The reduced levels would require reduced barge loadings, and an increase in groundings would also result. In a severe drought, not only would flows be reduced, but the season length would be reduced to as short as four months. The

carryover storage is designed to meet these minimum requirements, as well as water quality and water supply needs, in a recurrence of the 12-year critical period 1930 through 1941.

(9) In years of above normal runoff, releases may be scheduled at rates in excess of navigation requirements in order to evacuate the system storage to the desired carryover levels. These higher than normal flows benefit navigation and hydropower by permitting increased barge loadings and increased generation.

c. Sequence of Drafting Storage.

(1) The six projects are situated in a series, and because of the differing seasonal requirements of the various storage uses, this presented an interesting problem in determining the optimum sequence in which conservation storage should be drafted. The way in which this problem was solved can best be illustrated by examining the two storage uses which have the greatest influence on the sequence of draft: navigation and hydropower. It must be remembered, however, that irrigation, municipal and industrial water supply, fish and wildlife, and water quality are also important reservoir functions, and they are sometimes the controlling factor in determining the discharge at individual projects.

(2) If hydropower were the only function to be considered, the upstream reservoirs would be drafted first (see Section 5-14). This strategy would result in maximum energy production, but it would also result in relatively low releases from the downstream project (Gavins Point) in the early part of the drawdown season (late summer-early fall) and relatively high discharges from that project in the winter and early spring. This release pattern is opposite to the requirements of navigation (see paragraph M-5b(3)), and according to the Act which authorized these projects, navigation has a higher priority than hydropower. The solution to this conflict was to develop a procedure for transferring storage among projects in such a way that power generation could be maximized to the extent possible within the downstream release constraints established by navigation (and within the constraints established by other project purposes).

(3) Storage releases from the system as a whole are generally greatest in the late summer and fall months, in order to meet navigation requirements. Energy requirements are high in the summer and low in the fall months, and could be accomodated during this period by a variety of draft sequences. However, power demand is also high during the winter months, when river navigation is not supported and downstream releases are reduced. The drafting sequence is therefore designed to transfer water among the reservoirs in such

a way as to maintain a high level of power output during both the summer and winter, while permitting high releases from Gavins Point in the summer and fall months and low releases in the winter months.

(4) During the summer and fall months, drafts required to meet the navigation requirements come primarily from the main downstream storage projects, Oahe and Fort Randall. Oahe is the first to be drafted, and it provides most of the releases in the late summer and early fall months. Fort Randall drawdown does not usually become significant until late September. However, once the Fort Randall draft begins, storage is drafted rapidly, so that maximum space will be available to capture winter storage releases from the upstream reservoirs. The Big Bend project, which is located between Oahe and Fort Randall, is a pondage project, and is operated generally in tandem with Oahe, with some daily and weekly regulation for peaking (because of operating limitations at the other projects, most of the peaking is done at Oahe and Big Bend). Gavins Point is also basically a pondage project, and it serves primarily as a reregulator, maintaining the desired flow conditions in the open river downstream.

(5) High summer releases from Oahe through Big Bend, Fort Randall, and Gavins Point mean high generation rates at those plants. To avoid generating more power than can be marketed advantageously under these circumstances, the usual practice during this time of year is to reduce releases and generation at Fort Peck and Garrison to levels required only to meet the needs of irrigation, fish and wildlife, and other river uses. This plan of operation results in a large share of the power being produced in the summer and fall months at the four downstream projects. This fits well with the high summer demand experienced in the southern part of the region, and it also leaves vacated storage space at the two major downstream storage projects (Oahe and Fort Randall).

(6) With the onset of the winter (non-navigation) season, conditions are reversed. Releases from Gavins Point drop to about one-third to one-half of summer levels, and the chain reaction proceeds upstream, curtailing discharges from Fort Randall, Big Bend, and Oahe. At this time, Fort Peck and Garrison releases are maintained at relatively high levels (within the limits of downstream ice cover), to partially compensate for the reduction in generation downstream. Because of the low winter discharge requirements at Gavins Point, a portion of this water is captured in the vacated storage space of Oahe and Fort Randall. In fact, Fort Randall normally refills much of its annual multiple-purpose storage zone during this period. Thus, winter power needs are met primarily by the manner in which water is passed from the upstream projects through Oahe and Big Bend to fill Fort Randall. In addition, this strategy results in a high percentage of the winter generation being

produced at the projects that are located in the northern part of the region, which experiences its highest power demand in the winter months.

(7) Figure M-15 shows the normal seasonal sequence of draft for the four major storage projects plus Gavins Point. Gavins Point is drafted late in the winter period in order to provide added seasonal flood control storage space during the spring months. Because it is the last project in the system, Gavins Point provides the final increment of control for flood regulation.

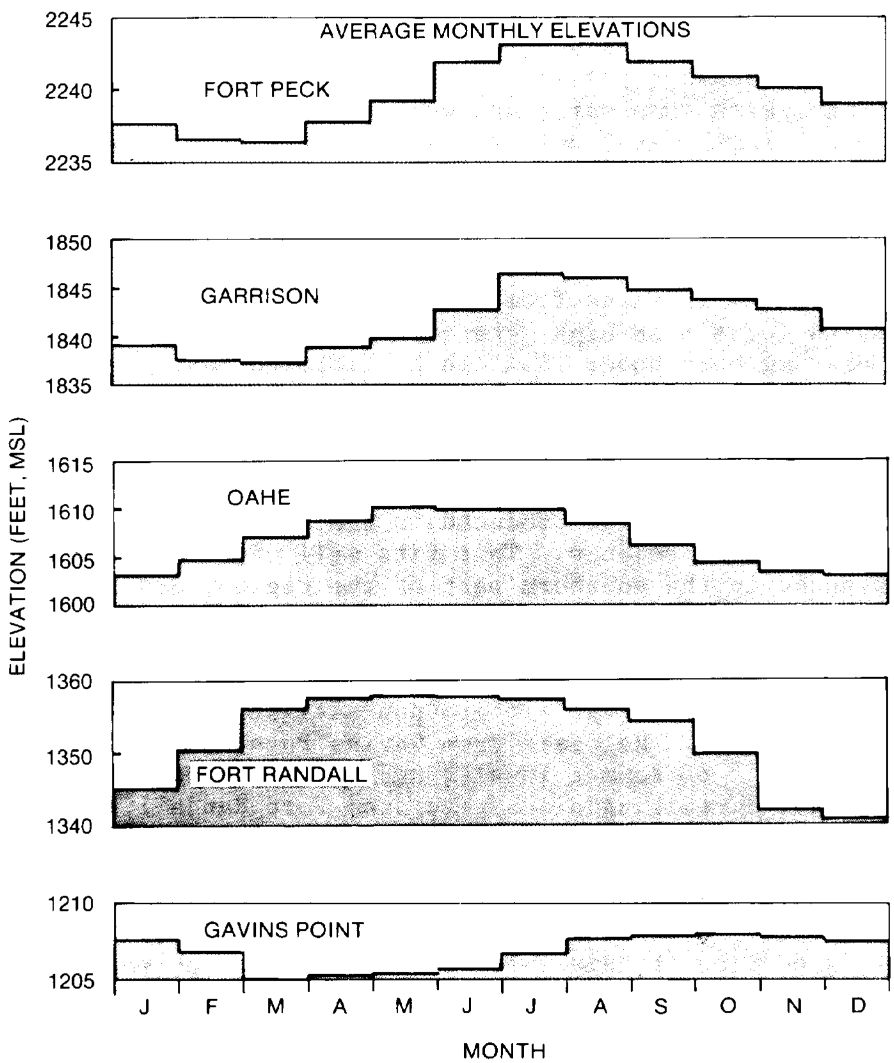


Figure M-15. Typical seasonal regulation patterns for the mainstem Missouri River storage projects

d. Critical Period. The firm yield of the Missouri River system is based on an eight-year drought that began in 1954. The critical year for establishing firm power is 1961. The storage is regulated to maximize firm energy production during this period while meeting minimum navigation flow requirements and consumptive use requirements for irrigation and municipal water supply.

e. System Management. The operation of the six mainstem Missouri River projects is managed by the Missouri River Division, Corps of Engineers, P.O. Box 103, Downtown Station, Omaha, NE 68101.

f. Summary.

(1) The storage regulation requirements of flood control, navigation and power generation are generally compatible with each other. The joint-use storage is drafted in the late summer, fall, and winter months to meet the requirements of navigation and power generation, leaving the space available for flood control in the spring and early summer months. The availability of exclusive flood control storage above and a considerable amount of carryover conservation storage below the annual joint use storage zone provides flexibility of operation while maintaining a high degree of reliablity in meeting operating objectives.

(2) The seasonal variation of navigation requirements, however, conflicts with the optimum operation of the reservoir system for power production. Maximum annual energy production would be achieved by drafting the upstream projects first. However, this would result in relatively low discharges from the downstream projects during the early part of the drawdown season, when high flows must be maintained for navigation, and high discharges near the end of the drawdown season (the winter months), when navigation is shut down and high flows can cause local flooding in the ice-choked river. A drawdown sequence was therefore developed which drafts the downstream reservoirs first. This provides high releases from Gavins Point for navigation in the summer and fall months while evacuating storage space in the downstream reservoirs. This space is refilled in the winter months while the upstream projects are being drafted for power production.

M-6. Colorado River Basin.

a. General.

(1) The Colorado River drains approximately 242,000 square miles located in seven western states. High annual flows in the Colorado River generally occur from April to July and are a result of

snowmelt in the Rocky Mountains (Figure M-16). The lower portion of the basin is quite arid, whith precipitation averaging only about five inches per year.

(2) Over 90 percent of the flow volume in the Colorado River Basin originates in the upper portion of the basin, above Glen Canyon Dam. Conversely, over two-thirds of the consumptive water use takes place at present in the lower portion of the basin. Therefore, the basin has become politically aligned into two sub-regions: (a) the Upper Basin states of Wyoming, Colorado, Utah, and New Mexico, whose present water requirements are relatively small, but who wish to reserve a "fair share" of the runoff for future use, and (b) the Lower Basin states of Arizona, Nevada, and California, who wish to protect their present water use and insure that additional water is available for future growth.

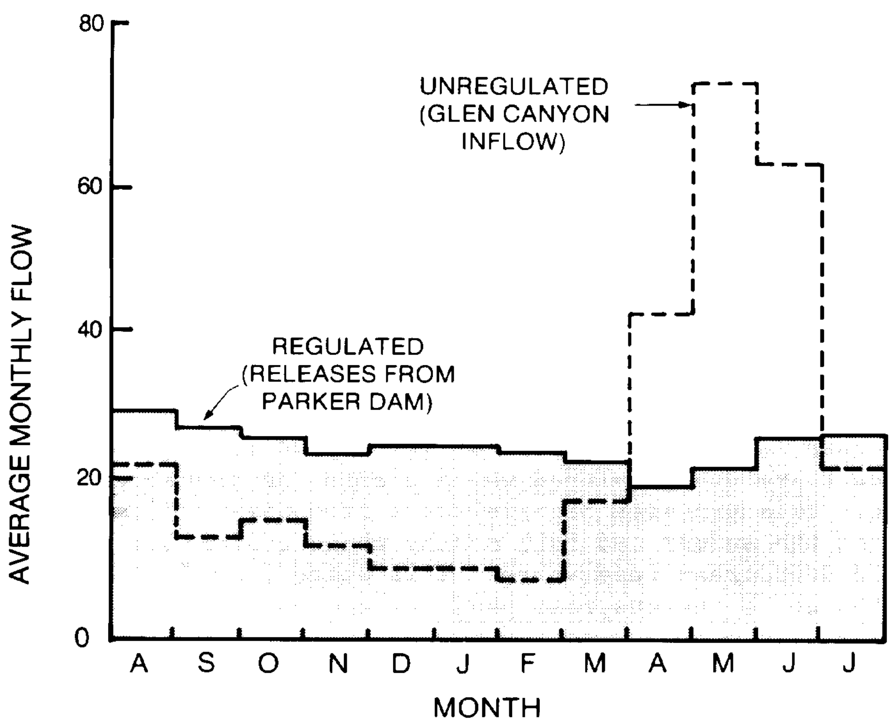


Figure M-16. Average monthly flow of the Colorado River, regulated (below Parker Dam) and unregulated (above Lake Powell), 1984-1985

(3) Although handicapped by lack of rainfall, the Lower Basin has many other desirable characteristics, and has attracted considerable agricultural and urban development. This development relies heavily on the Colorado River as its source of water, and this in turn has led to the development of an extensive system of dams, reservoirs, canals, pumping plants and other facilities, to insure that the water is delivered where and when it is needed.

(4) This system provides storage equal to about four times the average annual runoff of the Colorado River upstream of Lake Mead and a degree of control unmatched by any other large river basin in this country. This discussion concentrates on those system elements that have power facilities. This includes (a) the key storage projects in the system: Glen Canyon (Lake Powell) and Hoover (Lake Mead); (b) the primary reregulating facilities below Hoover: Davis (Lake Mojave) and Parker (Lake Havasu); and (c) some of the more important headwater storage projects: Flaming Gorge, Blue Mesa, and Navajo. Lake Mead at 27.4 MAF and Lake Powell at 25.0 MAF are the two largest reservoirs in the United States. Table M-5 lists the characteristics of these projects, as well as Morrow Point and Crystal, which are power and reregulation projects located downstream from Blue Mesa. Figure M-17 shows the locations of these projects.

(5) The Colorado River Basin projects are operated primarily for flood control, water supply (municipal and industrial as well as irrigation), and hydropower. Recreation, water quality, and fish and wildlife have also become important operating considerations. Operation of these projects is governed by a complex set of laws, compacts, treaties, and Supreme Court decisions, which are collectively referred to as the "Law of the River." Some of the major elements in the Law of the River are the interstate Colorado River Compact of 1922, the Boulder Canyon Project Act of 1928, the Mexican Treaty of 1944, the Colorado River Storage Project Act of 1956, and the Colorado River Basin Project Act of 1968.

(6) Major diversions in the Lower Basin begin at Lake Mead, where the Southern Nevada Project diverts water for the Las Vegas metropolitan area. Downstream at Lake Havasu, water is pumped by the Metropolitan Water District to urban Southern California via the Colorado River Aqueduct. The Central Arizona Project (CAP) is also beginning to pump from Lake Havasu, and when completed in 1992, the project will supply Colorado River water to the greater Phoenix and Tucson areas. Downstream from Parker Dam is the Headgate Rock Dam, which diverts water to irrigate agricultural lands of the Colorado River Indian Reservation near Parker, Arizona. The Palo Verde diversion dam supplies water to the Palo Verde Irrigation District near Blythe, California. Imperial Dam is the last diversion dam in the United States. It diverts Colorado River water into two canals:

TABLE M-5
Major Projects of the Colorado River
Multiple-Purpose Reservoir System

Dam	River	Owner or Operator	Reservoir Functions	Active Storage (1000 AF)	Installed Capacity (MW)
Blue Mesa	Gunnison	USBR	FISP 1/ 4/	749	60
Morrow Point	Gunnison	USBR	P	pondage	120
Crystal	Gunnison	USBR	P	pondage	28
Flaming Gorge	Green	USBR	FISPR 4/	3,516	108
Navajo	San Juan	USBR	FIS 4/	1,036	--
Glen Canyon	Colorado	USBR	FISPR 4/	25,000 2/	1,206
Hoover	Colorado	USBR	FIPSRW	27,377 3/	1,340
Davis	Colorado	USBR	IPSRW	1,810	240
Parker	Colorado	USBR	FIPSRW	180	120
Totals				59,668	3,222

1/ reservoir purposes: F - flood control
I - irrigation
P - hydropower
R - recreation
W - fish and wildlife
S - water supply (municipal and industrial)

2/ of which 20,876 KAF is usable for power generation

3/ of which 17,400 KAF is usable for power generation

4/ Flood control benefits at these projects are incidental to operation for other project purposes

(a) the Gila Gravity Canal, which supplies water to the Yuma Mesa and Wellton-Mohawk Projects in Arizona, and (b) the All-American Canal, which supplies water to the Coachella and Imperial valleys in California.

b. System Operation-General.

(1) The Colorado River reservoir system is an example of a system with sufficient storage to provide nearly complete control of the lower portion of the river. This control extends beyond seasonal control, in that large amounts of carry-over storage permit meeting

water requirements through multiple-year drought periods. This degree of control will become increasingly important as the Central Arizona Project is completed and the total consumptive use in the basin begins to approach the average annual inflow to the system.

(2) The history of the operation of the Colorado River reservoir system has been one of continual change. The physical characteristics of the reservoir system have changed over the years

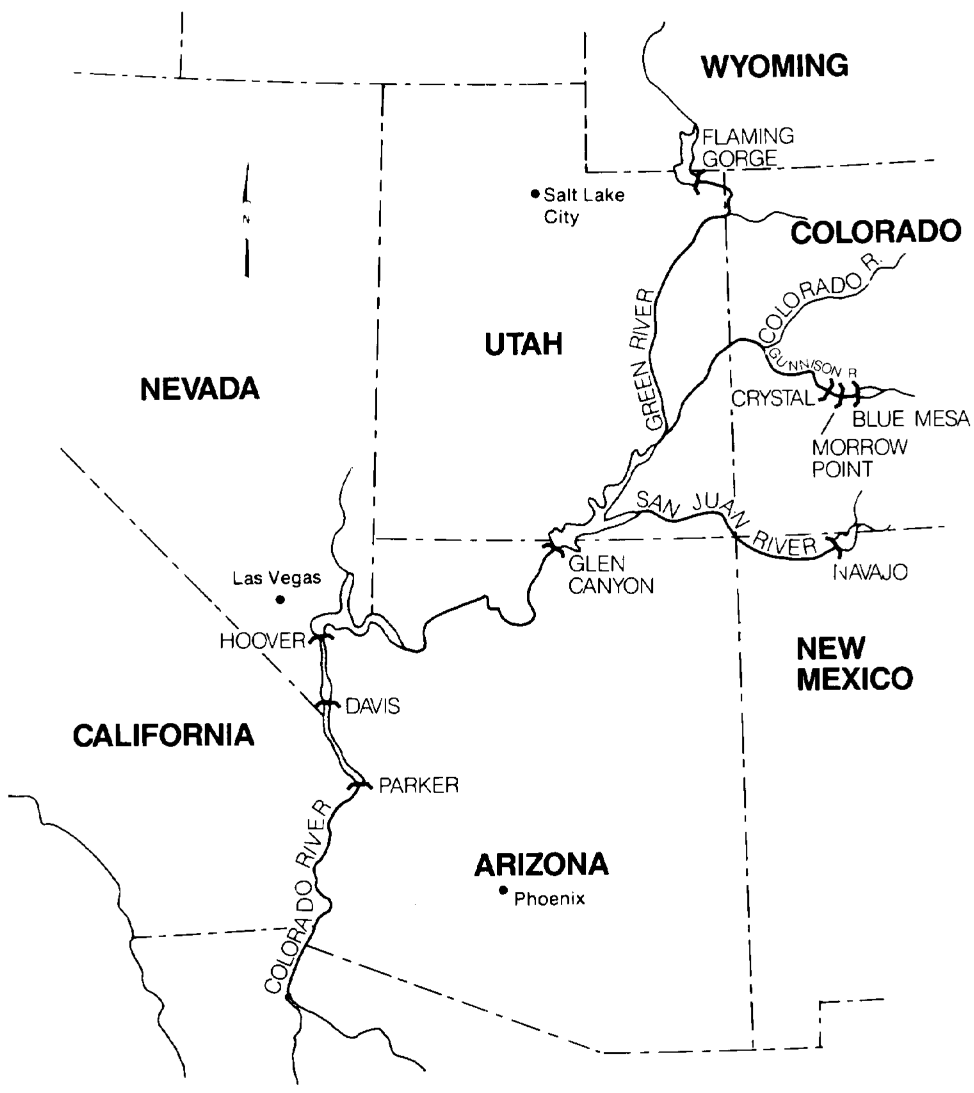


Figure M-17. Major projects in the Colorado River system as projects have been completed and the reservoirs have filled. The demands imposed on this system have been increasing as the region has developed. Perhaps most importantly, the Law of the River is continuing to evolve, in response to conflicting demands on the system and conditions that were not entirely anticipated when the initial laws and agreements were written. For these reasons, it is not yet possible to write a definitive description of the operation of this system. The following paragraphs therefore constitute only a general description of how the system is operated at the present time.

(3) Through the language of the Boulder Canyon Act of 1928, which authorized Hoover Dam, Congress established the operational priorities of the Colorado River reservoir system, specifically:

- controlling floods
- improving navigation and regulating the flow of the Colorado River
- providing for the storage and delivery of the stored waters for reclamation of public lands and other beneficial purposes
- generation of electrical energy

Superimposed on this is the Treaty requirement of providing 1.5 MAF annually to Mexico at the border. As a practical matter, water supply for irrigation and municipal and industrial (M&I) use is the dominant river use, and the primary purpose of system regulation strategy is to meet current water supply requirements and to insure that adequate reservoir storage is maintained to protect future requirements. Flood control does have a higher priority, particularly at Hoover, but this function will control operation only when the system is near full (see Sections M-6d(8) and (9)). Hydropower generation is maximized to the extent possible within the constraints imposed by the higher priority uses.

(4) Because of the flexibility required of the Colorado River system, the reservoir storage has not been formally allocated into zones. Therefore, it is not possible to prepare a detailed system rule curve. Figure M-18 shows only the approximate seasonal allocation of reservoir storage in the system.

(5) The top zone is 1.5 MAF of exclusive flood control space, which is provided at Lake Mead for the control of summer rainfall floods. Below this is a joint use zone, which is regulated for control of snowmelt floods and for seasonal conservation storage for water supply and power generation. The remaining storage, which constitutes the bulk of the usable storage capacity, is carry-over conservation storage, which is used to support firm water supply and power generation requirements in periods of extended drought.

c. Flood Control Operation

(1) Flood control requirements are designed primarily to protect the heavily developed reaches of the Colorado River below Davis and Parker Dams. The Hoover Reservoir (Lake Mead) is the key element in the flood control operation, with the other reservoirs contributing storage space to the extent possible, consistent with other project requirements. The headwater reservoirs also provide some local flood protection. The primary objective of the flood

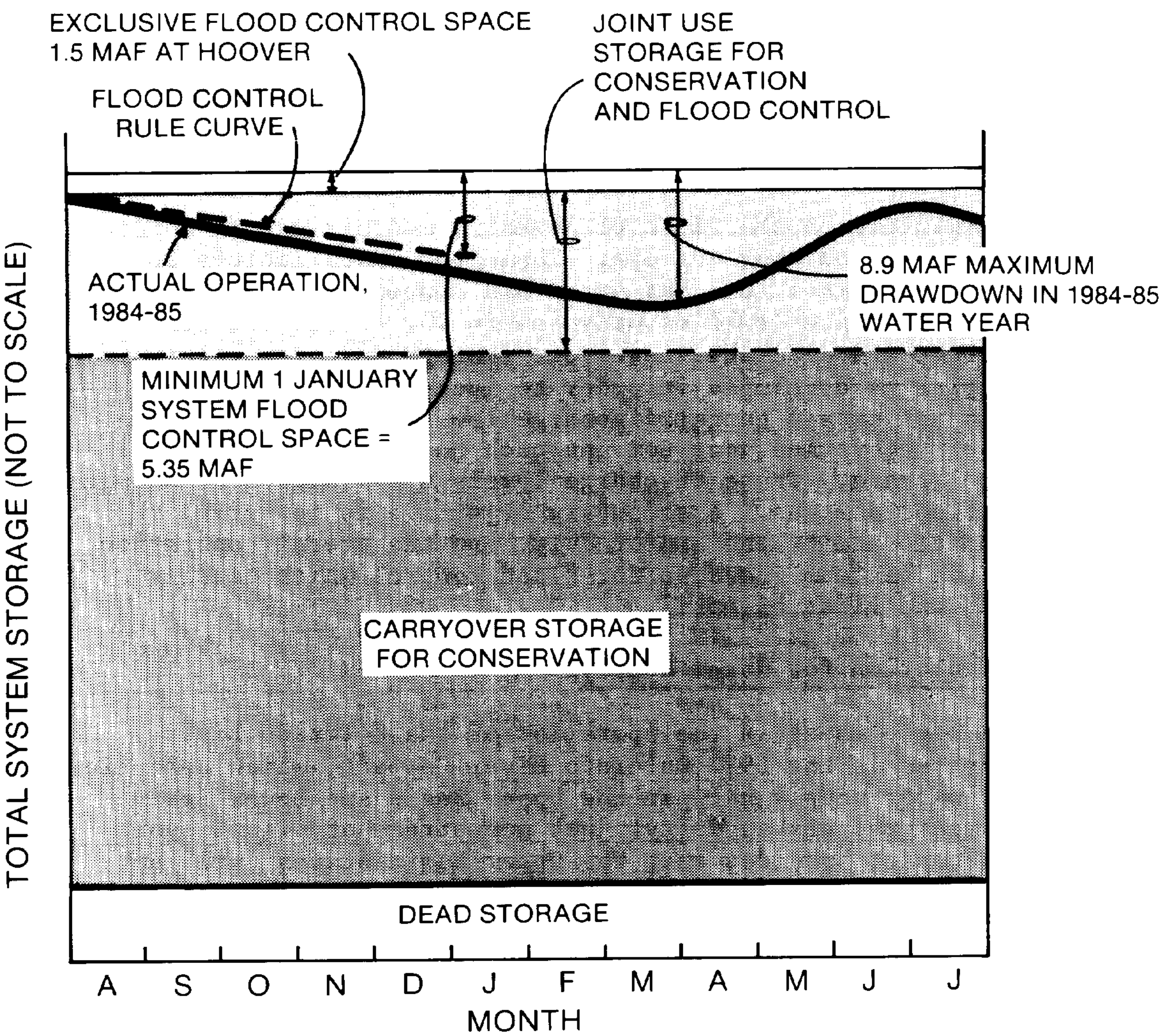


Figure M-18. Seasonal allocation of storage in the Colorado River system control operation is control of the spring snowmelt runoff, although a minimum of 1.5 MAF of flood control space is provided at Lake Mead to control summertime rainfall floods. As mentioned earlier, flood control influences reservoir operation only when the system is near full. When adverse water conditions have drawn the system into the carry-over storage zone or when a low spring runoff is anticipated, refill of conservation storage rather than flood control governs the reservoir operation.

(2) For those years when flood control is required, the following procedures are applied. At the end of the refill season (31 July), a minimum of 1.5 MAF of space is provided at Lake Mead for rainfall flood control. Over the next five months, drafts are scheduled to insure that a minimum of 5.35 MAF of flood control space is available in the reservoir system on 1 January. This is accomplished in part with drafts to meet water supply and irrigation requirements, but additional releases may be required in years of high runoff.

(3) Beginning on the first of January, monthly runoff forecasts are prepared based on snow surveys. These forecasts include an adjustment for possible forecast error and represent a runoff volume that has an exceedance level of only one in 20. Using the runoff forecast volume and available reservoir storage space, a reservoir regulation plan is developed in order to insure that flows below Davis Dam do not exceed target discharge levels and that the Lake Mead reservoir elevation does not encroach on the summer rainfall flood control space. These discharge levels are designed to minimize downstream flood damages. A secondary objective is to refill conservation storage by the end of July, and the overall operation results in the maximum drawdown for flood control which usually occurs about the first of April.

d. Regulation for Water Supply.

(1) A key element in the operation of the Colorado River reservoir system is the 1922 Colorado River Compact, which apportions the basin's water supply between the Upper Basin and Lower Basin states (as measured at Lee Ferry, just downstream of Glen Canyon Dam). The compact provides that the Upper Basin states "will not cause the flow at Lee Ferry to be depleted below an aggregate of 75 MAF for any period of 10 consecutive years." This is sometimes expressed as an average annual allocation of 7.5 MAF to the Lower Basin states.

(2) Development of the Lower Basin has progressed to the point where nearly the full apportionment of water is already required to meet irrigation and M&I water supply needs. Unfortunately, the

basin's natural runoff varies considerably, both within the year (Figure M-16), and from year to year, ranging from less than 6 MAF to nearly 25 MAF, and periods of four or five consecutive years of below average runoff are not unusual. Hence the objective of the Colorado River reservoir system is to convert this fluctuating runoff into a stable water supply.

(3) Glen Canyon (Lake Powell) is the keystone of this operation, with nearly 21 MAF of active storage (above the power intake), most of which can be classified as drought year carry-over storage. The headwater reservoirs (Flaming Gorge, Blue Mesa, and Navajo) provide additional regulating capability. The overall objective of the reservoir operation is to meet the Upper Basin's obligation to the Lower Basin at the Compact point (Lee Ferry) without impairment of Upper Basin consumptive uses during a period of extended drought. A secondary objective is to insure that additional water that is not required to meet the consumptive use requirements of the Upper Basin (but which could be used in the Lower Basin), will not be withheld from the Lower Basin.

(4) These objectives are defined in the Colorado River Basin Act of 1968, and Section 602(a) of that Act directs that criteria be established for determining the amount of carry-over storage that must be maintained in Glen Canyon and the headwater reservoirs to insure that these objectives will be met. The Secretary of the Interior has proposed criteria for computing the annual storage requirement (usually referred to as "602(a) storage"), but complete agreement has not yet been reached between the Upper Basin and Lower Basin states on this methodology. Hence, the operation described in the next paragraphs should be considered as one example of how the 602(a) storage requirement could be computed, but it should not be construed as being the official procedure.

(5) The first step is to select a critical streamflow period. Such a period might be the driest on record, or perhaps one having a 90 or 95 percent chance of exceedance. Take, as an example, the driest 12-year inflow above Lake Powell. The total water requirements on the system would be the sum of the estimated depletions from the Upper Basin for the next 12 years and an annual release to the Lower Basin from Glen Canyon of 8.23 MAF over the same period (8.23 MAF is the sum of 7.5 MAF, from paragraph (1), above, and approximately half of the 1.5 MAF Mexican treaty requirement). The difference between the total requirements and the 12-year inflow volume is the storage needed at Lake Powell and the headwater reservoirs to satisfy that year's 602(a) storage requirement.

(6) The 602(a) storage requirement is computed every year and compared with the amount of storage actually available in the reservoir at the end of the runoff season. If the available storage is less than 602(a) storage requirements, releases from Glen Canyon over the next year will be limited to 8.23 MAF. If the available storage is greater than the 602(a) requirement, surplus water is available, and Glen Canyon will release sufficient water to equalize storage at Lake Powell and Lake Mead by 30 September.

(7) Hoover Reservoir (Lake Mead) has about 27 MAF of storage capacity to the top of the exclusive flood control pool. In addition to providing flood control, this storage is used to store water released from Glen Canyon that is not needed to satisfy immediate downstream water requirements. The Glen Canyon seasonal release pattern is designed primarily to meet power requirements and avoid spills. These demands differ from the seasonal use pattern of the irrigation and M&I customers below Hoover, so the Hoover storage is used to provide the necessary seasonal reshaping. Finally, substantial evaporation and transpiration losses occur in the Hoover, Davis and Parker reservoirs, as well as from the open river reaches. These losses must be made up with drafts from Lake Mead.

(8) The degree of interplay between flood control and water supply (consumptive use) can best be described by examining the history of reservoir operation at Hoover. Until Glen Canyon Dam was completed in 1963, flood control releases dominated the annual operating plan at Hoover. Once filling of the Glen Canyon Reservoir (Lake Powell) began, ample flood control space was available in the partially-filled Lake Powell, so Hoover released only sufficient water to meet water supply requirements. Lake Powell filled in 1980, and the reservoir system was once again full. Since that date, flood control has again become the controlling function at Hoover, and releases have been made in excess of water supply requirements in order to insure that sufficient storage is available to maintain freshet season releases at levels which would minimize damage downstream.

(9) This mode of operation is expected to continue into the 1990's. By the mid-1990's, however, consumptive use requirements could begin to exceed the average inflow to the system. During periods of drought, heavy drafts will be required in order to meet water supply needs, and reservoirs will frequently be at levels below which flood control requirements control reservoir operation.

e. Operation for Hydropower.

(1) The basic annual operating plan for the reservoirs in the Colorado River system is defined by water supply requirements and,

where applicable, flood control requirements. However, within these constraints, some flexibility is given to power generation. The amount of flexibility varies from project to project.

(2) At Glen Canyon, the annual operating plan defines the amount of water to be released by month in the operating year. Within these constraints, the project is operated primarily for power production. For example, once the annual discharge requirements have been established, the day to day releases are defined primarily by power requirements. Power is marketed on a firm basis with firm energy defined as the project's average annual energy production. When Glen Canyon's discharge is insufficient to meet firm requirements, the shortfall is made up with thermal energy purchases. Daily operation is primarily to meet peak loads.

(3) At Hoover, the monthly discharges are defined primarily by water supply requirements, which differ considerably from the seasonal power demand pattern. Hence, some of the generation is usable only as thermal energy displacement. However, within each month, considerable flexibility exists in how the generation can be scheduled and the Hoover powerplant is normally operated for peaking.

(4) Parker and Davis Reservoirs have only limited storage capability, so the operation of Hoover must be coordinated with the operation of these projects. The main function of these projects is to regulate the Hoover discharges such that downstream and diversion water supply requirements are met. For example, both the Central Arizona Project and the Metropolitan Water District's Colorado River Aqueduct pump from the Parker reservoir, and there are a number of projects that draw from the Colorado River below Parker Dam. The power generation at Parker and Davis is scheduled within the limits imposed by these requirements.

f. Critical Period. As noted in paragraph M-6d(5), the annual 602(a) storage requirements for Glen Canyon and the headwater reservoirs are based on a critical drawdown period which is multi-year due to the large amount of storage compared to runoff in the system. However, because of the dynamic state of the Colorado River system and the fact that final agreement has not yet been reached on procedures for defining the 602(a) storage requirement, it is not possible at the present time to identify a single critical period that defines the system's firm yield.

g. System Management. The Colorado River Basin storage projects are operated by the Bureau of Reclamation, and Reclamation has primary responsibility for the system operating plan. The Upper Colorado Region (PO Box 11568, Salt Lake City, UT 84147) is responsible for Glen Canyon and the headwater projects, and the Lower

Colorado Region (PO Box 427, Boulder City, NV 89005) is responsible for Hoover, Davis, and Parker. Because the Colorado River Compact is one of the primary documents governing the operation of the system, the states also play a major role in the development of the operating plan. The Corps of Engineers is involved in the flood control aspects of the plan.

h. Summary. A high percentage of the Colorado River's runoff has been appropriated, primarily for irrigation and M&I water supply. Storage facilities having a usable capacity of about four times the average annual runoff have been constructed to (a) regulate the seasonal runoff to fit the seasonal demand pattern, and (b) to provide carryover storage to permit meeting water supply requirements during periods of extended drought. The reservoirs also provide flood protection for the highly developed reaches below Davis and Parker Dams. Flood control operation conflicts with the regulation for water supply in that it can reduce the probability of refill. Within the constraints of flood control operation, water supply requirements define the basic annual operating plan: i.e., how much water is to be stored in or drafted from the major storage projects during the operating year and what is to be the monthly release pattern from Hoover. The hydropower operation must fit within these constraints. The result is limited flexibility in matching generation to the seasonal demand pattern (except at Glen Canyon), but considerable flexibility in the daily scheduling of generation within the monthly release requirements. Because of the high degree of control of the river, the average annual generation of the system is marketed as firm power, with thermal purchases being made to cover for the occasional shortfall.

M-7. Central Valley Project, California.

a. General.

(1) California's Central Valley Project (CVP) is located in the Sacramento and San Joaquin River basins, entirely within the northern two-thirds of the State of California. Six of the 10 leading agricultural counties in the United States lie in the project area. Precipitation in this area is almost exclusively in the form of rainfall and ranges from 30 inches annually in the northern sections of the valley to 5 inches in the south. Three-quarters of this rainfall occurs in the period December-March, during the non-irrigation season. Since rainfall is sparse during the growing season, crops depend primarily on surface water and groundwater for irrigation. Figure M-19 shows the seasonal runoff pattern for the Sacramento River.

(2) The primary purpose of the Central Valley Project is to provide a reliable water supply for the rich agricultural lands of the semi-arid Sacramento and San Joaquin Valleys. Flood control and hydroelectric power generation are also important functions. A substantial amount of power generation is required to meet Project pumping requirements, and revenues from generation above these requirements serve to help repay the cost of reservoirs and other facilities. Reservoir recreation, navigation on the Sacramento River, municipal and industrial water supply, fish and wildlife, and control of salinity intrusion in the Sacramento-San Joaquin River delta also have an important influence on how the system is operated.

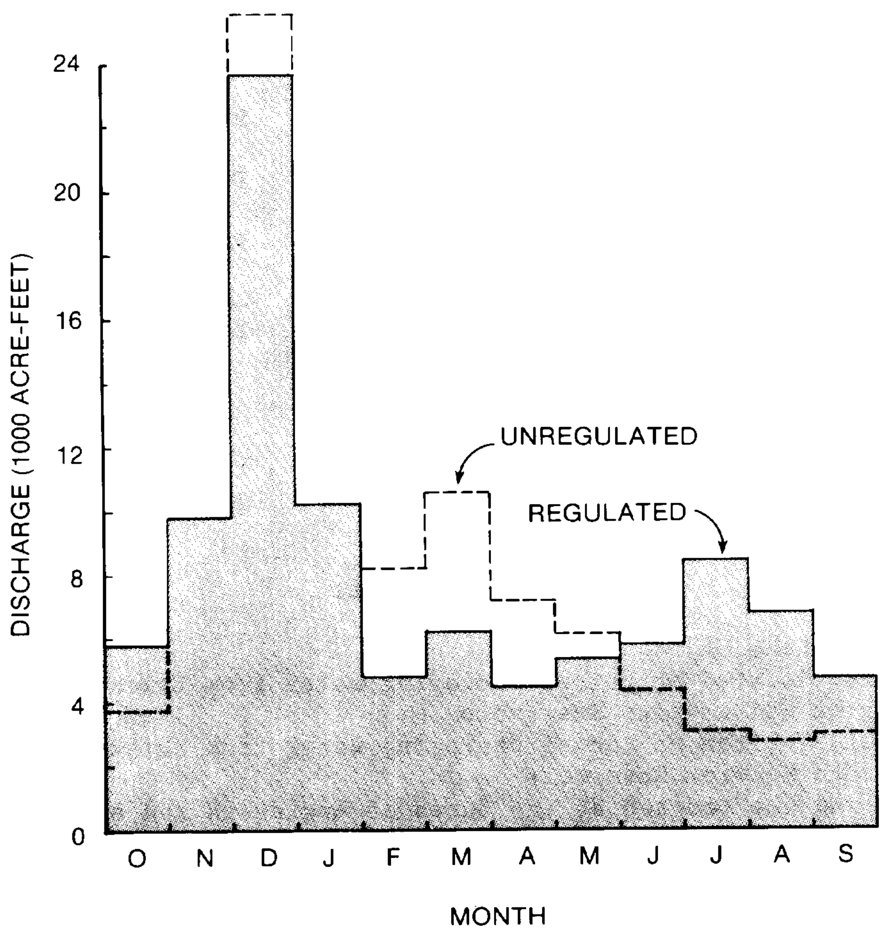


Figure M-19. Monthly discharge of the Sacramento River at Bend Bridge (near Redding), regulated and unregulated, water year 1984.

TABLE M-7
Major Hydropower Projects in the Central
Valley Project Multiple-Purpose Reservoir System

Project	River	Owner or Operator	Reservoir Functions	Conservation Storage (1000 AF)	Installed Capacity (MW)
Trinity 2/	Trinity	USBR	FIPR 1/	2,285	128
Lewiston	Trinity	USBR	IP	pondage	-
Francis Carr	3/	USBR	P	pondage	154
Whiskeytown	Clear	USBR	IP	214	-
Spring Creek	4/	USBR	P	pondage	190
Shasta	Sacramento	USBR	FIPNRWS	4,050	573
Keswick	Sacramento	USBR	FPR	pondage	90
Folsom	American	USBR 5/	FIPRWS	921	210
Nimbus 6/	American	USBR	FRP	pondage	15
New Melones	Stanislaus	USBR 5/	FIPRWS	2,090	392
O'Neill 7/	San Luis	USBR	IPRS	pondage	25
San Luis	San Luis	USBR	IPRS	1,961	424
Totals				11,521	2,201

1/ reservoir purposes:
- F - flood control
- I - irrigation
- P - hydropower
- N - navigation
- R - recreation
- W - fish and wildlife
- S - water supply

2/ Clair Engle Lake
3/ powerplant, located on tunnel conveying water from Lewiston Reservoir to Whiskeytown Reservoir
4/ powerplant, located on tunnel conveying water from Whiskeytown Reservoir to Keswick Reservoir
5/ designed and constructed by the Corps of Engineers and operated by the Bureau of Reclamation
6/ reregulating reservoir for Folsom powerplant
7/ reregulating reservoir for San Luis pumping-generating plant

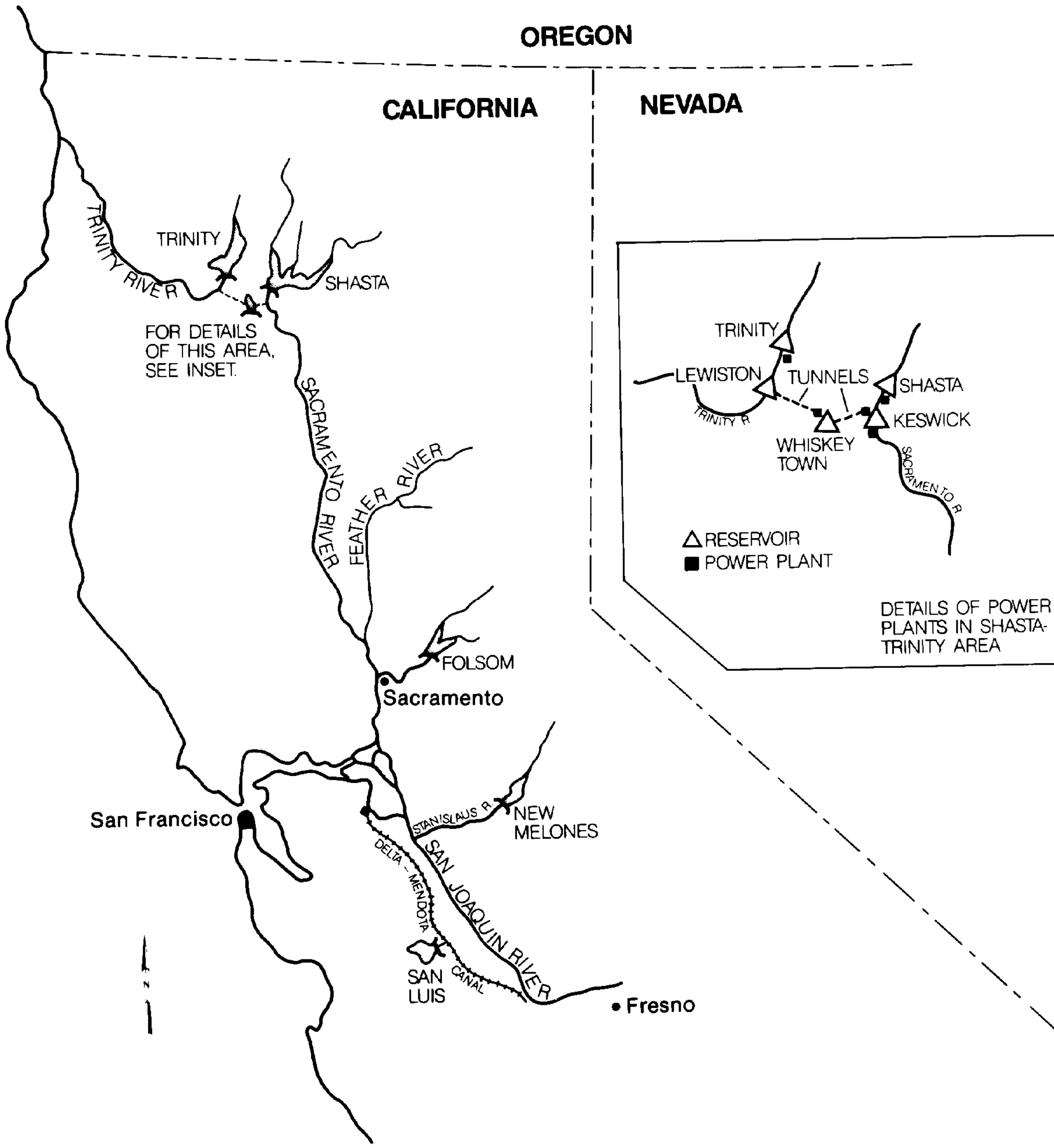


Figure M-20. Major hydropower components of the Central Valley Project, California

(3) The Project consists of seven major storage projects, together with 11 smaller reservoirs for regulation and power generation, 39 pumping plants, and more than 500 miles of canals (see Figure M-20 and Table M-7). Water is stored in the high runoff winter and spring months to meet irrigation requirements, which are greatest during the summer months (see Figure M-21). The extensive system of canals and pumping plants is used to transfer water from the water-rich Sacramento River basin in the north to the water-poor, but intensively cultivated, San Joaquin Valley in the south. The overall project was designed and operated by the Bureau of Reclamation. Most of the reservoirs and other project elements were constructed by the Bureau of Reclamation, but the Folsom and New Melones reservoirs were constructed by the Corps of Engineers. The Bureau of Reclamation has overall responsibility for operating the Central Valley Project.

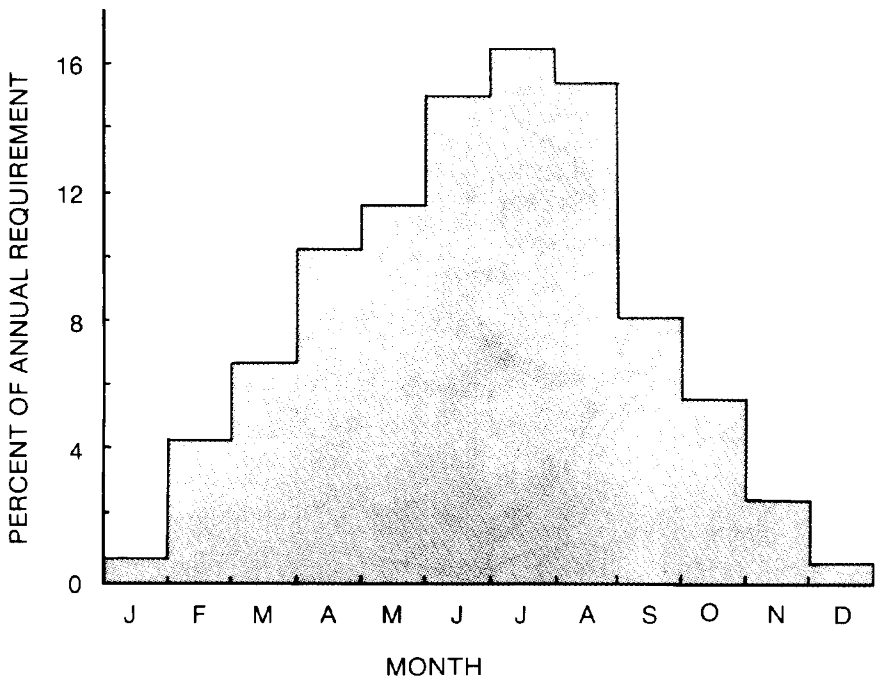


Figure M-21. Typical seasonal distribution of irrigation requirements, Central Valley Project

(4) The key storage projects are Trinity (Clair Engle Lake) and Shasta in the north and Folsom and New Melones in the central portion of the basin. San Luis is a large seasonal pumped-storage reservoir that is used to control flow through the Delta-Mendota and San Luis canals. Millertown provides water for the upper San Joaquin Valley. The volumes in parentheses represent usable storage.

b. Storage Regulation.

(1) Reservoir storage is divided into two zones. The upper zone is a joint use storage zone, which is regulated for flood control in the winter months and irrigation and power in the summer and fall months. Below this is a carryover storage zone, which is used to meet irrigation and power requirements in periods of extended droughts. About 30 percent of the usable storage space in the major reservoirs is allocated to joint use storage and the remaining 70 percent to carryover storage.

(2) Because of the differences in the runoff patterns in various parts of the basin, drafting of the individual reservoirs follows somewhat different operating schedules. For this reason, the easiest way to describe system operation is to begin about the first of October, following the end of the irrigation season, when the reservoirs are at their lowest elevations. Refill takes place in the winter and spring months, but it is constrained to some extent by flood control requirements. Water is required for irrigation the year around, but the bulk of the demand occurs from May through August (see Figure M-21).

(3) Much of the runoff in the basin comes from rainfall. Shasta, for example, is regulated almost exclusively to control rainfall runoff. A fixed flood control requirement is maintained through the first of January. Filling of the joint use storage begins at that date, following statistically derived rule curves which are designed to insure as great a probability of refill as possible while still maintaining flood control requirements through 1 February. Refill of Shasta is usually completed about the first of May.

(4) By way of contrast, the drainage area above New Melones is at a higher elevation, and most of the runoff is from snowmelt. Winter and early spring drafts are based on snowpack forecasts, thus permitting deeper drafts and greater power generation in high runoff years. Refill of New Melones is usually not complete until mid-July. For the other storage projects, runoff comes from both rainfall and snowmelt, and provision of flood control space and scheduling of refill are based on a combination of statistically derived refill curves and snowmelt forecasts.

(5) Figure M-22 shows the combined seasonal allocation of storage for the five major reservoirs (Trinity, Shasta, Folsom, New Melones, and San Luis). The figure shows how the refill schedule can vary, depending on the prevailing water conditions. Also plotted on Figure M-22 is the actual operation for water year 1984.

(6) A large part of the irrigated land in the San Joaquin Valley is served by the Delta-Mendota Canal. The canal originates in the Sacramento-San Joaquin River delta area ("the Delta") and extends in a southeasterly direction, generally parallel to the San Joaquin River, for about 115 miles, terminating about 30 miles west of Fresno. Although the irrigation demand occurs primarily in the summer months, water is pumped into the canal from the Delta the year around. Water excess to irrigation needs is pumped into the San Luis Reservoir, to be held until the peak irrigation demand season, when it is released back into the Delta-Mendota and San Luis Canals. A portion of the San Luis storage is also allocated to the state-operated California Water Project, with water being pumped from and discharged back into the California Aqueduct, which runs generally parallel to the CVP's Delta-Mendota Canal.

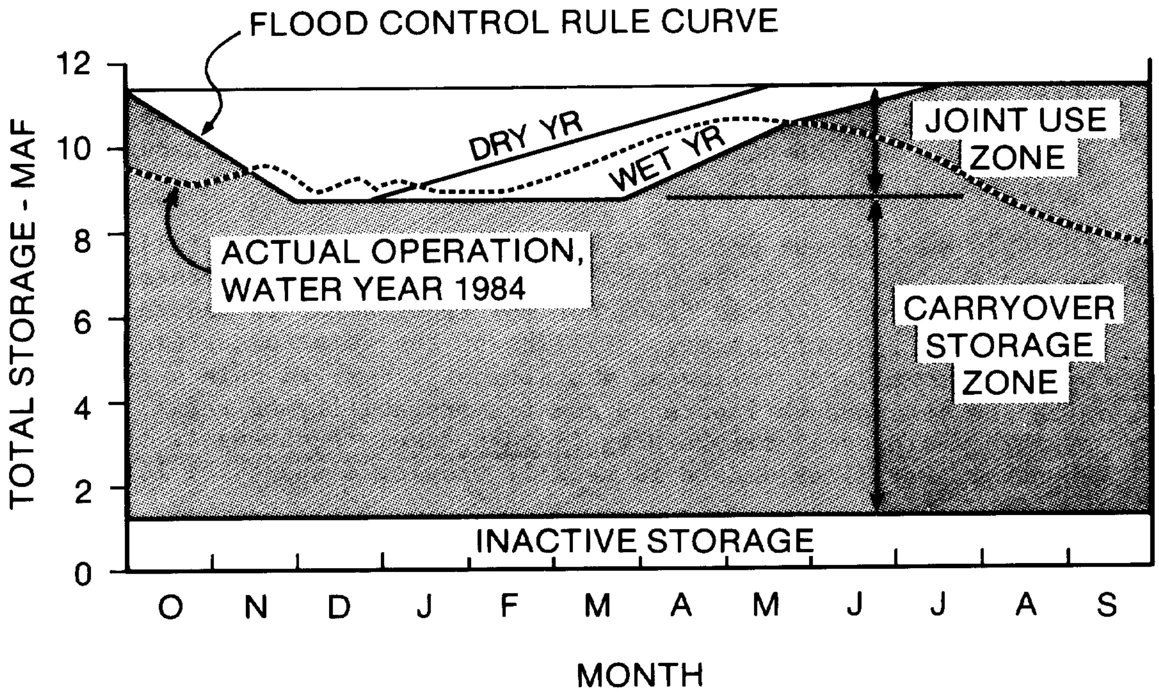


Figure M-22. Seasonal storage allocation, Central Valley Project, showing actual operation in water year 1984

(7) The San Luis Reservoir is one of the few examples of a seasonal pumped-storage plant located in the United States. Pumping is accomplished in periods of low power demand, when the cost of pumping energy is relatively low. Most of the releases are made during high demand periods, when the value of the generation is high.

(8) The water pumped from the Delta is a mix of natural runoff and releases from storage projects such as Trinity and Shasta. Minimum flows must be maintained within the Delta in order to prevent salt water intrusion, so a portion of the storage releases is allocated to meet this requirement.

(9) Recreational use of the Shasta and Folsom reservoirs is much higher than the other projects, so the sequence of draft from the various reservoirs is scheduled recognizing that it is desirable to maintain Shasta and Folsom as high as possible through Labor Day. This draft sequence insures that irrigation requirements are met, but it may be less than optimal from the standpoint of power generation.

(10) The hydropower plants of the CVP provide a dependable capacity of 800 to 1000 megawatts to the Pacific Gas and Electric Company (PG&E). Contracts with PG&E specify minimum 12-month, 6-month, and monthly energy delivery and provide benefits for exceeding these levels. The USBR submits a daily generating schedule which is based upon CVP reservoir conditions to PG&E, which dispatches this energy on an hour-by-hour basis to minimize system fuel costs.

c. Critical Period.

(1) The firm water yield of the system is based on the critical period 1928 through 1934. The reservoirs can meet about 80 percent of the CVP's irrigation water requirements during that period. During adverse water years, the farmers can supplement their CVP water supply with groundwater pumping. In years of plentiful water supply, the additional water can be used for increasing crop production or to recharge the ground water supply.

(2) The system's firm power output is also based on the 1928-34 critical period. A portion of the firm power is used to meet CVP pumping requirements, and the remainder is sold to local electric power utilities. The most effective use of hydropower in the local power systems is as peaking power, and the CVP hydro plants were sized to deliver dependable capacity supported by sufficient firm energy to permit them to operate at an annual plant factor of about 25 percent. In good water years, additional energy is also available, and this is marketed on a month-by-month basis, depending on forecasted runoff, reservoir levels, irrigation requirements, and other factors.

d. System Management. Operation of the Central Valley Project is the responsibilty of the Mid-Pacific Region, Bureau of Reclamation, 2800 Cottage Way, Sacramento, CA 95825.

e. Summary.

(1) The major project functions served by the CVP reservoirs (irrigation, flood control, and power generation) are generally compatible. Flood control space is maintained in the winter months, and the reservoirs are allowed to fill in the spring to provide storage for summer and fall irrigation releases. However, because a large portion of the spring runoff is from rainfall and cannot be predicted, maintaining winter flood control space sometimes results in joint use storage not refilling completely. Carryover storage is provided for years when joint use storage does not refill. Power is generated primarily from storage releases for irrigation. However, because a substantial portion of the power generation is used for summer irrigation pumping and because the remainder is used in summer-peaking power systems, this schedule conforms reasonably closely to the power demand pattern. Power exchange agreements with local utilities and the seasonal pumped-storage operation at San Luis provide additional flexibility in helping to optimize the use of CVP power generation.

(2) In adverse years, storage is regulated to maximize firm yield for irrigation and firm energy to meet CVP pumping requirements and dependable capacity sales contracts with utilities. In good water years, the additional runoff is regulated to maximize irrigation benefits and power revenues.

(3) Other water uses also affect reservoir operation. Storage releases above irrigation and power requirements must be made at times in order to meet in-stream flow requirements for fish and wildlife and to prevent salinity intrusion in the Sacramento River delta. Heavy recreational use of certain reservoirs in the summer months affects the sequence of storage drafts among the various reservoirs. Navigation requirements on the Sacramento River can generally be met with releases for other purposes.

M-8. Columbia River System.

a. General.

(1) The Columbia River drains an area of approximately 259,000 square miles in seven western states and British Columbia. This large basin includes vastly different climates and topography. Peak runoff occurs during the spring months and is largely a result of

snowmelt in the high interior mountains east of the Cascades (Figure M-23). Only fifteen percent of the Columbia River basin lies in British Columbia, but this region contributes forty percent of the river's average annual runoff at The Dalles (a key gaging station located downstream of most of the basin's hydropower facilities).

(2) More than 250 reservoirs and over 100 hydroelectric projects are located within the Columbia River Basin and adjacent coastal river basins. However, this discussion will be limited to the projects of the coordinated Columbia River System. About 75 projects, almost all of which have power generating facilities, are included in this system. The seasonal storage in the system is operated primarily for flood control and power generation, but some of the projects serve other purposes as well, including navigation, irrigation, fish and wildlife, and recreation. The total usable

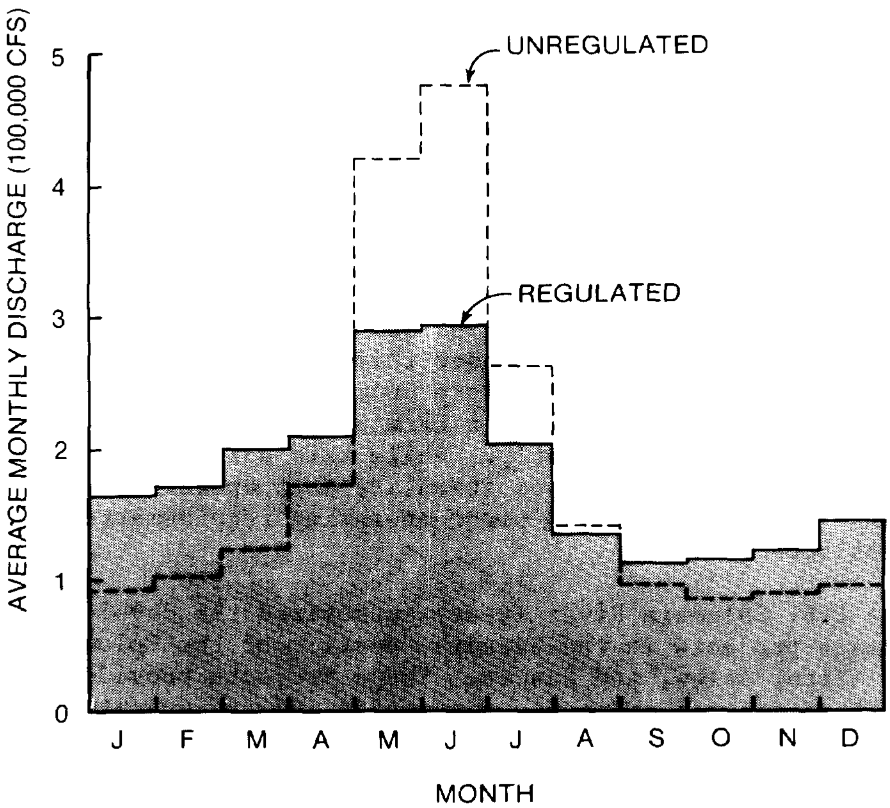


Figure M-23. Average monthly discharge of the Columbia River at The Dalles, Oregon, regulated and unregulated, based on historical streamflows for the period 1928-1978 reservoir storage available to the system (excluding projects located on tributaries below The Dalles Dam and in coastal river basins) is about 42 million acre feet, or about 30 percent of the average annual runoff of the Columbia River at The Dalles.

(3) Some of the projects in the coordinated system are owned by utility companies, but many of the key projects were constructed by the Corps of Engineers and the Bureau of Reclamation. Power generation from the Corps and Bureau projects is marketed by the Bonneville Power Administration (BPA). Three of the major headwater storage projects are located in Canada and are operated by the British Columbia Hydro and Power Authority (BC Hydro). Figure M-24 shows the major projects in the coordinated system, and Table M-7 lists the characteristics of those and other important projects.

b. The Coordinated System.

(1) The term "Coordinated Columbia River System" is used in this section to describe the projects operated under three separate but interrelated operating arrangements: (a) the Pacific Northwest Coordination Agreement, (b) the Columbia River Treaty, and (c) the statuatory flood control responsibilities of the Corps of Engineers. Not all of the projects in the system are covered by all three arrangements and authorities.

(2) The Pacific Northwest Coordination Agreement (PNCA) is a contract among the utility companies operating hydropower plants on the Columbia River and major tributaries and three Federal agencies (the Corps, the Bureau, and BPA). Under this agreement, the seasonal power storage is regulated as if it were under a single ownership. This results in a substantially larger firm power output than if the projects were operated independently. While this agreement does not govern non-power functions, it does stipulate that operation for power will not jeopardize the non-power operating requirements of individual projects.

(3) The 1961 Columbia River Treaty authorized the development of three storage projects in the Canadian portion of the Columbia River Basin: Mica, Arrow, and Duncan. These projects provide storage for flood control and power generation and are operated for the joint benefit of the United States and Canada. The Treaty also permitted the United States to construct the Libby reservoir to its optimum elevation, which required that the reservoir extend into Canada. The British Columbia Hydro and Power Authority constructed and operates the Mica, Arrow, and Duncan projects and is the Canadian member of the reservoir management team. The United States is represented by the Corps (flood control aspects) and BPA (power

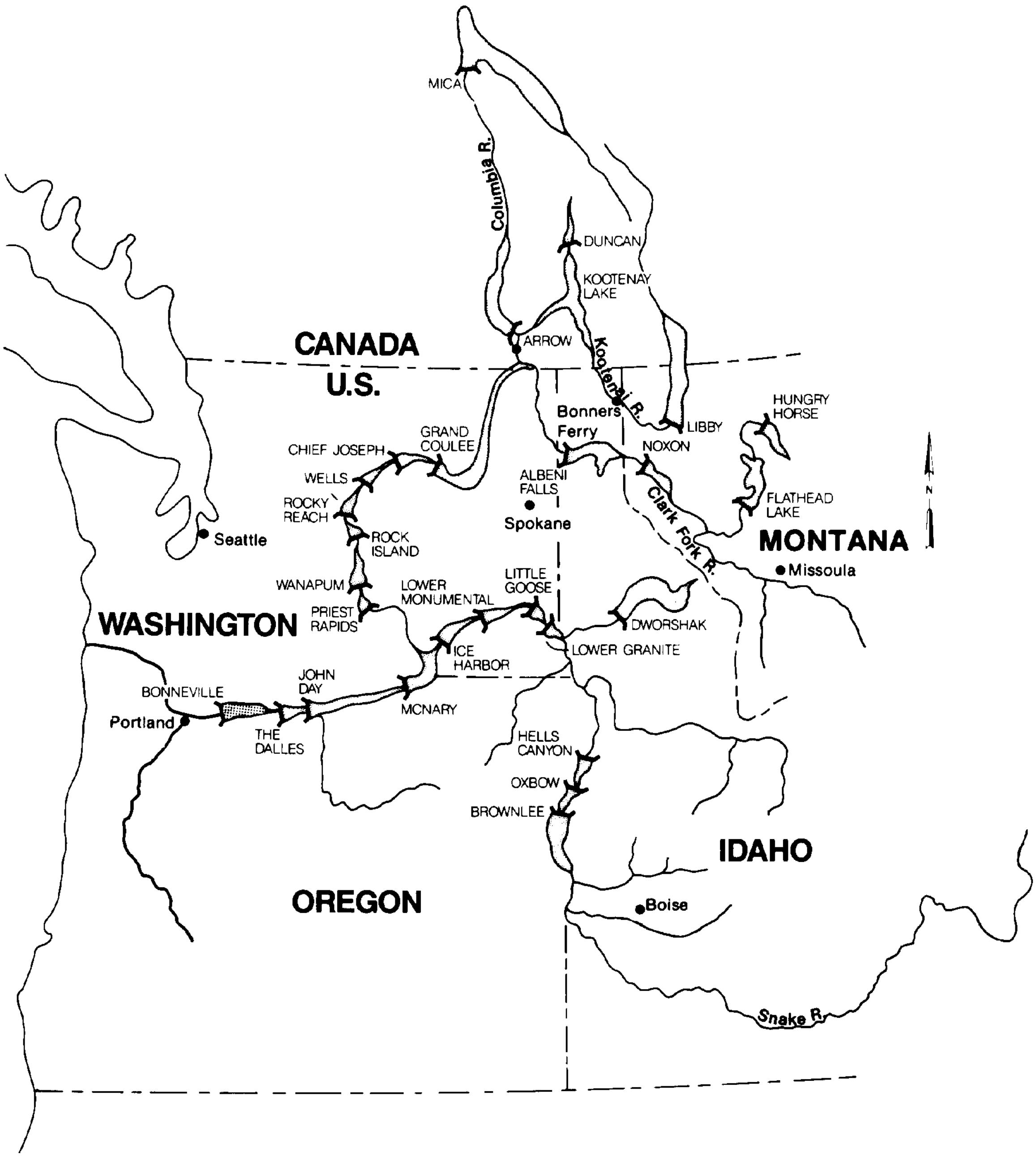


Figure M-24. Major projects in the Coordinated Columbia River system

TABLE M-7
Major Projects in the Coordinated Columbia River System

Dam	River	Owner or Operator 2/	Reservoir Functions 3/	Conservation Storage (1000 AF)	Inst. Cap'y (MW)
Columbia Mainstem System 1/					
Mica	Columbia	BC Hydro	FP 3/	12,000 4/	1,740 5/
Arrow	Columbia	BC Hydro	FP	7,100	--
Libby	Kootenai	Corps	FPR	4,980	525
Duncan	Duncan	BC Hydro	FP	1,399	--
Hungry Horse	N.Fk.Flathead	USBR	FPR	3,161	285
Kerr	Flathead	MPCo.	FPR	1,219	168
Noxon Rapids	Clark Fork	WWPCo.	P	231	397
Cabinet Gorge	Clark Fork	WWPCo.	P	pondage	200
Albeni Falls	Pend Oreille	Corps	FPR	1,155	43
Boundary	Pend Oreille	Seattle	P	pondage	635
Grand Coulee	Columbia	USBR	FIPR	5,185	6,580
Chief Joseph	Columbia	Corps	IPR	pondage	2,069
Wells	Columbia	Douglas	PR	pondage	774
Chelan	Chelan	Chelan	PR	677	48
Rocky Reach	Columbia	Chelan	PR	pondage	1,212
Rock Island	Columbia	Chelan	P	pondage	620
Wanapum	Columbia	Grant	PR	pondage	831
Priest Rapids	Columbia	Grant	PR	pondage	788
Brownlee	Snake	IPCo.	FP	980	585
Oxbow	Snake	IPCo.	P	pondage	190
Hells Canyon	Snake	IPCo.	P	pondage	392
Dworshak	N. Clearwater	Corps	FNPR	2,016	400
Lower Granite	Snake	Corps	INPR	pondage	810
Little Goose	Snake	Corps	INPR	pondage	810
Lwr. Monument.	Snake	Corps	INPR	pondage	810
Ice Harbor	Snake	Corps	INPR	pondage	603
McNary	Columbia	Corps	INPR	pondage	980
John Day	Columbia	Corps	FINPR	535 6/	2,160
The Dalles	Columbia	Corps	NPR	pondage	1,807
Bonneville	Columbia	Corps	NPR	pondage	1,077
Other projects	--	--	--	1,395	598
Subtotal				42,033	26,397
West Slope Projects (34) 7/				5,561	2,755
Total				47,594	29,480

TABLE M-7 (continued)

1/ major projects in the Columbia River Basin above Bonneville Dam (but excluding projects in the Snake River subbasin above Brownlee). Operation of these projects is described in Section M-8c.

2/ abbreviations:

BC Hydro	-	British Columbia Hydro and Power Authority
Corps	-	Corps of Engineers
USBR	-	U.S. Bureau of Reclamation
MPCo.	-	Montana Power Company
WWPCo.	-	Washington Water Power Company
Seattle	-	Seattle City Light
Douglas	-	Douglas County Public Utility District
Chelan	-	Chelan County Public Utility District
Grant	-	Grant County Public Utility District
IPCo.	-	Idaho Power Company

3/ reservoir functions:

F - flood control
I - irrigation
N - navigation
P - hydropower
R - recreation
W - fish and wildlife
S - water supply

4/ of which only 7,000,000 AF is operated under the terms of the Columbia River Treaty
5/ not included in the total generation (U.S. projects only)
6/ flood control storage, only pondage is available for power operations.
7/ projects on tributaries of the Columbia River below Bonneville dam and other projects in western Oregon and Washington. Operation of these projects is described in Section M-8g.

aspects). The Pacific Northwest Coordination Agreement ensures that the expected power benefits from the regulation of the Treaty projects are in fact realized in the United States.

(4) The storage projects constructed by the Corps of Engineers and the Bureau of Reclamation include flood control as an authorized purpose, and a number of the non-Federal hydro projects are required under terms of their license to provide flood control storage space.

The Corps of Engineers has responsibility for the flood control regulation of all of these projects. This regulation is accomplished on a coordinated basin-wide basis. The flood control regulation of the Canadian Treaty projects is included in this operation as well.

(5) A number of other operations are also involved in the regulation of the Coordinated Columbia River System. For example, storage drafts and spill are required at some projects to enhance the downstream migration of salmon and steelhead smolts. Navigation channels must be maintained on the Columbia River from the mouth to its confluence with the Snake River and on the Snake as far as Lewiston, Idaho. A number of irrigation projects draw water from the Columbia and certain tributaries, and this must be accounted for in system operation. There are also other operating agreements involving power, including an arrangement to coordinate the power operation of the seven mainstem projects (Grand Coulee through Priest Rapids) on a real-time basis. The generation from these projects is controlled by a diverse group of utilities and Federal agencies.

c. System Operation.

(1) The two dominant functions served by the reservoir system are power generation and flood control. The maximum runoff occurs in the late spring and early summer, while natural flows are relatively low from August through early April. The power demand is relatively uniform throughout the year, but reaches a peak in the winter months (Chapter 2, Figure 2-2). Thus, from the standpoint of power generation, the objective is to store snowmelt runoff in the spring and early summer months for release in the remaining months, with the highest firm storage releases in the winter months (see Figure M-23). This operation is generally compatible with flood control requirements, because the primary objective of the flood control operation is to reduce the peak of the spring freshet in order to provide protection for the intensively developed reach of the Columbia River below Bonneville Dam. Flood protection is also provided to local areas within the basin.

(2) The seasonal operation of the reservoirs is defined by a series of rule curves, which are developed at the start of each operating year and updated as the year progresses. The operating year can be divided into three seasons:

- August through December: the fixed drawdown period. No runoff forecast data is available, so the system operates in accordance with fixed rule curves.

- January through March: the variable drawdown period. Runoff forecasts are available, and the reservoirs are drafted at a rate that provides an adequate level of flood control, meets firm energy requirements, and generates as much additional energy as possible while maintaining a high assurance of refill.

- April through July: the refill season. The reservoirs store the spring runoff using the same basic operating criteria as applied in the January-March period.

(3) Prior to each operating year, period-of-record sequential streamflow routing studies are made to (a) identify the critical period, (b) determine the system's firm energy load-carrying capability, and (c) derive rule curves for defining the operation of individual projects. These parameters can vary from year to year depending on system load requirements, thermal generation available to the system, non-power operating constraints, and other factors. For example, with the storage presently available to the system, firm energy is usually defined by the 42-month critical drawdown period, September 1928 through February 1932, but under some circumstances, the 20-1/2 month period, August 1943 through mid-April 1945, controls.

(4) Once the basic operating parameters described in the preceding paragraph have been defined, the actual operation of the system over the course of a year is based on balancing three related but sometimes conflicting driving functions:

- providing adequate flood storage space for control of the spring runoff
- maximizing power generation
- maintaining a high probability of reservoir refill.

In the fixed drawdown period (August-December), forecasts are not available, so reservoir operation is guided by three fixed rule curves. These are the critical rule curve, the assured refill curve, and the mandatory rule curve (see Figure M-25). The critical rule curve (CRC) defines the reservoir elevations that must be maintained to ensure that firm energy requirements can be met under the most adverse historical streamflow conditions. Critical rule curves are derived for all four years in the critical period. If the system begins the operating year full, the CRC is based on the drawdown schedule for the first year in the critical period. The assured refill curve (ARC) defines the elevations that must be maintained to ensure refill if the third lowest historical water year should occur. The mandatory (or flood control) rule curve (MRC) defines the drawdown required to ensure that some flood control space has been evacuated by the time the first runoff forecasts become available.

(5) On the first of January, the first runoff forecast becomes available. At this point, it becomes possible to define some additional curves. The variable refill curve (VRC) is used to limit secondary generation and defines the minimum reservoir elevations to ensure refill of the reservoir by the end of July within a 95 percent probability. The runoff forecast also permits definition of the system flood control requirements, which in turn establishes a forecast-based MRC. New runoff forecasts are prepared monthly through June, and the VRC and MRC are revised to reflect the new data. In January, February, and March, an additional curve is defined: the lower limit energy contract curve (LLECC). This curve

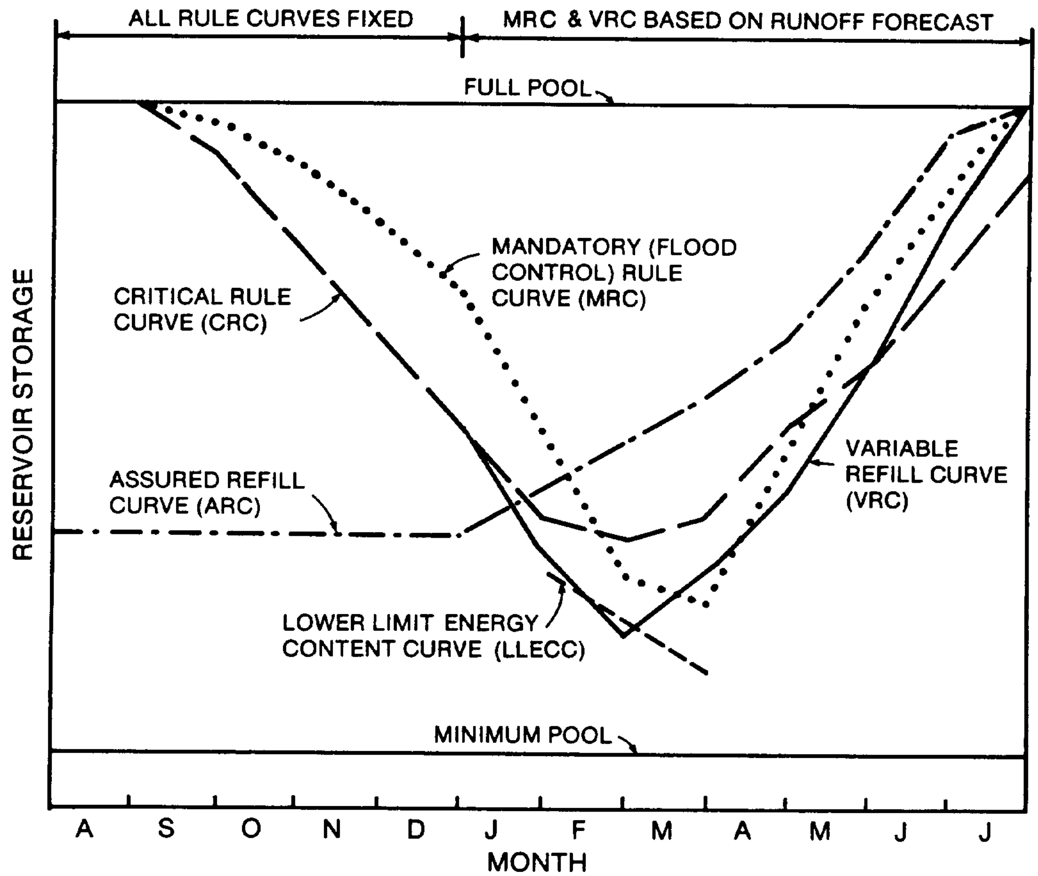


Figure M-25. Basic rule curves for typical Columbia River basin storage project for given operating year is based on a reverse routing for the most severe single late runoff water year, and it establishes a limit on draft in order to protect the system's ability to meet firm loads until the start of the spring runoff.

(6) The firm energy output of the hydro system represents the amount of energy that the system is obligated to supply. Regional power resource planning is based on the hydro system's firm energy capability. In most years, however, additional energy (secondary energy) is available. This energy is available for displacing thermal generation in the Pacific Northwest and for export to the Pacific Southwest. The primary strategy for maximizing secondary energy production is to draft as much storage as is practical in the winter months. An operating rule curve is developed to define the minimum levels to which a reservoir can be drafted while serving secondary loads without jeopardizing refill or firm energy production in either the current year or in subsequent years.

(7) The operating rule curve (ORC) is a composite curve based on the controlling rule curve for each time period, and is defined as follows:

- August-December: the higher of the ARC or the CRC, unless the MRC is lower, in which case it controls.
- January-March: the same as for August-December, unless the VRC is lower, in which case it controls. In no case can the ORC be lower than the LLECC, however.
- April-July: the same as for January-March except that the LLECC consideration does not apply.

Figure M-26 shows derivation of the operating rule curve (ORC) for a typical year based on the various rule curves shown on Figure M-25. The ORC defines the normal lower limit to reservoir operation and the MRC (flood control rule curve) defines the upper limit. The darker shaded area represents the normal range of reservoir operation. A project would operate below the normal range of operation only if required to meet firm loads and above the normal range of operation only when regulating floods.

(8) Because the streamflows are typically very low in the late summer and fall months, and because of the uncertainty regarding future runoff, reservoir operation in the August-December period typically follows the ORC quite closely. Sometimes, rainfall storms generate higher flows in the latter portion of this period, but because secondary energy has relatively high value, excess streamflow is usually converted to energy production rather than being stored. If the water supply is good during the period January-March, water in

excess of that required to meet firm energy obligations will either be used for generation or stored between the ORC and the MRC, depending on the current value of secondary energy and the expected future value. As a practical matter, during the runoff season the ORC is usually followed fairly closely. This is because water left in storage above that curve might have to be spilled if the reservoir fills, and its energy potential would be lost.

(9) The preceding paragraph describes operation in a good water year. In a year with a light snowpack, the ARC might define the post-January operating rule curve. However, reservoir operation

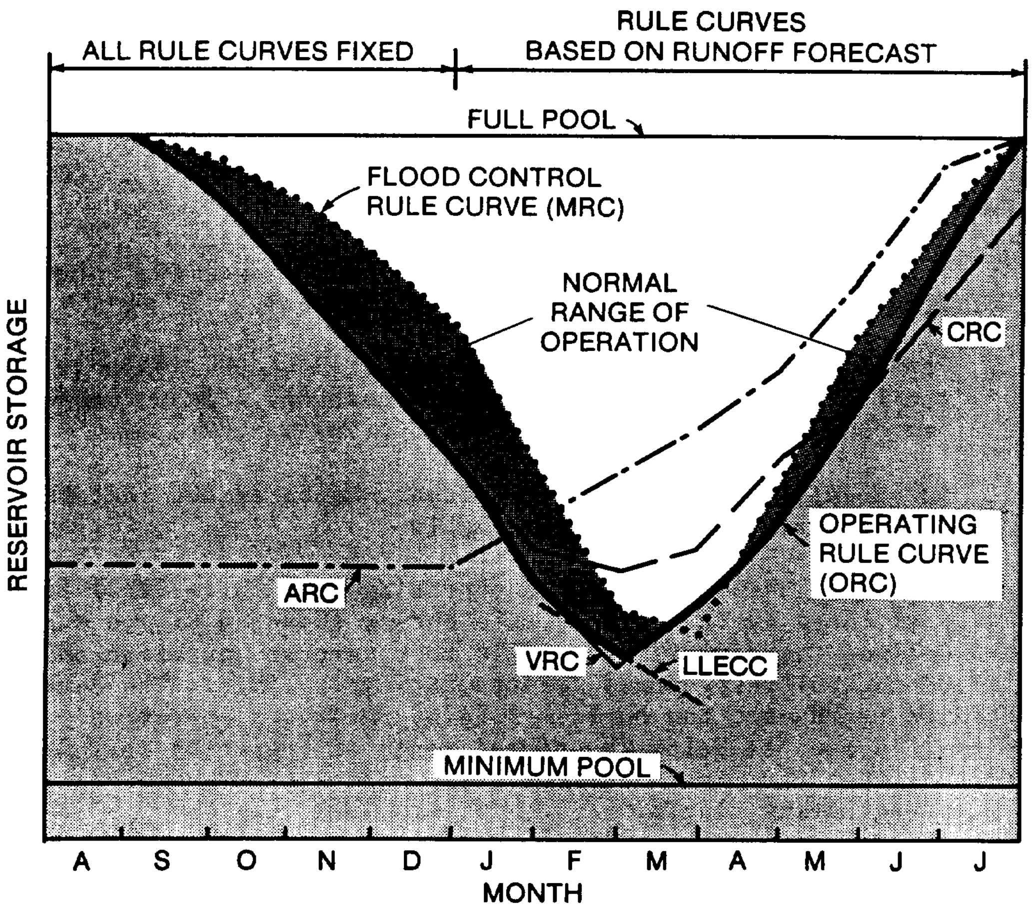


Figure M-26. Operating rule curve for typical Columbia River basin storage project for given operating year would not necessarily follow that curve, because the operating rule curve serves only to define the level below which no secondary energy will be produced. In an adverse year, it may be necessary to draft below the operating rule curve in order to serve firm loads. For example, if the first year of the critical period were to occur, reservoir operation would follow the CRC, which would be substantially lower than the ARC-defined operating rule curve. Over a long period of operation, there could be a number of occasions when it is necessary to draft below the operating rule curve, but this would be done only to meet firm load requirements.

(10) In about one year in four, the runoff is insufficient to permit the reservoir system to refill. If the system fails to fill, generation in subsequent months will be limited to firm energy requirements. The second-, third-, and fourth-year critical rule curves would be used to define reservoir operation in periods of extended drought.

(11) An interesting technique is used to increase system firm energy capability in most years. Firm energy capability is based on a four-year critical period, and the classic approach to reservoir operation would be to design rule curves such that the same amount of firm energy could be produced in all four years. However, the probability of having two or more adverse streamflow years in a row is low. Recognizing this low probability, the system rule curves are designed to produce more firm energy in the first year of the critical period than in the last three years. Thus, in years when the reservoir system fills (about three years out of four), the system is able to produce the higher level of firm energy output. In those years when the reservoir system fails to fill, the system's firm energy capability would be lower. The region's utilities believe that the benefits achieved by increasing firm capability in most years exceed the liabilities incurred in those years when the system does not refill and must operate at a reduced firm capability.

(12) The Columbia River system consists of a complex network of parallel and tandem reservoirs, with some run-of-river projects (with pondage) situated between reservoirs and other pondage projects located downstream of the entire reservoir system. The project rule curves are based on a system approach to determining the sequence of storage draft from individual reservoirs. The overall objective is to draft first from those reservoirs where the amount of energy produced (both at-site and downstream) is large compared to the loss in energy in subsequent months due to reduced head at-site (as a result of the draft). This is the "storage effectiveness" approach described in Section 5-14 of Chapter 5. Basing system operation exclusively on storage effectiveness would result in near-optimum power generation. However, other factors must also be considered in

defining the operation of both the system and individual projects. These factors include (a) flood control operation requirements, (b) minimum flow requirements for non-power purposes, (c) reservoir recreation considerations (which encourage equal drawdown to keep all reservoirs relatively high), (d) fish and wildlife requirements, (e) the requirements of the Columbia River Treaty, and (f) the specific requirements of individual project owners. System operation is therefore designed to produce as much power as possible within these constraints.

d. Other River Uses.

(1) Releases for power generation and flood control are generally adequate to maintain navigation on the lower Snake and lower Columbia Rivers. During the growing season, regulated flows on the mainstream Columbia and lower Snake are usually sufficient to meet irrigation requirements. Only at Grand Coulee and on some of the tributaries does irrigation influence reservoir operation.

(2) High flows must be maintained in the late spring for successful downstream fish migration. In above average years this can usually be accomplished without special regulation, but in low runoff years, operation to maximize power would result in too little water being released in the spring months to maintain adequate flows for downstream fish passage. Hence, some reservoir storage (called "water budget" storage) is reserved until the spring to insure that downstream fish passage requirements can be met.

(3) Reservoir recreation is generally compatible with the basic power-flood control regulation in that the reservoirs are maintained at their highest levels during the summer recreation season. However, in some years, the reservoirs either fail to fill, or below normal flows in late summer cause them to draft early, and the resulting lower reservoir elevations adversely affect reservoir recreation.

e. Hourly Power Operation.

(1) The preceding discussion applies primarily to the seasonal power operation of the Columbia River reservoir system. As of operating year 1985-86, hydro generation met about three-quarters of the region's firm energy requirements and system peaking capability. The remaining resources are primarily new base load nuclear and coal-fired steam plants. Accordingly, hydro meets almost all of the variable portion of the daily load (peaking and intermediate), as well as a large portion of the base load. Thermal plants carry the balance of the base load. Depending on their respective installed capacities, non-power operating restrictions, and flow character-

istics, individual hydro plants may be operated to meet peaking, intermediate, or base load requirements, or combinations thereof.

(2) The Pacific Northwest Coordination Agreement deals with the seasonal coordination of storage operation. Each individual utility handles its own short-term load dispatching. However, for adjacent hydro projects to be utilized effectively, their operation must be coordinated on at least an hourly basis. About two-thirds of the region's hydro capacity belongs to the Federal government (the Corps of Engineers and the Bureau of Reclamation), and these projects are dispatched on a coordinated basis by the Bonneville Power Administration. Most of the larger projects are on automatic generation control. BPA's main dispatch center coordinates the hourly operation of the chain of eight projects on the lower Snake and lower Columbia Rivers (Lower Granite through Bonneville). The other major continuously developed reach is the seven-project system on the middle Columbia River from Grand Coulee through Priest Rapids. These projects are owned by several different entities but are operated together under a special hourly coordination agreement. Most of the remaining intensively developed reaches are under the control of a single utility or agency.

f. Critical Period. The system's firm energy load carrying capability is defined by the 42-month critical drawdown period, September 1928 through February 1932. Under some combinations of system loads, resources, and other factors, the 20-month critical drawdown period, August 1943 through mid-April 1945, controls.

g. West-Slope Projects.

(1) The above discussion applies to the portion of the Columbia River basin above Bonneville Dam, which contains about 90 percent of the region's hydropower capability. The remaining projects are located on streams draining the west slopes of the Cascade Mountains or in coastal river basins. While these projects are operated as part of the Pacific Northwest Coordination Agreement, these streams have a different hydrologic pattern than the mainstream Columbia, and project operation follows a somewhat different pattern.

(2) Like the eastern portion of the Columbia River Basin, the bulk of the precipitation falls in the winter months. However, most of it occurs as rainfall rather than snow. Thus, natural streamflows are highest in the winter months and are normally quite low in the summer and early fall months.

(3) This runoff pattern fits the regional power demand pattern quite closely. However, operation for power conflicts somewhat with flood control requirements. Six of the hydro projects located on the

western slopes of the Cascade Mountains are Corps of Engineers multiple-purpose projects, which include flood control as a major purpose. Some of the non-Federal hydro projects in this part of the region also provide seasonal flood control storage.

(3) In order to meet the combined requirements of flood control, hydropower, and low flow augmentation in the late summer and early fall, the Corps projects are operated in accordance with a seasonal rule curve similar to that shown in Figure M-27. The storage is divided into three zones: (a) a small amount of exclusive flood control space on top, to protect against summer floods, (b) a large joint-use storage zone, and (c) a small exclusive power storage zone on the bottom, to help meet firm power requirements in dry winters.

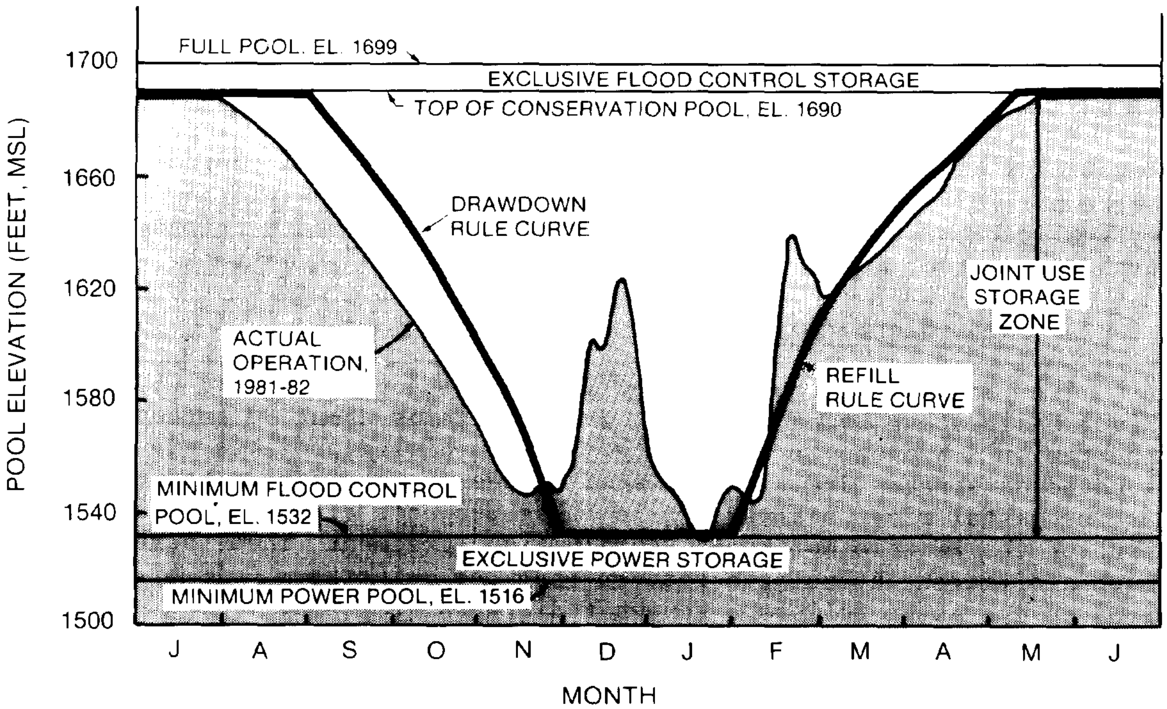


Figure M-27. Rule curve for Cougar Reservoir, a multiple-purpose project located in the western portion of the Columbia River basin, showing actual operation during the year 1981-1982

(4) Reservoirs are maintained at low levels during the winter months to provide maximum space for controlling rainfall-generated floods. Although flows are typically high in these months, the reduced head lessens generating capability. As the probability of flooding diminishes, the reservoirs are allowed to refill starting on 1 February, with the objective of filling the joint-use storage by about 1 June. Drafts are made through the summer and fall months for hydropower, irrigation, and low-flow augmentation for navigation, fish and wildlife, and other purposes. Additional drafts are made if necessary to insure that the winter flood control pool elevation is reached by 1 December.

(5) The utility-owned hydro storage projects located west of the Cascade Mountains are operated in accordance with power rule curves. However, because runoff is not forecastable, some of the curves shown on Figure M-25 do not apply (specifically, the VRC and LLECC). The CRC defines the lowest level to which a reservoir will be drafted in each period to meet secondary loads. Most of these reservoirs are annual reservoirs (operating on an annual cycle), and are completely drafted and refilled in every year. Some utility-owned projects provide seasonal flood control storage and thus have a mandatory rule curve (MRC).

h. System Management. Seasonal regulation of the hydro system is controlled by the 18-party Pacific Northwest Coordination Agreement and the Columbia River Treaty with Canada. Project operation within limits imposed by these agreements is controlled by the individual project owners. Overall responsibility for the operational management of the Federal hydro projects to meet multiple-purpose objectives belongs to the Corps of Engineers (North Pacific Division, PO Box 2870, Portland, OR 97208), and the Bureau of Reclamation (Pacific Northwest Region, PO Box 043, 550 West Fort Street, Boise, ID 83724). The Bonneville Power Administration (PO Box 3621, Portland, OR 97208), directs the power operation of the Federal projects within limits established by the Corps and the Bureau of Reclamation. Flood control operation of both Federal and non-Federal projects is monitored by the Corps of Engineers.

i. Summary.

(1) The Columbia River reservoir system provides about 42 MAF of usable storage, which is equivalent to about 30 percent of the average annual runoff at The Dalles. The bulk of the reservoir storage in the system is joint-use storage, regulated primarily for hydropower and flood control, although other river uses, such as irrigation, recreation, and fish and wildlife, also influence the operation of individual projects, as well as the system. The river is primarily a snowmelt stream, experiencing high runoff in the late spring and early summer and relatively low flows during the remainder

of the year. The seasonal power demand pattern is the reverse of the runoff patterns, with the peak power requirements occuring in the winter months.

(2) The reservoir storage is drafted from late summer through early spring to generate power and provide flood control space. Reservoirs refill in the late spring and early summer. The runoff is, in part, forecastable because it is snowmelt-based. The amount of storage drafted varies from year to year, depending on the loads and the amount of runoff expected. Reservoir operation is controlled by a series of rule curves based on firm power, flood control, fish and wildlife, and refill requirements, and these curves are adjusted during the operating year as runoff forecast data becomes available. Power operation is designed not only to insure that firm energy requirements are met, but also to produce as much secondary energy as possible without jeopardizing reservoir refill. Secondary energy is used for serving a portion of the region's electroprocess industry loads and for thermal energy displacement both within the region and in the Pacific Southwest.

(3) Hydropower is the predominant source of power in the Pacific Northwest, meeting about two-thirds of the region's firm energy requirement and three-quarters of its peaking requirements. Hydropower carries almost all of the variable portion of the daily load, as well as a large portion of the base load. Although the region's hydro projects are owned by a number of entities, seasonal operation of the system is coordinated through a series of operating agreements, including a treaty with Canada.

APPENDIX N

EXAMPLES OF HOURLY STUDIES

N-1. General. This appendix consists of sample calculations that illustrate sequential hand routings for three of the most commonly encountered short term power studies:

- determining the sustained peaking capacity and pondage requirements for a pondage project
- sizing a reregulating reservoir
- sizing an upper reservoir for a pumped-storage project

These examples are simplified, but they illustrate the approaches that can be applied to more complex hourly studies. These examples are referenced in Sections 6-8 and 6-9.

N-2. Case 1: Pondage Analysis.

a. General. The objective of this analysis is to estimate (a) the generating capacity that can be sustained, and (b) the amount of pondage required at a peaking project. In this study, a potential "worst case" scenario will be examined in order to help determine the minimum amount of capacity that can be sustained in the peak demand months and the corresponding pondage requirements. The peak demand month with the lowest average flow was selected for analysis in this example.

b. Project Data. Following are the physical characteristics of the proposed dam site:

- full pool elevation: El. 2306.0
- tailwater curve: see Figure N-1
- storage-elevation characteristics: 8000 AF of storage per foot of elevation
- head loss: 0.5 feet
- minimum average discharge for peak demand period: 6000 cfs
- minimum continuous discharge: 3000 cfs
- evaporation losses and withdrawals: assumed to be zero
- leakage losses: assumed to be zero
- powerplant efficiency: 85 percent
- available pondage: up to four feet of pondage (32,000 AF) can be drafted without affecting other project purposes

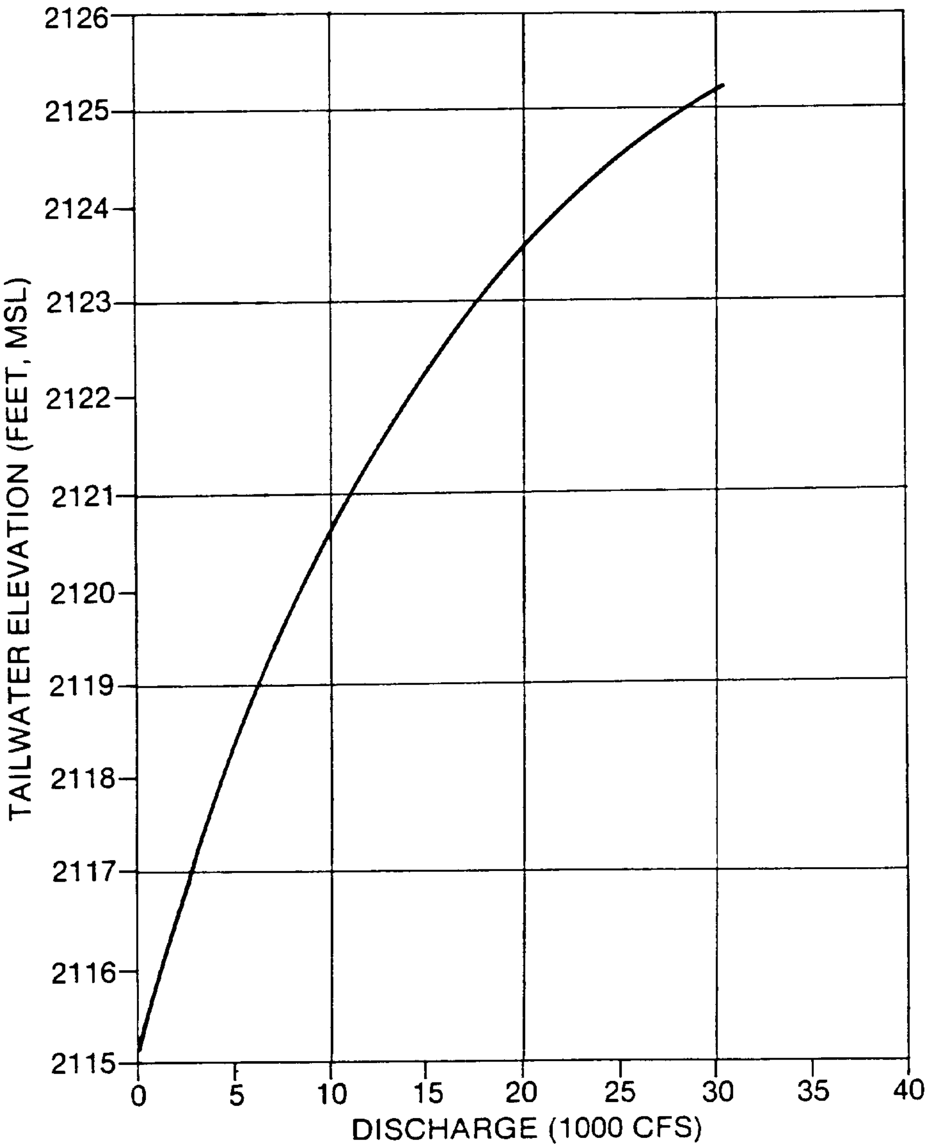


Figure N-1. Tailwater curve for peaking project

Assume that the regional Power Marketing Administration has indicated that on-peak power is required between 8 am and 6 pm, five days a week.

c. Preliminary Estimate of Sustained Peaking Capacity.

(1) A preliminary estimate of the installed capacity can be obtained by making a simple streamflow routing and assuming an average head. The average weekly discharge is 6000 cfs, and the minimum required discharge is 3000 cfs. This leaves

$$(6000 - 3000 \text{ cfs}) \times (168 \text{ hours})$$

to be used for peaking between 8 am and 6 pm (10 hours) on the five weekdays. Hence, the peak discharge will be approximately:

$$3000 \text{ cfs} + \frac{(168 \text{ hrs})(6000 - 3000 \text{ cfs})}{(5 \text{ days})(10 \text{ hrs})} = 13{,}080 \text{ cfs}$$

(2) Figure N-1 shows that the tailwater elevation at a discharge of 13,080 cfs is about El. 2121.5. Assume an average drawdown of 1.0 feet, which gives an average pool elevation of El. 2305.0. Thus, the average head is assumed to be (El. 2305.0 - El. 2121.5 - 0.5 ft (loss)) = 183.0 ft. Using the water power equation, the preliminary estimate of the sustained peaking capacity is:

$$\text{kW} = \frac{\text{Qhe}}{11.81} = \frac{(13{,}080 \text{ cfs})(183 \text{ ft})(0.85)}{11.81} = 172{,}300 \text{ kW.}$$

d. Hand Routing.

(1) A hand routing was then made to verify the sustained peaking capacity and to determine the pondage requirements. Since inflow is assumed to be constant throughout the week and the project is operating at only two levels (at the full 172,300 kW peak output or at the 3,000 cfs minimum discharge), it is possible to simplify the routing by using multi-hour blocks instead of hourly increments. The weekdays were divided into three blocks: (a) midnight to 8 am at 3,000 cfs, (b) 8 am to 6 pm at 172,300 kW peak output, and (c) 6 pm to midnight at 3,000 cfs. Saturday and Sunday were each treated as 24-hour blocks at 3,000 cfs. The routing was started at 8 am on Monday morning, when the reservoir was assumed to be full.

(2) The hand routing is summarized on Table N-1. A simplified version of Table 5-6 was used. The routing procedure follows the same general approach outlined in Appendix H, Section H-3b. The 172.3 MW

peaking requirement establishes the required discharge during the peak demand hours and the 3000 cfs minimum discharge controls during the remainder of the time. Since the net head used in each period is based on an estimated average head, more than one iteration was required in some hours to achieve convergence with the end-of-period elevation. However, only the final iterations are shown in the table.

(3) In examining Table N-1, it can be seen that the reservoir exactly refills to the starting elevation at 8 am Monday morning, so the routing is in balance. In addition, the full 172,300 kW was delivered in all of the specified hours. Therefore, the preliminary estimate for sustained peaking capacity is correct. Note also that the discharges during the peaking hours (13,000 to 13,100 cfs) are very close to the required average of 13,080 cfs and the average pool elevation (El. 2305.1) is very close to the assumed El. 2305.0. The required pondage (as measured at the point of maximum drawdown, at 6 pm on Friday) is 15,300 AF.

(4) The routing on Table N-1 is graphically displayed as Figure N-2.

N-3. <u>Case 2: Reregulating Reservoir Analysis.</u>

a. <u>General.</u> Assume the same peaking project as described in the previous example, except that a reregulating reservoir will be constructed to maintain a constant discharge downstream, thus permitting the peaking project to concentrate all of its generation in the peak demand hours of the day. The purpose of this analysis is to determine the amount of reregulating reservoir pondage required to meet this objective. In order to simplify the analysis, tailwater fluctuation due to encroachment of the reregulating reservoir on the peaking project will be ignored.

b. <u>Regulation of the Peaking Project.</u>

(1) The sustained peaking capacity was computed in the same way as for the previous example. The average on-peak discharge would be (6,000 cfs)x(168 hrs/50 hrs) = 20,160 cfs, and the corresponding tailwater elevation would be El. 2123.5. Assuming an average pool elevation of El. 2304.0, the head at full output would be

(El. 2123.5 - El. 2304.0 - 0.5) = 181.0 feet,

and the preliminary estimate of the sustained peaking capacity would be

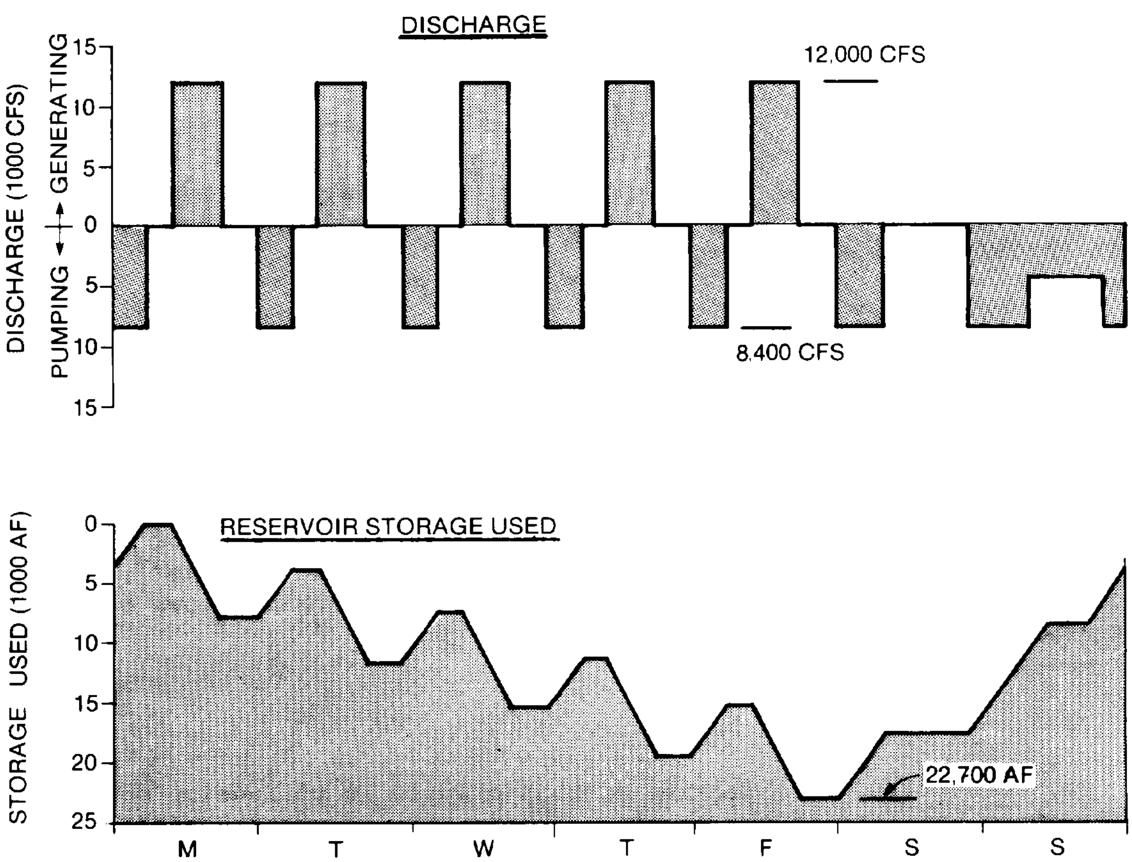


Figure N-2. Graphical illustration of pondage analysis for peaking project

$$KW = \frac{Qhe}{11.81} = \frac{(20,160 \text{ cfs})(181 \text{ ft})(0.85)}{11.81} = 263,000 \text{ kW.}$$

(2) A routing similar to that described in Section N-2 was made (not shown), and the following average peaking discharges were computed:

Monday	-	20,000 cfs
Tuesday	-	20,100 cfs
Wednesday	-	20,200 cfs
Thursday	-	20,200 cfs
Friday	-	20,300 cfs

The pondage requirement was determined to be 30,700 AF, which is within the allowable maximum of 32,000 AF (see Section N-2b).

c. Reregulating Reservoir Storage Requirement. Using the peaking discharge above as inflow, a routing was made to determine the amount of reregulating storage required to maintain the 6,000 cfs continuous discharge. Since it is assumed that there will be no power installation at the reregulating dam, the analysis, which is summarized on Table N-2, was a simple streamflow routing. The maximum storage requirement is 30,700 AF, which also occurs at 6 pm on Friday. This routing is shown on Figure N-3.

d. Additional Storage Required for a Three-Day Weekend. The above analysis is based on a normal week with five working days. When three-day weekends occur, holiday loads are frequently at low levels, so it may be necessary for the reregulating reservoir to maintain minimum flows for three full days instead of two. This requires additional storage. The supplemental routing at the bottom of Table N-2 shows that 11,900 AF of additional storage would be required to handle this demand, resulting in a total storage requirement of (30,700 AF + 11,900 AF) = 42,600 AF. This additional "reserve" storage would be refilled in subsequent weeks, as surplus flows become available.

N-4. Pumped-Storage Reservoir.

a. General. The objective of this example is to develop make a preliminary estimate of the upper reservoir storage requirements for an off-stream pumped-storage project. The project will be operated on a weekly cycle.

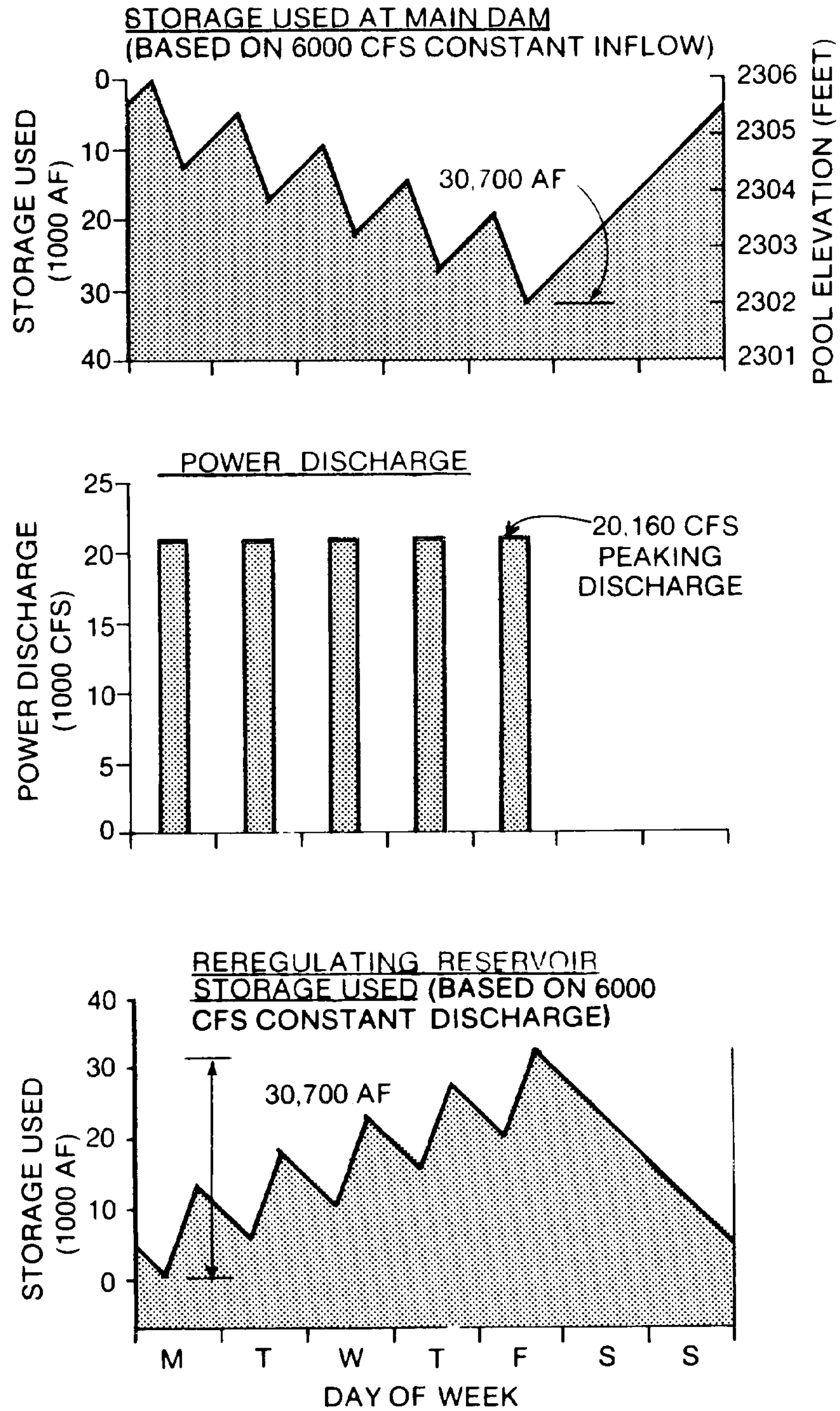


Figure N-3. Graphical illustration of reregulating reservoir analysis

b. Project Data. Following are the project characteristics:

- average net head: 1,200 feet
- generating capacity: 1,000 MW
- pumping capacity: same as generating capacity
- generating efficiency: 82 percent
- pumping efficiency: 85 percent
- required generating hours: 10 am - 6 pm, Monday-Friday
- available pumping hours:
  - Monday-Friday: 12 midnight - 6 am
  - Saturday: 12 midnight - 8 am, 8 pm - 12 midnight
  - Sunday: 12 midnight - 10 am, 6 pm - 12 midnight

Tailwater and reservoir elevation fluctuations are assumed to be small in comparison to the project's high head and can be ignored in a preliminary analysis of this type. Evaporation, local inflow, and leakage losses are assumed to be negligible.

c. Hand Routing.

(1) Because the objective is only to determine the storage requirement and because tailwater and forebay fluctuations are considered negligible, a simplified analysis is possible (i.e., it is not necessary to compute the head for each time increment). As with the previous examples, the week is divided into a series of multi-hour blocks. Except for Monday, computations are shown only for those time periods when pumping or generating is taking place. The generating discharge is computed as follows:

$$Q_g = \frac{11.81\text{kW}}{he_g} = \frac{(11.81)(1{,}000{,}000\text{ kW})}{(1{,}200\text{ ft})(0.82)} = 12{,}000\text{ cfs}$$

The pumping discharge is computed as follows:

$$Q_p = \frac{11.81\text{kW}e_p}{h} = \frac{(11.81)(1{,}000{,}000\text{ kW})(0.85)}{(1{,}200\text{ ft})} = 8{,}400\text{ cfs}$$

(2) Using the generating and pumping discharges computed above and the pumping and generating schedule shown in paragraph N-4b, a routing was made for the week (Table N-3). The maximum storage requirement (which occurred at 6 pm on Friday) is 22,700 AF.

(3) Note that the table shows the plant pumping at full capacity for all of the available weekend pumping hours, and the reservoir over-filling by 1000 AF as on 6 am Monday. Rather than over-filling the reservoir, the pumping would actually have stopped at full

reservoir capacity at some time prior to 6 am on Monday. One thousand acre-feet, converted to hours of pumping at full capacity, would be:

$$\frac{(1{,}000\ \text{AF})(43{,}560\ \text{ft}^3/\text{AF})}{(8{,}400\ \text{cfs})(3{,}600\ \text{sec/hr})} = 1.5\ \text{hours.}$$

Thus, the pumping would have stopped at 4:30 am instead of at 6 am. The routing for the week is shown on Figure N-4.

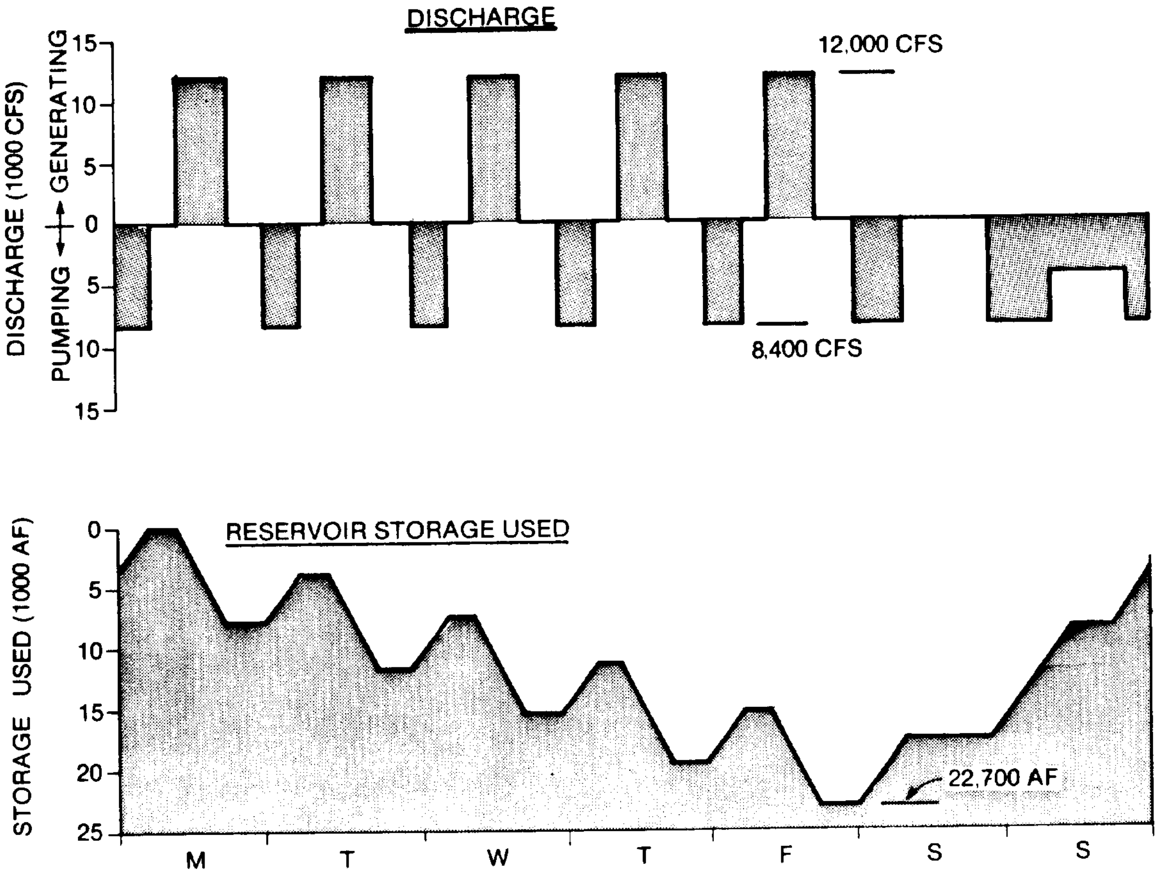


Figure N-4. Graphical illustration of off-stream pumped-storage project analysis

TABLE N-1. Regulation

	Interval	Hours	Inflow (cfs)	Generating Requirement (MW)	Average Res. Elev. (feet)	Net Head (feet)	Power Discharge (cfs)
M	0000-0800	8	-	-	-	-	-
M	0800-1800	10	6,000	172.3	2305.7	183.7	13,000
M	1800-2400	6	6,000	0.0	2305.4	183.4	0
T	0000-0800	8	6,000	0.0	2305.6	183.6	0
T	0800-1800	10	6,000	172.3	2305.3	183.3	13,000
T	1800-2400	6	6,000	0.0	2305.1	183.1	0
W	0000-0800	8	6,000	0.0	2305.3	183.3	0
W	0800-1800	10	6,000	172.3	2305.0	183.0	13,100
W	1800-2400	6	6,000	0.0	2304.8	182.8	0
Th	0000-0800	8	6,000	0.0	2305.0	183.0	0
Th	0800-1800	10	6,000	172.3	2304.8	182.8	13,100
Th	1800-2400	6	6,000	0.0	2304.5	182.5	0
F	0000-0800	8	6,000	0.0	2304.7	182.7	0
F	0800-1800	10	6,000	172.3	2304.4	182.4	13,100
F	1800-2400	6	6,000	0.0	2304.2	182.2	0
Sa	0000-2400	24	6,000	0.0	2304.6	182.6	0
Su	0000-2400	24	6,000	0.0	2305.4	183.4	0
M	0000-0800	8	6,000	0.0	2305.9	183.9	0

of Pondage Project

Minimum Discharge (cfs)	Required Discharge (cfs)	Change in Storage (cfs)	Change in Storage (AF)	End of Period Storage (AF)	End of Period Elev. (ft.)	Hourly Generation (MW)
-	-	-	-	0	2306.0	-
3,000	13,000	-7,000	-5,800	-5,800	2305.3	172.3
3,000	3,000	3,000	1,500	-4,300	2305.5	39.6
3,000	3,000	3,000	2,000	-2,300	2305.7	39.6
3,000	13,000	-7,000	-5,800	-8,100	2305.0	172.3
3,000	3,000	-7,000	1,500	-6,600	2305.2	39.5
3,000	3,000	3,000	2,000	-4,600	2305.4	39.6
3,000	13,100	-7,100	-5,900	-10,500	2304.7	172.3
3,000	3,000	3,000	1,500	-9,000	2304.9	39.5
3,000	3,000	3,000	2,000	-7,000	2305.1	39.5
3,000	13,100	-7,100	-5,900	-12,900	2304.4	172.3
3,000	3,000	3,000	1,500	-11,400	2304.6	39.4
3,000	3,000	3,000	2,000	-9,400	2304.8	39.4
3,000	13,100	-7,100	-5,900	-15,300	2304.1	172.3
3,000	3,000	3,000	1,500	-13,800	2304.3	39.3
3,000	3,000	3,000	5,900	-7,900	2305.0	39.4
3,000	3,000	3,000	5,900	-2,000	2305.8	39.6
3,000	3,000	3,000	2,000	0	2306.0	39.7

TABLE N-2
Regulation of Reregulating Reservoir

Interval		Hours	Inflow (cfs)	Required Discharge (cfs)	Change in Storage (cfs)	Change in Storage (AF)	End of Period Storage (AF)
M	0000-0800	8	-	-	-	-	0
M	0800-1800	10	20,000	6,000	14,000	11,500	11,500
M	1800-2400	6	0	6,000	-6,000	-3,000	8,500
T	0000-0800	8	0	6,000	-6,000	-3,900	4,600
T	0800-1800	10	20,100	6,000	14,100	11,600	16,200
T	1800-2400	6	0	6,000	-6,000	-3,000	13,200
W	0000-0800	8	0	6,000	-6,000	-3,900	9,300
W	0800-1800	10	20,200	6,000	14,200	11,700	21,000
W	1800-2400	6	0	6,000	-6,000	-3,000	18,000
Th	0000-0800	8	0	6,000	-6,000	-3,900	14,100
Th	0800-1800	10	20,200	6,000	14,200	11,700	25,800
Th	1800-2400	6	0	6,000	-6,000	-3,000	22,800
F	0000-0800	8	0	6,000	-6,000	-3,900	18,900
F	0800-1800	10	20,300	6,000	14,300	11,800	30,700
F	1800-2400	6	0	6,000	-6,000	-3,000	27,700
Sa	0000-2400	24	0	6,000	-6,000	-11,900	15,800
Su	0000-2400	24	0	6,000	-6,000	-11,900	3,900
M	0000-0800	8	0	6,000	-6,000	-3,900	0

Supplemental Regulation to Determine Additional
Storage Required for Three-Day Weekend

Su	0000-2400	24	-	-	-	-	3,900
M	0000-2400	24	0	6,000	-6,000	-11,900	-8,000
T	0000-0800	8	0	6,000	-6,000	- 3,900	-11,900

TABLE N-3
Regulation of Off-Stream Pumped-Storage Reservoir

	Interval	Hours	Generating Requirement (MW)	Pumping Capacity (MW)	Dis-charge (cfs)	Change in Storage (AF)	End of Period Storage (AF)
M	0000-0600	6	-	-	-	-	0
M	0600-1000	4	0	0	0	0	0
M	1000-1800	8	1,000	0	-12,000	-7,900	-7,900
M	1800-2400	6	0	0	0	0	-7,900
T	0000-0600	6	0	1,000	8,400	4,200	-3,700
T	1000-1800	8	1,000	0	-12,000	-7,900	-11,600
W	0000-0600	6	0	1,000	8,400	4,200	-7,400
W	1000-1800	8	1,000	0	-12,000	-7,900	-15,300
Th	0000-0600	6	0	1,000	8,400	4,200	-11,100
Th	1000-1800	8	1,000	0	-12,000	-7,900	-19,000
F	0000-0600	6	0	1,000	8,400	4,200	-14,800
F	1000-1800	8	1,000	0	-12,000	-7,900	-22,700
Sa	0000-0800	8	0	1,000	8,400	5,600	-17,100
Sa	2000-2400	4	0	1,000	8,400	2,800	-14,300
Su	0000-1000	10	0	1,000	8,400	6,900	-7,400
Su	1800-2400	6	0	1,000	8,400	4,200	-3,200
M	0000-0600	6	0	1,000	8,400	4,200	1,000 1/

1/ see paragraph N-4c(3)

APPENDIX O

CAPACITY CREDITS, INTERMITTENT CAPACITY AND ENERGY VALUE ADJUSTMENTS

O-1. Introduction.

a. Power Benefit Analysis. Chapter 9 presents the basic principles and procedures used in evaluating power benefits. Section 9-3 describes how power values are used in computing power benefits, and Section 9-5 describes how these power values are derived. Principles and Guidelines (77) requires that hydropower benefits reflect power system impacts. This appendix describes techniques that can be used to adjust capacity and energy values to account for these impacts.

b. Source of This Material. This appendix was drawn essentially intact from Chapter 6 of the Water and Energy Task Force report, Evaluating Hydropower Benefits, dated December 1981 (78). Several wording changes have been made to the original text of the Task Force report to reference the 1983 Principles and Guidelines (77) in lieu of the 1979 NED Manual, (79), and to make the material conform to current implementation practices. The text and tabular data relating to mechanical availability (Section O-2d) was revised to reflect current information and practices. Some editorial changes were also made to make the text conform to the standard Engineering Manual format.

O-2. Capacity Value Adjustments and Intermittent Capacity.

a. Introduction.

(1) The capacity benefit computed for a hydropower project is intended to reflect the capacity costs saved by not constructing alternative power generating facilities. Historically, the annual capacity benefits have been computed by multiplying the hydro project's dependable capacity by the annual unit ($/kW) fixed costs of the most likely thermal alternative. This unit cost has normally included an adjustment to reflect differences in operating flexibility and reliability between the hydropower project and its thermal alternative. Aside from the question of what constitutes the most likely alternative to the hydropower project, this historical approach has suffered from three major deficiencies: (a) there are many varying interpretations of the traditional definition of dependable capacity; (b) this definition does not allow proper credit for intermittent capacity which is available a substantial amount of the time but does

not quality as dependable capacity; and (c) the reliability/flexibility adjustments applied to the thermal plant unit cost are rather arbitrary and frequently do not reflect current relative performance of thermal and hydropower plants.

(2) Section 2.5.8.(a)(3) of Principles and Guidelines confirms that the concept of a reliability/flexibility credit is valid. Section 2.5.8.(a)(4) recognizes that some credit may be warranted for intermittent capacity. However, Principles and Guidelines fails to provide an effective procedure for resolving the deficienciea cited above.

(3) The basic objective of the capacity benefit is to determine the cost of thermal plant capacity that would contribute the same peak load-carrying capability to a system as the hydropower project. Using a system loss-of-load probability (LOLP) model, the Federal Energy Regulatory Commission's (FERC) Washington office has developed some relationships which make it possible to compute a hydropower plant's capacity benefit directly, considering (a) the hydropower plant's dependable capacity and intermittent capacity, and (b) the relative reliabilities of hydropower and thermal capacity. This approach meets both the capacity value adjustment and intermittent capacity provisions of Principles and Guidelines. Following is a general discussion of the proposed procedure and details for application to specific project studies.

b. The Capacity Benefit Equation.

(1) The basic equation for deriving a hydropower project's capacity benefit is as follows:

$$\text{Capacity benefit} = (IC)(CV) \times \frac{HA}{100} \times \frac{HMA}{TMA} \times (1 + F) \qquad \text{(Eq. 0-1)}$$

where:

Capacity benefit = average annual capacity benefit, dollars
IC = hydropower project installed capacity, kW
CV = thermal plant unit investment cost (capacity value), $/kW/yr
HA = hydropower project average hydrologic availability (%) during peak demand period
HMA = hydropower plant mechanical availability (%)
TMA = thermal plant mechanical availability (%)
F = hydropower plant flexibility factor

(2) The hydropower project installed capacity is the total rated capacity of the generators, including overload capacity where appropriate. The thermal plant unit capacity value is the average annual unit capacity value of the most likely thermal alternative, without any adjustments for reliability or flexibility. The remaining terms are used to compute the capacity value adjustment and are discussed in more detail in the following sections.

c. Hydrologic Availability.

(1) The dependable capacity of a hydropower project is intended to be a measurement of the amount of capacity that can be counted on as being available when needed. As such, it is intended to reflect hydrologic availability. A project's dependable capacity is frequently less than its installed capacity, because the amount of capacity available when needed may be reduced because of low flows or reduced heads caused by reservoir drawdown or tailwater encroachment.

(2) Various techniques have been used to measure dependable capacity including (a) the amount of capacity available in a selected historical month that is considered most critical from the standpoint of both loads and hydrologic conditions (see Section 6-7d), (b) the amount of capacity available some selected percentage of the time (say 85 percent) in the peakload months (Section 6-7f), and (c) the amount of firm energy required per kilowatt of dependable capacity (Section 6-7e). Values derived using these procedures were very significant when system reliability was measured by reserve margin, and they may still be meaningful in predominantly hydroelectric power systems and for use in negotiating certain types of power sales contracts. However, dependable capacity based on such criteria loses its meaning in large, diverse hydrothermal or predominantly thermal power systems, especially where system reliability criteria are based on the more realistic probabilistic methods, such as LOLP (loss-of-load probability).

(3) It is widely agreed that in most power systems, traditional procedures for measuring dependable capacity frequently underestimate the true value of hydroelectric capacity in a system. This is because most of these procedures are often overly conservative and because no credit is given for intermittent capacity -- capacity that is available a substantial part of the time but does not strictly meet the criteria for dependable capacity. Attempts have been made to recognize intermittent capacity by allowing partial credit, but these attempts are rather arbitrary and difficult to defend technically.

(4) When system reliability is measured probabilistically, the varying availability of hydropower capacity due to variations in head and/or streamflow can be treated in a manner similar to mechanical

availability of thermal plants. In a large diverse power system, the "derating" of a hydropower plant at some particular point in time due to reduced head or low streamflow is a statistical event analogous to the derating or complete shutdown of a thermal unit due to a forced outage. The problem is that a hydropower plant's capacity availability is usually a continuous distribution over a wide range of outputs, unlike a thermal plant which can be represented as on, off, or at several discrete levels of partial output.

(5) In addressing the problem of how to quantitatively measure the hydrologic availability of a hydropower project in a manner in which it could be reflected in a LOLP model, FERC started with a capacity-duration curve, which reflects the degree and amount of time a hydropower project's installed capacity is derated due to reservoir drawdown, tailwater encroachment, or low streamflows. This curve was broken into a number of segments, each representing a discrete "powerplant" of a given size which has an availibility equal to the amount of time that its capacity was hydrologically available during the peak load period. Thus, the hydropower plant was represented in the model as a series of "powerplants" of varying sizes and availabilities. A series of LOLP model runs was made to determine the amount of thermal capacity that would be required to serve the same amount of additional system load as the composite hydropower plant while maintaining the same level of system reliability. By applying this approach to various types of power systems, it was determined that it was not necessary to depict the availability of hydropower capacity as a probability distribution when the hydropower project was relatively small compared to system size. Rather, it could be represented almost as accurately by the hydrologic availability of the hydropower plant's capacity - a single value that could be readily derived.

(6) Various techniques can be used for deriving average hydrologic availability. The values can be derived from capacity or generation-duration curves (Figure O-1) or directly from power routing studies. For simple run-of-river projects, the values should be based on duration curves derived from daily flows and should reflect the impact of minimum unit output and head loss due to encroachment, as well as variations in streamflow. For storage projects or pondage projects on regulated streams, the daily variations in streamflow are not as important. In these cases, the availability can be derived from monthly or weekly routing studies, and it would reflect primarily the variation in machine capability due to variation in head. The analysis should be based only on the system peakload season (e.g., June, July, and August for a summer peak system), because system capacity requirements are normally determined by the annual peak load.

If the hydropower plant cannot deliver any capacity in the peakload months, then it does not displace thermal capacity and hence has no capacity benefit.

(7) For pure run-of-river projects, or projects where operating restrictions preclude regulation of discharge for peaking purposes, the generation-duration curve and capacity-duration curve will be identical. In these cases, the average hydrologic availability factor can be derived from the generation-duration curve, and it will be identical to the plant factor for the peakload months. For projects having hourly load following or peaking capability, the average hydrologic availability factor must be derived from a peaking capacity-duration curve. This curve would be based on daily peak discharges rather than daily average flows, and would it reflect the number of hours per day that the peak discharge must be sustained, the amount of daily/weekly storage available, and any nonpower operating criteria that would limit the plant's ability to peak.

(8) Figure 0-2 shows generation and peaking capacity-duration curves for a 16.0 megawatt hydropower project having a hydraulic capacity of 4,000 cfs; a constant head of 56.0 feet; an overall efficiency of 84 percent; a peaking requirement of 6 hours per day, 5 days per week; sufficient weekly storage to accommodate this operation; and a maximum allowable daily discharge fluctuation of 2,000 cfs. Figure 0-3 shows the computations supporting derivation of the curve. For this type of operation the average hydrologic availability factor would be about 97 percent. If the project were precluded from peaking operation because of inadequate daily/weekly storage or severe nonpower operating constraints, the average hydrologic availability factor would be about 75 percent.

(9) For most large, diverse power systems, the product of the average hydrologic availability factor and installed capacity could be used in place of the traditional dependable capacity parameter in power benefit computations, and in a sense this product can be considered to be a measure of dependable capacity. For small power systems, isolated power systems, and systems having a high percentage of hydroelectric generation (particularly where all of the hydroelectric generation is influenced by the same hydrologic regime), it may not be appropriate to use the average hydrologic availability concept described above. In these cases, it would be necessary to use dependable capacity values derived using traditional procedures.

d. Mechanical Availability.

(1) The second major factor in the capacity benefit equation is the ratio of mechanical availability, HMA/TMA. This ratio is intended to reflect the relative mechanical reliability of hydroelectric com-

Plant Size (MW)	Area Under Curve 1/	Average Capacity (MW) 2/	Hydrologic Availability (Percent) 3/
8.0	9.74	7.8	97.4
12.0	13.14	10.5	87.5
16.0	14.94	11.9	74.7
20.0	15.80	12.6	63.2

1/ Square inches (on original graph). The graph in this report has been reduced.
2/ 5 square inches equals 4.0 MW.
3/ (Average capacity)/(plant size)

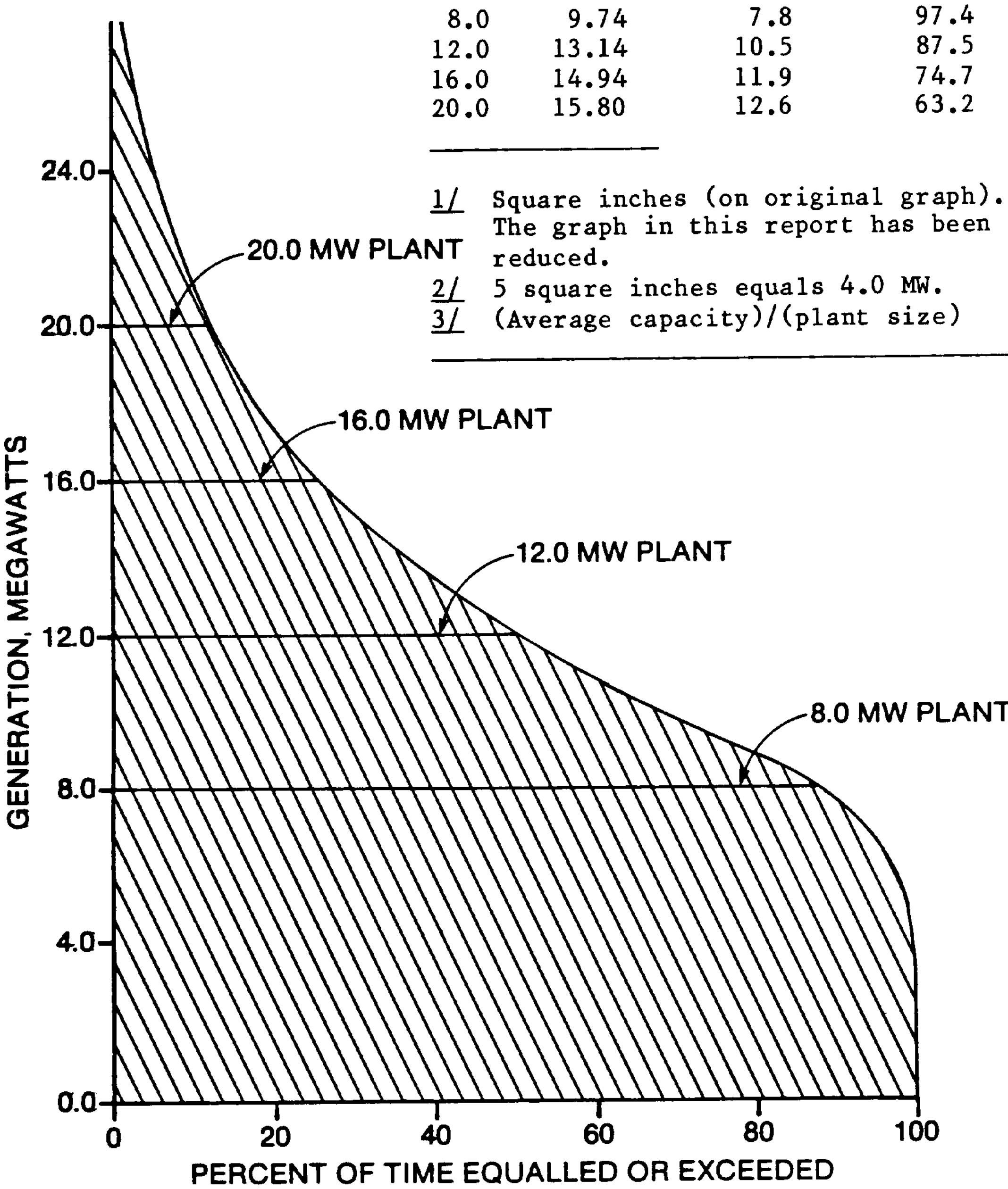


Figure 0-1. Generation-duration curve for hydropower site.

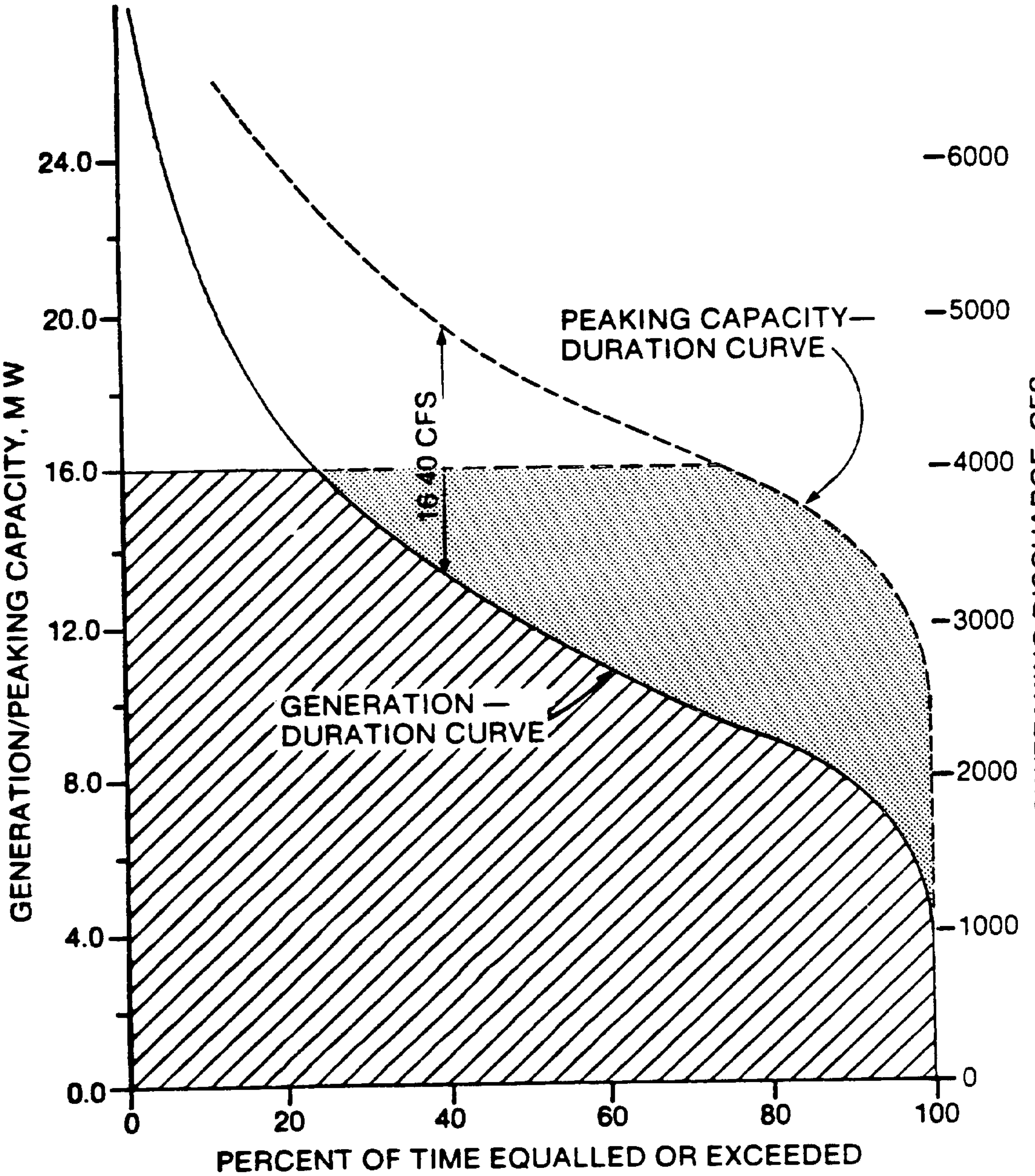
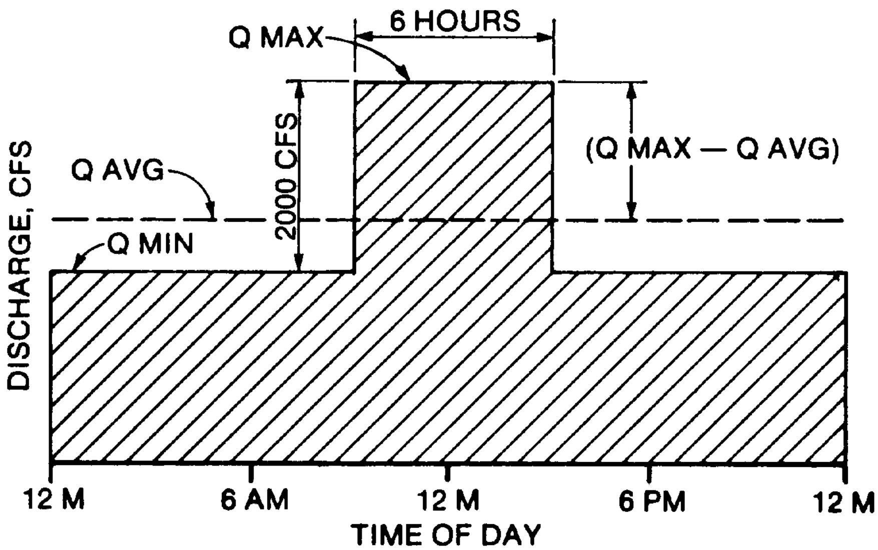


Figure 0-2. Generation-duration and peaking capacity-duration curves for a 16.0 megawatt hydropower plant



A typical weekday operation is shown above. It is assumed that this plant would operate five days a week and that the project would discharge at Q_{min} all day Saturday and Sunday.

Q_{avg} = average weekly flow
Q_{max} = peak discharge
Q_{min} = minimum discharge

The allowable ($Q_{max} - Q_{min}$) is 2,000 cubic feet per second (cfs).

The following two equations describe the weekly peaking operation.

(1) $Q_{max} - Q_{min} = 2{,}000$ cfs

(2) $(Q_{avg})\text{x}(24 \text{ hours})\text{x}(7 \text{ days}) = (Q_{max})\text{x}(6 \text{ hours})\text{x}(5 \text{ days}) + (Q_{min})\text{x}(8 \text{ hours})\text{x}(5 \text{ days}) + (Q_{min})\text{x}(24 \text{ hours})\text{x}(2 \text{ days})$

Solving the two equations simultaneously yields a project dependable peak discharge of ($Q_{max} - Q_{avg}$), or 1,640 cfs above the average weekly flow. Thus, for each flow level on the flow duration curve, the corresponding point on the peaking discharge-duration curve is 1,640 cfs greater. This is a simplified example for illustration purposes. Detailed hydraulic studies may be required to define Qmax.

Figure O-3. Derivation of peaking capacity-duration curve pared to thermal generation. (Note: the bulk of the capacity value adjustments formerly used reflected relative mechanical reliability). Normally, mechanical reliability reflects only forced outages, but where maintenance must be scheduled in the peakload months, scheduled maintenance outages should be accounted for also.

(2) Table O-1 is a summary of power plant availabilities, taken from NERC (National Electric Reliability Council) data, which is considered to be representative of recent experience (27). Note that two types of availabilities are presented.

(3) The equivalent availability factor is a standard NERC performance parameter, which reflects the net annual availability once forced outages, scheduled outages, and maintenance outages are deducted. The forced outage availability factor was developed by the Water and Energy Task Force to reflect the reliability of the plants during the peak demand periods. It was assumed that, in most systems, maintenance outages (interim as well as annual maintenance) would not be scheduled during the peak demand hours of the high demand months. Hence, for most types of plants, the forced outage availability factor was defined as 100 percent minus the NERC equivalent forced outage rate (in percent), where the NERC equivalent forced outage rate is defined as the ratio of the forced outage hours to the sum of the service (on-line) hours and the forced outage hours.

(4) However, this definition is not satisfactory for peaking and reserve units, such as combustion turbines, diesel units, and pumped-storage plants. The forced outage rates for these units (which are typically very high) tend to be distorted because of the relatively small number of hours the units operate per year. The forced outage availability values presented for these three types of plants in Table O-1 are instead estimated values, taking into consideration successful start ratios and the average number of forced outages per year, as well as forced outage rates. NERC does not maintain availability data for combined cycle plants, so both values were estimated for this type of plant.

(5) It is recommended that the forced outage availability values be used in most cases as the measure of mechanical availability. However, for systems where maintenance outages cannot be concentrated in the off-peak months (due to extended periods of peak demand and/or a large number of units requiring maintenance), it may be desirable to use values that are between the forced outage availability and equivalent availability factors.

(6) NERC data does not differentiate between conventional hydro units operated for peaking and base load units. However, units that are required to follow load or stop and start frequently typically

TABLE O-1
Summary of power plant availability

	Unit Size (megawatts)	Forced Outage Availability 2/ (percent)	Equivalent Availability 3/ (percent)
Coal fired	100-199	90.0	81.2
Coal fired	200-299	88.1	79.3
Coal fired	300-399	84.2	73.4
Coal fired	400-599	84.9	73.0
Coal fired	600-799	81.5	70.7
Coal fired	800-1200	80.0	69.3
Nuclear	All	82.3	65.2
Comb. turbine	All	85.0 (est.)	86.6 3/
Combined cycle	All	86.0 (est.)	85.0 (est.)
Diesel	All	90.0 (est.)	93.8
Hydro (base load)	All	98.0 4/	95.0 4/
Hydro (peaking)	All	95.0 4/	92.0 4/
Pumped storage	All	93.0 (est.)	85.5

1/ Equivalent availability factor = $\dfrac{(PH - (FOH + EUDH + POH + MOH))}{PH}$

where: PH = total hours in period (year)
FOH = forced outage hours
EUDH = equivalent unplanned derated hours (partial forced outages)
POH = outage hours (annual maintenance)
MOH = maintenance outage hours (interim maintenance)

2/ Forced outage availability = (100%) - (equivalent forced outage rate, %)

1/ Weighted average of industrial combustion turbines and jet engine type units.

4/ See Paragraph O-2d(6).

have higher outage rates than base load units. Hence, estimated values are presented for both base load and peaking hydro units. It is recommended that base load values be used for pure run-of-river projects and other base load plants, and that the peaking values be used for plants that are expected to see heavy peaking service. Intermediate values could be used for other plants, depending on the degree of peaking operation anticipated.

(7) Where coal-fired units are used as the alternative, availibility should be based upon the size of the coal-fired units that probably would be built in the area (600 MW, for example) rather than on a hypothetical coal-fired plant of the same size as the hydropower plant. Thus, the mechanical availability ratio of a base load hydropower plant compared to a 600-MW coal-fired plant would be;

$$\frac{HMA}{TMA} = \frac{98.0}{81.5} = 1.20 \qquad \text{(Eq. 0-2)}$$

e. Flexibility.

(1) Hydropower traditionally has been acknowledged as having an advantage over most thermal units because of its ability to start quickly, follow load, motor to improve system power factor, and in other ways contribute flexibility to power system operation. Although no attempt has ever been made to precisely quantify the benefits of flexibility, some credit for flexibility has been included in the capacity value adjustments historically used. Now that mechanical availability is treated explicitly, it becomes necessary to make a specific assumption regarding the value of flexibility. It is proposed that a 5 percent flexibility credit be given to hydropower compared to a nuclear or coal-fired unit. Combustion turbine units have many of the same flexibility characteristics as hydropower, and thus a flexibility credit may not be warranted. In some cases, however, a hydro peaking project may have considerable operating flexibility and a small flexibility credit (compared to combustion turbines) may be appnopriate. The basis for such credit should be documented.

(2) Caution should be used in applying this credit. If operating restrictions (such as a limitation on the rate of change in discharge) limit the hydropower plant's inherent ability to respond quickly to demand fluctuations, no flexibility credit is warranted. Similarly, if no daily or seasonal storage is available at site or immediately upstream to permit the plant to shape discharges to follow demand, it is questionable whether this credit should be claimed.

(3) At the time this manual was completed, the Electric Power Research Institute (EPRI) was attempting to develop a methodology for quantifying flexibility, or "dynamic" benefits of energy storage projects of all types, including conventional and pumped-storage

hydro. Reference (68) is the proceedings of a conference sponsored by EPRI to deal with this subject.

f. Implementation.

(1) Traditionally, FERC has handled the mechanics of the capacity value adjustment in computing the capacity value of a hydropower plant. This has been appropriate because of FERC's greater expertise in the areas of powerplant reliability and flexibility. However, with hydrologic availability as a component, it will be necessary for the construction agency to be involved in the capacity value adjustment computation process. The following procedure is proposed:

- FERC will continue to determine the annual investment cost (CV) of the thermal alternative, and will compute that portion of the capacity value adjustment dealing with reliability and flexibility. An adjusted annual investment cost, or adjusted capacity value (adjusted CV), will then be determined.

$$\text{Adjusted CV} = \text{CV} \times \frac{\text{HMA}}{\text{TMA}} \times (1 + \text{F}) \qquad \text{(Eq. 0-3)}$$

- the construction agency would have the responsibility for deriving the average (or hydrologic) availability factor (HA), based on the peakload period for the area. The average availability factor applied to the installed capacity (IC) would result in an "adjusted capacity" which could be used as a measure of dependable capacity:

$$\text{Dependable capacity} = (\text{IC})(\text{HA}) \qquad \text{(Eq. 0-4)}$$

- the construction agency would apply the adjusted capacity value to the dependable capacity to compute project annual capacity benefits:

$$\text{Capacity benefit} = (\text{Adjusted CV})(\text{Dependable cap.}) \qquad \text{(Eq. 0-5)}$$

(2) For systems where hydropower is the predominant power source, the use of average hydrologic availability to define dependable capacity will generally not be appropriate. In those cases, dependable capacity as traditionally defined would be used. In such cases, the annual capacity benefits equal the adjusted capacity value times the project dependable capacity.

(3) The term "equivalent thermal capacity" (equiv. thermal cap.) is sometimes used to describe the amount of thermal capacity which

would be displaced by the hydro plant. This would be computed as follows:

$$\text{Equiv. thermal cap.} = (IC)(HA) \times \frac{HMA}{TMA} \times (1 + F) \qquad \text{(Eq. 0-6)}$$

Equivalent thermal capacity would be used in computing capacity benefits only if the capacity values provided by FERC did not include the adjustment for mechanical availability and flexibility.

(4) The following example illustrates how capacity benefits would be computed using the procedure described above.

Given: Hydropower project installed capacity (IC)= 16.0 MW
Hydropower project mechanical availability (HMA) = 98.0 percent
Thermal alternative = 600 MW baseload coal-fired plant
Thermal plant mechanical availability (TMA) = 79.0 percent
Unadjusted capacity value (CV) = \$100/kW-yr
Assume hydropower plant has daily/weekly storage and no operating restrictions which would limit flexibility. Therefore, flexibility credit (F) = 0.05

$$\text{Adjusted capacity value} = (\$100/\text{kW-yr}) \frac{(98.0)}{(79.0)} (1 + 0.05) = \$130/\text{kW-yr}$$

From the peaking capacity duration curve for the peakload months (Fig. 0-2), the average hydrologic availability of the 16.0 MW hydropower plant is estimated to be 97 percent.

Dependable capacity = (0.97) x (16.0 MW) = 15.5 MW
Capacity benefit = (\$130/kW-yr) x (15.5 MW) = \$2,020,000

(5) If the hydropower plant were a pure run-of-river plant with no daily/weekly storage and/or operating restrictions which limit operating flexibility, the flexibility credit would be zero.

$$\text{Adjusted capacity value} = (\$100/\text{kW-yr}) \frac{(98.0)}{(79.0)} (1.0) = \$124/\text{kW-yr}$$

The average hydrologic availability factor would be based on the generation-duration curve (Figure 0-1), rather than the peaking capacity-duration curve, and would be 75 percent.

Dependable capacity = (0.75)(16.0 MW) = 12.0 MW
Capacity benefit = ($124/kW-yr)(12.0 MW) = $1,490,000

O-3. Energy Value Adjustment.

a. Conceptual Basis of Energy Value Adjustment.

(1) Section 2.5.8(a)(2) of *Principles and Guidelines* requires that "the effect on system production expenses shall be taken into account when computing the value of hydroelectric power." If a hydroelectric plant is selected instead of a thermal powerplant to meet the requirements of load growth, the hydropower plant may result in the costs of operating the other powerplants in the system being either greater or lesser than if the thermal alternative were added to the system. For example, the installation of a new baseload thermal plant instead of a peaking hydropower plant would reduce the hours of operation of existing, more costly thermal generating facilities, and thus effect a decrease in system production costs. Conversely, the addition of thermal-peaking capacity, such as combustion turbines, rather than peaking or low-plant factor hydroelectric capacity could result in an increase in system production costs.

(2) In such cases, it is appropriate to introduce an adjustment in the economic analysis of the energy components of the hydroelectric plant. When the alternative thermal generation would lower the system's average cost of thermal energy, this adjustment should be negative. The adjustment should be positive if the alternative thermal generation would increase the system's average cost. Where the adjustment changes with time, present worth procedures should be used in determining the average energy value adjustment over the life of a project. For convenience of computations, the net adjustment should be applied to the market cost of the alternative thermal-electric energy. The adjusted cost is the market value of hydroelectric energy.

b. Methods for Calculating Adjustment. The effect of system production expenses can be accounted for in two ways. Energy value reflecting system costs can be computed directly through the use of system production cost models. If such a model is not available, an adjustment factor can be estimated through use of an equation. This "energy value adjustment" can be applied to the cost of energy produced by the alternative thermal plant to obtain an adjusted energy value which reflects the impact of system costs.

c. System Models. The use of system models such as POWRSYM (see Section 6-9f) would involve making detailed comparative analyses of annual system production expenses with, alternatively, the hydroelectric project and equivalent amounts of each type of alternative thermal capacity deemed appropriate. Applicable variable costs of fuel and operation and maintenance would be assigned to all generating plants in the system, and the total annual system production expenses would be determined for each type of capacity being considered. The difference between the total system costs with the hydroelectric project and the total system costs with the most likely thermal-electric alternative, divided by the avevage annual energy output of the hydroelectric project, gives an adjusted energy value for the particular year being considered. Successive evaluation of ensuing years, and the use of present worth procedures, can be used to determine the equivalent levelized energy value applicable over the economic life of the hydroelectric project.

d. Equations. Instead of these detailed studies, the unit energy value (or capacity value) adjustments may be approximated in any year by the following equations:

$$E_n = \frac{PF_t - PF_h}{PF_h} \times \Delta C \qquad \text{(Eq. 0-7)}$$

or:

$$CP_n = (PF_t - PF_h)(\Delta C) \times \frac{(8760 \text{ hours/year})}{(1000 \text{ mills/dollar})} \qquad \text{(Eq. 0-8)}$$

where: E_n = Energy value adjustment for the year, in mills per kilowatt-hour of hydroelectric generation
CP_n = Capacity value adjustment for the year, in dollars per kilowatt-year of dependable hydroelectric capacity
PF_t = Plant factor of the alternative thermal-electric plant
PF_t = Plant factor of the hydroelectric plant
ΔC = $EC_t - EC_d$
EC_t = Energy costs (mills per kilowatt-hour) of the thermal alternative
EC_d = Average energy cost of those plants which the thermal-electric alternative might reasonably be expected to displace.

By making assumptions as to the plant factor of the alternative thermal plant, and the difference in energy costs between the alternative plant and those plants it might replace, Equations 0-7 and 0-8 may be used to derive periodic estimates of energy value and capacity value adjustments. By the use of present worth procedures, an average equivalent adjustment applicable over the assumed life of the hydroelectric project may be computed.

e. Impact of Adjustment. It should be noted that the energy value adjustment can be a significant factor in the overall power value of a hydroelectric project where there is a considerable difference in the plant factors of the thermal-electric alternatives and the proposed hydroelectric project, or where there is a wide range between the thermal-electric alternative energy costs and the average energy costs of the plants it would replace. Due to the potential impact of such adjustments on final hydroelectric power values, every hydroelectric power evaluation must consider these adjustments.

f. Selection of Method. The use of a system model is the preferred method because it is very difficult to estimate EC_d without using a model. FERC has several models which can be used for this purpose, and they are in the process of implementing these models for their power value work on a region-by-region basis as manpower permits. In regions where models are not yet operable, the approximate equation method is being used on an interim basis. The approximate, or "short-cut" equation method will probably continue to be the most practical method for evaluating small isolated systems, as in Alaska. The hydro-dominated Pacific Northwest power system cannot be evaluated using a standard production cost model such as POWRSYM, but the regionally developed system analysis model (SAM) has been adapted for analysis of energy benefits for this system. The Bureau of Reclamation is investigating the use of generating expansion models, which also account for system energy cost impacts for use in deriving power benefits.

APPENDIX P

FUEL COSTS AND FUEL COST ESCALATION

P-1. General.

a. The assumptions governing the determination of fuel costs are critical in the evaluation of hydropower, because they affect a significant portion of the benefits (see Section 9-5f). Two points are important: (a) the establishment of the fuel cost base that is representative of current market conditions, and (b) recognition of past and future price shifts in order to identify real fuel escalation rates and to develop specific procedures to account for those rates. Section 2.5.8 of the Principles and Guidelines (P&G) provides some guidance in these areas, and the following paragraphs propose procedures for accounting for both aspects within the framework of this guidance.

b. This appendix was drawn essentially intact from Chapter 4 of the Water and Energy Task Force report, Evaluating Hydropower Benefits, dated December 1981 (78). Several wording changes have been made to the original text of the Task Force report in order to reference the 1983 Principles and Guidelines (77) in lieu of the 1979 NED Manual (79), and to make the material conform to current implementation practices. Some editorial changes were also made to make the text conform to the standard Engineering Manual format.

P-2. Base Fuel Costs.

a. Fossil-Fueled Plants.

(1) Sources of Data. The type and cost of fossil fuel used to estimate steam-electric power costs should be determined on the basis of the fuel available and most likely to be used in the particular area under consideration. In most instances, this can be done by examining current fuel purchases. Detailed monthly data describing quantity, price, and thermal content of each utility purchase are maintained by the Department of Energy's Energy Information Administration (EIA). This data is available and can be summarized from computer data files maintained by EIA. This information is supplied for all fossil-fuel steam plants and combustion turbine plants with a combined capacity of 25 MW or greater. The information in DOE data files includes average purchase costs summarized by plant, state, or region. These averages include the effects of purchases made under the terms of both old and new contracts.

(2) Real Fuel Prices. Section 2.5.8(a)(5) of the Principles and Guidelines stipulates that "... fuel costs used in the analysis should reflect economic prices (market clearing) rather than regulated prices." (emphasis added). Care must be exercised, therefore, to insure that costs incurred under old contracts, which may not reflect real economic prices in today's market, are not included. In periods of rising relative fuel prices, the use of upper quartile prices instead of average prices may more accurately reflect economic (market-clearing) prices.

(3) Computation of Fuel Costs. The Federal Energy Regulatory Commission (FERC), through its Regional Offices, can provide the latest available fuel price information based on EIA data. As an example, Tables P-1 and P-2 summarize this data by DOE regions and states for October 1980 fuel costs. In some instances, it may be appropriate to base fuel costs on a larger or smaller geographic area than a DOE region. In general, fuel costs should be representative of the "system" within which the hydropower project is to be operated. Depending on the size of this system, fuel costs typical of a single state or a group of states may be appropriate. FERC can provide cost data for any combination of states and/or DOE regions requested.

(4) Regional vs. National Average Values. Coal prices vary considerably in various parts of the country because of the large differences in mining costs among the different coal-producing areas and the fact that substantial transportation cost components may be reflected in coal prices for nonproducing areas. Accordingly, it is appropriate that specific coal prices be derived for each area or system. However, because the average price of oil for a given powerplant is affected more by world market prices than by variations in source, because oil is readily transportable, and because the cost of transportation is only a small part of the at-site cost of oil, the national average upper quartile price is considered to be a more accurate measure of the "market clearing" price of oil for a given system than the individual regional prices. Table P-1 shows that there is relatively little variation in the upper quartile prices of light oil (or distillate oil). The regional variations in prices of heavy oil (residual oil) are greater, probably because even the fourth quartile prices reflect a fair proportion of long-term contract prices. In time, as the effect of oil price deregulation takes hold, it is expected that the regional variation will be less pronounced.

(5) Fuel Use Limitations. In some cases, certain fuels are strictly limited in availability and should not be considered as real alternatives. The Powerplant and Fuel Use Act of 1978 provides that ". . . natural gas or petroleum shall not be used as a primary energy source in any new electric powerplant . . ." except to the extent that exemptions may be granted. The Act provides for the granting of per-

TABLE P-1.
Regional Electric System Fuel Costs, October 1980 Prices 1/

DOE 2/ Region	Coal Avg.	Coal Upper 1/4	Lignite Avg.	Lignite Upper 1/4	Light Oil Avg.	Light Oil Upper 1/4	Heavy Oil Avg.	Heavy Oil Upper 1/4
1	162.54	164.74	0.0	0.0	625.58	655.52	415.81	461.24
2	161.71	199.08	0.0	0.0	607.18	633.67	448.13	505.40
3	144.10	193.94	0.0	0.0	604.49	631.45	411.78	448.57
4	156.16	198.94	0.0	0.0	599.90	642.67	393.85	431.77
5	145.25	202.07	95.17	103.77	604.76	634.11	595.88	687.70
6	139.24	208.35	58.18	65.00	420.82	596.62	403.34	493.95
7	127.68	179.24	0.0	0.0	596.25	622.53	323.66	330.15
8	77.09	112.31	66.89	86.53	638.03	677.16	0.0	0.0
9	105.73	174.76	0.0	0.0	610.64	640.45	520.19	603.22
10	102.34	112.94	0.0	0.0	622.36	624.95	0.0	0.0
U.S. Average					589.30	642.90 (est.)	535.90	595.30 (est.)

1/ Prices in cents per million BTU. A value of 0.0 is indicated when no purchases were reported. Upper quartile prices are based on an average of upper quartile of total BTU's purchased.

2/ States included in Department of Energy regions;

1 - Maine, New Hampshire, Vermont, Massachusetts, Connecticut and Rhode Island
2 - New York and New Jersey
3 - Pennsylvania, Maryland, Virginia, West Virginia, District of Columbia and Delaware
4 - Kentucky, Tennessee, North Carolina, South Carolina, Mississippi, Alabama, Georgia and Florida
5 - Minnesota, Wisconsin, Michigan, Illinois, Indiana and Ohio
6 - Texas, New Mexico, Oklahoma, Arkansas and Louisiana
7 - Kansas, Missouri, Iowa and Nebraska
8 - Montana, North Dakota, South Dakota, Wyoming, Utah and Colorado
9 - California, Arizona, Nevada and Hawaii 3/
10 - Washington, Oregon, Idaho and Alaska 3/

3/ Data from Alaska and Hawaii not included in average fuel costs.

TABLE P-2. Electric System Fuel

	Coal 3/		Light oil		Heavy oil	
State	Average	Upper 1/4 1/	Average	Upper 1/4 1/	Average	Upper 1/4 1/
Alabama	164.79	199.21	655.74	773.34	0.0	0.0
Alaska	140.16	173.33	652.17	977.94	471.43	471.43
Arizona	103.20	176.95	636.13	640.10	544.31	654.90
Arkansas	149.33	156.20	487.01	490.93	349.15	352.08
California	0.0	0.0	597.01	630.14	566.10	600.61
Colorado	86.38	114.64	560.00	560.00	0.0	0.0
Connecticut	0.0	0.0	615.32	618.10	459.14	463.82
Delaware	178.41	239.20	591.44	591.60	410.31	415.25
D. C.	0.0	0.0	0.0	0.0	420.30	420.30
Florida	183.66	213.26	592.31	611.44	395.44	432.77
Georgia	152.50	188.71	623.18	632.38	363.50	363.50
Hawaii	0.0	0.0	629.97	632.30	360.38	406.76
Idaho	0.0	0.0	0.0	0.0	0.0	0.0
Illinois	158.00	226.23	612.22	644.00	668.54	687.70
Indiana	127.78	194.68	607.62	621.92	0.0	0.0
Iowa	146.17	194.56	590.03	613.09	0.0	0.0
Kansas	112.46	169.01	503.00	503.00	0.0	0.0
Kentucky	129.85	189.91	648.17	786.97	0.0	0.0
Louisiana	197.70	197.70	575.55	586.22	424.08	440.90
Maine	0.0	0.0	649.10	649.10	388.20	388.20
Maryland	157.43	177.32	601.79	619.34	397.45	420.99
Massachusetts	0.0	0.0	621.01	634.40	398.58	422.34
Michigan	156.33	203.15	631.27	634.77	422.58	470.62
Minnesota	108.45	133.68	600.00	600.00	440.50	442.60
Mississippi	191.54	251.67	592.45	605.10	371.37	371.80
Missouri	124.45	172.32	593.08	600.90	321.50	321.50
Montana	43.07	62.32	537.10	537.10	0.0	0.0
Nebraska	134.72	195.16	648.87	657.53	348.40	348.40

1/ Based on average of upper quartile of total BTU's purchased.
2/ A value of 0.0 indicates no purchases reported.

Costs by State, October 1980

	Coal		Light oil		Heavy oil	
State	Average	Upper 1/4 1/	Average	Upper 1/4 1/	Average	Upper 1/4 1/
Nevada	113.53	163.59	0.0	0.0	380.21	438.36
New Hampshire	162.54	164.74	632.87	672.56	401.68	410.50
New Jersey	185.25	216.79	607.07	634.02	456.19	497.54
New Mexico	56.77	99.90	507.75	641.40	423.40	423.90
New York	149.18	174.43	609.40	609.40	447.12	506.37
North Carolina	161.45	192.93	606.38	609.29	0.0	0.0
North Dakota	0.0	0.0	605.43	617.10	0.0	0.0
Ohio	151.20	193.88	591.77	625.83	366.67	505.87
Oklahoma	132.27	149.92	0.0	0.0	0.0	0.0
Oregon	149.00	149.00	621.50	621.50	0.0	0.0
Pennsylvania	135.77	193.51	603.94	636.27	426.93	471.34
Rhode Island	0.0	0.0	0.0	0.0	389.30	389.30
South Carolina	157.73	171.51	611.80	624.56	387.40	388.00
South Dakota	89.70	90.40	651.23	659.24	0.0	0.0
Tennessee	165.31	187.77	597.84	676.48	0.0	0.0
Texas	179.62	217.28	355.96	566.44	462.55	550.70
Utah	108.68	136.07	627.60	652.90	0.0	0.0
Vermont	0.0	0.0	0.0	0.0	0.0	0.0
Virginia	173.32	202.57	599.25	606.84	406.79	431.70
Washington	98.80	98.80	664.10	664.10	0.0	0.0
West Virginia	146.83	189.02	626.13	639.32	0.0	0.0
Wisconsin	143.05	161.51	592.37	598.01	492.70	492.70
Wyoming	62.00	73.63	678.10	733.17	0.0	0.0

3/ Lignite costs reported, by state:

State	Average	Upper 1/4
Minnesota	95.17	103.77
Montana	97.10	97.10
N. Dakota	63.08	83.00
S. Dakota	87.50	87.50
Texas	58.18	65.00

manent exemptions for the use of natural gas or petroleum where it is demonstrated that the plant is to be operated solely as a "peakload powerplant." A peakload powerplant is defined as a plant operating at an average annual plant factor of 17 percent or less. Also, but with somewhat more restrictive conditions, an exemption may be granted for the use of petroleum in an intermediate level powerplant. An intermediate load powerplant is defined as a plant that operates at an average annual plant factor of between 17 and 40 percent per year. Neither oil nor gas should be considered where the alternative would be used as baseload generation.

(6) Special Cases. Some of the procedures proposed above may not be applicable to isolated regions, such as Alaska, Hawaii, and Puerto Rico. The relatively small loads, the unavailibility of coal, and other factors may dictate the use of oil or gas for baseload as well as for peaking generation. Even where coal is a potential fuel (such as some parts of Alaska), the unavailability of DOE/EIA data makes cost estimating difficult. In these areas, it may be necesaary for FERC and the planning agencies to conduct special studies to identify the most appropriate future fuel sources and fuel costs.

b. Nuclear-Fueled Plants. Nuclear fuel costs, although dependent to a degree on use of a depletable resource, are more related to costs associated with processing, handling, and disposal. As a manufactured fuel with a relatively high ratio of value to transport cost, it has a national rather than a regional value. Periodic estimates of current nuclear fuel costs are available from two principal sources: DOE/EIA and Data Resources, Inc. (DRI). The basic differences between the two information sources are discussed in Section P-3c. It is recommended that DOE/EIA nuclear fuel data be used for developing energy values.

P-3. Real Fuel Cost Escalation.

a. Current Procedures. Current procedures require that NED cost-benefit comparisons are to be expressed in terms of constant dollars. No accounting is made for expectations of future general price inflation since, in the long run, it is not expected to affect the relative values of resources. However, Principles and Guidelines (Section 2.5.8(a)(5)) specifically requires the evaluation of real escalation in fuel prices when the most likely alternative to a hydropower project is a thermal powerplant.

b. Forecast Uncertainty. It must be recognized that fuel price forecasts are not highly reliable. Many variables which are themselves hard to predict impinge on fuel prices. The resultant fuel price forecasts inherently contain a great deal of uncertainty.

Unfortunately, it is not possible to "not forecast" fuel prices, because making the assumption that there is no change in real fuel prices over time is equivalent to using a forecast of zero fuel price escalation. Consequently, the choice which analysts must make is not between forecasting and not forecasting, but instead between one forecast and another.

c. Forecast Sources.

(1) Fuel price forecasts developed by DOE and DRI were studied (67), (4). Fuel price escalation rates based on the 1980 DOE forecast are shown in Table P-3 and those based on the 1980 DRI forecast are shown in Table P-4. Fuel price forecasts are also available from EPRI (Electric Power Research Institute), and the SRI (Stanford Research Institute). However, only the DOE and DRI forecasts are long-term, regionally disaggregated, and periodically updated.

(2) The DOE forecast has been used widely as the source of fuel cost escalation rates in the past. It also has some "official" stature and is available at no cost. Differences between DOE and DRI forecasts are as follows:

- DRI forecasts prices of fuels delivered to electric utilities. DOE also forecasts future utility fuel prices, but at present DOE has no current utility fuel prices which are comparable to the forecast prices. For this reason, 1980-85 price escalation rates cannot be determined from the DOE forecast. To date, DOE forecasts of industrial fuel price escalation rates have been used as a proxy for utility fuel price escalation rates.

- the continued availability of a regionalized DOE forecast is somewhat uncertain.

- region-to-region variation in escalation rates is not as severe in the DRI forecast as in the DOE forecast.

- some aspects of the DOE forecast, including real declines in the prices of fuels in some regions, greater escalation rates for coal prices than for petroleum products over the 1980-85 period, and a substantial real rise in the price of nuclear fuel over the next 5 years, are absent in the DRI forecast.

- an updated DRI forecast is published quarterly. The DOE forecast is updated less frequently and does not become official for several months after the forecast is developed. At the time this study was done, the most recent official

TABLE P-3. Compound Annual Real Energy Price Escalation

Fuel Type	Region 1	2	3	4	5
			1980-1985		
Residual 2/	8.3	7.4	7.4	7.5	7.4
Distillate 2/	3.7	3.1	3.1	3.1	3.1
Coal 2/	10.1	8.7	8.1	13.6	11.0
Nat. gas 2/, 3/	0.1	-0.3	1.0	1.9	1.8
Nuclear 4/	2.9	2.9	2.9	2.9	2.9
			1985-1990		
Residual	2.1	2.0	2.0	2.1	2.2
Distillate	2.1	2.1	2.1	2.1	2.2
Coal	-2.7	2.0	2.5	3.0	2.0
Natural gas	0.1	-0.3	1.0	1.9	1.8
Nuclear	3.4	3.4	3.4	3.4	3.4
			1990-2010		
Residual 5/	3.6	3.5	3.4	3.7	3.4
Distillate	3.8	3.8	3.8	3.8	4.0
Coal	0.3	0.4	0.5	0.0	0.1
Natural gas	2.7	2.7	3.1	4.0	3.1
Nuclear	1.1	1.1	1.1	1.1	1.1

1/ See footnote 2, Table P-4, for a description of DOE regions.

2/ Escalation rates for residual, distillate oil, coal and natural gas were computed using 1980 base prices from October 7, 1980 Federal Register, Table C-1, and forecast prices from November 1980 DOE/EIA Service Report SR/1A 180-16, medium price path, average prices, industrial fuels. Service Report prices converted to 1980 dollars using GNP price deflator. Update factor was 1.094.

3/ Because of uncertainty about schedules and timing of effects of natural gas price deregulation, average escalation rates for natural gas were computed over 1980-1990 period and used for both the 1980-1985 and 1985-1990 periods.

Rates by Region, DOE Forecast (1980-2010) 1/

Region 6	7	8	9	10	Average	Fuel Types
		1980-1985				
7.5	7.5	7.4	7.4	7.4	7.5	Residual
3.1	3.1	3.1	3.1	3.1	3.2	Distillate
14.9	10.2	10.1	10.7	5.7	11.7	Coal
5.0	3.8	4.7	-0.4	2.4	2.9	Nat. gas
2.9	2.9	2.9	2.9	2.9	2.9	Nuclear
		1985-1990				
2.2	2.1	2.1	2.3	2.3	2.1	Residual
2.1	2.2	2.1	2.2	2.2	2.1	Distillate
1.5	2.0	0.0	1.3	10.4	2.5	Coal
5.0	3.8	4.7	-0.4	2.4	2.9	Nat. gas
3.4	3.4	3.4	3.4	3.4	3.4	Nuclear
		1990-2010				
3.6	3.4	3.7	3.6	3.7	3.4	Residual
3.9	4.0	4.0	4.0	4.0	3.9	Distillate
1.4	0.4	0.6	0.3	-0.5	0.7	Coal
3.3	3.3	2.2	0.8	-1.1	3.0	Nat. gas
1.1	1.1	1.1	1.1	1.1	1.1	Nuclear

4/ Nuclear fuel escalation rates were computed from Service Report price projections appearing in utility fuel price tables and 1980 base price supplied by DOE staff.

5/ Service Report indicates decline in real price of residual oil in Regions 5 and 7 after 1980. DOE staff indicated that this is an anomaly created by assumptions about synfuels as a substitute for residual oil, and suggested substituting the average escalation rate for other regions.

TABLE P-4
Compound annual real energy price escalation rates by region (1980-2010), DRI forecast 1/ , 2/

Fuel Type	NENG	MATL	SATL	ENC	WNC	ESC1	ESC2	WSC1	WSC2	MTN1	MTN2	MTN3	PAC	US Avg.
1980-1985														
Residual 3/	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	2.1
Distillate 3/	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	2.3
Coal 4/	3.5	5.2	6.0	4.3	3.5	5.3	5.9	5.2	5.2	5.1	5.3	5.5	3.8	5.0
Natural gas 5/	7.6	10.2	12.7	10.5	14.3	11.4	11.5	14.8	12.8	12.5	11.1	8.9	9.9	15.5
Nuclear 6/	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
1985-1990														
Residual	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Distillate	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Coal	3.7	2.3	3.2	1.9	2.7	2.7	2.3	2.2	4.1	4.5	1.8	3.7	3.7	2.1
Natural gas	4.4	5.5	12.4	6.1	7.2	8.7	7.3	9.9	9.7	6.3	8.3	7.0	4.8	8.6
Nuclear	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
1990-1995														
Residual	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Distillate	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Coal	2.6	2.9	2.4	2.0	1.6	2.3	1.7	2.4	1.8	2.5	0.7	2.2	3.2	2.3
Natural gas	5.3	6.4	7.3	6.5	7.7	7.1	8.0	5.6	5.7	5.8	6.3	8.2	4.9	5.8
Nuclear	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
1995-2010 7/														
Residual	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Distillate	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Coal	2.1	1.4	1.5	1.4	1.5	1.6	0.9	1.9	0.9	1.7	2.2	2.5	2.3	1.4
Natural gas	1.8	1.9	1.8	2.0	2.0	1.9	2.0	2.5	2.4	2.0	1.9	1.9	2.0	2.7
Nuclear	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3

1/ Projected nominal fuel prices were deflated using DRI forecast of GNP deflator (DRI variable PGNP)

2/ Regional definitions used in the DRI energy model:

Region	Abbrev.	States
New England	NENG	Massachusetts, Maine, Vermont, Rhode Island, New Hampshire, and Connecticut
Middle Atlantic	MATL	Pennsylvania, New Jersey, and New York
South Atlantic	SATL	Delaware, Maryland, District of Columbia, Virginia, West Virginia, Georgia, Florida, South and North Carolina
East North Central	ENC	Ohio, Wisconsin, Indiana, Michigan, and Illinois
West North Central	WNC	Kansas, Nebraska, North Dakota, South Dakota, Minnesota, Iowa, and Missouri
East South Central #1	ESC1	Kentucky and Tennessee
East South Central #2	ESC2	Alabama and Mississippi
West South Central #1	WSC1	Oklahoma
West South Central #2	WSC2	Texas, Arkansas, and Louisiana
Mountain #1	MTN1	New Mexico
Mountain #2	MTN2	Montana, Colorado, Wyoming, Idaho, Utah
Mountain #3	MTN3	Nevada and Arizona
Pacific	PAC	California, Oregon, Washington, Alaska, and Hawaii

3/ Residual and distillate rates from forecasts of national wholesale price indexes for residual and distillate fuels (DRI variables PRF and PDF). Forecasts of price of oil prices to electric utilities by region were also available (DRI variable POILEUB) but were not used because regional price changes reflected changing proportions of distillate and residual fuels as well as changes in the price of each fuel. Also, because there was not a significant difference between escalation rates of oil delivered to utilities and the wholesale price indexes for distillate and residual oil.

4/ Coal rates from forecast of marginal delivered price of coal, including scrubbing costs (DRI variable PDS @), from the DRI coal model.

5/ Natural gas rates from forecast of price of natural gas to utilities, including effective Federal "user" tax on national gas use by utilities (DRI variable PNGEUB @).

6/ Nuclear fuel rates from forecast of acquisition cost of nuclear fuel (DRI variable PNUCACQ).

7/ DRI forecast extends to the year 2000. Rates are held constant to the year 2010. Zero real escalation assumed after 2010.

DOE escalation rates were those that appeared in the October 27, 1980 Federal Register, which were based on a forecast done in the fall of 1979. More recent DOE forecasts were included in the 1980 Annual Report to Congress, but that forecast included no 1980 base year prices from which to compute escalation rates. (Note that DOE has issued updated forecasts periodically since the Water and Energy Task Force report was published, but they continue to be prepared less frequently than the DRI data and they lag the comparable DRI price data by a number of months).

- the DOE forecast is primarily intended to be at the national level. Regionalization of the forecast has secondary priority, and the regional forecasts admittedly are much less reliable than the national forecasts.

- the DRI forecast offers somewhat more regional detail (13 regions vs. 10 regions in the DOE forecast). The DRI forecast extends to the year 2000, while the DOE forecast extends to 1995.

(3) Further in-depth comparison of model structure, input data, and assumptions used in the DOE and DRI models would strengthen the cost escalation analyses and should be performed. Though the DOE forecasts should continue to be used, it is recognized that further in-depth evaluation of the forecasts' changes in energy markets, changes in forecasts, or circumstances surrounding specific project studies may dictate that the DRI forecast or some other forecast be used. Regular semiannual, or at least annual updating, of DOE forecasts is needed for power value work, and these should be made available within 3 months of the base date. More rigorous analysis of regional coal prices in nonproducing coal areas, such as in the states of Oregon, Washington, and California, is also needed. In addition, DOE estimates would be more useful if fuel costs (including nuclear) were separately presented for the electric utility industry.

d. Escalation Rate Applications.

(1) The Principles and Guidelines also requires that future benefits be discounted and presented as an annualized value. To permit easy and quick application of the effects of the real fuel cost growth rates shown in Tables P-3 and P-4, standard discounting procedures have been employed under the following conditions.

(2) The real escalation rate forecast has been limited to a 30-year period from the present. However, a shorter period should be used if the situation warrants. The values shown in Tables P-3 and P-4 are based on escalation over the period 1980-2000. The 30-year

cutoff is based on the expectation that the supply of petroleum products and natural gas will be heavily depleted by the end of that period and that a transition to alternative energy sources and technologies will be well underway. Given the high degree of uncertainty about the nature and costs of replacement energy sources and the diminished (through discounting) impact of further increases in prices, a zero escalation rate beyond 30 years is considered to be the best assumption. A further rationale for the 30-year cutoff is that 30 years is the end of the expected life cycle of the thermal plants being completed today. Sensitivity tests of alternative cutoff dates are encouraged to assess the influence of the 30-year cutoff on hydropower analysis results.

(3) The project economic life is estimated at 100 years, beginning with the POL (power-on-line) date of the project. The common point to which all costs and benefits are brought is the POL date. Real escalation occurring between the present and POL is not discounted while that subsequent to POL is discounted (this is consistent with how costs are treated, for example, where interest during construction is charged on resources committed before the POL date). A graphic depiction of the discounting procedure appears in Figure P-1.

(4) The result of the above procedure is to express in one multiplier the equivalent of 30 years of growth in real escalation, discounted and annualized over the 100-year economic life of the project beginning with the POL date. Tables P-5 and P-6 summarize these multipliers for five fuel types by region and for the United States as a whole, for both the DOE and DRI projections, at a discount rate of 7-3/8 percent.

(5) The fuel cost escalation rates and multipliers are only applicable to the fuel cost component of alternative costs. Thus, adjustments will need to be made in variable energy costs to eliminate O&M costs which may account for approximately 5 to 15 percent of the total.

e. Use of the Multipliers. The multipliers shown in Tables P-5 and P-6 are to be applied under the following conditions:

- when the base current fuel prices approximate 1980 price levels.

- when the project would displace the same type of fuel over its entire life (when the amount or mix of thermal generation displaced by a hydropower project would change over the project's life, the fuel cost escalation adjustment must be computed on a case-by-case basis, using standard discounting techniques).

TABLE P-5. Summary of Equivalent Annual Fuel Cost Multipliers 1/, by

Fuel Type	Region 2/ 1	2	3	4
		1980 POL Date		
Residual (heavy)	1.94	1.85	1.84	1.89
Distillate (light)	1.62	1.58	1.58	1.58
Coal	1.42	1.58	1.58	1.95
Natural Gas	1.19	1.15	1.31	1.51
Nuclear	1.35	1.35	1.35	1.35
		1985 POL Date		
Residual (heavy)	2.24	2.12	2.10	2.18
Distillate (light)	1.84	1.78	1.78	1.78
Coal	1.46	1.71	1.71	2.15
Natural Gas	1.27	1.22	1.43	1.70
Nuclear	1.46	1.46	1.46	1.46
		1990 POL Date		
Residual (heavy)	2.52	2.37	2.34	2.46
Distillate (light)	2.08	2.02	2.02	2.02
Coal	1.44	1.75	1.77	2.19
Natural Gas	1.38	1.32	1.58	1.93
Nuclear	1.54	1.54	1.54	1.54

1/ Factors which express in one number the 100-year average annual equivalent of real growth (escalation) in fuel prices through the year 2010. Future values have been discounted at 7-3/8 percent interest to the POL dates specified. To use, multiply the factor by the fuel component of unadjusted 1980 energy value.

Fuel Type, Region, and POL Date - DOE Forecast, 1980 Price Level

Region 2/						
5	6	7	8	9	10	U. S. Average
			1980 POL Date			
1.85	1.89	1.85	1.89	1.89	1.90	1.85
1.61	1.59	1.61	1.60	1.61	1.61	1.60
1.71	2.13	1.68	1.59	1.67	1.73	1.85
1.40	1.83	1.66	1.64	1.01	1.13	1.51
1.35	1.35	1.35	1.35	1.35	1.35	1.35
			1985 POL Date			
1.11	2.17	2.11	2.17	2.16	2.19	2.11
1.83	1.80	1.83	1.82	1.83	1.83	1.81
1.85	2.40	1.83	1.70	1.80	1.96	2.05
1.54	2.12	1.89	1.86	1.03	1.15	1.69
1.46	1.46	1.46	1.46	1.46	1.46	1.46
			1990 POL Date			
2.37	2.44	2.37	2.44	2.44	2.47	2.37
2.08	2.04	2.08	2.07	2.08	2.08	2.05
1.88	2.53	1.88	1.73	1.83	2.05	2.13
1.71	2.39	2.13	2.04	1.05	1.13	1.88
1.54	1.54	1.54	1.54	1.54	1.54	1.54

2/ See footnotes to Table P-3 for definition of regions.

TABLE P-6. Summary of Equivalent Annual Fuel Cost Multipliers, 1/

Fuel Type	Region 2/ NENG	MATL	SATL	ENC	WNC	ESC1
			1980 POL Date			
Residual	1.78	1.78	1.78	1.78	1.78	1.78
Distillate	1.77	1.77	1.77	1.77	1.77	1.77
Coal	1.52	1.52	1.61	1.41	1.39	1.54
Natural gas	1.97	2.37	3.45	2.47	3.12	2.86
Nuclear	1.45	1.45	1.45	1.45	1.45	1.45
			1985 POL Date			
Residual	2.03	2.03	2.03	2.03	2.03	2.03
Distillate	2.02	2.02	2.02	2.02	2.02	2.02
Coal	1.69	1.68	1.79	1.53	1.52	1.70
Natural gas	2.28	2.81	4.32	2.95	3.82	3.49
Nuclear	1.64	1.64	1.64	1.64	1.64	1.64
			1990 POL Date			
Residual	2.26	2.26	2.26	2.26	2.26	2.26
Distillate	2.26	2.26	2.26	2.26	2.26	2.26
Coal	1.85	1.81	1.93	1.63	1.62	1.83
Natural gas	2.55	3.20	5.07	3.38	4.43	4.04
Nuclear	1.90	1.90	1.90	1.90	1.90	1.90

1/ Factors which express in one number the 100-year annual equivalent of real growth (escalation) in fuel prices through the year 2010. Future prices have been discounted 7-3/8 percent interest to the POL dates specific. To use, multiply the factor by the fuel component of unadjusted 1980 energy value.

by Fuel Type, Region, and POL Date - DRI Forecast, 1980 Price Level

Region 2/

ESC1	ESC2	WSC1	WSC2	MTN1	MTN2	MTN3	PAC	Avg.
				1980 POL Date				
1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78
1.77	1.77	1.77	1.77	1.77	1.77	1.77	1.77	1.77
1.54	1.49	1.53	1.54	1.62	1.47	1.67	1.57	1.48
2.86	2.81	3.40	3.09	2.65	2.71	2.49	2.20	3.39
1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45
				1985 POL Date				
2.03	2.03	2.03	2.03	2.03	2.03	2.03	2.03	2.03
2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
1.70	1.62	1.69	1.71	1.84	1.60	1.89	1.77	1.61
3.49	3.42	4.20	3.81	3.18	3.29	3.01	2.57	4.18
1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.64
				1990 POL Date				
2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26
2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26
1.83	1.71	1.82	1.81	2.01	1.70	2.06	1.96	1.73
4.04	3.98	4.87	4.41	3.62	3.79	3.49	2.89	4.85
1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90

2/ See footnote 2, Table P-4 for definitions of regions.

- when the project life is 100 years and the discount rate is 7-3/8 percent.

Multipliers can be computed for current price levels, discount rates, and other criteria using the technique described in the preceding section. North Pacific Division's Economics Branch has developed a computer program for doing this automatically for any POL dates.

f. Actual and Forecast Price Differences.

(1) One common problem in application of fuel price escalation rates is that the fuel prices used in project analyses are often not the same as the base year fuel prices which appear in the price forecast. This gap between actual fuel prices and those which appear in the forecast can occur for several reasons. In most cases, it is appropriate to use the actual current fuel price and apply the forecast escalation rates to it. This will be incorrect only when the gap

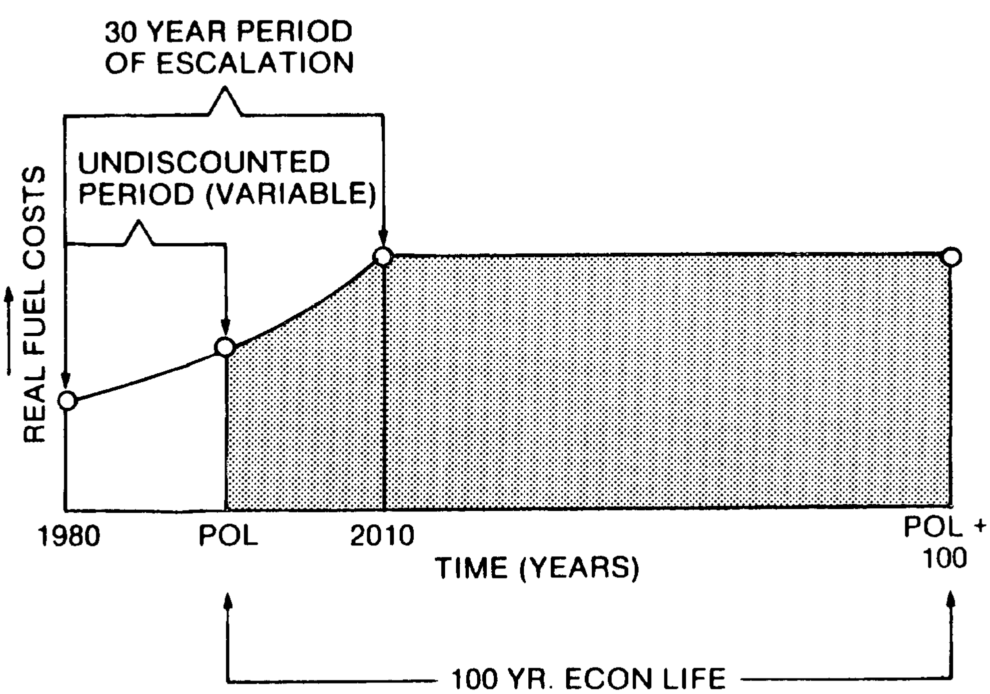


Figure P-1. Discounting methodology for real fuel escalation (shaded area represents accumulated present worth to project on-line (POL) date plus 100 years) between the actual price and the price from the forecast results from a transitory disturbance in the fuel market, such as a temporary glut or shortage. If a significant price gap is known to result from such a temporary market disturbance, then the escalation rate should be revised. Otherwise, the escalation rates should not need modification. Figure P-2 illustrates this problem. In this situation, the analyst has three options:

- Option 1: disregard the actual price and use the current price from the price forecast instead. This is not an acceptable option in most instances, since actual energy prices are subject to rapid change, and the hydropower analysis should reflect the most current information. The forecast also represents regional averages, which may not be applicable to a specific locality.

- Option 2: use the actual current price and recompute the real price escalation rate so that future prices converge with the forecast. This option requires the assumption that the actual price is simply a temporary deviation from the price forecast. This approach is depicted as Price Path 1 on Figure P-2.

- Option 3: use the actual current price and the price escalation rates from the original or some new escalation rates (Price Path 2). As Figure P-2 shows, this results in a forecast of future real prices which may be higher (or lower) than the original forecast.

(2) The choice between the second and third options is more difficult. Actual current fuel prices can deviate from the price forecast for a number of reasons, including the following:

- some basic long-term change in energy market relationships may have occurred. Examples are: a technological breakthrough which reduces energy production costs, a large new energy resource discovery, or a drastic change in OPEC pricing policy. Such changes in basic energy market relationships can be expected to change the future path of energy prices, as illustrated by Price Path 2 in Figure P-2.

- a transitory change in market relationships may have occurred. Examples are a price increase caused by temporary shortage due to a transport system breakdown, or a price reduction caused by a temporary oversupply due to suppliers' miscalculation. Such temporary changes do not invalidate the original price forecast. Price Path 1 represents the most reasonable assumption in such cases.

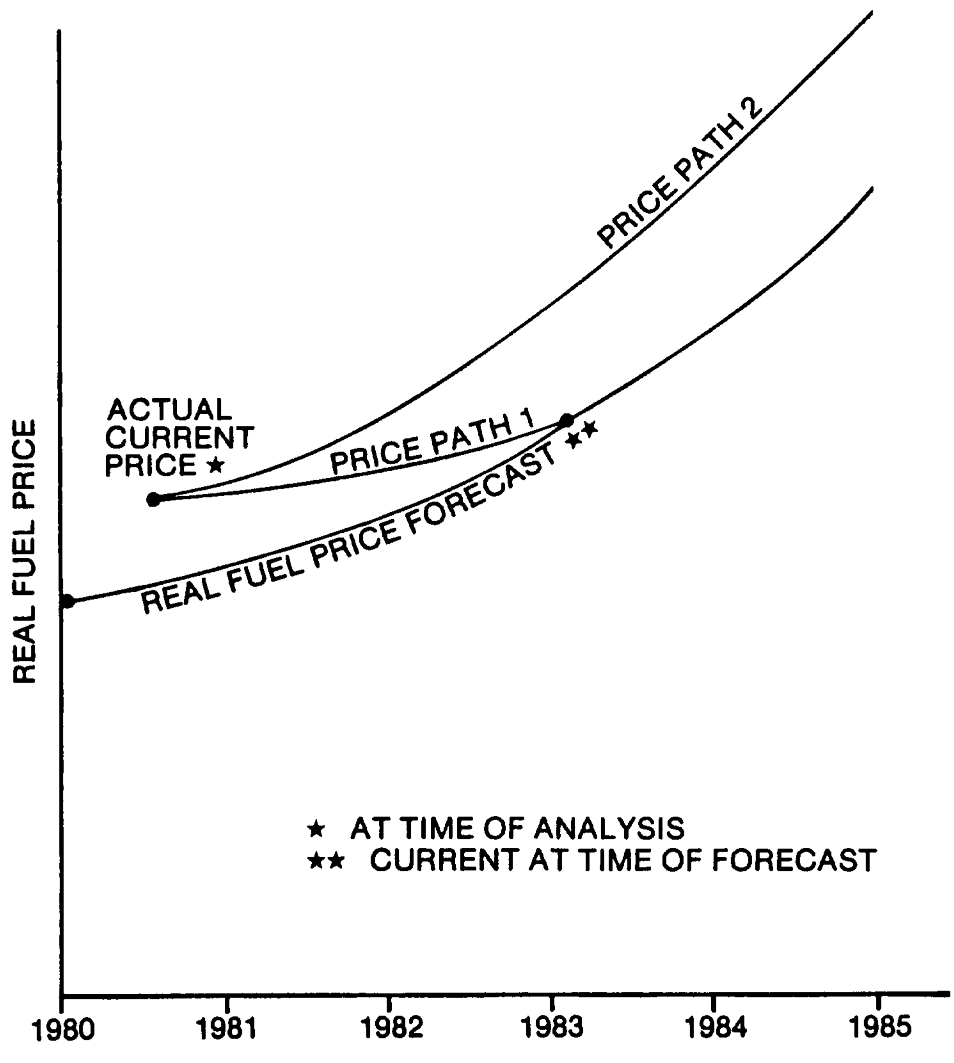


Figure P-2. Price paths reflecting different base prices

- the fuel prices shown in the forecast are averaged over large regions. Prices in any local area may be different from the regional average due to transportation cost differentials, requirements for specific grades of fuel, and other reasons. In such cases, the actual price for the local area should be used, and regional price escalation rates probably remain appropriate. Price Path 2 is again the correct choice in most cases, but changes in regional mix of fuel sources may require modification of escalation rates.

- actual prices may differ from those used in the forecast because a different source was employed, using different price-reporting conventions than was used by the forecasting agency. In such cases, it is generally reasonable to assume that the forecast escalation rates are applicable to the actual price. Again, Price Path 2 is indicated.

- finally, actual prices may differ simply because the wrong price has been chosen as the source of "actual" prices. Use of a current average price for petroleum products rather than a price based on the world oil price is an example of this problem. The solution is to find the correct actual price.

(3) As this discussion indicates, there is no single "correct" procedure to be followed when there are significant differences between actual current fuel prices and those shown in the price forecast. Fortunately, the severity of the problem is reduced if regularly updated forecasts are used. This should tend to keep prices shown in the forecast reasonably consistent with actual current prices.

(4) This discussion also strongly suggests that any particular gap between actual and forecasted fuel prices is less likely to be the result of transitory energy market disturbances than of one of the other reasons cited. This conclusion indicates that Price Path 2 will be the best assumption in most cases. As drawn in Figure P-2, Price Path 2 would yield higher alternative thermal plant costs.

(5) Given the complexity of energy markets and the difficulty of obtaining energy price data, it is not possible to identify the real reason for the fuel price gap in many cases, if not in most cases. Where the reason for the price gap cannot be identified, the best choice is to apply the forecast price escalation rates to the actual current fuel price. This will result in a continuing gap between the original price forecast and the future prices used in the project analysis. This approach is the most realistic solution when the

reason for the price gap is not known because, as discussed above, fuel price gaps are less often due to transitory energy market disturbances than to other factors.

(6) Considering the great number of variables and assumptions that enter into the calculation of the multipliers, only significant price gap differences would justify reconstructing the multipliers.

APPENDIX Q

POWER SYSTEM BENEFITS

Q-1. Introduction. The analysis of benefits for a system of interdependent hydropower projects generally follows the basic procedures outlined in Chapter 9. However, system benefit analysis is more complex than single-project analysis because (a) downstream projects may be dependent upon headwater storage projects for a portion of their power benefits, and (b) a share of those downstream benefits must often be allocated to the headwater project for it to be incrementally justified. The concepts of system benefit analysis can best be illustrated by examining some simple systems. Procedures for allocating benefits between headwater storage projects and downstream projects which benefit from storage regulation are illustrated by a single-reservoir system. Allocation of benefits among multiple storage projects is illustrated by a two-reservoir system.

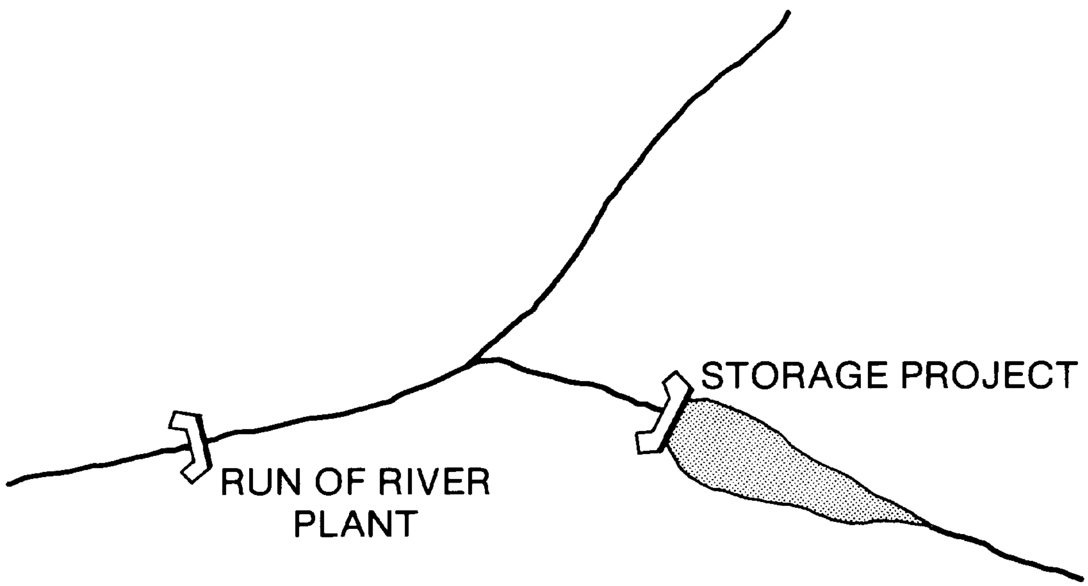
Q-2. Single-Reservoir System.

a. System Description.

(1) The general concept of reservoir power system benefit analysis will be illustrated by examining a simple system consisting of an existing run-of-river plant and a proposed storage project to be located upstream (Figure Q-1). Although in a normal planning study alternative power installations would be tested to simplify the example, it is assumed that installed capacities at both plants will be based upon a 30 percent firm plant factor.

(2) Power studies would be made for two scenarios: (a) with the existing 100 MW run-of-river project only, and (b) with the run-of-river project plus the proposed storage project. The table at the bottom of Figure Q-1 shows the output of the projects under the two scenarios. Note that increasing the firm energy output of the run-of-river project permits expansion of the powerplant by 30 MW. The annual costs associated with the proposed plan are:

Storage Project	
Dam and reservoir costs	$10,000,000
At-site power costs	7,500,000
Run-of-River Project	
Powerhouse expansion	2,500,000
Total Cost	$20,000,000



	Average Energy (MWh)	Firm Energy (MWh)	Installed Capacity (MW)	Dependable Capacity (MW)
Initial Installation				
Run-of-river plant	420,000	263,000	100	65
Proposed Plan				
Run-of-river plant	440,000	342,000	130	110
Storage project	217,000	197,000	75	70

NOTE: The average annual and firm energy values were obtained from sequential routing studies (Sections 5-8 through -14). The installed capacities are based upon a firm plant factor of 30 percent, and the dependable capacity values are based upon the average capacity available in the peak demand months (Section 6-7g).

Figure Q-1. System with one storage project and one run-of-river plant

TABLE Q-1
Computation of Benefits for One-Reservoir System

<u>Initial Installation</u>

Capacity benefit = (65,000 kW) x ($196.40/kW-yr) =	$12,800,000
Energy benefit = (420,000,000 kWh) x (17.1 mills/kWh) =	7,200,000
Total benefit =	$20,000,000

<u>Run-of-River Plant</u>

Capacity benefit = (110,000 kW) x ($196.40/kW-yr) =	$21,600,000
Energy benefit = (440,000,000 kWh) x (17.1 mills/kWh) =	7,500,000
Total benefit =	$29,100,000

Incremental gain in benefits at run-of-river plant =
$29,100,000 - $20,000,000 = $9,100,000

<u>Storage Project</u>

Capacity benefit = (70,000 kW) x ($196.40/kW-yr) =	$13,700,000
Energy benefit = (217,000,000 kWh) x (17.1 mills/kWh) =	3,700,000
Total benefit =	$17,400,000

Total benefits of plan = $9,100,000 + $17,400,000 = $26,500,000

b. <u>At-Site Benefits</u>. Table Q-1 shows the computation of benefits for each power installation using power values for the coal-fired alternative from Tables 9-3 and 9-5. The net benefits of the total plan are ($26,500,000 - $20,000,000) = $6,500,000; so the overall plan appears to be justified. However, in accordance with Section 1.6.2(b) of <u>Principles and Guidelines</u>, each separable component of the plan must also be incrementally justifiable. The two power installations are separable, and the incremental net benefits of each can be computed as follows:

Powerhouse expansion at run-of-river project:

Net Benefit = (incremental benefits at run-of-river plant) - (cost of run-of-river plant expansion)
= \$9,100,000 - \$2,500,000 = \$6,600,000

At-site power at storage project:

Net Benefit = (at-site power benefits) - (at-site power costs)
= \$17,400,000 - \$7,500,000 = \$9,900,000

c. Cost Allocation.

(1) It can be seen that each separable component can be individually justified. However, the dam and reservoir costs associated with the storage project must also be covered. If the storage project did not exist, neither the at-site benefits at the storage project nor the incremental benefits at the existing run-of-river project would have been realized. Therefore, the dam and reservoir costs must be allocated to the two power installations.

(2) In accordance with accepted practice, the separable cost-remaining benefits (SCRB) allocation method would be used for making this allocation. In this case, the remaining benefits from the two separable components are the same as the respective net benefit values computed above. The total remaining benefits would then be \$6,600,000 + \$9,900,000, or \$16,500,000. The joint costs to be allocated are the dam and reservoir costs for the storage project, which equal \$10,000,000 (see Section Q-2a(2)).

(3) The joint costs would be allocated as follows:

Powerhouse expansion at run-of-river project:

Allocated joint cost

$$= (\text{total joint cost}) \frac{(\text{net benefit at run-of-river plant})}{(\text{total remaining benefits})}$$

$$= (\$10{,}000{,}000) \frac{(\$6{,}600{,}000)}{(\$16{,}500{,}000)} = \$4{,}000{,}000$$

At-site power at storage project:

Allocated joint cost

$$= (\text{total joint cost}) \frac{(\text{net benefits of storage project})}{(\text{total remaining benefits})}$$

$$= (\$10{,}000{,}000) \frac{(\$9{,}900{,}000)}{(\$16{,}500{,}000)} = \$6{,}000{,}000$$

d. Benefit Allocation.

(1) The above analysis satisfies cost allocation requirements. However, it is sometimes necessary to do a benefit allocation as well. For example, an overall benefit-to-cost ratio for the storage project may be required for display purposes. This can be done in several ways, but all methods begin by allocating sufficient benefits to cover the cost of each component. That is, \$17,500,000 in benefits would be allocated to the storage project to cover the cost of the dam and reservoir (\$10,000,000) and the cost of at-site power (\$7,500,000), and \$2,500,000 in benefits would be allocated to the powerhouse expansion at the run-of-river project. The "surplus" benefits available for allocation would be computed as follows:

$$\begin{aligned}\text{Surplus benefits} &= (\text{total benefits}) - (\text{benefits already allocated})\\ &= (\$26{,}500{,}000) - (\$17{,}500{,}000 + \$2{,}500{,}000)\\ &= \$6{,}500{,}000\end{aligned}$$

(2) Historically, the surplus benefits have been allocated between projects in several ways:

- using the same ratio as used in allocating joint costs
- maintaining the same benefit-to-cost ratio for each component
- dividing the surplus benefits equally between the projects.

The first method is generally preferred. Using that approach, the benefits to be allocated to the run-of-river project would be computed as follows:

$$\text{Allocated benefits} = (\text{surplus benefits}) \frac{(\text{allocated joint costs})}{(\text{total joint costs})}$$

$$= (\$6{,}500{,}000) \frac{(\$4{,}000{,}000)}{(\$10{,}000{,}000)} = \$2{,}600{,}000.$$

The benefits allocated to the storage project would be:

$$\text{Allocated benefits} = (\$6{,}500{,}000)\ \frac{(\$6{,}000{,}000)}{(\$10{,}000{,}000)} = \$3{,}900{,}000.$$

e. Project Benefit-Cost Ratios. The resulting project benefit-cost ratio will be (\$2,500,000 + \$2,600,000) to (\$2,500,000), or 2.0 to 1 for the expansion of the run-of-river plant, and (\$17,500,000 + \$3,900,000) to (\$17,500,000), or 1.2 to 1 for the storage project.

Q-3. Multiple Storage Projects.

a. General. Two situations can arise which would involve the evaluation of multiple-reservoir systems. The first would be the evaluation of a new multiple-reservoir system, and the other would be the addition of a storage project to a system with one or more existing storage projects.

b. System Description. In order to illustrate the allocation of benefits for a new multiple-purpose reservoir system, the system shown on Figure Q-2 will be examined. This system consists of two proposed new headwater storage projects and a single existing run-of-river plant. The annual costs of the elements of the proposed plan are as follows:

Reservoir A	
Dam and reservoir costs	\$10,000,000
At-site power	7,500,000
Reservoir B	
Dam and reservoir costs	\$ 6,000,000
At-site power	5,000,000
Run-of-river project	
At-site power	\$ 2,600,000
Total annual costs	\$31,100,000

c. At-Site Benefits.

(1) In the case of a new multiple-reservoir system, benefits occuring at downstream projects would be allocated to the upstream projects in proportion to their "last added" contribution. For the two-reservoir example (Figure Q-2), power studies would be made for four cases:

- with no storage projects (initial installation)
- with both storage projects (proposed plan)
- with only Reservoir A
- with only Reservoir B.

Figure Q-2 shows the power output for each case, and Table Q-2 shows the computation of at-site benefits. Note that the existing run-of-river plant and Reservoir A are identical to the existing run-of-river plant and storage project in the example shown in Section Q-2.

(2) The last added benefits at the run-of-river plant attributable to Reservoir A are computed by subtracting the total at-site benefits for the system without Reservoir A (i.e., the system with Reservoir B only) from the benefits for the system with both storage projects. These last-added benefits would be ($30,200,000 - $27,000,000) = $3,200,000. The last-added benefits attributable to Reservoir B would be ($30,200,000 - $29,100,000) = $1,100,000. Thus, the total incremental benefits at the run-of-river project resulting from the plan ($10,200,000) would be allocated to the storage project in the following proportions: $3,200,000 /($3,200,000 + $1,100,000) = 74% to Reservoir A and the remaining 26% to Reservoir B.

d. <u>Cost Allocation.</u>

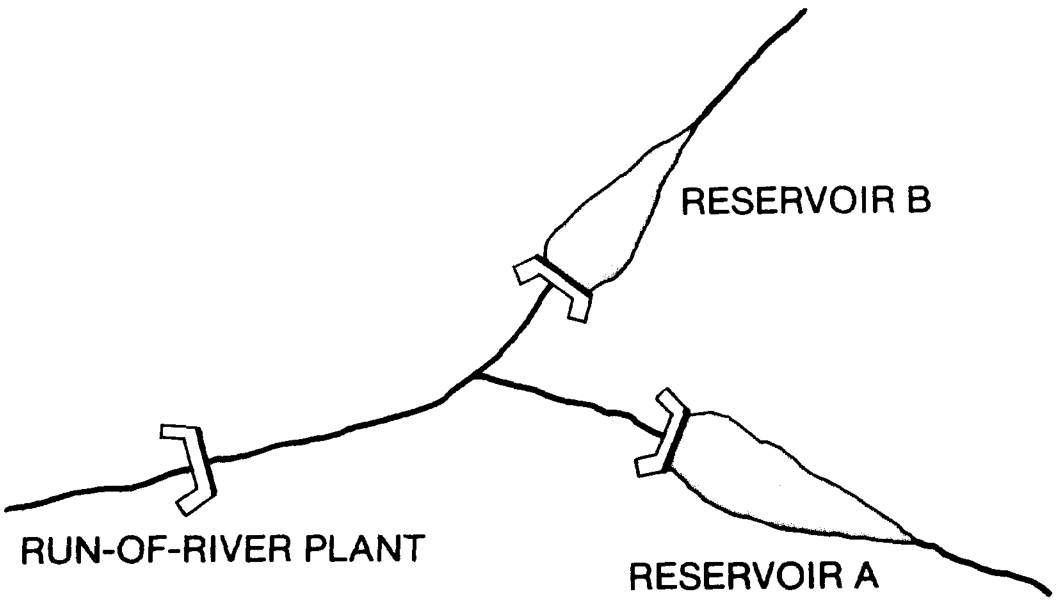
(1) Joint costs of Reservoirs A and B would be allocated as described in Section Q-2b. The first step is to compute the remaining benefits.

Remaining benefits	=	(at-site benefits)	-	(at-site costs)	
Remaining benefits/Reservoir A	=	$17,400,000	-	7,500,000	= $ 9,900,000
Remaining benefits/Reservoir B	=	$11,300,000	-	5,000,000	= $ 6,300,000
Remaining benefits/R-of-R plant	=	$10,200,000	-	2,600,000	= $ 7,600,000
Total remaining benefits					= $23,800,000

(2) The remaining benefits at the run-of-river plant would be allocated to the reservoirs according to the proportions computed in the 'last-added' analysis (Section Q-3c(2)). Remaining benefits would be allocated as follows:

(74%) x ($7,600,000) = $5,600,000 to Reservoir A and
(26%) x ($7,600,000) = $2,000,000 to Reservoir B.

Thus, the total remaining benefits to be allocated to Reservoir A would be the sum of the remaining benefits for Reservoir A and the remaining benefits for run-of-river plant allocated to Reservoir A, or = ($9,900,000 + $5,600,000) = $15,500,000. For Reservoir B, the



	Average Energy (MWh)	Firm Energy (MWh)	Installed Capacity (MW)	Dependable Capacity (MW)
Initial Installation				
Run-of-river plant	420,000	263,000	100	65
Proposed Plan				
Run-of-river plant	445,000	354,000	135	115
Reservoir A	217,000	197,000	75	70
Reservoir B	145,000	131,000	50	45
System With Reservoir A				
Run-of-river plant	440,000	342,000	130	110
Reservoir A	217,000	197,000	75	70
System with Reservoir B				
Run-of-river plant	435,000	318,000	121	100
Reservoir B	145,000	131,000	50	45

Figure Q-2. System with two storage projects and one run-of-river plant

TABLE Q-2. Computation of Benefits for Two-Reservoir System

<u>Initial Installation</u>	
Run-of-river plant	
Total benefit (same as shown on Table Q-1)	= $20,000,000
<u>Proposed Plan</u>	
Run-of-river plant:	
Capacity benefit = (115,000 kW)($196.40/kW-yr)	= $22,600,000
Energy benefit = (445,000,000 kWh)(17.1 mills/kW-yr)	= 7,600,000
Total benefit	$30,200,000
Incremental benefit = ($30,200,000 - $20,000,000)	= $10,200,000
Reservoir A:	
Total benefit = (same as shown on Table Q-1)	= $17,400,000
Reservoir B:	
Capacity benefit = (45,000 kW)($196.40/kW-yr)	= $8,800,000
Energy benefit = (145,000,000)(17.1 mills/kWh)	= 2,500,000
Total benefit	$11,300,000
Total plan: Incremental benefits	
$10,200,000 + $17,400,000 + $11,300,000	= $38,900,000
<u>System with Reservoir A</u>	
Total Plan:	
Incremental benefits (same as shown on Table Q-1)	= $26,500,000
<u>System with Reservoir B</u>	
Run-of-river plant:	
Capacity benefit = (100,000 kW)($196.40/kW-yr)	= $19,600,000
Energy benefit = (435,000,000)(17.1 mills/kWh)	= 7,400,000
Total Benefit	$27,000,000
Incremental benefit = $27,000,000 - $20,000,000	= $7,000,000
Reservoir B:	
Total benefit (same as shown for proposed plan)	= $11,300,000
Total Plan:	
Incremental benefit = $11,300,000 + $7,000,000	= $18,300,000

allocation would be ($6,300,000 + $2,000,000) = $8,300,000.

(3) The allocation of the joint costs of the reservoirs would be computed as follows. The Reservoir A joint costs allocated to powerhouse expansion of the run-of-river plant would be the product of the Reservoir A joint costs ($10,000,000) and the ratio of the remaining benefits at the run-of-river plant allocated to Reservoir A ($5,600,000) to the total remaining benefits allocated to Reservoir A ($15,500,000), or:

For the powerhouse expansion at the run-of-river plant:

$$\text{Allocated joint cost} = (\$10{,}000{,}000)\ \frac{(\$5{,}600{,}000)}{(\$15{,}500{,}000)} = \$3{,}600{,}000$$

The Reservoir A joint costs allocated to at-site power at Reservoir A would be the product of the Reservoir A joint costs ($10,000,000) and the ratio of the remaining benefits at Reservoir A ($9,900,000) to the total remaining benefits allocated to Reservoir A ($15,500,000), or

For at-site power at Reservoir A:

$$\text{Allocated joint cost} = (\$10{,}000{,}000)\ \frac{(\$9{,}900{,}000)}{(\$15{,}500{,}000)} = \$6{,}400{,}000$$

(4) The allocation for Reservoir B would be computed in a similar manner.

Powerhouse exoansion at run-of-river olant:

$$\text{Allocated joint cost} = (\$6{,}000{,}000)\ \frac{(\$2{,}000{,}000)}{(\$8{,}300{,}000)} = \$1{,}400{,}000$$

At-site oower at Reservoir B:

$$\text{Allocated joint cost} = (\$6{,}000{,}000)\ \frac{(\$6{,}300{,}000)}{(\$8{,}300{,}000)} = \$4{,}600{,}000$$

(5) The total amount of joint costs allocated to the run-of-river project would be

($3,600,000 + $1,900,000) = ($4,500,000).

e. Benefit Allocation.

(1) Using the same procedure for allocating "surplus benefits" as was used in Section Q-2d, the net benefits for the individual elements of the plan would be computed as follows. The first step is to allocate sufficient benefits to cover the costs of all components of the plan. Subtracting the total cost of the plan (Section Q-3b) from the incremental benefits of the plan (Table Q-2), the surplus benefits are computed as follows:

Surplus benefits = (\$38,900,000 - \$31,100,000) = \$7,800,000.

(2) The surplus benefits would be allocated among the components of the plan in accordance with their allocated joint costs (Section Q-3d).

Surplus benefits, Reservoir A

$$= (\text{total surplus benefits}) \frac{(\text{allocated joint costs, Reservoir A})}{(\text{total joint costs})}$$

$$= (\$7{,}800{,}000) \frac{(\$6{,}400{,}000)}{(\$10{,}000{,}000 + \$6{,}000{,}000)} = \$3{,}100{,}000$$

$$\text{Surplus benefits, Reservoir B} = (\$7{,}800{,}000) \frac{(\$4{,}600{,}000)}{(\$16{,}000{,}000)} = \$2{,}300{,}000$$

Surplus benefits, run-of-river project

$$= (\$7{,}800{,}000) \frac{(\$3{,}600{,}000 + (\$1{,}400{,}000)}{(\$16{,}000{,}000)} = \$2{,}400{,}000$$

(3) The total benefits for each component would be the sum of the benefits allocated to cover the cost of that component (Section Q-3b) plus the allocated surplus benefits.

Total benefits, Reservoir A:
(\$10,000,000 + \$7,500,000) + (\$3,100,000) = \$20,600,000

Total benefits, Reservoir B:
(\$6,000,000 + \$5,000,000) + (\$2,300,000) = \$13,300,000

Total benefits, run-of-river:
(\$2,600,000 + (\$2,400,000) = \$5,000,000

(4) The respective benefit-to-cost ratios would be:

Reservoir A: (\$20,600,000) to (\$10,000,000 + \$7,500,000) = 1.2 to 1
Reservoir B: (\$13,300,000) to (\$6,000,000 + \$5,000,000) = 1.2 to 1
Run-of river: (\$5,000,000) to (\$2,600,000) = 1.9 to 1.

As noted in Section Q-2d, these allocated system benefits and individual benefit-to-cost ratios are not used in overall plan formulation, but they may be required for budgetary submittals and in the detailed planning of the component projects.

f. Net Benefits.

(1) In formulating the plan for a multiple project system, net benefits must be computed for the total plan, and tests must be made to insure that each separable component of the plan is incrementally justified. For the example system, the separable components are (a) the addition of power at the run-of-river project, (b) the total Reservoir A project, (c) at-site power at Reservoir A, (d) the total Reservoir B project, and (e) at-site power at Reservoir B. Note that the benefits at the individual reservoir projects are based on the last-added analysis: i.e., the sum of the at-site power benefits and the last-added benefits realized at the run-of-river project.

Net benefits/total plan = \$38,900,000 - \$31,100,000 = \$7,800,000

where: \$38,900,000 = incremental benefits of total plan (Table Q-2)
\$31,100,000 = total costs of plan (Section Q-3b)

Net benefits/expansion of R of R plant
= \$10,200,000 - \$2,600,000 = \$7,600,000

where: \$10,200,000 = incremental benefit at R-of-R plant (Table Q-2)
\$ 2,600,000 = cost of added power at R-of-R plant (Sec. Q-3b)

Net benefits/total Reservoir A project
= (\$17,400,000 + \$3,200,000) - \$17,500,000 = \$3,100,000

where: \$17,400,000 = at-site benefits at Reservoir A (Table Q-2)
\$ 3,200,000 = last added benefits at R-of-R plant due to Reservoir A (Section Q-3c(2))
\$17,500,000 = total cost of Reservoir A (Section Q-3b)

Net benefits/at-site power, Reservoir A
= \$17,400,000 - \$7,500,000 = \$9,900,000

where: \$17,400,000 = at-site benefits at Reservoir A (Table Q-2)
\$ 7,500,000 = at-site power cost at ?eservoir A (Sec. Q-3b)

Net benefits/total Reservoir B project
= (\$11,300,000 + \$1,100,000) - \$11,000,000 = \$1,400,000

where: \$11,300,000 = at-site benefits at Reservoir B (Table Q-2)
\$ 1,100,000 = last added benefits at run-of-river plant due to Reservoir B (Section Q-3c(2))
\$11,000,000 = total cost of Reservoir B (Section Q-3b)

Net benefits/at-site power, Reservoir B
= \$11,300,000 - \$5,000,000 = \$6,300,000

where: \$11,300,000 = at-site benefits, Reservoir B (Table Q-2)
\$ 5,000,000 = at-site power cost, Reservoir B (Sec. Q-3b)

(2) The total plan and all of its components are feasible. The net benefits of the total plan, at \$7,800,000, are larger than the net benefits of the plan with only Reservoir A, which were computed to be \$6,600,000 in Section Q-2b.

(3) Note that the Reservoir B project, treated as a whole, is only marginally feasible. If the total plan were feasible, but Reservoir B were not feasible as a separate increment, several courses of action would be available. If it were clearly infeasible, it would be deleted from the plan. On the other hand, if it were only marginally infeasible, Section 1.6.2(b) of Principles and Guidelines possibly could be applied. It states that "Increments that do not provide net NED benefits may be included, except in the NED plan, if they are cost-effective measures for addressing specific concerns." Even though Reservoir B was not in itself justified on a last-added basis, it could possibly be included if it were an element of the plan that produced maximum net benefits.

Q-4. More Complex Systems.

a. The example outlined above represents the simplest case of a multiple-reservoir system. However, the same general principles can be applied to more complex systems. The key to the analysis of complex systems is correctly setting up the with- and without-project power studies.

b. If a storage project is added to an existing reservoir system, it must be analyzed on a last-added basis. Thus, if Reservoir B were added to an existing system which already includes the run-of-river project and Reservoir A, power studies would be made with and without Reservoir B and incremental benefits would be computed. Costs would include the dam and reservoir costs at Reservoir B, the cost of at-site power at Reservoir B (if at-site power is included), and any additional costs required at the run-of-river plant to permit it to develop the additional power resulting from the regulation of Reservoir B. The analysis of the total plan would be similar to the computation of net benefits for the total Reservoir B project, shown in Section Q-3f(1), except that it would be necessary to include any additional costs that might be incurred at the run-of-river plant.

c. The examples described in Section Q-3 assume that the addition of a second reservoir to the system would not change the output of the first storage project. In some cases, addition of a reservoir to an existing system might change the operation of the existing reservoirs, and may even change their energy output and dependable capacity. If this occurs, at least a portion of these increases (or losses) should be credited to the added reservoir. These gains or losses could be identified from the with- and without-project system power studies.

APPENDIX R

CONVERSION FACTORS

R-1. Volume.

1 acre foot (AF)	=	43,560 cubic feet
	=	1,233 cubic meters
	=	0.505 cfs-days (sfd) 1/
1 cubic foot	=	7.48 U.S. gallons
	=	0.0283 cubic meters
1 cubic meter	=	35.31 cubic feet
1 cfs-day (sfd)	=	1.983 AF
	=	86,400 cubic feet

R-2. Rate of Flow.

1 cubic foot per second (cfs)	=	448.83 gallons per minute (gpm)
	=	0.646 million gallons per day (mgd)
	=	1.98 AF/day
	=	724 AF/year
	=	0.0283 cubic meters per second (cms)
1 acre-foot/day (AF/day)	=	0.504 cfs
	=	0.0143 cms

R-3. Energy.

1 kilowatt-hour (kWh)	=	3,413 BTU 2/
	=	2,656,000 foot-pounds
	=	3,600,000 joules
	=	860 kg-calories

1/ the term cfs-day is sometimes called "second-foot day" (sfd).
2/ 1 BTU (British thermal unit) is the amount of energy required to raise the temperature of one pound of water one degree Farenheit.

R-4. Power.

1 kilowatt (kW)	=	1,000 watts
	=	1.341 horsepower
	=	56.88 BTU/minute
	=	737.56 ft-lbs/second
1 megawatt (MW)	=	1,000 kilowatts
1 gigawatt (gW)	=	1,000 megawatts

R-5. Energy Equivalents.

1 barrel of oil (42 gals.)	=	470 kWh @ 27% efficiency 3/
	=	520 kWh @ 30% efficiency
	=	660 kWh @ 38% efficiency 4/
1 ton of coal	=	2,500 kWh @ 37% efficiency 5/
1,000 cubic feet (mcf) of natural gas	=	59 kWh @ 27% efficiency 3/
	=	83 kWh @ 38% efficiency 4/

3/ typical efficiency for a combustion turbine
4/ typical efficiency for new oil- or gas-fired base load steam plant or combined cycle plant
5/ typical efficiency for a new base load coal-fired steam plant

APPENDIX S

GLOSSARY

ADVERSE WATER CONDITIONS. See Water Conditions, Adverse.

AVERAGE WATER CONDITIONS. See Water Conditions, Average.

AVAILABILITY.

Average Availability. The ratio of the average capacity of a hydroelectric plant in the peak demand months to its rated capacity. This ratio accounts for variations in streamflow and head, and is also called Hydrologic Availability (see Section 6-7g).

Hydrologic Availability. See Average Availability.

Mechanical Availability. The ratio of the number of days in total period minus days out of service due to maintenance and forced outages, to the number of days in the total period. (see also Outages and Section O-2d).

BACKWATER. Water level controlled by either a downstream reservoir, a channel restriction, or a stream confluence that affects the tailwater level of an upstream plant.

BASE LOAD. The minimum electrical system load over a given period of time (see also Figure 2-3).

BLOCK LOADING. A generating plant is said to be block loaded when its output is increased or decreased in definite steps without regard to following a particular load shape. A generating plant carries a block load when its output is maintained at a fixed level for an extended period of time (see also Figure 6-21).

BUSWORK. A conductor or group of conductors that serves as a common connection for two or more circuits. In powerplants, buswork comprises the three rigid single-phase connectors that interconnect the generator and the step-up transformer(s) (see also Section 2-5f).

CAPABILITY. The maximum load which a generator, turbine, transmission circuit, apparatus, station, or system can supply under specified conditions for a given time interval, without exceeding approved limits of temperature and stress.

Peaking Capability. See Capacity, Peaking Capacity.

CAPACITY. The load for which a generator, turbine, transformer, transmission circuit, apparatus, station or system is rated. Capacity is also used synonymously with capability (see also Sections 2-2b(3) and 6-1b). For definitions pertinent to the capacity of a reservoir to store water, see Reservoir Storage Capacity.

Assured System Capacity. The dependable capacity of system facilities available for serving system load after allowance for required reserve capacity, including the effect of emergency interchange agreements and firm power agreements with other systems.

Dependable Capacity. The load-carrying ability of a station or system under adverse conditions for the time interval and period specified when related to the characteristics of the load to be supplied. The dependable capacity of a system includes net firm power purchases (see also Sections 6-1b(6) and 6-7).

Equivalent Thermal Capacity. The amount of thermal generating capacity that would carry the same amount of system peak load as could be carried by a given hydroelectric plant (see also Section 6-7b).

Hydraulic Capacity. The maximum flow which a hydroelectric plant can utilize for energy (see also Section 6-1b(8)).

Installed Capacity. The sum of the capacities in a powerplant or power system, as shown by the nameplate ratings of similar kinds of apparatus, such as generating units, turbines, or other equipment (see also Section 6-1b(4)).

Overload Capacity. The maximum load that a generating unit or other device can carry for a specified period of time under specified conditions when operating beyond its normal rating but within the limits of the manufacturer's guarantee, or, in the case of expiration of the guarantee, within safe limits as determined by the owner (see also Section 6-1b(3)).

Peaking Capacity. The maximum peak load that can be supplied by a generating unit, powerplant, or power system in a stated time period. It may be the maximum instantaneous load or the maximum average load over a designated interval of time. Sometimes called peaking capability (see also Section 6-1b(5)).

Rated Capacity. The electrical load for which a generator, turbine, transformer, transmission circuit, electrical apparatus, powerplant, or power system is rated (see also Section 6-1b(2)).

Reserve Generating Capacity. Extra generating capacity available to meet unanticipated demands for power or to generate power in the event of loss of generation resulting from scheduled or unscheduled outages of regularly used generating capacity (see also Section 2-2e).

Sustained Peaking Capacity. Capacity that is supported by a sufficient amount of energy to permit it to be fully usable in meeting system loads (see also Section 6-7i).

CAPACITY VALUE. That portion of the at-site or at-market value of electric power which is assigned to capacity (se^ also Section 9-5b).

CAVITATION. The formation of voids within a body of moving liquid (or around a body moving in a liquid) when the local pressure is lower than the vapor pressure, and the particles of liquid fail to adhere to the boundaries of the passageway. These voids fill with vapor and then collapse violently, causing pitting of metal on turbine blades (see Chapter 7 of reference (81)).

CHARGE/DISCHARGE RATIO. The ratio of the average pumping load on a pump-turbine unit to its rated generating output (see also Section 7-2k).

CIRCUIT BREAKER. Any switching device that is capable of closing or interrupting an electrical circuit (see also Section 2-5f).

COMBINED CYCLE. See Plant, Combined Cycle.

COMBUSTION TURBINE. See Plant, Combustion Turbine.

CONSERVATION STORAGE. See Reservoir Storage Capacity, Conservation.

CRITICAL DRAWDOWN PERIOD. That portion of the critical period in which the reservoir storage is drafted, i.e., the sequence of historical streamflows in which the available reservoir storage capacity is fully drafted while meeting firm energy requirements (see also Section 5-10d and Figure 5-32).

CRITICAL PERIOD. The multiple-month period when the limitation of hydroelectric power supply due to the shortage of available water is most critical with respect to system load requirements, as determined from an analysis of the historical streamflow record. The reservoir begins the critical period full; the available storage is fully drafted at one point during the period; and the critical period ends when the storage has completely refilled (see also Section 5-10d and Figure 5-32).

CRITICAL WATER CONDITIONS. See Water Conditions, Adverse.

CYCLE EFFICIENCY. The ratio of the generating output of a pumped-storage plant to its pumping energy input. Includes motor, pump, turbine, and generator efficiency losses and penstock head losses (see also Section 7-2j).

CYCLING. Powerplant operation to meet the intermediate portion of the load (9 to 14 hours per day) (see also Section 2-2c(5)).

DEMAND. The rate at which electric energy is delivered to or by a system, part of a system, or piece of equipment, usually expressed in kilowatts or megawatts, for a particular instant or averaged over a designated period of time (see also Section 2-2b(4)).

DISCHARGE. The rate of water flow through, over, or around water control facilities. The rate of flow is measured by stream gage or calculated from predetermined rating tables. The term may be applied to the rate of flow from each individual source (such as a particular turbine) or to the algebraic summation from all individual sources (which would be the total rate of flow). Total discharge is synonymous with outflow.

Rated Discharge. Turbine discharge at rated head, with wicket gates in fully open position (see also Section 5-5c(4)).

DRAFT. The withdrawal of water from a reservoir.

DRAFT TUBE. A water conduit which carries water from a reaction turbine runner or crossflow turbine runner to the tailrace. Designed to maximize head utilization by the turbine (see also Section 2-4h).

DRAWDOWN. The distance that the water surface elevation of a storage reservoir is lowered from a given or starting elevation as a result of the withdrawal of water to meet some project purpose (i.e., power generation, creating flood control space, irrigation demand, etc.).

DURATION CURVE. A curve of quantities plotted in descending sequential order of magnitude against time intervals for a specified period. The coordinates may be absolute quantities or percentages (see also Sections 2-2f(2), 4-4d and 5-7).

ELECTRIC POWER SYSTEM. Physically connected electric generating, transmission, and distribution facilities operated as a unit under one control.

ENCROACHMENT. The reduction in generating head at a hydroelectric project caused by a rise in tailwater elevation resulting from the backwater effects of a downstream reservoir.

ENERGY. That which does or is capable of doing work. It is measured in terms of the work it is capable of doing; electric energy is usually measured in kilowatt-hours (see also Section 2-2b).

Average Annual Energy. The average amount of energy generated by a hydroelectric project or system over the period of record (see also Section 5-2b).

Dump Energy. Energy generated in hydroelectric plants by water that cannot be stored or conserved and which energy is in excess of the needs of the electric system producing the energy.

Firm Energy. Electric energy which is intended to have assured availability to the customer to meet any or all agreed upon portion of his load requirements (see also Section 5-2c).

Fuel Displacement Energy. Electric energy generated at a hydroelectric plant as a substitute for energy which would otherwise have been generated by a thermal-electric plant (see also Section 9-6a).

Nonfirm Energy. Electric energy having limited or no assured availability.

Off-peak Energy. Electric energy supplied during periods of relatively low system demands.

On-peak Energy. Electric energy supplied during periods of relatively high system demands.

Primary Energy. Hydroelectric energy which is available from continuous power. Primary energy is firm hydroelectric energy (see also Section 5-2c).

Pumping Energy. The energy required to pump water from the lower reservoir to the upper reservoir of a pumped-storage project (see also Section 7-1b).

Secondary Energy. All hydroelectric energy other than primary energy. Secondary energy is generally marketed as non-firm energy (see also Section 5-2d).

EXPORTS. Electric power which is transferred from a given power system to another (usually adjacent) power system. Export power must be included in the given power system's loads (see also Section 3-3b(2)).

FACTOR.

Availability Factor. The ratio of the time a machine or equipment is ready for or in service to the total time interval under consideration (see also Section 0-2d).

Capacity Factor. The ratio of the average load on a machine or equipment for the period of time considered, to the capacity rating of the machine or equipment (see also Section 6-1b(10)).

Hydrologic Availability. See definition of Availability, Average, and Section 6-7g.

Load Factor. The ratio of the average load over a designated period to the peak-load occurring in that period (see also Section 2-2b(6)).

Plant Factor. The ratio of the average load on the plant for the period of time considered to the aggregate rating of all the generating equipment installed in the plant (see Section 6-1b(9)).

Power Factor. The ratio of kilowatts to kilovolt-amperes, which is indicative of a generator's ability to deliver reactive power in addition to real power (kilowatts), (see also Section 6-3b(12)).

FLASHBOARDS. Temporary structures installed at the top of dams, gates, or spillways for the purpose of temporarily raising the pool elevation, and hence the gross head of a hydroelectric generating plant, thus increasing power output. Normally, flashboards are removed either at the end of the water storage season, or during periods of high streamflow.

FLEXIBILITY. The characteristics of a generating station or group of stations, which permits shaping the energy produced to fit a desired load shape or operating plan (see also Section 6-71).

FOREBAY. The impoundment immediately above a dam or hydroelectric plant intake structure. The term is applicable to all types of hydroelectric developments (i.e., storage, run-of-river and pumped-storage).

FULL-GATE DISCHARGE. The discharge through a turbine when the turbine wicket gates are wide open.

GENERATION. The act or process of producing electric energy from other forms of energy; also, the amount of electric energy so produced.

GENERATING UNIT. A single power-producing unit, comprised of a turbine, generator, and related equipment.

GENERATOR. The electrical equipment in power systems that converts mechanical energy to electrical energy (Section 2-5d and Figure 2-29).

GIGAWATT. One million kilowatts.

GOVERNOR. The device which measures and regulates turbine speed by controlling wicket gate angle to adjust water flow to the turbine (Section 2-5e and Figures 2-30 and 2-31).

HEAD.

Critical Head. The hydraulic head at which the full-gate output of the turbine equals the generator rated capacity (full-gate referring to the condition where the turbine wicket gates are wide-open, thus permitting maximum flow through the turbine). Below critical head, the full-gate turbine capability will be less than the generator rated capacity. Above critical head, generator rated capacity can be obtained at a discharge less than full-gate discharge. At many older plants, generators have a continuous overload rating. At these plants, critical head is defined as the head at which full-gate output of the turbine equals the generator overload capacity. In recent Corps of Engineers practice, the term critical head is used to refer only to operating projects. For planning and design purposes, the term rated head is used to describe the same head condition (see also Section 5-5c(10)).

Design Head. The head at which the turbine will operate to give the best overall efficiency under various operating conditions (see also Section 5-5c(1)).

Gross Head. The difference of elevations between water surfaces of the forebay and tailrace under specified conditions (see also Section 5-3c).

Net Head. The gross head less all hydraulic losses except those chargeable to the turbine (see also Section 5-3c).

Rated Head. Technically, the head at which a turbine at rated speed will deliver rated capacity at specified gate and efficiency. However, for planning and design purposes, rated head is identical to critical head (see also Section 5-5c(4)).

HEADWATER BENEFITS. The benefits brought about by the storage and release of water by a reservoir project upstream. Application of the term is usually in reference to benefits realized at a downstream hydroelectric power plant.

HEADWATER PROJECT. A storage reservoir located in the upper reaches of a river basin.

HEAT RATE. A measure of generating station thermal efficiency, generally expressed as BTUs per net kilowatt-hour. It is computed by dividing the total BTU content of the fuel burned (or of heat released from a nuclear reactor) by the resulting net kilowatt-hours generated.

HYDRAULIC CAPACITY. See Capacity, Hydraulic.

HYDROGRAPH. A graphical representation of the variations of the flow of a stream at a given station plotted in chronological order, usually with time as the abscissa and flow as the ordinate.

HYDROLOGIC AVAILABILITY. See definition of Availability, Hydrologic, and Section 6-7g.

IMPORTS. Electric power which is transferred into a power system from another (usually adjacent) power system. Import power is usually considered to be a generating resource (see also Section 2-2d(9)).

IMPULSE TURBINE. A turbine which utilizes the kinetic energy of a high velocity water jet to produce power.

INFLOW. The rate of water flow into a reservoir or forebay during a specified period.

INTERCONNECTION (INTERTIE). An electrical connection between two utility systems permitting the flow of power in either direction at different times between the two systems.

KILOWATT (kW). The electric unit of power, which equals 1,000 watts or 1.341 horsepower.

KILOWATT-HOUR (kWh). The basic unit of electric energy. It equals one kilowatt of power applied for one hour of time.

LOAD. The amount of electric power delivered at a given point.

Base Load. The minimum load in a stated period of time (see also Figure 2-3).

Intermediate Load. That portion of the load between the base load and the peaking portion of the load (see also Figure 2-3).

Interruptible Load. Electric power load which may be curtailed at the supplier's discretion, or in accordance with a contractual agreement (Section 2-2d(10)).

Peak Load. The maximum load in a stated period of time. The peaking portion of the load is that portion of the load that occurs for less than eight hours per day (see also Figure 2-3).

LOAD CENTER. A point at which the load of a given area is assumed to be concentrated.

LOAD CURVE. A curve of demand versus time showing in chronological sequence the magnitude of the load for each unit of time of the period covered (see also Figures 2-2 and 6-1).

LOAD FACTOR. See Factor, Load.

LOAD-RESOURCE ANALYSIS. A year-by-year comparison of expected power loads with existing and scheduled generating resources, which is undertaken to determine when additional generating resources will be required (see also Sections 3-3 and 3-10d).

LOSS.

Consumptive Loss. Water that is removed from a reservoir and not returned to downstream flow. Examples are evaporation and withdrawals for irrigation and water supply (see also Section 4-5h).

Electric System Loss. Total electric energy loss in the electric system. It consists of transmission, transformation, and distribution losses, and unaccounted-for energy losses between sources of supply and points of delivery.

Energy Loss. The difference between energy input and output as a result of transfer of energy between two points (see also Line Loss).

Head Loss. Reduction in generating head due to friction in the water passage to the turbine: includes trashrack, intake, and penstock friction losses (see also Section 5-61).

Line Loss. Energy loss and power loss on a transmission or distribution line (see also Section 9-5g)

Nonconsumptive Loss. Water that is unavailable for a specific project purpose but which is included in downstream flow from a project. Examples are losses due to seepage, turbine leakage, and the operation of navigation and fish passage facilities (see also Section 4-5h).

Power Loss. The difference between power input and output as a result of transfer of energy between two points (sometimes referred to as "Capacity Loss") (see also Line Loss).

Transmission Loss. See Line Loss.

MARKETABILITY. The generating output of a proposed powerplant is marketable if it can be used in the system load and the fixed and variable costs of the plant can be recovered with interest within an appropriate period of time (see also Sections 3-12 and 9-9).

MASS CURVE. A cumulative plot of reservoir inflow versus time (see also Appendix F).

MEGAWATT. 1,000 kilowatts.

MINIMUM DISCHARGE.

Project Minimum Discharge. The minimum flow that must be released from a project to meet environmental or other non-power water requirements.

Turbine Minimum Discharge. The minimum permissible discharge through a turbine (see also Section 5-5d).

MULTIPLE-PURPOSE RESERVOIR. A reservoir planned to be used for more than one purpose.

OUTAGE. The period during which a generating unit, transmission line, or other facility is out of service (see also Section O-2d).

Forced Outage. The shutting down of a generating unit, transmission line, or other facility for emergency reasons.

Maintenance Outage. The removal of a generating unit for required maintenance at any time between scheduled outages.

Scheduled (Planned) Outage. The shutdown of a generating unit, transmission line, or other facility for inspection or maintenance in accordance with an advance schedule.

PEAK DEMAND MONTHS. The month or months of highest power demand (see also Section 6-7g(6)).

PENSTOCK. A conduit used to convey water under pressure to the turbines of a hydroelectric plant (see also Section 2-4e).

PERIOD OF RECORD. The historical period for which streamflow records exist (see also Section 5-6c).

PLANT (STATION).

Base Load Plant. A power plant which is normally operated to carry base load and which, consequently, operates essentially at a constant load (see also Section 6-3b(3)).

Conventional Hydroelectric Plant. A hydroelectric power plant utilizing falling water only once as it passes downstream, as opposed to either a pump-back or pumped-storage plant, which recirculates all or a portion of the streamflow during the production of electric power (see also Section 2-2d(6)).

Combined Cycle Plant. An electric power plant consisting of a series of combustion turbines with heat extractors on their exhausts (see also Section 2-2d(5)).

Combustion Turbine Plant. An electric power plant consisting of natural gas or distillate oil-fired jet engines connected to a generator (see also Section 2-2d(4)).

Energy Displacement Plant. A power plant (usually hydro electric), whose output is used to displace generation from existing high-cost thermal plants (see also Section 3-11).

Fossil-Fuel Plant. An electric power plant utilizing fossil fuels (coal, lignite, oil, or natural gas) as its source of energy (see also Section 2-2d(2)).

Nuclear Power Plant. An electric generating station utilizing the energy from a nuclear reactor as the source of power (see also Section 2-2d(3)).

Peak Load (or Peaking) Plant. A power plant which is normally operated to provide power during maximum load periods (see also Section 6-3b(6)).

Pondage Plant. A hydroelectric plant with sufficient storage to permit daily or weekly shaping of streamflows (see also Section 2-3c).

Power Plant (Powerplant). A generating station where prime movers (such as turbines), electric generators, and auxiliary equipment for producing electric energy are located.

Pump-Back Hydroelectric Plant. An on-stream pumped-storage project. This type of plant utilizes a combination of natural streamflow and pumped water as its source of energy (see also Section 2-3e(3)).

Pumped-Storage Hydroelectric Plant. A hydroelectric power plant that generates electric energy for peak load use by utilizing water pumped into a storage reservoir, usually during off-peak periods. The two major types of pumped-storage hydroelectric plants are pump-back and off-stream pumped-storage plants (see also Sections 2-3e and 7-1b).

Run-of-River Plant. A hydroelectric power plant utilizing pondage or the flow of the stream as it occurs (see also Section 2-3b).

Steam-Electric Plant. An electric power plant utilizing steam for the motive force of its prime movers. Steam plants can be either nuclear or fossil fuel-fired, or they can utilize geothermal energy.

Storage Plant. A hydroelectric plant associated with a reservoir having power storage (see see also Section 2-3d).

Thermal Plant. An electric power plant which derives its energy from a heat source, such as combustion, geothermal water or steam, or nuclear fission. Includes fossil-fuel and nuclear steam plants and combustion turbine and combined cycle plants.

PONDAGE. Reservoir storage capacity of limited magnitude, that provides only daily or weekly regulation of streamflow (see also Sections 2-3c and 6-8b).

POWER. The time rate of transferring energy. Electrical power is measured in kilowatts. The term is also used in the electric power industry to mean inclusively both capacity (power) and energy.

Continuous Power. Hydroelectric power available from a plant on a continuous basis under the most adverse hydraulic conditions contemplated. Same as prime power.

Firm Power. Power intended to have assured availability to the customer to meet all or any agreed upon portion of his load requirements.

Interruptible Power. Power made available under agreements which permit curtailment or cessation of delivery by the supplier (see also Section 2-2d(10)).

Nonfirm Power. Power which does not have assured availability to the customer to meet his load requirements.

Prime Power. Same as continuous power.

Seasonal Power. Power generated or made available to customers only during certain seasons of the year.

POWER BENEFITS. The monetary benefits associated with the output of a hydroelectric plant (see also Section 9-2).

POWER POOL.

Reservoir Power Pool. That portion of a reservoir's storage capacity which is allocated to the storage of water for power production.

Electric Power Pool. Two or more interconnected electric power systems that are coordinated to supply power in the most economical manner for their combined loads.

POWER VALUES. Annualized unit costs of constructing and operating the thermal alternative to a hydroelectric plant (see also Sections 9-3b and 9-5a).

At-Market (or At-load Center) Value. The value of power at the market as measured by the cost of producing and delivering equivalent alternative power to the market (see also Section 9-5g).

At-Site Value. The value of power at the site of the hydroelectric plant as measured by the at-market value minus the cost of transmission facilities and losses from the hydroelectric plant to the load center. The amount of power at the site is more than the amount of power at the market due to transmission losses (see also Section 9-5g).

Capacity Value. That part of the at-site or at-market power value which is assigned to capacity (see also Section 9-5b).

Energy Value. That part of the at-site or at-market power value which is assigned to energy (see also Section 9-5d).

Fuel Displacement Value. The value of electric energy, usually hydro, which may be substituted for energy generated in a fuel-electric plant, in terms of the incremental cost of producing the energy in the fuel-electric plant (see also Section 9-6)

PUMP-TURBINE (REVERSIBLE TURBINE). A hydraulic turbine, normally installed in a pumped-storage plant, which can be used alternately as a pump and prime mover (turbine) (see also Sections 7-2f and g).

RAMP RATE. The maximum allowable rate of change in output from a powerplant. The ramp rate is established to prevent undesirable effects due to rapid changes in loading or (in the case of hydroelectric plants) discharge.

REACTION TURBINE. A turbine which utilizes both kinetic energy and the pressure of the water column for producing power. Francis, Kaplan, and fixed-blade turbines are all reaction turbines (see also Section 2-6c).

REREGULATING RESERVOIR (REREGULATOR). A reservoir located downstream from a hydroelectric peaking plant. A reregulator has sufficient pondage capacity to store the widely fluctuating discharges from the peaking plant and to release them in a relatively uniform manner downstream (Sections 2-3f and 6-8c).

RESERVE. The additional capacity of a power system that is used to cover contingencies, including maintenance, forced outages, and abnormal loads (Sections 2-2e and 6-3b(7)).

Cold Reserve. Thermal generating capacity available for service but not maintained at operating temperature.

Hot Reserve. Thermal generating capacity maintained at a temperature and condition which will permit it to be placed into service promptly.

Spinning Reserve. Generating capacity connected to the bus and ready to take load. It also includes capacity available in generating units which are operating at less than their capability (see also Section 2-2e).

Standby Reserve. Reserve capacity which can be placed on-line in a matter of minutes. Includes hot reserve capacity, combustion turbines, and most idle hydroelectric capacity (see also Section 2-2c).

System Required Reserve. The system reserve capacity needed as standby to insure an adequate standard of service.

RESERVOIR STORAGE.

Active Storage. The portion of the live storage capacity in which water normally will be stored or withdrawn for beneficial uses, in compliance with operating agreements or restrictions.

Conservation Storage. That portion of the water stored in a reservoir that is impounded for later use. Synonymous with active storage. Conservation storage is the portion of a reservoir's live storage that is normally conserved for beneficial use at-site or downstream but does not include any live storage space reserved exclusively for flood control (see also Section 5-12c).

Dead Storage. The volume of a reservoir which is below the invert of the lowest outlet and cannot be evacuated by gravity.

Flood Control Storage Space. Reservoir storage space that is kept available for impounding potential flood flows. Exclusive flood control storage space is evacuated as soon as streamflows recede to the point when storage releases can be made without exceeding channel bankfull capacity. Seasonal flood control storage space is discussed under joint use storage (see also Sections 5-12d and e).

Inactive Storage. The portion of the live storage capacity from which water normally will not be withdrawn, in compliance with operating agreements or restrictions.

Joint Use Storage. Storage space that is used for flood control for part of the year and to impound conservation storage during the remainder of the year (see also Section 5-12e).

Live Storage. The volume of a reservoir exclusive of dead and surcharge storage capacity.

Pondage. Reservoir storage capacity of limited magnitude, that provides only daily or weekly regulation of streamflow (see also Sections 2-3c and 6-8b).

Power Storage. Conservation storage that is regulated for hydroelectric power generation (see also Section 5-10a).

Seasonal Storage. Reservoir storage capacity of sufficent magnitude to permit carryover from the high flow season to the low flow season, and thus to develop a firm flow substantially greater than the minimum natural flow (see also Sections 2-3d and 5-10 through 5-14).

Storage Capacity. The volume of a reservoir available to store water.

REVERSIBLE UNIT. See Pump-Turbine.

RULE CURVE. A curve or family of curves indicating how a reservoir is to be operated under specific conditions to obtain best or predetermined results. Rule curves can be designated to regulate storage for flood control, hydropower production, and other operating objectives, as well as combinations of objectives (see also Sections 5-11, 12, and 13).

RUNNER. The rotating part of a turbine.

SEQUENTIAL STREAMFLOW ROUTING (SSR). The chronological routing of streamflows through a project or system of projects in order to define a project's firm yield, its energy or peaking power output, or its performance under specified operating criteria (see also Sections 5-4c and 5-10 through 5-14).

SERVICE AREA. Territory in which a utility system is required or has the right to supply or make available electric service to ultimate consumers.

SPILL. The discharge of water through gates, spillways, or conduits which bypasses the turbines of a hydroelectric plant.

SPIRAL CASE. A steel-lined conduit connected to the penstock or intake conduit that evenly distributes water flow to the turbine runner (Section 2-5b).

STATION USE. Energy power used in a generating plant as necessary in the production of electricity. It includes energy consumed for plant light, power, and auxiliaries regardless of whether such energy is produced at the plant or comes from another source.

STEAM PLANT. See Plant, Steam-Electric.

STORAGE CAPACITY. See Reservoir Storage.

STORAGE DRAFT. Stored water released from a reservoir during a specified interval of time, thereby lowering the elevation of the water surface in the reservoir.

STORAGE PROJECT. A project with a reservoir of sufficient size to permit carryover from the high-flow season to the low-flow season, and thus to develop a firm flow substantially more than the minimum natural flow. A storage project may have its own powerplant or may be used only for increasing generation at some downstream plant (see also Sections 2-3d and 5-10 through 5-14).

STREAMFLOW. The rate at which water passes a given point in a stream, usually expressed in cubic feet per second.

Average Streamflow. The average rate of flow at a given point during a specified period.

Depleted Streamflow. Streamflow which has been adjusted to remove existing or projected withdrawals or diversions for irrigation or municipal and industrial water supply (see also Sections 4-3b and e).

Maximum Streamflow. The maximum rate of flow at a given point during a specified period.

Median Streamflow. The rate of flow at a given point for which there are equal numbers of greater and lesser flow occurrences during a specified period.

Minimum Streamflow. The minimum rate of flow at a given point during a specified period.

Natural Streamflow. Streamflow at a given point of an uncontrolled stream, or regulated streamflow which has been adjusted to eliminate the effects of reservoir storage or upstream diversions (see also Section 4-3b(1)).

Regulated Streamflow. The controlled rate of flow at a given point during a specified period resulting from reservoir operation.

SWITCHYARD. An assemblage of electrical equipment for the purpose of tying together two or more electric circuits through switches, selectively arranged in order to permit a circuit to be disconnected or to change the electric connection between the circuits. In a hydroelectric project, the switchyard is the point at which the energy generated at the project is connected to the distribution system (see also Section 2-5h).

TAILRACE. The channel or canal that carries water away from a dam. Also sometimes called afterbay (see also Section 2-4h).

TAILWATER ELEVATION. The elevation of the water surface downstream from a dam or hydroelectric plant (see also Section 4-5b).

THERMAL PLANT. See Plant, Thermal.

TAILWATER ELEVATION. The elevation of the water surface downstream from a dam or hydroelectric plant (see also Section 4-5b).

THERMAL PLANT. See Plant, Thermal.

TRANSFORMER. An electromagnetic device used to change the voltage of alternating current electricity (see also Section 2-5g).

TRANSMISSION. The transporting or conveying of electric energy in bulk to a convenient point at which it is subdivided for delivery to the distribution system. Also used as a generic term to indicate the conveying of electric energy over any or all of the paths from source to point of use.

WATER CONDITIONS.

Adverse Water Conditions. Water conditions limiting the production of hydroelectric power, either because of low water supply or reduced gross head or both. Also sometimes called critical water conditions (see also Section 5-10d).

Average Water Conditions. Precipitation and runoff conditions which provide water for hydroelectric power development approximating the average amount and distribution available over a long time period, usually the period of record.

Critical Water Conditions. See Adverse Water Conditions.

Median Water Conditions. Precipitation and runoff conditions which provide water for hydroelectric development approximating the median amount and distribution available over a long time period, usually the period of record.

WATER HAMMER. Potentially damaging pressure changes in a closed pressure conduit or penstock that are caused by changes in rate of water flow (see also Section 2-4f(2)).

WATT. The basic electrical unit of power or rate of doing work. The rate of energy transfer equivalent to one ampere flowing under a pressure of one volt at unity power factor. One horsepower is equivalent to approximately 746 watts.

WHEELING. The transfer of power and energy from one utility over the transmission system of a second utility for delivery to a third utility, or to a load of the first utility.

WICKET GATES. Adjustable vanes that surround a reaction turbine runner and control the area available for water to enter the turbine (see also Section 2-5b).

APPENDIX T

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APPENDIX U

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