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).

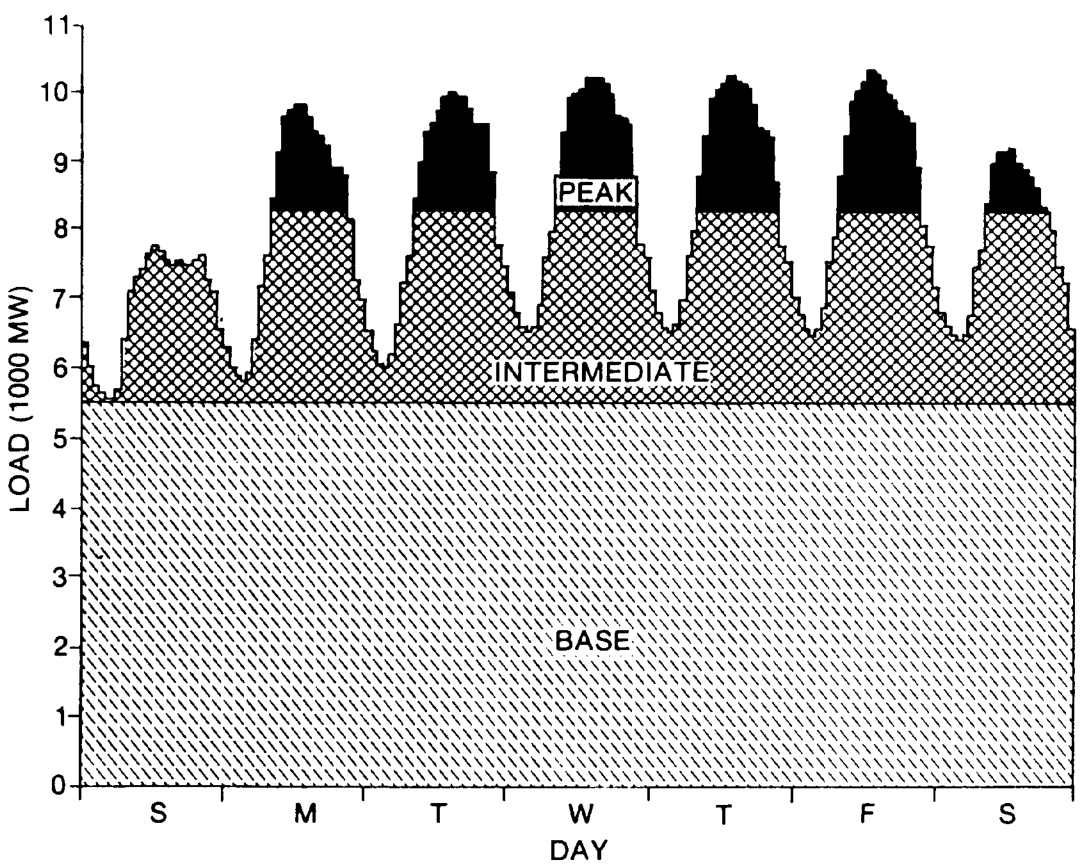

Figure 6-1. Weekly load shape showing load types

(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) <u>Reserve Capacity.</u> 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) <u>Hydro as Reserve Capacity.</u> 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) <u>Economic Limitations on Hydro as Reserve Capacity.</u> 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.

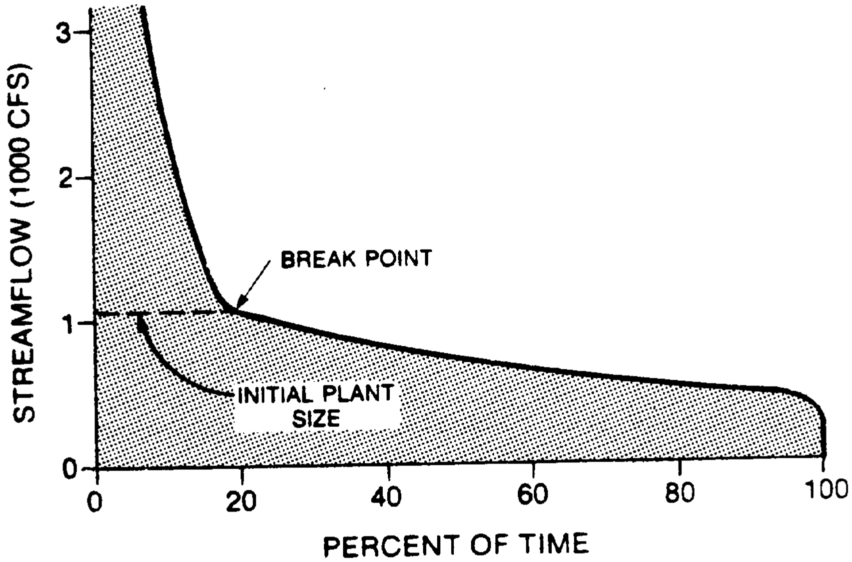

Figure 6-2. Flow-duration curve with break point

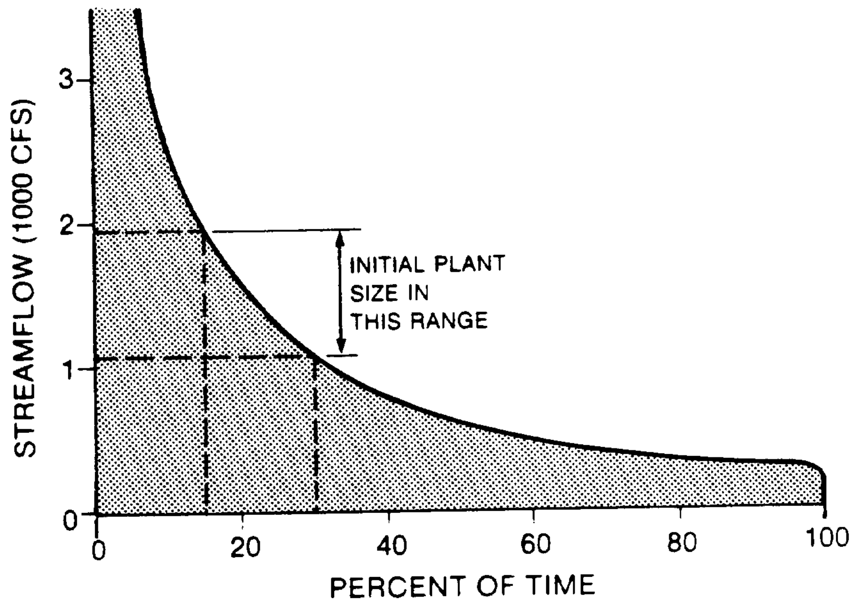

Figure 6-3. Uniform flow-duration curve

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.

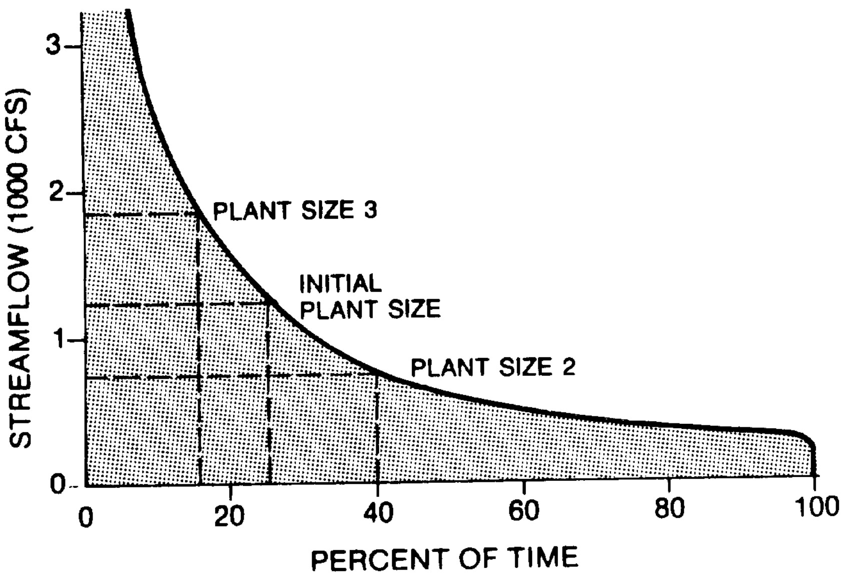

Figure 6-4. Range of plant sizes for run-of-river project used to generate base load power

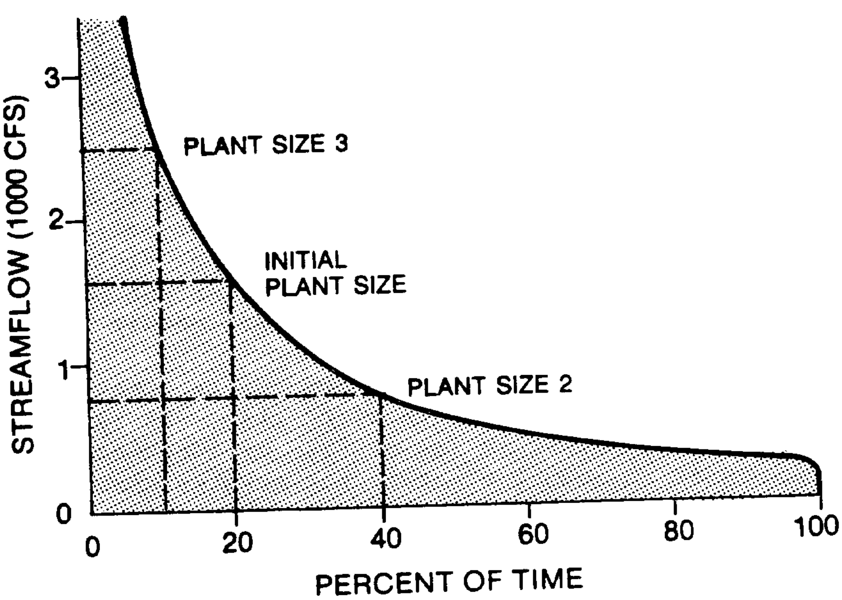

Figure 6-5. Range of plant sizes for run-of-river project used for fuel displacement

(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.

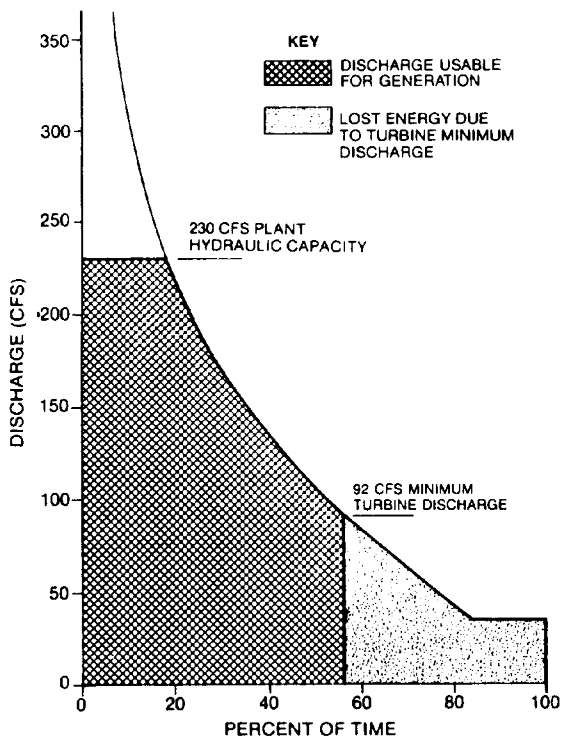

Figure 6-6. Flow-duration curve showing streamflow usable for generation: one 230 cfs unit

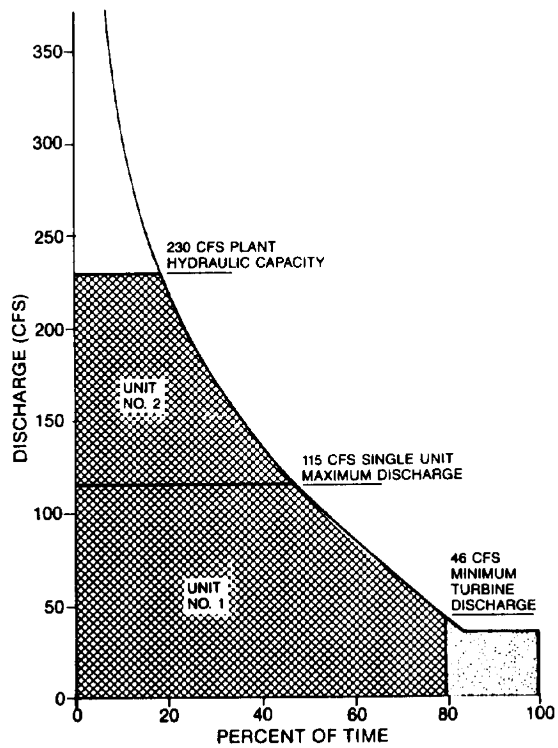

Figure 6-7. Flow-duration curve showing streamflow usable for generation: two 115 cfs units

(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.

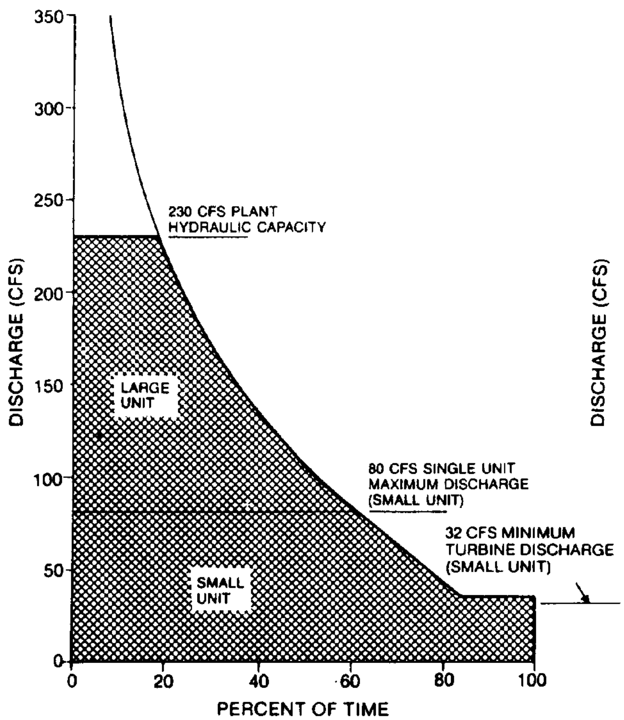

Figure 6-8. Flow-duration curve showing streamflow usable for generation: one 80 cfs unit and one 150 cfs unit

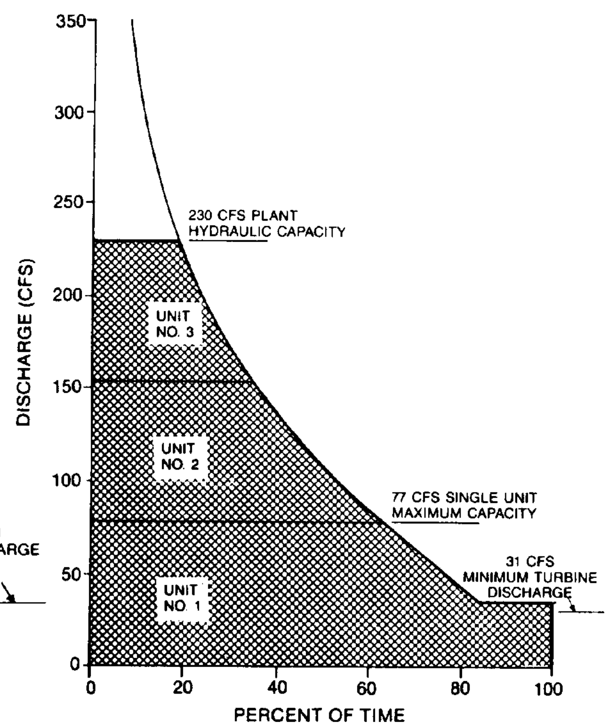

Figure 6-9. Flow-duration curve showing streamflow usable for generation: three 77 cfs units

(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 O 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 O, 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. <u>Firm Plant Factor Method.</u>

(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)

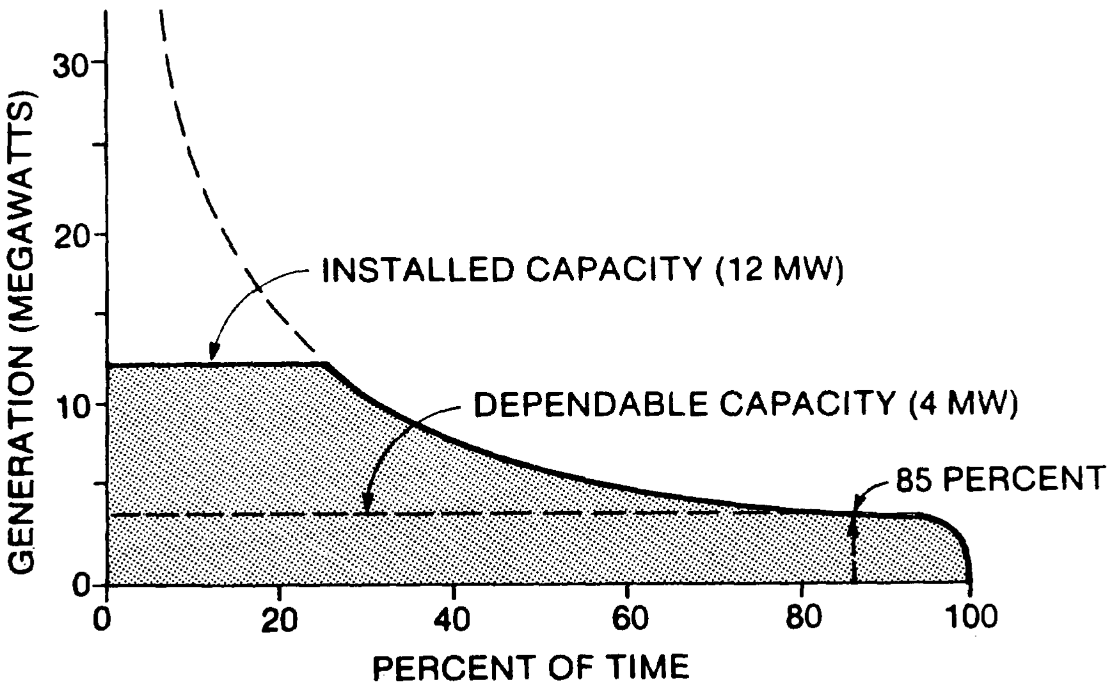

Figure 6-10. Determining dependable capacity using the specified availability method.

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.

$$\text{Dependable capacity} = (\text{HA})(\text{Installed capacity}) \qquad \text{(Eq. 6-9)}$$

(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

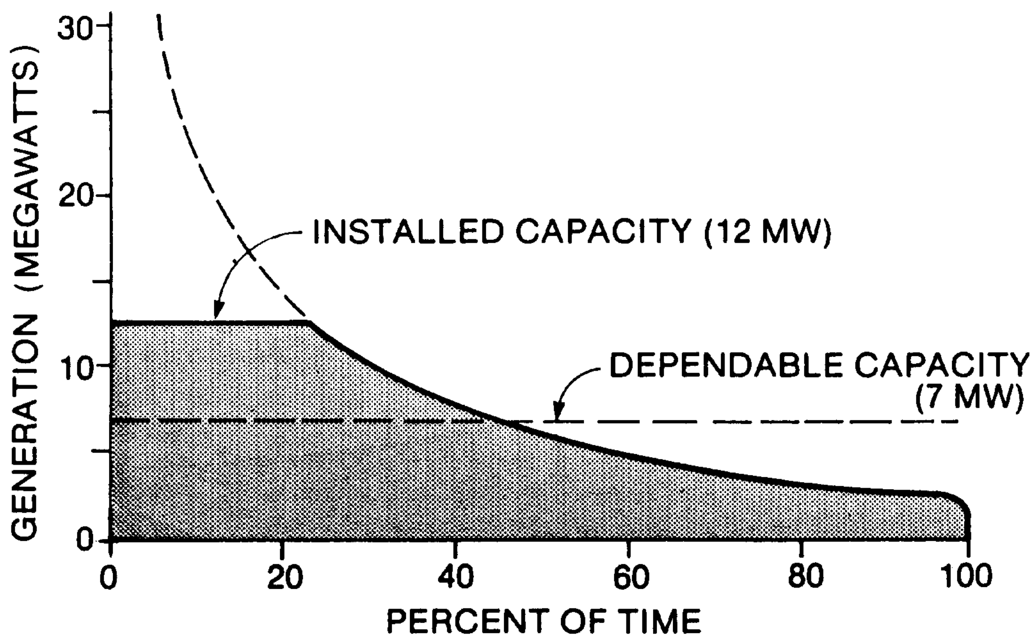

Figure 6-11. Determining dependable capacity using the average availability method

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. <u>Sustained Capacity.</u>

(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. <u>Dependable Capacity of Pumped-Storage Projects</u>.

(1) The dependability of an off-stream pumped-storage project's capacity is a function of its storage volume and the desired load

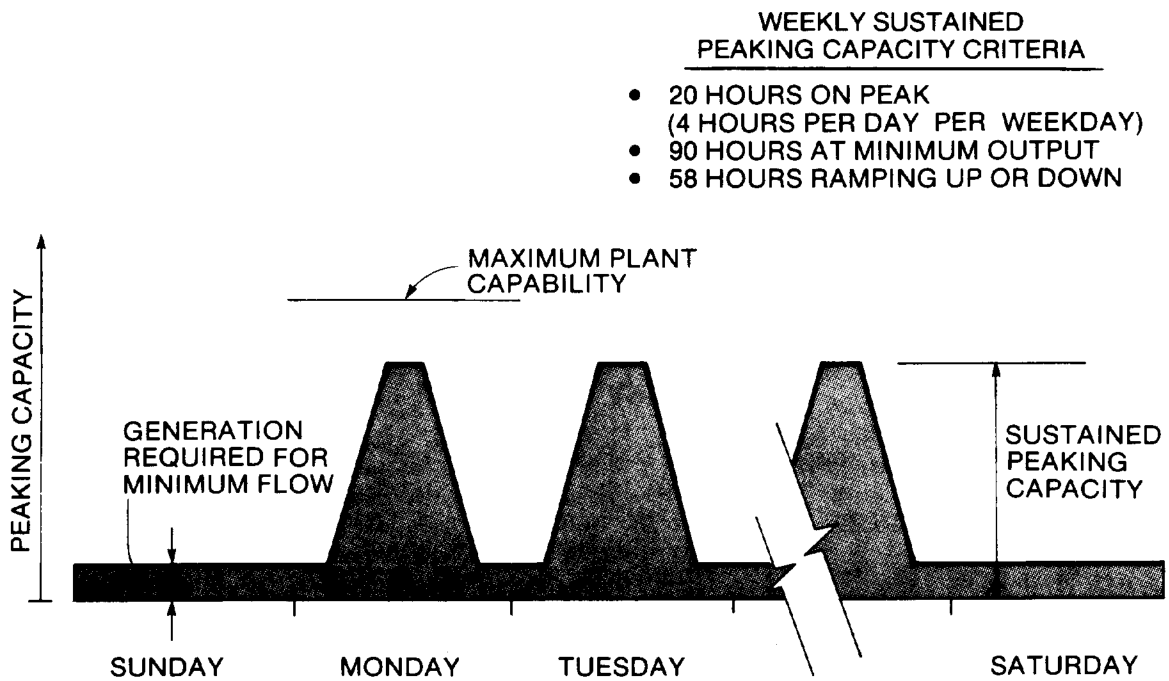

Figure 6-12. Example of sustained peaking capacity criteria

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

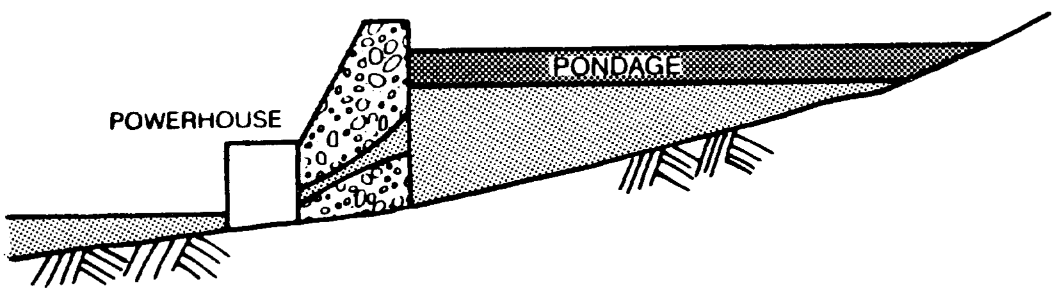

Figure 6-13. Run-of-river project with pondage

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,

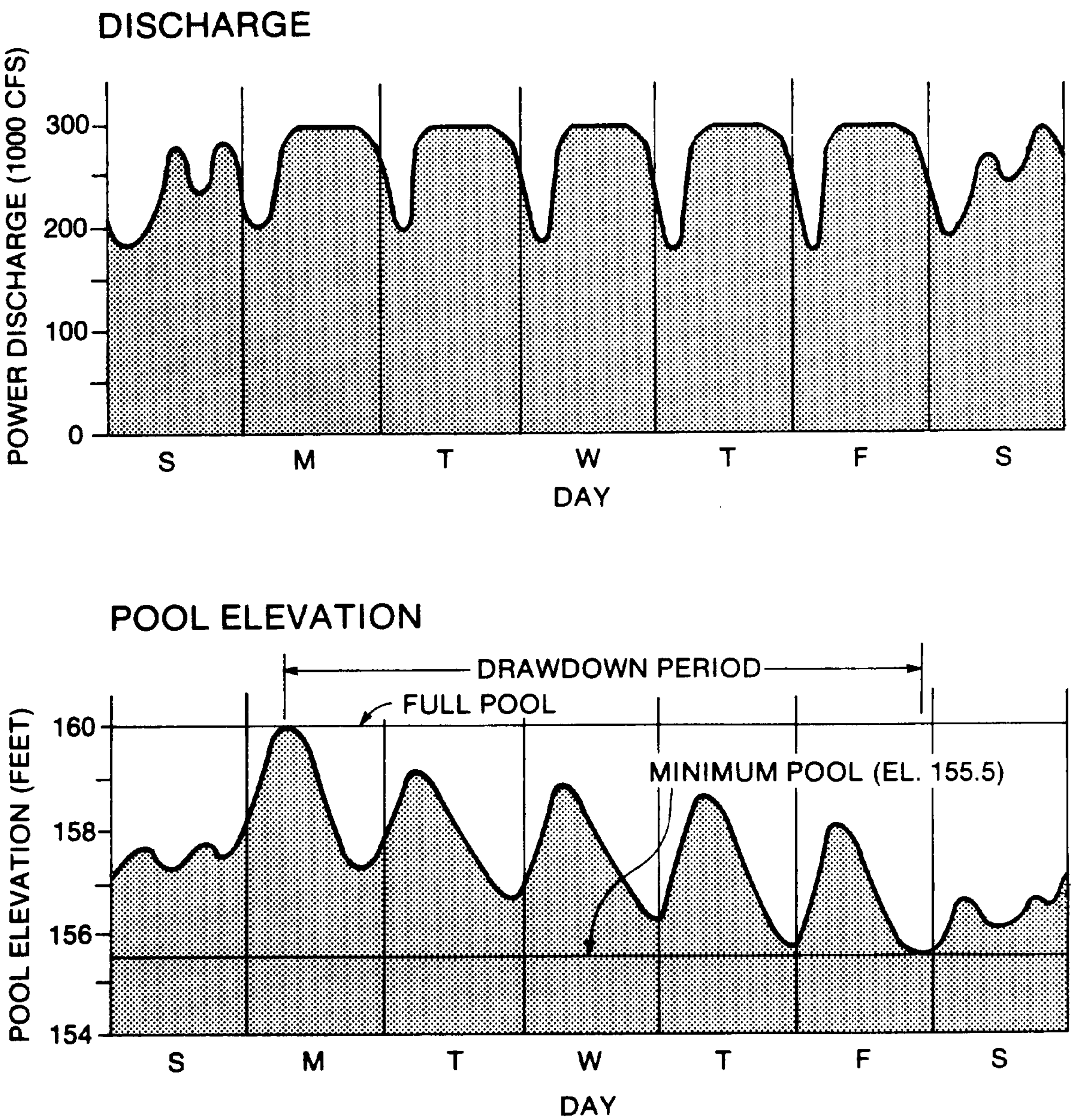

Figure 6-14. Regulation of a pondage project

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.

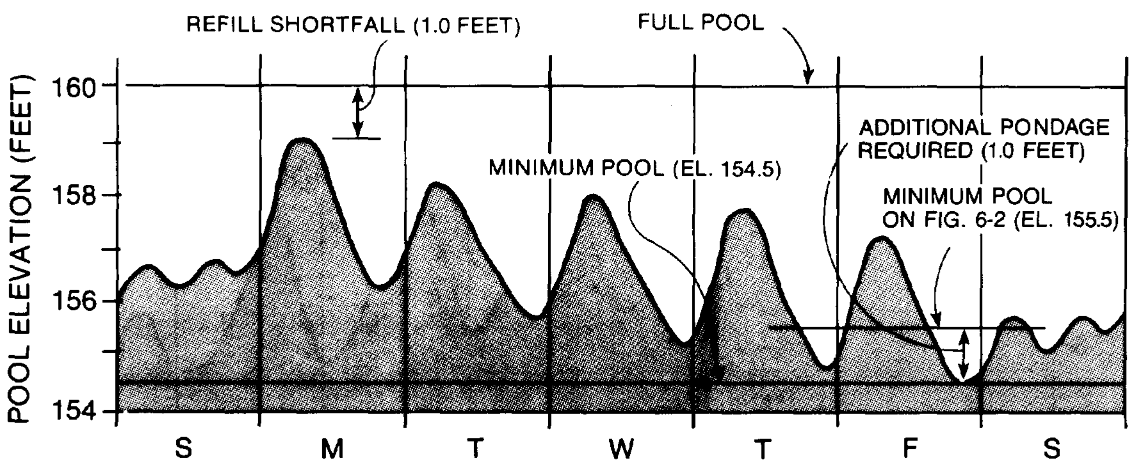

Figure 6-15. Regulation of a pondage project where the pool fails to refill by the start of the weekly operating cycle

(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.

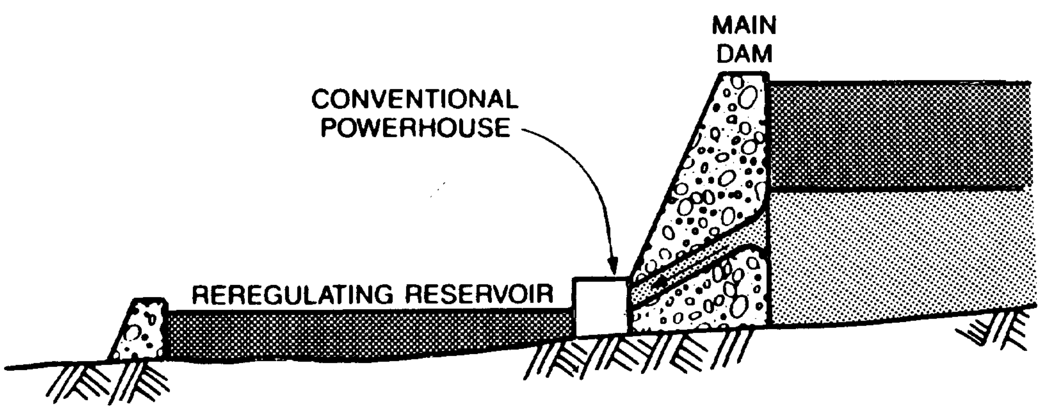

Figure 6-16. Peaking project with reregulating reservoir

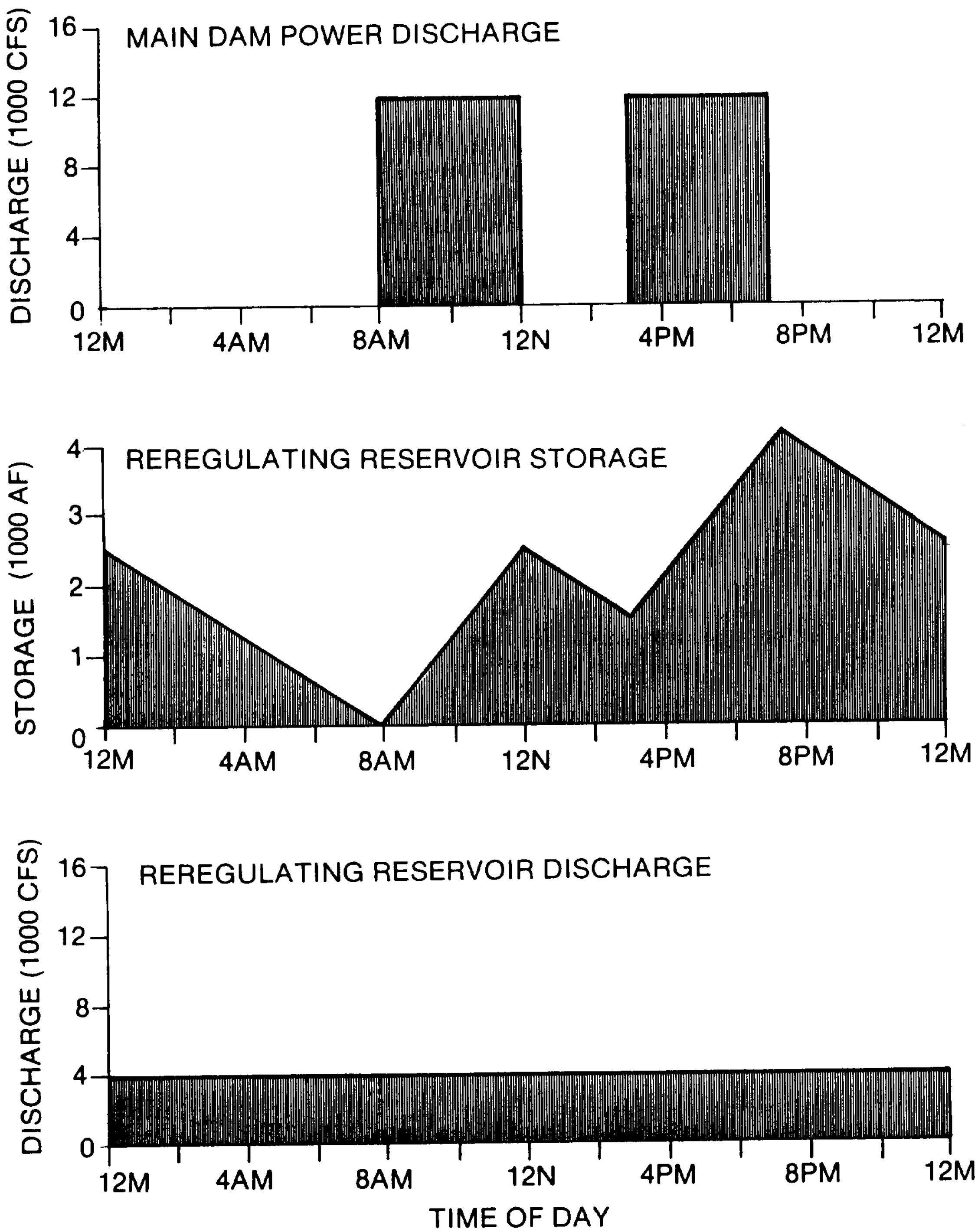

Figure 6-17. Reregulating reservoir daily operating cycle

(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

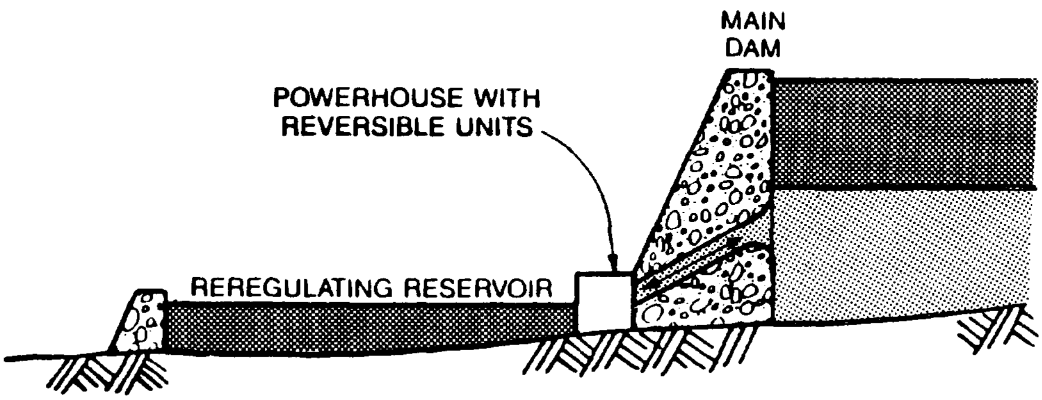

Figure 6-18. Pump-back project

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).

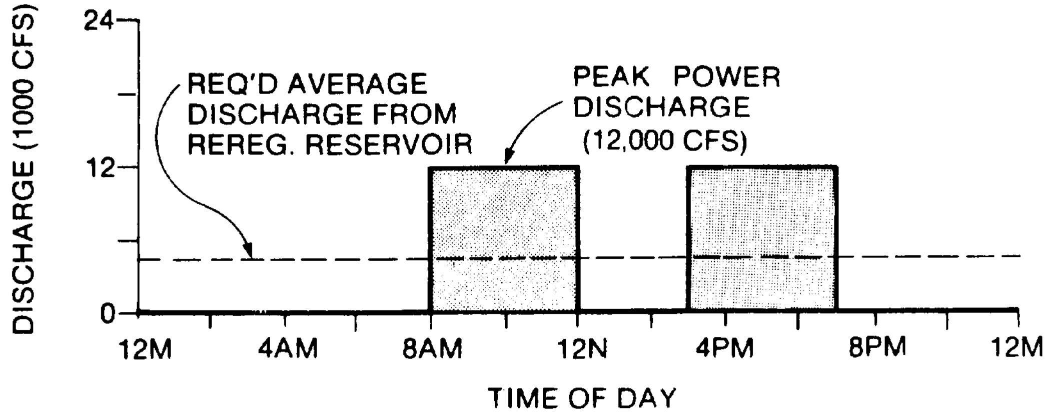

Figure 6-19. Power operation without reversible units

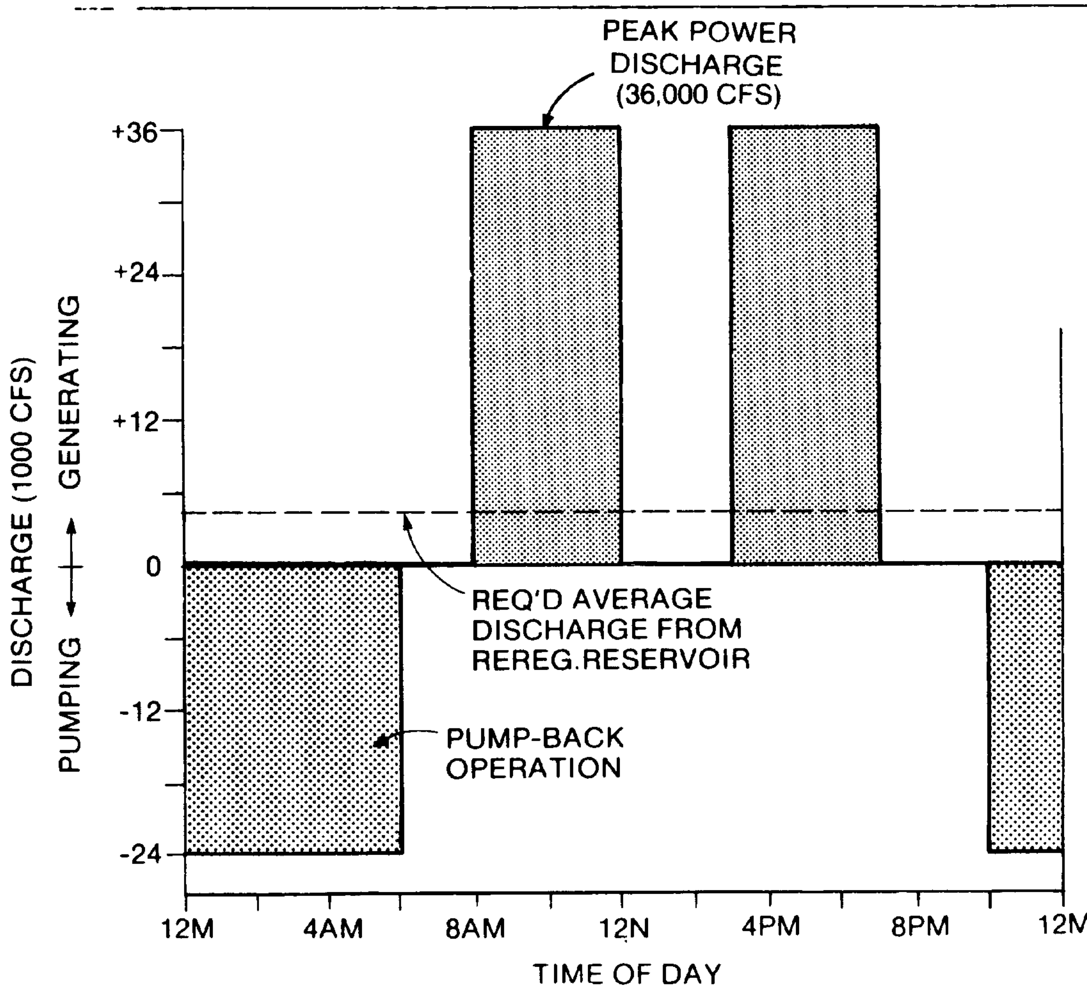

Figure 6-20. Power operation with reversible units

- 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

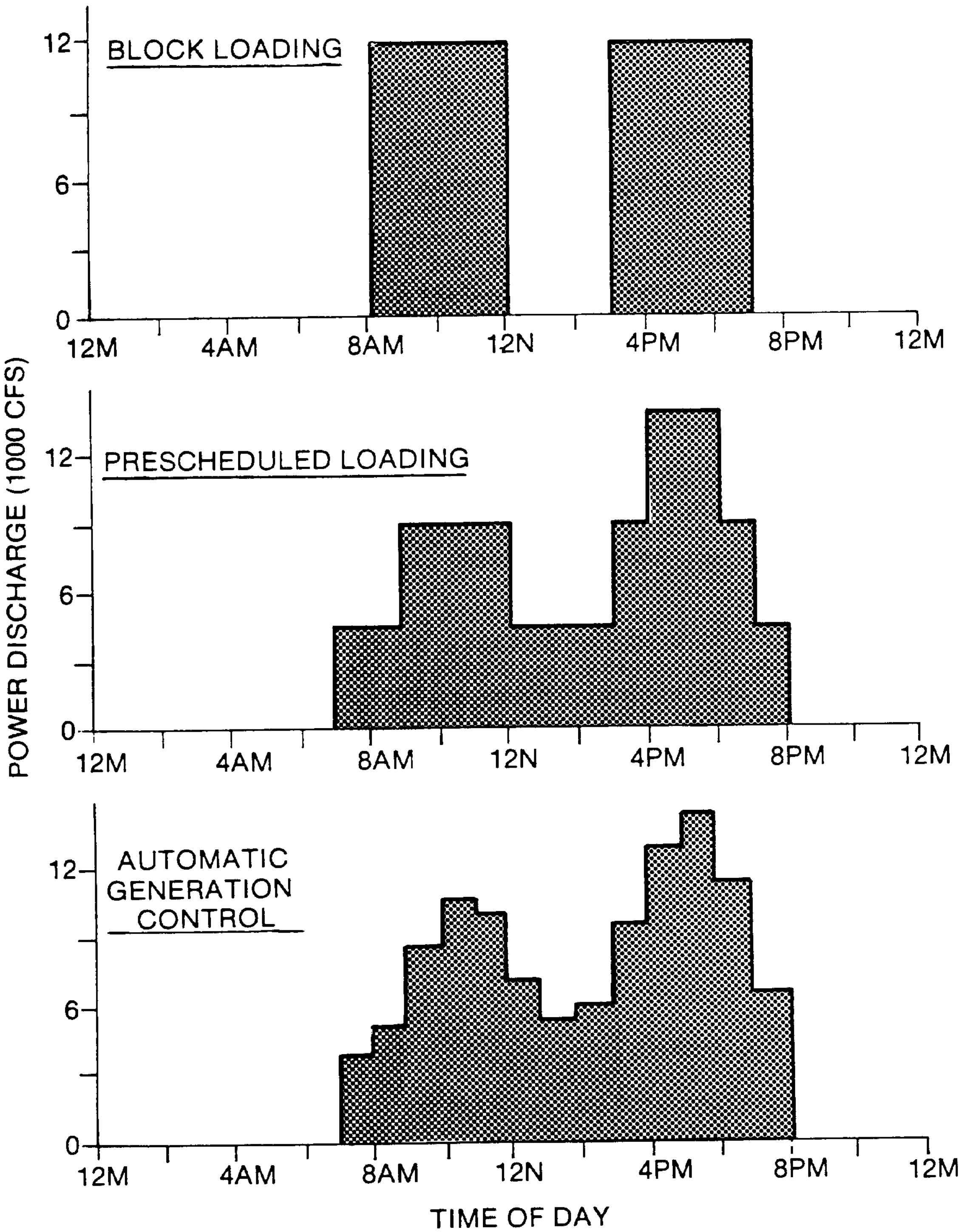

Figure 6-21. Alternative loading modes for peaking plant

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

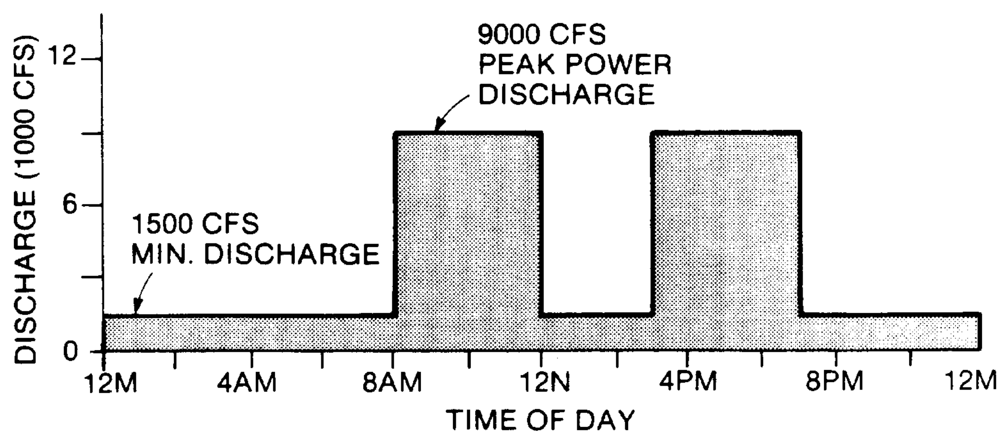

Figure 6-22. Peaking operation with minimum discharge

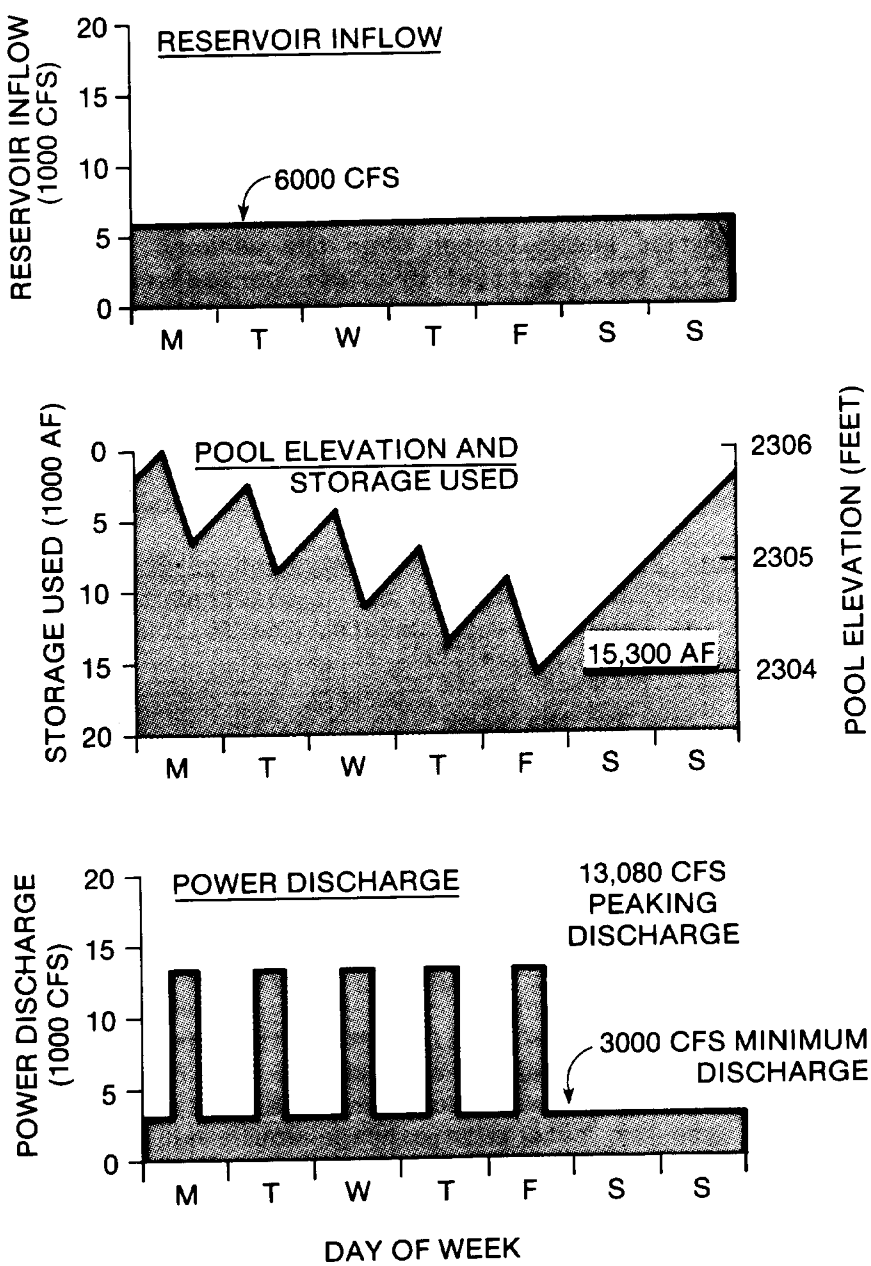

Figure 6-23. Graphical illustration of pondage analysis for peaking project

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

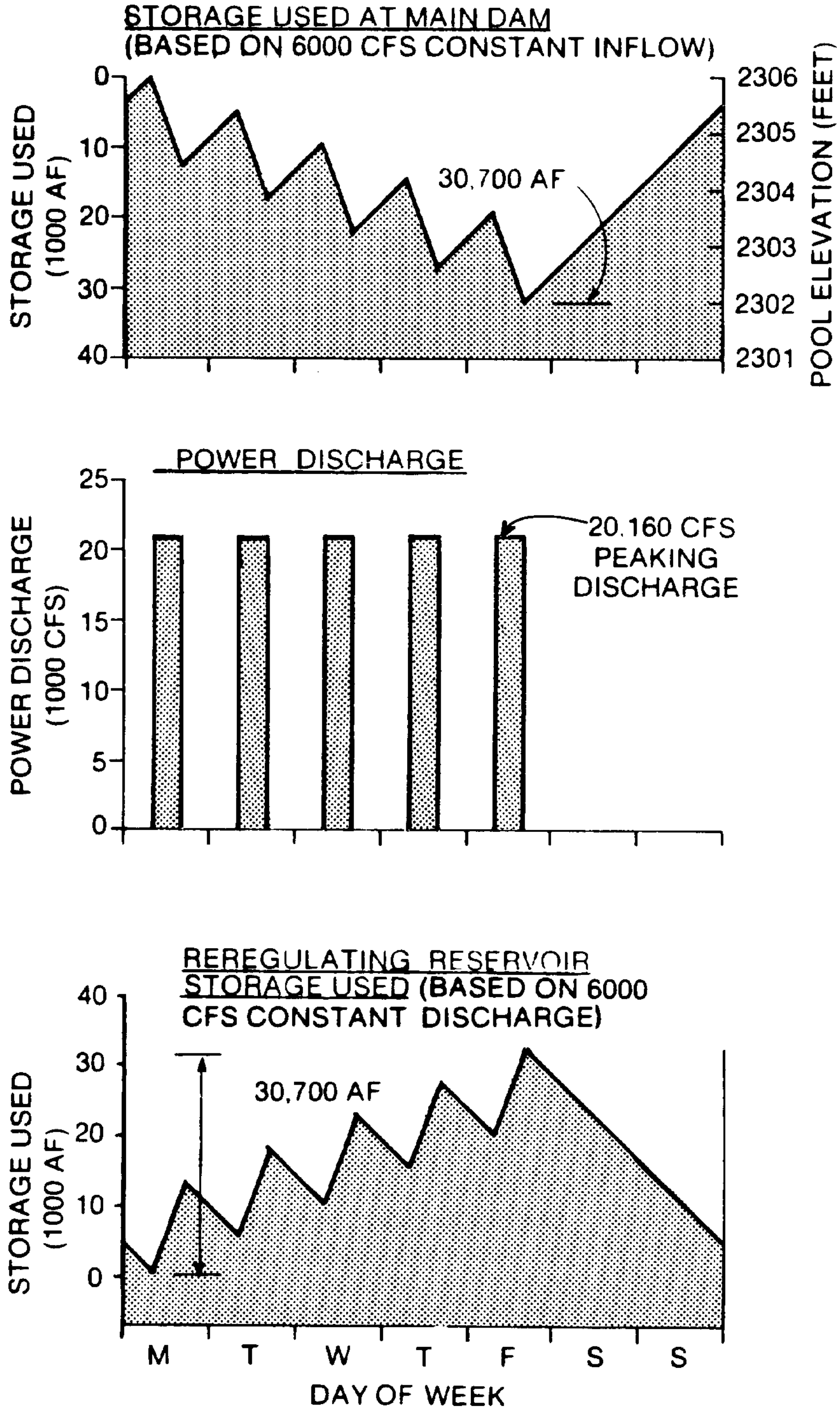

Figure 6-24. Graphical illustration of reregulating reservoir analysis

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.

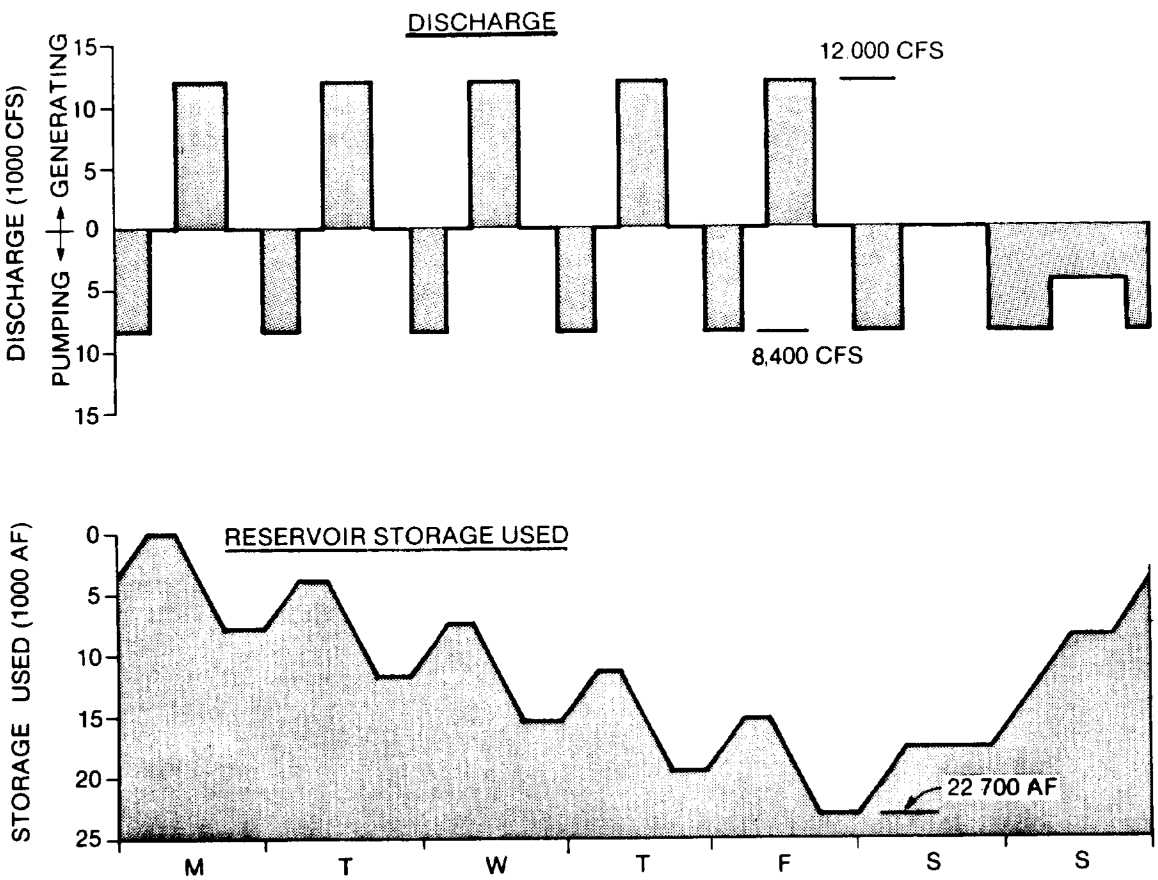

Figure 6-25. Sizing an upper reservoir for an off-stream pumped-storage project

(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).