CHAPTER 5

DETERMINING ENERGY POTENTIAL

5-1. Introduction.

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

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

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

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

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

5-2. Types of Hydroelectric Energy.

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

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

c. Firm Energy.

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

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

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

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

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

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

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

5-3. The Water Power Equation.

a. General.

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

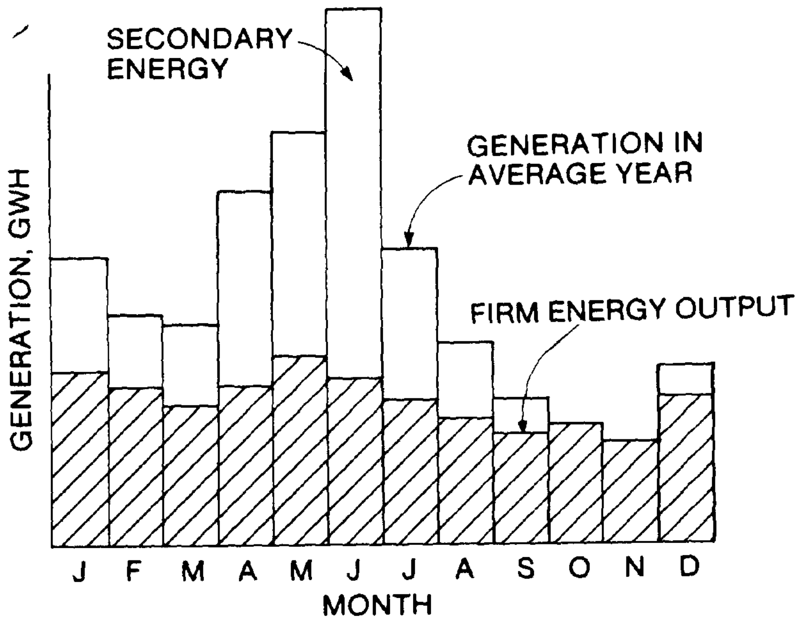


Figure 5-1. Monthly energy output of a typical hydro project

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

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

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

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

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

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

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

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

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

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

c. Head.

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

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

(2) Net head represents the actual head available for power generation and should be used in calculating energy. Head losses due to intake structures, penstocks, and outlet works are deducted from the gross head to establish the net head. Information on estimating head loss is presented in Section 5-61.

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

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

5-4. General Approaches to Estimating Energy.

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

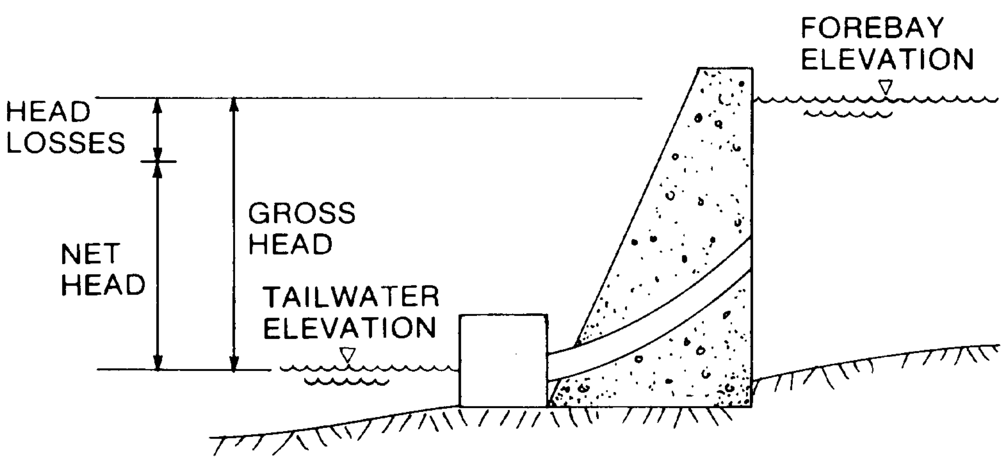


Figure 5-2. Gross head vs. net head

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

b. Flow-Duration Curve Method.

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

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

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

c. Sequential Streamflow Routing (SSR) Method.

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

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

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

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

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

e. Selection of Method.

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

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

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

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

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

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

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

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

5-5. Turbine Characteristics and Selection.

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

b. Usable Head Range.

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

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

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

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

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

c. Design and Rated Heads.

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

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

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

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

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

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

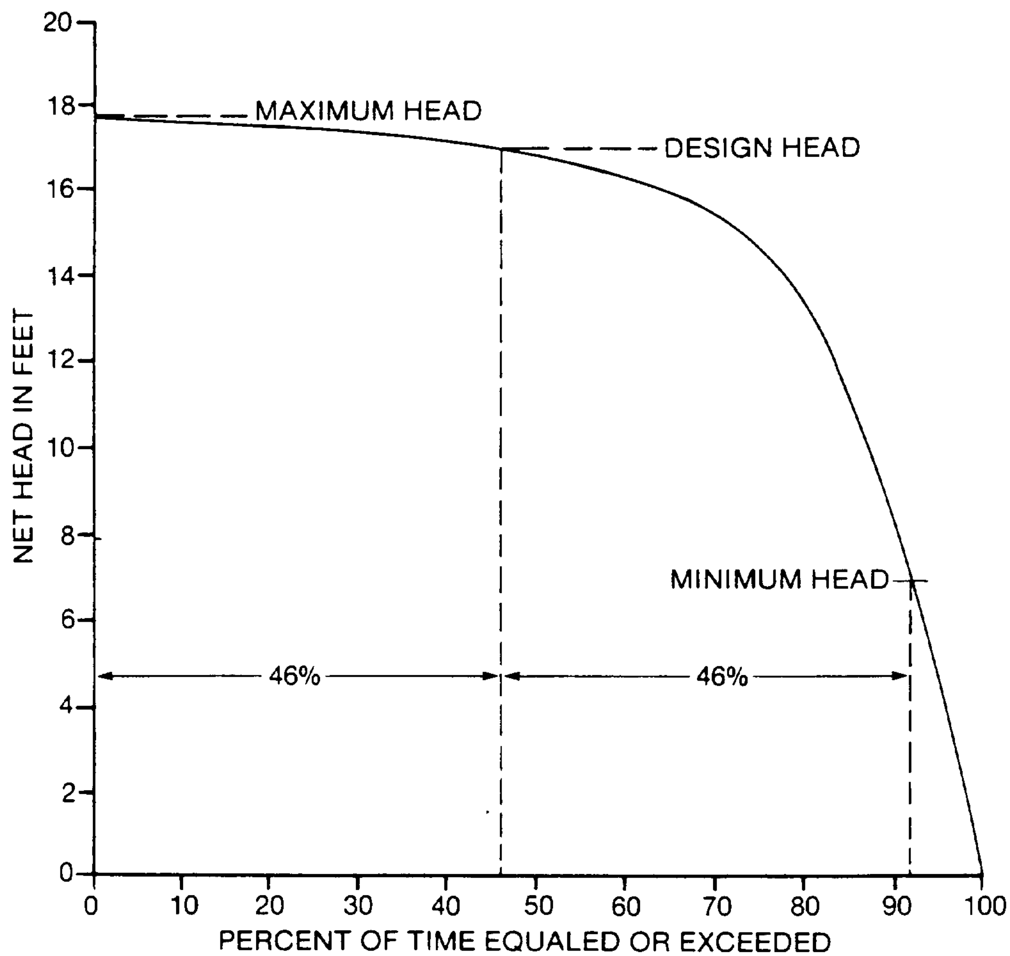


Figure 5-3. Head-duration curve for run-of-river project, showing how design head can be determined

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

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

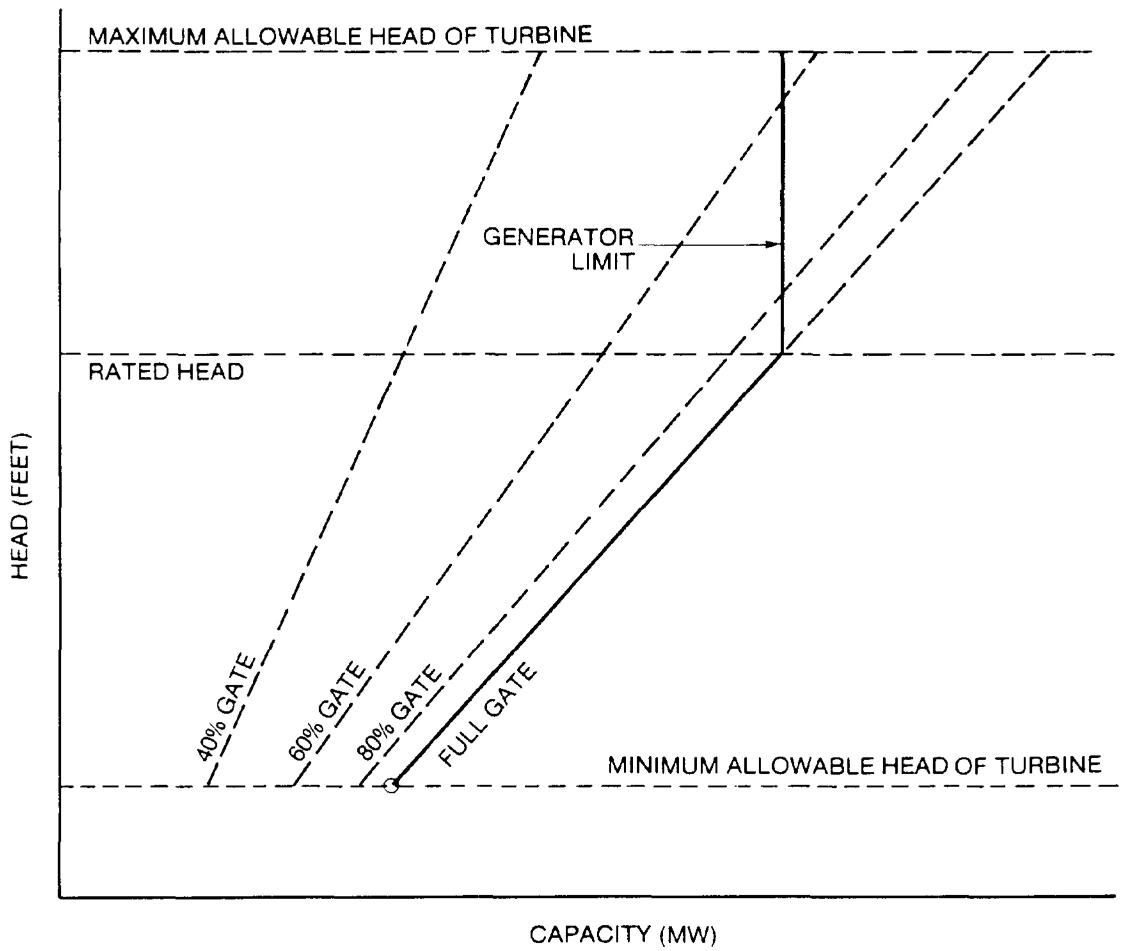


Figure 5-4. Turbine performance curve for a specific design (solid line represents maximum output of unit)

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

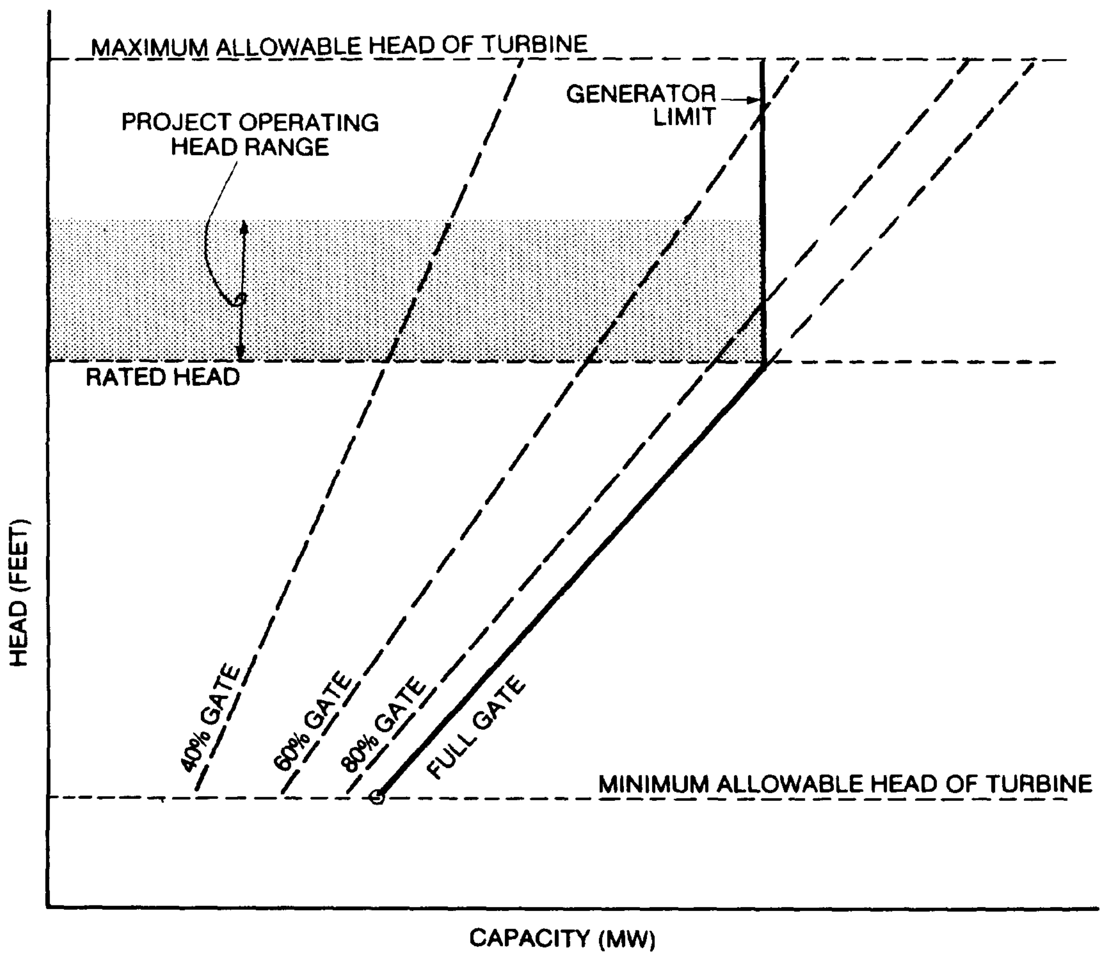


Figure 5-5. Turbine design from Figure 5-4 as applied
to a project with a narrow operating head range

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

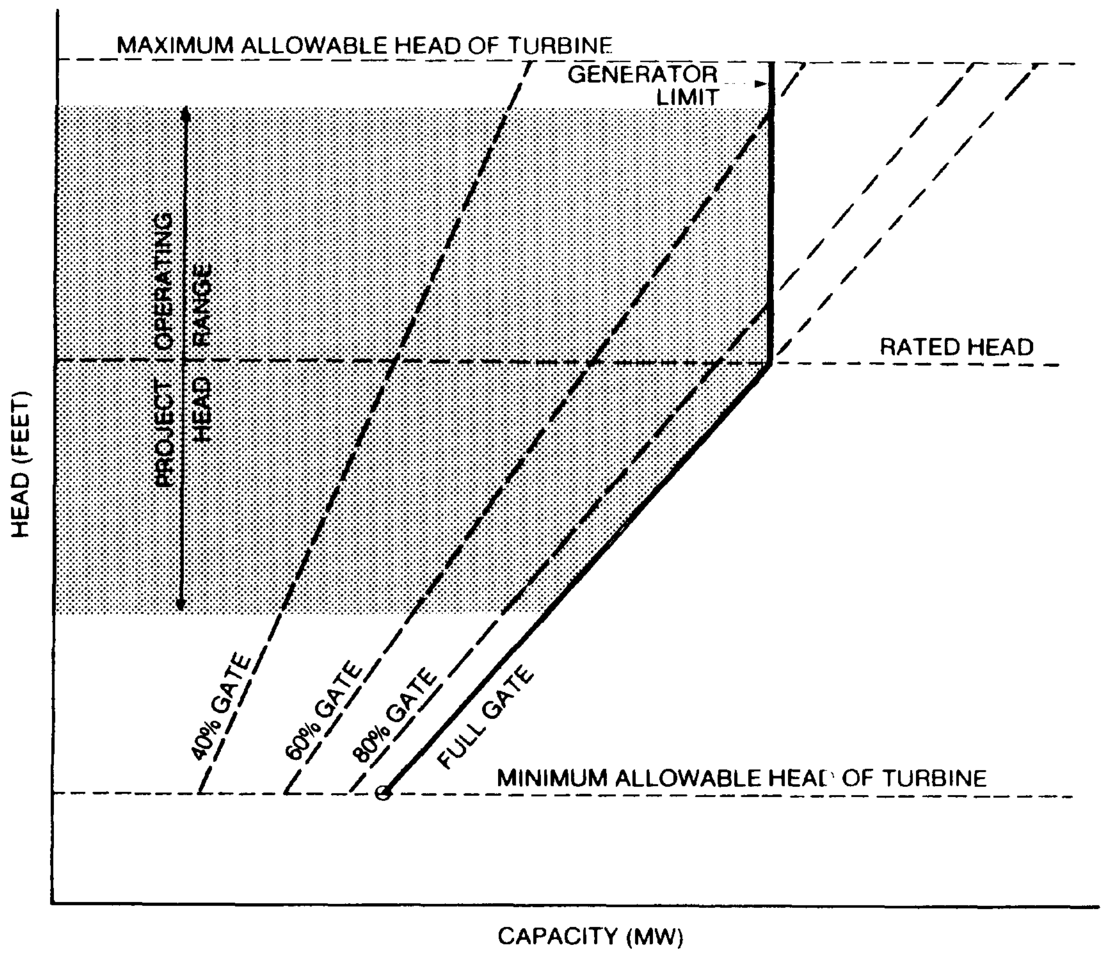


Figure 5-6. Turbine design from Figure 5-4 as applied to a storage project with large operating head range

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

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

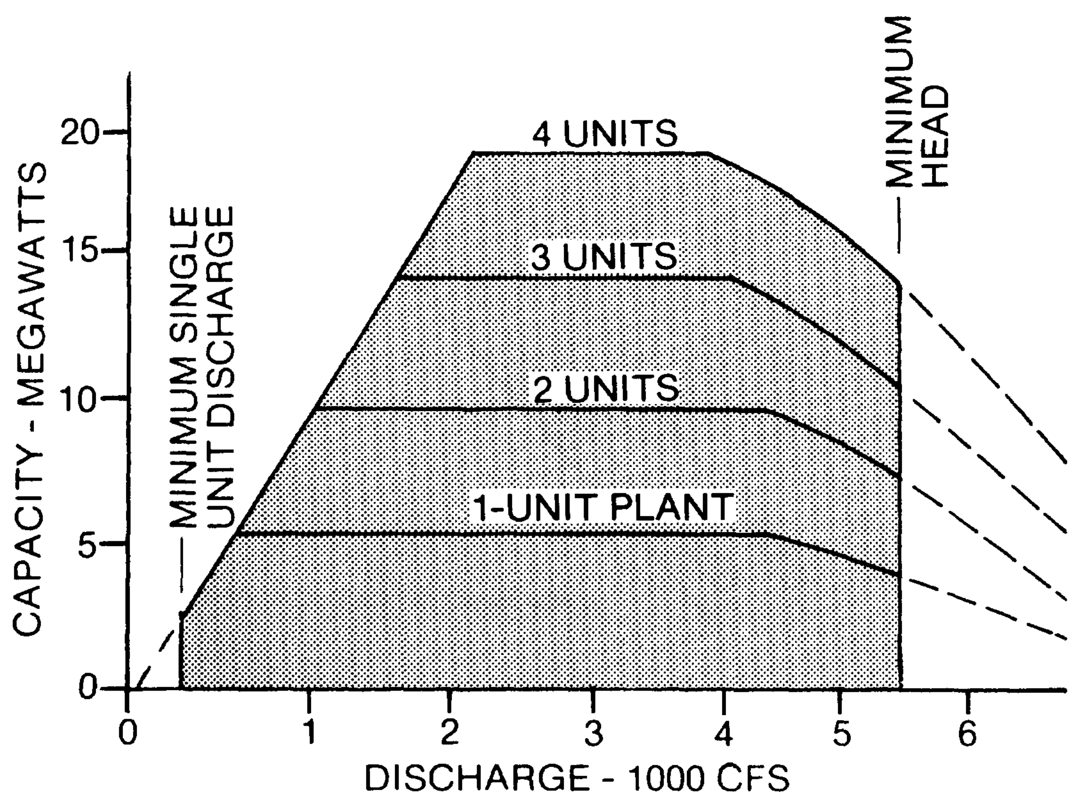


Figure 5-7. Capacity vs. discharge for run-of-river project for alternative plant sizes

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

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

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

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

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

d. Minimum Discharge.

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

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

e. Efficiency.

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

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

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

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

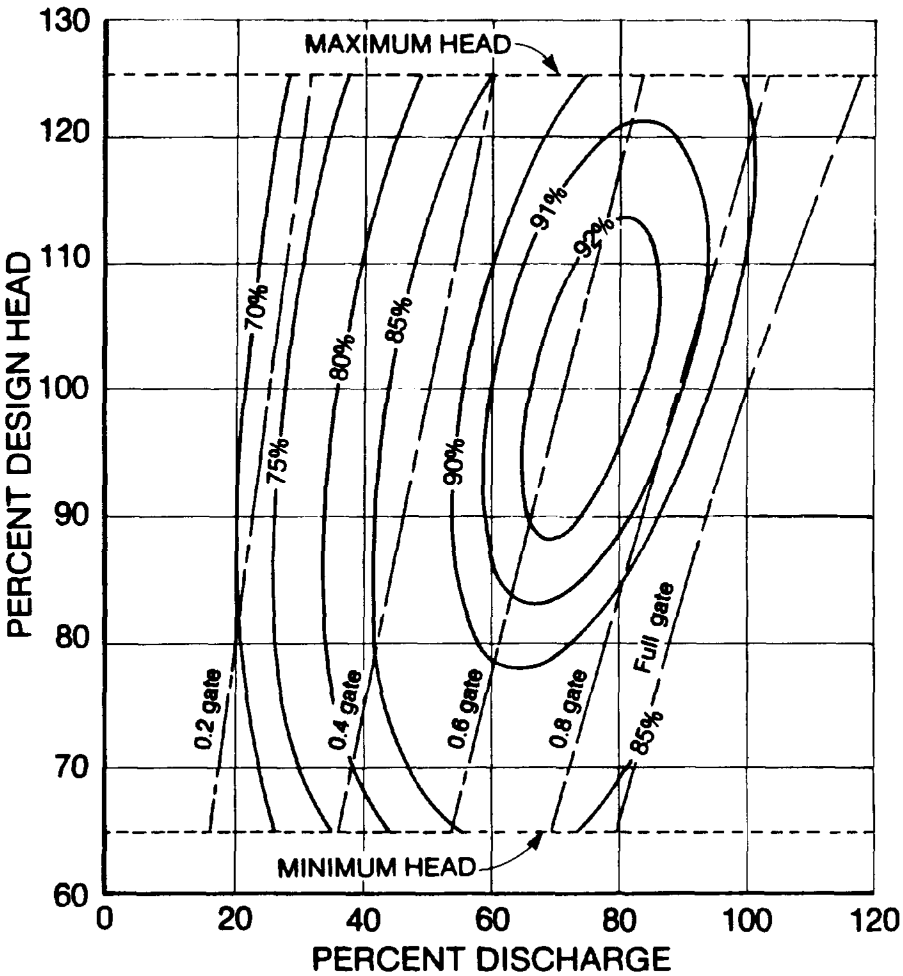


Figure 5-8. Typical Francis turbine performance curve

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

f. Turbine Selection.

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

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

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

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

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

g. Matching Generator to Turbine.

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

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

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

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

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

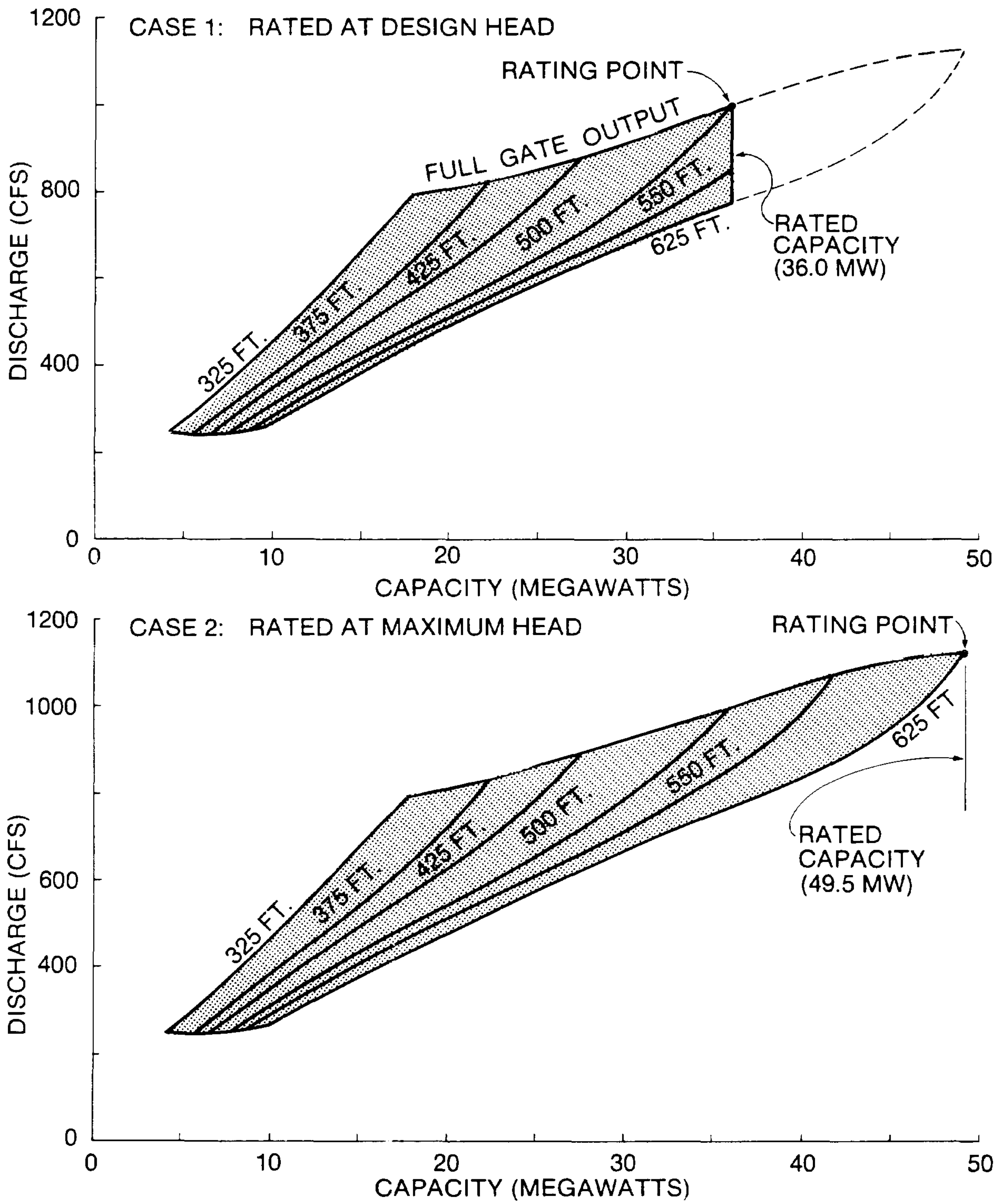


Figure 5-9. Alternative rating points for a given Francis turbine design applied to a given storage project

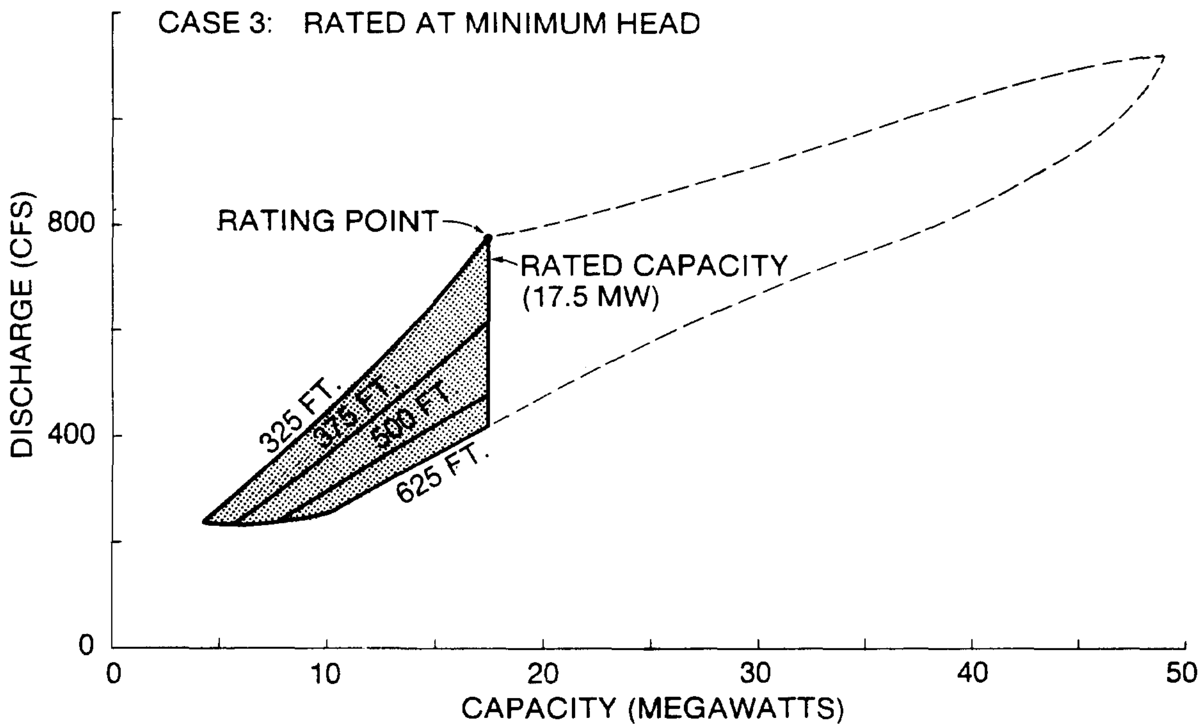


Figure 5-9 (continued)

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

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

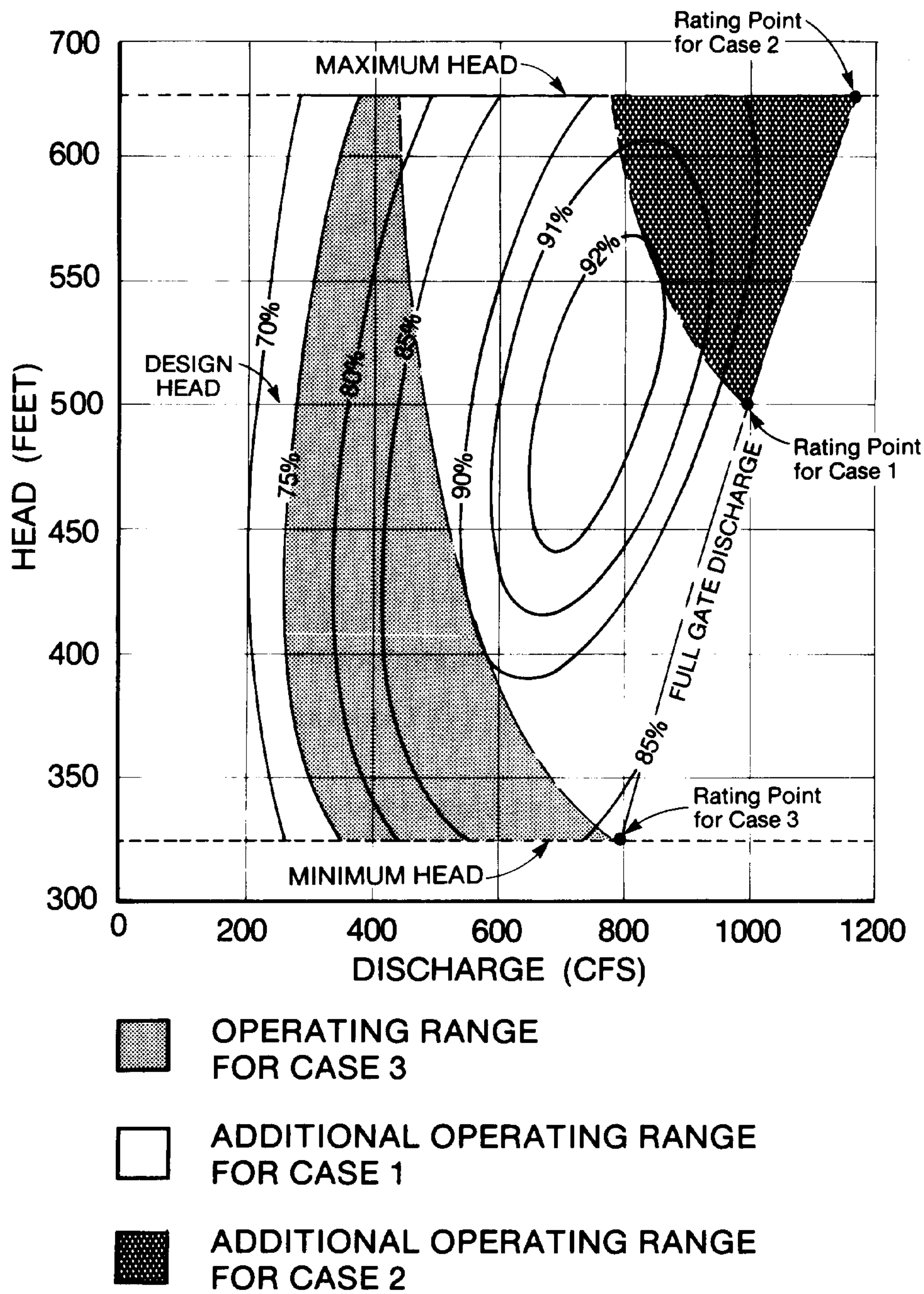


Figure 5-10. The operating ranges and efficiencies for the alternative turbine rating points shown on Figure 5-9

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

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

5-6. Data Requirements.

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

b. Routing Interval.

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

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

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

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

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

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

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

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

c. Streamflow Data.

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

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

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

d. Length of Record.

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

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

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

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

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

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

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

e. Streamflow Losses.

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

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

The non-consumptive losses include:

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

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

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

f. Reservoir Characteristics.

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

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

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

g. Tailwater Data.

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

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

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

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

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

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

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

h. Installed Capacity.

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

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

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

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

i. Turbine Characteristics.

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

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

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

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

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

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

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

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

k. Efficiency.

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

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

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

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

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

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

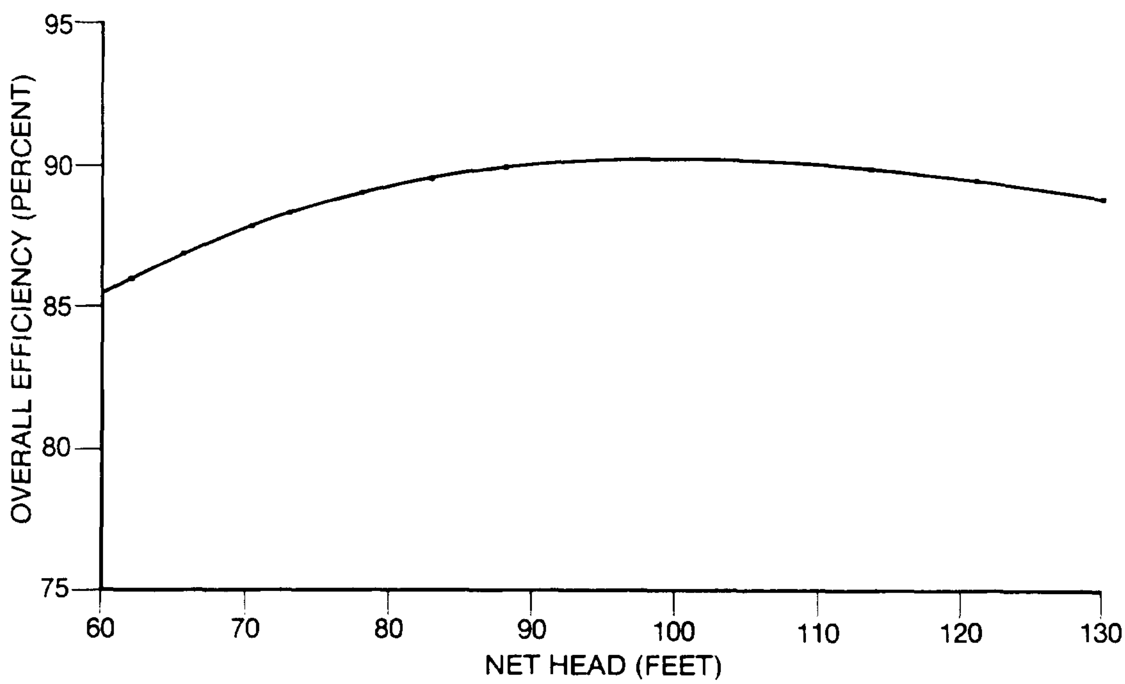


Figure 5-11. Net head vs. efficiency curve
for Francis turbine (multiple-unit installation)

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

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

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

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

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

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

l. Head Losses.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

m. Non-Power Operating Criteria.

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

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

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

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

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

n. Channel Routing Characteristics.

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

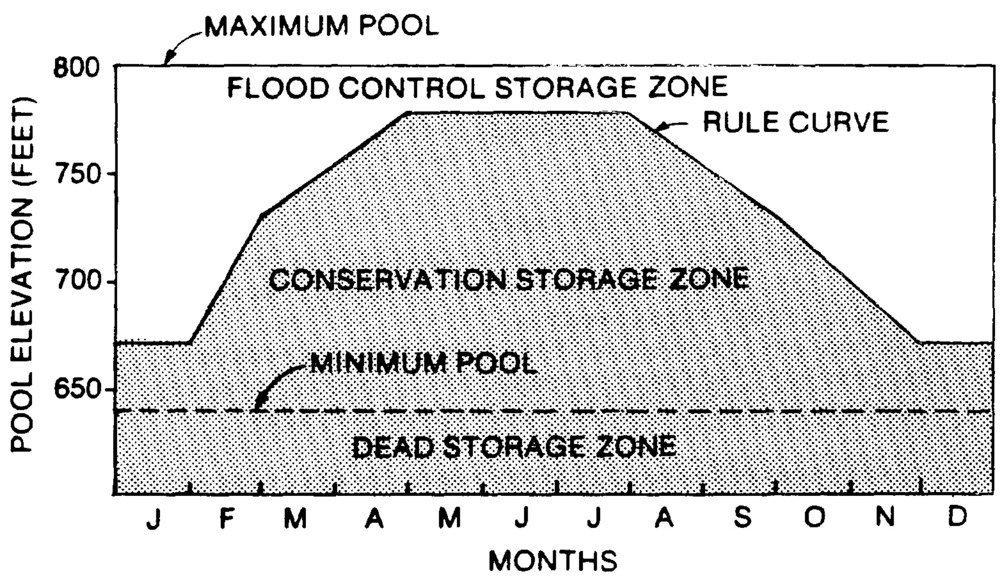


Figure 5-12. Rule curve for project with flood control and conservation storage

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

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

o. Generation Requirements.

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

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

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

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

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

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

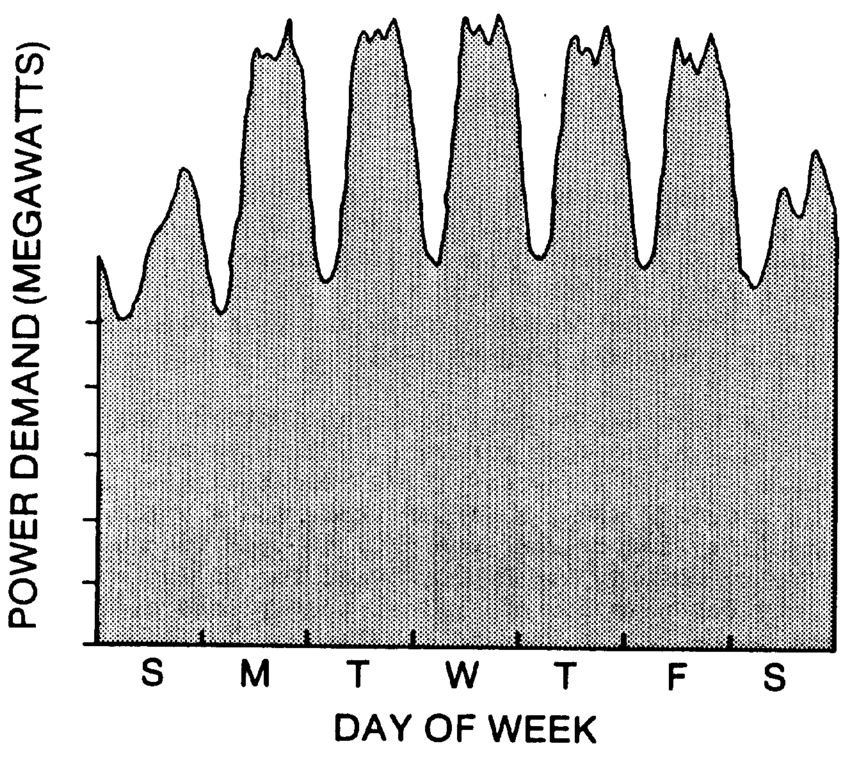


Figure 5-13. Weekly load shape

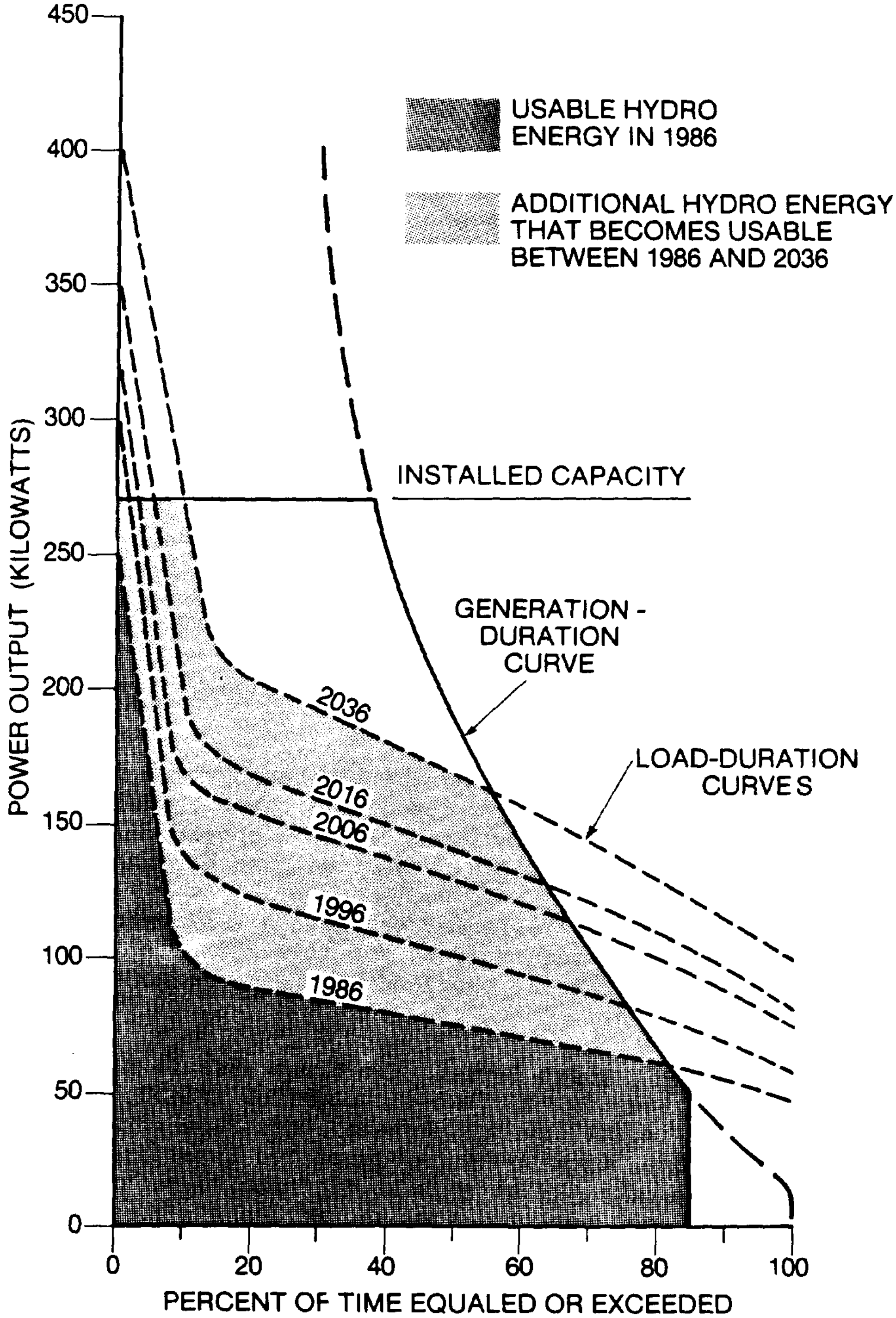


Figure 5-14. Diagram showing increase in usable energy with load growth for small hydro project serving isolated Alaskan community

5-7. Flow-Duration Method.

a. Introduction.

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

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

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

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

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

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

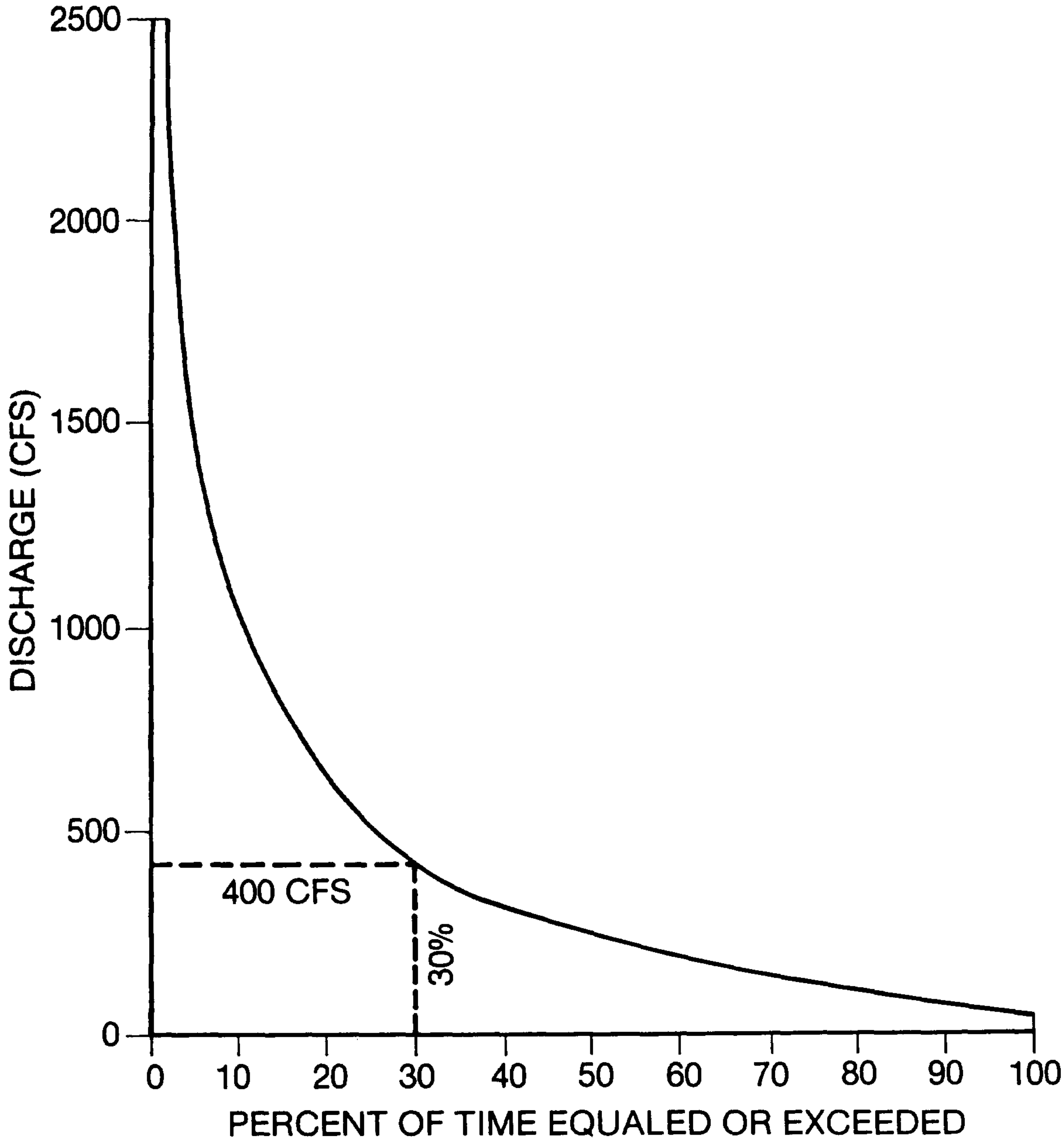


Figure 5-15. Flow-duration curve

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

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

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

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

f. Develop Head Data.

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

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

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

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

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

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

g. Select Plant Size.

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

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

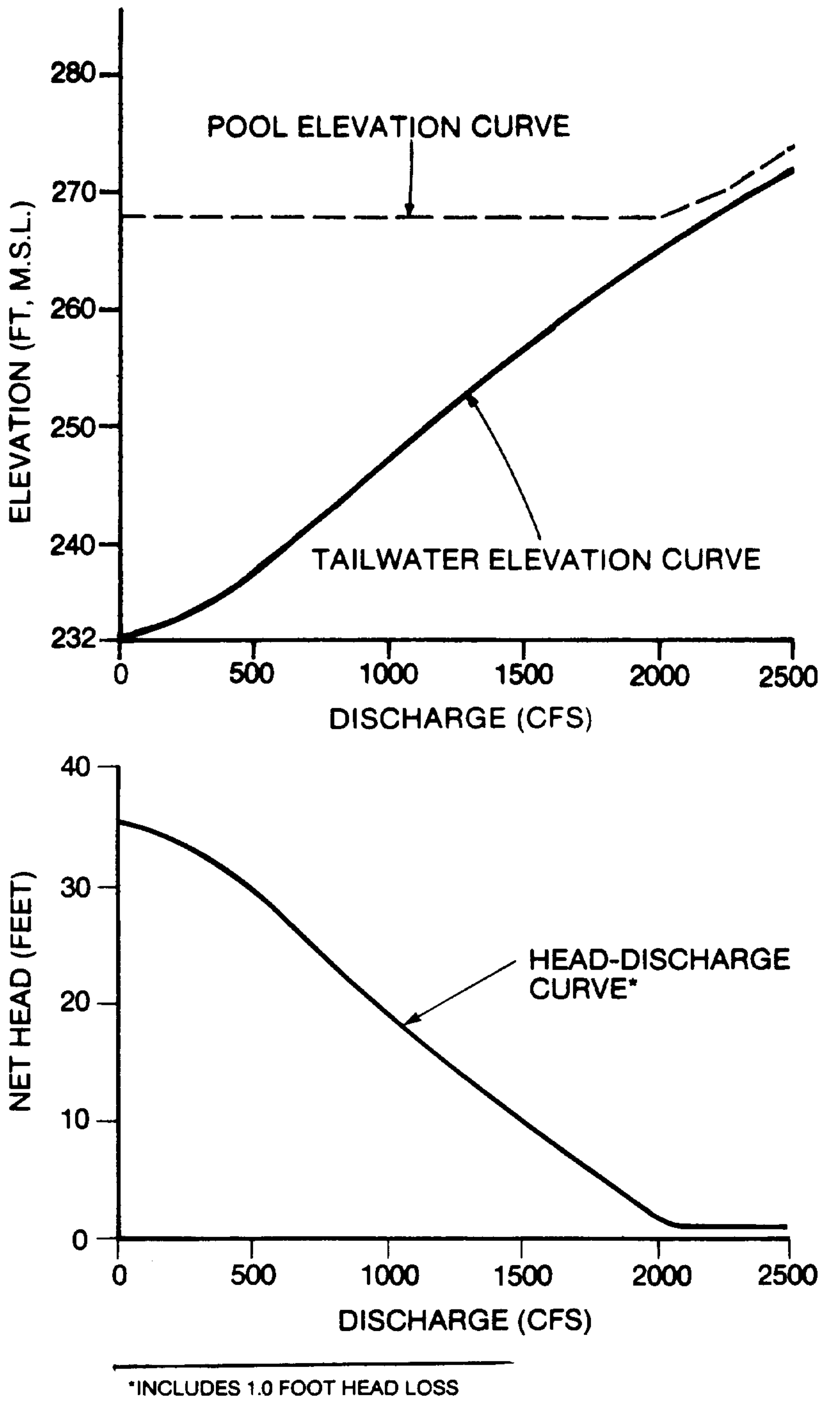


Figure 5-16. Tailwater and head-discharge curves

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

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

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

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

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

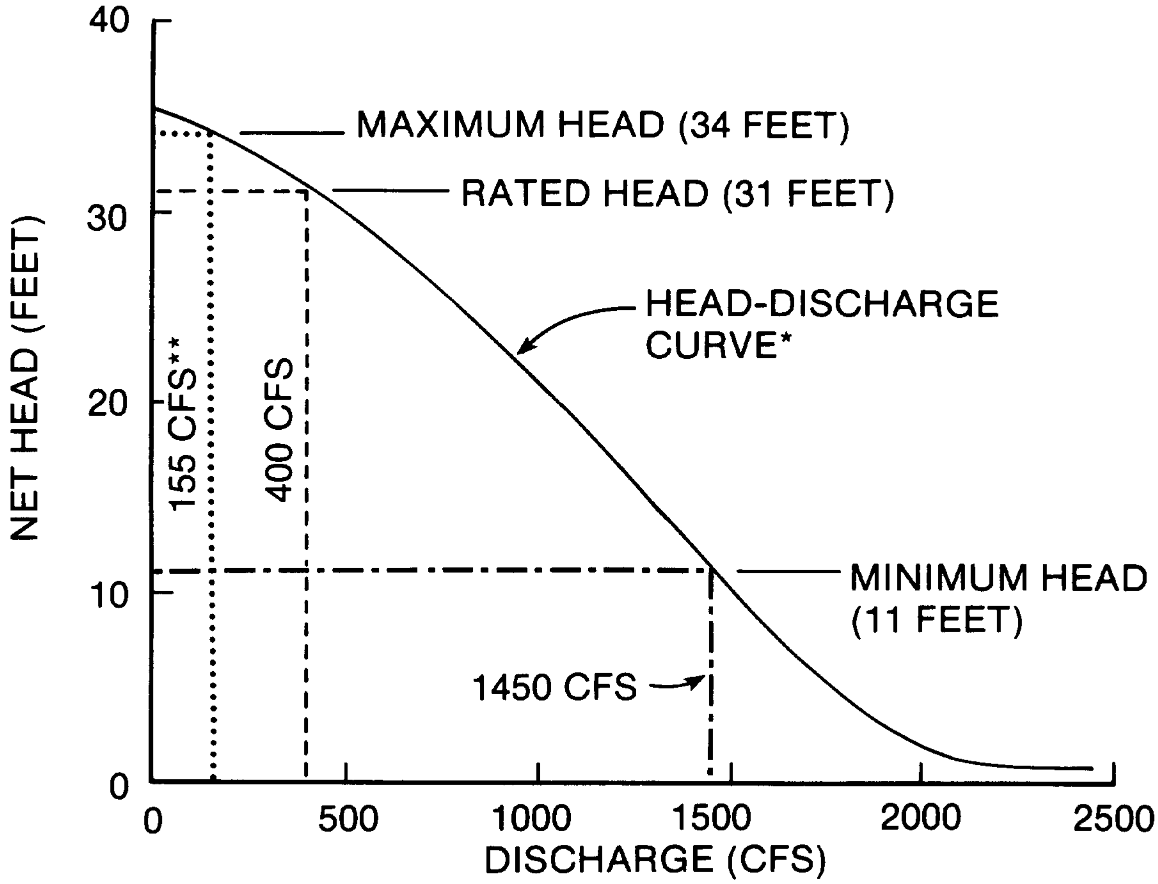
(6) Assume that a single tubular turbine with moveable blades (horizontal shaft Kaplan) will be installed. Table 5-1 summarizes the minimum head and minimum discharge characteristics of different types of turbines. The minimum discharge for a horizontal shaft Kaplan unit would be about 35 percent of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

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

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

h. <u>Define Usable Flow Range and Derive Head-Duration Curve.</u>

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



* Includes 1.0 foot head loss

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

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

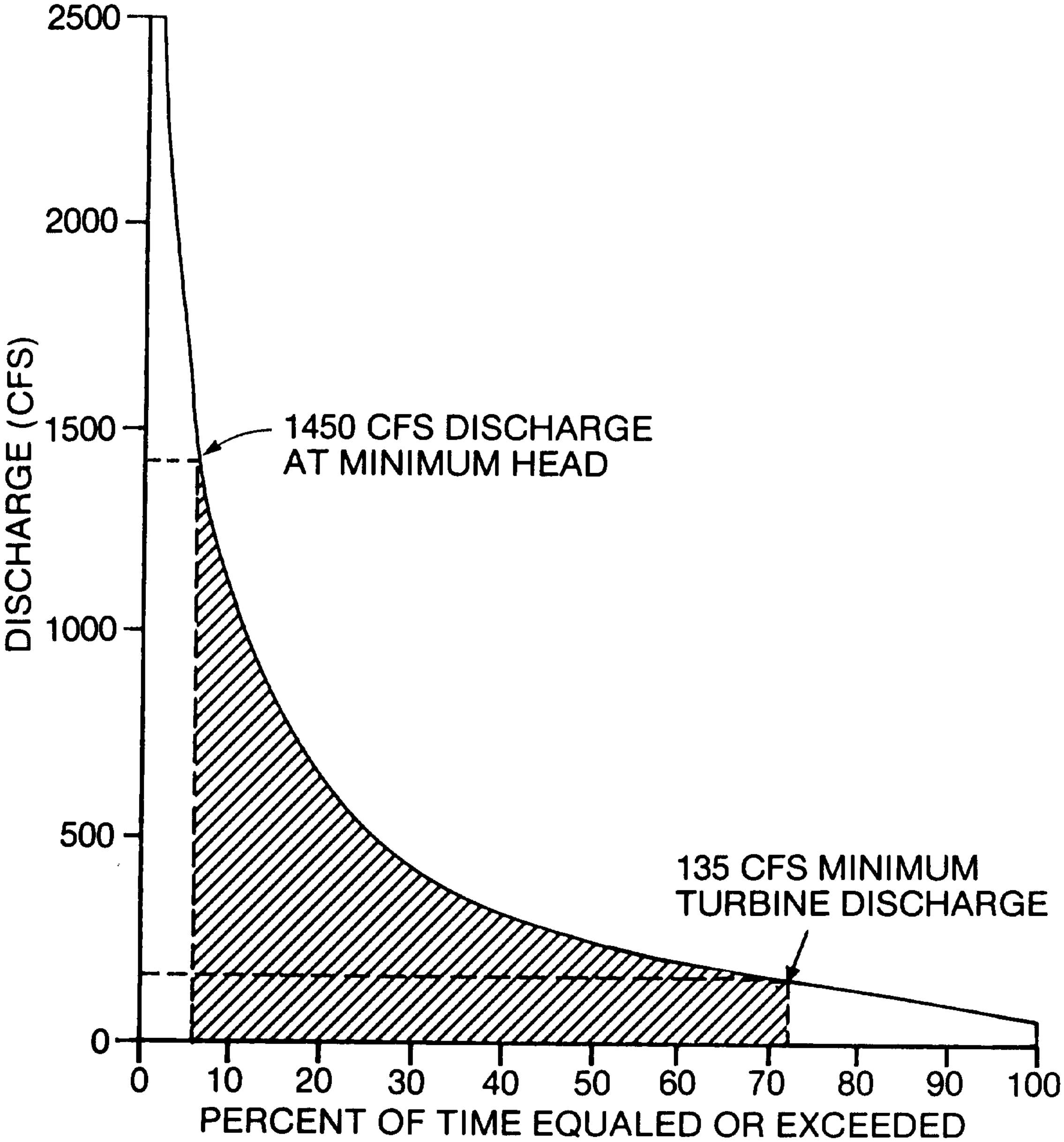


Figure 5-18. Total flow-duration curve showing limits imposed by minimum head and maximum discharge

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

i. Derive Power-Duration Curve.

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

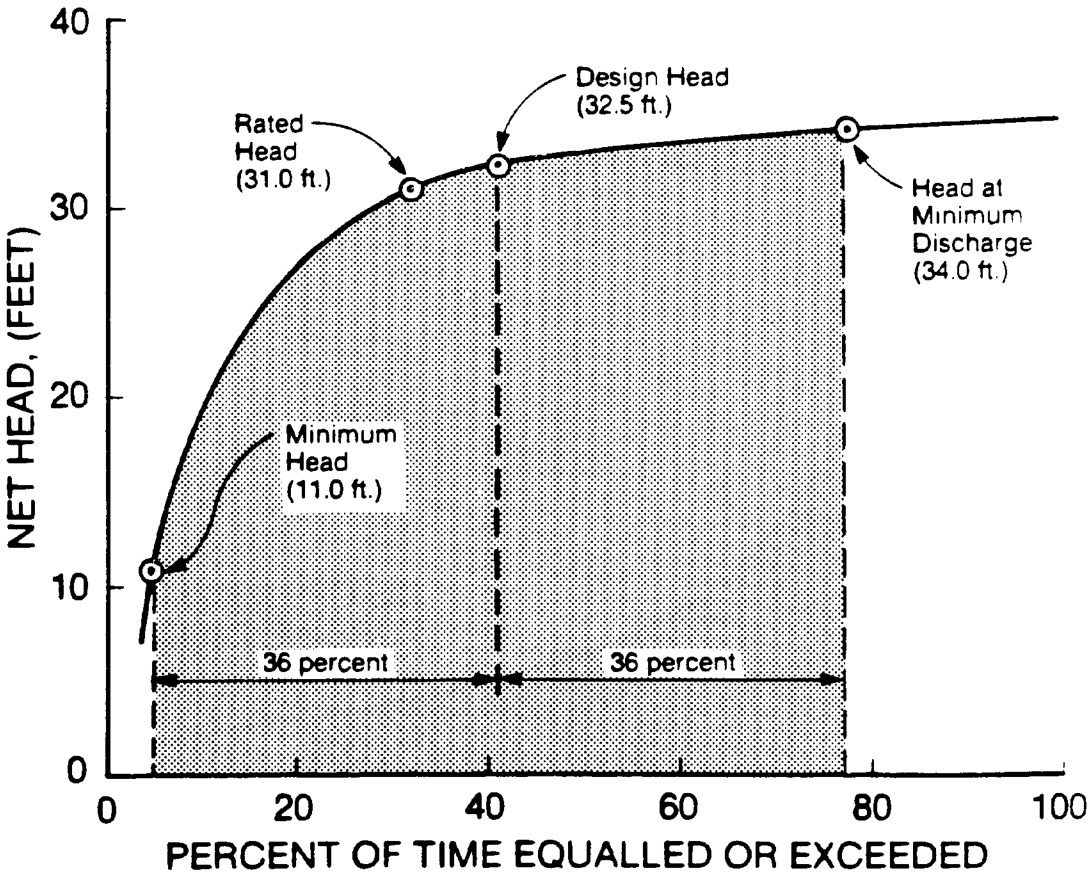


Figure 5-19. Head-duration curve showing minimum head, maximum head, design head, and rated head

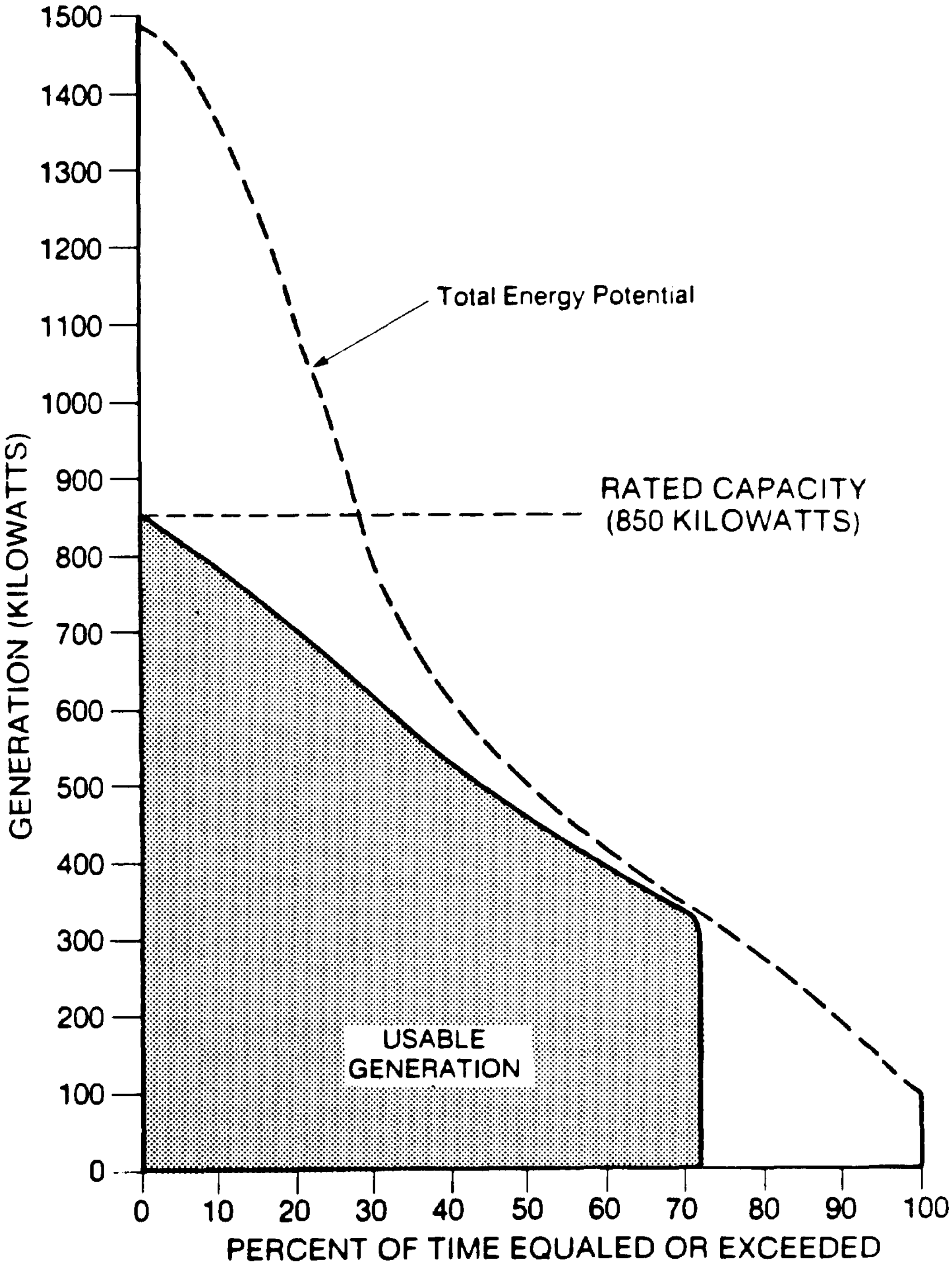


Figure 5-20. Usable power-duration curve

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

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

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

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

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

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

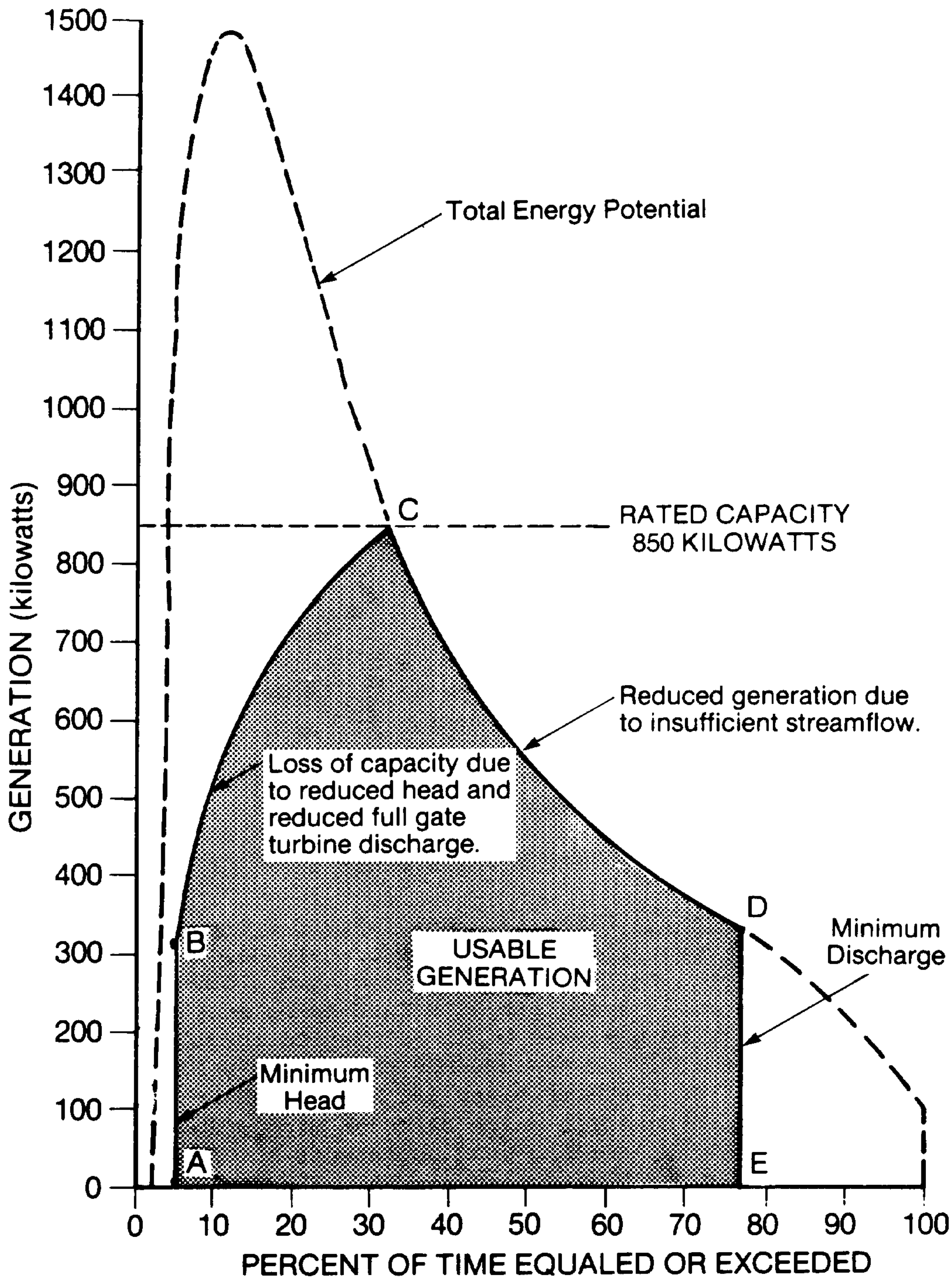


Figure 5-21. Usable generation-duration curve

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

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

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

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

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

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

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

The dependable capacity for the example would be 338 kW.

l. Compute Dependable Capacity; Pondage Projects.

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

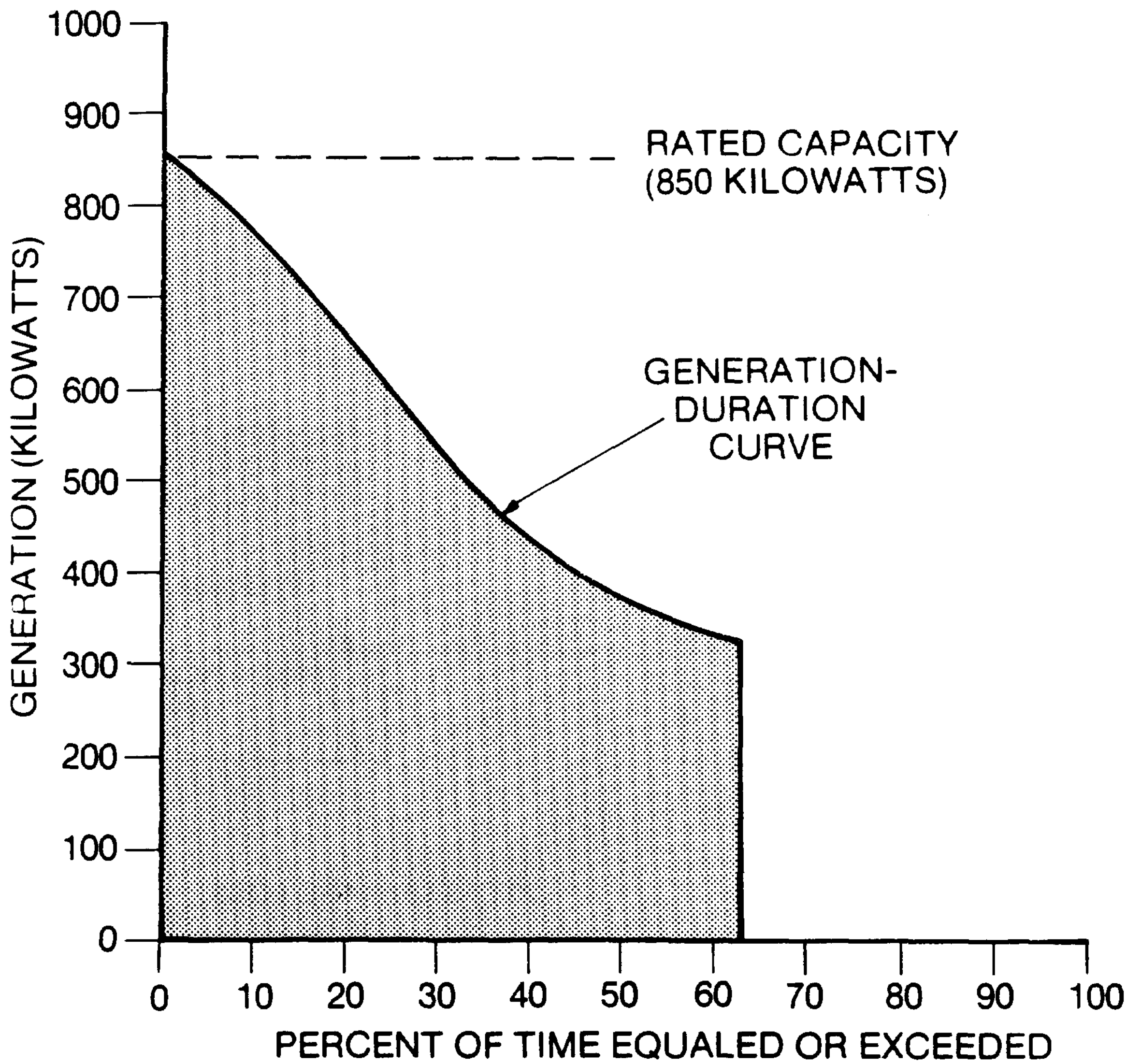


Figure 5-22. Generation-duration curve for peak demand months

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

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

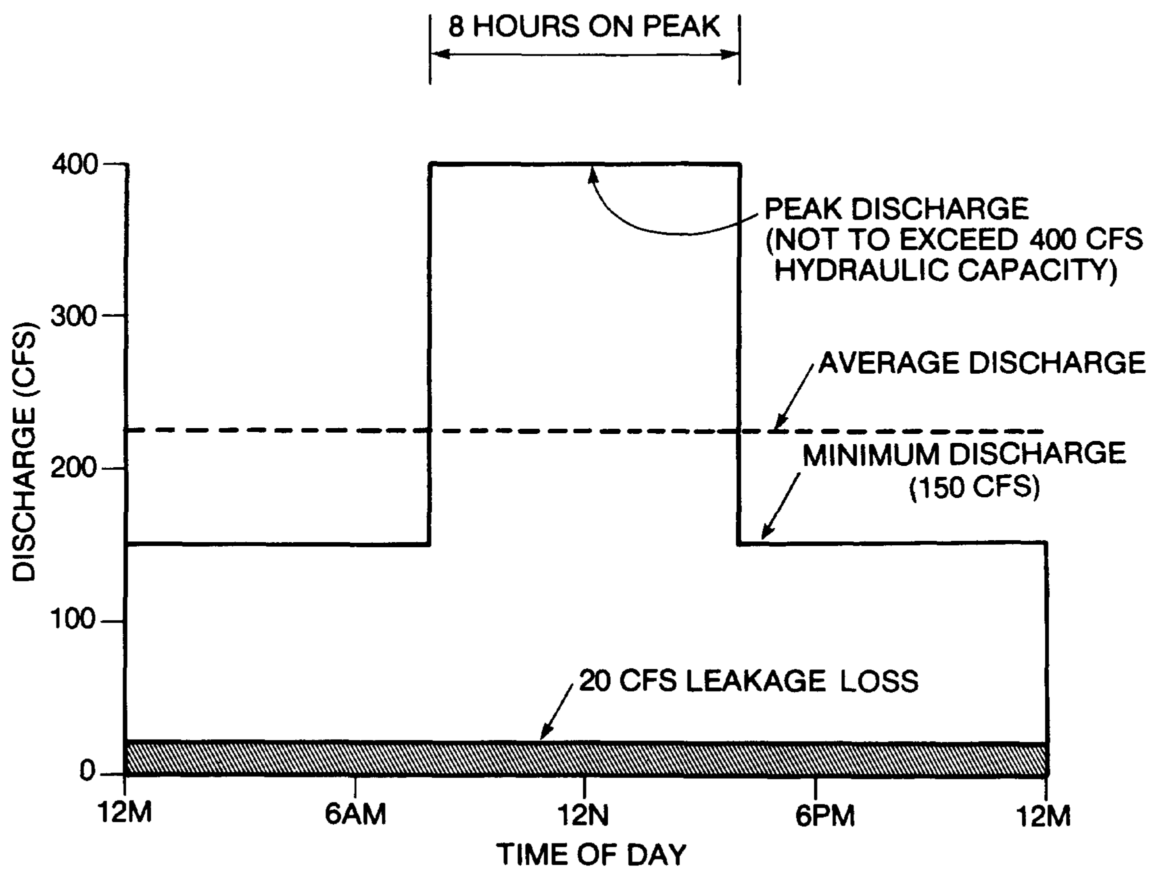


Figure 5-23. Assumed daily operation pattern

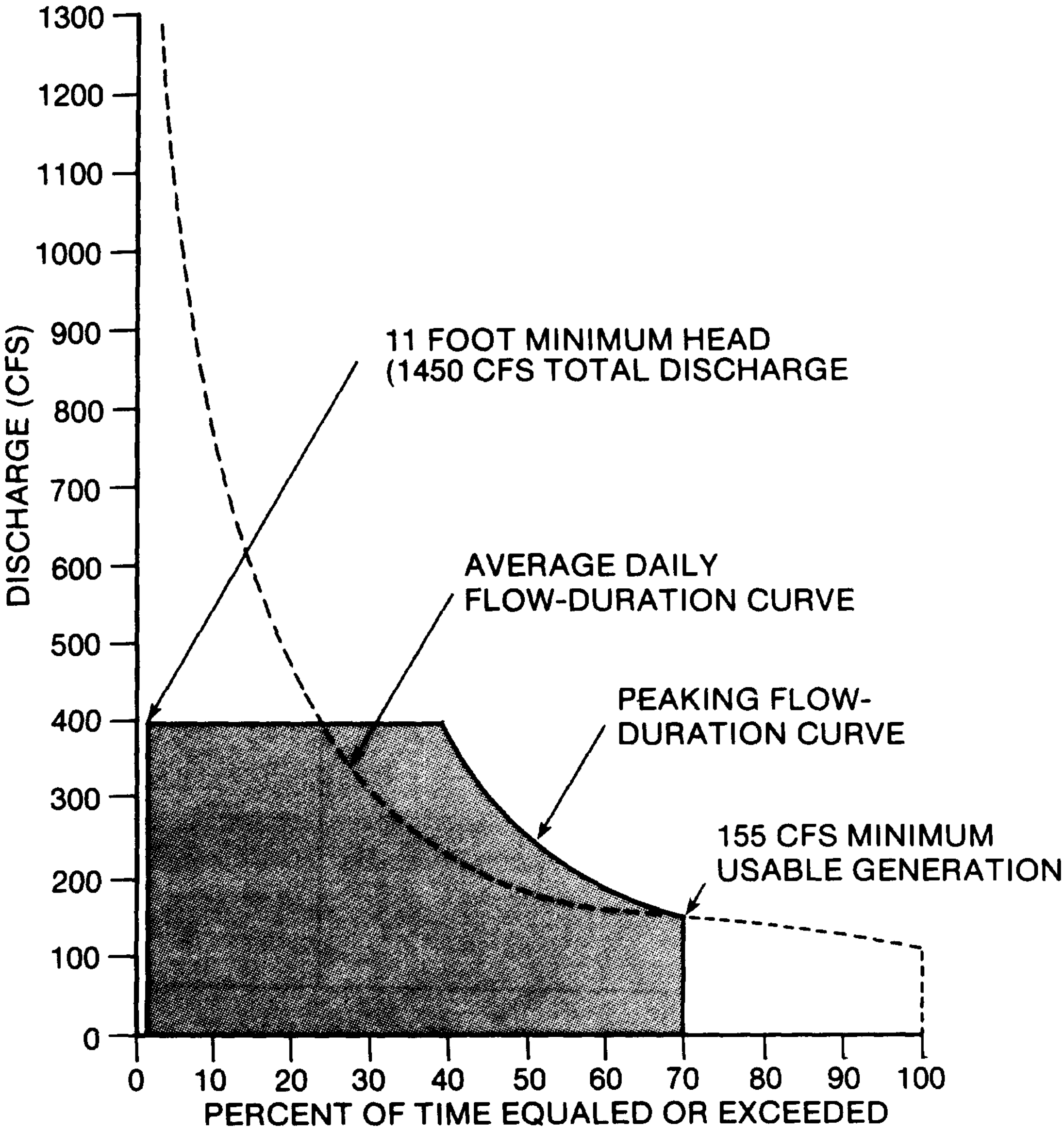


Figure 5-24. Peaking flow-duration curves (for peak demand months)

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

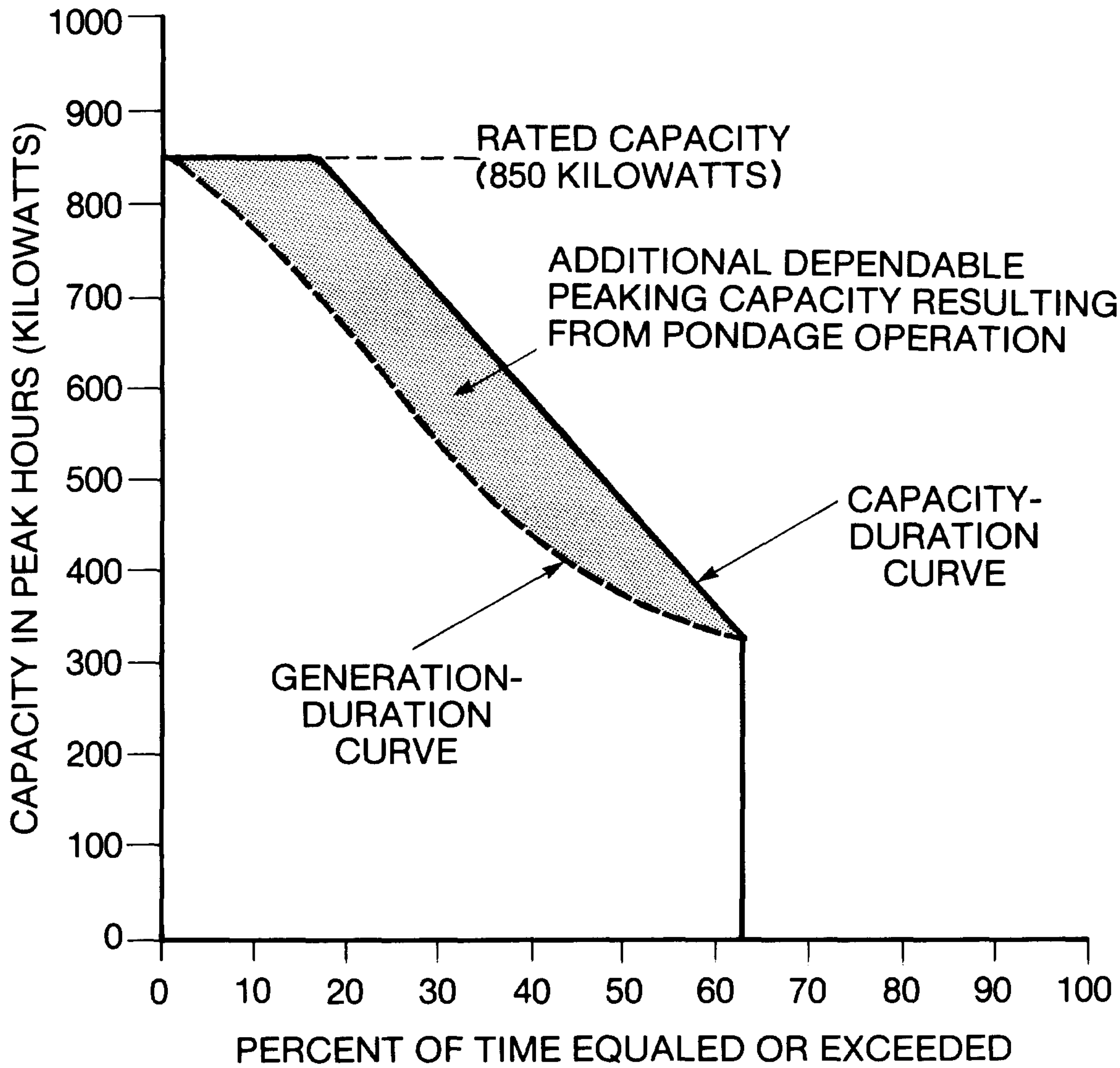


Figure 5-25. Capacity-duration curve for pondage project (for peak demand months)

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

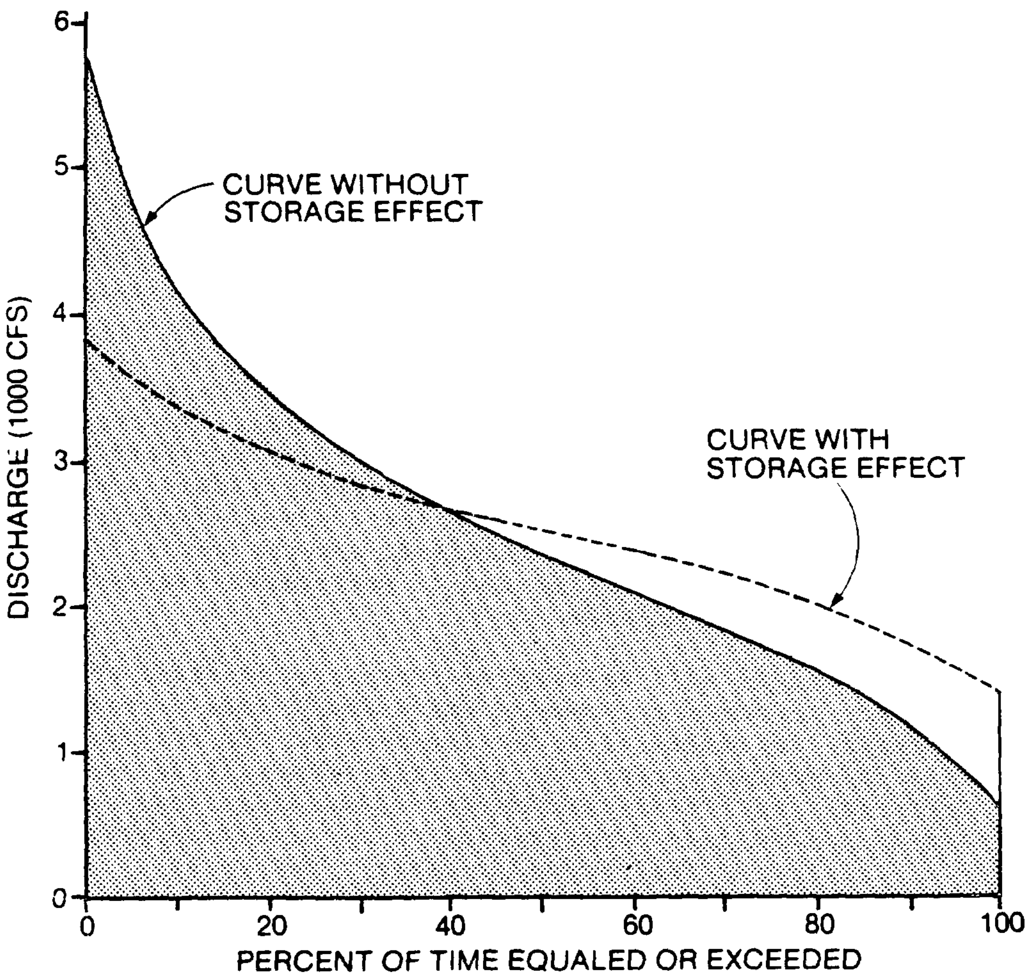


Figure 5-26. Flow-duration curve adjustment
to reflect seasonal storage

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

n. Treatment of Efficiency.

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

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

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

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

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

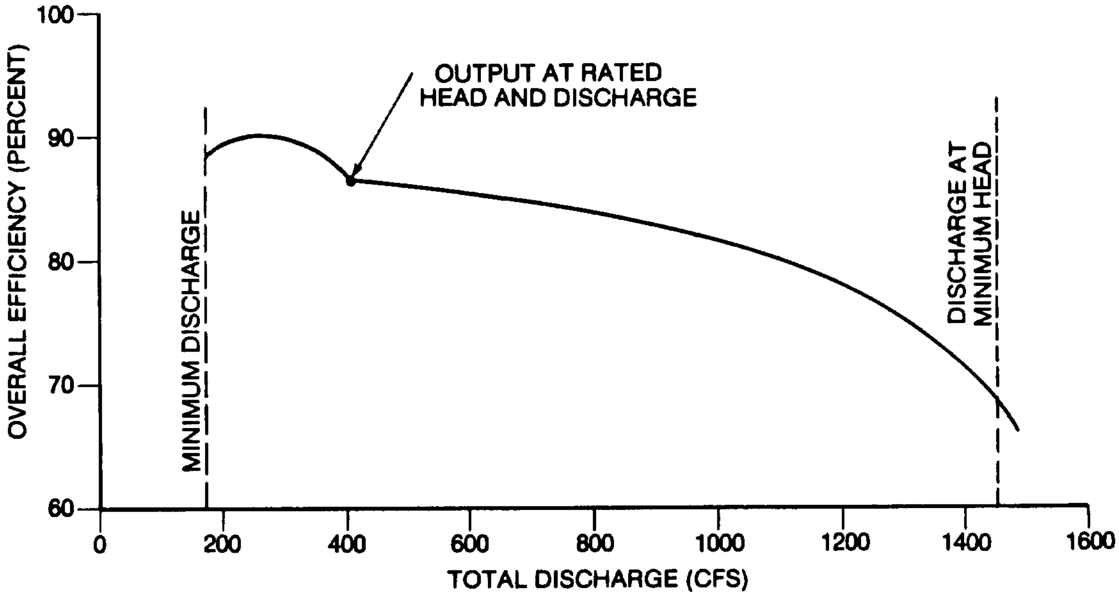


Figure 5-27. Efficiency-discharge curve for one 868 kilowatt unit

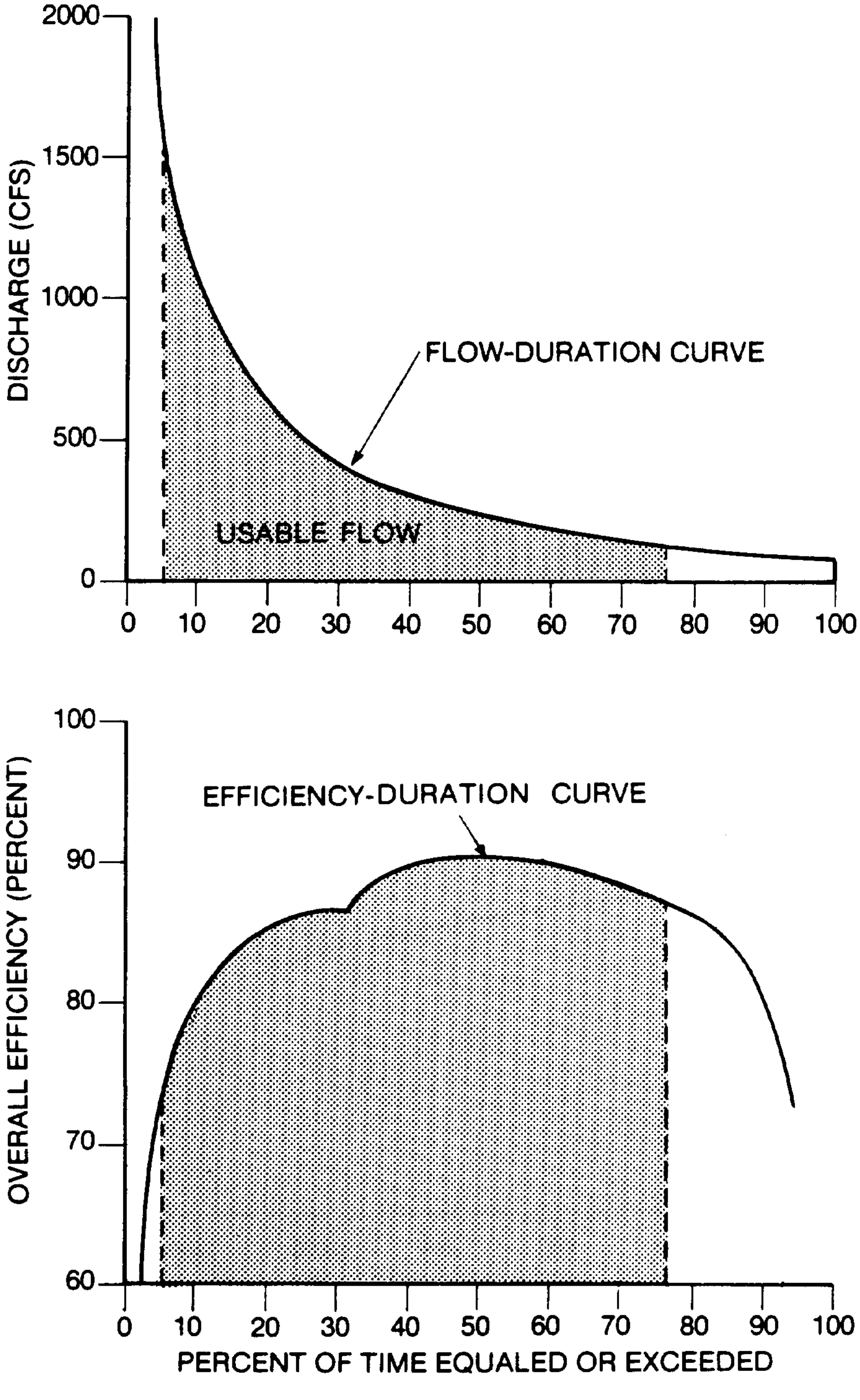


Figure 5-28. Flow-duration curve and efficiency-duration curves for one 868 kW unit

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

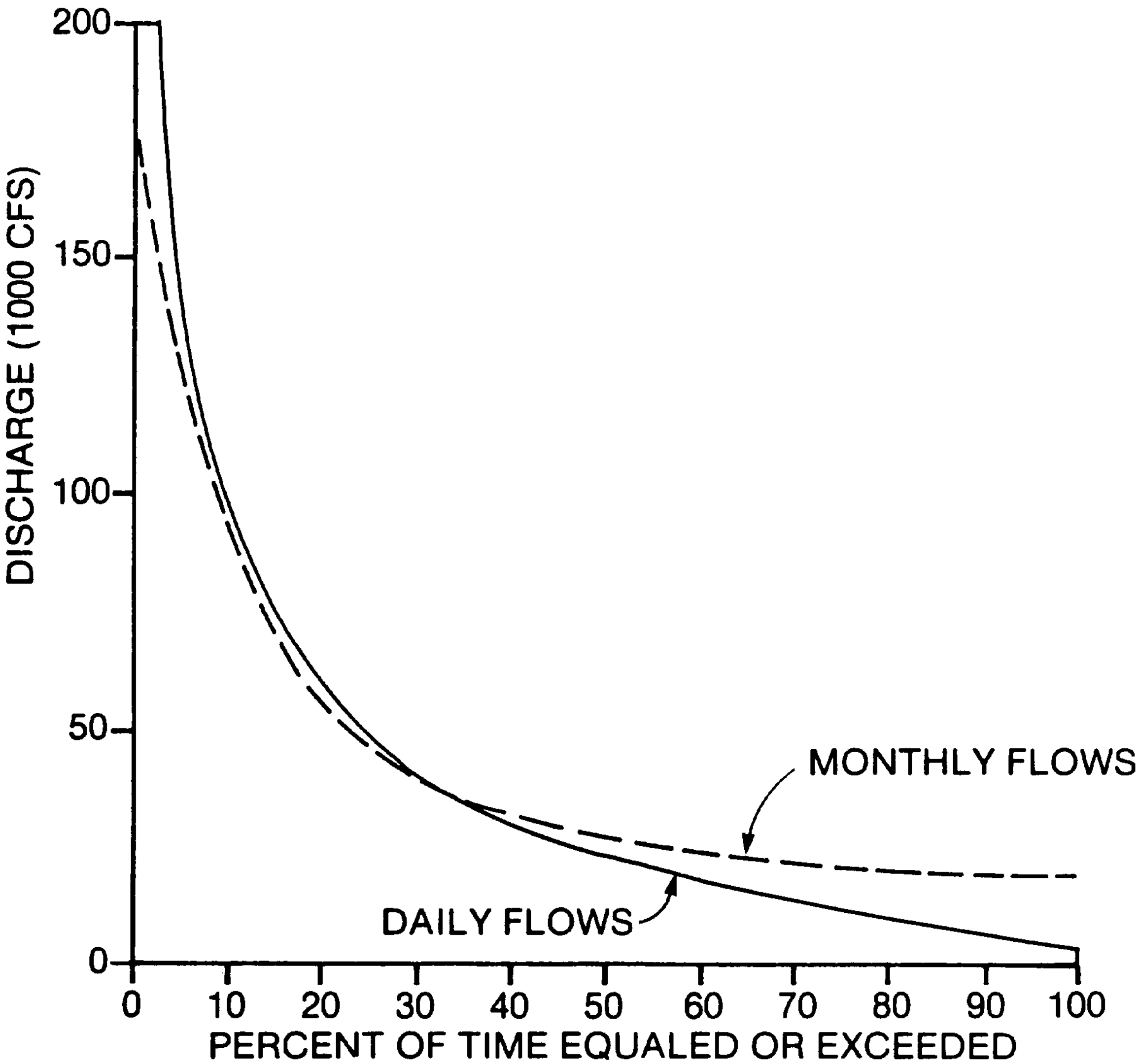


Figure 5-29. Comparison of flow-duration curves based on daily and monthly streamflow values

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

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

a. General Approach.

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

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

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

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

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

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

b. Application of Sequential Analysis.

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

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

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

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

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

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

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

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

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

a. General.

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

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

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

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

c. The Routing Procedure.

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

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

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

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

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

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

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

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

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

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

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

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

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

d. Other Considerations.

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

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

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

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

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

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

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

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

a. <u>Introduction.</u>

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

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

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

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

. identify critical period

. make preliminary estimate of firm energy potential

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

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

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

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

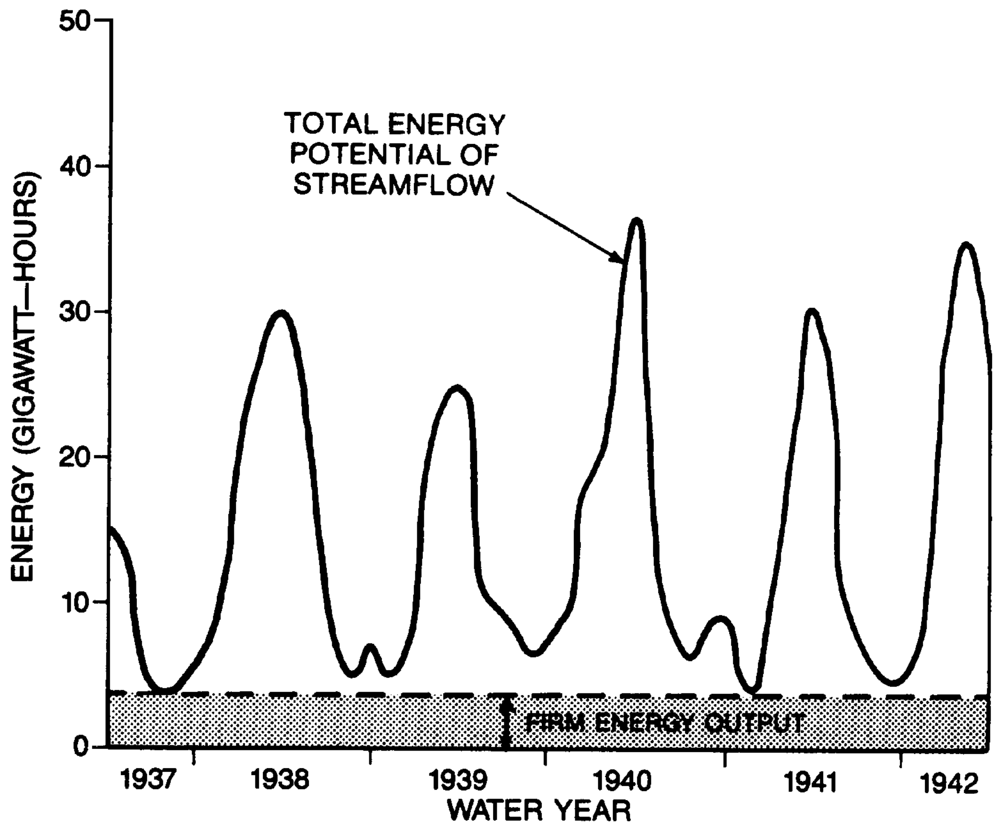


Figure 5-30. Energy potential and firm energy output of dam site without seasonal storage

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

c. Regulation of Power Storage to Increase Firm Energy.

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

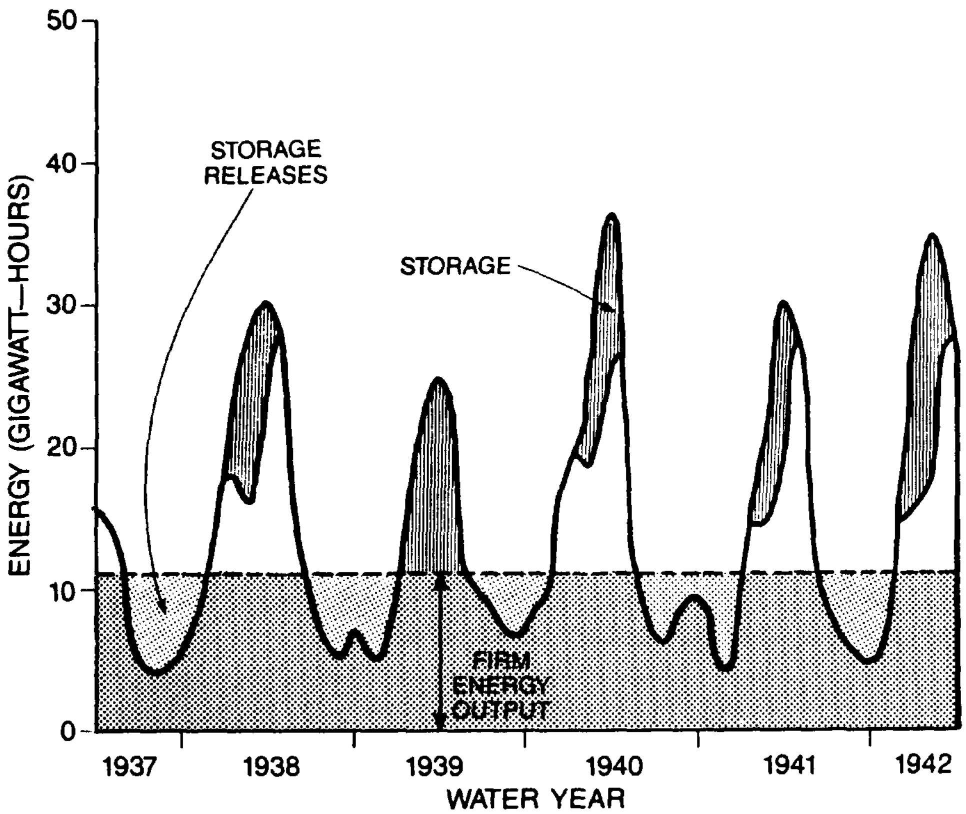


Figure 5-31. Energy potential and firm energy output of dam site with seasonal storage

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

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

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

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

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

d. Critical Period.

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

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

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

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

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

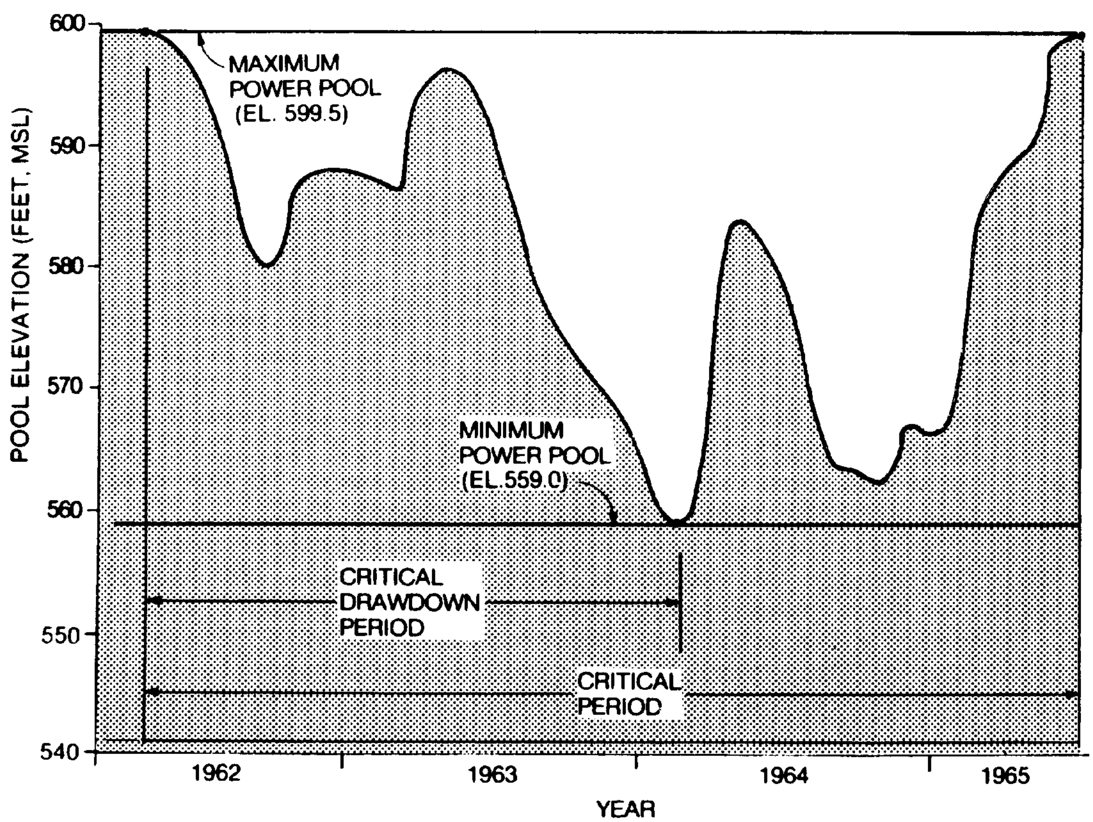


Figure 5-32. Critical period and critical drawdown period

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

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

e. Preliminary Firm Energy Estimate.

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

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

f. The Sequential Routing Procedure.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

TABLE 5-6.

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

(COLUMN NUMBERS)

Routing Worksheet

REQ'D DISCHARGES Power 'Q_p' (cfs)	Nonpower (cfs)	Total Discharge (cfs)	Δ STORAGE, $(S_1 - S_2)$ (cfs)	(AF)	END OF PERIOD RESERVOIR STATUS (AF)	(Elev.)	(area)	Total Energy (MWh)

(10) (11) (12) (13) (14) (15) (16) (17) (18)
(COLUMN NUMBERS)

TABLE 5-7.

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

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

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

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

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

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

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

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

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

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

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

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

Explanation of Data in Table 5-6

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5/ ΔS (AF) = C_s x ΔS (cfs)

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

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

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

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

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

g. Determining Firm Energy.

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

- firm energy requirements are exactly met in all months during the critical drawdown period

- storage is fully drafted at one point in the critical period

- the project refills at the end of the critical period.

Figure 5-33 illustrates such a routing.

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

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

regulation is obtained, the project's firm energy output will have been determined. An estimate of the annual firm energy output can be obtained by summing the monthly energy requirements that can be met for all twelve months.

(4) There is also the possibility that the incorrect critical period was identified. This will become apparent when the period-of-record routing is made (see Section 5-10h). This routing will be based on the monthly firm energy requirements derived as described above. If the project is drafted below the bottom of the power pool (or fails to meet firm energy requirements) at some point outside of the assumed critical drawdown period, then the wrong period was selected. The new critical drawdown period must then be defined (it would end with the month with the greatest overdraft). The monthly firm energy requirements would be adjusted as described in the preceding paragraph, and one or more iterations would be made for the new critical period in order to determine the final firm energy output.

(5) The above discussion applies to estimation of firm energy using hand routing techniques. Sequential routing computer models follow the same basic procedure, except that the computations may

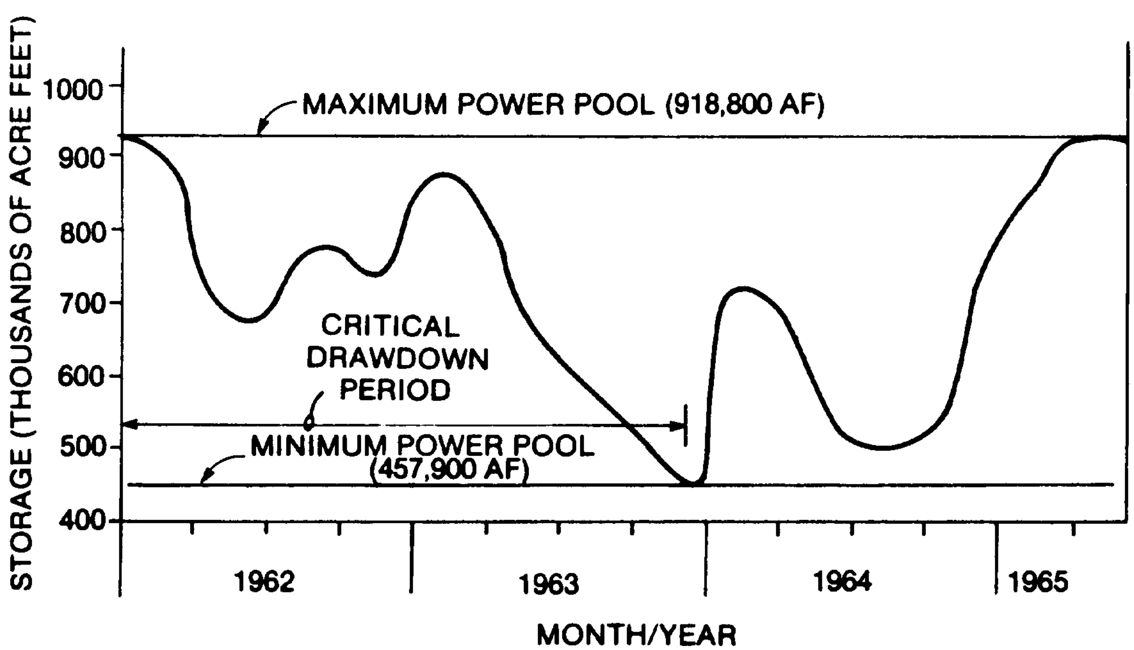


Figure 5-33. Routing of Broken Bow Reservoir, Oklahoma through critical period.

follow a somewhat different sequence and routines may be available to automatically optimize firm energy output. Appendix C describes some of the SSR models that are readily available to Corps power planners, and Appendix K describes how HEC-5 is used for estimating firm energy output.

h. Average Annual Energy.

(1) Once the firm energy estimate has been made, the next step is to determine the project's average annual energy output. To determine the average annual energy, a sequential routing would be made for the entire period of record using the monthly firm energy requirements derived from the critical period routing. The project's average annual energy would be the average of the annual energy production values for all of the years in the period of record. The average annual secondary energy would be the difference between the average annual energy and the annual firm energy.

(2) Several alternative strategies are available for operating in better than critical streamflow conditions. The simplest is to operate primarily to meet the firm energy requirements, producing secondary energy only when the reservoir is at the maximum power pool

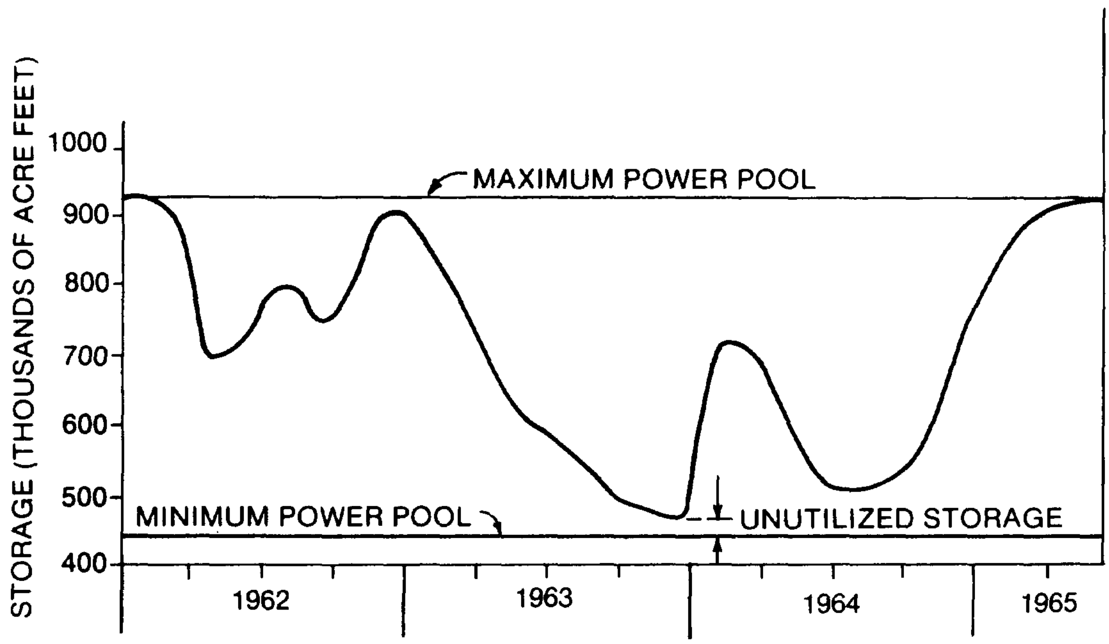


Figure 5-34. Critical period routing of a reservoir that does not utilize all of conservation storage.

and when net reservoir inflow exceeds the discharge required to meet firm energy requirements. Where a project has flood control storage space above the power pool, secondary energy could also be generated when evacuating the flood control space during flood control operations. Figure 5-35 illustrates a regulation through an average water year following this strategy. The back-up computations are shown as Case 1 in Appendix I, the project being the same as that used in the firm energy example (Figure 5-33 and Appendix H).

(3) The strategy described above may be appropriate for single-purpose power storage projects operating in an all-hydro system, where no market for secondary energy exists and there are no alternative uses for the stored water. This approach might also be used where at-site recreation is an important project use and it is desired to keep

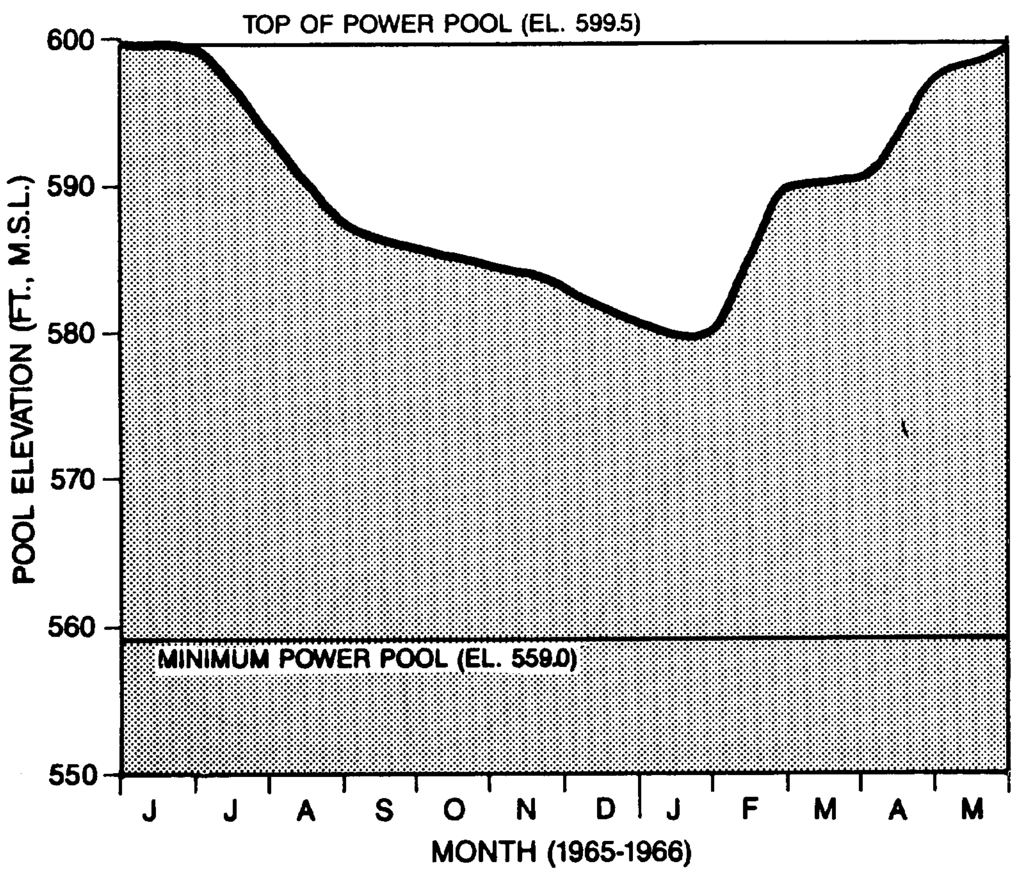


Figure 5-35. Regulation of a reservoir through an average water year drafting storage only to meet firm energy requirements (Case 1, Appendix I)

the reservoir close to the full power pool elevation as much of the time as possible. However, this approach permits no flexibility of operation during periods of better than critical streamflow. To permit better use of secondary energy and more flexibility in using storage for non-power river uses, rule curves may be developed to govern reservoir regulation. Where rule curves are used, average annual energy would be developed as follows: (a) make sequential streamflow routing for the critical period and for other low flow periods, (b) develop the rule curves, (c) regulate the project over the period of record using the rule curves, and (d) estimate average annual energy from the period-of-record regulation.

5-11. Power Rule Curves.

a. General.

(1) A rule curve is a guideline for reservoir operation, and is generally based on detailed sequential analysis of various critical combinations of hydrologic conditions and demands. Rule curves may be developed for flood control operation as well as to govern use of conservation storage for irrigation, water supply, hydropower, and other purposes. The development and use of a single-purpose rule curve for power operation will be examined in this section. The constraints of flood control operation and the development of rule curves to meet both functions are addressed in Section 5-12. The development of rule curves to meet multiple conservation storage functions will also be discussed in Section 5-12.

(2) The power operating rule curve was defined by the United States Inter-Agency Committee on Water Resources as ". . . a curve, or family of curves, indicating how a reservoir is to be operated under specific conditions to obtain best or predetermined results." Although rule curves are generally developed for individual reservoirs, there may be instances where a single rule curve for a hydraulically integrated system of storage plants would better serve the needs of the system operation. Rule curves for power operation may assume many forms, depending upon the nature of the power system, the hydrologic characteristics of the basin, and the operating constraints associated with the storage plants involved.

(3) A rule curve for power operation of a typical storage project is shown in Figure 5-36. The curve defines the minimum reservoir elevation (and consequently the minimum storage) required to assure generation of firm power at any time of the year. The general shape of the rule curve is tailored to the hydrologic and power demands of the area: (a) power storage must be at a maximum during the middle of the calendar year in anticipation of high summer power

demands coincident with low inflows; (b) droughts usually begin during the late spring and early summer; and (c) a low pool elevation is acceptable in the fall and winter season, because power demands are lower and winter and spring inflows are higher.

(4) Firm energy can be defined as that generation which would exactly draw the reservoir level to the bottom of the power pool during the most severe drought of record. Therefore, if (a) all potential droughts begin with the reservoir level on or above the rule curve elevation, (b) generation is to be limited to firm energy production, and (c) the generation pattern is in general agreement with the assumed monthly distribution used in the studies, the pool should not fall below rule curve unless a drought more severe than any of record is experienced. Such a rule curve can be constructed by regulating all of the major droughts in the period of record and developing a rule curve which encloses all of these regulations. Appendix J illustrates how a rule curve of this type can be developed.

(5) Appendix J describes the derivation of a rule curve to govern use of power or conservation storage in an exclusive storage use zone. Using Figure 5-36 as an example, the storage between "Minimum Power Pool" and "Top of Power Pool" is reserved exclusively for power. Flood control storage (if any) would be located above the "Top of Power Pool." Rule curves governing storage that is jointly used for both flood control and

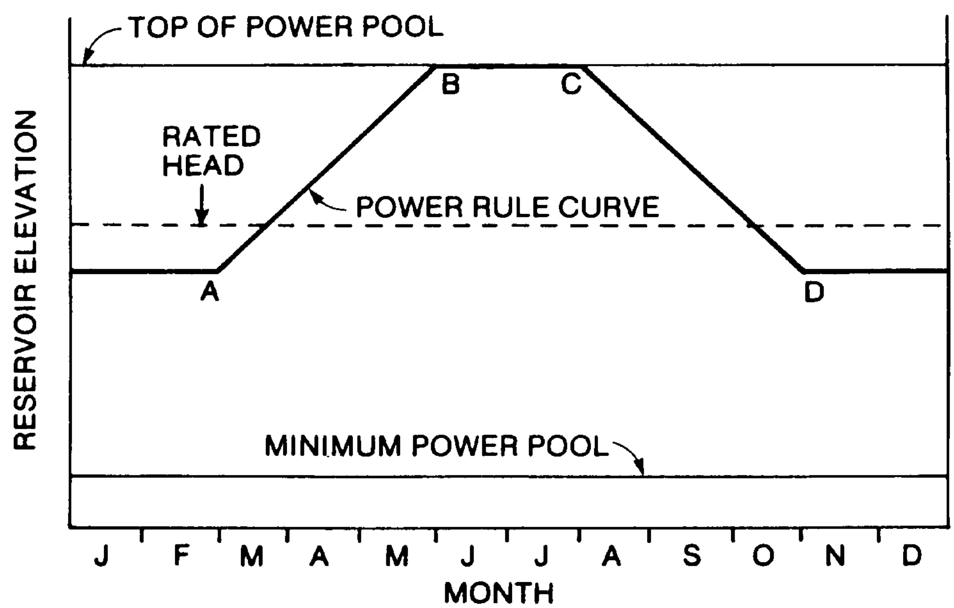


Figure 5-36. Rule curve for power operation of a typical storage project

power (or flood control and multiple conservation purposes including power) would be derived somewhat differently (see Section 5-12e). Likewise, Figure 5-36 illustrates a fixed rule curve. For river basins where much of the runoff comes from snowmelt, the runoff volume is to some extent predictable, and variable rule curves can be developed to maximize the use of the energy potential (see Section 5-12f).

b. Project Operation Using Power Rule Curves.

(1) The regulation of a project using a power rule curve can be illustrated by examining the operation of a project having a zone of exclusive power storage and a fixed power rule curve (Figure 5-36).

(2) Assume that the rule curve was derived as described in Appendix J and that the primary objective of regulating power storage is to meet firm energy requirements. Most of the time, streamflows will be greater than the adverse flows used to derive the curve, and it will be possible to meet firm energy demands while maintaining the reservoir level at or above the rule curve. In addition, it may also be possible to generate secondary energy in some periods. However, if a sequence of adverse flows occurs, it may be necessary to draft storage below the rule curve, but as long as the reservoir is below the rule curve, releases will be limited to those required to meet firm energy requirements.

(3) Because the rule curve is based on the most adverse sequence of flows in the period of record, the project can be operated through the period of record without any failure to meet firm energy requirements or any violation of the minimum power pool. However, in actual operation, there is always the possibility that a more adverse sequence of flows will occur. Hence, if an extended period of low flows occurs, and the reservoir falls well below the rule curve, contingency measures would likely be taken to conserve the remaining storage. First, attempts might be made to purchase thermal generation to help meet the firm energy requirement. If this is not enough, opportunities for reducing firm load would then be examined.

(4) Operation above the rule curve could vary, depending on the time of year, the state of the power system, and other project purposes to be served. During that period when the project is maintained at the top of power pool (B-C on Figure 5-36), the total net inflow (inflow minus evaporation minus withdrawals) must be passed through the project. Streamflow in excess of firm generation requirements will be used to produce secondary energy, up to the plant's maximum generating capability, and the remainder of the flow (if any) will be spilled (for projects with flood control storage above top of power pool, see Section 5-12d.

(5) During the period C-D-A-B, several operating strategies are possible. One extreme would be to maintain the resrvoir as high as possible, limiting generation to firm energy requirements, except that higher discharges would sometimes be required during periods of high inflow to prevent the reservoir elevation from exceeding the top of the power pool. This approach would maximize head and maintain capacity at high levels, and, under some circumstances, it could maximize average annual energy. On the other hand, this operation could have a high risk of spilling, specifically whenever inflows exceeding plant capacity occur at times the reservoir is at the top of the power pool. The other extreme would be to follow the rule curve as closely as possible, operating the powerplant at full output whenever the reservoir elevation is above the rule curve. This approach would minimize the possibility of spilling, but it would increase the risk of not meeting firm energy requirements should a streamflow sequence more adverse than the critical period occur.

(6) In some systems, the reservoir might be operated somewhere between the two curves, depending on the value of secondary energy at any given time. If opportunities exist for displacing very expensive thermal generation, the project may be drafted below the top of power pool to maximize secondary energy production. The closer the draft approaches the rule curve, the greater the risk to firm energy capability and the greater the potential energy loss due to reduced head, so the operator has to balance these potential losses and risks against the value of the immediate secondary sale. When the value of secondary energy drops, generation would be reduced, possibly to firm energy requirements, and the reservoir allowed to refill. Tennessee Valley Authority has developed a series of intermediate "rule curves" (economic guide curves) based on probabilistic analysis, which ties secondary energy production to the current value of the energy (see Figure 5-49).

(7) Another approach would be to operate using a power guide curve similar to that shown as Figure 5-51. When the reservoir is at or below the rule curve, only firm energy would be produced. When the reservoir is above the power rule curve (in the shaded area in the upper diagram on Figure 5-51), the plant would operate at a plant factor that is a function of the distance above the rule curve, up to a maximum of 100 percent plant factor at full pool.

(8) An additional consideration is that the power plant's rated head may be above the lower portion of the rule curve. If the pool is allowed to drop below rated head, the plant's dependable capacity will be reduced, and this is an important consideration at projects which are operated primarily for peaking. The dashed line on Figure 5-36 illustrates a possible soft limit defined by the rated head. One possible operating strategy would be not to draft the reservoir below rated head

except: (a) to meet firm energy requirements, or (b) in response to unusual power system requirements (severe combinations of loads and/or power plant outages).

(9) While it is important to recognize that there are virtually an infinite number of ways to utilize power storage in better-than-critical streamflow conditions, it would be difficult to model these permutations in a planning study. The most important consideration in the planning stage is to insure that as much flexibility as possible is built into the reservoir operation.

c. Computing Average Energy Using Rule Curves.

(1) While flexibility is important from the standpoint of actual day-to-day project operation, the regulation of storage above the rule curve must be defined more precisely when making a period-of-record sequential analysis for the purpose of estimating average annual energy. As described earlier, the simplest approach is to base the sequential routing on maintaining the reservoir at the top of the power pool at all times except when drafts are necessary to meet firm energy requirements (Figure 5-35 and Appendix I, Case 1). Secondary energy would only be generated when the reservoir is at the top of power pool and inflow exceeds firm energy discharge requirements.

(2) An alternative analysis could be made, based on a maximum allowable drawdown through the entire period of record, to bracket the range of secondary energy output. Such a regulation could be based on following the power rule curve as closely as possible in all years, with storing above the rule curve being permitted only when net inflow exceeds the power plant capacity and when such storing will not exceed the top of power pool. The reservoir would be drafted below the rule curve, if required, to meet firm energy requirements. Case 2 in Appendix I describes the regulation of the example project through the same water year as Case 1 except that the power operation rule curve is followed as closely as possible. The resulting regulation is shown as Figure 5-37.

(3) Another approach would be to meet a level of power requirements greater than the firm requirement whenever the reservoir is above the rule curve. This requirement could be fixed (e.g. 120 percent of the firm requirement), it could vary by month, or it could vary with zone. In the case of variation by zone, the storage between the rule curve and the top of power pool would be divided into several zones, each having a different percentage of the firm requirement. The top zone would have the highest percentage, the bottom zone would be close to the firm requirement, and the zones in between would have intermediate values.

(4) In some cases, it may be possible to define operating parameters for operation in better than critical streamflow years by examining historical records for similar projects located in the system where the proposed project's output would be marketed. An example is the power guide curve developed by Tulsa District in their analysis of the use of power storage in the Arkansas-White system (Section 5-13d(3)).

(5) The above discussion applies to computation of average energy using regulation strategies designed to maximize firm energy production. This strategy may be appropriate for some power systems, but for thermal-based systems, maximizing average annual energy or maximizing peaking capability may produce greater benefits. In some cases, a system's reservoir storage may be regulated primarily for another function, such as irrigation, and the power operation may be

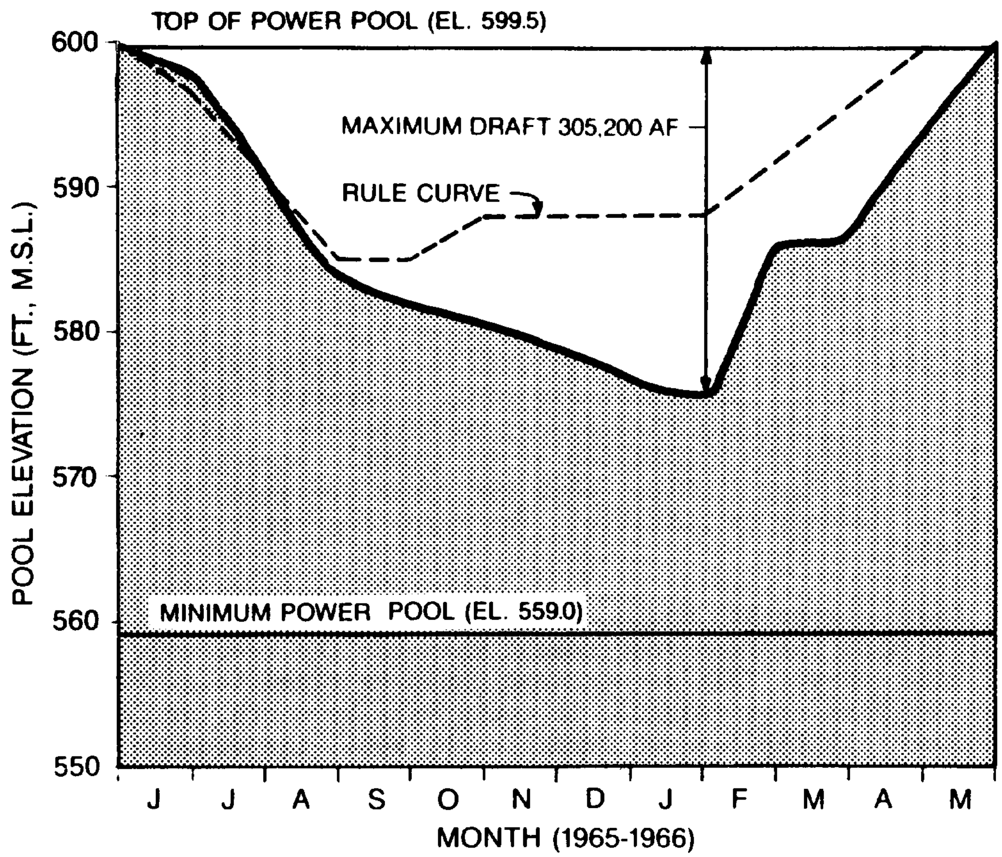


Figure 5-37. Regulation of reservoir through an average water year using a power rule curve (Case 2, Appendix I)

heavily influenced by this operation. Section 5-13m describes some of the alternative power regulation strategies and how average energy might be derived using those strategies.

(6) A final point to consider is that the value of secondary energy often varies with time, depending on the state of the total power system, and in some cases, it may have no value at all. The latter situation would arise only in a system with a substantial amount of hydro, but in these systems, the market for secondary energy may sometimes be limited. For example, in the Columbia River power system, potential secondary generation from existing hydro projects in freshet seasons with high runoff may exceed the secondary market (sum of the displaceable thermal generation within the region and the transmission capability for exporting secondary energy outside the region). A proposed hydro project may be capable of producing additional secondary energy in these periods, but it would have no value.

(7) In an all-hydro system, secondary energy may have no value at all. While all-hydro systems are rare in the United States, some isolated systems in Alaska may operate entirely on hydro at least part of the time, and the value of secondary energy in such systems should be examined very carefully.

5-12. Multiple-Purpose Storage Operation.

a. General. Most Corps of Engineers storage projects having power storage also provide space for flood control regulation, and at some projects, the conservation storage meets other water needs in addition to power production. This section addresses how the other functions are integrated with power operations in an SSR analysis to achieve a balanced operation.

b. Storage Zones. Discussion of multiple-purpose operation can best be described by dividing total reservoir storage into functional zones, as shown in Figure 5-38. The top zone would be the flood control storage space, which would be kept empty except when regulating floods. Below the flood control zone would be the conservation storage zone. This space would store water to be used to serve various at-site and downstream water uses, which could include power generation, irrigation, municipal and industrial water supply, navigation, water quality, fish and wildlife, and recreation. The term power storage is sometimes used instead of conservation storage when discussing power operation (as in Section 5-10), but conservation storage is the term most often used when describing multiple-purpose operation. Below the conservation zone is the dead storage zone, which is kept full at all times to provide minimum head for power generation, sedimentation storage space, etc.

c. Conservation Storage Zone. The conservation storage zone is often subdivided into two or more zones, based on the level of service that can be provided with the amount of available storage. A common division is into (a) an upper zone, where releases can be made in excess of those required to meet firm or minimum requirements, and (b) a lower zone (sometimes called a buffer zone), where releases are made only to meet firm or minimum requirements. The division between the upper and lower zone may vary seasonally. The power rule curve shown on Figure 5-36 is an example of a seasonally varying division.

d. Fixed Flood Control Zone. The simplest flood control configuration is that where a fixed amount of storage space is maintained above the top of the conservation pool the year around. This approach is followed in basins where large floods can be expected at any time of the year, such as in the South Atlantic coastal basins. The reservoir is normally maintained at or below the top of conservation pool, with the flood control space being filled only to control floods. Following the flood, this space is evacuated as quickly as possible within the limits of downstream channel capacity. During the period when flood runoff is being stored, it is sometimes necessary to reduce reservoir releases to zero in order to minimize downstream flooding, and this results in the interruption of power production. During the evacuation period, the reservoir releases required to evacuate the flood control space in the specified time period may exceed the power plant capacity, resulting in spilled

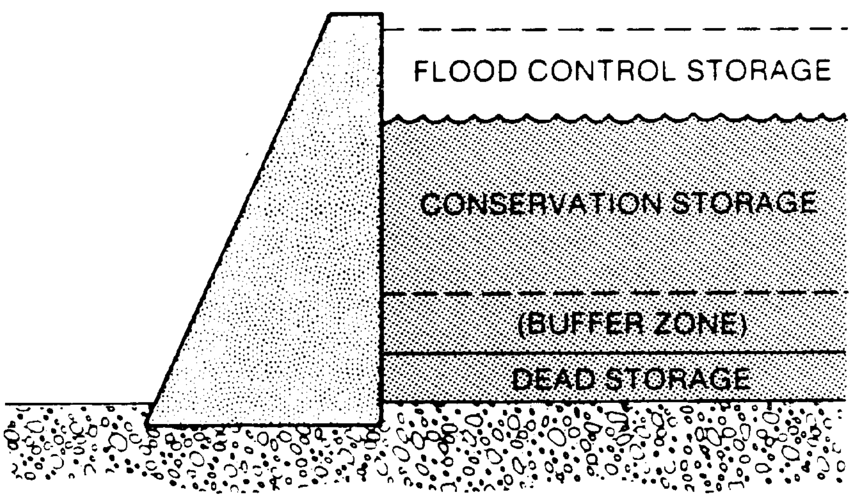


Figure 5-38. Storage zones

energy. To reduce this loss, it is sometimes possible to divide the flood control space into two zones, an upper zone, which must be evacuated as rapidly as possible, and a lower zone, which can be evacuated at a rate equal to the power plant hydraulic capacity (Figure 5-39).

e. Joint-Use Storage.

(1) In many river basins, major floods are concentrated in one season of the year. This permits establishment of a joint-use storage zone, which can be used for flood regulation during part of the year and conservation storage in the remainder of the year (Figure 5-40). Such an allocation requires less total reservoir storage than providing separate exclusive storage zones for flood control and conservation, so the utilization of joint-use storage should be considered wherever hydrologic conditions permit.

(2) Because the joint use zone must be evacuated annually, not all of the conservation storage may contribute to the project's firm energy capability. The refill curve (A-B on Figure 5-40) would be

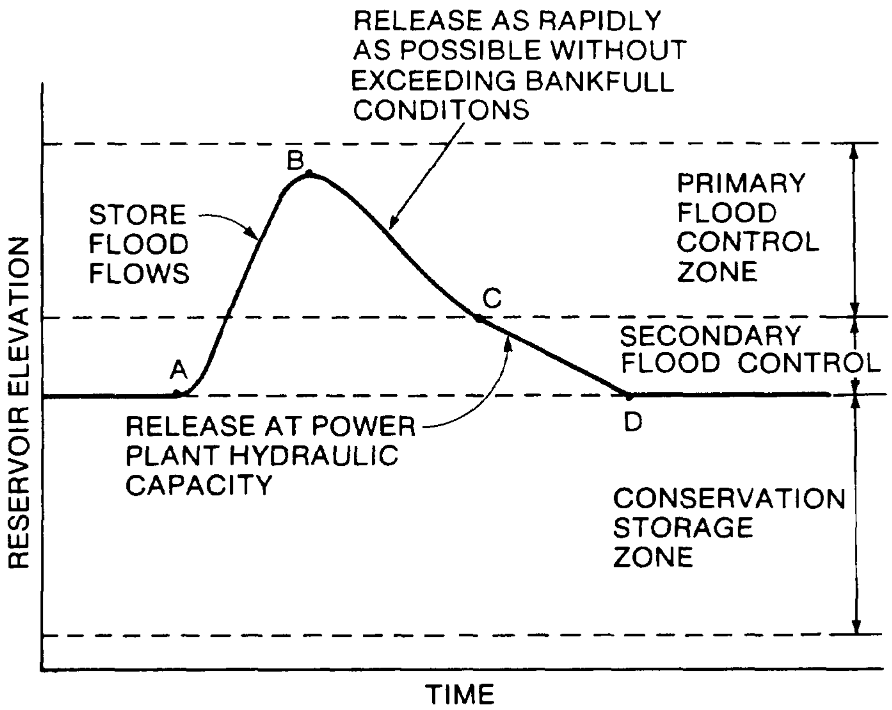


Figure 5-39. Primary and secondary flood control zones

defined by a careful balancing of the probability of floods of various magnitude in each interval within the refill period against the probability of sufficient runoff to permit refill. At some projects, it may be impossible to develop a rule curve that always satisfies the needs of both flood control and conservation storage. Take Figure 5-40 as an example. If flood control is the dominant function, and the flood control rule curve must be followed at all times, there may be some years where the spring runoff may not be sufficient to refill the conservation storage. The project's firm energy capability would therefore be based on a starting reservoir elevation (May 1st) that could be assured in all (or nearly all) water years. The conservation storage would in effect have two zones. Storage below the assured May

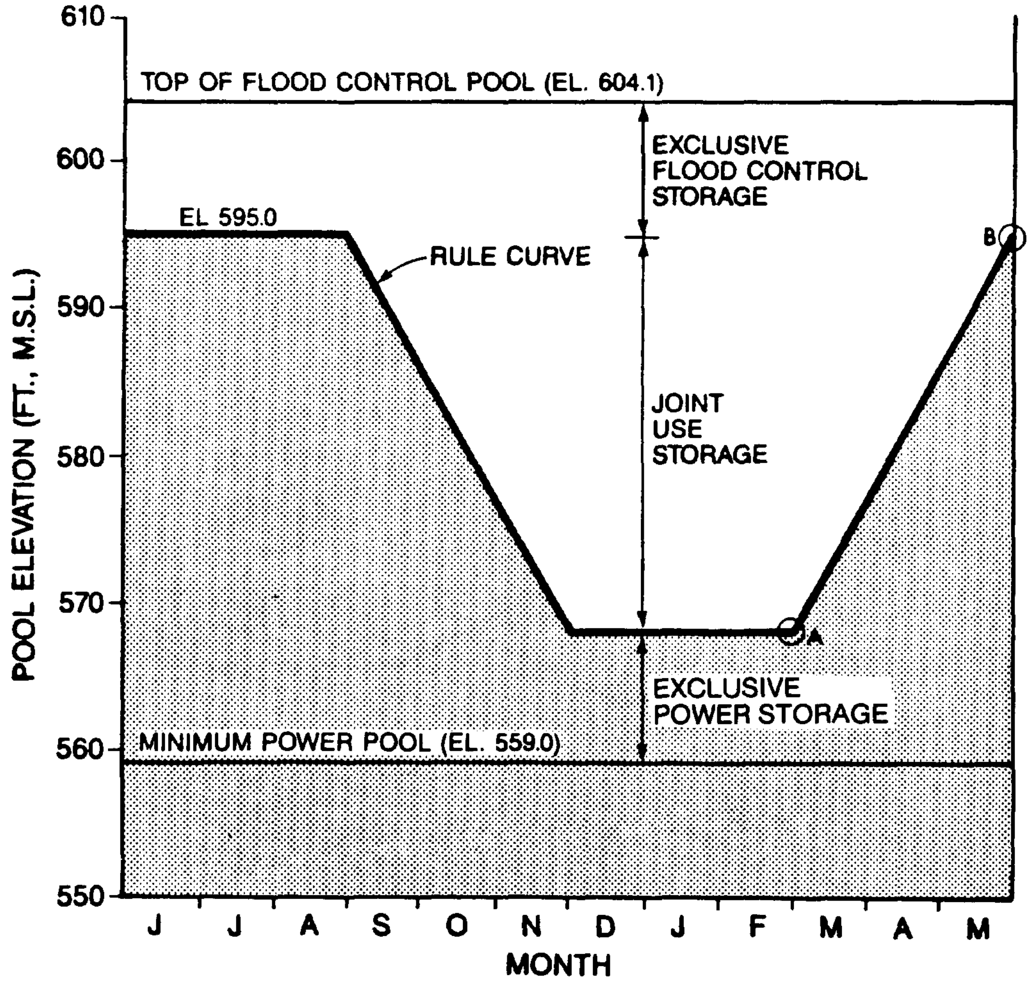


Figure 5-40. Rule curve for regulating joint-use storage

1st reservoir elevation would be primary conservation storage, and storage above that elevation would be secondary conservation storage.

(3) Figure 5-41 illustrates such a case, the lower curve being the firm power rule curve, which defines the project's firm energy capability. The upper curve defines the storage required for flood control. Typically, a project of this type would be refilled in the spring to the extent possible without violating flood control requirements. If runoff permits filling conservation storage above the power rule curve, that storage could be drafted as required (based on power system needs and the value of that energy for thermal displacement). The rate of draft would be such that firm energy capability would be protected while meeting the drawdown requirements

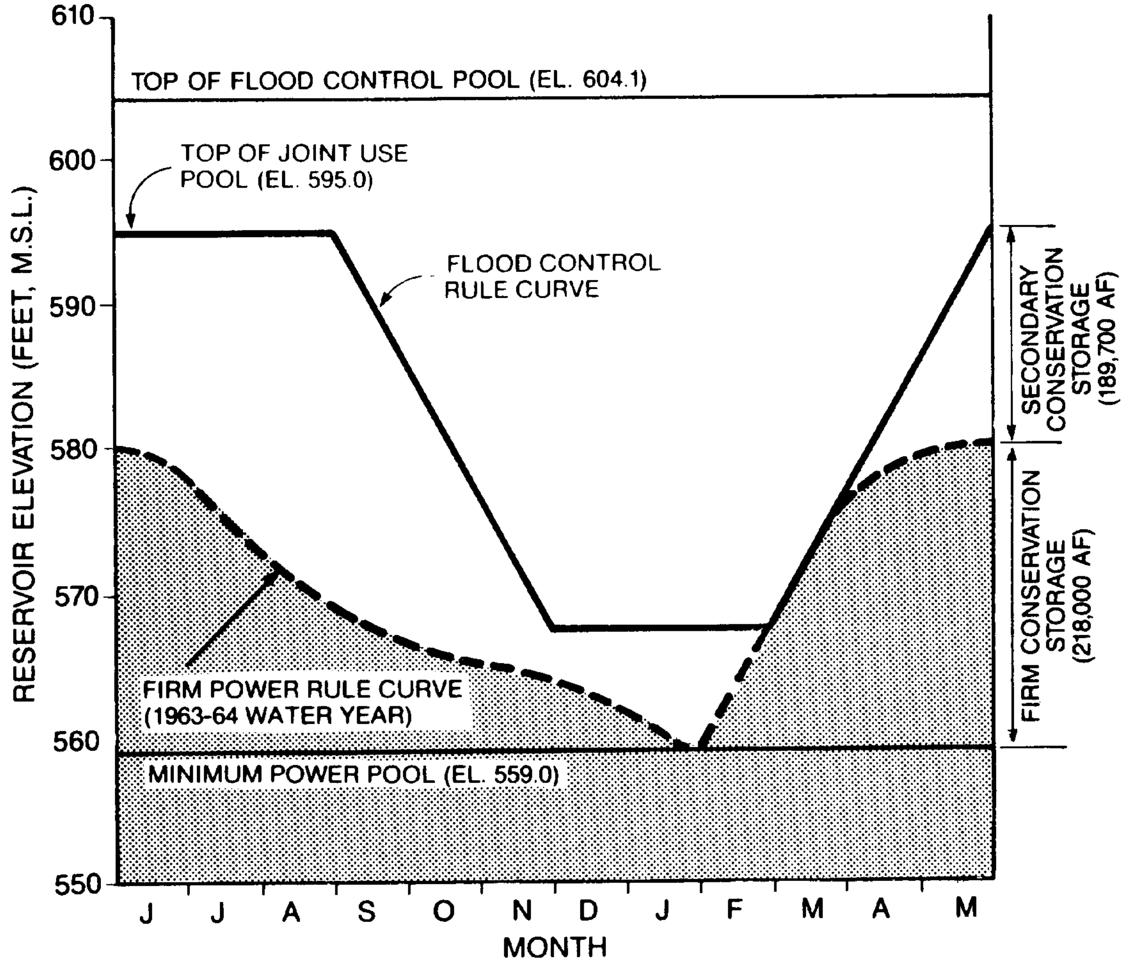


Figure 5-41. Firm and secondary conservation storage

for winter flood control. However, at many projects of this type, other project functions may help define the rate of draft. For example, at-site recreation requirements may encourage maintaining the pool level as high as possible in June, July, and August, but this may be offset by storage drafts for other uses, such as downstream water quality. Also, there would be little incentive to provide for secondary conservation storage unless it fills in a reasonably high percentage of the years. However, if (in the case of the example project), secondary energy has a higher value in July and August than it does during the refill season, providing secondary conservation storage to retain this energy might prove to be economically attractive.

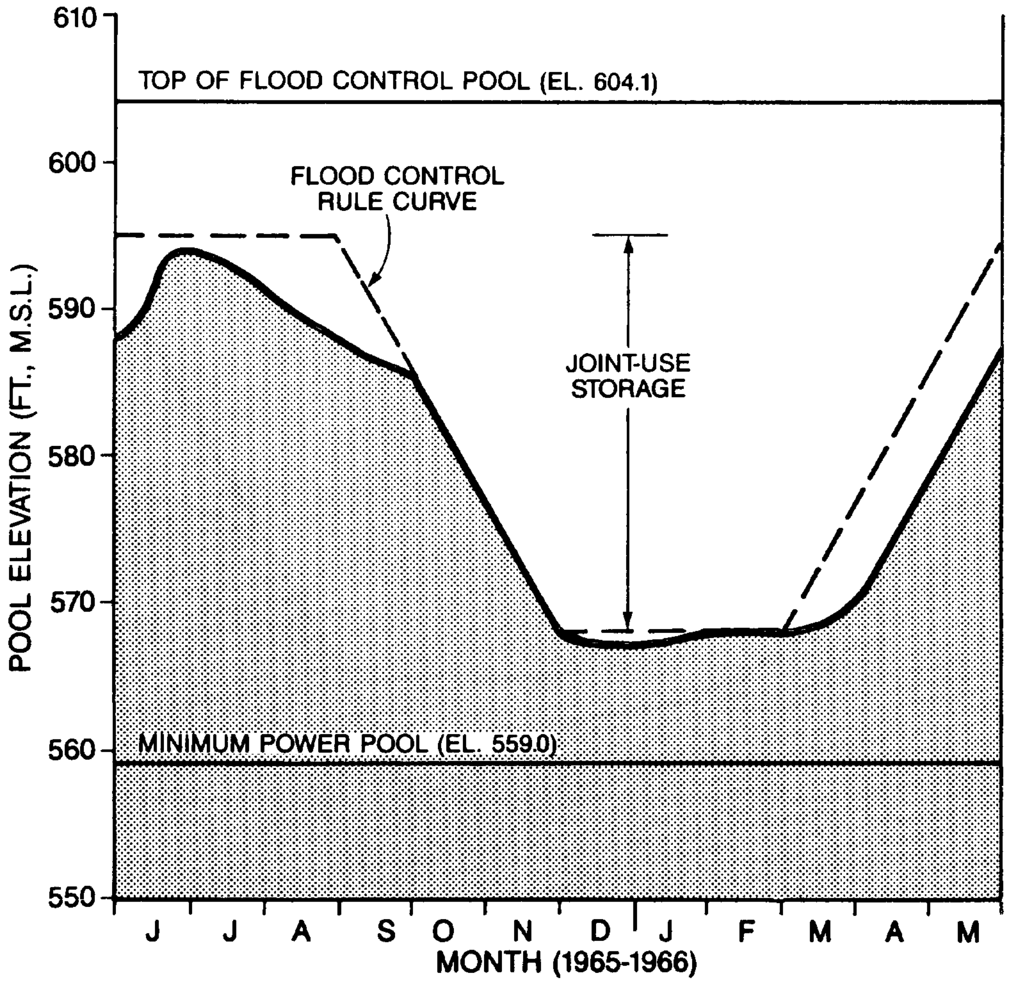


Figure 5-42. Regulation of a reservoir with joint-use storage through an average water year (Case 3, Appendix I)

(4) Figure 5-42 illustrates regulation of a reservoir with joint-use storage for flood control, hydropower, at-site recreation, and downstream water quality through an average water year. The supporting computations, which include the computations of the project's energy output, are included in Appendix I as Case 3. It should be noted that to simplify the example, monthly average flows have been used to estimate energy output in the flood season. Because of the wide day-to-day variation of releases during the flood season, daily routings would normally be required to provide an accurate estimate of energy output.

f. Joint-use Storage with Snowmelt Runoff.

(1) In the mountainous river basins of the western United States, much of the runoff is from snowmelt, and the magnitude of that runoff can be forecasted several months in advance with some degree of confidence. This makes it possible to manage joint use storage space more efficiently. Precipitation occurs primarily in the winter months, and the first forecasts of runoff volume are available in January or February. Drafts for flood control are scheduled to insure that sufficient flood control space is provided to maintain the required level of protection, while at the same time, sufficient conservation storage is maintained to permit refill in most years. Through the remainder of the winter and into the spring runoff season, forecasts are periodically updated, and the reservoir draft and refill schedules adjusted accordingly. In a low runoff year, flood control drafts are limited, to insure that sufficient conservation storage is available at the end of the runoff season to meet the coming year's firm power and other conservation requirements. In a high runoff year, the heavy drafts required to provide adequate flood control space also permit generation of secondary energy at a time when it is more readily marketable. Figure 5-43 illustrates regulation patterns for such a reservoir in both low and high runoff years.

(2) The Columbia, Colorado, and Sacramento-San Joaquin River Basins are examples of this type of hydrologic regime, and the way in which they are operated to meet flood control and conservation requirements is discussed in Appendix M. The papers by Green and Jones in reference (34) describe the complex system of rule curves that are used to regulate the operation of reservoirs in the Columbia River System.

g. Flood Control Storage Requirements. Extensive reservoir regulation and flood routing studies must be made to determine the amount of flood control space that must be maintained at various times of the year. Reference should made to publications such as EM 1110-2-3600, Reservoir Regulation (52), ER 1110-2-240, Reservoir Regulation, and Reservoir Operation for Flood Control (44b). Many of the SSR models used for making power studies also have the capability for doing the flood control regulation at the same time, provided that downstream flood control objectives have been established (see Appendix C).

h. Non-Power Conservation Requirements.

(1) At most projects having power storage, releases must also be scheduled to meet other downstream uses, which might include navigation, irrigation, municipal and industrial water supply, fish and wildlife, water quality, and recreation. In some cases, these requirements may be determined independently of the reservoir regulation study, such as (a) a minimum flow required to maintain sufficient depth to permit navigation in the reach below the reservoir, (b) the water supply requirements of a downstream community, or (c) minimum releases to maintain downstream fish populations. These requirements may be constant or they may vary seasonally. Sometimes, two levels of discharge may be specified, (a) a desired flow level that should be met as long as storage is above the critical rule curve, and (b) an absolute minimum flow that must be

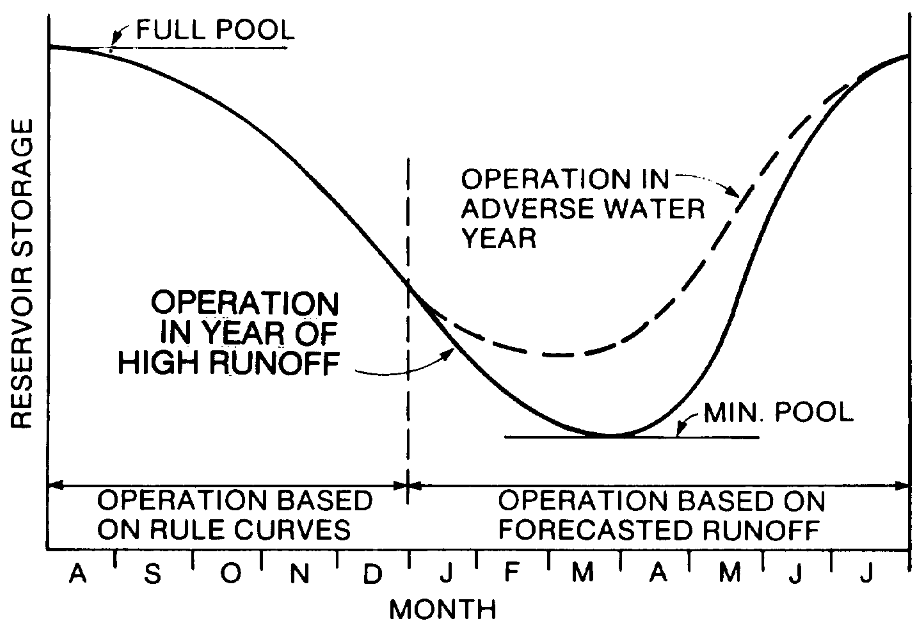


Figure 5-43. Regulation of a reservoir with joint-use storage where runoff can be forecasted (Libby Reservoir, Montana)

maintained at all times and is hence a part of the firm discharge requirement.

(2) The water quality requirement in the regulation in Appendix H is an example of a requirement that was established outside of the regulation study but had to be maintained throughout the period of analysis. In this case, releases for power were large enough in all months to maintain the water quality requirement, but in other cases, releases for other functions may constrain power operations.

(3) Sometimes the level of non-power requirements that can be maintained is determined in the regulation study. An example would be a project intended to provide both power generation and releases for irrigation. Each function could have different seasonal demand pattern (see Figure 5-44). To determine the optimum regulation would require a series of studies to test alternative storage release patterns, with the regulation providing maximum net benefits being selected as the optimum plan. In some cases, where multiple

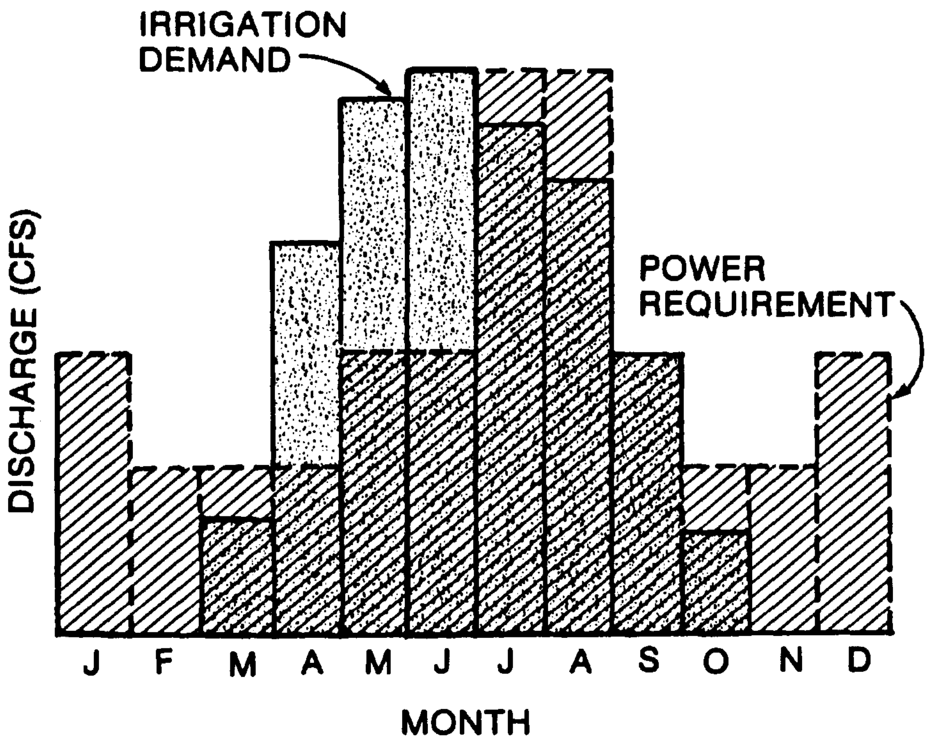


Figure 5-44. Irrigation demand vs. power requirements

objectives have been identified, it may not be possible to quantify the benefits for all functions, and judgement may be required to select the best plan. The 1981 operation policy analysis the Sam Rayburn Reservoir in Texas is an example of such a study (16).

i. Multiple-Purpose Operational Studies.

(1) Making an operational SSR study to determine the energy output of a project serving multiple purposes is basically the same as making a study for a single-purpose power storage reservoir. The steps described in Section 5-10 would be followed, and the requirements of other functions would be superimposed on the power regulation. In some periods, it may not be possible to meet all requirements. This requires a set of operating rules which establish priorities, and it is sometimes necessary to make alternative studies with different priority orders to identify the plan that maximizes net benefits. Other considerations may also help establish the priority order, or at least limit the alternatives that need to be considered. Within this context, it is important to recognize that priorities among the various water resource purposes vary with locale, with water rights, with the relative demands of the different water users, with legal and political considerations, and with social, cultural, and environmental conditions.

(2) Although these variations make it impossible to specify a priority system that applies in all cases, it is possible to identify a set of priorities that would be typical of many projects. Operation for the safety of the structure has the highest priority unless the consequences of failure of the structure are minor (which is seldom the case). Of the functional purposes, flood control must have a high priority, particularly where downstream levees, bridges, or other vital structures are threatened. It is not unusual for conservation operations to cease entirely during periods of flood regulation if a significant reduction in flooding can be realized thereby. Among the conservation purposes, municipal and industrial water supply and hydroelectric power generation are often given a high priority, particularly where alternatives supplies are not readily available. High priority is also usually assigned to minimum flows required for fish and wildlife. Navigation and irrigation may receive a somewhat lower priority, and water-quality management and other low-flow augmentation priorities would be somewhat lower yet, because temporary shortages are usually not disastrous. Finally, recreation and aesthetic considerations would usually have the lowest priority, although these functions sometimes warrant higher priorities. It should be emphasized again that: (a) there can be marked exceptions in the relative priorities as listed above, (b) there are regional differences in relative needs, and (c) legal and institutional factors may greatly affect priorities.

(3) Table 5-9 illustrates a listing of rules for hypothetical storage project in descending order of priority. Figure 5-45 describes the storage zones and rule curves for this project. It is possible to follow all of these rules in a hand regulation, but the advantages of computerized SSR models become obvious when the rules are numerous and complex.

(4) A considerable body of literature exists on multiple-purpose reservoir regulation. In addition to EM 1110-2-3600, Reservoir Regulation (52), and Volumes 1, 7, 8 and 9 of Hydrologic Engineering Methods for Water Resources Development (44), references (19) and (34) would be good starting points. Appendix M to this manual describes how multiple operating objectives are accomodated in the operation of several representative U.S. reservoir power systems.

5-13. Alternative Power Operation Strategies.

a. Introduction. The power regulation procedures described in the preceding sections are designed to insure that firm energy capability will be provided in all years in the period of record. Several alternative strategies might be considered in regulating power storage.

b. Maximize Average Annual Energy.

(1) Average annual energy could theoretically be maximized by maintaining the reservoir at maximum power pool (maximum head) at all times. However, this may not be a satisfactory operation because (a) the powerplant may not have sufficient capacity to fully utilize streamflows during the high runoff season, or (b) the value of energy in the high runoff season may be substantially less than during other periods. In these cases, some use of storage may be desirable to avoid spill and to maximize power benefits.

(2) One approach would be to apply monthly energy requirements greater than the firm energy output. Different levels of energy requirements could be tested to determine which level maximizes average annual energy. When a project is required to meet energy requirements greater than the firm, there will be months when those requirements cannot be met (at the end of the critical drawdown period, for example). This type of regulation would be implemented only in power systems where thermal energy is available to make up the shortfall in months when the energy requirement cannot be met. Section 5-13d(3) describes a technique for applying variable energy requirements, depending on pool elevation and/or time of year. This technique may not maximize average annual energy, but it might prove to be a satisfactory procedure for some projects.

TABLE 5-9
Operating Rules for Hypothetical Storage Project

1. When reservoir elevation approaches the top of flood control pool, spillway gates are opened to pass inflow, to prevent overtopping of dam.
2. Flood control storage space requirements are as follows:

December through February:	600,000 AF
June through August:	300,000 AF

   Storage in spring and fall months will follow the proportional rule curve shown in Figure 5-45. Flood control storage space is not to be filled except to control floods.
3. Flood control storage will be regulated to maintain a maximum flow of 10,000 cfs at the Fort Mudge gage, 15 miles downstream of this project.
4. Flood control regulation may require total project discharge to be reduced to zero, thus discontinuing power generation and releases for fish.
5. Primary flood control zone (upper two-thirds of flood control storage) is to be evacuated as rapidly as possible following the flood without exceeding downstream channel capacity.
6. Secondary flood control zone (lower third of flood control storage) is to be evacuated as rapidly as possible within constraints of power plant hydraulic capacity.
7. The diversions shown on Table 5-10 must be provided at the dam for a local municipal water system.
8. A minimum discharge of 200 cfs is required between April and September to maintain fish population in reach below dam.
9. The firm energy requirements shown on Table 5-10 must be met.
10. If reservoir is at or below critical rule curve, (power rule curve) only firm power requirements will be met.
11. The minimum desirable discharges shown on Table 5-10 will be met if possible for downstream navigation and water quality.
12. To protect dependable capacity, the reservoir will not be drafted below rated head (El. 737.0) except to meet firm energy requirements.
13. While in the conservation storage zone, discharge will not exceed powerplant hydraulic capacity.
14. Reservoir will be maintained as close to top of conservation pool as possible from Memorial Day through Labor Day for at-site recreation.
15. Maximum possible energy will be generated from October through February.

(3) In some cases, maximizing average annual energy may not produce maximum energy benefits. In order to determine the optimum regulation, the analysis would have to consider the cost of purchasing thermal energy in months of shortfall as well as the benefits of the increased average annual energy.

(4) If the value of energy varies from month to month, specific values could be assigned to the energy output in each month, and

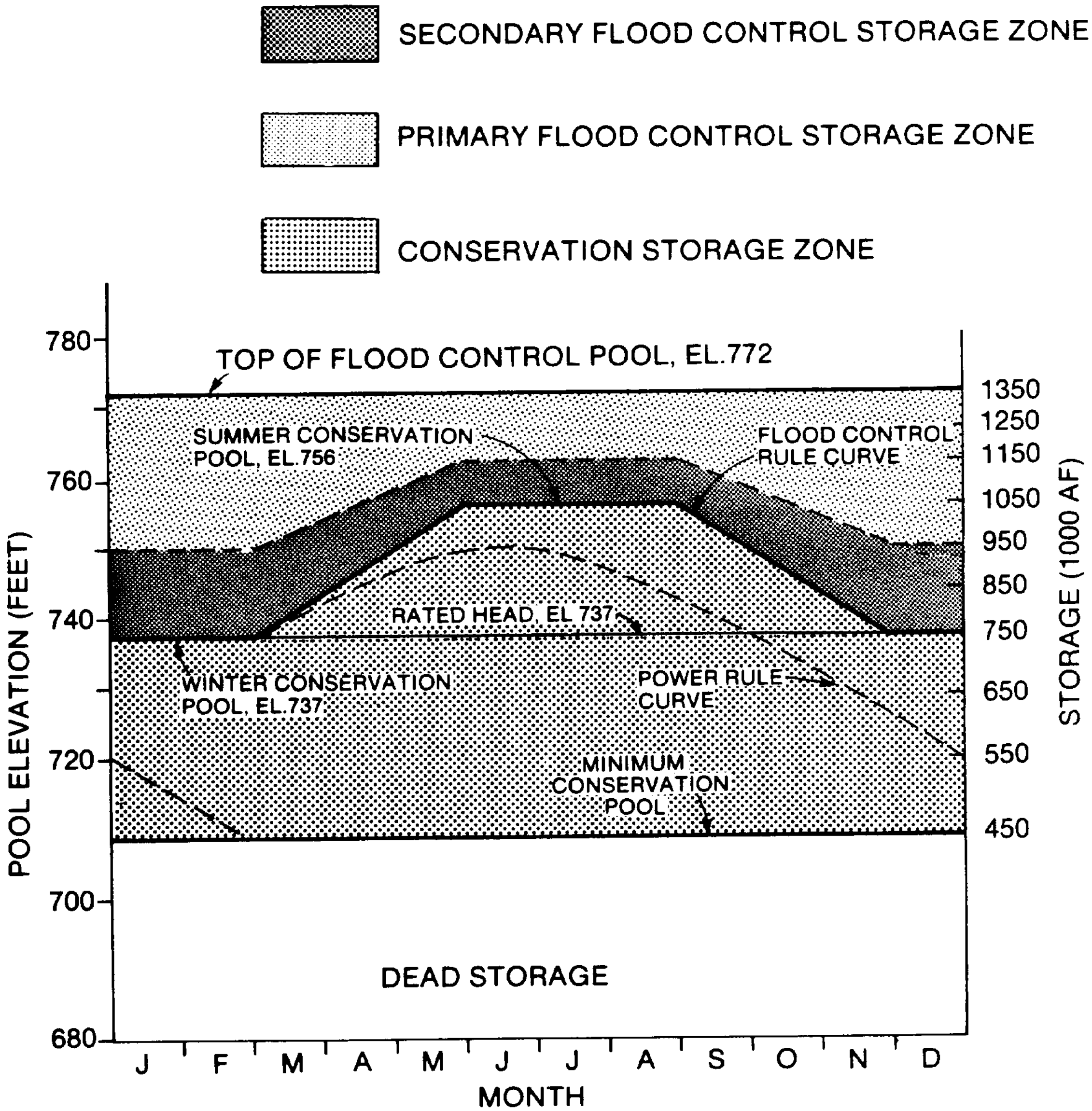


Figure 5-45. Storage zones and rule curves for hypothetical storage project

TABLE 5-10
Monthly Operational Requirements for Multiple-Purpose Storage Project Described in Table 5-9 and Figure 5-45

Month	Muncipal Water Diversion (cfs)	Required Minimum Discharge 1/ (cfs)	Desired Minimum Discharge 2/ (cfs)	Firm Energy (kWh)
January	35	0	300	13,700
February	35	0	300	11,800
March	35	0	300	12,300
April	37	200	300	11,600
May	43	200	300	11,300
June	65	200	400	10,800
July	87	200	400	11,300
August	83	200	400	11,300
September	61	200	400	10,900
October	43	0	400	11,600
November	39	0	300	11,900
December	35	0	300	13,200

1/ For fish and wildlife.

2/ For navigation and water quality.

successive iterations made to develop operating rules which maximize energy benefits. It should be noted that operating rules of this type would have to be updated periodically as the relative monthly energy values change. Figure 5-46 shows operation in an average year based on following operating rules designed to maximize energy benefits compared to an operation when the reservoir was maintained as close to the top of the power pool as possible the year around. Based on the energy values shown in Appendix I (Figure I-1), the energy output and energy benefits for that year would be as follows:

	Energy (gWh)	Energy Benefits ($1,000)
Maintain full power pool	95,500	3,350
Maximize energy benefits	92,600	3,770

The backup computations are shown as Cases 4 and 5 in Appendix I. Note that the operating rules used in Case 5 may not be the rules that would give the absolute maximum power benefits over the period-of-record, but they do illustrate how power benefits can be increased by taking into consideration seasonal variations in the value of energy.

c. Maximize Dependable Capacity.

(1) The objective in this case would be to maintain the reservoir at or above the rated head, to insure that the project's full rated capacity is available at all times. This would maximize the project's dependable capacity (assuming that dependable capacity is measured as described in either Section 6-7d or 6-7g). Theoretically, this could be assured by maintaining the reservoir at full

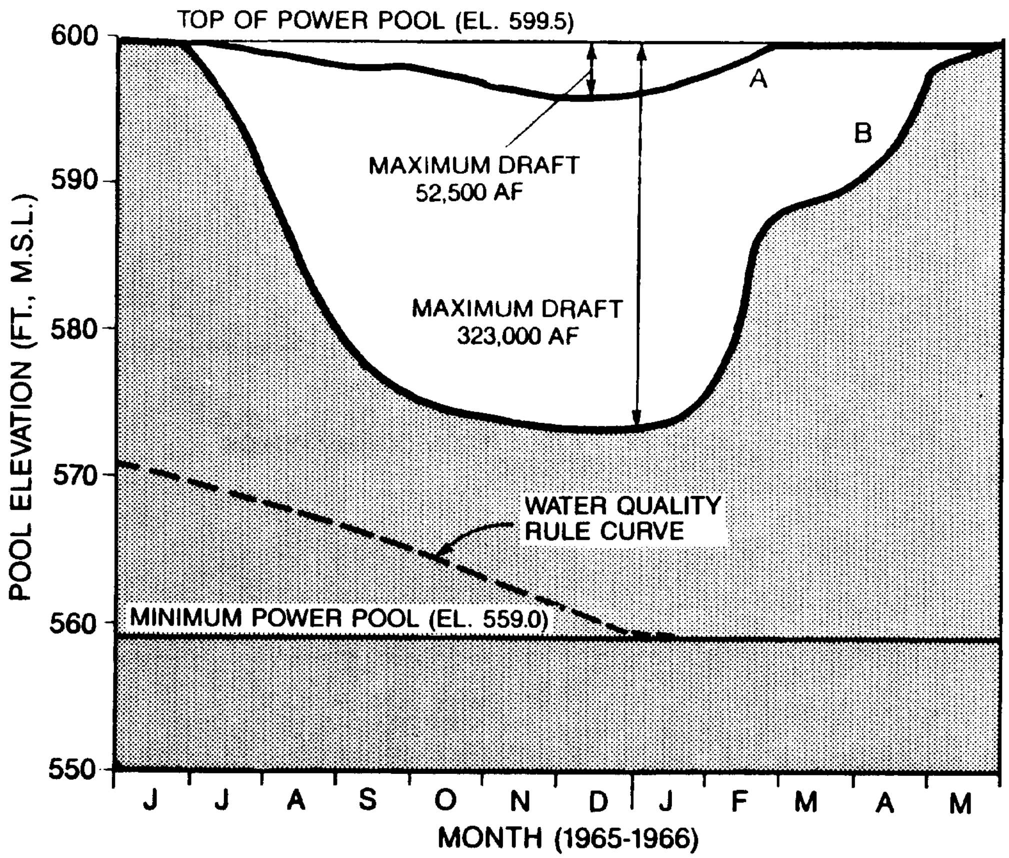


Figure 5-46. Reservoir operation in an average water year based on maximizing average energy (Curve A), and maximizing energy benefits (Curve B)

power pool at all times. However, for the capacity to be of value, it must be supported by sufficient energy to permit it to be operated for a specified number of hours in each period. For example, in some systems, for the capacity to be marketable, it must be supported by a specified amount of firm energy in each week or month. Storage drafts would be required to provide this energy in periods of low flow. This could be accomplished by developing a critical period rule curve based on only the storage available above critical head. Figure 5-47 indicates how the example project might be operated in an adverse water year, following the rule curve based on dependable capacity. Following this rule curve would insure that rated capacity would be available at all times. However, some firm energy capability would be sacrificed. For comparison, the regulation based on maximizing firm energy is also shown on Figure 5-33. The annual firm energy output in the two cases would be as follows:

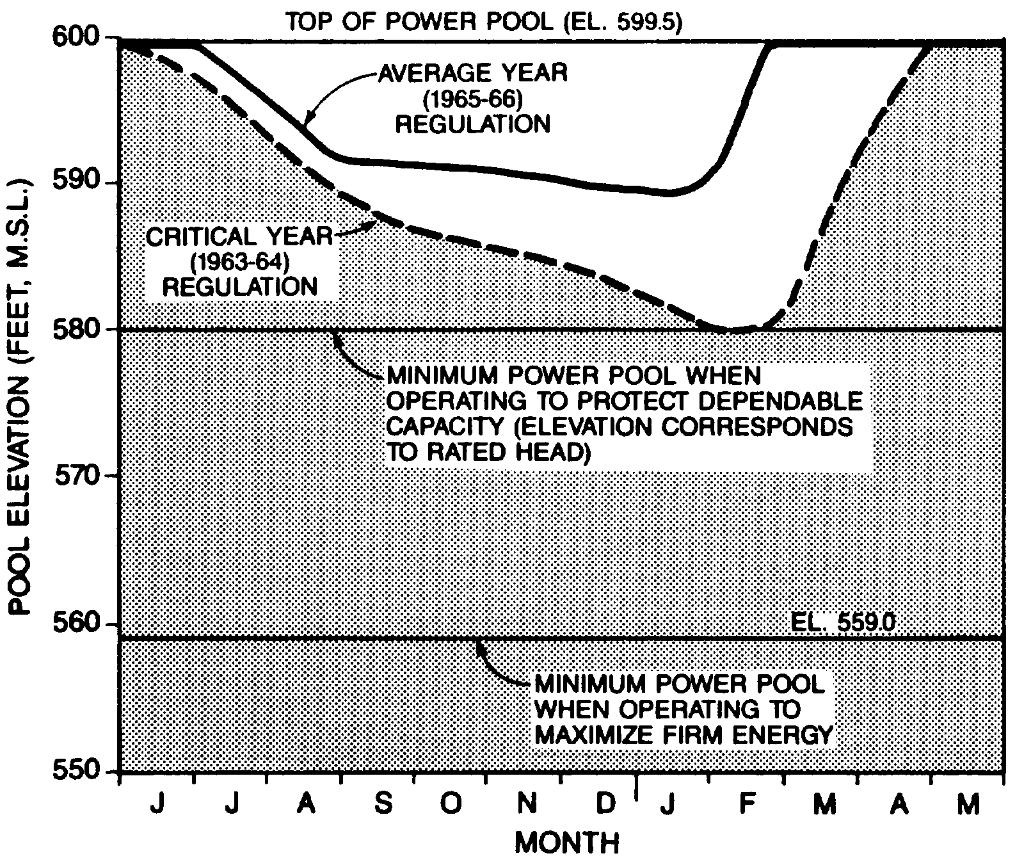


Figure 5-47. Operation of reservoir to maximize dependable capacity, in critical and average water years (Case 6, Appendix I)

Maximize firm energy 74,000 MWh

Maximize dependable capacity 45,700 MWh

Figure 5-47 also shows the dependable capacity operation in an average streamflow year. The backup calculations are shown as Case 6 in Appendix I, and the calculations for the routing to maximize firm energy are shown in Appendix H.

(2) A variation on this approach would be to maintain the pool at or above rated head through the end of the peak demand season

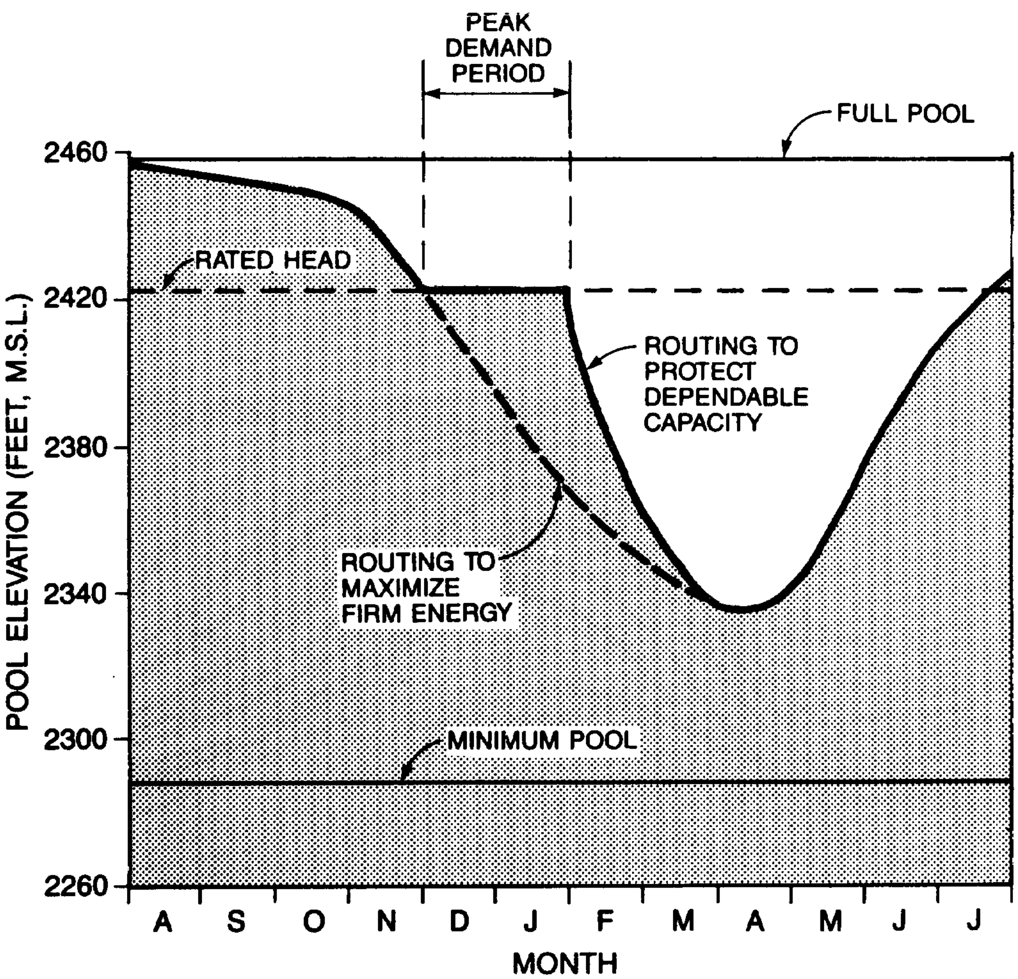


Figure 5-48. Operation of reservoir with joint use storage to maximize dependable capacity (in average year)

and then draft below that elevation to maximize average energy production during the interval prior to the refill season. This approach would be particularly attractive for a system where runoff is from snowmelt, where the amount of draft following the peak demand period would be based on forecasted runoff (see Figure 5-48).

d. Variable Draft.

(1) Another approach, which is now being used either explicitly or implicitly in several U.S. hydropower systems, is to base draft of power storage for secondary energy production on the market value of energy at the time. Such an operation might be superimposed on the primary objective of maximizing firm energy output. This means that the project would operate between the top of power pool and the critical year rule curve. During adverse water years, the project would operate on the rule curve and generate only firm energy. In good water years, drafting storage above the rule curve to produce secondary energy would be based on the value of the energy.

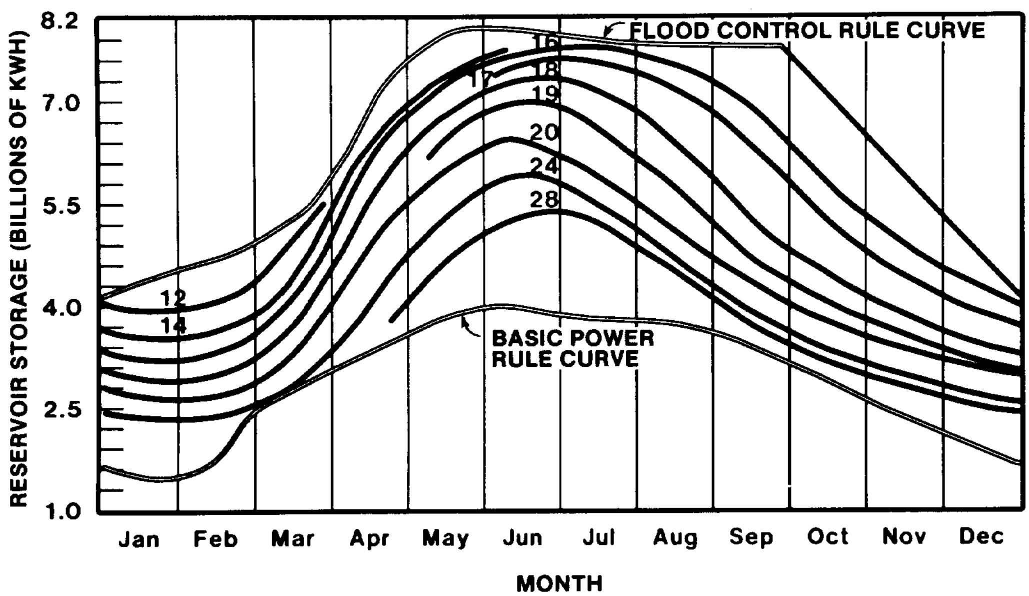


Figure 5-49. TVA intermediate guide curves for 1979. The curves between the flood control rule curve and the basic power rule curve are the intermediate guide curves. The numerical values above the curves represent the value of storage in mills/kWh.

(2) The most sophisticated example of an operation of this type is in the TVA system, where a series of intermediate (or economy) guide curves is developed which shows what the value of secondary energy must be for storage to be drafted to that level (Figure 5-49). Similar operations are followed in other systems as well, except that the decision whether to draft may be more judgemental, and may be based on non-power considerations as well as the present and expected future value of the secondary energy.

(3) In the Arkansas-White River power system, a variable draft strategy is employed by the marketing agency to protect dependable capacity as well as firm energy capability, while attempting to maximize energy output and yet maintain a satisfactory pool elevation for recreation. Studies by Tulsa District have succeeded in empirically quantifying this somewhat complex operation. In order to protect dependable capacity (and reservoir recreation), the reservoirs are almost never drafted below the elevations where 80 hours of power storage remains. To help maintain this elevation and still meet firm energy obligations, the marketing agency purchases low

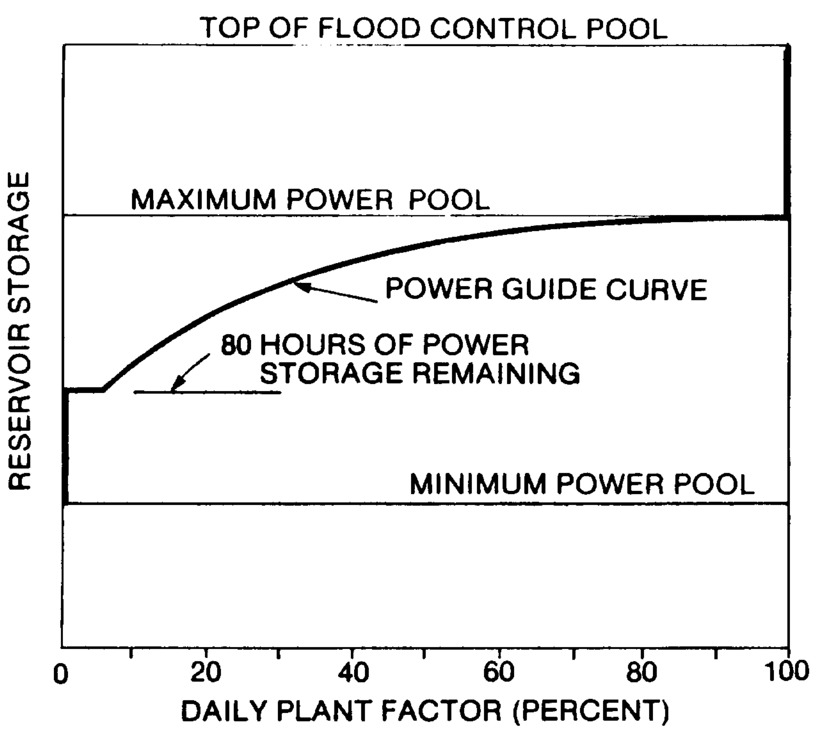


Figure 5-50. Power guide curve for Arkansas-White system

cost thermal energy whenever available. When the reservoir is above the 80-hour elevation, releases are made for power at a daily plant factor that is a function of pool elevation. This plant factor varies from 100 percent while in the flood control pool (i.e., at or above the top of power pool) to about 5 percent at the 80-hour elevation (see Figure 5-50). The 80 hours of storage is held in reserve, being used only in emergency situations, such as a severe heat storm occurring at a time when reservoir inflows are low and thermal energy is not available for purchase. Tulsa District has used a guide curve of this type to simulate the power operation of new power projects which would be operated in the coordinated Arkansas-White River power system. Both the HEC-5 and SUPER models have been adapted to simulate this type of operation.

(4) It should be noted that the 80-hour limit described above is based on historical operation experience in the early 1980's. The 80-hour limit corresponds to 40 percent of power storage remaining. The regional Power Marketing Administration expects this limit to move up, perhaps as high as 75 of percent power storage remaining by the 1990's. Where this approach is used, the studies should be closely coordinated with the regional PMA to insure that the guide curves reflect expected future operations.

(5) The power guide curve concept could also be applied to a reservoir that is regulated using a seasonally varying power rule curve (Section 5-11). The power guide curve would be flexible, expanding or contracting to fit the distance between the power rule curve and the maximum power pool (Figure 5-51). Using this approach, the plant factor required to produce firm energy could be varied seasonally also.

(6) A similar but somewhat simpler approach would be to use a series of intermediate rule curves to govern operation between the power rule curve and the maximum power pool. These curves would define zones within which the plant would operate at a fixed plant factor. These plant factors would vary with elevation in a manner similar to the power guide curve.

e. System Power Reserve. In systems with a high percentage of hydropower, it may be acceptable to draft below the critical rule curve to meet firm load during periods when base load thermal plant outages are higher than normal, with the expectation that later, when the thermal plants are back in service, they can operate at full output until the storage projects return to their rule curves. However, such departures from the rule curve would normally be limited. In the event of extended outage, other actions would be taken, such as purchasing energy from outside of the system and attempting to reduce loads.

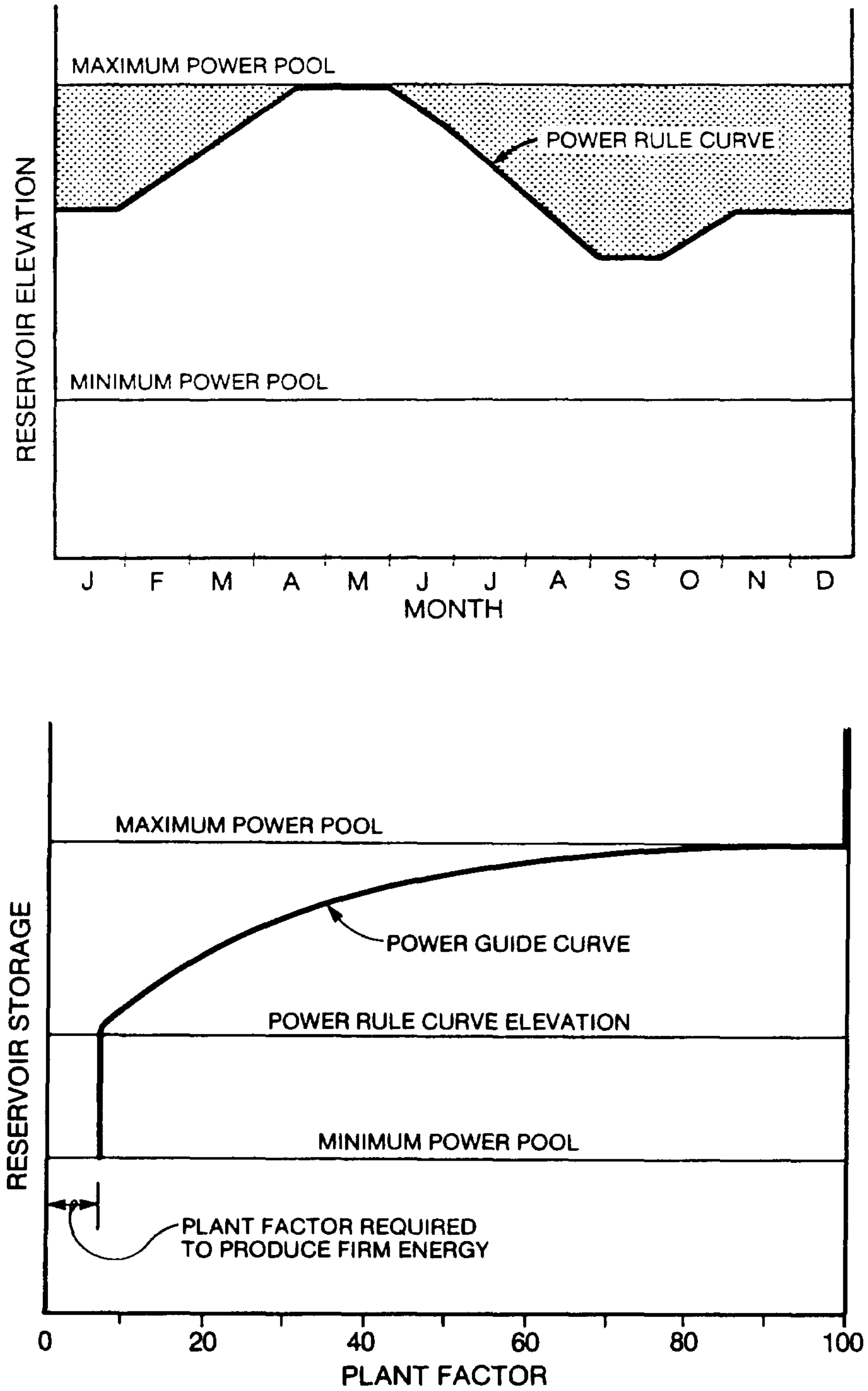


Figure 5-51. Appliction of power guide curve to reservoir operated using a power rule curve

f. Composite Energy Operation. In the mainstem Missouri River system, storage is several times the average annual runoff, thus permitting considerable flexibility in operation. System storage is divided into two zones, an upper or "Annual Multiple-Purpose Storage Zone" and a lower or "Carry-Over Storage Zone." In most years runoff is sufficient to operate in the upper zone, and regulating the project to meet normal flood control and navigation requirements usually results in power output close to average annual energy. During extended periods of drought (2 years or more), the operating strategy will result in the reservoir elevations dropping into the carry-over zone. When this occurs, energy production is reduced to the firm requirement until the reservoirs return to their normal operating range.

5-14. System Analysis.

a. Introduction.

(1) The analysis of a system of hydropower projects follows the same basic principles as single hydro storage project. The major difference is that analysis of a hydropower system is more complex, and when the system is operated for multiple purposes, the analysis is even more complex. For adequate analysis of systems, computerized SSR models become a necessity.

(2) In the context of this section, a "system" refers to a multi-reservoir system where the operation of all projects is coordinated to maximize power benefits (within the constraints of other project and system functions). System studies might be required at the planning stage for several reasons:

- to examine new hydropower systems
- to examine the proper sequence of construction for projects in a hydropower system
- to examine the addition of new projects to an existing system
- to examine the desirability of operating existing hydropower projects as a system instead of as independent projects
- to examine multiple-purpose aspects of reservoir system design and operation

- to examine the desirability of modifying the operation of an existing system to reflect changed operating requirements (either power or non-power)

(3) In the following paragraphs the general principles of reservoir system operation will be discussed, several examples will be presented, and sources of additional information will be cited.

b. Storage Effectiveness.

(1) The basic problem in operating a system of reservoir projects (Figure 5-52, for example), is to determine the order of drafting storage from the various reservoirs which will maximize power output. The overall approach to sequence of drafting can be understood by examining the storage effectiveness concept.

(2) When storage is drafted from a reservoir, (a) energy is generated from the water which was drafted, both at-site and at downstream projects, and (b), as a result of the removal of the storage, there is a loss in generating head at the storage project's powerplant. This loss of head reduces generation in subsequent months (until the reservoir fills once again). In order to determine the

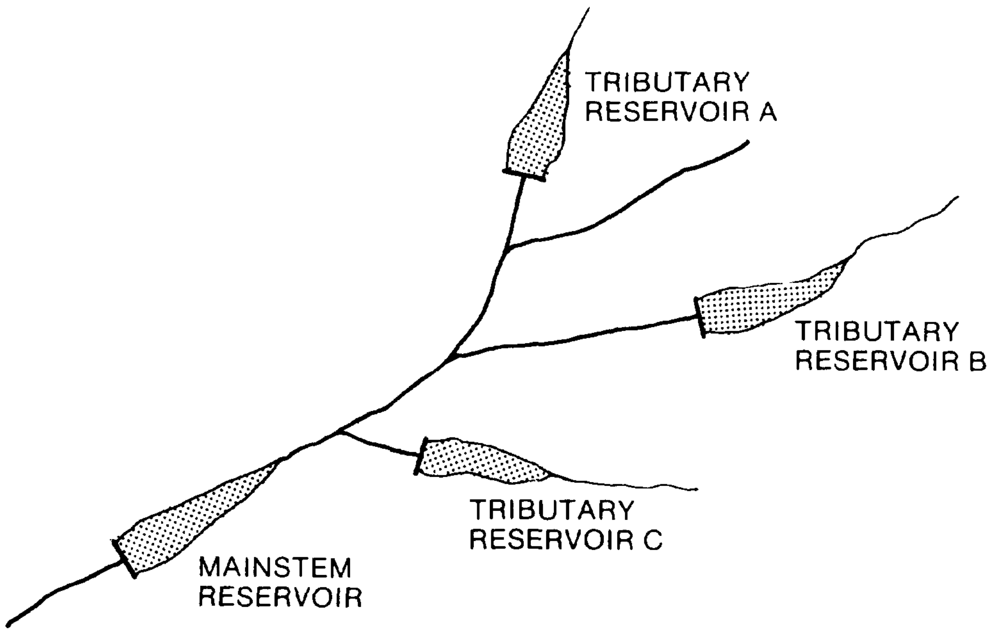


Figure 5-52. System of reservoir projects

order of reservoir draft, both the produced generation and the resulting loss in head must be taken into account. This can be achieved through the use of the storage effectiveness index, which is the inverse ratio of the gain in generation in a given routing interval to the generation loss in subsequent intervals:

$$\text{Storage Effectiveness Index} = \frac{\text{kWh lost in subsequent intervals}}{\text{kWh from storage release}}$$

At the start of each month, for example, storage effectiveness indices might be computed for each reservoir, and water would be drafted from the one with the most favorable (lowest) index.

c. General Approach.

(1) To illustrate the storage effectiveness concept, several different types of reservoir combinations will be examined. In order to simplify the explanation, it will be assumed that the system is being regulated only for hydropower and the objective is to maximize the system's firm energy output. The monthly routing interval will be used in the examples.

(2) The following steps would apply to the analysis of such a system:

- identify the historical streamflow period that appears most likely to be the system critical period.

- estimate the load that is to be carried by the system in each month of the critical drawdown period.

- for the first month in the period, determine the generation that can be produced by operating all powerplants using only reservoir inflow.

- determine the generation shortfall for that month by deducting the generation resulting from inflow from the required generation. This shortfall will then be met by drafting storage from one or more reservoirs.

- compute storage effectiveness indices for each reservoir

- select the project or projects with the lowest storage effectiveness index and draft sufficient storage to cover the generation shortfall

- repeat the four preceding steps for each subsequent month

(3) If the firm load which can be met by the hydro system has been estimated correctly, the loads will have been met in all months and all reservoirs will have been fully drafted by the end of the critical drawdown period. If the reservoirs have been drafted prior to the end of the critical drawdown period, the load estimate was too high. If storage remains at the end of the period, the estimate was too low. If the load estimate is either too high or too low, the load estimate must be adjusted and another routing must be made (see Section 5-10g).

(4) Once a routing is made which exactly uses the available storage, the system's firm energy output will have been identified for each month in the critical drawdown period. Using these firm energy requirements, a routing must be done for the entire period of record in order to (a) verify that the proper critical period has been selected, and (b) to determine the system's average annual energy production. If the reservoirs fully draft and loads cannot be met in some months, then another period is more critical. The entire process must then be repeated using the new critical drawdown period.

d. System Critical Period.

(1) The critical period for the system is defined by the regulating capability of the total amount of storage available to the system. As a result, it may be different than the critical period of individual projects operated independently.

(2) When a computerized SSR model is being used, the system critical period is usually identified by making trial routings. Various historical adverse flow sequences are tested in order to identify the period that is most adverse (produces the least amount of firm energy).

(3) If components of the system are located in hydrologically dissimilar basins or sub-basins, it may be necessary to identify one or more potential critical periods for each sub-area and test each with the entire system.

e. Estimate System Firm Energy Loads.

(1) Making a preliminary estimate of the firm energy load that could be carried by a system of projects is much more complicated than estimating the firm output of a single reservoir. Rather than attempting to make such an estimate, the usual approach when using computerized routing models is to determine the system's firm energy output by trial and error, applying various loads until the reservoirs are all exactly drafted at the end of the critical drawdown period (see Section 5-14c).

(2) In hydro-based power systems, some complicating factors may occur, particularly when examining the operation in the immediate future. Reasonably accurate estimates of expected loads and expected thermal resource capabilities (if any) are usually available. Hence, the hydro system would be operated against actual expected net loads. In some cases, this may result in a firm energy surplus or deficit, rather than an operation in which firm loads are exactly met. This could be handled by applying the surplus or deficit uniformly to all months in the critical drawdown period. This approach would simulate, in the case of a surplus, the shutting down of the most expensive thermal plants for the entire critical period, and, in the case of a deficit, accepting a uniform shortage over the entire critical period.

(3) In the case of a deficit, another approach would be to apply the deficit to the last months in the critical drawdown period. This would result in larger shortfalls in those months (compared to applying a uniform deficit to all months). However, extended low flow periods are usually infrequent occurrences, so over the long term, the system will seldom reach the state where deficits will actually occur. If it does appear that the system is entering an extended low flow period, actions would be taken to accomodate the resulting deficits (reduce loads, make purchases from outside systems, etc.).

f. Examples of Storage Effectiveness.

(1) General. Several examples of two-reservoir systems will be examined using the storage effectiveness technique in order to illustrate the principles of system operations. Detailed calculations will be shown only for the first example. For subsequent examples, the calculations used to derive the storage effectiveness ratios are summarized in Appendix L. The appendix also includes the storage-elevation curves for the three major reservoir configurations.

(2) Identical Reservoirs in Tandem. Figure 5-53 shows two identical reservoirs in tandem, both with at-site generation. Both also have 100 feet of head at full pool and 200,000 AF of power storage, located in the top 40 feet of the reservoir. Each reservoir has 80,000 AF of dead storage, so the total storage at full pool would be 280,000 AF. It is assumed that (a) there is no local inflow between the projects, so the same unregulated inflow applies to both projects, (b) net evaporation, leakage, withdrawals, and other losses are zero, and (c) the elevation of Reservoir A has no effect on the tailwater elevation at Reservoir B. The critical drawdown period is assumed to be eight months, June through January, and to simplify the problem, an inflow of 1000 cfs is assumed to apply to all months in the critical drawdown period. All months are assumed to be 30 days in length. The energy calculations are made using the water power equation.

(3) Estimate Energy Shortfall. It is assumed that the monthly firm energy requirement is 14,800 MWh for all months. The first step is to calculate the generation from natural inflow, using the water power equation (Eq. 5-4). Drafting storage from the downstream reservoir (Reservoir A) will be examined first. The energy output at the upstream reservoir for the first month would be

$$kWh = \frac{QHet}{11.81} = \frac{(1000\ cfs)(100\ feet)(0.85)(720\ hours)}{11.81} = 5{,}200\ MWh.$$

At the downstream project, the average available head would be less than 100 feet, because some head will be lost when storage is drafted to meet the deficit. An average head of 95 feet is assumed (note that more than one iteration may be required to reach a solution for the storage draft for a given month). The generation from inflow at Reservoir A would therefore be

$$kWh = \frac{(1000\ cfs)(95\ feet)(0.85)(720\ hours)}{(11.81)} = 4{,}900{,}000\ KWh$$

The energy shortfall would therefore be

(14,800 - 5,200 - 4,900) = 4,700 MWh.

(4) Draft Required from Reservoir A. If the draft is made at Reservoir A, the full 4,700 MWh of additional generation would have

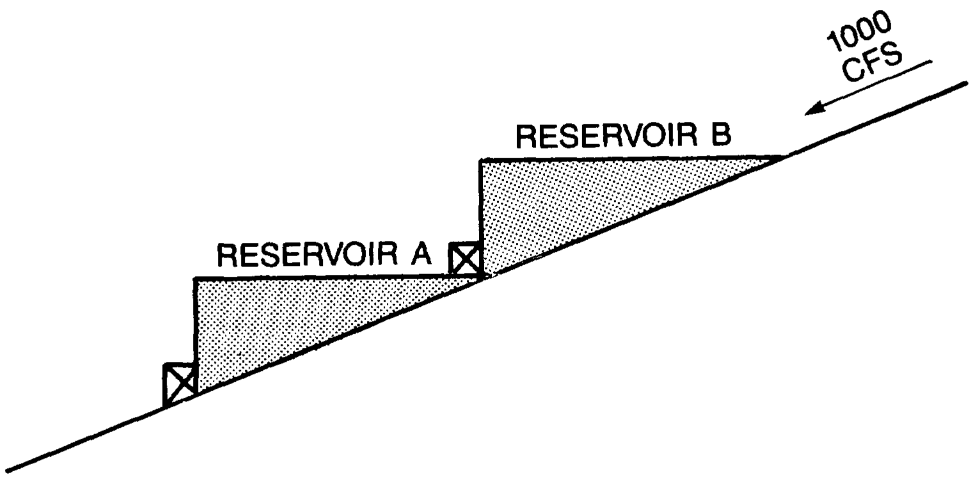


Figure 5-53. Two identical reservoirs in tandem, both with at-site generation (Case 1)

to be produced at that reservoir's powerplant. The average discharge required through the powerplant to produce 4,700 MWh would be

$$Q = \frac{11.81\ \text{kWh}}{\text{Het}} = \frac{(11.81)(4{,}700{,}000\ \text{kWh})}{(95\ \text{feet})(0.85)(720\ \text{hours})} = 955\ \text{cfs.}$$

This corresponds to a storage draft of

$$(955\ \text{cfs})(59.5\ \text{AF/cfs}) = 56{,}800\ \text{AF},$$

where 59.5 AF/cfs is the conversion factor for a 30-day month (Table 5-5).

Deducting the storage draft from the starting storage, the end-of-month storage is found to be (280,000 AF - 56,800 AF) = 223,200 AF. Referring to Figure L-1, the end-of-period head is found to be about 90 feet. The average head for the period would therefore be (0.5)(100 + 90) = 95 feet, which verifies the head assumed in previous steps.

(5) Loss in Subsequent Months. The loss of head at Reservoir A at the end of the first month would be (100 - 90) = 10 feet, which would in turn affect generation in the remaining seven months in the critical drawdown period. The average streamflow passing through the powerplant at Reservoir A through the remainder of the critical period would be the sum of (a) the unregulated inflow and (b) the remaining power storage at the two reservoirs, drafted over the course of the remaining seven months.

At-site unregulated inflow = 1000 cfs

$$\text{Releases from Reservoir B} = \frac{(200{,}000\ \text{AF})}{(59.5\ \text{AF/cfs})(7\ \text{months})} = 480\ \text{cfs.}$$

$$\text{Releases from Reservoir A} = \frac{(200{,}000 - 56{,}800\ \text{AF})}{(59.5\ \text{AF/cfs})(7\ \text{months})} = 344\ \text{cfs.}$$

The total average flow would be (1000 + 480 + 344) = 1824 cfs. The resulting energy loss would therefore be

$$\text{kWh} = \frac{\text{QHet}}{11.81} = \frac{(1824\ \text{cfs})(10\ \text{ft})(0.85)(7\ \text{X}\ 720\ \text{hrs})}{11.81} = 6{,}600\ \text{MWh}.$$

(6) Storage Effectiveness Index For Reservoir A. The storage effectiveness index for Reservoir A would be the ratio of the energy loss in subsequent months to the energy produced in the month being evaluated, or

$$\text{Storage Effectiveness Index} = \frac{6{,}600\ \text{MWh}}{4{,}700\ \text{MWh}} = 1.40$$

(7) Analysis of Reservoir B. Reservoir B would be analyzed in the same way. The resulting storage effectiveness index is 0.47. The backup calculations are summarized as Case 1 in Appendix L.

(8) Sequence of Drafting. Reservoir B has a much lower storage effectiveness index (0.47) than Reservoir A (1.40). Hence, it is obvious that the first draft should be made from the upstream Reservoir B. Drafts from Reservoir B will pass through a larger generating head, and thus require less draft to produce a given amount of generation. If storage is drafted from Reservoir A, not only will a larger head loss occur because of the larger draft, but the resulting head loss will affect subsequent generation from storage releases from both Reservoirs A and B. For these reasons, upstream reservoirs should generally be drafted first. The only possible exception (other than non-power operating constraints) would be where the upper reservoir has a much steeper storage-elevation relationship than the lower reservoir. The upstream project would therefore suffer a much larger loss in head in order to provide the required draft, and this may produce a higher storage effectiveness index at the upstream reservoir. In most cases, however, there is local inflow between tandem reservoirs, so the loss in head due to storage draft at the lower reservoir would cause a proportionately larger loss in generation in subsequent months, making drafts from the upper reservoir even more effective.

(9) Regulation Over the Critical Drawdown Period. Routing the two reservoirs shown in Figure 5-53 through the critical drawdown period would result in the regulation shown on Figure 5-54. The upstream Reservoir B would be completely drafted before storage is drawn from Reservoir A. Note also that the downstream reservoir is filled first, for the same basic reasons that it was drafted last. Refilling the downstream reservoir first also increases the probability that it will refill, and that generation of secondary energy will be maximized in the spring months of high runoff years.

The plots for the critical drawdown period could be used as rule curves to guide the operation of the reservoirs through the total period of record.

(10) Two Identical Reservoirs in Parallel. Figure 5-55 shows two identical reservoirs in parallel with the same characteristics as Reservoirs A and B. Assume first that both have identical inflows and both have powerplants. In this case, both would also have identical storage effectiveness indices of 0.91 for the first month in the critical drawdown period (Case 2, Appendix L), so the two would be drafted at the same rate.

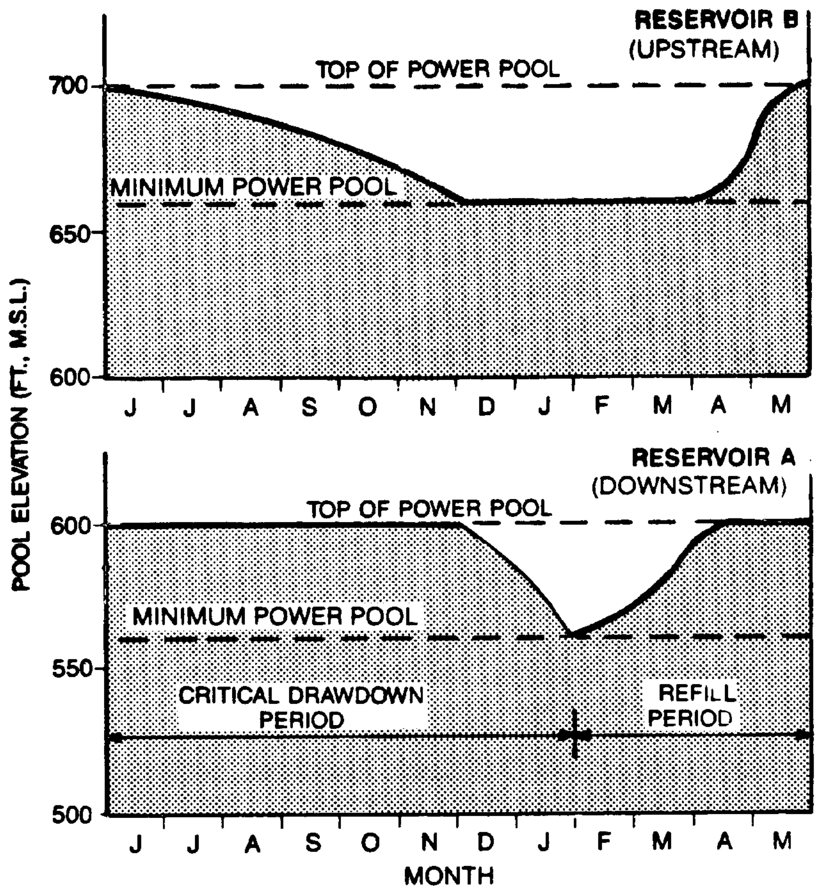


Figure 5-54. Regulation of two identical tandem reservoirs over the critical drawdown period

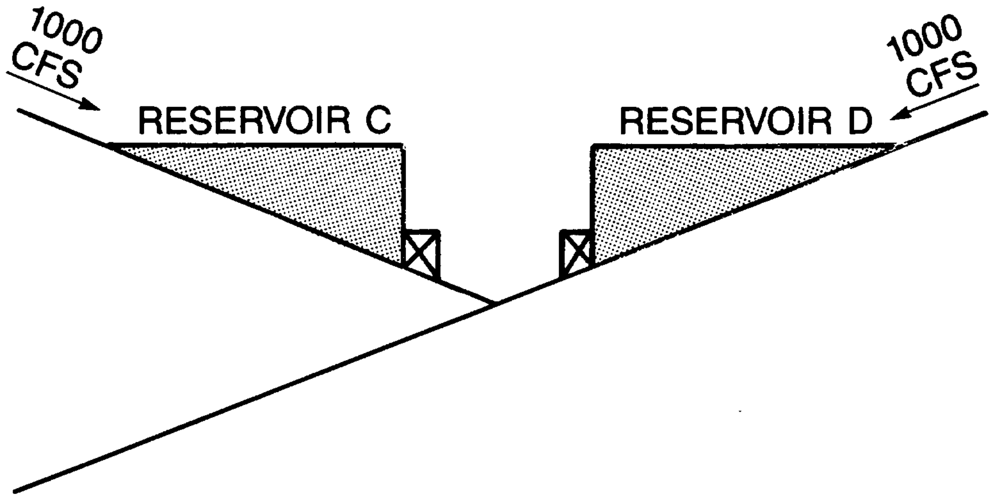


Figure 5-55. Two identical reservoirs in parallel (Case 2)

(11) Two Identical Reservoirs in Parallel (One with Downstream Power). Assume the same situation as in the previous example, except that a run-of-river plant with 30 feet of head is located just downstream from Reservoir D (Figure 5-56). Because the effective head of releases from Reservoir D is increased by 30 feet, the draft required from that reservoir to meet a given increment of load is reduced, resulting in a higher average head at-site and reduced losses in subsequent months. The first-month storage effectiveness index for

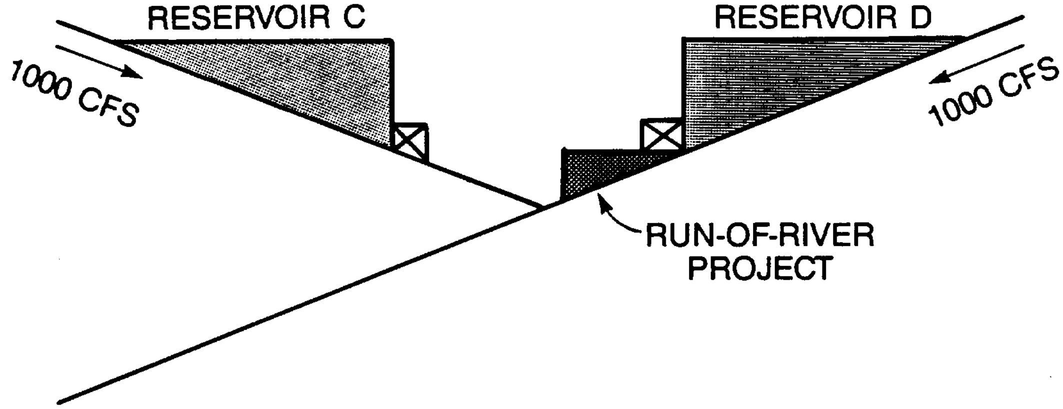


Figure 5-56. Two identical reservoirs in parallel (one with downstream power) (Case 3)

Reservoir D would be 0.70 (Case 3, Appendix L), compared to 0.97 for Reservoir C, making Reservoir D the first reservoir to draft. Note that as Reservoir D is drafted, its head is reduced. Before the storage is fully drafted the sum of the head at Reservoir D and the run-of-river plant will be less than the head at a full Reservoir C. Thus, at some point during the critical drawdown period, the storage effectiveness indexes of the two reservoirs could become equal, at which time simultaneous drafts would be made from both reservoirs.

(12) <u>Two Identical Reservoirs in Parallel (One Without Power).</u> Consider a situation similar to the preceding example, but where only Reservoir C has at-site power and there are run-of-river projects located below the confluence of the two streams (Figure 5-57). Even though Reservoir D has no at-site power, storage releases would be usable for increasing generation at the run-of-river projects. It can be seen without computations that the loss in generation at Reservoir D in subsequent months due to reduced head will be zero, because there is no at-site generation. Hence, the storage effectiveness index for Reservoir D will be zero, and it should be drafted before drafting Reservoir C. Where power generation is the only consideration, reservoirs without at-site power should be drafted in preference to those with at-site power. However, it is not always desirable to fully draft the reservoir without at-site power prior to drafting the one with at-site power. Consideration should also be given to insuring that Reservoir D has a reasonable probability of refill in normal water years. This could be accomplished by developing an assured refill level (or curve) for each reservoir. As long as a reservoir is not drafted below this level, it will refill in most water years. In the example, Reservoir D would be drafted to the

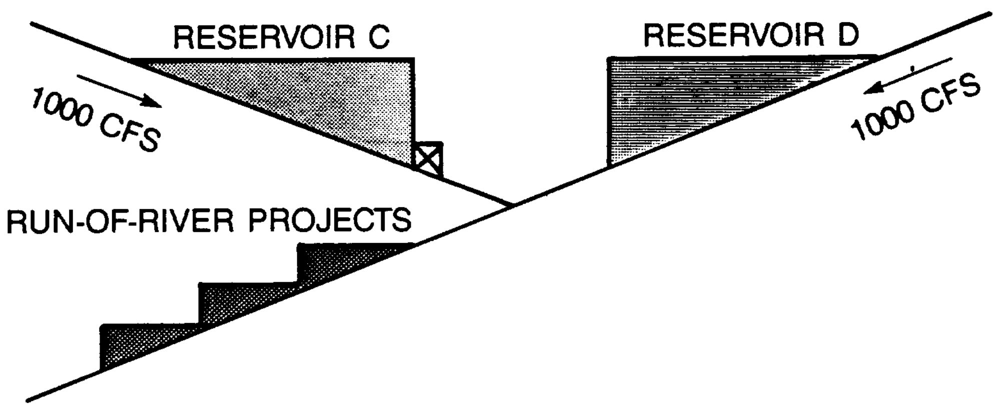


Figure 5-57. Two identical reservoirs in parallel (only one with power)

assured refill level. Then, Reservoir C would be drafted to its assured refill level. Finally, in years when further draft is required, the remaining storage in both reservoirs would be drafted. Such a strategy would tend to reduce firm energy slightly, but would increase energy production in most years. Pages 302-309 of reference (23) discuss the regulation of multiple reservoirs with no at-site power.

(13) Two Equal Reservoirs in Parallel (Unequal Inflow). Assume again that there are two identical reservoirs in parallel, both with at-site power, but that the inflow at Reservoir D is half of the inflow at Reservoir C (Figure 5-58). The same draft would be required at each reservoir to meet a given increment of generation. However, because of the smaller inflow at Reservoir D, the generation loss in subsequent months due to loss in head will be less than the loss at Reservoir C. Hence, Reservoir D has a lower storage effectiveness index (0.59) than Reservoir C (0.99) and would be drafted first (Case 4, Appendix L).

(14) Two Reservoirs of Different Slope in Parallel. Assume in this case that there are two reservoirs of equal storage (200,000 AF) located in parallel, but Reservoir E has a steep storage-elevation curve, while Reservoir F has a flat storage-elevation curve (Figures 5-59 and L-1). The heads at full pool are assumed to be 150 feet at Reservoir E and and 50 feet at Reservoir F. Assume that both have at-site power and that both have identical inflows (1000 cfs). Because of the greater head, less draft will be required to produce a given increment of generation at Reservoir E than at Reservoir F (Case 5,

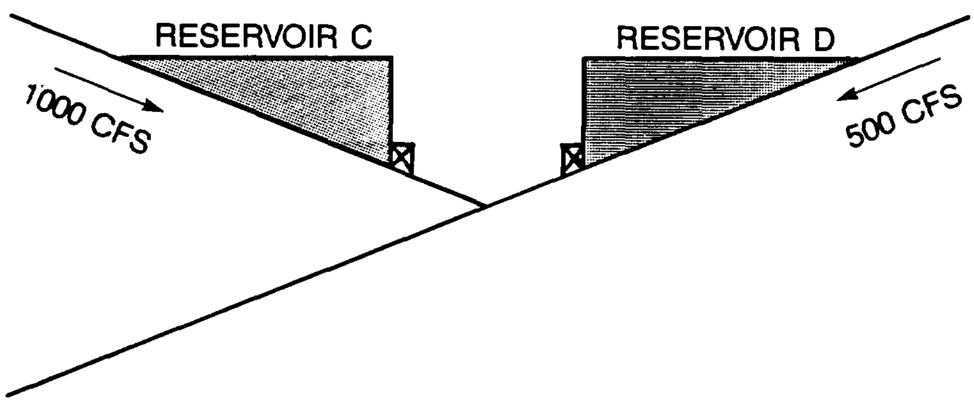


Figure 5-58. Two identical reservoirs
in parallel with unequal inflow (Case 4)

Appendix L). However, because of the steeper storage-elevation relationship, Reservoir E incurs about the same amount of head loss as Reservoir F. Even though the head loss is the same at both reservoirs, the energy loss in subsequent months is less at Reservoir F than at Reservoir E, because not as much storage remains to augment inflow. Hence, the storage effectiveness index at Reservoir F (0.91) is less than at Reservoir E (0.96), so Reservoir F should be drafted. However, it should be noted that the indices are relatively close.

g. Discussion of Storage Effectiveness Examples.

(1) Six different two-reservoir systems were analyzed in the previous section using the storage effectiveness concept. Other combinations could have been examined also, but the ones presented are sufficient to permit making some general statements about the optimum sequence of drafting for multiple-reservoir systems.

- reservoirs without at-site power should be drafted before reservoirs with at-site power.
- when reservoirs are located in series (tandem), the upstream reservoir should usually be drafted first.
- a flatter storage-elevation relationship tends to favor early draft.
- a lower total at-site discharge (inflow plus storage draft) over the critical drawdown period tends to favor early draft.

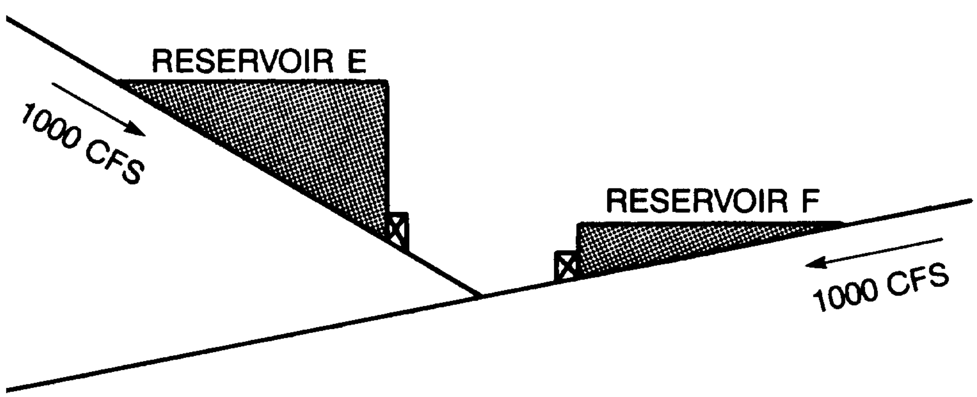


Figure 5-59. Two reservoirs of equal size but different slope in parallel (Case 5)

- a higher effective head (at-site head plus total head at downstream projects) tends to favor early draft.

(2) In many systems, however, the configuration of projects and the characteristics of reservoirs and the streams on which they are located are such that the optimum sequence of draft is not obvious. Development of a plan for regulating a system of reservoirs often requires a large number of trial-and-error iterations, and this can be accomplished effectively only with computerized SSR models.

(3) Computerized SSR models for evaluating the hydropower output of reservoir systems fall into three general categories:

- models which use some type of storage effectiveness index (although not necessarily the one described above) as the basis for selecting the reservoir(s) to draft in each time increment.

- models which run a large number of combinations of draft sequences to determine the optimum sequence (practical only for analyzing relatively simple systems only).

- models of complex existing systems, where the draft sequence is based on rule curves (which are the result of many trial-and-error iterations, augmented by actual system operating experience).

A good model is essential for reservoir system analysis, but the model can be used effectively only if the operator understands how the routings are made and how reservoirs are selected for draft. This knowledge is essential first of all to insure that the proper model has been selected and that the various projects are accurately represented in the model. Such knowledge is also necessary to permit the operator to review the output, to determine if a given routing has been done correctly, and to enable him to modify a routing to improve the system's performance.

(4) The examples discussed above are based on a single-year critical period. In systems having a multi-year critical period, some of the reservoirs may fully draft in each year, either because of flood control requirements, or because they have a relatively small proportion of storage to runoff. Others may have carry-over storage, and will not reach the bottom of the power pool until the last year of the critical period. The multi-year or "cyclical" reservoirs would have a relatively large ratio of storage volume to runoff volume compared to the annual reservoirs. The draft schedule would have to reflect the different characteristics of these two types of reservoirs.

(5) Some projects in a system may be under the control of entities which do not elect to participate in coordinated operations. These projects may have to be operated according to fixed rules rather than be operated for the benefit of the system.

(6) An additional problem that is sometimes encountered is "trapped storage." This can occur at projects where there are natural restrictions (such as the channel capacity of the outlet of a natural lake that is being regulated for power), or where there is a limited powerplant hydraulic capacity, either at the storage project or at a downstream project. At projects like this, it might not be possible to evacuate the usable power storage at the time and rate that system analysis studies determine is optimum, because the natural restrictions limit flow or because the powerplant hydraulic capacity would be exceeded and spill would occur. In such cases, it may be necessary to adjust the draft sequence to work around these constraints.

(7) The examples discussed above were all based on operating the system to maximize firm energy output. The same basic concepts could also be used to regulate a system to meet one of the other objectives described in Section 5-13, such as maximizing dependable capacity or maximizing average annual energy.

h. Multiple-Purpose Operating Considerations.

(1) The examples discussed above were also based on single-purpose power operation. In most real situations, however, the system is operated to meet other objectives as well, such as providing storage for flood control, maintaining minimum discharges for environmental purposes, and maintaining high reservoir levels in the summer months for recreation. The same basic principles as were outlined earlier in this section would be followed for a multiple-purpose system analysis except that non-power operating requirements must also be followed. The application of these requirements could lead to a completely different sequence of drafting than would be indicated by power considerations alone.

(2) In making the routings, successive iterations are often required in order to develop a viable multiple-purpose operating plan. One approach would be to first perform the reservoir drafts required to meet mandatory non-power operating requirements. If such a regulation does not in itself meet the firm energy requirements, further drafts would then be made based upon storage effectiveness criteria. In some cases, storage drafts for non-power requirements conflict with the optimum draft schedule for power. In these cases, it is usually necessary to develop operating rule curves based on a compromise between the power and non-power objectives (see Section 5-12).

i. Coordination with Other Entities.

(1) In some systems, all of the hydro plants may be under the control of a single entity, but in other systems, two or more entities may be involved. While benefits can almost always be gained through coordinated operation, in some cases these benefits may not be realized because of institutional constraints, or because of the differing operational objectives of the various entities involved in the coordination. Where opportunities for coordinated operation exist and Federal projects would be involved, Corps field offices should explore such possibilities, in the interest of increasing both project and system NED benefits.

(2) An example of a system where such coordination has been achieved is the Columbia River power system. The Federal government controls a large share of the power storage, either through direct ownership of the reservoirs, or through the Columbia River Treaty with Canada. However, some of the storage is controlled by non-Federal entities. The mainstem run-of-river projects, where most of the system's energy is produced, are also divided between Federal and non-Federal ownership. Altogether, 18 different entities are involved, including three Federal agencies and the British Columbia Hydro Authority (representing the Canadian government), and 14 electric power utilities. Coordination of the seasonal operation of the storage projects is achieved through the Pacific Northwest Coordination Agreement (among the various U.S. entities), and the Columbia River Treaty (between the United States and Canada). The hourly operation of the Grand Coulee storage project and the chain of six pondage projects located immediately downstream is coordinated through another operating agreement. Although the development and implementation of these agreements has not been without its problems, the overall operation has been very successful. It should be noted that the system is operated to provide flood control, navigation, irrigation, fish and wildlife, and recreation benefits in addition to power production. Section M-8 of Appendix M briefly describes the Columbia River power system, and references (2), (30), (85), and papers in references (19) and (34) describe various aspects of the operational agreements.

j. Sources of Further Information.

(1) References (19), (34), and (52) provide further information on the analyses of power systems. Reference (19) also includes an extensive bibliography. Additional references may be found in the proceedings of the American Society of Civil Engineers and the Institute of Electrical and Electronic Engineers, and in the journal Water Power and Dam Construction (formerly Water Power).

(2) Most of the SSR models described in Appendix C have system analysis capabilities. The documentation of these models provides some insight into the system analysis techniques used in each. For example, Appendix K contains a brief description of the techniques used by HEC-5 to make system power studies. The analysts responsible for operating and maintaining these models can provide further assistance on system analysis techniques and on the application of their respective models to power system problems.

(3) The field offices of the agencies responsible for operating the major hydropower and multiple-purpose reservoir systems in the United States would be additional sources of information. Table 5-11 provides a listing of some of these systems, and a brief discussion of the characteristics of these systems is included in Appendix M. Special attention should be given to those systems that most closely resemble the hydrologic characteristics and operating objectives of the system being studied.

(4) In addition, the Hydrologic Engineering Center is capable of assisting Corps field offices in system analysis problems, and both North Pacific Division and Southwestern Division have experience in applying their models to the analysis of systems outside of their geographic area of responsibility. Because of the complexity of system analysis and the fact that development of effective operating rules is to some extent an art, field offices are encouraged to consult with those who are experienced in working with these problems.

k. Examples of Existing Hydropower Systems. Table 5-11 lists eight major existing water resources systems which are regulated for multiple purposes including hydropower. A description of the individual system characteristics and operating criteria for most of these systems is presented in Appendix M.

5-15. Hybrid Method.

a. Introduction. The hybrid method is designed to examine the addition of power at projects where head varies independently of streamflow, but there is no regulation of seasonal storage for hydropower. Examples would be a flood control reservoir or a storage project where the conservation storage is regulated entirely for non-power purposes. The hybrid method does the power computations sequentially and then arrays the results in duration curve format for further analysis.

b. Data Requirements. Data requirements (Table 5-12) would be essentially the same as for the flow-duration curve method except that daily values of reservoir elevation must be provided in addition to

TABLE 5-11
Major Existing Water Resources Systems in the United States
Regulated for Multiple Purposes Including Hydropower

System	Area
South Atlantic	Georgia, Alabama, Florida, South Carolina
Cumberland River	Kentucky, Tennessee
Tennessee River	Tennessee, North Carolina, Georgia, Alabama, Kentucky
Arkansas-White Rivers	Oklahoma, Arkansas, Missouri
Mainstem Missouri River	Montana, North Dakota, South Dakota, Nebraska
Colorado River	Colorado, Wyoming, Utah, Arizona, California, Nevada, New Mexico
Central Valley Project	California
Columbia River	Montana, Idaho, Washington, Oregon

daily streamflow values. This data could be obtained from USGS records, project operating records, or from system regulation models such as SUPER. As with the flow-duration method, daily data would be used in most cases.

c. Methodology. Basically, the method involves computing the project's power output day-by-day for the period of record using sequential streamflows and reservoir (forebay) elevations obtained from the historical record or a regulation model. The procedure followed is essentially the same as that described in Section 5-9. The results are then arranged in power-duration curve format, either for the year or for specified months or seasons. Normally, computations would be made both for specified power installations and without the constraint of a specified plant size. The results can then be plotted to show what portion of the site's energy potential is developed by the specified power installation (Figure 5-60). With DURAPLOT, the turbine characteristics (minimum and maximum heads and

TABLE 5-12
Summary of Data Reguirements for Hybrid Method

Input Data	Paragraph 1/	Data Required
Routing interval	5-6b	daily time interval
Streamflow data	5-6c	historical records or SSR regulations
Minimum length of record	5-6d	30 years or representative period
Streamflow losses		
Consumptive	5-6e	normally included in streamflows
Nonconsumptive	5-6e	see Section 4-5h (4) thru (10)
Reservoir characteristics	5-6f	use (a) elevation vs. discharge curve, (b) fixed elevation, or (c) data from historical records or SSR regulation
Tailwater data	5-6g	tailwater curve or fixed value
Installed capacity	5-6h	can specify capacity or let model determine plant size
Turbine characteristics	5-6i	specify maximum and minimum discharges and maximum and minimum heads
KW/cfs table	5-6j	not used
Efficiency	5-6k	fixed efficiency or efficiency curve
Head losses	5-6l	use fixed value or head loss vs. discharge curve
Non-power operating criteria	5-6m	use flow data which incorporates these criteria
Channel routing	5-6n	not required
Generation requirements	5-6o	not required

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

minimum and maximum discharges) can be specified, and the program will automatically select the proper plant size.

d. Models. North Pacific Division's DURAPLOT is the only specifically designed hybrid model currently being used in the Corps. It is described in Section C-4b of Appendix C.

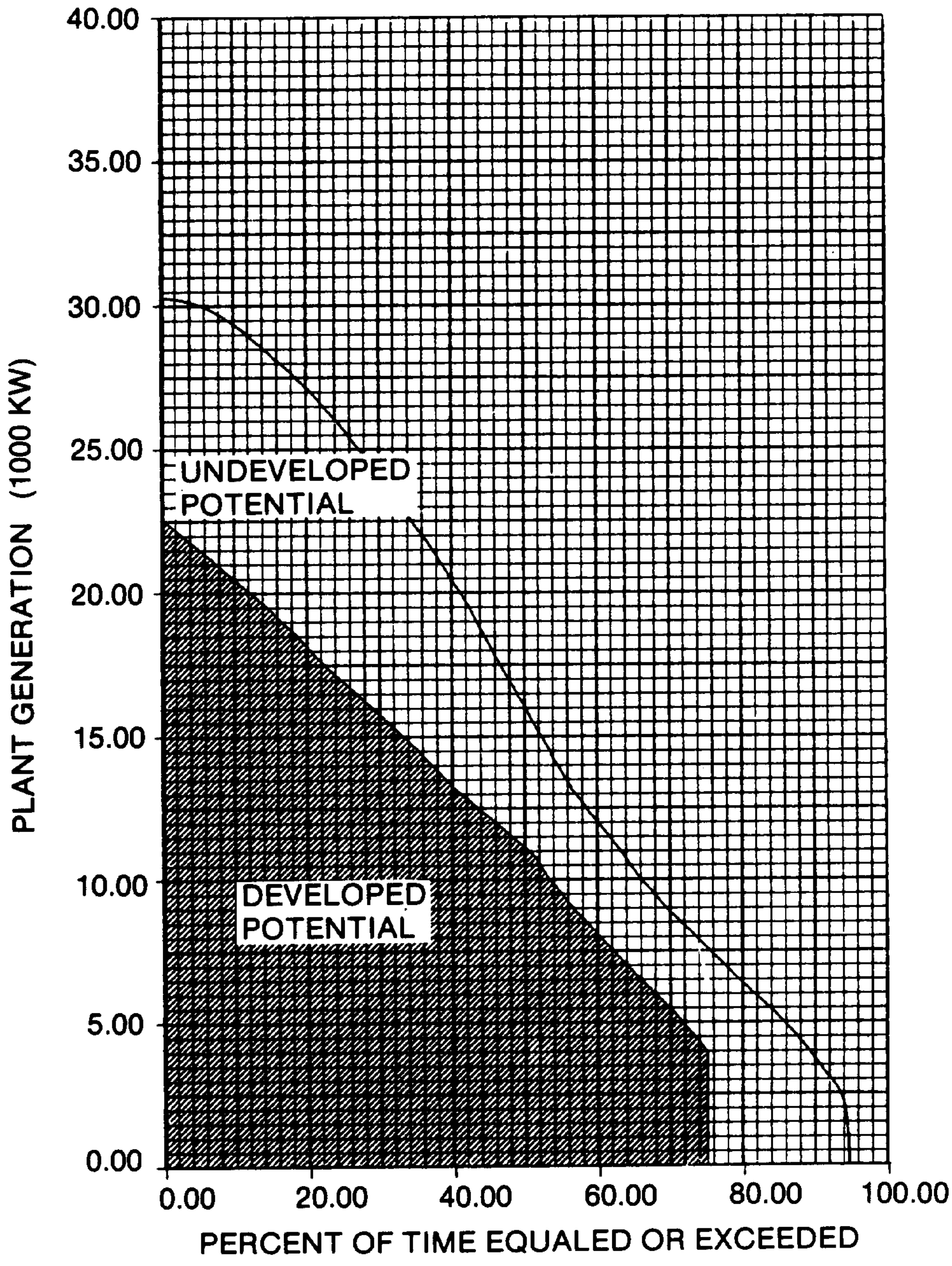


Figure 5-60. Annual power-duration curve from DURAPLOT model showing total energy potential and energy developed by 22.5 MW plant

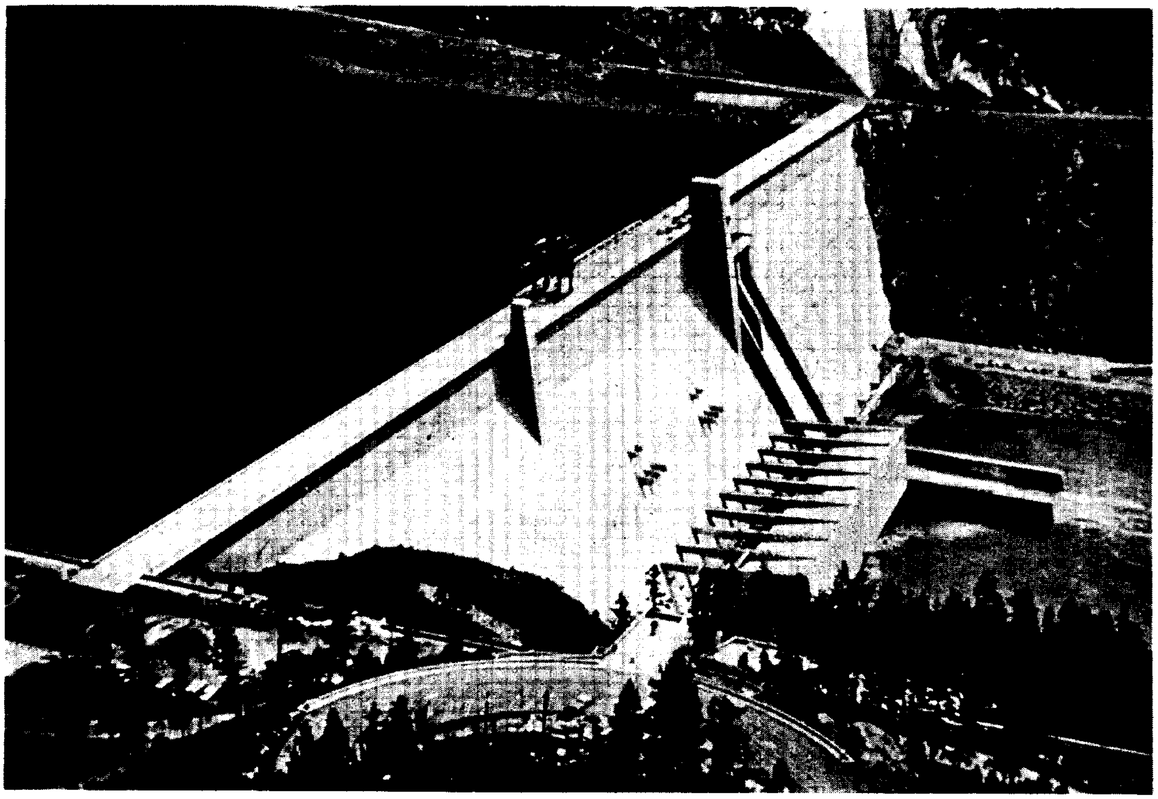


Figure 5-61. Libby Dam and Lake Koocanusa, the Corps of Engineers' largest storage project, with 4,980,000 AF of joint-use storage regulated for hydropower, flood control, and other purposes (Seattle District)