SECTION 3
MARKET ANALYSIS

A variety of complex factors affect the marketability and value of output from a small hydro project. This chapter provides guidance on establishing what the project's power production characteristics are and how these characteristics relate to the value of the project. Also, institutional considerations and potential marketing arrangements are considered.

Institutional Factors

The ability to market power from a small hydro project may be affected by institutional factors at the federal, state and organizational level. This discussion provides background information concerning these factors and is intended to highlight items important to the marketability of small hydro power output.

Purchasing Utility. Under certain circumstances private, or investor-owned utilities (IOUs) may be less inclined than public utilities to purchase output from small hydro projects. This will be particularly true if the plant has significant quantities of dependable capacity and the total development cost is borne by the sponsor. The potential disincentive to IOUs for leasing capacity from another organization has been discussed at length in the economic literature (for instance, Alfred Kahn, 1971), and the explanations for this are briefly put forth below.

Marketing power to investor-owned utilities may be complicated, particularly if the project has significant quantities of dependable capacity. Like any other business enterprise, one of the objectives of an IOU is to make a profit. In contrast to unregulated enterprises, the amount of profit an IOU can make is limited by the size of their rate base (capital assets) and the regulated fair rate of return on this rate base. Consequently, to show an earnings growth requires growth in the rate base, which is primarily accomplished by the addition of companyowned capacity. If the company were to lease all of its capacity additions, there would be no earnings growth; conversely, earnings growth can be maximized by owning all capacity additions. For this reason, an IOU may not be inclined to purchase capacity and the associated energy production. It should be noted that this concept has yet to be empirically proven as a real tendency.

Publicly and cooperatively owned electric utilities encompass federal, state, municipal and cooperatively owned organizations. They are discussed below (excerpted from U.S. Senate Report No. 95-1292):

> In 1975, there were 1,835 municipals, 946 cooperatives, 306 investor owned, 123 State and county, 72 Federal and 22 industrial producers or distributors. The type of ownership tends to vary geographically. For example, in New England only 2 percent of the capacity is publicly owned, whereas in the East South Central Region 63 percent is publicly owned. By and large, public ownership tends to be more common in the Western states. There are five major Federal organizations which market power. The largest by far is the Tennessee Valley Authority (TVA) followed by the Bonneville Power Authority, Southwest Power Authority, Southeast Power Authority, and the Bureau of Reclamation. TVA is the largest electric utility in the United States, and like the other federally owned organizations, is primarily a wholesaler.
>
> The non-Federal public systems include municipals and States. These often purchase their energy from Federal installations, as well as from investor-owned utilities. In some cases, they produce a portion of their energy requirements.
>
> The most common form of non-Federal publicly owned system is the municipal system. Included in this group are several State-owned authorities. The municipals vary from very small to quite large, as in the case of the Los Angeles Department of Water and Power. The State-owned systems tend to be wholesalers operating hydro facilities. Some, such as the Power Authority of the State of New York, have both hydro and thermal power.
>
> Cooperatives tend to be small in terms of number of customers but also tend to have more circuit miles in distribution facilities than do other utilities. These utilities, owned by their consumers, are located primarily in rural areas and are almost always exclusively distributors. Some cooperatives, however, have joined together to create generation and transmission (G. & T.) cooperatives. There are approximately 50 G. & T.'s in the United States which generate approximately 27 percent of the cooperative requirement. Cooperatives obtain the bulk of their financing from a Federal agency — the Rural Electrification Administration — usually at relatively low interest rates.

The primary motivation of these organizations is to deliver the lowest-cost service while meeting reliability and other constraints. Marketing small hydro output to these organizations should be relatively easy if it offers the system a cost savings.

National Energy Act. The Public Utility Regulatory Policies Act of 1978, one of the five sections of the President's National Energy Act legislative package, has a number of provisions affecting small hydroelectric developments. These provisions can be grouped as those concerning power marketing (discussed here) and those providing funding for feasibility investigation and construction (discussed in Section 6). The Public Utility Regulatory Policies Act of 1978 contains provisions on wheeling, which, in specific situations, could result in an order from the FERC to the local utility to wheel power on behalf of a small hydro producer.

Wheeling may be defined as an electric utility providing transmission services for another utility, power producer, or power purchaser. If a small hydro producer could wheel output to end users or other utilities, this wider market might allow the power to be marketed more successfully. Consequently, the possibility of wheeling should be addressed in the economic and financial investigation.

Sections 202 and 203 of the Act give the FERC authority to order interconnection and wheeling of power produced from a "small power production facility" if such an order is in the public interest and would:

a) Conserve a significant amount of energy,

b) Significantly promote the efficient use of facilities and resources, or

c) Improve the reliability of any electric utility system to which the order applies.

Small hydro as defined herein qualifies as a "small power production facility".

There are a number of restrictions on the FERC's authority but the most important one to small hydro is: "No (wheeling) order may be issued...which provides for the transmission of electric energy directly to an ultimate consumer."

The FERC's authority appears to be restricted to wheeling power to organizations reselling the power. State agencies, however, may have broader authority than the FERC.

More important than the wheeling provisions are the rules concerning the sale and purchase of power from cogenerators and small power producers. Section 210 requires the FERC to prescribe rules that require electric utilities to:

1. Sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities, and
2. Purchase electric energy from such facilities.

The rules are prohibited from authorizing a small power producer to make any sale for purposes other than resale.

The rates for purchases by electric utilities are to be set such that they:

1. Shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and
2. Shall not discriminate against qualifying cogenerators or qualifying small power producers.

The purchase rules are required not to exceed the incremental cost of the electric utility for alternate electric energy.

Clearly, these regulations, when promulgated by the FERC, will have an important impact on small hydro power marketing. The small hydro power marketing analysis must examine the regulations governing the rates for purchases and interpret them in the context of the project at hand. The regulations should be available by the end of 1979 at the latest.

Regulatory Commissions. Early in the 1900s, the electric utility business started being regulated at the state level to protect the general public welfare. Regulation in its modern form confers on the IOUs certain advantages such as protection from direct competition in its service area by another private utility, the right to use streets and highways, and the right to condemn property. There are also certain obligations and disadvantages that arise from regulations which include the limitation of earnings, the obligation to serve all who apply for service, and the prohibition against withdrawal of service without regulatory approval.

The state-level organizations that oversee the investor-owned utilities (IOUs) are the Public Utilities Commission or Public Service Commissions (PUC/PSC), depending on the particular state. In some cases these agencies have been placed in an overall state energy agency that has a broader purview. To locate these agencies, see the *Directory of State Government Energy-Related Agencies*, National Energy Information Center, Federal Energy Administration, 1975 or updated versions.

While one of the main concerns of the regulatory commissions is limiting utility earnings to a fair rate, their main objective is protecting the public interest by seeing that the lowest-cost reliable service is provided. In this role, the Commissions frequently examine supply planning, managerial efficiency in general and other pertinent subjects. Because of these responsibilities, a PUC or PSC would likely intervene if an IOU were to refuse to purchase small hydro power output that offered the system a genuine cost saving.

It is recommended that the PUC/PSC in the state involved be contacted early in the power marketing assessment. The staff will be knowledgeable about any applicable laws and other pertinent information on the marketability of small hydro power in the state of the project's location.

Hydroelectric Capacity and Energy

There are essentially three types of hydroelectric developments in the United States:

1. *Run-of-the-river* plants whose generation is solely controlled by available flow as it occurs or is dictated by some controlling concern, such as irrigation needs.
2. *Storage* plants where there is storage available for use with the hydroelectric plant to control its power output over more than a short period.
3. *Pumped storage* plant where reversible turbines are

installed to use low-cost off-peak energy to pump water to an upper reservoir where it is stored for subsequent use to generate high-value peak-load power.

Combined projects are ones with both storage and pumped storage, and they have recently become more common. As a general rule, small hydroelectric developments will be run-of-the-river plants with little, if any dependable capacity and widely varying annual energy production.

The value of hydroelectric development is based on two components — capacity and energy costs of the most likely alternative developments. To establish the value of a hydro project, the amount of alternate capacity that the hydro development can substitute for, or is equivalent to, must be determined, as well as the cost of the energy the project will displace or replace.

Capacity. A large body of literature examines the interrelated power system concepts of system reliability, effective load-carrying capability, loss of load probability and other concepts. After maintenance and the probability of forced outages have been accounted for, the portion of peak demand that a unit will carry at a stated reliability level is termed the "Effective Load Carrying Capability" (ELCC). There has been less discussion concerning the amount of thermal generation capacity a run-of-the-river plant can substitute for. To establish the capacity value of a small hydro project, this substitute capacity is what needs to be determined.

The current FERC definition of "dependable hydro capacity" is explained and presented in Figure 3-1. In essence, dependable capacity is the amount of load a hydroelectric plant can carry under adverse hydrologic conditions during the period of peak system load. The adverse hydrologic conditions are usually based on the most adverse year of record. The period of peak system load depends on the particular utility and may occur during the winter or summer months.

This definition addresses two of the criteria necessary for determining the amount of thermal capacity a small hydro plant can substitute for. These are the annual flow variability in the river and the most critical period for the utility. The measure is conservative because no consideration is given to the low forced-outage and maintenance rates of hydro plants when compared to thermal plants. It is also conservative to base the assessment on the most adverse year of record. Doing so may subject the project to extremely stringent standards if the most adverse year is a rare occurrence with frequency of less than once in 100 years.

While capacity credits could be negotiated based on the FERC definition, a number of adjustments in the capacity credit may be justified. Several possibilities are suggested below.

The FERC recognizes that the low forced-outage rates for hydroelectric equipment, when compared to thermal-based generation, may warrant a capacity credit to the hydro project (FERC, 1978). Average forced-outage rates are published periodically by the Edison Electric Institute.

The FERC recommends that consideration of the particular utility in question should usually justify a capacity credit of 5 to 15 percent due to low forced-outage rates and rapid emergency start-up for hydro facilities. The FERC does not provide any guidance on determining what is justified.

Another technique that might be used to account for both adverse years and forced-outage rates is illustrated in Figure 3-2. The power availability curve for a small hydro plant can be constructed from daily stream flow records during the operation study. The following procedure is applicable in cases where the project is likely to have some dependable capacity.

1. The critical period of utility system load must be established. This will generally include several months on either side of the system peak.

2. The stream flow records during this period of the year must be examined to establish if any of the periods of low flow are extremely rare occurrences during this period. If so, excluding them from the record *may* be justified.

3. With the stream flow records from 2 above, a histogram of the daily power producible from the proposed installation can be calculated.

4. The histogram can then be converted into the power availability curve shown in Figure 3-2. Note that the horizontal axis of the power availability curve is equal to one minus the cumulative probability that the capacity available will be less than or equal to the stated capacity.

5. The forced-outage rate adjustment and its rationale are clearly illustrated in Figure 3-2 by showing the power availability curve for a thermal plant. Note that this two-state on-and-off reliability model of a thermal plant is the simplest and most commonly used. The thermal-equivalent capacity can then serve as the basis for negotiating capacity credits.

A slightly different procedure achieving the same results would be to use the stream-flow records in 2 above to construct a flow-duration curve. This curve can then be converted into the power availability curve.

The amount of dependable capacity arrived at by any of the procedures described will almost always be less than the generator nameplate rating. Depending on the specific circumstances, assigning some value to the non-dependable capacity may be justified.

Energy. Project energy production is the amount of kilowatt-hours (kWh) input into the utility system or delivered to a final user. The power factor of generation can be an important factor in the value of energy, and, hence, it should always be stated.

Because project revenues will ultimately be based on the energy delivered to the ultimate purchaser, care

SAMPLE—The sample is precented to avoid a lengthy explanation of the manner of preparation of Schedule 2

Schedule 2

SYSTEM HYDROELECTRIC DATA

A. AGGREGATE DEPENDABLE HYDROELECTRIC CAPACITY AND POTENTIAL ENERGY.

This schedule need not be completed if there have been no changes affecting the data previously reported. In such case the following notation should be made at the bottom of the page: "Data reported on FPC Form 12 for the year 19. . . , correct as of December 31 of the year herein reported." *Furnish data indicated below in accordance with the instructions in paragraphs 1-5, page 7.*

ADVERSE FLOW CONDITIONS*

Month	PLANNED USE OF STREAM FLOW AND STORAGE Energy (Megawatt-hours)					MACHINE CAPABILITY (Megawatts)		Dependable Capacity (Megawatts)
	Storage Plants: Natural flow	Storage Plants: Storage[1]	Run-of-River Plants	Total Available (Col. 2 plus col. 3 plus col. 4)	In Storage End of Month[2]	Run-of-River Plants	Storage Plants	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Dec.	xxxxxx	xxxxxx	xxxxxx	xxxxxx	2,800	xxxxxx	xxxxxx	xxxxxx
Jan.	33,200	(2,000)	12,500	43,700	4,800	40.0	126.3	148.0
Feb.	32,000	(3,100)	11,900	40,800	7,900	40.0	127.5	149.0
Mar.	48,900	(14,200)	18,900	53,600	22,100	40.0	133.0	165.0
April	52,700	(17,700)	21,700	56,700	39,800	39.5	138.0	176.0
May	47,100	(11,700)	18,200	53,600	51,500	40.0	140.0	171.0
June	39,700	(3,500)	15,400	51,600	55,000	40.0	140.0	166.0
July	22,800	0	8,400	31,200	55,000	40.0	140.0	149.0
Aug.	11,000	11,600	4,200	26,800	43,400	40.0	139.0	142.0
Sept.	13,200	9,800	4,900	27,900	33,600	40.0	136.6	143.5
Oct.	14,300	15,600	5,600	35,500	18,000	40.0	131.5	141.0
Nov.	19,900	11,100	7,700	38,700	6,900	40.0	127.2	141.0
Dec.	27,900	5,400	10,500	43,800	1,500	40.0	125.0	143.0
Year	362,700	1,300	139,900	503,900	xxxxxx	xxxxxx	xxxxxx	xxxxxx

AVERAGE OR MEDIAN FLOW CONDITIONS*

Month	PLANNED USE OF STREAM FLOW AND STORAGE Energy (Megawatt-hours)					MACHINE CAPABILITY (Megawatts)		Dependable Capacity (Megawatts)
	Storage Plants: Natural flow	Storage Plants: Storage[1]	Run-of-River Plants	Total Available (Col. 2 plus col. 3 plus col. 4)	In Storage End of Month[2]	Run-of-River Plants	Storage Plants	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Dec.	xxxxxx	xxxxxx	xxxxxx	xxxxxx	1,500	xxxxxx	xxxxxx	xxxxxx
Jan.	47,300	(7,100)	19,400	59,600	8,600	40.0	128.0	161.0
Feb.	43,400	(6,800)	18,200	54,800	15,400	40.0	130.5	164.5
Mar.	58,200	(13,600)	24,600	69,200	29,000	36.5	135.5	172.0
April	62,700	(17,400)	25,500	70,800	46,400	36.0	139.7	175.7
May	58,200	(6,300)	24,000	75,900	52,700	37.0	140.0	177.0
June	51,600	(2,300)	21,600	70,900	55,000	39.5	140.0	177.5
July	42,000	0	18,200	61,100	55,000	40.0	140.0	171.0
Aug.	36,300	2,300	14,800	53,400	52,700	40.0	140.0	165.0
Sept.	33,500	6,600	13,700	53,800	46,100	40.0	139.5	163.5
Oct.	35,200	15,200	14,700	65,100	30,900	40.0	136.0	161.5
Nov.	39,000	13,100	15,900	68,000	17,800	40.0	132.0	155.0
Dec.	41,200	15,000	17,100	73,300	2,800	40.0	125.5	150.5
Year	549,500	(1,300)	227,700	775,900	xxxxxx	xxxxxx	xxxxxx	xxxxxx

[1] When energy is drawn from storage, show as a positive quantity. When energy is stored, show as a negative quantity in parentheses.
[2] Change in storage based on entry in column 3.

*NOTE.—The method or basis used in determining the above data for adverse flow and average or median flow conditions should be explained in accordance with instructions 2 and 3 of this schedule.

SAMPLE EXPLANATION

Notes:

Data reported under "Adverse Flow Conditions" are based on stream flows in the calendar year (19_____), which is the most adverse year of record. The critical flow period normally occurs during the last 6 months of the calendar year.

Data reported under "Average or Median Flow Conditions" are based upon the average of monthly stream flows during the period of record (19____19____).

(6-a) Rev. (12-75)

Figure 3-1. Source: FERC Form 12, "Power System Statement," for the year ended December 31, 1977.

Schedule 2—Continued

SYSTEM HYDROELECTRIC DATA—Continued

1. The data to be reported in Part A of Schedule 2 are intended to present a realistic picture of the potential energy and capacity of system hydroelectric plants under the specified flow conditions. The data to be reported should be based upon an assumed schedule of system operation that would permit serving the maximum possible annual system load with existing facilities and arrangements for purchase or sale of firm power, assuming a continuance of the relative seasonal and hourly variations of load that occurred during the year of this report. Contracts for purchase or interchange of off-peak energy also may be taken into account. In determining the magnitude of the seasonal load that could be carried by the system and the necessary scheduling of system operations, provisions for necessary maintenance scheduling and reserve capacity to be supplied by own system should be taken into account. Explanatory notes relative to Schedule 16 should be referred to in connection with this schedule. If the seasonal and hourly variations in load are expected to change materially, the information given may be based on the expected load shape, explaining in a footnote.

2. The information to be reported under adverse flow conditions should, in general, be based on stream flows equivalent to the year giving the most adverse flow conditions of record during the critical period of system operation. Where stream-flow records indicate that the most adverse flows are not likely to occur except at long intervals of time and are likely to be of a very short duration, the figures used in determining the capacity and energy available from hydro plants may be modified, treating such abnormal limitations as emergency conditions to be covered by the reserve capacity; such modifications, however, should be fully explained. Any system which maintains comparable data based on flows during a year which would give the minimum potential annual output, or based on minimum flow or output for each month, may report on whichever basis it believes will present the most realistic condition for its system. The basis of reporting should be fully explained in the space provided for notes with addenda sheets if needed.

3. Information to be reported under average or median flow conditions may be made on the assumption of the recurrence of flows equivalent to a year which would give the average annual potential output or may be based on median flow or output for each month, or average flow or output for each month, whichever it is believed will present the most realistic condition for its system. The basis of reporting should be fully explained in footnotes or addenda sheets.

4. "Run-of-river" refers to those plants whose operation cannot be regulated over a period of more than a few hours, either from storage at site or above, but whose operation is, in general, controlled by the volume of flow which must be utilized as it occurs or be wasted.

"Storage" refers to those plants whose operations can be varied as desired because of storage at site or above. This regulation may be weekly, monthly, or seasonal.

"Total available energy" refers to the maximum potential output of the existing hydro-generating facilities on the basis of the regulated stream flow, regardless of whether such output can be fully utilized in serving system load or by transfer to other systems. The monthly distribution of storage energy should be such as to permit the serving of the maximum annual peak load under the conditions outlined in instruction 1. However, where required releases for irrigation, navigation, flood control, and other water-use are controlling, the monthly distribution of available energy should reflect the effect of such requirements and full explanation should be given in footnotes.

"Capability" in any month is the machine capability under the most adverse conditions to be expected in that month under the assumed flow conditions without respect to the energy available or the characteristics of the load to be served other than the power factor conditions normally to be expected.

"Dependable capacity" in any month is that capacity that can be relied upon for serving system load and firm power commitments on the basis of the energy available in that month and its use as limited by the characteristics of the load to be served.

5. Dependable hydroelectric capacity as used in this power system statement is intended to be the capacity value of the system hydroelectric plants in serving, together with the other available system capacity, the maximum annual system peak load under the conditions given in instruction 1. For any specified period it represents, on the basis of complete utilization of available storage energy over the critical flow periods, the difference between the peak load for that period and the maximum other capacity required. Where a portion of storage energy is scheduled to be held as a reserve for emergency use only, the dependable capacity should also include the reserve capacity value of such energy reserve. The dependable hydroelectric capacity shown in column 9 under adverse flow conditions for the month of annual peak demand may not necessarily be the same as the annual dependable hydroelectric capacity to be reported in schedule 16, as the annual peak demand may not occur in the month requiring the maximum capacity from other than system hydroelectric plants. This is illustrated by the following graph:

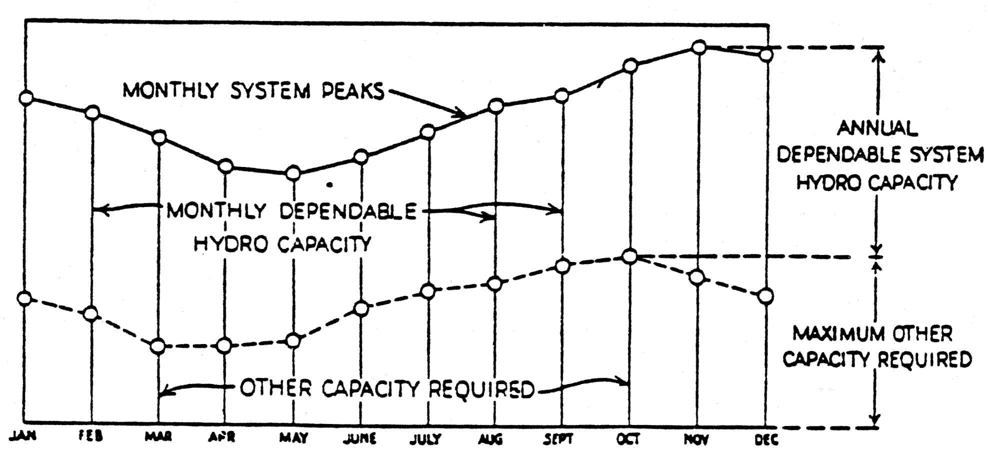

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Figure 3-1. (continued)

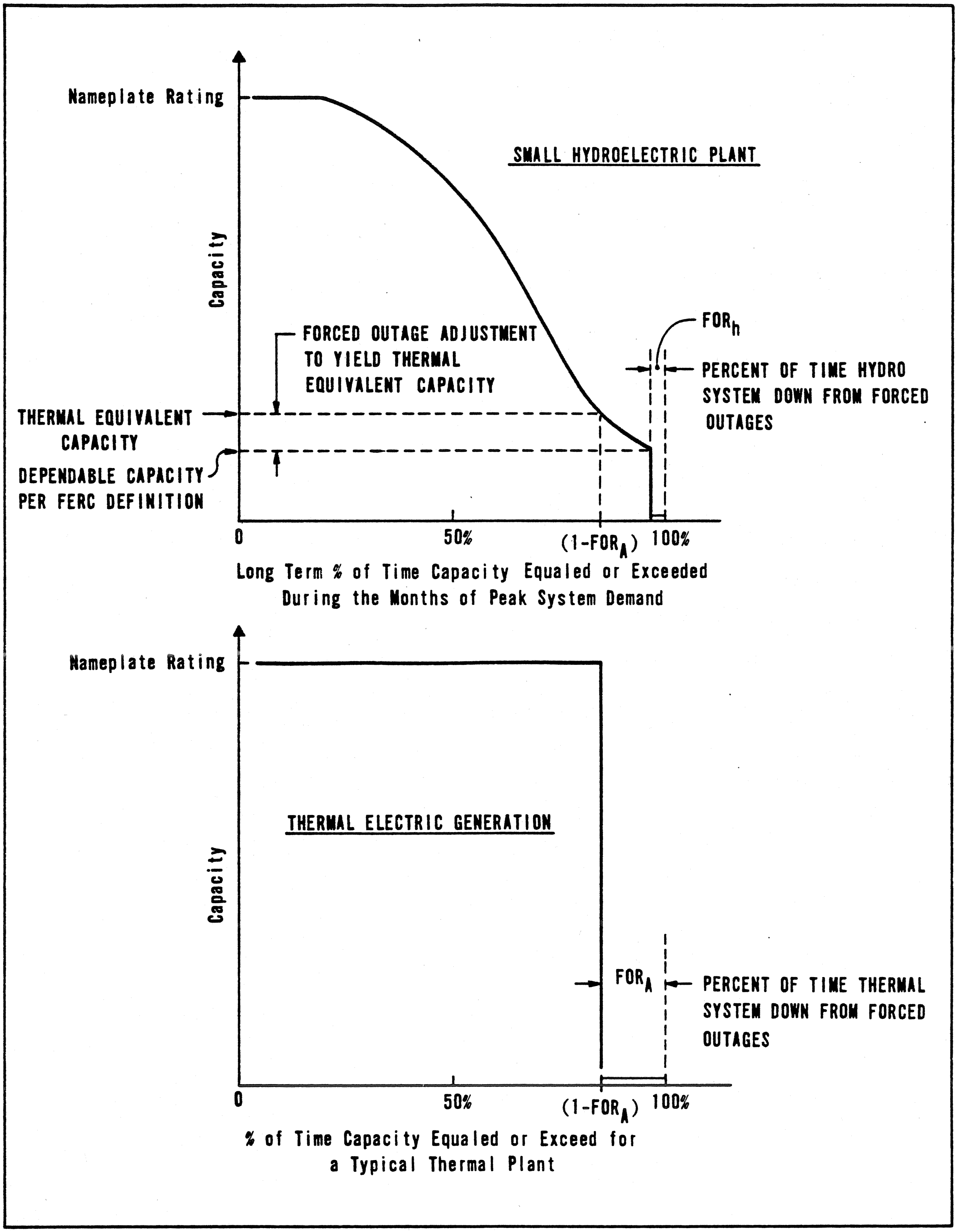


Figure 3-2. Capacity availability curves for small hydro and thermal plants.

should be taken to account for all losses up to the point of ownership transfer. If extensive transmission is required, these losses must be included as well as step-up transformer losses, generator and speed increaser losses, and station service use. Also, a loss due to forced outage should be included to avoid overstating the average annual energy output.

Energy production will vary on a yearly, monthly, and daily basis. The effects of daily fluctuations and the impacts on dependable capacity have already been discussed. Annual and monthly variability can be portrayed in a number of ways. One desirable method is to consider the annual energy production as a random variable and construct annual production histograms and cumulative probability distributions as in Figure 3-3. This curve can be useful in assessing project risk and will be discussed in Section 6 on financial feasibility.

The seasonality of power production can be portrayed as in Figure 3-4. This curve is useful for assessing in broad terms how the project output would fit into a utility system and the effects of adding capacity. For example, if the project of Figure 3-4 were located in a summer peaking utility, it is apparent that adding to installed generation capacity will do little to increase the project's ability to serve system peak-load.

At a minimum, the average annual energy production and its annual variability must be established. Additional information on the seasonality of energy production can be helpful both in project design and in establishing whether dependable capacity is present. To establish that the project has dependable capacity, very detailed energy production estimates will be required, possibly on a daily basis.

Peaking Capability. For a small hydro plant to serve as a peaking unit, it must incorporate storage. Operationally, water is accumulated for release through the turbines during the hours of peak demand. The storage capability allows the energy available to be scheduled at the time of maximum value.

When the small hydro project does have working storage available for power operations, a peaking operation may be explored as a way of increasing project value. The dependable capacity from a storage reservoir which is to be operated as a peaking unit can be established using the FERC definition (Figure 3-1). Note that this is not an easy task. Even if no dependable capacity is present, operating the storage reservoir and powerhouse as a peaking unit will generally increase its value to the local utility over what it would be in run-of-the-river operation. Storage capacity, turbine capacity and the flow regime must be integrated into a model by the hydrologic study to determine the amount of energy that may be shifted to peak periods. The value can then be calculated as indicated later in the discussion of the value of energy to a utility purchaser.

Value of Capacity and Energy

The value of small hydroelectric capacity and energy output is based on the costs of equivalent alternatives available to the prospective power purchaser. Consequently, the value of a small hydro project can vary widely, based on the potential purchaser. This discussion first considers in broad terms how the value of a project is established and then presents detailed examples of how the value of power can be calculated for an industrial and utility purchaser.

Opportunity Cost as a Basis for Establishing Small Hydro Project Value. The value of a small hydro project is determined by the power purchaser's opportunity to reduce existing costs while maintaining the same level of service. To do so, equivalent situations with and without the small hydro project are determined. The difference in total cost between the two cases, *without assigning any cost to the small hydro project*, will be the project's maximum value to the purchaser. The difference in total cost, after including the actual cost of the small hydro project, is the *net* value of the project and represents the opportunity cost of foregoing the project.

The proviso of maintaining the same level of service is important. While small hydro may allow a purchaser to reduce some costs, such as power purchases or fuel expenditure, maintaining the same level of service required without the small hydro project may entail additional costs such as standby service or generation capacity. The project information developed on dependable capacity and annual energy production allows the equivalent situations to be determined.

Since the project's value is established by looking at the power purchasers and the costs of their alternatives, a particular purchaser can significantly alter a project's value. Some general observations in this regard follow.

Industrial or Other End User Power Purchasers. Generally, industrial electric users require electric service more reliable than that afforded by the typical run-of-the-river small hydro project. Consequently, they will have to maintain some sort of a standby service arrangement with the local utility. This type of service may increase or decrease the electricity displacement benefits of the small hydro project, thereby altering the incremental cost savings attributable to small hydro.

Utility Systems. In general, utilities with higher-cost fuels will find small hydro projects have higher value to them because of the cost of the fuels displaced by small hydro. This is particularly true of utilities using oil to fire base load units. Some Eastern and Western utilities, by necessity, will be generating baseload energy with oil for a number of years.

Publicly owned utilities will place less value on capacity than IOUs. This is because their lower cost of capital and exemptions from property and income taxes significantly lower their fixed costs when compared to IOUs.

User as Power Purchaser. The gross value of small hydro output to an end user, such as an industrial plant,

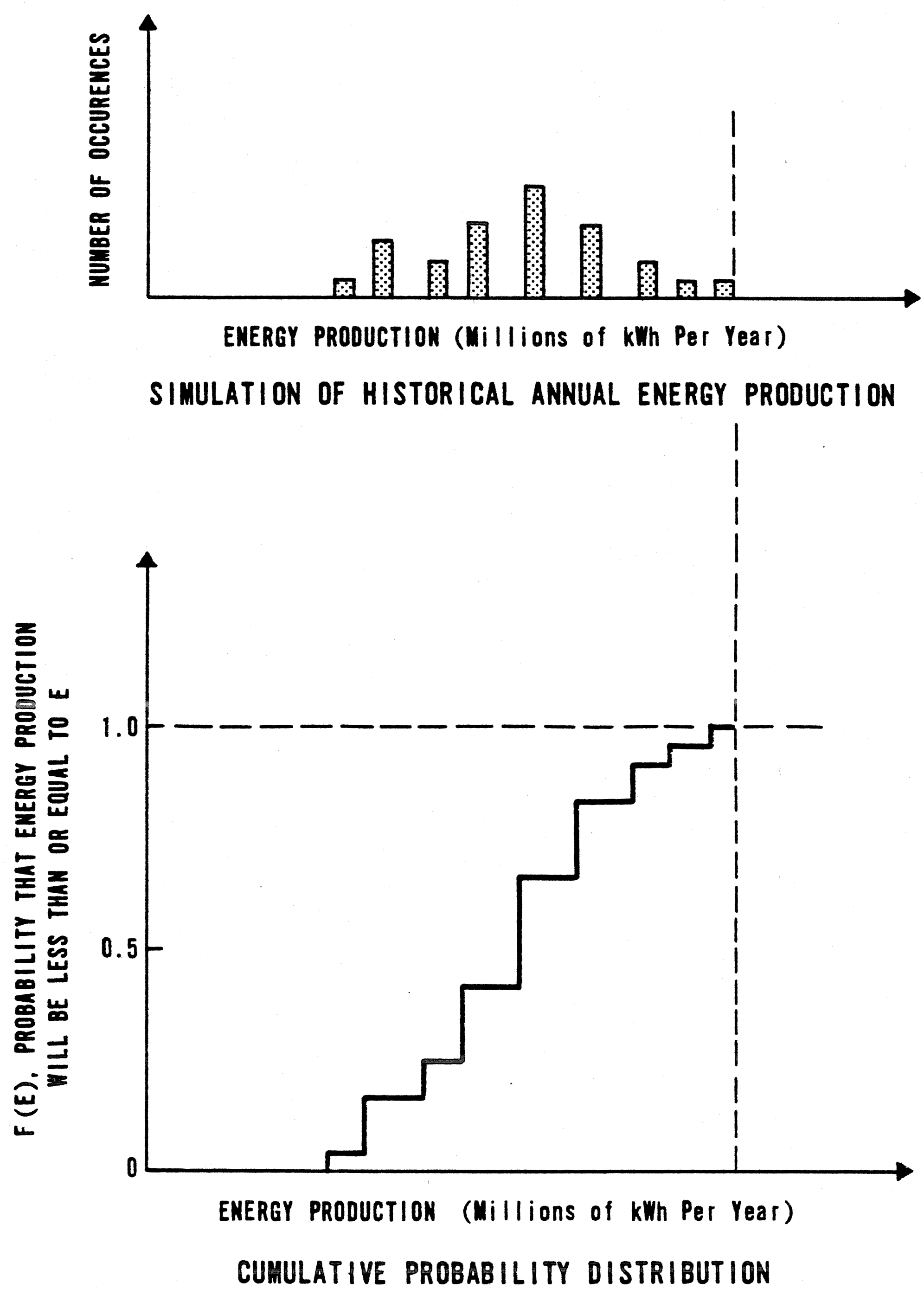


Figure 3-3. Annual energy production histogram and cumulative probability distribution.

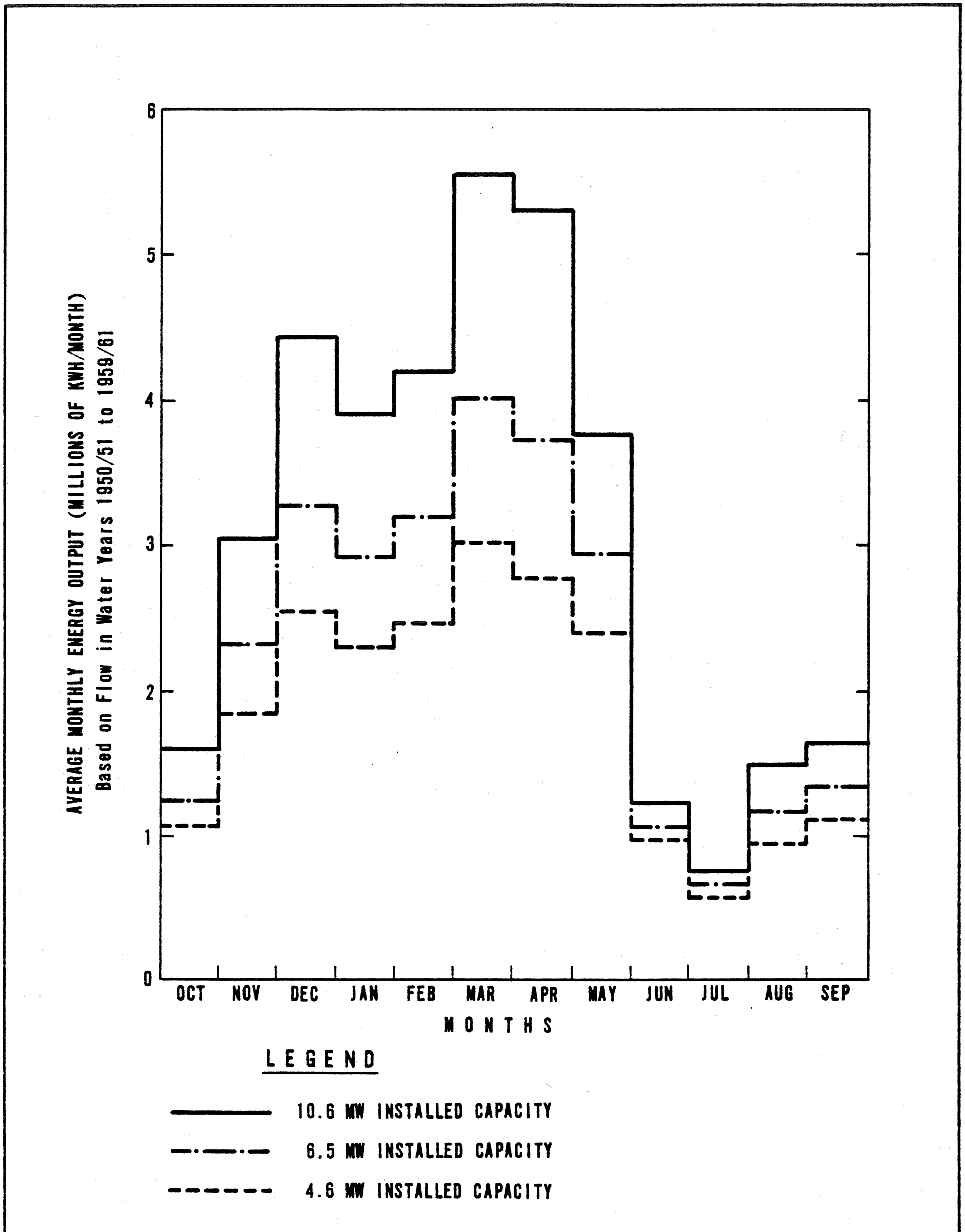


Figure 3-4. Average monthly energy output.

municipality or irrigation district, is the maximum cost reduction the purchaser can achieve without assigning any cost to the small hydro plant. In this calculation make certain the user is receiving the same level of service before and after the addition of small hydro output. If not, the cost comparison will be between different situations and will not truly reflect the value of small hydro. The purchaser will find the small hydro output attractive if the actual hydro costs are less than the maximum cost reduction. If so, a net cost reduction will be achieved.

Information about the small hydro project's output, the user's load characteristic and the applicable utility tariffs is necessary to establish the value of small hydro to the user. In many cases, the average monthly electric production from the small hydro plant will be sufficient for the analysis. Using average data will lead to "expected" benefits, but yearly variations in these benefits must be expected. The user load should be readily typified either through utility or user-metering records. The utility tariffs are also accessible from a number of sources. The *National Electric Rate Book* gives summaries by state of utility rates nationwide. The state level regulatory commissions will have detailed rates and the local utility will also supply any necessary rate information.

The following example demonstrates the calculation of the maximum value of a small hydro project to an industrial purchaser. The example is simplified but contains all the essential elements that need to be accounted for. Figure 3-5 specifies the load characteristics of the industrial purchaser and the average monthly power production of the small hydro project. Also shown is the minimum monthly power production from the hydro plant. This value will determine the billing demand. The industrial plant is assumed to have a continuous demand of 5,000 kW. The small hydro project has maximum production in the winter months and drops to zero during the summer. No dependable capacity is present. Figure 3-5(c) shows the industrial purchaser's demand on the utility system after including the small hydro power.

A simplified utility tariff for general and standby service is given in Table 3-1. A common type of rate, the Hopkinson demand rate, with flat demand and energy charge has been assumed (for more information on rates, Caywood, 1972). Typically, a flat monthly customer charge is present, but has been left out for simplicity.

Two other common rate provisions are provided. Minimum charges are frequently levied and may be calculated in a number of ways. In this case, the minimum bill is based on the maximum amount of demands. A billing demand ratchet has also been included. This clause associates the billing demand to the highest demand in the last X months where X may be between 2 and 12, or on the average demand over some time period or on a percentage of these two. The effect of a billing demand ratchet is to increase demand charges to a customer.

Table 3-2 and 3-3 calculate the annual utility-supplied electricity cost to the industrial purchaser with and without the small hydroproject. With all other things equal, the difference in total annual costs, $587,300, is the *maximum* value of the small hydro output to the industrial user. Note that on a per kWh basis, this value is 3.83¢ per kWh, which is greater than just the cost of

TABLE 3-1
SIMPLIFIED RATE SCHEDULE

GENERAL SERVICE

Rate:
Demand Charge:
$6.00 per kW demand per month
Energy Charge:
3.5¢ per kWh
Minimum Bill: The demand charge on 10 percent of maximum demand.
Billing Demand: The maximum 15-minute measured demand during the month, but not less than 90 percent of the highest demand in the preceding three months. (Note: This type of clause is known as a billing demand ratchet clause.)

STANDBY OR AUXILIARY SERVICE

Contract Demand: The maximum demand the customer will place on the utility system. The utility will not meet a demand higher than the contract demand.
Rate: Same as general service.
Minimum Bill: $3.00 per kW of contract demand.

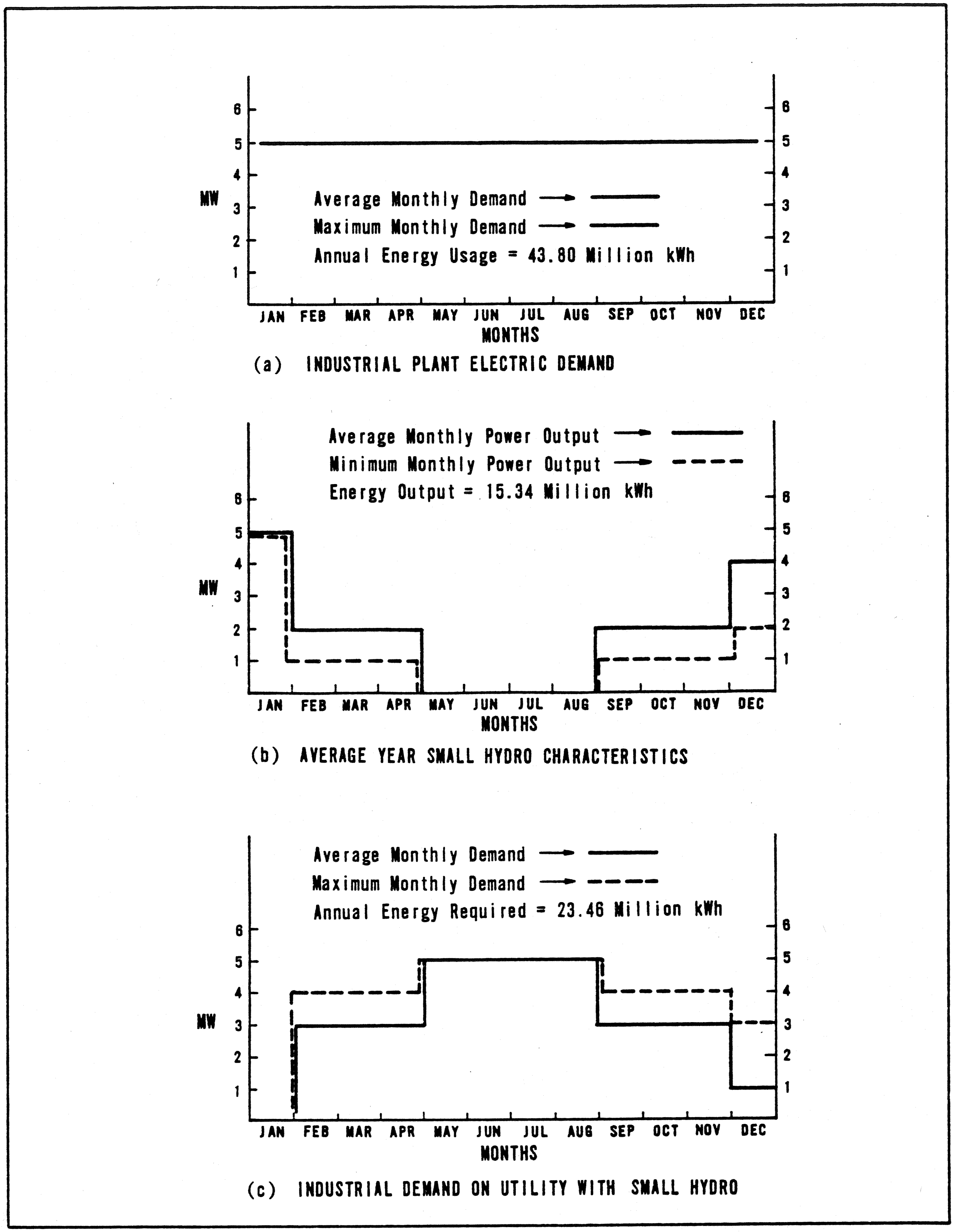


Figure 3-5. Demand pattern and small hydro output for example calculation of small hydro benefit to an industrial purchaser.

the energy displaced. This will not always be the case, and only the facts of the individual situation will determine the results.

Utility as Purchaser. The correct way of determining the value of a small hydro project to a utility is to determine the reduction in total system cost that would result from adding the small hydro plant to the utility system, without assigning any cost to the small hydro project. To be valid, the comparison must be between like systems before and after the small hydro addition.

A small hydro project will displace fuels, and if it has dependable capacity, it will reduce the need for new utility investment. Some operational cost savings may also be possible. These cost reductions can be reasonably approximated by considering a simple production cost model of utility generating units. In the following material, the production cost model will be explained and the connection between the type of hydro development and the appropriate production cost will be discussed. The value of the small hydro plant will then be calculated as the cost savings indicated by the production cost model.

The basic production cost model of thermal electric generation is composed of three components: capital costs, fuel costs, and operation and maintenance costs. (For more information, see Sullivan, 1977, or the draft *Hydroelectric Power Evaluation*, Federal Energy Regulatory Commission, August 1978.) This is:

$$TC_i = CC_i + FC_i + OM_i$$

where:

TC_i = Total cost of generation type i
CC_i = Capital associated costs
FC_i = Fuel costs
OM_i = Operation and maintenance

Capital Associated Costs. It is common practice to calculate the annual fixed costs per unit of generating capacity by specifying a fixed charge rate as a percentage of capital cost. The annual capital cost per unit of generator type i is then:

$$CC_i = FCR \times I_i$$

where:

FCR = Fixed charge rate
I_i = Investment per unit of capacity i, $/kw

The fixed charge rate is composed of five components:

1. The weighted average cost of new capital.
2. Depreciation or amortization.
3. Insurance.
4. Ad valorem or property taxes.

TABLE 3-2
EXAMPLE INDUSTRIAL GENERAL SERVICE ANNUAL CHARGES

Month	Maximum Actual Demand (kw)	Billing Demand (kw)	Energy Used (10^6kwh)	Demand Charge[1] ($)	Energy Charge[2] ($)	Total Charge[3] ($)
(1)	(2)	(3)	(4)	(5)	(6)	(7)
January	5000	5000	3.72	$ 30,000	$ 130,200	$ 160,200
February	5000	5000	3.36	30,000	117,600	147,600
March	5000	5000	3.72	30,000	130,200	160,200
April	5000	5000	3.60	30,000	126,000	156,000
May	5000	5000	3.72	30,000	130,200	160,200
June	5000	5000	3.60	30,000	126,000	156,000
July	5000	5000	3.72	30,000	130,200	160,200
August	5000	5000	3.72	30,000	130,200	160,200
September	5000	5000	3.60	30,000	126,000	156,000
October	5000	5000	3.72	30,000	130,200	160,200
November	5000	5000	3.60	30,000	126,000	156,000
December	5000	5000	3.72	30,000	130,200	160,200
	TOTALS		43.80	$360,000	$1,533,000	$1,893,000

1/ Calculated as Billing Demand, column (3), times General Service Demand Charge, $6/hr.
2/ Calculated as energy used, column (4), times energy charge, 3.5¢/kWh.
3/ Sum of (5) + (6), *or* the minimum bill.

Assumptions

1. Demand as in Figure 3-5(a)
2. Rate schedule in Table 3-1
3. Minimum bill = .1 × 5000 kW × $4/kW = $2,000 per month

5. Income taxes (federal, state or local).

As a general rule, the cost of capital and depreciation will be the largest components of the fixed charge rate.

Accurately calculating the fixed charge rate for a utility from basic financial data is difficult. For this reason, it is recommended that the appropriate fixed charge rate be obtained by contacting the local utility or state regulatory commission.

Fuel Costs. The annual fuel cost of operating unit i for t_i hours in the year is given by the linear approximation:

$$FC_i = HR_i \times EC_i \times t_i$$

where:

HR_i = the heat rate of unit i defined as the number of Btu's of energy input required to produce one kWh.

EC_i = the energy cost of the fuel used in unit i expressed in \$/Btu

t_i = hours of operation of unit i in the year.

The heat rate used can be based on generic heat rates or the actual values for the utility in question. Generic values by type of plant and fuel are available from numerous sources. A few examples are the FERC, Edison Electric Institute, Electric Power Research Institute and trade journals. The actual values of a specific utility's existing plants are also available in the annual FERC Form 12 filed by all utilities and in SEC Form 10-K filed by publicly traded investor-owned utilities (see Exhibit I).

Operation and Maintenance Costs. O&M costs, exclusive of fuel use, are usually broken into fixed and variable components.

Many factors, such as kind of plant, location, size, plant factor, operational plan, and age affect the O&M costs. These costs are generally much less than fuel and capital costs.

Because small hydro plants have a capacity of 15 MW or less and will usually be run-of-the-river, utility system O&M cost reductions will be small if they exist. As a general rule, in calculating the value of a small

TABLE 3-3
EXAMPLE STANDBY SERVICE ANNUAL CHARGES FOR INDUSTRIAL USER PURCHASING SMALL HYDRO OUTPUT

Month	Maximum Actual Demand (kw)	Billing Demand (kw)	Energy Used (10^6kwh)	Demand[1] Charge (\$)	Energy[2] Charge (\$)	Total[3] Charge (\$)
(1)	(2)	(3)	(4)	(5)	(6)	(7)
January	-0-	-0-	-0-	-0-	-0-	\$15,000[4]
February	4000	4000	2.02	\$ 24,000	\$ 70,700	94,700
March	4000	4000	2.23	24,000	78,050	102,050
April	4000	4000	2.16	24,000	75,600	99,600
May	5000	5000	3.72	30,000	130,200	160,200
June	5000	5000	3.60	30,000	126,000	156,000
July	5000	5000	3.72	30,000	130,200	160,200
August	5000	5000	3.72	30,000	130,200	160,200
September	4000	4500[5]	2.16	27,000	75,600	102,600
October	4000	4500[5]	2.23	27,000	78,050	105,050
November	4000	4500[5]	2.16	27,000	75,600	99,600
December	3000	3600[5]	0.74	21,600	25,900	47,500
	TOTALS		28.46	\$294,600	\$966,100	\$1,305,700

1/ Calculated as Billing Demand, column (3), times General Service, Demand Charge, \$6/kW.
2/ Calculated as energy used, column (4), times energy charge, 3.5¢/kWh
3/ Sum of (5) + (6), *or* the minimum bill.
4/ Minimum bill effective.
5/ Billing demand ratchet clause effective.

Assumptions

1. Demand as in Figure 3-5(c)
2. Rate schedule in Table 3-1
3. Minimum bill = \$3/kW × 5000 kW = \$15,000 per month

hydro project to a utility system no cost saving for O&M should be assigned.

This type of production cost model is used by utilities in power system planning at both simple and extremely sophisticated levels (Knight, 1972). A basic application is to generate linear cost curves for electric production from different generating technologies. These cost curves, and their application for determining target amounts of generating capacity of each type, are shown in Figure 3-6.

Levelized Cost. Utilities will frequently make comparisons between generation technologies based on levelized annual costs. The technique is used to account for differences in the rate of escalation of total costs for the different production alternatives. While it will generally be unnecessary to use levelizing procedures to establish the value of small hydro plants, the technique will be outlined here for completeness.

Levelized annual cost of an alternative is calculated by first projecting the total annual costs for the life of the alternative using the best estimates of escalation in energy and other costs. This escalating cost stream is converted into a constant annual cost by finding the pesent value of the cost stream in the first year of operation and then calculating the constant annual cost over the project life that is equivalent to the present value of the cost stream. The appropriate interest rate to use is the company's weighted average cost of capital. This constant annual cost equivalent to the escalating actual cost stream is known as the levelized cost.

Time of Day. Figure 3-7 shows how the type of generating units are used to meet daily demands. The unit-cost lines in Figure 3-6 shown that the greatest decrease in cost for an hourly reduction in operation is for peaking units, then intermediate sources, and finally, baseload units. This is because the fuel-cost component of generation is arrayed in this order. Mathematically, this is shown by noting that for each generation type:

$$\partial TC_i/\partial t = HR_i \times EC_i$$

From Figure 3-7, it is also apparent that the value of replacing a unit of energy is a function of the time of day. This is why hydro is used whenever possible as a peaking unit to replace the highest-cost energy.

The characteristics of the hydro project will determine the type of thermal unit it can substitute for or the value of energy it can displace. If the project has dependable capacity, then the project will have both capacity and energy value to the utility. If no dependable capacity is available, only energy displacement value will be possible.

Run-of-the-River Projects. In the typical run-of-the-river project with no dependable capacity, the time or source of energy a small hydro project will be replacing will generally be unknown. The *minimum* value of energy displaced will be the energy cost of the most costly baseload source. The example following this section will illustrate this calculation.

Rather than using this minimum value for the energy displaced, an alternative and more accurate method is applicable if the energy production from the hydro plant is fairly randomly distributed throughout the year. The method is to determine the amount of time that each major generation type is the marginal (most expensive) energy source. These times can then be used to calculate a weighted average fuel displacement value for the system. With information as shown in Figure 3-8, this is a feasible technique in small hydro analysis.

Projects with Peak Power. If peaking power is present, the amount of energy produced on peak must be determined. The value of the energy will then be based on the energy displacement of the thermal peaking unit.

The balance of the project's energy production can be valued in the same manner as in run-of-the-river projects.

To summarize, the maximum value of small hydro to an electric utility is the reduction achievable in total system costs without assigning any cost to the small hydro project. This value is determined by the production characteristics of the small hydro project and the production costs of the utility.

Example of Utility Power Value Calculation. The following example illustrates how the value of power from a small hydro plant is calculated. To establish the value of power, information about both the small hydro project and the utility must be specified.

Small Hydroelectric Project. A typical run-of-the-river plant has been assumed for this example, with the following characteristics:

Installed capacity	7.5MW
Plant factor	49%
Average annual energy	32.2 million kWh
Peak production	February to August
Dependable capacity	None

Electric Utility. The electric utility is assumed to be a major utility with a 6000 MW summer peak and a lesser winter peak. Figure 3-8 is assumed to be the company's load-duration curve. Tables 3-4 and 3-5 summarize pertinent information typical for such a utility. This information would be available for an actual utility in the FERC publication *Steam Electric Plant Construction and Annual Production Expenses* and SEC Form 10-K.

Value of the Small Hydro Project. Since the small hydro project has no dependable capacity, its value is based on the cost of the fuels it can displace. The energy costs for each type of fossil-fired generation are calculated below using the information in Tables 3-4 and 3-5. These costs are the plant heat rate times the cost of fuels expressed in the correct units. This is:

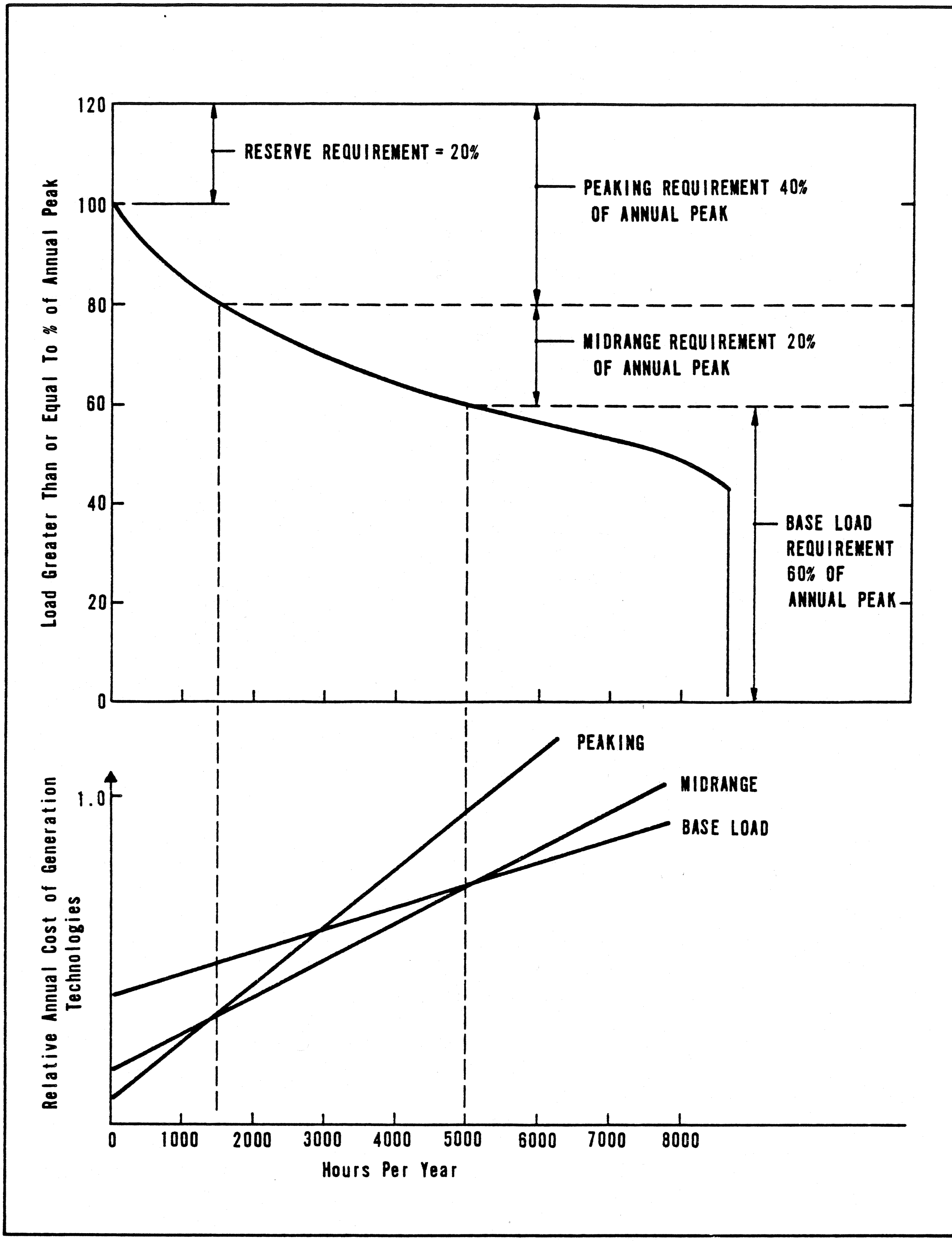


Figure 3-6. Basic application of production cost curves to power system planning.

Plant Type	Average Heat Rate (Btu/kWh)	Fuel Cost (¢/million Btu)	Energy Cost of Electricity (¢/kWh)
Coal-fired steam	9,409	143.4	1.35
Combined cycle	9,044	276.5	2.50
Gas turbines	13,777	276.5	3.81

From the load duration curve, Figure 3-8, at a minimum the small hydro plant would displace energy from baseload coal-fired units. Therefore, the minimum value of the small hydro energy is 1.35¢/kWh.

However, the value of this small hydro project is probably higher than this because it will frequently be displacing higher-cost electricity than that from the coal-fired units. Making the assumption that the small hydro output occurs randomly with respect to the load-duration curve, the small hydro plant will be displacing energy from the three sources in proportion to the time these sources are the marginal energy source. From Figure 3-8, it is seen that gas turbines are the marginal source 16 percent of the time, combined cycle units 44

TABLE 3-4
EXAMPLE UTILITY POWER PLANT HEAT RATES

Baseload generation — coal-fired steam plants

Plant Name	Capacity (MW)	Heat Rate (Btu/kWh)
Coal - 1	600	9700
Coal - 2	1100	9200
Coal - 3	600	9500
	2300	

Weighted average heat rate = 9409 Btu/kWh

Intermediate generation — distillate-fired combined cycle

Plant Name	Capacity (MW)	Heat Rate (Btu/kWh)
CC-1	625	9200
CC-2	675	8900
	1300	

Weighted average heat rate = 9044 Btu/kWh

Peaking Units — distillate-fired gas turbines

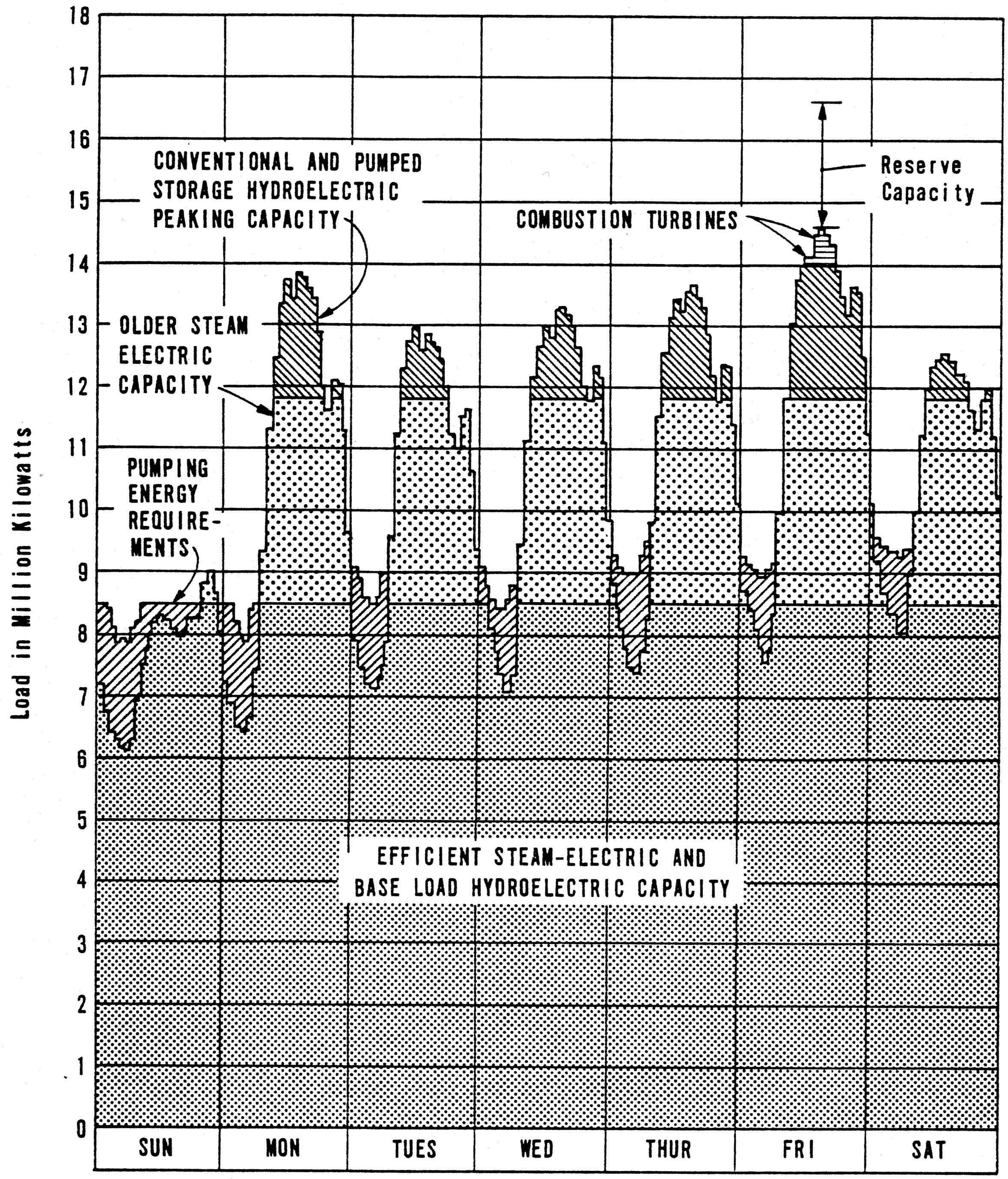
Plant Name	Capacity (MW)	Heat Rate (Btu/kWh)
GT - 1	450	16,100
GT - 2	550	13,750
GT - 3	450	14,250
GT - 4	700	12,000
	2150	

Weighted average heat rate = 13,777 Btu/kWh

TABLE 3-5
EXAMPLE FUEL COSTS

	Coal		Distillate	
Year	$/ton	¢/million Btu[1]	$/bbl	¢/million Btu[1]
1972	10.70	48.6	5.25	90.8
1973	11.06	50.2	5.38	93.1
1974	14.72	66.9	9.35	161.5
1975	19.50	88.6	11.86	208.8
1976	23.79	108.1	13.04	229.8
1977	27.23	123.8	15.09	266.7
1978	31.55	143.4	15.98	276.5

1/ Assuming coal with 22.0 million Btu/bbl
2/ Assuming distillate with 5.78 million Btu/bbl



(Adopted from 'Hydroelectric Power Evaluation', FERC, draft 1978)

Figure 3-7. Weekly load curve of a large electric utility system.

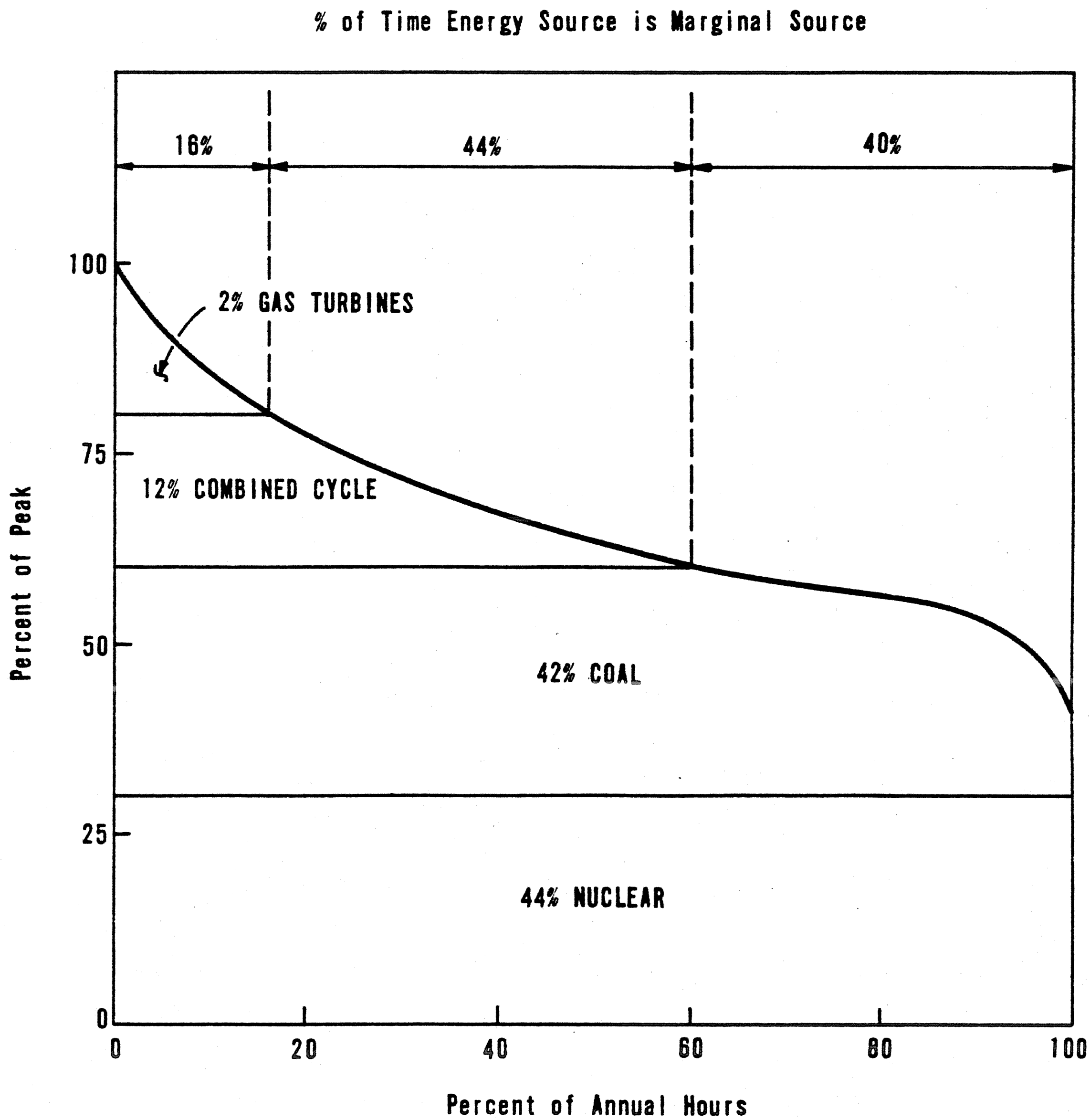


Figure 3-8. Annual load duration curve with energy by source superimposed (used in example utility power value calculation).

percent of the time, and coal fired steam units 40 percent of the time. These percentages can be used to calculate the weighted average value of small hydro output as:

$$\text{Value} = (.16 \times 3.81) + (.44 \times 2.50) + (.40 \times 1.35) = 2.25¢/\text{kWh}$$

As is seen, this procedure substantially and justifiably increases the small hydro value.

Regional Power Values

The Federal Energy Regulatory Commission (FERC) has prepared generalized estimates of the value of electrical power on a regional basis. These estimates can be used for preliminary analysis of the value of energy and capacity from small hydro installations.

The regional power values can be obtained from the FERC's five regional offices whose locations and service areas are listed in Exhibit I.

Market Arrangement

The manner in which small hydro output is marketed is an important factor in determining if financing will be available and at what price. It is imperative that adequate financial and legal consultation be obtained prior to entering into the actual power marketing agreement. Section 6 discusses the role of the financial advisor in more detail.

The capital investment in small hydro projects will be committed for a long period at a fixed price. Consequently, the "investors" will be unwilling to assume any business or technical risk associated with the project. As used here, "investors" may be a bank, insurance company or other long-term lenders, in addition to bond purchasers. This means the principal and interest obligation associated with project financing must be assured with a high degree of certainty. This assurance can be obtained in four ways: (1) Occasionally the project will have sufficient financial strength on its own so that the risk to investors is acceptable without any guarantees; (2) Guarantees can be given by a credit-worthy sponsor; (3) A credit-worthy power purchaser can "guarantee" the debt service through the marketing agreement; or (4) A third party, such as a state government, can guarantee the debt service. These guarantees will generally be required for the duration of the project's financing.

Time-of-Day Considerations. The section titled "Utility as Purchaser" discussed utility production economics in basic terms and the incremental cost of electric energy as a function of the time of day. If the small hydro project being analyzed has significant quantities of storage available for peaking power generation, then the marketing agreement should account for the higher value of energy displaced. This could be done in a simple fashion by adjusting a flat rate per kWh charge. At the other end, a complex rate, fully reflecting time-of-day factors, could be negotiated for use with a time-of-day meter to record energy production.

Whatever method is used, the value, if any, associated with project peaking capability should be established and set forth in the market analysis.

This discussion will examine four potential types of marketing agreements and examine the security effects of these arrangements on project financing.

Cost Plus a Percentage of Debt Service. This is a potential marketing arrangement which has been used to secure financing for hydroelectric development in the United States. An example of this arrangement is the June 1978 issue of $10,000,000 of revenue bonds by the Public Utility District No. 1 of Chelan County, Washington, to expand the Columbia River-Rock Island Hydroelectric System (Public Utility District No. 1 of Chelan County, Washington, 1978). A portion of the output was sold under this type of power contract to Puget Sound Power and Light Company.

The power purchaser and the project sponsors enter into a "power contract" for sale of all or a portion of the electric output. The essential elements of this contract are that the project sponsor agrees to deliver all or a part of the output, and, in return, the purchaser agrees to pay, "in all events", a pro rata share of "all costs" of the plant, plus an additional fixed percentage of the pro rata share of debt service. "All costs" include operating costs; taxes and other payments to governmental agencies; debt service, including principal and interest; amounts required for repairs and replacements not provided for otherwise; and any other costs associated with ownership, operation and maintenance allocated along the percentage of output sold.

The security of debt service repayment is obtained through the operation of the in-all-events clause. Such a clause will contain language similar to this:

> Payment to be made whether or not the operation of said facilities is interrupted, suspended, or interfered with, in whole or in part, for any cause whatsoever during the term of the power contract.

With this type of clause included in the contract and a credit-worthy power purchaser, the holders of the project debt will have sufficient security to place their funds in the project and allow implementation.

The major drawback to this type of agreement is that the compensation to the project sponsor is fixed at a constant amount for the duration of the power contract, which may be for 30 to 40 years. With the consensus expectation that the real value of electric and other forms of energy will be increasing, the fixed percentage of debt service may become a lesser percentage of the true value of the electricity. While the arrangement may be fair at the start of the power contract, as time passes the power purchaser may receive a disproportionate share of the benefits. The next type of arrangement discussed can rectify this problem.

Cost Plus a Royalty Subject to Escalation. This type of power contract has been used to secure financing for hydroelectric development in the U.S. An example is the July 1978 issuance of $7,800,000 of revenue bonds by Nevada Irrigation District (NID, California) for construction of a powerhouse at Rollins Reservoir, which is a part of NID's Yuba-Bear River Development. The security for the bonds was obtained through a power contract with Pacific Gas and Electric Company (Nevada Irrigation District, CA., 1978).

The contract is very similar to the one just discussed. Once again the project sponsor agrees to deliver power and the power purchaser agrees to pay all costs. The difference is that in lieu of having the project sponsor receive a fixed percentage of debt service as compensation, the sponsor receives a minimum per kWh payment, *which is subject to escalation.*

With this type of agreement, the power purchaser's payment to the project sponsor above "all costs" will fluctuate based on actual energy production. However, the per kWh rate of payment has a floor and is subject to escalation. The escalation clause will generally work as follows: At periodic intervals of one to five years, the per kWh factor will be adjusted for use in the following period by the same percentage some index of energy costs has changed in the same period. A logical index to use is the fuel-cost component of the utility's thermal electric generation.

This type of contract provides the debt service security needed to obtain funds and also recognizes that the future value of the project's output is likely to rise. This combination leads to a desirable marketing plan for the project sponsors to pursue.

Sales per Kilowatt-Hour. Project output could be sold on a per kWh basis, with the price being subject to adjustment based on an index. In this case, the power purchaser would not guarantee to pay "all costs", but would simply pay for energy actually produced. This arrangement could lead to wide variations in yearly revenues as annual power production varied.

Without purchaser guarantees to cover debt service in all events, some other method of assurance is needed before financing is possible. Usually, either sponsor or third-party guarantees will be necessary; however, occasionally the project will be strong enough on its own to lower the risk of revenue deficits to acceptable levels. In section 6 the method for calculating the probability of a revenue deficit under a per kWh sales agreement is discussed.

The difficulties in assuring debt service payments with this type of sale will usually preclude the possibility of obtaining project financing. Consequently, except with unusually attractive projects, one of the other forms of marketing the power output should be attempted.

Sales per Kilowatt-Hour with Cost Guarantee and Balancing Account. This type of arrangement values the plant output on a per kWh basis but also provides the revenue security necessary to obtain financing. Once again, the project sponsor agrees to supply electricity that the power purchaser agrees to purchase at a per kWh rate that is indexed. In addition, to provide security for debt service, the power purchaser agrees to pay "all costs"; the excess is used to reduce the balancing account balance, if any, with the remainder going to the project sponsor.

With this arrangement, the power purchaser is, in effect, providing short-term financing to assure the project's debt service. If the project is economically sound, at the end of the financing period the balancing account balance will be zero.

This contract has the two desirable characteristics of providing sufficient security to obtain financing and recognizing that the future value of electricity will rise. This arrangement will also lead to greater sponsor revenues than in the cost plus escalating royalty contract described earlier. This is because a larger value will be subject to escalation.

Market Information Used in Project Sizing

Market information is necessary for project sizing since it provides data on expected project value versus installed capacity. Using cost-versus-capacity information generated by the project engineers, the appropriate project size can be chosen. Clearly, at the feasibility level where market and cost information are both estimates, only an approximate "best" project size may be selected. The actual installed capacity will generally be chosen after equipment bids are received.

In general, project sponsors will want to maximize "profits" from the project. A well-established body of economic theory deals with the conditions for profit maximization. In a non-inflationary and competitive business environment, the conditions for maximum profit are satisfied if total revenues are equal to marginal costs. Inflation complicates the picture, since both total revenues and costs are escalating, but at different rates. However, a useful approximation to the best project size comes from maximizing the profits in the first year of operation. This will enhance the ability to obtain financing and market power by reducing project risk.

SECTION 4
ECONOMIC ANALYSIS

Traditionally, economic analysis for projects has meant development of benefit-cost ratios. This section shows how economic analysis of small hydro projects can be performed by public and private organizations. Guidelines are provided for formulating the benefit and cost streams and several commonly used procedures for comparing the benefits and costs are explained.

Definition of Economic Analysis

Economic analysis deals primarily with the development and applications of benefit-cost analysis which is the most frequently used procedure for project economic evaluation. The objective of this type of analysis is to relate all project economic benefits to all project economic costs accruing to the project sponsor. The appropriate scope of the analysis (the benefits and costs that should be included in the analysis) depends largely on the nature of the sponsoring organization.

Important components of the economic analysis are the project's initial and recurring annual costs and annual revenues which are the primary concern in the financial analysis. However, other costs and benefits not included in the project financial analysis may properly be included in the economic analysis. An example would be recreational benefits accruing to a county's population from reestablishing an impoundment for small hydro purposes. Such benefits would accrue to the area, but probably would not influence the finances of the project.

Analytical Scope and Framework

Framework of Economic Evaluation. The most efficient use of resources is the objective of economic analysis as measured by economic evaluation criteria such as the B/C ratio. This objective will generally be met if the project sponsor maximizes their net benefits and the scope of the analysis is properly formulated.

Within this framework, many small hydroelectric projects can be analyzed as single-purpose, stand-alone ventures if they are additions to, or replacements of, already existing facilities and their purpose is strictly power production. Such things as irrigation and urban water supply, flood control, navigation, recreation, and fish and wildlife might not be considered in the benefit-cost analysis because rehabilitation or add-on projects frequently have little or no effect on these items. If this is the case, the benefits are those associated with selling power, and the costs are those associated with supplying the power including rehabilitation.

If other objectives are of importance to the project's sponsors, such as environmental quality or employment, the analysis may be structured to include these additional objectives. Multi-objective analysis is used to analyze this type of project. In multi-objective analysis, each separate objective served by the project is considered independent but not necessarily of equal rank or priority. Each objective generates its own benefit stream, and carries its own costs and its fair share of any joint project costs. The multi-objective project is economically justified if, at a minimum, total economic benefits exceed costs and if each project purpose provides benefits at least equal to its separable costs.

Price level escalation, or inflation, may or may not be included in the economic analysis. The present federal government practice is to not escalate prices. Many private and other governmental analysts do escalate prices. This manual will explicitly include inflation in the analyses. The equivalent analysis without escalation can be obtained by using zero percent inflation and adjusting the discount rate.

Scope of Economic Analysis. A properly formulated small hydro project proposal attempts to maximize the net benefits of the project as determined by the scope of the analysis. The scope of the analysis, or the objectives, benefits, and costs to be included, depends on the nature of the sponsoring organization. The appropriate scope of analysis is to include costs and benefits which accrue to the sponsoring organization. If the sponsor is a private organization then the analysis would include items directly affecting profitability (revenues and expenses). Local governments might have a broader scope and include flood control, recreation or other local benefits. The federal government, whose purpose is broadest, would include all costs and benefits on the local, regional, and national level.

Cost and Benefit Streams

Benefits and costs are broadly categorized as monetary and non-monetary. Most nonmonetary benefits and costs can be quantified into dollar values if certain assumptions are made during the evaluation procedure. For example, in a local government sponsored project, recreation could be quantified into the user-days of recreational facilities and a dollar value determined for a user-day.

Components of Economic Costs and Benefits. In all small hydroelectric projects, the largest components of economic costs and benefits will be the present value of future cash inflows on the benefit side and the present value of the original and any future cash outlays on the cost side. Many of the elements from which these costs and benefits are calculated are contained in the *Uniform System of Accounts* prescribed for public utilities and licensees and published by the Federal Energy Regulatory Commission (FERC). Excerpts of these accounts are contained in Exhibit II. The accounts established by the FERC include balance sheet, electric plant, income, retained earnings, operating revenue, and operation and maintenance expense accounts. The various elements of these accounts, when properly quantified into present value, become the components of the economic costs and benefits.

As previously noted, other costs and benefits will properly be included in the analysis depending on the sponsoring organization. The individual situation determines which benefits and costs should be included. Examples of the types of considerations of interest are water supply, flood control, recreation, fish and wildlife, permanent employment, land use, and historical preservation.

Inflation. Escalation in the market value of power and project costs will occur over the project life. This escalation in price levels is composed of two components: inflation, or generalized price level increases, and real price increases due to shifts in supply-demand relationships for commodities.

Real price increases cause some items to escalate more rapidly than others. For instance, construction costs have increased at a substantially greater pace than inflation in recent years. This is also true of energy values. In some cases it may be desirable to escalate various cash inflows and outflows at different rates. This decision must be based on judgment about the project at hand and anticipated changes in the general economy and the future real price increases in the value of energy.

If inflation is explicitly included in the economic analysis, the future benefit and cost streams must be escalated by the expected inflation rate. This is done by using the factor for the future value of a present sum with the inflation rate in the place of interest. This is

$$P_t = P_o \times (1 = e)^t$$

where:

P_t = price t years in the future
P_o = current price
t = years in future
e = inflation rate.

This factor is multiplied times the future unescalated estimates of costs and benefits in the appropriate year to obtain the escalated amount.

Table 4-1 illustrates how escalation during construction is calculated for a four-year project. Also shown is the calculation of completed capital cost. First the lump sum cost estimate is broken into the amount to be spent in each year of construction. This unescalated cost estimate is then escalated to the expected future cost by using the factor to calculate the future amount of a present sum with the appropriate escalation rate. The contribution to complete cost includes the interest to finance the expenditure until the construction is complete.

This technique can be used for each separate portion of a construction project. In this manner, variation in escalation rates for different project components, such as the civil works or the mechanical equipment, can be incorporated in the completed cost estimate. (Table 4-2 is a complete example showing how inflation is incorporated in the benefit and cost streams.)

Formulating Benefit and Cost Streams. The period over which the benefit and cost streams must be calculated is the economic, or useful, life of the project. In the case of small hydro, this will frequently be the length of the financing period since periodic major replacements are usually required for continued operation and the financing plan will typically provide these funds only through the financing period.

If escalation is going to be included in the analysis, all the costs and benefits must be escalated in a consistent manner. Depending on the given project, different escalation rates for different portions of the project may be desirable. In particular, the general expectation that energy values will escalate more rapidly than general inflation should be considered.

The cost stream is composed of the capital costs, operation and maintenance costs, future replacements, quantified nonmonetary costs and any other cost associated with the project affecting the project sponsor. The benefit stream will include the value of power generation, quantified nonmonetary benefits accruing to the sponsor, and other benefits. The timing of these streams is important and must be accurately established.

Note that the receipts and outlays associated with the actual financing of a project, together with any effects on income taxes that follow, are excluded from the benefit and cost streams. Payments made into sinking funds to provide for future replacements are also excluded.

For more detail, a private sponsor should consult a basic text on managerial finance (Bolten, 1976) and a public sponsor a text on benefit/ cost analysis (Mishan, 1976).

Economic Evalutation Criteria

A number of frequently used decision criteria are available for evaluating the economic feasibility of small hydro projects. All of the theoretically correct criteria are based on the time-value of the project's benefit and cost streams formulated according to generally accepted practices.

Discount Rate. A discount rate is used in calculating the economic evaluation criteria which reflects the time-value of money. For private project sponsors and local governments, this is properly the cost of capital. The private sector will use their weighted average cost of capital and the public sector their cost of borrowing in the bond market or from other sources. The federal government and some state governments have their discount rates, and economic practices, set by law. For example, federal projects use a constant dollar analysis and a discount rate set at 6-7/8 percent as of October 1, 1978, which is adjusted annually.

TABLE 4-1
IMPACT OF ESCALATION DURING CONSTRUCTION AND CALCULATION OF COMPLETED CAPITOL COST

CONSTRUCTION WITHOUT ESCALATION

PROJECT DATA

ITEM	AMOUNT
Cost of Financing	10.0% Per Year
Financing Period	30 Years
Construction Period	4 Years
Construction Costs Per Year	Shown Below
Construction Cost Escalation	0.0% Per Year
Lump Sum Project Cost Estimate	$1,000,000

CAPITAL COST CALCULATIONS

YEAR	UNESCALATED COST ESTIMATE	ESCALATED TO YEAR OF PAYMENT	CONTRIBUTION TO COMPLETED COST INCLUDING INTEREST DURING CONSTRUCTION
1	$ 300,000	$ 300,000	$ 399,300
2	300,000	300,000	363,000
3	200,000	200,000	220,000
4	200,000	200,000	200,000
TOTALS	$1,000,000	$1,000,000	$1,182,300

Completed Cost = $1,182,300

Fully amortized over 30 years at 10% interest,
Annual Debt Service = $125,417 Per Year

CONSTRUCTION WITH ESCALATION

PROJECT DATA

ITEM	AMOUNT
Cost of Financing	10.0% Per Year
Financing Period	30 Years
Construction Period	4 Years
Construction Costs Per Year	Shown Below
Construction Cost Escalation	10.0% Per Year
Lump Sum Project Cost Estimate	$1,000,000

CAPITAL COST CALCULATIONS

YEAR	UNESCALATED COST ESTIMATE	ESCALATED TO YEAR OF PAYMENT	CONTRIBUTION TO COMPLETED COST INCLUDING INTEREST DURING CONSTRUCTION
1	$ 300,000	$ 300,000	$ 399,300
2	300,000	330,000	399,300
3	200,000	242,000	266,200
4	200,000	266,200	266,200
TOTALS	$1,000,000	$1,138,200	$1,331,000

Completed Cost = $1,331,000

Fully amortized over 30 years at 10% interest,
Annual Debt Service = $141,191 Per Year

TABLE 4-2
EXAMPLE CALCULATION OF
NET PRESENT VALUE

*** NET PRESENT VALUE CALCULATION ***

(0.0% PRICE ESCALATION , 10.0% INTEREST)

YEAR	CAPITAL COSTS	OTHER COSTS	BENEFITS	NET ANNUAL BENEFITS (4-2-3)	PRESENT VALUE FACTOR	PRESENT VALUE (5)*(6)
(1)	(2)	(3)	(4)	(5)	(6)	(7)
0	$600,000			$ -600,000	1.000	$-600,000
1	900,000			- 900,000	0.909	- 818,181
2		45,000	245,000	200,000	0.826	165,289
3		45,000	245,000	200,000	0.751	150,262
4		45,000	245,000	200,000	0.683	136,602
5		45,000	245,000	200,000	0.620	124,184
6		45,000	245,000	200,000	0.564	112,894
7		45,000	245,000	200,000	0.513	102,631
8		45,000	245,000	200,000	0.466	93,301
9		45,000	245,000	200,000	0.424	84,819
10		45,000	245,000	200,000	0.385	77,108
11		45,000	245,000	200,000	0.350	70,098
12		45,000	245,000	200,000	0.318	63,726
13		45,000	245,000	200,000	0.289	57,932
14		45,000	245,000	200,000	0.263	52,666

NET PRESENT VALUE OF PROJECT = $- 126,662

(7.0% PRICE ESCALATION , 10.0% INTEREST)

YEAR	CAPITAL COSTS	OTHER COSTS	BENEFITS	NET ANNUAL BENEFITS (4-2-3)	PRESENT VALUE FACTOR	PRESENT VALUE (5)*(6)
(1)	(2)	(3)	(4)	(5)	(6)	(7)
0	$600,000			$ -600,000	1.000	$-600,000
1	963,000			- 963,000	0.909	- 875,454
2		51,520	280,500	228,980	0.826	189,239
3		55,126	300,135	245,008	0.751	184,078
4		58,985	321,145	262,159	0.683	179,058
5		63,114	343,625	280,510	0.620	174,174
6		67,532	367,678	300,146	0.564	169,424
7		72,260	393,416	321,156	0.513	164,803
8		77,318	420,955	343,637	0.466	160,309
9		82,730	450,422	367,691	0.424	155,937
10		88,521	481,952	393,430	0.385	151,684
11		94,718	515,688	420,970	0.350	147,547
12		101,348	551,786	450,438	0.318	143,523
13		108,443	590,412	481,969	0.289	139,609
14		116,034	631,740	515,706	0.263	135,801

NET PRESENT VALUE OF PROJECT = $619,738

Screening and Ranking. Economic decision criteria can be grouped into two classes: those most suitable for screening and those most suitable for ranking.

Screening refers to determining if a project has an acceptable economic return. In a small hydro development, a number of potential development plans must be considered. Screening the various plans will yield those that have acceptable results; all others will be rejected as uneconomic developments.

Ranking refers to determining the order of economic preference among projects. In a small hydro situation, the screening process may yield two or more installed capacities or turbine types that are viable development alternatives. The ranking process helps choose which is the most economically desirable project among the group of acceptable plans.

The example presented below will be useful to illustrate the discussion of the various criteria. The example project parameters are:

The example presented below will be useful to illustrate the discussion of the various criteria. The example project parameters are:

1.	Installed capacity	2 MW
2.	Annual energy production	9.8 million kWh/year
3.	Plant factor	56 percent
4.	Lump sum cost per kw	$750
5.	Annual O&M	$45,000
6.	Expected financing cost	10 percent
7.	Construction period	2 years
8.	Financing period	12 years
9.	Escalation	0.0 and 10.0 percent
10.	Value of energy	2.5¢/kWh

Net Present Value (NPV). The net present value criterion incorporates all of the pertinent economic data into a consistent one-figure decision rule that allows projects to be both screened and ranked. The criterion requires that a discount rate be specified for use in present value calculations.

The general procedure is to determine the present value (at the time of the first expenditure) of the future stream of net benefit flows. The screening decision criterion is to reject the project if the NPV is less than or equal to zero. Without constraints on the amount of capital available for the project, the project with the highest NPV is ranked highest. If capital is constrained, as may very possibly be the case, the project with the highest NPV within the budget constraint is ranked highest.

Explicitly, NPV is calculated as

$$NPV = \sum_{i=0}^{n} (CF_i/(1+k)^i) + (S_n/(1+k)^n)$$

where:

Σ = summation

CF_i = *net* cash flow in period i, starting with the initial outlay.

n = last period of cash flow

S_n = salvage value if any

k = discount rate

The example presented in Table 4-2 illustrates the calculation. Without escalating the benefit and cost streams the project has a negative NPV while including escalation indicates an economically feasible project.

Benefit-Cost Ratio (B/C). The B/C ratio, the most commonly used decision rule, reduces the analysis to a single consistent figure like the NPV. The rule incorporates all the essential elements of a valid economic comparison. The ratio compares the present value of future cash inflows to the present value of the original and all subsequent outflows by dividing the inflows by outflows. The decision rule is to reject projects that have B/C ratios less than one. For the example in Table 4-2, the present value of the escalating stream of benefits is $2.567 million and of the escalating stream of costs is $1.947 million. The B/C ratio is then 1.32 indicating an economically feasible project.

Internal Rate of Return (IRR). The IRR, which is primarily a screening criterion, is the discount rate that results in the project's NPV being zero. Like the NPV, internal rate of return incorporates all the pertinent economic data. IRR is calculated through an iterative process.

The decision criterion is to reject projects whose IRR is less than the expected cost of financing used to implement the project. This criterion has the appeal of being expressed as a percentage that is readily comparable with the expected cost of financing. The criterion does not, however, reflect any information on project scale, and, consequently, it cannot be used as the sole ranking criterion.

The IRR for the example project in Table 4-2 was calculated and is presented below for a range of initial energy values.

Energy Value (¢/kWh)	**IRR (percentage)**
2.3	14.1
2.4	15.0
2.5	15.9
2.6	16.8
2.7	17.7

Note that for energy at 2.5¢/kWh, the project's IRR is 15.9 percent. Consequently, for financing at less than 15.9 percent, the NPV of the project must be greater than zero, as is the case.

Other Criteria. Several other decision criteria are available for evaluating investment alternatives, but these are considered less competent at providing adequate evaluation information. These include the average rate of return (ARR) and the payback method (PB), among others. The ARR method is similar to the IRR, but does not discount future cash inflows and outflows; thus it does not take into account the time value of money. The payback method is one of the most commonly used methods in the United States, but it also fails to take into account the time value of money. PB is actually a measure of how quickly the original investment is returned in absolute dollars, and it ignores potentially great future gains.

Uncertainty

Uncertainty is the lack of sureness about an outcome or quantity. In small hydro projects, uncertainty surrounds capital cost estimates, future annual costs, escalation rates, and the future value of energy. Because these quantities are not known with certainty, an outcome unfavorable to the project sponsor is possible. This risk should be analyzed and minimized to the extent feasible. The discussions on sensitivity and risk analysis address the analysis of risks.

Analytical Procedure

Sensitivity analysis and risk analysis are two of the techniques used in analyzing investment decisions. The purpose of these techniques is to explore more fully the ramifications of uncertainty on the economic and financial decision criteria. Following a discussion of these techniques, a general procedure for the economic analysis of small hydroelectric projects is put forth.

Sensitivity Analysis. Sensitivity analysis, when applied to investment decision criteria, may be defined as the investigation of the impact on the decision criteria of variations in the important project parameters taken one at a time. The analysis is very useful for examining the degree to which the overall project desirability could be affected by changes in parameters whose values may vary.

The procedure is to determine the range over which the parameter being investigated might vary. The value of the decision criteria is then calculated over the range of the parameter. The results are then usually presented graphically as in Figure 4-1, which shows an example of the sensitivity of IRR with respect to the initial value of the project's energy production.

Some of the variables whose effect on the project might be investigated are complete cost, operation and maintenance costs, interest rates, and the initial value of the project's energy.

Risk Analysis. The risk associated with a small hydro project may need to be evaluated. Risk may be defined as the probability of the occurrence of an unacceptable outcome. Several methods of evaluation account for risk. Two of these are discussed here: the discount rate approach, and the Monte Carlo simulation approach.

The discount rate approach accounts for risk by increasing the discount rate associated with a project. An increase in the discount rate lowers future net benefits, thereby decreasing the NPV, IRR, or B/C ratio. In this way, a project with more risk, identified by a higher discount rate, would have to meet higher requirements in order to be judged economically feasible.

A more advanced technique for evaluating risk is the Monte Carlo simulation analysis. Monte Carlo simulation allows uncertainty in a number of the project's parameters to be simultaneously accounted for and the impacts on the decision criteria to be quantified. A brief description of the method is given below.

The procedure entails first deciding which of the project's economic parameters are uncertain either initally or year by year. Next, a probability distribution associated with each uncertain parameter is specified to embody the uncertainty in the parameter's value. A typical method for doing so is to use the triangular probability distribution as shown in Figure 4-2.

The evaluation criterion is calculated many times (as many as 400 times in some cases) each time using the probability densities for the uncertain parameters to choose values for the parameters. The resulting set of values for the evaluation criterion forms a histogram of possible outcomes, such as shown in Figure 4-3. In the figure, if A represents the minimum acceptable outcome, then the shaded area represents the probability of an unacceptable outcome and the risk associated with implementing the project.

The use of this simulation technique is becoming more widespread, and financial simulation packages are available from a number of computer software vendors. Occasionally, this level of analysis may be justified for small hydro projects.

Economic Evaluation Procedure

Table 4-3 summarizes the steps in the economic evaluation procedure for a small hydro development option.

TABLE 4-3
ECONOMIC EVALUATION PROCEDURE

Step	Description
1	Determine if inflationary or constant dollar analysis will be used. In an inflationary analysis, establish the general escalation rate. If items such as energy values or construction costs will be escalated at a rate different than the general inflation rate, determine the appropriate rate(s).
2	Establish the project economic life.
3	Assemble the unescalated cost stream (by year) for the economic life of the project. This includes the capital costs by year, operation and maintenance, replacements, quantified nonmonetary costs and other costs.
4	Assemble the unescalated benefit stream (by year) for the life of the project. This includes the value of power generation, quantified nonmonetary benefits, and other benefits.
5	Escalate costs and benefits as determined in Step 1.
6	Establish the appropriate discount rate.
7	Calculate the economic evaluation criterion chosen for use.

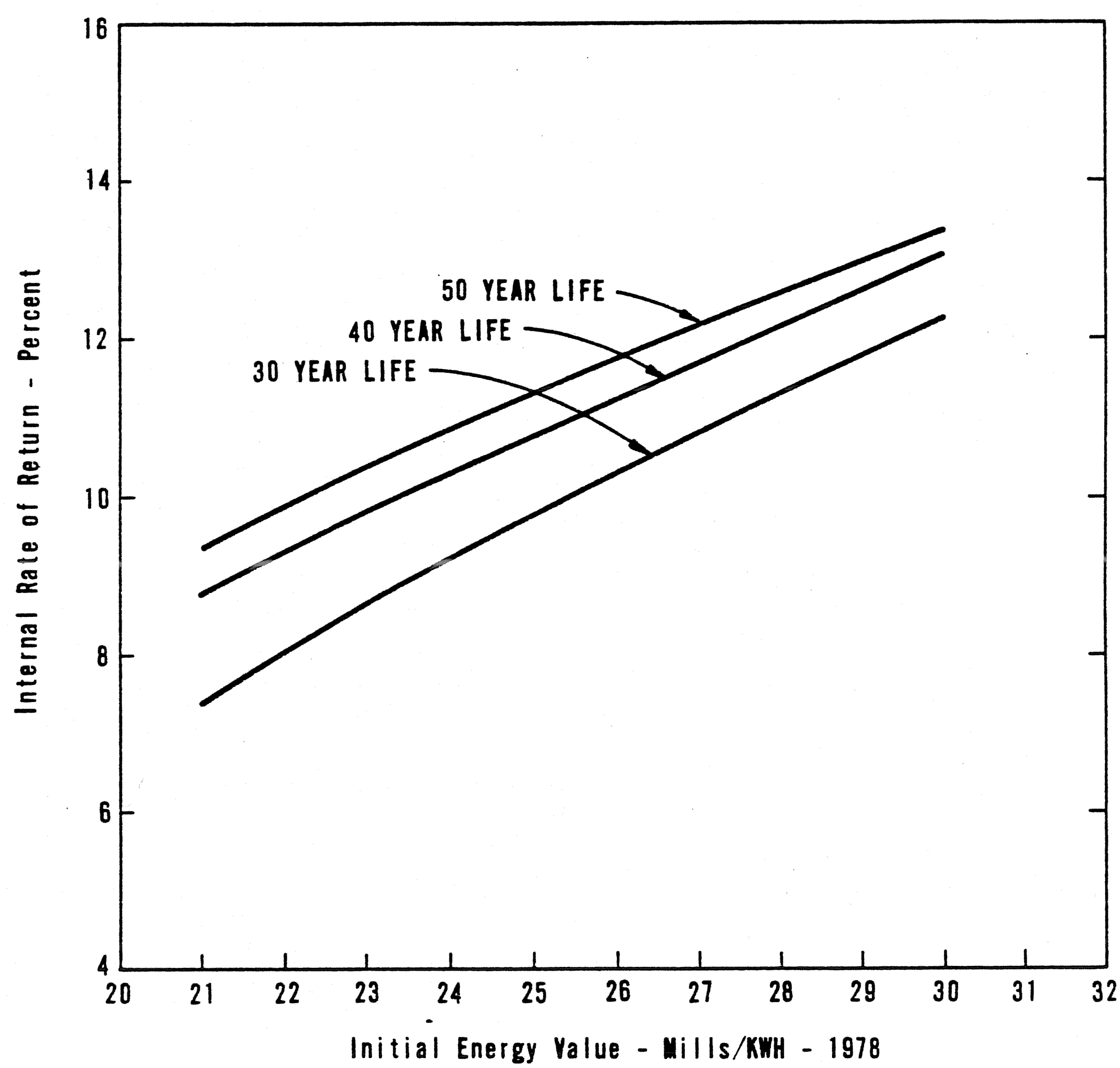


Figure 4-1. Example of sensitivity analysis.

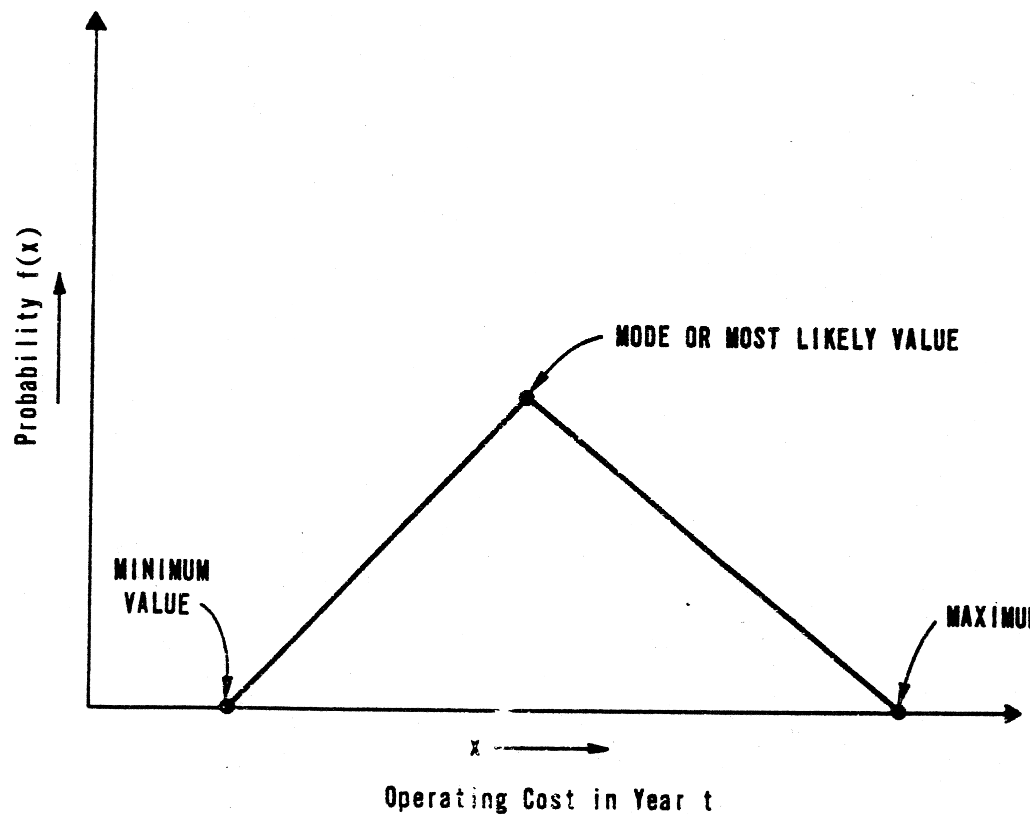


Figure 4-2. Example of triangular probability distribution of a project parameter.

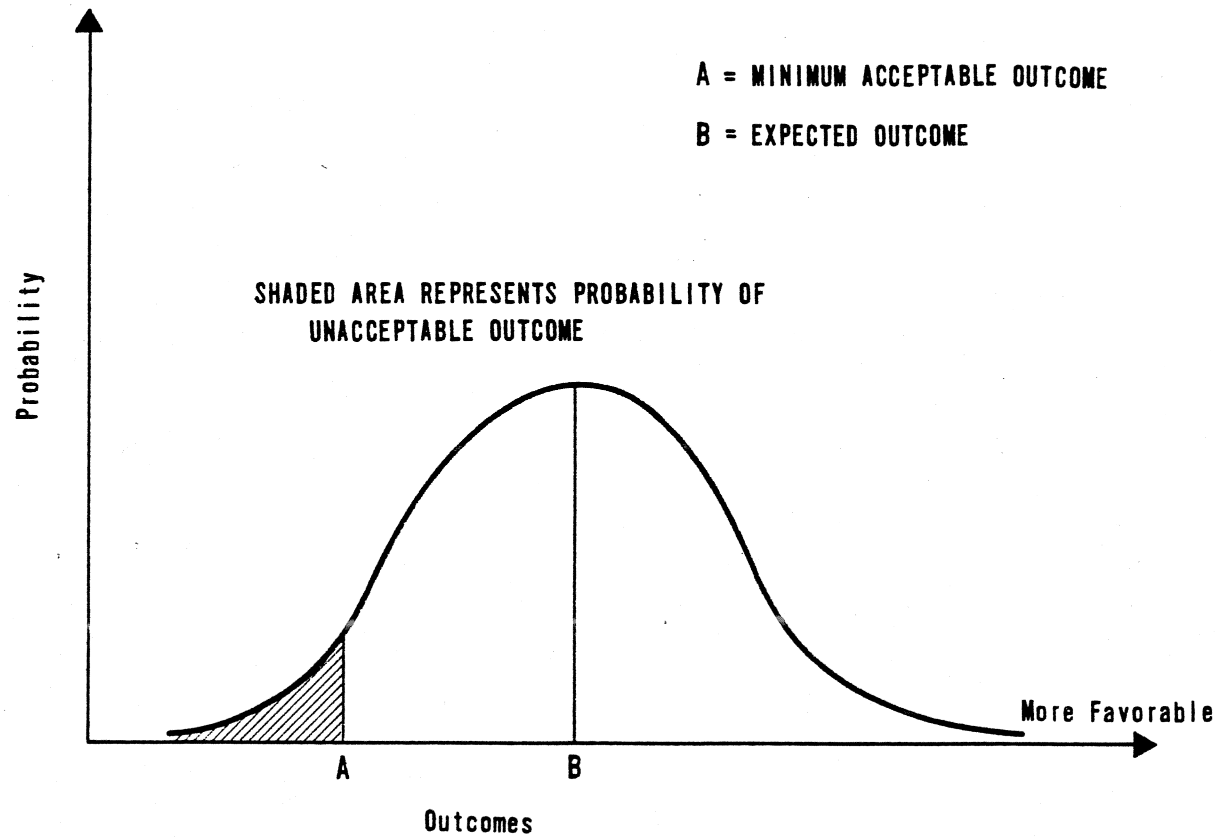


Figure 4-3. Probability of possible outcomes from Monte Carlo simulation.