A GUIDANCE MANUAL TO ASSIST AID LOAN OFFICER PERSONNEL IN THE REVIEW AND ANALYSIS OF ELECTRIC POWER PROJECTS

for

AGENCY FOR INTERNATIONAL DEVELOPMENT

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November 25, 1967

Dr. Leonard G. Rosenberg
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Dear Leonard:

The accompanying draft of a manual for AID loan officers is submitted in accordance with Task Order No. 1 under AID's Central Engineering Contract with Zinder International, Ltd., AID/CSD 1574.

Best wishes.

Sincerely,

Herschel F. Jones
Consultant

Enclosure

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TABLE OF CONTENTS

TABLE OF CONTENTS

INTRODUCTION

Purpose

This manual is intended to assist AID loan officers and others in their review and analysis of proposed electric power projects and especially in their evaluation of feasibility reports prepared by applicants in support of requests for AID assistance. The manual has been prepared in conjunction with the drafting of an AID manual describing the required contents of the Economic and Technical Soundness Analysis of Electrical Power Projects.

It is hoped that the Guidance Manual will assist AID loan officers to understand the Soundness Analyses and to raise all questions which must be answered before AID approval is given to proposed electric power projects.

Terminology

Increasingly, the subdivisions of the professional and business world have adopted their own terminology. The electric power industry, its engineers and its consultants, are no exception to this trend. Readers are therefore referred to two documents which will assist them in understanding the language used in electric power project feasibility reports. These are:

(1) Glossary of Important Power and Rate Terms, Abbreviations, and Units of Measurement, prepared under the direction of the Inter-Agency Committee on Water Resources and promulgated by the Federal Power Commission in 1965 (available from the Superintendent of Documents, U.S. Government Printing Office, Washington, D.C.).

(2) Glossary of Electric Utility Terms, Financial and Technical, prepared by the Statistical Committee of the Edison Electric Institute (available from the Institute, 750 Third Avenue, New York, E.E.I. Publication No. 61-31).

In addition, many of the most frequently used terms are defined in Appendix A, attached hereto.

I

ELECTRIC POWER PROJECTS

Electric Energy and Electric Systems

Electric energy is the most versatile form of energy presently available to man. It can be used to provide light and heat, to perform work, and to supply communications. It is the indispensible tool of modern production. Electric power projects are conceived, designed, constructed and operated for the purpose of furnishing electric energy to ultimate consumers. Most projects will be additions to an existing electric system or systems, and the analysis of such projects must consider the effects of the additions upon the system, its output, its capacity, its efficiency, its costs, and its financial soundness.

Although electric energy can be supplied from many sources, the AID-assisted power projects which are the subject of this paper will be concerned primarily with central station generating plants to convert the energy from falling water, the combustion of fossil fuels, or the fission of uranium into electric energy. Each electric system will also include facilities to transmit the electric energy from one or more central generating stations to distribution substations and facilities to distribute the electricity from distribution substations to customers. Very small systems may omit the transmission facilities and deliver the electric energy from the generating stations to the customers by means of a distribution system only.

Hydroelectric Stations

As indicated above, generating stations convert energy from other forms into electricity. Hydroelectric generating stations convert falling water--

which may be measured as foot-pounds per second--into electric capacity, i.e., kilowatts. The ratio of conversion is 1.356 foot-pounds per second = 1,000 kw. The principal machines required in a hydroelectric generating plant are the hydroelectric turbine (or water wheel) and generator, which have a common shaft. Electric energy flows from the generator to a transformer, which increases the voltage from the generator voltage to the transmission voltage. Various switches or circuit breakers may be interposed in the electrical circuits between the generators and the transformers and between the transformers and the transmission line. The flow of water through the turbines and the speed of rotation of the turbine-generator set will automatically be regulated by a governor which acts to maintain a constant speed of rotation by varying the flow of water through the turbine as the electrical load on the generator changes. Most electric generating stations constructed today produce current alternating at either 50 or 60 cycles per second. Hydroelectric governors are able to control the speed of the turbine-generator set to within a fraction of a cycle per second during normal operations.

Steam-Electric Stations

Steam-electric generating stations convert the heat produced by the combustion of fossil fuels or by the fission of uranium into steam at high pressures and high temperatures.

The average conversion rate in terms of Btu per kilowatt-hour is called the "heat rate" and in modern plants, may range from as high as 14,000 Btu per kilowatt-hour to as low as 8,700 Btu per kilowatt-hour. The average for all fossil fuel steam-electric plants operated in the United States in 1965 was 10,453. The available heat in a kilowatt-hour is 3,413 and the overall efficiency of a generating plant is the relationship between its heat rate and 3,413 Thus, a plant with a heat rate of 10,000 Btu per kilowatt-hour would be 34.13 percent efficient in the conversion of fuel to electricity.

Steam is produced in a boiler if fossil fuels are burned, or in a reactor if uranium is fissioned. When passed through a steam turbine and into a condenser, this steam causes the rotation of the steam turbine at high speed. The steam-electric generator is on the same shaft as the steam turbine and spins with the turbine at high speed to produce electric energy. Again, electricity is transmitted from the generators through transformers to the transmission lines. The flow of steam into the turbines from the boiler, or reactor, is regulated by a governor which maintains the rotation of the turbine-generator set at a constant speed even though the load may vary. Other regulating devices control the consumption of fossil fuel in the boiler or of uranium in the reactor in response to the governor's demand for more or less steam for the turbine. The steam condenser is a heat exchanger which removes heat from the steam exhausted from the turbine and converts it to water which is pumped back into the boiler to be heated again and changed to steam. The usual cooling agent for the condenser is water from a stream, lake, pond or ocean. Where limited quantities of cooling water are available, it is necessary to construct cooling towers which reduce the temperature of the water passed through the condensers. Steam-electric generating stations require substantial quantities of make-up water for the steam cycle and also makeup water for the cooling cycle, particularly if the cooling towers use evaporation to assist in cooling the water.

Diesel, Gas Engine and Gas Turbine Stations

A third type of central station is powered by internal combustion engines. The most popular are the diesel engines, which burn light fuel oil or a combination of light and heavy oils. Where natural gas is available, gas engines are also common. Electric generators are connected to the diesel or gas engines. As with steam and hydroelectric stations, the energy generated passes from the generators through transformers to the transmission system. Governors regulate the flow of fuel into the engines in response to increases and decreases in the demand for electric energy, keeping the engines at a constant speed. Other central stations using natural gas or oil for fuel are gas turbine stations. In these stations, the generator is connected to a gas turbine instead of to a gas or diesel engine. The gas turbine is similar in design to the jet engines on aircraft and is powered by the expansion of the hot gases resulting from the burning of fuel under pressure. Some gas turbine generating units use aircraft engines to provide the hot gases to spin the turbines. Governors control the throttle so that fuel intake is matched to the demand for electricity.

Transmission Facilities

Depending upon the size and extent of the electric system, electric transmission voltages may vary from 33,000 to 750,000 volts. Generating voltages, on the other hand, may vary from 400 volts to about 13,000 volts, again depending upon the size of the generating equipment. Most large modern generating stations today produce electric energy at about 13,000 volts. Generating station transformers change the lower voltages to transmission voltages.

A very rough guide to transmission voltages in terms of normal limits of capacities and distances is given below.

TRANSMISSION VOLTAGE	CAPACITY OF LINE (Kilowatts)	TRANSMISSION DISTANCE (Miles)
33,000	2,000 - 6,000	to 40
66,000	4,000 - 20,000	to 80
115,000	10,000 - 60,000	to 125
132,000	50,000 - 100,000	to 160
161,000	75,000 - 130,000	to 200
230,000	100,000 - 250,000	to 250
345,000	200,000 - 500,000	to 350
500,000	400,000 - 1,000,000	to 500
750,000	800,000 - 1,500,000	to 750

Lines will have higher capacities if power is carried less than the indicated distances or if heavier than usual conductors are installed. Mileage greater than that indicated can be obtained by lighter line loadings and by accepting higher than usual losses.

Distribution Systems

Distribution system voltages range from 400 to 25,000. The most commonly used distribution voltages in the United States, however, range from 11,000 to 13,000 volts. Cooperatively owned rural distribution systems in the United States financed by the Rural Electrification Administration are usually 12,500 volts. In some cases where the loads are heavy and the distance is great, 25,000 volts may be used.

Distribution transformers change the distribution voltages to the utilization voltages. This is usually 220/110 volts in the United States. For large loads, however, the utilization voltage may be higher to meet the particular needs of the customer. In many foreign countries, the utilization voltage for residential use is 460/230 volts, although it varies from place to place.

Alternating and Direct Current

Only alternating current can be easily transformed from one voltage to another. For this reason, most electric utility systems generate, transmit, and distribute alternating current. Direct current, however, is required for many industrial processes which are based on electrolysis. It is also frequently used to power electric locomotives and streetcars because it is easy to control the speed of direct-current motors.

In recent years long-distance, extra high-voltage direct-current transmission of large blocks of power has become practical and economic. Both underwater cables and overhead transmission lines now carry direct-current power long distances.

The conversion of alternating current to direct current is usually effected by rectifiers, either mercury-arc or solid state. The latter, using pure silicon metal, have been greatly improved and increased in size in recent years and this has reduced the cost of converting alternating current to direct current.

II

THE POWER MARKET

The analysis of every power market depends upon two basic considerations: (1) How many customers will be using electricity in the future? and (2) How much electricity will be used by each customer?[1/]

The number of utility customers of course depends upon the size of the population, the average number of persons per household, and the number of business establishments and governmental agencies which are potential users of electricity. People cannot use electricity, however, unless they have the equipment, appliances, and apparatus necessary for such use. Since these items cost money, and in many cases their acquisition involves the use of scarce foreign exchange, it is important to examine the level of income of potential electric customers and to determine what proportion of the potential customers will in fact be able to acquire the equipment, appliances, and apparatus to use electricity and to pay for the electricity so used.

The analyst should begin, if possible, with the statistics of electricity sold during past years (ten years if possible). The trend of annual use per customer should be examined for each class of customer, as well as the trends of the number of customers served in each class. Most electric systems establish different rates for different classes of customers. Their purpose in defining class distinctions is to increase their revenue. Also, electricity rates are usually designed so as to reduce the average cost per kilowatt-hour purchased as the quantity of electric energy used by a customer increases.

1/A Checklist of Data Useful to the Power Market Analyst is attached as Appendix B.

This rate characteristic also acts to increase the net revenues of the electric system, since the major cost of serving a customer is for providing the facilities to deliver electric energy to him. Once these facilities have been established, the costs of delivering additional quantities of electric energy are small.[1/]

A minimum of three classes of customers is found on most electric systems, namely, domestic (or residential), commercial, and industrial. The dividing lines between these classes of customers are frequently somewhat hazy. In many foreign countries where household shops and household industries are common, much commercial and industrial energy may, perforce, be sold at residential rates. In addition to the major classes of customers, most utilities have special rates for large customers, including large industrial plants, street lighting systems, municipal water systems, sewage treatment plants, and irrigation pumping. In many cases, the rates to these large loads must be low enough to provide a cost saving to the purchaser as compared with installing and operating his own electric generating plant.

Where adequate statistics of numbers of customers and electrical use per customer exist for a number of years, it is possible to project the number of customers to be added to the system and the increased use per customer on the basis of past trends. Such projections, however, will be misleading if the trends in population growth are changing or if the growth of electrical customers is reaching a saturation point (either because of area coverage or because limitations of income prevent a proportion of the population from obtaining electric service). Similarly, the projection of past trends will be misleading if the use of electricity has reached a saturation point because of

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1/For a more complete discussion of rates, see page 35 to 41 *infra*.

income limitations or because of the effective competition of other fuels for a portion of the potential electric load. Electric customers will pay a premium for electricity for lighting and heating if they can afford it. Where rates are very high in comparison with the cost of kerosene, gas, wood, or coal, or where incomes are low, not much electricity will be used for cooking, water heating or space heating. The analyst can determine the potential increase in electric sales for cooking and heating applications by determining the average cost per million Btu for electricity and the competing fuels in the area under study. Electricity may be compared with other fuels, on the basis of heat content, as follows:

ENERGY FORM	UNIT	HEAT CONTENT IN BTU per unit
Electricity	kilowatt-hour	3,413
Natural Gas (Methane)	cubic foot	1,035
Liquified Petroleum Gas (Butane-Propane)	U.S. gallon	95,500
Kerosene	U.S. gallon	135,000
No. 1 and No. 2 Heating Oil (Diesel)	U.S. gallon	136,000
No. 6 or Residual (Bunker C)	U.S. barrel	6,384,000
Anthracite (Hard coal)	short ton	25,400,000
Bituminous (Soft coal)	short ton	26,200,000
Lignite (Brown coal)	short ton	13,660,000
Wood and Wood Wastes (Hogged fuel)	cord	20,960,000

There is appended a more complete energy conversion table (See Appendix C).

Where available, the data regarding the saturation of electrical appliances in the home can greatly assist the analyst in forecasting the future power market. The amount of electricity used per appliance is a function of the wattage of the appliance and the average hours used. Both of these tend to vary between countries. In the United States the largest single user of electric energy in the home (except for space heating) is water heating. Automatic water heaters may use an average of 5,000 kilowatt-hours per year. Other large users are the electric range, which may average as much as 1,200 kilowatt-hours per year, and the refrigerator-freezer, which may average as much as 1,400 kilowatt-hours per year. The only other appliance which can be expected to use more than 1,000 kilowatt-hours per year is the electric clothes dryer, where the average use may be as much as 1,100 kilowatt-hours per year. The ordinary kitchen refrigerator and the average television set can be expected to use about 300 kilowatt-hours per year each.

Washing machines, vacuum cleaners, and other motor-driven equipment use much less electricity; even automatic washing machines may use only three kilowatt-hours per month. House heating, on the other hand, can consume very large quantities of electric energy, depending upon the climate, the efficiency of use, the size of the average dwelling, and other factors. (For a more complete list of appliance usage, see Appendix D.)

In the Pacific Northwest, where electric energy for house heating sells at less than one cent per kilowatt-hour, a six-room house equipped with baseboard heaters and fully insulated can be expected to use 14,000 kilowatt-hours per year. In a colder climate, this same house could easily use 30,000 kilowatt-hours per year in a typical heating season.

In many, if not most, of the developing countries, statistics on sales of electric energy, numbers of customers, appliance saturation, and similar data may be difficult to obtain. Instructions to applicants preparing feasibility studies suggest that substitute data may be used if power system data is unavailable. For example, census information on equipment in occupied dwellings may be a source of information concerning the number of families which have refrigerators, washing machines, electric ranges, and the number which heat their houses with electricity. Also, most developing countries will find it necessary to import electrical equipment, apparatus and supplies. Annual statistics on the numbers of electric appliances imported may provide a reasonably good guide to the number of appliances placed in service during past years. Such alternative sources of information may also be used to check information received from electric power systems.

In addition to the use of energy by the three major classes of customers, the use of electricity by other classes must also be determined. These include: street lighting, water and sewage systems, transportation systems, irrigation systems, and large industrial loads of various kinds. Usually these loads will be large enough to make it necessary for the electric system to establish special rates to serve them. Also, rates to these large loads will usually be two-part rates--that is, they will include a demand charge as well as an energy charge. Such rates will have to be set at a level which will provide a saving in energy costs to the customer when compared with installing and operating his own electric generating facilities.

Large loads should be investigated individually and projected on the basis of the plans of the customers for operations and expansion. Where such plans are not available, reference to past trends and estimated future output may be substituted as a basis for load projections. (Appendix E lists conversion factors for large electroprocess plants--those where the cost of electric energy will be an important factor in the location of a new plant.)

Projections of use per customer and numbers of customers will, of course, be extended to provide projections of total electric sales for each class of customer and for the system as a whole. These sales can then be converted into annual energy requirements by adding appropriate factors for transmission and distribution losses.

Line Losses

Transmission losses can be estimated quite accurately if the amounts of power to be transmitted over various facilities can be estimated. If such estimates are not available, past trends may be used as a guide. Distribution losses usually include not only power lost in the distribution process but also power that is unaccounted for. Unaccounted-for energy may become an important factor in the success of a utility distribution system, particularly if a substantial amount of "meter jumping" is encountered on a system. (Meter jumping is the illegal practice of wiring around the meter so that electric energy delivered is not recorded and, therefore, is not paid for.) Similar dishonest practices--sometimes with the connivance of utility employees--will be reflected in excessive distribution losses or "lost and unaccounted-for energy." Most well-designed distribution systems in urban areas should operate with losses in the range of from five to fifteen percent. Even in rural areas, distribution losses should rarely exceed twenty percent of sales.

Load Factor

Conversion of annual energy requirements to annual capacity requirements requires the estimation of future annual load factors for the electric system. Annual load factor is the relation of the annual average energy requirements, stated in average kilowatts, to the system peak for the year.

(Energy requirements in terms of kilowatt-hours for the year divided by the number of hours for the year, 8,760, yields average kilowatts of energy.) The projections of future annual load factors are usually based upon trends of annual load factors for past years. However, the introduction of new large loads with exceptional load factors should always be considered in predicting future load factors. Thus, the introduction of seasonal loads such as electric space heating will usually reduce the average load factor of a system. Similarly, the introduction of electric air-conditioning loads in a country which requires air-conditioning for only part of the year will also reduce the system load factor.

Addition of high-load factor industrial loads, on the other hand, will improve the overall load factor of an electric system. The introduction of large irrigation pumping loads may affect the system load factor in either direction, depending upon whether or not the large irrigation pumping loads will coincide with the system peak load. If irrigation loads can be discontinued at the time of the system peak load, they can be used to "fill the valleys" and, thus, improve the system load factor. It should also be noted that the use of increased amounts of energy by existing customers will generally be accompanied by improved system load factors.

Growth Trends

The load projections, if possible, should be checked by making comparisons of the rate of load growth (percent per year) with other growth trends of the area or country in which the project is proposed. The appropriate growth trends to consider are for: population, gross national product (GNP), per capita personal income, agricultural production, and industrial output. Such growth rates should always be compared with the rates of growth projected for electric loads.

It may sometimes be useful to compare the projected growth rates with the growth rates anticipated in other developing countries. A word of caution is necessary, however, since the environment within which the growth rate is postulated is almost never the same in two countries at the same time.

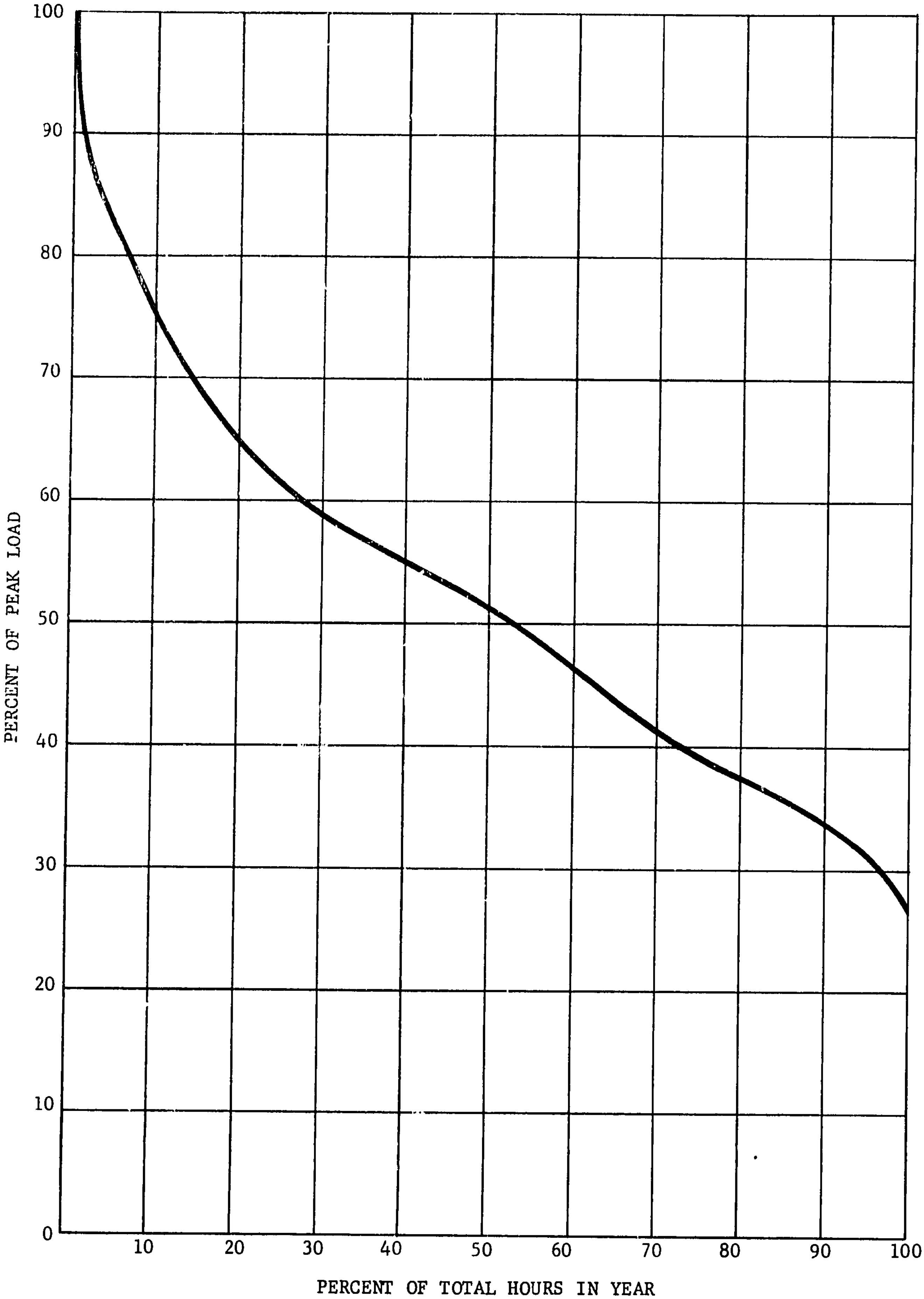
Load Duration Curves

Once the analyst is satisfied with the projections of energy and capacity requirements for an area, he should compare these requirements with the capacity of the existing system to produce energy and to meet peak loads. Two devices are normally used for making such comparisons. They are the load duration curve and the energy load curve which is derived therefrom. The load duration curve usually states the percent of the peak load equalled or exceeded for varying percents of the total hours in the year. (See the example on the following page.) It is derived by arraying the integrated hourly loads for one year in order of magnitude and counting the number of hours the load exceeds decreasing percentages of the annual peak load. These numbers of hours are then divided by 8,760 hours (the total hours of the year) to obtain the percent of the time during which the load exceeds given amounts. By comparing the dependable capacity of the system generating plants (after allowing for reserves) with the load duration curve, it is possible to determine whether or not sufficient capacity will be available on the system to meet system needs. Any shortfalls indicate the need for additional capacity. While most thermal-generating plants are available to meet peak

15W

CHART I

LOAD DURATION CURVE



loads from 85 to 90 percent of the time, the availability of hydroelectric stations may be substantially less. Care should be taken to match the availability of hydroelectric capacity to the load duration curve, taking into consideration the loss of capacity due to reduced head if reservoir levels are reduced as a result of peaking operations. Also, some hydroelectric plants will have substantially less peaking capability at the end of the storage release period as a result of reduced heads.

The accompanying illustrations, Charts I and II, are a load duration curve and an energy load curve respectively. They are fairly typical of small systems with annual load factors of about fifty percent. The load duration curve shows that the highest fifteen percent of the load occurs during only five percent of the time; that fifty percent of the peak load occurs about fifty-two percent of the time; and that the load is less than twenty-seven percent of the peak load less than one percent of the time. The energy load curve shows that the relation of the percent of peak load to percent of total energy is about one to two from zero to about thirty-five percent. This means that the area under ten percent of the peak load on the load duration curve accounts for twenty percent of the annual system energy requirements; the area under twenty percent accounts for forty percent of the energy; and the area under thirty-five percent of the peak accounts for about seventy percent of the total system energy.

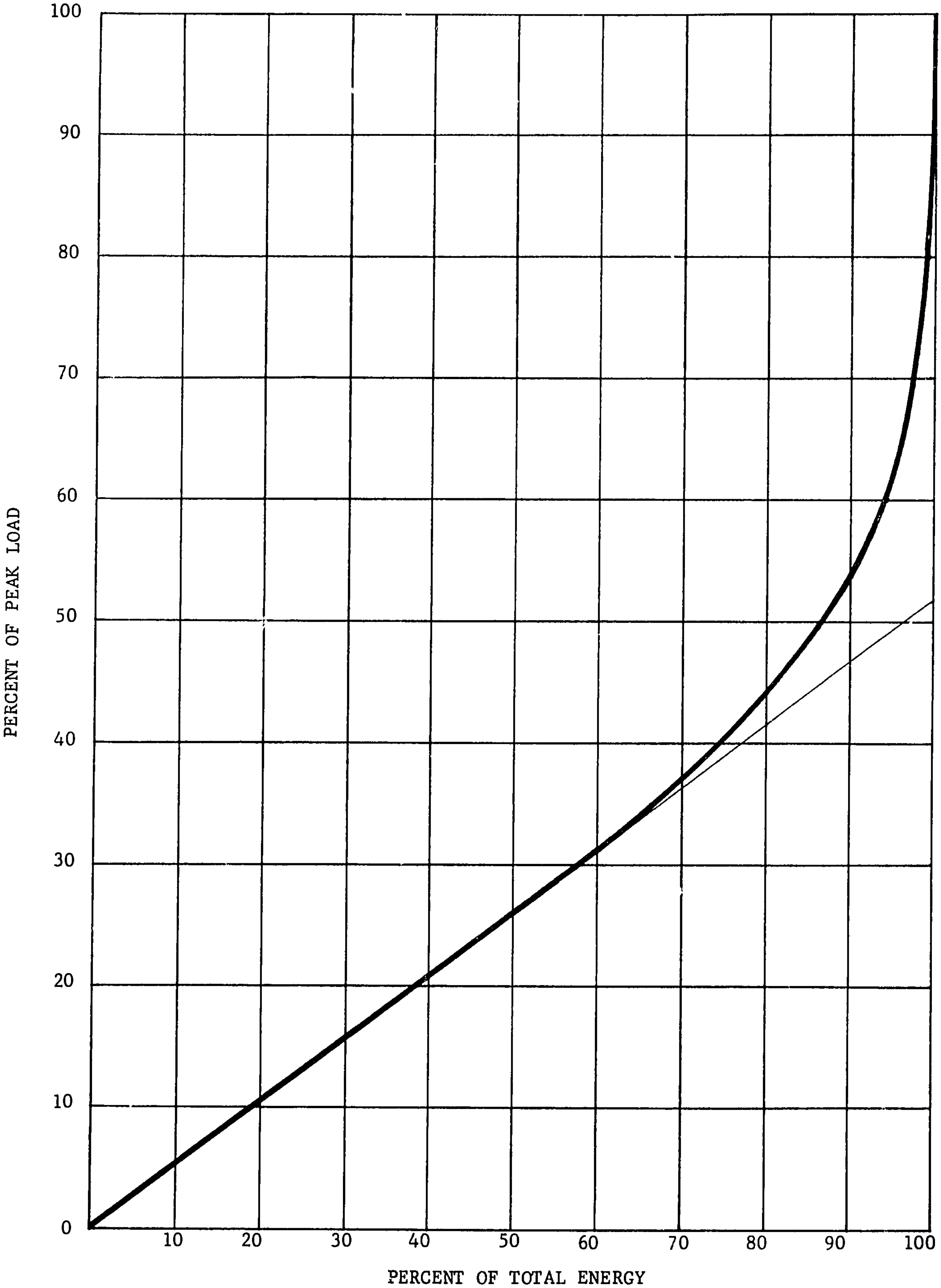
Above thirty-five percent the relationship becomes curvelinear, with the area above sixty percent of the peak load accounting for only five percent of the system energy and the area above eighty percent of the peak load accounting for about one percent of the system energy.[1/]

[1/] The extension of the straight-line portion of the Energy Load Curve intersects the vertical axis at fifty-two percent. This is the annual load factor of the load.

CHART II

16W

ENERGY LOAD CURVE



Before comparing future requirements with existing capabilities, the load duration curve vertical scale should be changed from percent to kilowatts for the year under consideration. Then the dependable capacity and energy capability of the existing system can be plotted on the diagrams. If more than one generating plant is to be plotted, care must be taken to put the capacity of the most economical plant on base load, followed by the second most economical plant, and so on.

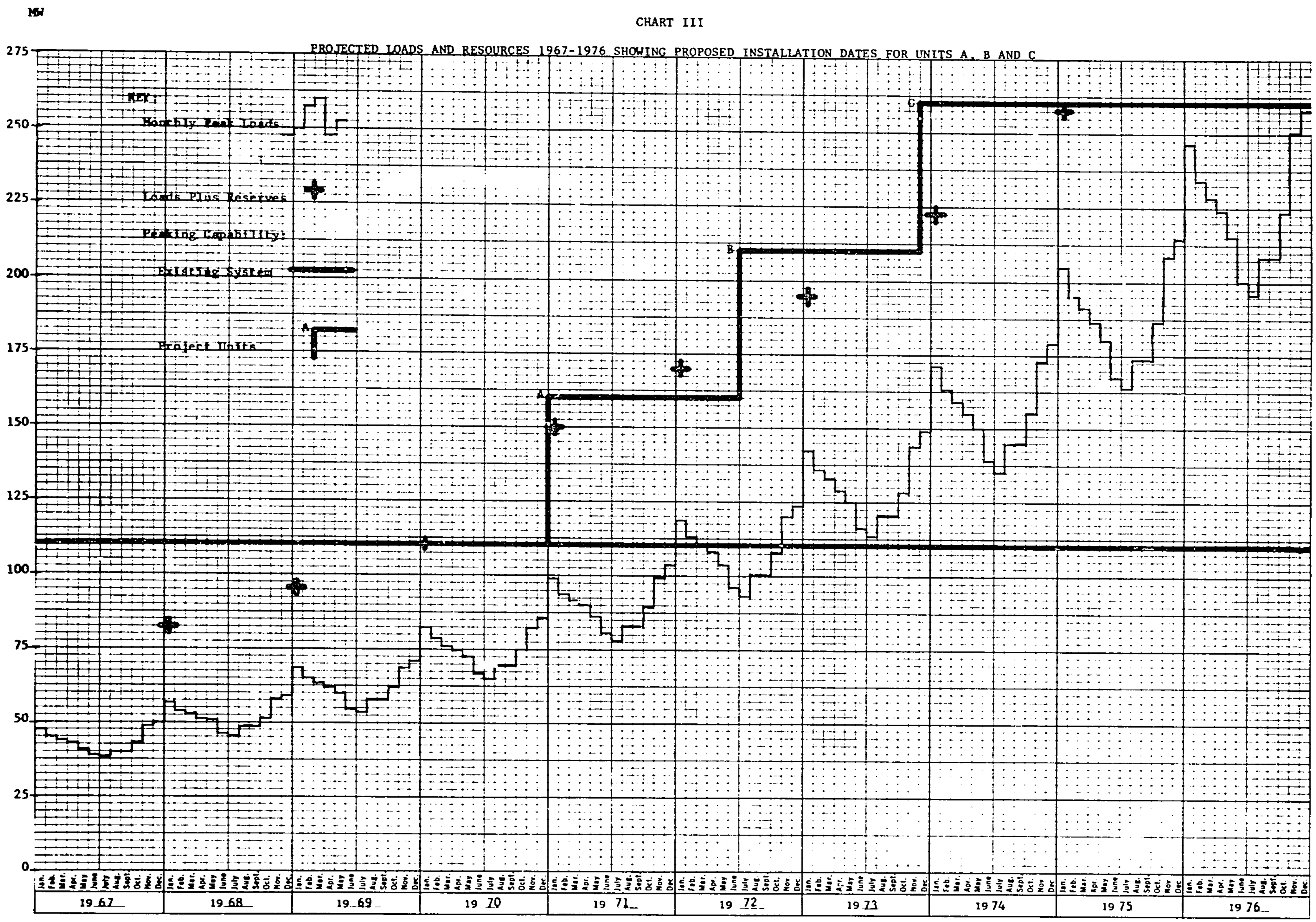
A third chart showing monthly peak and energy loads in future years should also be drawn with the capability of available and planned generation shown in comparison with the load projection. This chart is necessary to determine the proper timing of capacity installations. It also affords an opportunity to see how alternative plans would compare as discussed in the following section. An example of such a chart is Chart III on the following page.

Relation of Load Forecasts to the Design of Transmission Systems

The selection of the location, voltage and capacity of transmission lines and substations must be preceded by a study to determine the loads and load centers in the area to be served. Alternative systems can then be designed to most economically serve the area. Factors to be considered include not only the initial investment, but also annual maintenance and operation costs and capacity and energy losses. It is important that the transmission system and additions thereto be designed so that it remains a useful, low-cost system in the future as the system loads grow. For this reason, particular attention should be paid to the long-range forecasts of future loads and their locations.

CHART III

PROJECTED LOADS AND RESOURCES 1967-1976 SHOWING PROPOSED INSTALLATION DATES FOR UNITS A, B AND C



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Relation of Load Forecasts to the Design of Distribution Systems

Longer range load forecasts are essential to the design of economical distribution systems. The selection of distribution voltages and the selection of distribution substation sites should be consistent with the lowest cost design to meet future as well as present loads. Again, it is important to consider future investment, operation and maintenance costs and losses of energy and capacity in determining the design of the system.

III

ECONOMIC ASPECTS OF PROJECT SELECTION AND BENEFIT-COST ANALYSIS

Consideration of Alternative Projects

After it has been decided that a need exists for an AID-assisted power project, it is necessary to determine which particular project is best fitted to the need. There is usually more than one facility which will provide the capacity to meet the growing electrical requirements of a developing country. All of the proposed facilities may be feasible from the engineering point of view. For example, if the comparison of loads and resources indicates that 100,000 kilowatts of generating capacity will be required within three years, it might be possible to meet the requirements by the construction of hydroelectric, steam electric, diesel-electric, or gas-turbine generating units. It might also be possible to meet the requirements by installing one 100,000-kilowatt unit or two 50,000-kilowatt units or four 25,000-kilowatt units. From the engineering point of view, any of the possible alternative facilities would operate and could be supplied with labor and materials, including fuel and/or water.

From an economic point of view, however, only one of the proposed projects to add capacity will be the best solution, and that one will provide the additional capacity at the lowest cost.

In reviewing the feasibility of any power project, it is important to consider all possible alternatives to the proposed facilities. Any feasibility report should state which facilities were considered and the reasons for rejecting the facilities not proposed and include cost comparisons between the proposed facilities and the alternative facilities with the next lowest cost.

Discounted Cash-Flow

The method of making cost comparisons by the discounted cash-flow method involves estimating the annual cost of operation and maintenance for each year during the life of the facility, including the cost of interim renewals and replacements of facilities which have a shorter life than the project as a whole. Also included is the original investment made in each facility in the year in which it is constructed and the salvage value of the facility, which is taken as a negative value at the close of the last year of the facility's operating life.

Total cash expenditures are accumulated for each year, and the present value of each year's cash expenditures is computed using an interest rate equivalent to the opportunity cost of capital in the country or area where the project is to be constructed. Opportunity cost of capital may be defined as the rate of interest which could be earned by investing in the most profitable business of equivalent risk in the country.

It will be recognized that the determination of the opportunity cost of capital is likely to be imprecise, but the use of a rate of interest considerably in excess of the interest rate which will be paid for AID loan funds by either the borrowing country or the electric system is advisable. Thus, an opportunity rate of from ten to twelve percent would not be unusual in a country where interest charges paid on the electric system's long-term debt average from five to seven percent.

Alternative Locations

In addition to considering different types of facilities and different sizes of facilities, it is important that the best possible location of facilities be selected to meet the demonstrated need. The comparison of costs between locations is parallel to the comparison of alternative projects described above, using the discounted cash-flow method.

In general, electric generating plants should be located as close to the load center of a system as possible in order to minimize transmission investment, operation and maintenance costs and transmission losses. Other location factors, however, may offset added transmission costs and deserve careful consideration. For example, cooling water may be abundant and low in cost at one location and may be scarce or high in cost elsewhere. Or, air polution problems may be greater at one site than at another, requiring a more expensive stack or the use of expensive equipment to reduce the polution from stack gases.

The location for any hydroelectric project is unique, but thermal stations can usually be located in any of several plances on a system. Sometimes, where more than one major load center exists, the lowest system cost can be achieved by alternating locations of major generating station additions so that the capacity is distributed among the load centers. Where this is done, the short-run, higher-cost locations prove to be the lowest cost locations over the life of the additions.

Transmission and distribution line and substation locations should also consider the longer range growth of the system so that today's projects continue to be economical in the long run. Without long-range planning based on longer term load forecasts, installations made today may have to be replaced tomorrow because of functional obsolescence.

System Reliability

Experienced utility operators in the United States consider the continuity of service to be a major objective of all utility operations. This attitude toward service reliability does not cause economic problems in the United States because the alternative of service interruptions is costly to the utility customers and to the utility itself. Furthermore, public utilities in the United States are sensitive to public opinion, and nothing incurs more ill will than a series of service interruptions and the ensuing inconvenience to a public which has become used to a high degree of service continuity. It is believed that the act of providing a high degree of service reliability has within itself a built-in ratchet. Electric utilities may improve service reliability, but once the improvement is made, they may not reduce the reliability without suffering a substantial deterioration in their public image. It is believed, further, similar reactions occur to reductions in service reliability in other countries. For this reason, electric power projects which would result in a significant deterioration in the reliability of electric service should not be approved.

On the other hand, it is questionable whether all developing countries can afford the high degree of service continuity maintained by electric utilities in the United States. Set forth below are the methods of determining the economic degree of system reliability for any existing or proposed system based on the costs of service outages. Using these techniques, it is possible to compare the cost of improving the system reliability with the savings to the public which would accompany such improvement.

Each item of equipment used for generating, transmitting, and distributing electricity has a forced outage rate based upon the average experience of utilities in the use of such items of equipment. Overall reliability can be computed by multiplying together the outage rates of the individual items of equipment necessary to serve any single customer or group of customers.

Engineers estimate the prospective reliability of an electric system by the use of one of several methods. The most common method appears to be the "loss-of-load probability" method. This involves a determination of the anticipated "forced-outage rate" of each type of equipment needed to provide service. The forced outage rates, when subtracted from one hundred percent, describe the proportion of the service lives of the equipment which will be available for service. The resulting percents are called "availability rates." By multiplying these rates by each other, an availability rate for an entire system can be obtained. However, only those forced outages which occur at times when they restrict the delivery of power are relevant to system reliability. Other outages do not interrupt service. System availability rates must, therefore, be modified by a factor to estimate loss-of-load probability.[1/]

Generating Reserves

With respect to generating stations, it is customary on small systems to provide generating reserves at least equal to the capacity of the largest single unit on the system. This means that if the largest single unit fails at the time of the system peak, sufficient capacity will be available to carry the load. It is also generally assumed that routine maintenance

1/One of the clearest explanations of the mathematics involved in these calculations can be found on Page 1165 of Power Apparatus and Systems for February, 1961, in an article entitled "Application of Probability Methods to Generating Capacity Problems, an AIEE Committee Report."

of the largest unit can be carried on during the "off-peak period." Occasionally utilities have load patterns which are relatively flat and appear not to be sensitive to seasonal changes. In these cases, it may not be possible to remove the generating plant for periodic maintenance during off-peak periods, and additional generating facilities will need to be provided to carry the loads during the maintenance period.

It is recommended that the relevant electric systems be analyzed for degree of service reliability before addition of the proposed facilities included in the electric power project. If the analysis indicates that service continuity would deteriorate as a result of the construction of the project, it is recommended that sufficient facilities be added to the project to at least maintain the degree of service continuity achieved by the existing system. If it is proposed to improve service continuity by increasing the system's reserves by means of the proposed electric power project, a test should be made to determine the additional investment and other costs associated with this improvement. Once the incremental costs have been determined, they may be compared with the savings to the public achieved by the improved service continuity.

Costs to the public of service interruptions include, first, the net loss of revenue to the electric system. This can be computed by determining the average revenue per kilowatt-hour sold and the number of kilowatt-hours which cannot be delivered because of the outage. From the result of this calculation should be subtracted the incremental costs which would be saved because of the outage--mainly fuel costs. In addition, calculations should be made of the loss of production at the industrial plants which are shut down because of the outage. An alternative to the latter calculations would be the loss of wages resulting from the interruption of production, since for most industrial plants value added is roughly equivalent to wages paid. Other costs which can be developed include damage to equipment and spoilage of goods (for example, spoilage of perishables in refrigeration when power outages exceed the ability of the refrigerator to remain cold).

In the less-developed countries where manufacturing is in its infancy and where there are few cold storage plants, these costs will be minimal. It may prove cheaper in these countries to provide small standby generating plants to protect equipment and products in storage than to provide the necessary system reserves to reduce outages on the electric system. Recent experience in the United States indicates that strategic loads to which the potential damage from unanticipated outages is great should be protected by auxiliary generating equipment. Such has long been the practice of United States' hospitals, and it is now becoming common for office buildings to protect their elevator services, for food storage plants to protect the temperatures of their cold storage rooms, and for similar loads to install standby plants.

A possible alternative to providing redundancy on the system to protect against forced outages of equipment is to arrange the system so that service outages which cannot be eliminated can be shortened by spreading the shortage over a number of distribution feeders. Thus, on a 10,000-kilowatt system a shortage of 2,000 kilowatts might be alternated among five distribution feeders during the period required to restore the malfunctioning equipment to service.

Direct Economic Benefits

Economic benefits of several kinds may be available from proposed electric power projects. Direct benefits relate to either the value of the increased output of the electric system after the completion of the project or to a reduction in costs of service resulting from the completion of the project. The value of the increased output should be measured by the use of the electric rates assumed in making the power market projections.

If no change in rates is anticipated as a result of the project's construction, a first approximation of economic benefits can be made by applying the historical revenue per kilowatt-hour for the last year of record to the increased output anticipated for the project. If, however, it is expected that lower power costs from the project will result in a lowering of rates, the effect of the rate decrease on the overall revenues of the system must be taken into account in estimating the net increase in revenues resulting from the sale of the project's output.

It is usually not practical to apply specific rate schedules to the individual loads to be served. A reasonable estimate can be made by using the average overall revenue per kilowatt-hour assumed for each of the years of the life of the proposed facility and multiplying this average rate per kilowatt-hour by the output of the project (or the system) for each year.

Transmission and distribution projects may be essential to the expansion of the output of an electric system but may be financed separately. A fair comparison of the direct economic benefits and costs of such projects needs to include the total increase in electric revenues, as well as the total increase in electric-system costs. The latter, of course, will include the investments and operating costs of the additions to the generating facilities, as well as those of the transmission and distribution projects.

In some cases, transmission and distribution projects will be proposed to reduce electric system costs, even though they are not associated with increases in electric supply from generating plants. In these cases, the direct economic benefit will be the net reduction in system costs related to the projects.

Indirect Economic Benefits

Indirect power benefits are related to the increase in production of the economy resulting from the increase in its power supply. Not all increased production is measurable; however, in many cases estimates can be made of the estimated increase in factory production resulting from the substitution of electric energy for other forms of energy in the production process. Other indirect economic benefits from the creation of increased power resources may be improvements in the standard of living, improvements in communications, and, in some cases, improvements in the educational process. While these economic benefits are real, it is difficult to place a monetary value on them, and they will ordinarily be counted as plus values but not quantified in the benefit-cost analysis.

Project Costs

The project costs to be used in the benefit-cost analysis include both the costs of the initial investment and the operation and maintenance costs associated with the project during its service life. The operation and maintenance costs must also be supplemented by the costs of interim renewals and replacements for those facilities which have a lesser service life than the project as a whole. At the conclusion of the final year of the service life, the salvage value of the facilities should be treated as a negative cost. After determining the benefits and costs by years, each year's benefits and costs should be discounted by an interest rate equivalent to the opportunity cost of capital, as discussed in the previous chapter. The sums of these discounted annual cash flows are then compared.

In reviewing the estimated investment and operation and maintenance costs of the project, the analyst should check the reasonableness of such estimates by comparing the unit cost of the proposed project with unit costs for similar projects in other developing countries and in the United States. The analyst will find unit costs for steam-electric generating stations and hydroelectric generating stations in publications of the Federal Power Commission.[1/]

Thermal-Generating Station Costs

In general, thermal-station investment per kilowatt of capacity will vary inversely with the size of the generating units and with the size of the station. Other factors, however, must also be considered. A full outdoor or semi-outdoor steam-electric station will have a lower investment than a conventional (fully enclosed) plant of the same size; cooling towers will add to the cost of a steam-electric station; a station which requires coal or oil

1/These publications are:

(1) Steam Electric Plant Construction Cost and Annual Production Expenses, 1965, No. F.P.C. S-179, available from the U.S. Superintendent of Documents, Washington, D.C.; and

(2) Hydro-Electric Plant Construction Cost and Annual Production Expenses, 1965, No. F.P.C. S-180, available from the U.S. Superintendent of Documents, Washington, D.C.

storage and handling equipment will require more investment than a gas-fired station, but an oil-fired station will cost less than a coal-fired plant. Investment increases when operating steam pressures and temperatures are increased, but within certain technical limits, such increased investment is offset by lower fuel requirements.

Operating expenses per kilowatt-hour generally decrease as the size of the station increases, especially when the size of the generating units also increases. Essentially the same number of workers are needed to operate a small unit as a large unit. Heat rates (Btu's per kw.-hr.) are usually lower for large units than for small units, but they will also vary inversely with the average plant factor of the generating unit or station. This variation results in part from the loss of heat when a unit is shut down and then restarted.

Because of the possible savings in investment and operating expenses (including fuel), AID-financed power projects should always propose the largest generating units which are compatible with system objectives, not excluding system reliability.

Hydroelectric Generating Station Costs

By far the most important costs of hydroelectric stations are those associated with the investments in dams, reservoirs, waterways, and power stations. Since no fuel is consumed in the production of hydroelectric energy, costs other than interest and depreciation are the labor and materials used in the operation and maintenance of the station. These noninvestment costs do not normally vary with changes in the output of the plant, so it is customary to consider all hydroelectric-station costs as being fixed and the incremental costs of hydroelectric stations (those associated with an increase in output at a given plant) to be approximately zero. Hydroelectric station investment and operating costs also vary inversely with the size of generating units and plants. Also the "head" of a hydroelectric station (the distance between the elevation of the water in the forebay and the water in the tail-race of a station) is an important factor in determining its costs. Generally, the greater the head, the lower the investment per unit of capacity.

Allocation of Costs of Hydroelectric Projects

The feasibility of a hydroelectric power project will frequently depend upon how much of the investment in a multi-purpose project is allocated to power production. Most multi-purpose water control projects in the United States are built and operated by agencies of the United States Government (T.V.A., U.S. Bureau of Reclamation, or U.S. Army Corps of Engineers). These agencies over the years have evolved various methods of allocating the joint costs of multi-purpose water control projects to their various functions, such as power, irrigation, navigation, flood control, municipal water supply, industrial water supply, fisheries, and recreation. At the present time the preferred method of cost allocation is the "separable costs-remaining benefits method." A brief description of this method is attached as Appendix F. It should be kept in mind that all cost allocations are arbitrary, and none of them are "correct." It may, therefore, be desirable to use a different method of cost allocation in certain situations if the chosen method will achieve more desirable results than the "separable costs-remaining benefits method."

Transmission Project Costs

Economies of scale apply to both transmission lines and substations. In particular, unit capacity costs tend to vary inversely with voltage. Best economy is therefore achieved by using the highest transmission voltages which can be justified by anticipated line and substation loadings. If an electric system has already established transmission and sub-transmission voltage levels, however, adding different voltage facilities which will require extra transformer capacity may be uneconomic.

Distribution Project Costs

Here again the economies of scale are important, and the highest voltage system which can be reasonably loaded in the near future will generally prove to be the most economic. Another important factor in the cost and design criteria of distribution systems is customer density. Generally, the more customers served per mile of distribution circuit, the less will be the cost per unit of capacity or per customer. In very densely populated areas, however, it is frequently necessary to place all distribution facilities underground. This may result in a far more costly distribution system per unit of capacity than can be built in less densely populated areas where aerial construction is adequate.

In recent years, American utilities and manufacturers have been developing lower-cost undergrounding methods and materials for distribution systems. This has come about as a direct result of public pressure to improve the appearance of public streets. While in most cases there is still a cost differential in favor of overhead compared with underground construction, technology is closing the gap and may in time eliminate it.

In many places where high winds and sleet storms are common, underground systems require less maintenance than overhead lines, and this offsets to a considerable extent the higher investment in underground facilities.

General

Operating and maintenance costs should be scrutinized to detect and identify any hidden subsidies or taxes included in the estimate. Where the supply of fuel is a government monopoly or a government-controlled monopoly, an attempt should be made to determine what the cost of fuel would be from an independent source, and any differences between the cost of fuel estimated by the consultant and the independent price should be pointed out.

Working Capital Requirements

In addition to the capital-cost estimates discussed above, some power projects will require that the working capital of the operating utility or agency be increased as a result of the construction of the power project. Allowances for working capital are necessary to cover the payments in advance of costs which are later recovered by the collection of revenues. In the United States, electric utilities commonly include in their working capital requirements the average investment in materials and supplies (determined by averaging the year-end inventory figures), average prepayments (determined in a like manner), and one-eighth of the annual electric operation and maintenance expenses (not including the cost of purchased power). From this is deducted one-half of the Federal Income Taxes paid during the year. It will be seen that this formula assumes a time lag of one and one-half months between the payment of wages and operation and maintenance expenses, including fuel, and the collection of revenues. The logic behind this assumption is that the utility bills the customer at the end of a monthly period, and the average customer pays the bill within fifteen days. Obviously, if the utility is on a two-month billing cycle, more working capital will be required.

It should be noted that in most cases the amount of working capital stated as a percent of the investment in the facilities to be added will usually be smaller than the relation of existing working capital related to a system's existing investment. This is true because prepayments and materials and supplies are not likely to increase in proportion to the increased investment in the additional facilities.

Shadow Prices

The analyst should be concerned with the content of the cost estimates for the proposed project and the assumptions made therein concerning the cost of labor, the foreign exchange rate, and the prices of local and foreign materials and equipment. To the extent possible, wage rates should be checked against the prevailing wages for similar work within the country. The foreign exchange rate should be identified as either the actual free-market rate or the pegged rate of the borrowing country. If it is the latter, it is important to estimate what the free-market rate of exchange would be and to recompute both the economic and financial feasibility equations using "shadow prices" for items bought abroad. (These shadow prices are the estimated prices adjusted by a factor to account for the differences between the official rate of exchange and the estimated market rate of exchange of the local currency.)

If other pegged prices--for example, for labor or for fuel--are detected, similar analyses using shadow prices for these inputs should be made.

Comparison of Costs and Benefits

The discounted cash-flow analysis, discussed earlier as the basis for comparing alternative projects, is also used to compare economic benefits and costs. The estimated cash outlay during each year from the start of a project until the facilities are retired is discounted at the opportunity cost of capital. Similarly, the economic benefits are estimated for each year from the completion of the project until its retirement and discounted at the same rate. The sum of the discounted streams of benefits and costs can then be compared to determine the soundness or economic feasibility of the project.

IV

FINANCIAL ASPECTS OF ELECTRIC POWER PROJECTS

Financial Feasibility

To be financially feasible, an electric power project must produce enough revenue or save enough costs during its economic life: to pay its operating and maintenance costs, including interim replacements; to meet the interest on and the amortization of the investment; and to provide a reasonable "margin" for unforeseen contingencies. This margin is sometimes referred to as "coverage." Its first use is to protect the lender or bondholder against default of interest or principal payments. If the project is successful, however, it will usually be available to finance additions to the electric system to meet a portion of its load growth. A measure of the reasonableness of the margin may be its relation to the unamortized investment in the project. If the margin plus the interest paid in each year would approximate the opportunity cost of capital, when applied to the unamortized investment, the total return would be considered reasonable.

Electric Rates and Revenues

While the general purposes of market prices and electric rates are the same (i.e., to balance demand and supply), the similarity ends at that point. Market prices of commodities are expected to fluctuate whenever market conditions change, while electric rates are expected to be constant in the short run and to change infrequently even in the long run. Market prices respond to competitive forces. Electric rates generally relate to a monopoly and are usually established administratively.

Commodity market prices tend to be uniform for each product. Electric rates are usually established for a number of classes--each paying a different rate for an identical commodity (i.e., electric energy).

Because a high proportion of the total costs of electric service is fixed, it is advantageous to establish rates which provide substantial quantity discounts. Such rates tend to follow the cost of service and to promote greater use of existing facilities and, thus, promote economic efficiency.

Rates for large quantities of power--whether for resale or for industrial use--are usually "two-part" rates. These rates impose a "demand charge" based on the largest number of kilowatt-hours delivered during any one hour (or half-hour) during each month (or each year). The demand charge is usually stated as a price per kilowatt of maximum demand.

The other part of the two-part rate is the energy charge, which is imposed on the total number of kilowatt-hours purchased during each month. Typically, the charge per kilowatt-hour varies inversely with the number of kilowatt-hours purchased. This is accomplished by establishing "blocks" of energy with lower rates for each succeeding block sold.

Rates to ultimate consumers such as residential and commercial customers are usually single-part rates and are based solely upon the monthly energy consumption of each customer. Such rates also customarily decrease for the succeeding blocks of energy purchased (i.e., the rate per kilowatt-hour decreases with each successive block). Frequently, a high rate is charged for a small number of kilowatt-hours included in the first block, and each customer is required to pay the rate for the initial block of energy whether or not he uses this amount. Usually this "minimum bill" is designed to be high enough to offset the cost of reading the customer's meter and collecting his bill.

Because of the quantity discount features of typical electric rates, the average cost of electric energy decreases as the average use of energy per customer increases--even though no change in rate schedules is made. In analyzing future revenues for electric systems where average customer usage is expected to increase, this factor should be taken into consideration.

Relation of Costs to Usage and Promotional Rates

Electric-system costs per unit of output almost always decrease as the system-load factor increases. This happens because a large part of the system costs are fixed, i.e., they do not change (or they change very little) as output increases. For example, the customer's electric service connection to the distribution system which is needed to provide service one hour per day (or per year) will be sufficient to provide the same level of service twenty-four hours a day.

Electric systems in setting rates attempt to promote additional sales by pricing large usage at low rates and, thus, induce their existing customers to use more energy. Frequently these low rates are available to customers only if they install certain combinations of basic appliances such as an electric range (cooking stove) and water heater.

Construction Schedule

The applicant's feasibility report will include a construction schedule showing the period required for each major step in the development of the project, including engineering, land acquisition, site preparation, plant construction, and installation and testing of equipment. While this will be of particular interest to the AID Technical Support staff, the analyst will wish to familiarize himself with the time period involved, since the construction period will be the basis for the interest during construction added to the construction cost.

The analyst may also wish to check the assumed delivery time for major items of equipment to see that they are realistic with respect to the time required by American manufacturers for the fabrication of the equipment. For the most part, large power equipment is not a shelf item and is manufactured to order on a custom basis. From time to time the manufacturers' order boards become clogged with domestic orders so that very long lead times must be assumed for equipment to be delivered abroad. The analyst will also wish to satisfy himself that sufficient time has been allowed for overseas transportation. Finally, he will wish to make sure that facilities--rail, highway or barge--are adequate to move the heavy equipment from dockside to the plant site in the applicant's country.

Interest During Construction

It is customary for an applicant to borrow the entire sum required for an AID-assisted project prior to the start of construction. Consequently, the applicant will need to pay interest on the sum during the period of construction. This interest becomes a part of the overall cost of the project and should be added to it. In some cases, it will be possible to employ unused funds on a short-term basis and receive an offsetting interest payment. If this is contemplated, the interest during construction can be reduced by the amount of interest earned on the idle construction funds. In other cases it may be possible to borrow the money in successive amounts and thus reduce the amount of interest which needs to be paid during construction.

Contingencies

The estimated investment will usually include an item for contingencies in order that sufficient funds will be borrowed to complete the project. By the time the feasibility report is completed by the applicant, many of the uncertainties concerning the cost of the project should have been resolved. Nevertheless, not all cost estimates will be definitive, and an allowance of ten percent for contingencies would appear to be proper for thermal-generation stations. In the case of hydroelectric projects, it is not possible to estimate precisely the quantities of excavation, fill, and concrete which will be required. To allow for additional quantities, an allowance of fifteen percent for contingencies would not be unusual.

Escalation During Construction Period

The allowance for contingencies noted above should not be confused with the allowance for escalation. Allowances for escalation are made to cover the possible increases in prices usually due to cost inflation in the United States or in the applicant's country. Construction costs have risen almost every year since World War II in the United States, and the best estimates based on today's prices are likely to be wrong because of increased wage rates and increased cost of construction supplies and machinery. In addition, some manufacturers include in their sales contracts for large equipment provisions for escalation of price based on changes in the value of money during the period the equipment or machinery is being manufactured. It is realistic to take into account these prospective changes in cost due to decreases in the value of money during the long construction period of the project. It is also prudent to estimate probable escalation of construction costs for five years beyond the anticipated construction period, since delays can easily extend the period and inflation may be a continuing phenomena.

Escalation Allowances During Operations

In the earlier section on electric rates it was noted that it is normal for rates to be changed infrequently. It is not uncommon for electric system costs to increase due to inflation over a considerable period of time before rates are increased to compensate for the new cost level. If inflation is expected to continue into the future for an indefinite period, it will be necessary to consider the lag of revenue behind cost increases in analyzing the financial feasibility of a project.

Demonstration of Financial Feasibility

The attached table shows how a 100,000-kilowatt steam-electric generating plant project might be proved financially feasible. The annual revenues (column 10) are determined by assuming a rate of $1.50 per kilowatt per month ($18/kw/yr.) of capacity (column 1) and an average rate of one-half cent (5 mills) per kilowatt-hour sold.

Initially the project plant will be used on base load and will operate at full capacity for 7,884 hours each year, i.e., at ninety percent

DEMONSTRATION OF FINANCIAL FEASIBILITY OF A 100,000 KW STEAM-ELECTRIC GENERATING PLANT ADDITION

Year	Capacity Available Kw	Energy Generated Mwh	Unamortized Debt End of Year	Debt Service	Operation & Maintenance Except Fuel	Annual Fuel Expense	Renewals & Replacements @ .35% of Investment	Administrative & General Expense	Total Annual Charges	Annual Revenues From Power Sales	Surplus or Coverage	Return On Unamortized Debt
1967			$ 2,000,000									
1968			6,500,000									
1969			11,000,000									
1970			15,000,000									
1971	100,000	788,400	14,865,392	$1,034,608	$500,000	$3,035,340	$52,500	$125,000	$4,747,448	$5,742,000	$994,552	12.69
1972	100,000	788,400	14,722,708	1,034,608	500,000	3,035,340	52,500	125,000	4,747,448	5,742,000	994,552	12.76
1973	100,000	788,400	14,511,462	1,034,608	500,000	3,035,340	52,500	125,000	4,747,448	5,742,000	994,552	12.83
1974	100,000	788,400	14,411,142	1,034,608	500,000	3,035,340	52,500	125,000	4,747,448	5,742,000	994,552	12.90
1975	100,000	788,400	14,241,203	1,034,608	500,000	3,035,340	52,500	125,000	4,747,448	5,742,000	994,552	12.98
1976	100,000	657,000	14,061,067	1,034,608	500,000	2,588,580	52,500	125,000	4,300,688	5,085,000	784,312	11.58
1977	100,000	657,000	13,870,123	1,034,608	500,000	2,588,580	52,500	125,000	4,300,688	5,085,000	784,312	11.65
1978	100,000	657,000	13,667,722	1,034,608	500,000	2,588,580	52,500	125,000	4,300,688	5,085,000	784,312	11.74
1979	100,000	657,000	13,453,177	1,034,608	500,000	2,588,580	52,500	125,000	4,300,688	5,085,000	784,312	11.83
1980	100,000	657,000	13,225,760	1,034,608	500,000	2,588,580	52,500	125,000	4,300,688	5,085,000	784,312	11.93
1981	100,000	569,400	12,984,698	1,034,608	500,000	2,294,682	52,500	125,000	4,006,790	4,647,000	640,210	10.93
1982	100,000	569,400	12,729,172	1,034,608	500,000	2,294,682	52,500	125,000	4,006,790	4,647,000	640,210	11.03
1983	100,000	569,400	12,458,314	1,034,608	500,000	2,294,682	52,500	125,000	4,006,790	4,647,000	640,210	11.14
1984	100,000	569,400	12,171,205	1,034,608	500,000	2,294,682	52,500	125,000	4,006,790	4,647,000	640,210	11.26
1985	100,000	569,400	11,866,869	1,034,608	500,000	2,294,682	52,500	125,000	4,006,790	4,647,000	640,210	11.39
1986	100,000	438,000	11,544,273	1,034,608	500,000	1,800,180	52,500	125,000	3,512,288	3,990,000	477,712	10.14
1987	100,000	438,000	11,202,321	1,034,608	500,000	1,800,180	52,500	125,000	3,512,288	3,990,000	477,712	10.26
1988	100,000	438,000	10,839,852	1,034,608	500,000	1,800,180	52,500	125,000	3,512,288	3,990,000	477,712	10.41
1989	100,000	438,000	10,455,635	1,034,608	500,000	1,800,180	52,500	125,000	3,512,288	3,990,000	477,712	10.57
1990	100,000	438,000	10,048,365	1,034,608	500,000	1,800,180	52,500	125,000	3,512,288	3,990,000	477,712	10.75
1991	100,000	350,400	9,616,659	1,034,608	500,000	1,471,680	52,500	125,000	3,183,788	3,552,000	368,212	9.83
1992	100,000	350,400	9,159,051	1,034,608	500,000	1,471,680	52,500	125,000	3,183,788	3,552,000	368,212	10.02
1993	100,000	350,400	8,673,986	1,034,608	500,000	1,471,680	52,500	125,000	3,183,788	3,552,000	368,212	10.25
1994	100,000	350,400	8,159,817	1,034,608	500,000	1,471,680	52,500	125,000	3,183,788	3,552,000	368,212	10.51
1995	100,000	350,400	7,614,798	1,034,608	500,000	1,471,680	52,500	125,000	3,183,788	3,552,000	368,212	10.84
1996	100,000	262,800	7,037,078	1,034,608	500,000	1,151,064	52,500	125,000	2,863,172	3,114,000	250,828	9.56
1997	100,000	262,800	6,424,695	1,034,608	500,000	1,151,064	52,500	125,000	2,863,172	3,114,000	250,828	9.90
1998	100,000	262,800	5,775,569	1,034,608	500,000	1,151,064	52,500	125,000	2,863,172	3,114,000	250,828	10.34
1999	100,000	262,800	5,087,495	1,034,608	500,000	1,151,064	52,500	125,000	2,863,172	3,114,000	250,828	10.93
2000	100,000	262,800	4,358,137	1,034,608	500,000	1,151,064	52,500	125,000	2,863,172	3,114,000	250,828	11.76
2001	100,000	175,200	3,585,017	1,034,608	500,000	797,160	52,500	125,000	2,509,268	2,676,000	166,732	10.65
2002	100,000	175,200	2,765,510	1,034,608	500,000	797,160	52,500	125,000	2,509,268	2,676,000	166,732	12.03
2003	100,000	175,200	1,896,833	1,034,608	500,000	797,160	52,500	125,000	2,509,268	2,676,000	166,732	14.79
2004	100,000	175,200	976,035	1,034,608	500,000	797,160	52,500	125,000	2,509,268	2,676,000	166,732	23.08
2005	100,000	175,200	-	1,034,597	500,000	797,160	52,500	125,000	2,509,268	2,676,000	166,732	

Notes to Accompany Demonstration of Financial Feasibility

Col. 1 Entire capacity of plant assumed to be available during thirty-five year life.

Col. 2 Unit used on base load at 90 percent plant factor for first five years; then at 75 percent, 65 percent, 50 percent, 40 percent, 30 percent and 20 percent plant factors during subsequent five-year periods.

Col. 3 Debt increases during construction period of four years and is amortized at 6 percent interest over thirty-five years using level debt service.

Col. 4 Debt interest capitalized during construction period. Level payment debt service is 6.897386 percent of $15 million.

Col. 5 Based on United States experience.

Col. 6 Assumes fuel at $0.35 per million Btu and a heat rate increasing from 11,000 Btu per kwh in the first five years of operation to 11,250 Btu, 11,500 Btu, 11,750 Btu, 12,000 Btu, 12,500 Btu, and 13,000 Btu in subsequent five-year periods.

Col. 7 Assumes a straight-line annual contribution which together with interest will provide sufficient funds to meet renewal and replacement costs as they occur. Based on United States experience.

Col. 8 Based on U.S. experience, twenty-five percent of operation and maintenance costs.

Col. 9 Sum of columns 4, 5, 6, 7 and 8.

Col. 10 Revenue computed at $18 per kilowatt per year ($1.50 per kilowatt per month) and one-half cent (five mills) per kilowatt-hour.

Col. 11 Column 10 minus column 9.

Col. 12 Column 11 divided by column 3, plus 6 percent (figure for year 2005 not significant).

plant factor. Since the electric system is expected to add newer, larger, and more efficient stations in the future, however, the average plant factor of the project decreases during its service life, so that during each of its last five years of operation it will operate only 1,752 hours.

During the construction period the funds borrowed to meet construction costs increase each year until the total investment of $15 million has been made at the end of 1970 (column 3). Subsequently, by means of a level debt payment at six percent interest over thirty-five years (factor is 6.897386), the debt is amortized. (It is assumed that the salvage value equals the cost of dismantling the plant at the end of its service life.)

Operating and maintenance costs are based on United States experience and are estimated at $500,000 per year (column 5). Fuel expenses (column 6) are based on a fuel cost of 35 cents per million Btu and a heat rate increasing from 11,000 Btu per kilowatt-hour when operating at ninety percent plant factor to 13,000 Btu in the last five years of operation.

Renewals and replacements of equipment and plant items with service lives shorter than thirty-five years are provided for by annual contributions to a sinking fund of an amount equivalent to 0.35 percent of the original investment (column 7). Administrative and general costs, which include supervision, accounting, insurance and similar expenses, are estimated at twenty-five percent of the operation and maintenance expenses in line with American experience.

A comparison of total expenses and total revenues shows a surplus available for contingencies (column 11). Adding interest on the unamortized investment to this surplus and dividing by the investment (column 3) yields the return shown in column 12. This appears to be a reasonable return and would likely be consistent with the opportunity cost of capital.

United States electric utilities which are privately owned usually earn an overall rate of return on investments in utility property of from twelve to fourteen percent before payment of Federal Income Taxes.

GLOSSARY

Definitions are given below for some of the more often used electric utility terms. Unless the definition is marked with an asterisk (*) it is quoted from the Edison Electric Insitute Glossary, while those so marked are quoted from the Federal Power Commission Glossary.[1/]

ALTERNATING CURRENT (A-C) An electric current that reverses its direction of flow periodically (see FREQUENCY) as contrasted to direct current.

AVERAGE ANNUAL USE PER CUSTOMER Average annual kilowatt-hours used per customer. Usually refers to residential service. Annual kilowatt-hour sales divided by the average number of customers for the same period. A customer with two or more meters at the same location because of special services, such as water heating, etc., is counted as one customer.

AVERAGE NUMBER OF CUSTOMERS The average of the number of customers counted regularly once in each of 12 consecutive months.

AVERAGE REVENUE PER KILOWATT-HOUR SOLD (AVERAGE PRICE OF ELECTRICITY) Revenue from the sale of electricity (exclusive of forfeited discounts and penalties) for a particular class of service divided by the corresponding number of kilowatt-hours sold.

BASE LOAD The minimum load over a given period of time.

BASE LOAD STATION A generating station which is normally operated to take all or part of the base load of a system and which, consequently, operates essentially at a constant output.

1/Glossary of Electric Utility Terms, Financial and Technical (New York: Edison Electric Institute Publication No. 61-31, 1961). U.S. Federal Power Commission, Glossary of Important Power and Rate Terms, Abbreviations, and Units of Measurement, 1965.

BTU (BRITISH THERMAL UNIT) The standard unit for measuring quantity of heat energy, such as the heat content of fuel. It is the amount of heat energy necessary to raise the temperature of one pound of water one degree Fahrenheit.

CONTENT OF FUEL, AVERAGE The heat value per unit quantity of fuel expressed in Btu as determined from tests of fuel samples. Examples: Btu per pound of coal, per gallon of oil, etc.

EQUIVALENT OF FUELS BURNED The Btu equivalent of fuels burned is the aggregate heat energy of all fuels burned. It is derived by calculating total Btu content of each kind of fuel burned and totalizing to establish the Btu content of all fuels burned.
Based on its Btu content, any kind and quantity of fuel burned may be expressed as an equivalent.

CAPACITY The load for which a generating unit, generating station, or other electrical apparatus is rated as stated usually by manufacturer's name plate ratings. Sometimes used synonymously with CAPABILITY. See NAME PLATE RATING.

DEPENDABLE The load-carrying ability for the time interval and period specified when related to the characteristics of the load to be supplied. Dependable capacity of a station is determined by such factors as capability, operating power factor, and portion of the load which the station is to supply.

HYDRAULIC The manufacturer's rating of a hydroelectric generating unit or the sum of such ratings for all units in a station or stations.

INSTALLED GENERATING See NAME PLATE RATING.

PEAKING Generating units or stations which are available to assist in meeting that portion of peak load which is above base load.

CAPACITY (Continued)

PURCHASE The amount of firm power available for purchase from a source outside the system to supply energy or reserve capacity.

RESERVE

COLD Thermal generating units available for service but not maintained at operating temperature.

HOT Thermal generating units available, up to temperature and ready for service, although not actually in operation.

SPINNING Generating units connected to the bus and ready to take load.

THERMAL The manufacturer's rating of a thermal electric generating unit or the sum of such ratings for all units in a station or stations.

CAPACITY FACTOR The ratio of the average load on a machine or equipment for the period of time considered to the capacity rating of the machine or equipment.

CIRCUIT (ELECTRIC) A circuit is a conductor or a system of conductors through which an electric current flows or is intended to flow.

CONSTRUCTION EXPENDITURES (GROSS) Expenditures (including Interest Charged to Construction) for construction including additions to and betterments, renewals, and replacements of utility plant (including land and land rights) during a specific period, but not money spent for maintenance or for the acquisition of existing utility plant.

*CURVE

*DURATION CURVE A curve of quantities plotted in descending order of magnitude against time intervals for a specified period. The coordinates may be absolute quantities or percentages.

*CURVE (Continued)

*INTEGRATED ENERGY CURVE A curve of demand versus energy showing the amount of energy represented under a load curve, or a load duration curve, above any point of demand. The coordinates may be absolute quantities or percentages. (Also referred to as a "peak percent curve.")

*LOAD CURVE A curve of demand versus time of occurrence showing in chronological sequence the magnitude of the load for each unit of time of the period covered.

CUSTOMER (ELECTRIC) A customer is an individual, firm, or organization who purchases electric service at one location under one rate classification, contract, or schedule. If service is supplied to a customer at more than one location, each location shall be counted as a separate customer.

DEMAND The rate at which electric energy is delivered to or by a system, part of a system, or a piece of equipment expressed in kilowatts, kilovolt-amperes, or other suitable unit at a given instant or averaged over any designated period of time. The primary source of "Demand" is the power-consuming equipment of the customers....

ANNUAL MAXIMUM The greatest of all demands of the load under consideration which occurred during a prescribed demand interval in a calendar year.

ANNUAL SYSTEM MAXIMUM The greatest demand on an electric system during a prescribed demand interval in a calendar year.

AVERAGE The demand on, or the power output of, an electric system or any of its parts over any interval of time, as determined by dividing the total number of kilowatt-hours by the number of units of time in the interval.

DEMAND (Continued)

COINCIDENT The sum of two or more demands which occur in the same demand interval.

MAXIMUM The greatest of all of the demands of the load under consideration which has occurred during a specified period of time. (Peak load.)

NON-COINCIDENT The sum of two or more individual demands which do not occur in the same demand interval. Meaningful only when considering demands within a limited period of time, such as a day, week, month, a heating or cooling season, and usually for not more than one year.

DEMAND CHARGE The specified charge to be billed on the basis of the billing demand, under an applicable rate schedule or contract.

*DISTRIBUTION SYSTEM That portion of an electric system used to deliver electric energy from points on the transmission or bulk power system to the consumers.

DIVERSITY That characteristic of variety of electric loads whereby individual maximum demands usually occur at different times. Diversity among customers' loads results in diversity among the loads of distribution transformers, feeders, and substations, as well as between entire systems. (See also LOAD DIVERSITY.)

DIVERSITY FACTOR The ratio of the sum of the non-coincident maximum demands of two or more loads to their coincident maximum demand for the same period.

*EFFICIENCY, STATION OR SYSTEM The ratio of the energy delivered from the station or system to the energy received by it under specified conditions.

*ELECTRIC RATE The unit prices and the quantities to which they apply as specified in an electric rate schedule or sales contract.

*ENERGY That which does or is capable of doing work. It is measured in terms of the work it is capable of doing; electric energy is usually measured in kilowatt-hours.

ENERGY CHARGE That portion of the billed charge for electric service based upon the electric energy (kilowatt-hours) supplied, as contrasted with the demand charge.

FREQUENCY The number of cycles through which an alternating current passes per second. Frequency has been generally standardized in the electric utility industry at 60 cycles per second.

FUNDED DEBT The Long-Term Debt which has arisen from the sale or assumption of debt securities with maturities of more than one year.

GENERATING STATION (GENERATING PLANT) A station at which are located prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or nuclear energy into electric energy.

GENERATING UNIT An electric generator together with its prime mover .

GENERATION, ELECTRIC This term refers to the act or process of transforming other forms of energy into electric energy; or to the amount of electric energy so produced, expressed in kilowatt-hours.

GROSS The total amount of electric energy produced by the generating units in a generating station or stations.

NET Gross generation less kilowatt-hours consumed out of gross generation for station use.

GENERATOR, ELECTRIC A machine which transforms mechanical energy into electric energy.

HEAT RATE A measure of generating station thermal efficiency, generally expressed in Btu per net kilowatt-hour. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting net kilowatt-hour generation.

HYDRO A term used to identify a type of generating station or power or energy output in which the prime mover is driven by water power.

INCREMENTAL COSTS (ENERGY) The cost of generating or transmitting additional electricity above some previously determined base amount.

INTERDEPARTMENTAL SALES Kilowatt-hour sales of electric energy to other departments (gas, steam, water, etc.) and dollar value of such sales if the charges are at tariff or other specified rates for the energy supplied.

KILOVOLT (KV) 1,000 volts (defined herein).

KILOWATT (KW) 1,000 watts (defined herein).

KILOWATT-HOUR (KWHR) The basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour.

LOAD DIVERSITY Load diversity is the difference between the sum of the maxima of two or more individual loads and the coincident or combined maximum load, usually measured in kilowatts.

LOAD FACTOR The ratio of the average load in kilowatts supplied during a designated period to the peak or maximum load occurring in that period.

LONG-TERM DEBT Includes outstanding mortgage bonds, debentures, advances, and notes which are due one year or more from date of issuance. The portion of such securities (inclusive of sinking fund requirements) that is due within one year from the date of the balance sheet is usually included in Current and Accrued Liabilities.

LOSS (LOSSES) The general term applied to energy (kilowatt-hours) and power (kilowatts) lost in the operation of an electric system. Losses occur principally as energy transformations from kilowatt-hours to waste heat in electrical conductors and apparatus.

AVERAGE The total difference in energy input and output or power input and output (due to losses), averaged over a time interval and expressed either in physical quantities or as a percentage of total input.

ENERGY The kilowatt-hours lost in the operation of an electric system.

LINE Kilowatt-hours and kilowatts lost in transmission and distribution lines under specified conditions.

PEAK PER CENT The difference between the power input and output, as a result of losses due to the transfer of power between two or more points on a system at the time of maximum load, divided by the power input.

SYSTEM The difference between the system net energy or power input and output resulting from characteristic losses and unaccounted-for between the sources of supply and the metering points of delivery on a system.

MEGAWATT (MW) 1,000 kilowatts.

NAME PLATE RATING The full-load continuous rating of a generator and its prime mover or other electrical equipment under specified conditions as designated by the manufacturer. It is usually indicated on a name plate attached mechanically to the individual machine or device. Name plate rating is generally less than, but for older equipment may be greater than, demonstrated capability of the installed machine.

*OUTPUT The amount of power or energy delivered from a piece of equipment, station, or system.

PEAK LOAD STATION A generating station which is normally operated to provide power during maximum load periods.

*PLANT FACTOR The ratio of the average load on the plant for the period of time considered to the aggregate rating of all the generating equipment installed in the plant.

*PLANT (STATION)

BASE LOAD PLANT A power plant which is normally operated to carry base load and which, consequently, operates essentially at a constant load.

*FOSSIL-FUEL PLANT An electric power plant utilizing fossil fuel, coal, lignite, oil, or natural gas, as its source of energy.

*HYDROELECTRIC PLANT An electric power plant utilizing falling water for the motive force of its prime movers.

*NUCLEAR POWER PLANT An electric generating station utilizing the energy from a nuclear reactor as the source of power.

*PEAK LOAD PLANT A power plant which is normally operated to provide power during maximum load periods.

*POWER PLANT (GENERATING STATION) A generating station at which are located prime movers, electric generators, and auxiliary equipment for producing electric energy.

*PUMPED STORAGE PLANT A power plant utilizing an arrangement whereby electric energy is generated for peak load use by utilizing water pumped into a storage reservoir usually during off-peak periods. A pumped storage plant may also be used to provide reserve generating capacity.

*PLANT (STATION) (Continued)

*RUN-OF-RIVER PLANT A hydroelectric power plant utilizing pondage or the flow of the stream as it occurs.

*STEAM-ELECTRIC PLANT An electric power plant utilizing steam for the motive force of its prime movers.

POWER (ELECTRIC) The time rate of generating, transferring or using electric energy, usually expressed in kilowatts.

SATURATION, APPLIANCE The quantity of a specific household appliance connected to a utility's lines divided by the total number of domestic customers.

SATURATION, CUSTOMER The total number of customers served with electricity divided by the sum of the total served and unserved premises in a specified service area.

STANDBY SERVICE Service that is not normally used but which is available through a permanent connection in lieu of, or as a supplement to, the usual source of supply.

STATION USE (GENERATING) The kilowatt-hours used at an electric generating station for such purposes as excitation and operation of auxiliary and other facilities essential to the operation of the station. Station use includes electric energy supplied from house generators, main generators, the transmission system, and any other sources for this purpose. The quantity of energy used is the difference between the gross generation plus any supply from outside the station and the net output of the station.

STEAM-ELECTRIC GENERATING STATION An electric generating station utilizing steam for the motive force of its prime movers.

SUBSTATION A substation is an assemblage of equipment for the purpose of switching and/or changing or regulating the voltage of electricity. Service equipment, line transformer installations, or minor distribution or transmission equipment are not classified as substations. See also SWITCHING STATION.

STEP-DOWN A step-down substation is used to change electricity from a higher to a lower voltage.

STEP-UP A step-up substation is used to change electricity from a lower to a higher voltage.

SUMMER PEAK The greatest load on an electric system during any prescribed demand interval in the summer (or cooling) season....

SWITCHING STATION An assemblage of equipment for the sole purpose of tying together two or more electric circuits through switches, selectively arranged to permit a circuit to be disconnected, as in case of trouble, or to change the electric connections between the circuits. A type of substation.

SYSTEM, ELECTRIC The physically connected generation, transmission, distribution, and other facilities operated as an integral unit under one control, management or operating supervision.

THERMAL A term used to identify a type of electric generating station, capacity, or capability, or output in which the source of energy for the prime mover is heat.

TRANSFORMER An electromagnetic device for changing the voltage of alternating-current electricity.

TRANSMISSION The act or process of transporting electric energy in bulk from a source or sources of supply to other principal parts of the system or to other utility systems. Also a functional classification relating to that portion of utility plant used for the purpose of transmitting electric energy in bulk to other principal parts of the system or to other utility systems, or to expenses relating to the operation and maintenance of transmission plant.

TRANSMISSION LINE A line used for bulk transmission of electricity between a generating or receiving point and major substations or delivery points.

TURBINE-GENERATOR A rotary-type unit consisting of a turbine and an electric generator.

TURBINE (HYDRAULIC) An enclosed rotary type of prime mover in which mechanical energy is produced by the force of water directed against blades fastened to a vertical or horizontal shaft....

TURBINE (STEAM) OR (GAS) An enclosed rotary type of prime mover in which heat energy in steam or gas is converted into mechanical energy by the force of a high velocity flow of steam or gases directed against successive rows of radial blades fastened to a central shaft.

VOLT The unit of electromotive force or electric pressure analogous to water pressure in pounds per square inch. It is the electromotive force which, if steadily applied to a circuit having a resistance of one ohm, will produce a current of one ampere.

VOLTAGE OF A CIRCUIT The voltage of a circuit in an electric system is the electric pressure of that circuit measured in volts. It is generally a nominal rating based on the maximum normal effective difference of potential between any two conductors of the circuit.

WATT The electrical unit of power or rate of doing work. The rate of energy transfer equivalent to one ampere flowing under a pressure of one volt at unity power factor. It is analogous to horsepower or foot-pounds per minute of mechanical power. One horsepower is equivalent to approximately 746 watts.

WINTER PEAK The greatest load on an electric system during any prescribed demand interval in the winter or heating season.

CHECKLIST OF DATA USEFUL TO THE POWER MARKET ANALYST1/

A. Electric Utility Load Information.

1. Number of electric customers, by classes (residential, farm, commercial, small industrial, large industrial, street lighting service, municipal water and sewerage systems, transportation system, other government)
2. Total and average use of electric energy for each class of customer
3. Frequency distributions of customers in those classes with the largest numbers of customers (residential, rural, commercial, and small industrial) by average annual use
4. Individual loads of large industrial customers with largest energy loads
5. Numbers of major electric appliances in use by residential and rural customers
   a. Water heaters
   b. Ranges and stoves for cooking
   c. House heaters
   d. Clothes dryers
   e. Refrigerators
   f. Freezers
   g. Washing machines
      (1) Automatic
      (2) Nonautomatic

1/This list is included in Chapter I of the draft AID manual, "Economic and Technical Soundness Analysis of Electric Power Projects Submitted for Capital Financing," Herschel F. Jones, Zinder International, Ltd., November 27, 1967.

h. Air-conditioners

i. Television sets

j. Other (only if important users of electric energy)

6. The local average annual use per major appliance

7. Electric energy sales by months

8. Electric energy generation by months (also at each major generating plant if more than one)

9. Electric energy lost and unaccounted for

   a. Transmission losses

   b. Distribution losses

   c. Other

10. Peak-hour generation by months (also at each major generating plant if more than one)

11. Installed generating capacity at time of system peak

12. Annual load duration curves

13. Annual energy load curves

B. National, Regional or Area Census Data or Estimates.

1. Population

   a. Urban

   b. Rural

2. Occupied dwellings

   a. Urban

   b. Rural

3. Households

   a. Urban

   b. Rural

4. Farms

5. Commercial enterprises

6. Industrial plants by type of industry

7. Employment by type of industry

8. Unemployment

C. <u>National, Regional or Area Income Data</u>.

1. Gross product

    a. Total

    b. Per capita

2. Personal income

    a. Total

    b. Per capita

    c. Per household

3. Income distribution by households

ENERGY CONVERSION FACTORS[1/]

Each detailed energy origin and disposition table in Appendix A (tables A-1 through A-41) shows both physical quantities and B.t.u. equivalents. The following list gives all of the energy conversion factors used and the references for their sources. These sources include relevant appendix tables, where an internally derived conversion factor was utilized. Several of these factors differ to a greater or lesser extent from conventional or accepted averages, including the average for bituminous coal consumed by other than electric utilities, unprocessed natural gas, bagasse, thermal electric power, and still gas. These differences are reviewed and discussed in Chapter III; therefore, they are not explained at this time. Also, there is no discussion here of the conceptual questions involved in measuring hydro-electric energy in terms of the energy input required to generate the same amount of thermal electric power, or of assuming identical heat rates for utility and non-utility thermal power generation.

LINE NO	ENERGY COMMODITY	AVERAGE ENERGY CONTENT	PER UNIT INDICATED	SOURCE[2/]
	Primary Energy:			
1	Anthracite	25,400,000	short ton	L & C, table, p.24
2	Bituminous coal & Lignite (production)	26,200,000	short ton	L & C, table, p.24
3	Electric utility coal	24,252,000	short ton	Table A-2, footnote 1
4	All other consumers	27,112,000	short ton	Table A-2, footnote 1
5	Crude petroleum	5,800,000	barrel	L & C, table, p.24
6	Natural gas, unprocessed (gross production)	1,100	cubic foot	Table C-6
7	Natural gas, unprocessed (throughput at NG-L plants)	1,130	cubic foot	Table C-6
8	Wood & wood wastes	20,960,000	cord	L & C, table, p.24
9	Bagasse (dry basis)	16,700,000	short ton	Table A-5
10	Hydro-electric energy (thermal plant fuel equivalent)	11,739	gross KW-Hr.	3/
11	Hydro-electric energy (thermal plant fuel equivalent)	12,337	net Kw-Hr.	4/

See footnotes directly following table.

LINE NO	ENERGY COMMODITY	AVERAGE ENERGY CONTENT (B.t.u.)	PER UNIT INDICATED	SOURCE[2/]
	Secondary Energy:			
12	Fuel briquets and packaged fuel	23,000,000	short ton	L & C, table, p.24
13	Coke	26,000,000	short ton	L & C, table, p.24
14	Breeze	20,000,000	short ton	M.Y., Coke, table 46
15	Coke oven gas	550	cubic foot	M.Y., Coke, table 46
16	Crude light and intermediate light oils	(130,000 (5,460,000	gallon) barrel)	M.Y., Coke, table 46 M.Y., Coke, table 46
17	Motor grade benzene (benzol)	132,000	gallon	Bureau of Mines estimat
18	All other derivatives of crude light oil	---	---	See table A-12, footnote 1
19	Coal tar	(160,000 (6,720,000	gallon) barrel)	Bureau of Mines estimat Bureau of Mines
20	Pitch	(170,000 (7,140,000	gallon) barrel)	Bureau of Mines estimat Bureau of Mines estimat
21	Manufactured and mixed gas utility gas	872[5/]	cubic foot	Table A-14, line 19
22	Charcoal	26,000,000	short ton	Bureau of Mines estimat
23	Blast furnace gas	90	cubic foot	[6/]
24	Natural gas, residue	1,035	cubic foot	M.Y., Bituminous coal, table 58, footnote 1
25	Natural gasoline, cycle condensate, etc.	(110,000 (4,620,000	gallon) barrel)	M.Y., Bituminous coal, table 58, footnote 1
26	LP-gases and LR-gases	(95,500 (4,011,000	gallon) barrel)	M.Y., Bituminous coal, table 58, footnote 1
27	Gasoline	5,248,000	barrel	M.Y., Bituminous coal, table 58, footnote 1
28	Kerosene	(130,000 (5,670,000	gallon) barrel)	M.Y., Bituminous coal, table 58, footnote 1
29	Distillate fuel oil	5,825,000	barrel	M.Y., Bituminous coal, table 58, footnote 1
30	Residual fuel oil	6,287,000	barrel	M.Y., Bituminous coal, table 58, footnote 1

See footnotes directly following table.

LINE NO	ENERGY COMMODITY	AVERAGE ENERGY CONTENT (B.t.u.)	PER UNIT INDICATED	SOURCE[2/]
31	Jet fuel	5,383,000	barrel	Table A-29
32	Petroleum coke	6,024,000	barrel	L & C, table, p.24
33	Lubes	6,064,800	barrel	M.Y., Bituminous coal, table 58, footnote 1
34	Wax	5,565,000	barrel	L & C, table, p.24
35	Petroleum asphalt	6,636,000	barrel	L & C, table, p.24
36	Road oil	6,636,000	barrel	L & C, table, p.24
37	Still gas	1,244.3	cubic foot	Table A-35, footnote 1
38	Unfinished oils and miscellaneous products	5,796,000	barrel	M.Y., Bituminous coal, table 58, footnote 1
39	Thermal electric energy (fuel equivalent)	11,739	Gross Kw-Hr.	3/
40	Thermal electric energy (fuel equivalent)	12,337	Net KW-Hr.	4/

1/ Teitelbaum, Perry D. Energy Production and Consumption in the United States: an Analytical Study Based on 1954 Data. (Washington) U.S. Department of the Interior, Bureau of Mines (1961).

2/ The following sources occur most frequently:
L & C - Lyon, William H., and Colby, D.S., Production, Consumption, and Use of Fuels and Electric Energy in the United States in 1929, 1939, and 1947: Bureau of Mines Report of Investigations 4805, 1951, 90 pp.
M.Y. - Minerals Yearbook, 1954, Vol. II, Fuels: U.S. Bureau of Mines, Washington, D.C., 1958, 465 pp. Table numbers refer to Teitelbaum 1961 report.

3/ The figure shown is derived as the ratio of total fuel consumption (in B.t.u.) at utility thermal electric power plants ($4,498.4 \times 10^{12}$ B.t.u.), as derived in table B-12, to their estimated gross electric power production (383,194 million KW-Hr.) as derived in table A-39. This ratio is used throughout the present study for conceptual completeness, since every other commodity's output is also measured in gross terms.

4/ Same as footnote 3/, except that net rather than gross production of thermal electric power at utility plants is used (364,618 million KW-Hr.; see table A-39). The figure shown compares closely with an Edison-Electric Institute estimate of 12,180 B.t.u. per net kilowatt-hours, shown in its Statistical Bulletin, 1955, table 37, p.47. In deriving their estimate, the Edison-Electric Institute excluded power generation from wood, which helps explain why the average rate used here is higher (see table A-5, footnote 6, regarding the estimated heat rate at wood burning plants). Offsetting this to some extent, however, the Edison-Electric Institute assumed that the reported total of 1165.5 billion cubic feet of gas consumed at electric utility plants was all natural gas, whereas, as shown in table B-12, this total included 4.5 billion cubic feet of coke-oven gas and 9.9 billion cubic feet of blast furnace gas. As a result, the total Edison-Electric Institute estimate of B.t.u. input in thermal plants except those burning wood is slightly overstated, which tends to overstate its ratio of B.t.u. to kilowatt-hours.

5/ See table A-14, footnote 1, regarding relatively minor correction necessary in this figure.

6/ The figure shown is given on page 181 in The Making, Shaping, and Treating of Steel, by Camp and Francis, U.S. Steel Company, Pittsburgh, Pa., 6th ed., 1951, where it is identified as an "approximate" average.

LIST OF MAJOR REFERENCES

The list below includes the most frequently occuring data sources referred to in the source and footnotes of the detailed appendix tables. For the sake of convenience and brevity, each of these data sources is there referred to either by a simple abbreviation or by a letter in parentheses, as indicated below, with other information, such as chapter name, page, or table number also shown.

I. Indicated by abbreviations:

M.Y. - Minerals Yearbook, 1954, Vol. II, Fuels, Bureau of Mines, Washington, D.C., 1958. In a few instances, where reference is made to the 1955 issue or to Vol. 1, Metals and Minerals (except Fuels), this is specifically indicated. Each reference to the Minerals Yearbook includes the name or other indication of the particular chapter in question.

M.C. - Census of Manufactures, 1954, Bureau of the Census, Washington, D.C., 1957. Each reference to the Census includes the subject Bulletin number.

M.I. - Census of Mineral Industries, 1954, Bureau of the Census, 1957. Each reference to the Census includes the Bulletin number and, in some instances, its name.

II. Indicated by letter:

(a) American Gas Association, Gas Facts, 1955. Austin, Texas.

(b) Bureau of the Census, 1954 Census of Manufactures, unofficial tabulations of partially complete fuel consumption responses by 4-digit manufacturing industry groups. As explained in the introductory note to table B-15, the data shown there, as well as in other Appendix tables, represents expansions of these partial totals, based on proportional allocation of each unidentified fuel component to the identified components.

(c) American Petroleum Institute. Petroleum Facts and Figures, New York, N.Y., 12th ed., 1956.

(d) Federal Power Commission, Consumption of Fuel for Production of Electric Energy, 1954, FPC S-119, 1954.

(e) U.S. Tariff Commission, Synthetic Organic Chemicals, 1954.

(f) U.S. Department of Agriculture, Timber Resource Review (preliminary draft of Timber Resources for America's Future, Forest Service, Washington, D.C., January, 1958).

(g) Edison-Electric Institute. Statistical Bulletin, 1955.

(h) Bureau of the Census. Statistical Abstract, 1956.

(i) Bureau of Mines. Fuel Briquets and Packaged Fuel in 1954, Mineral Market Survey 2431.

(j) American Iron and Steel Institute. Annual Statistical Report, 1957.

(k) Bureau of Mines. Crude Petroldum and Petroleum Products, 1954 (Final Summary), APS 398.

(l) Bureau of Public Roads. Highway Statistics, 1954.

(m) Bureau of Mines, Sales of Fuel Oil and Kerosene in 1954, Mineral Market Survey 2412.

(n) Railroad Commission of Texas. Annual Summary of Texas Natural Gas, Year, 1954.

(p) U.S. Department of the Army, Corps of Engineers. Waterborne Commerce of the United States, Calendar Year 1954, in 5 parts.

(q) U.S. Department of Agriculture. Liquid Petroleum Fuel, Consumption for Farm Purposes, Statistical Bull.188, Washington, D.C., July, 1956.

(r) Bureau of the Census. Census of Agriculture: 1954, Vol. III, Special Reports, part II, Farmers' Expenditures, Washington, D.C., 1956.

(s) Interstate Commerce Commission. Transport Statistics in the United States, Year Ended December 31, 1954, part 1, Washington, D.C., 1956.

(t) National Coal Association. Steam-Electric Plant Fuel Consumption and Costs, 1954, Washington, D.C., 1955.

(u) Federal Power Commission. Steam-Electric Plant Construction Cost and Annual Production Expenses, 1954 supplement, FPC S-117.

Appendix D

REPRESENTATIVE U.S. APPLIANCES:
U.S. WATTAGE RATINGS AND U.S. AVERAGE HOURS USE AND ELECTRICITY USE

APPLIANCE	AVERAGE WATTS	AVERAGE HOURS USE	AVERAGE KILOWATT HRS USED
Air Conditioner (Window)	1,325	1,000	1,325
Air Conditioner (Central-3 ton)	5,560	1,000	5,560
Baby Food Warmer	160	531	85
Carving Knife	85	35	3
Clock	2	8,760	18
Clothes Dryer	4,350	221	960
Coffee Maker	850	118	100
Dehumidifier	250	1,600	400
Dishwasher	1,180	292	345
Electric Blanket	190	684	130
Fan (Attic)	365	890	325
Fan (Circulating)	85	529	45
Fan (Window)	200	875	175
Floor Polisher	335	45	15
Food Blender	290	52	15
Food Freezer, 15 cu. ft.	350	3,000	1,050
Food Freezer, Frostless	440	3,466	1,525
Food Mixer	110	91	10
Food Waste Disposer	400	63	25
Frying Pan	1,160	168	195
Germicidal Lamp	20	7,000	140
Griddle	1,500	83	125
Grill (sandwich)	1,180	25	30

APPLIANCE	AVERAGE WATTS	AVERAGE HOURS USE	AVERAGE KILOWATT-HRS USED
Hair Dryer	260	38	10
Heat Lamp (Infrared)	250	40	10
Heat Pump	4,650	?	?
Heater (Radiant)	1,270	134	170
Heating Pad	60	167	10
Humidifier	70	2,214	155
Iron (hand)	1,085	134	145
Oil Burner	255	1,529	390
Phonograph (Stereo, portable)	30	?	?
Phonograph (Stereo, console)	75	?	?
Radio	75	1,200	90
Range	12,000	100	1,200
Refrigerator (12 cu. ft.)	265	3,226	855
Refrigerator (frostless)	295	3,220	950
Refrigerator-Freezer (14 cu. ft.)	290	4,121	1,195
Refrigerator-Freezer (frostless)	435	3,621	1,575
Roaster	1,325	155	205
Rotisserie	1,500	200	300
Sewing Machine	75	133	10
Shaver	15	133	2
Shoe Polisher	75	27	2
Sun Lamp	280	54	15
TV Portable (black and white)	110	1,500	165
TV Console (black and white)	255	1,373	350
TV Color	315	1,460	460

APPLIANCE	AVERAGE WATTS	AVERAGE HOURS USE	AVERAGE KILOWATT-HRS USED
Toaster	1,130	31	35
Toothbrush	2	3,000 1/	6
Vacuum Cleaner (portable)	210	52	11
Vacuum Cleaner	700	57	40
Waffle Iron	1,080	19	20
Warming tray	325	49	16
Washing machine (automatic)	600	133	80
Washing machine (non-automatic)	280	214	60
Water Heater (quick recovery)	4,500	978	4,400
Water Pump	450	444	200

Sources: Edison Electric Institute, January, 1965, and General Electric Company, 1967 Diary, December, 1966.

1/ Battery charging

PROCESS INDUSTRIES

Electric Energy Required Per Unit of Product and
Capacity Required Per Unit of Annual Production Capacity

PRODUCT	PRINCIPAL PROCESS	KWH/Ton (2000#) of Product	KW/Ton of Annual Production Capacity
Electro-Metals:			
Aluminum	Electrolytic	12,000 - 16,000	1.4 - 1.8
Magnesium	Electrolytic	19,000	2.2
Silicon	Electric Furnace	13,000	1.5
Copper	Electrolytic Refining	615	0.1
Zinc	Electrolytic Refining	3,600	0.4
Ferro-Alloys:			
Ferro-Nickel	Electric Furnace	24,000	3.3
Ferro-Chrome	Electric Furnace	4,000 - 10,000	0.6 - 1.4
Ferro-Silicon	Electric Furnace	6,000 - 10,000	0.8 - 1.4
Ferro-Phosphorous	Electric Furnace	2,400	0.3
Ferro-Manganese	Electric Furnace	4,500	0.6
Phosphorous	Electric Furnace	13,000	2.0
Steel	Electric Furnace	500 - 600	0.1
Electro-Chemicals:			
Ammonia	Compression	1,500 1/	0.2
Chlorine & Caustic	Electrolytic	2,980 2/	0.4
Calcium Carbide	Electric Furnace	3,100	0.4
Hydrogen Peroxide	Electrolytic	16,000	1.9
Other:			
Pulp	Chipping	730	0.1
Paper & Paperboard	Motors & Chipping	1,100 3/	0.2
Cement	Grinding	120	4/

1/ per ton of ammonia
2/ per ton of chlorine
3/ includes chipping for pulp manufacture
4/ less than 0.1

DESCRIPTION OF THE METHOD

"The method consists of (1) determining the separable cost of including each function in the multiple-purpose project, and (2) determining an equitable distribution of costs incurred for several purposes in common. It makes allowance for any economic significance attributable to the peculiarities of any one purpose in its use of facilities or its prior right to project services. Thus, the use of benefits as a basis for cost allocation under this method makes allowance for both the use made of facilities and any prior rights because estimates of benefits reflect the conditions assumed with respect to those factors. Furthermore, the separable costs determined through project formulation reflect the costs of providing facilities used by each purpose as explained more fully below.

"Separable Costs

"The separable cost for each project purpose is the difference between the cost of the multiple-purpose project and the cost of the project with the purpose omitted. Separable costs include more than the direct or specific costs of physically identifiable facilities serving only one purpose, such as an irrigation distribution system. They also include all added costs of increased size of structures and changes in design for a particular purpose over that required for all other purposes, such as the cost of increasing reservoir storage capacity. In effect, separable costs are computed from a series of project cost estimates, each representing the multiple-purpose project with one purpose omitted. Such information will be readily available when the recommended practices of project formulation have been followed. Where project formulation has not been of the detail suggested in the recommended procedure and separable costs are not available, specific costs may be used in lieu of separable costs (as in the alternative justifiable expenditure method).

"Distribution of residual or remaining joint costs

"Residual costs are here defined as the difference between the cost of the multiple-purpose project as a whole and the total of the separable costs for all project purposes. Residual costs thus represent a remaining joint cost attributable to all or several purposes. The amount of project benefits used as a basis for allocation of residual costs to any purpose is limited by the cost of providing equivalent services from the most likely economically feasible alternative source available in the area to be served. From such benefits for each purpose, separable costs are deducted to give remaining benefits. Then residual costs are distributed in proportion to the remaining benefits for each purpose. The distribution of residual costs in proportion to the excess of benefits over separable cost assigns to each purpose an equitable share of project savings.

"If the total separable costs of all purposes should exceed the cost of the multiple-purpose project, there are in effect no residual costs as defined above, but rather a joint saving, which can be distributed among purposes by reducing separable costs to obtain the allocation to each purpose instead of by adding a portion of residual costs to each separable cost as illustrated herein.

"Total allocation

"The sum of the separable costs and the allocated residual cost for each purpose constitutes the total allocation to that purpose. Under the separable costs-remaining benefits method, the total cost allocated to each purpose will not be less than the cost of including that purpose in the project (unless the total of separable costs for all purposes exceeds the multiple-purpose project costs as explained in preceding paragraph), and will not be more than the benefits of that purpose or the cost of the most economical single-purpose alternative.

"GENERAL APPLICATIONS OF PROCEDURE

"The recommended method of cost allocation is illustrated below for a multiple-purpose project for which the total project costs amount to $1,765,000. These include investment costs and operation, maintenance, and replacement costs, all reduced to a common time basis, and are expressed either as an average annual amount or a present worth amount."

"ALLOCATION OF COSTS BY SEPARABLE COSTS-REMAINING BENEFITS METHOD"

GENERAL CASE

(In thousands of dollars)

ITEM	FLOOD CONTROL	POWER	IRRI-GATION	NAVI-GATION	TOTAL
1) Benefits	500	1,500	350	100	2,450
2) Alternative cost	400	1,000	600	80	2,080
3) Benefits limited by alternative cost (lesser of items 1) and 2))	400	1,000	350	80	1,830
4) Separable costs	380	600	150	50	1,180
5) Remaining benefits (Items 3) - 4))	20	400	200	30	650
6) Allocated residual cost1/	18	360	180	27	585
7) Total allocation (Items 4) + 6))	398	960	330	77	1,765

1/ In this example, the total residual costs to be allocated ($585,000 in line six) are 90 percent of total remaining benefits ($650,000 in line five). Therefore, each purpose is charged with residual costs equal to 90 percent of its remaining benefits. The same results will be obtained by using distribution ratios (percent of each item in line five to their total).

Appendix F

"RECOMMENDED METHOD OF COST ALLOCATION" 1/

"The separable costs-remaining benefits method of cost allocation is a method for obtaining an equitable distribution of the costs of a multiple-purpose project among the purposes served. Briefly, it provides for: (1) assigning to each purpose its separable costs; i.e., the added costs of including the purpose in the project; and (2) assigning to each purpose a share of the residual or remaining joint costs in proportion to the remaining benefits; i.e., the benefits (as limited by alternative costs) less the separable costs. Thus, the method provides for an equitable sharing among the purposes in the savings resulting from multiple-purpose development.

"The separable costs-remaining benefits method described in detail below is recommended for general use in allocating costs of Federal multiple-purpose river basin projects. It differs from the generally recognized benefits method in that the amount of benefits used as a basis for the allocation in the recommended method is limited by the costs of available single-purpose alternative projects. In this respect it resembles closely the alternative justifiable expenditure method, except that the concept of specific costs for each purpose is replaced by the concept of separable costs for each purpose. The separable costs for each purpose are determined as part of the procedures recommended herein for project formulation, so that no added work should be required by this method of cost allocation. Since separable costs include all specific costs and generally include other added costs, residual joint costs to be allocated are usually smaller under the separable costs-remaining benefits method than under the alternative expenditure method. Thus the separable costs-remaining benefits method maximizes the direct allocation of costs and minimizes the residual costs to be apportioned.

1/ Federal Inter-Agency Committee on Water Resources, Proposed Practices for Economic Analysis of River Basin Projects, 1958, Washington, D.C. pp. 47-49.