Nuclear Power and its Fuel Cycle

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Expansion Planning for Electrical Generating Systems

A Guidebook

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Chapter 6

GENERATING SYSTEM COSTS

This chapter presents techniques that are *helpful* in *determining the* components of the costs of a generating system. Some methods for simplified comparisons between alternative generating units, such as lifetime levelized cost, are developed from the economic principles presented in Chapter 5. Key factors in determining generating system costs, such as forced outage rates and incremental heat rates, are reviewed in some detail in preparation for the example calculation of production cost that follows. The advantages and limitations of a less rigorous method, known as screening curves, which is sometimes used to estimate output from generating units and least-cost capacity mixes, are presented in the final section.

The examples in this chapter are related primarily to greatly simplified thermal generating systems. The additional considerations and complications encountered in analysing mixed thermal-hydro systems are briefly noted here and are presented more fully in Chapter 8.

6.1. DEFINITION OF COSTS

This section defines and briefly discusses the types of costs associated with electric power generating plants and systems. Appendix H discusses some of these basic concepts in greater detail together with illustrative economic data for alternative power plants. Cost accounting practices and terminology vary from country to country and, in many instances, within countries. Furthermore, special terminology and conventions are often used in conjunction with specific types of generating unit, such as coal and nuclear power plants. Therefore, while the terminology and conventions presented in this section are typical, they are not universal and are intended only to illustrate the basic concepts and categories of costs for power plants and electric generating systems. Some of the terms defined here may be defined differently elsewhere depending on the cost accounting system used or the type of analysis being performed.

6.1.1. Basic cost concepts

From an economic point of view, it is desirable (but seldom possible) to expand a power generating system by adding plants that are both cheap to build and that produce electrical power at the lowest possible cost. Two distinct figures of merit are therefore important when discussing or comparing the economics of

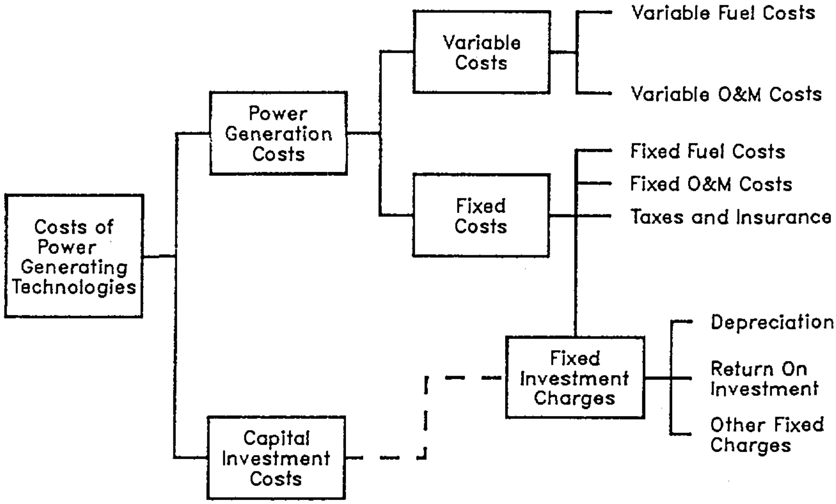

FIG. 6.1. Categories of costs for power generating technologies.

power generating technologies: (1) *capital investment costs,* expressed in \$/kW[1] of installed capacity, that denote the capital outlay necessary to build a power plant; and (2) *power generation costs,* expressed in mills/kW·h of generation[2], that represent the total cost of generating electricity. Power generation costs consist of the costs associated with the initial capital investment in a power plant *(fixed investment charges),* fuel costs, and operation and maintenance (O&M) costs. For discussion, these costs can be divided into two broad categories: *fixed costs* and *variable costs.* A breakdown of the general categories of costs for power generating technologies is presented in Fig.6.1. As illustrated, fuel and O&M costs have both fixed cost and variable cost components. The dashed line indicates that the fixed investment charges are a function of the capital investment costs. The levels of costs for the cost categories identified in Fig.6.1 will vary considerably depending on the technology examined. For example, nuclear power plants are characterized by high capital investment costs and low fuel costs, while no fuel costs are usually associated with a hydroelectric power plant.

Fixed costs are related to the expenditures for items used over an extended period of time, such as a boiler or reactor, and are independent of the amount of electricity generated by the plant. Fixed investment charges, which include depreciation (i.e. the annual charge for recovering the initial capital investment in a power plant), return on investment (for private utilities in the USA, for example,

[1] As in Chapter 5, for convenience, all examples in this chapter are in US dollars.
[2] A mill is defined as 1/1000 of a monetary amount.

this includes interest paid to bondholders (debt) and return to stockholders (equity)) in addition to (where applicable) interim replacement and funds for decommissioning, all of which may be treated as proportional to the initial capital investment in plant and facilities, are classified as a fixed cost. The annual fixed investment charges for a plant can be calculated as the product of the *fixed charge rate* and the plant capital investment costs. In the absence of tax and insurance complications, which are very important considerations in some countries, the annual fixed charge rate is equal to the sum of the charges for depreciation and for the annual return on investment. Typical fixed O&M costs include wages and salaries, while fixed fuel costs could include, for example, the costs associated with stockpiling fuel (e.g. coal).

In contrast, variable costs, often called *expenses,* represent expenditures for goods and services consumed within a relatively short period of time (usually one year or less). Variable costs generally depend directly on the amount of electricity generated (i.e. they are expressed in terms of a monetary amount per kW·h production). Variable fuel costs and variable O&M costs are the two primary categories of variable costs.

From a utility point of view, the money received from customers, called *revenue,* must in the long run be sufficient to cover all costs of providing service. (this may not be the case in countries where electricity production is subsidized). Therefore, the annual *revenue requirement* is simply defined as the sum of the annual fixed and variable costs associated with all plants in the utility system. Variable costs are usually paid from annual revenues, while total investment costs must normally be recovered over an extended period of time because annual revenues would normally be insufficient to cover large capital expenditures. In addition, fixed costs represent money spent for items whose usefulness continues for a long time (e.g. a power plant), thereby producing benefits for both present and future customers. As a result, utilities often obtain revenue from customers through two kinds of service charges: (1) a *demand charge,* which depends on the maximum number of kW of power the utility contracts to supply, and (2) an *energy charge,* which depends on the total number of kW·h of electricity actually consumed. The demand charges are based on the fixed costs while the energy charges are based on the variable costs.

For purposes of analysis, utility system economics can be examined in terms of (a) overall revenue requirements and (b) production costs. *Revenue requirements analysis* refers to an economic analysis of both fixed and variable costs of providing service. In contrast, *production cost analysis* is only concerned with the costs which vary with the level of unit or system generation (i.e. variable fuel and variable O&M costs). Production cost analysis is used as a basis for determining economic loading order (Section 6.3) and is useful for examining the changes in utility system costs associated with fuel substitutions and unit outages.

Capital investment cost, fuel costs and O&M costs, the three major types of costs associated with power generating technologies, are discussed in the next subsections.

6.1.2. Capital investment costs

The capital investment cost denotes the total capital outlay necessary to build a power plant and bring it into commercial operation. For hydroelectric, coal and nuclear power plants, the fixed investment charges (which are proportional to the capital investment costs) are the largest contributor to power generation costs.

Total capital investment costs include the construction or overnight costs[3] of building the power plant, commonly referred to as fore costs, and costs related to escalation and interest charges accrued during the project period. Fore costs are generally divided into direct and indirect costs, comprising what is commonly referred to as base costs, and include items such as owner's costs, spare parts costs and contingencies.

Table H.1 in Appendix H shows the structure of capital investment costs for a power plant. The direct capital costs are directly associated on an item-by-item basis with the equipment and structures that comprise the complete power plant (e.g. boiler/reactor, turbine and electric plant equipment), land and land rights, and special materials, e.g. the initial loading of coolant and moderator materials for nuclear power plants. (Transmission plant costs, such as for the main power transformers, are, when considered, also classified as direct capital costs.) The direct costs can be divided into *depreciating* and *non-depreciating* assets. The depreciating capital costs are all capital costs, with the exception of land and (when used) reactor-grade heavy water inventory. The indirect capital costs are expenses of a more general nature and consist mainly of expenses for services (e.g. construction, engineering and management services), temporary facilities, and rentals. Taxes, duties and fees are excluded in national planning studies because they are normally recycled in the national economy.

Plant capital costs are sensitive to numerous factors, including the plant site (e.g. geographical location, subsurface conditions, site meteorological conditions, and proximity to population centres), length of construction schedule, unit size, effects of escalation during construction, interest rates and regulatory requirements. The addition of flue gas desulphurization equipment on coal-fired power plants, for example, can substantially increase the total cost of each generating unit.

6.1.3. Fuel costs

The terms *fuel cost* and *fuel cycle cost* refer to those charges that must be recovered in order to meet all expenses associated with consuming and owning fuel in a power plant. In general, cost analysis of nuclear fuel is more complicated than that for a power plant using a conventional fuel (e.g. coal, oil or gas), partly because conventional fuels are essentially consumed instantaneously while a single

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[3] Overnight construction costs refer to construction costs at a particular point in time, i.e. assuming instantaneous construction.

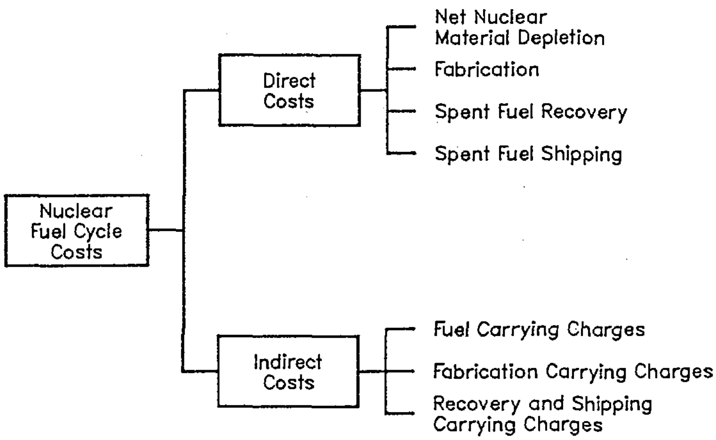

FIG. 6.2. Breakdown of nuclear fuel cycle costs.

batch of nuclear fuel may be used in a reactor for several years and then recycled. There are also many different types of nuclear fuel cycles, each of which may be composed of a large number of time-dependent steps (e.g. mining, milling, conversion, enrichment, fabrication, irradiation, storage, shipping, reprocessing and waste disposal).

Figure 6.2 shows a breakdown of nuclear fuel cycle costs. The direct costs refer to the expenses for materials, processes and services required to put the fuel into a form in which energy can be extracted. The direct cost item in Fig.6.2 labelled 'net nuclear material depletion' is the difference between the cost of fuel (e.g. ^{235}U and ^{238}U) supplied to a reactor and, provided reprocessing is an available option, the credit for fuel recovered after discharge from the reactor. The 'spent fuel recovery' category includes (when appropriate) reprocessing, reconversion and waste disposal costs.

In addition to the actual costs of carrying out each of the fuel cycle operations, there are the interest costs, or *carrying charges,* on investments. These indirect costs are the result of the time separation between expenditures for fuel and revenues from the sale of energy generated with the fuel. For example, fuel used in a light-water reactor is typically irradiated for three years and is then stored at the reactor site for another multiyear period. These and other time lags between fuel cycle operations lead to extensive carrying charges. For conventional fuels, coal and oil stockpiling may also lead to significant carrying charges. A methodology for calculating nuclear fuel cycle costs can be found in Appendix F.

6.1.4. Operation and maintenance (O&M) costs

O&M costs include all non-fuel costs that are not included in the fixed cost category. They include items such as the direct and indirect costs of labour and

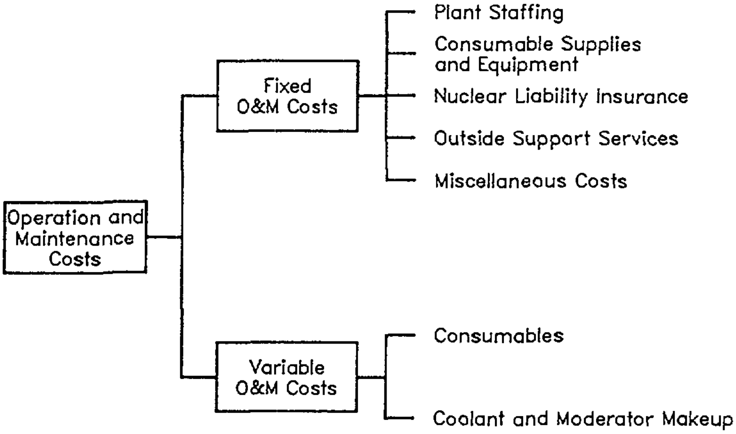

FIG.6.3. Breakdown of nuclear power plant O&M costs.

supervisory personnel, consumable supplies and equipment, outside support services, and (if applicable) moderator and coolant makeup and nuclear liability insurance. Reactor decommissioning costs are sometimes included as an O&M cost or as an economic adjustment to total annual costs. Typically, O&M costs are estimated on the basis of an average capacity factor for a power plant operating in its normal load-following manner.

Power plant O&M costs are generally divided into fixed and variable cost components, as the example in Fig.6.3 shows for a nuclear power plant. The fixed O&M costs ($/kW per year) are determined by the size and type of plant and are independent of the plant capacity factor. The variable O&M costs (mills/kW·h) vary directly with production (i.e. with capacity factor). Some cost accounting systems classify separately, as *consumable O&M costs,* the cost of all materials other than fuel consumed during operation of the plant. The cost of limestone used in a sulphur removal system is an example of a consumable O&M cost.

Working capital is usually regarded as a non-depreciating investment, and the annual fixed charges on this item must be added to the fixed O&M costs. Plant working capital is composed of two parts: the average net cash required for plant operations, and the value of the inventory of materials and supplies.

6.2. POWER PLANT LIFETIME LEVELIZED COST OF GENERATION

The annual revenue requirement for a particular power generating technology or for an entire electric utility system was described in the previous section as being uncertainties are often implicit in the decisions or are embedded throughout the cost and performance estimates without consideration of their combined effects. The decisions can be improved if an effort is made to recognize and quantify the uncertainties explicitly. The probabilistic model can be summarized as a tool that is relatively easy to understand and use. It is not a means for removing uncertainty from technology choices; it is a method that yields insights into the combined effects of many component uncertainties.

6.5. PRODUCTION COST ANALYSIS

In this section an explanation is given for the probabilistic simulation method of determining expected generation from a group of generating units. Following an illustrative example, some typical complications are discussed, such as blocking of units, spinning reserve, and purchases. The problems of accuracy tradeoffs are also discussed. Finally, some recent innovations are briefly reviewed.

The discussion and subsequent example calculation focus on a simplified generating system composed of thermal units only. Emphasis is placed on the modelling of random forced outages of generating units, which is the only time, apart from scheduled maintenance outage, when thermal units are assumed to be unable to supply generation. For hydroelectric generating units, there are two distinct additional types of failure:

– Energy deficit, e.g. lack of water in the reservoir,
– Power deficit due to a variable head.

The first type of failure primarily affects production costs, while the second is of primary concern for system reliability. Proper representation of hydroelectric operation requires complex simulations of hydro inflows and storage, as discussed in Chapter 8.

6.5.1. Role of production cost analysis in generation planning

As discussed in the preceding sections, the mix and characteristics of the generating units in a system affect the generation that is expected from any particular unit. A key part of any generation planning effort is estimating the fuel and variable O&M expenses expected for a particular configuration of the system in a particular time period. These calculations must be performed repeatedly for optimizations over long time horizons; they must be reasonably accurate representations of the expected system performance, and must not be prohibitively complicated so that computer time becomes a severe limitation for performing thorough sensitivity analyses.

An important step toward more sophisticated generation planning techniques was the development of probabilistic simulation for calculating expected production costs (see, e.g. Refs [19–21]). Probabilistic simulation provides a mathematically rigorous method for simulating random forced outages of generating units and, in turn, for estimating capacity factors for all the generating units in the system. Just as any modelling technique is an imperfect representation of the real world, probabilistic simulation does not allow exact simulation of all operating considerations facing a generating system. However, depending on the accuracy needed for a particular application, more detailed representations and improved assumptions can be used to obtain more accurate results at the cost of a more complicated and time-consuming analysis. For example, if the generation planner was interested in preparing estimates of fuel needs for the next year or two, a more detailed production cost analysis would be desirable than if alternative expansion plans are being examined over a 30 year planning horizon.

6.5.2. Loading order for generating units

To calculate the expected generation from a group of generating units, a loading order (sometimes called the merit order) must be established. The loading order states the order in which the individual units are expected to be called upon to meet the demand facing the generating system. (For simplicity in the following example calculations, generating units will be considered to consist of a single block of capacity. Multiple block representations are discussed in Section 6.5.6.)

To illustrate the principles of probabilistic simulation, a fictitious example is used throughout this section. The characteristics of the generating units for this example are listed in Table 6.XI. The generating units are listed in the order in which they would be loaded if the economic loading order were followed, i.e. the unit with the lowest variable cost of production is loaded first, . . . , and the unit with the highest variable cost is the last unit called upon to generate. As discussed in Section 6.3 above, the loading order will be altered from the apparent economic loading order by practical considerations such as spinning reserve.

6.5.3. Load representation

If chronological hourly loads of a utility are plotted against the hour of occurrence during an extended period, say a day or a week, the resulting curve gives a chronological representation of the hourly power demand required from the electric system. A hypothetical daily load curve with a sharp afternoon peak load is shown in Fig. 6.12(a). The area under the curve is the energy requirement to be delivered by the power system. If these same hourly loads are rearranged against the same abscissa in decreasing order of magnitude, the resulting curve is the load duration curve, previously defined in Chapter 4. Figure 6.12(b) shows the load duration curve corresponding to the chronological curve in Fig.6.12(a). The area under the resulting curve is identical to the chronological representation and still represents the kW·h energy requirement of the system. The meaning of the abscissa is now the number of hours the load equals or exceeds the corresponding

TABLE 6.XI. CHARACTERISTICS OF GENERATING UNITS FOR A FICTITIOUS GENERATING SYSTEM

Unit No.	Unit name	Rated capacity (MW(e))	Forced outage (%)	Type of fuel	Variable cost ($/MW·h)
1	NUC1	200	20	Nuclear	6.5
2	NUC2	200	20	Nuclear	6.5
3	COAL1	200	10	Coal	27.0
4	COAL2	200	10	Coal	27.0
5	OIL1	100	10	Oil	58.1
6	OIL2	100	10	Oil	58.1
7	OIL3	100	10	Oil	58.1
8	OIL4	100	10	Oil	58.1
9	CT1	100	5	Distillate oil	113.2
System capacity		1300			

Note: These names and numbers were selected in order to present a simple example of probabilistic simulation. No significance should be attached to the names or numbers listed. More realistic values for generating units are given in Appendices G and H.

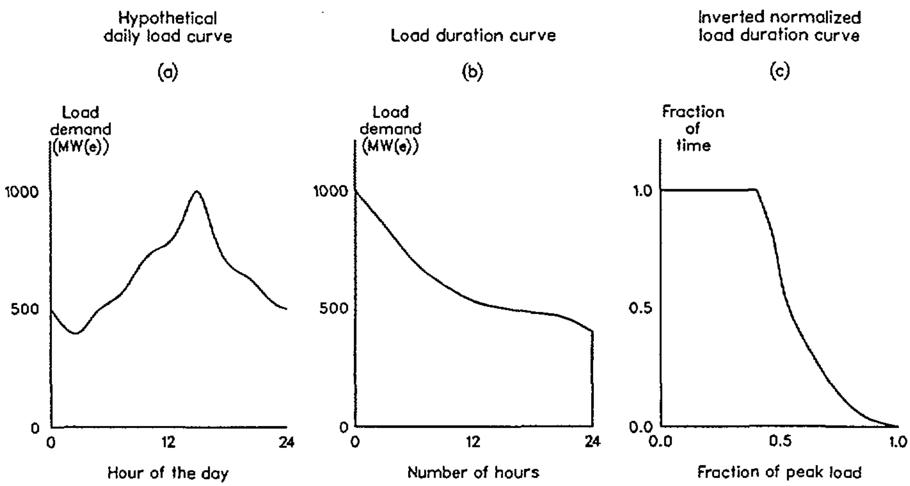

FIG. 6.12. Representations of load data.

TABLE 6.XII. LOAD DURATION CURVE

Load MW(e)	Fraction of time load exceeds given load
0	1.00
100	1.00
200	1.00
300	1.00
400 (minimum load)	1.00
500	0.80
600	0.40
700	0.20
800	0.10
900	0.05
1000 (peak load)	0.00

load. The load duration curve can be further transformed by normalizing each axis to a reference value; the resulting curve, converted by interchanging the x and y axes for computational convenience, is called the inverted normalized load duration curve (Fig.6.12(c)). For any chosen value of the fraction of peak load, the associated ordinate is the probability that the chosen load will be equalled or exceeded at any randomly chosen time during the period.

Let us use the daily load duration curve in Fig. 6.12 as if it were the annual load duration curve for the example problem. The data for the assumed load duration curve are shown in Table 6.XII. Load intervals of 100 MW(e) have been used for convenience of calculation. The incremental load probability for any load interval can be determined by subtracting the corresponding fraction of time for the upper bound of the load interval from the fraction of time for the lower bound of the load interval. For example, the probability that the load falls between 400 and 500 MW(e) is 1.0–0.8, or 0.2.

The incremental load curve can be used to calculate the total demand in kW·h (energy requirement) by associating the probability with the midpoint of the load interval; for example, the probability of the load being 450 MW(e) is 0.20. The calculation of total demand is shown in Table 6.XIII for a year (8760 hours) and the load duration curve is given in Table 6.XII. The load factor, the energy demand divided by the quantity peak load times hours in the period, is 0.605 for the example problem.

TABLE 6.XIII. TOTAL DEMAND BY LOAD INTERVAL

(a) Load (MW)	(b) Load probability	(c) 10^6 kW·h/a	(d) Contribution to average demand ($\overline{MW}$(e)) ((a) × (b))
50	0.00	0	0
150	0.00	0	0
250	0.00	0	0
350	0.00	0	0
450	0.20	788.4	90
550	0.40	1927.2	220
650	0.20	1138.8	130
750	0.10	657.0	75
850	0.05	372.3	42.5
950	0.05	416.1	47.5
		5299.8	605.0

Load factor: 5299.8 × 10^6 kW·h/(10^6 kW(e) × 8760 h) = 0.605, or
Load factor: 605 $\overline{MW}$(e)/1000 MW(e) = 0.605.

6.5.4. Capacity outage distribution

A stochastic method of treating the reliability of a generating unit is to assign a probability to each of its possible states of available capacity. A generating unit (labelled unit 1) of total capacity c_1 can be in one of s states such that the available capacity is $a_{1,i}$ if it is in state i. The probability of being in state i is $p_{1,i}$ and the sum of the $p_{1,i}$ is 1.0. Alternatively, when the unit is in state i, the unavailable capacity for the capacity in outage, $b_{1,i}$ is equal to $c_1 - a_{1,i}$.

The simplest stochastic method of treating the reliability of a generating unit is to assign it only two possible states of availability, i.e. s = 2. Either it is available or it is not. Under this assumption, if the unit is available it is capable of full power output ($a_{1,1} = c_1$). If the unit is unavailable it is capable of no power output ($a_{1,2} = 0$). Let $p_{1,1} = p_1$ be the probability that unit 1 is available and $p_{1,2} = q_1$ be the probability that the unit is not available. In this case $p_1 + q_1 = 1$. This is the approach used in WASP-III. The outage probability is the equivalent forced outage rate defined in Section 6.3 above. This definition of forced outage represents the likelihood that a generating unit will not be able to generate when called upon during periods when the unit is not scheduled for maintenance.

TABLE 6.XVI. EXPECTED GENERATION FROM INDIVIDUAL UNITS

Unit	Expected values: Unit capacity factor	Expected values: kW·h/a ($\times 10^9$)
1	0.800	1.4016
2	0.800	1.4016
3	0.756	1.3245
4	0.419	0.7342
5	0.224	0.1961
6	0.134	0.1174
7	0.073	0.0641
8	0.038	0.0334
9	0.019	0.0164
Expected total generation		5.2893
Energy demanded (from Table 6.XIII)		5.2998
Expected unserved energy (by subtraction)		0.0105

6.5.6. Operation

Several characteristics of an operating generating system can be dealt with in various ways to make the probabilistic simulation more realistic. This subsection discusses some of the more common characteristics.

6.5.6.1. Scheduled maintenance

The simplified example in the previous section did not consider scheduled maintenance. The most desirable way to treat scheduled maintenance is to perform a probabilistic simulation for a relatively short period, such as a week or two, so that units scheduled for maintenance can be removed from the generating system for the appropriate periods. Since maintenance is not random, it is incorrect to treat maintenance as if it were a forced outage. Treatment of maintenance as forced outages does not give the system credit for the maintenance schedule, which presumably was prepared with consideration of reliability and cost tradeoffs. However, in long-run optimizations, such as in WASP, it is not usually practical to carry out all the probabilistic simulations on a weekly or biweekly basis. One method is to derate the capacity of the unit in those periods during which maintenance is expected. For example, for a problem having only four periods per year (13 weeks each), a 50 MW(e) combustion turbine with two weeks of annual scheduled maintenance would have a capacity of only 11/13 × 50, or 42.3 MW(e), in the period when the maintenance is expected. The forced outage rate is not affected by this approximation. Explicit treatment of maintenance (short simulation periods) is preferable to derating for maintenance whenever possible.

6.5.6.2. Instant on-off assumption

The two-state approximation for operating generating units assumes the unit is either completely forced out or operating at full power. No other possibilities are included when the unit is being called upon to operate. Clearly, this is not a realistic assumption even though equivalent forced outage rate accounts for partial forced outages. For example, when a unit is being loaded after a cold startup, there is a maximum rate at which the unit can approach full power (ramp rate). One way to partially account for the fact that a unit sometimes operates at partial power without having a forced outage is to split the unit into more than one block of capacity. These blocks can then occupy non-consecutive positions in the loading order. This is discussed further in the next paragraph.

6.5.6.3. Blocking of generating units

A more reasonable representation of the operation of the generating system can sometimes be achieved by splitting the generating units (or at least the major units) into two or more blocks of capacity. One explanation of why such a representation is more reasonable than single-block loading is that it is sometimes more economical from the point of view of the utility system to reduce the output from a base load unit than to shut down a unit with higher variable cost [7]. It is important that the average heat rates for each block are calculated to represent correctly the actual thermal energy required for generation from that block. In the probabilistic simulation of multiblocked units, the first block of a particular generating unit encountered in the loading order is treated as if it were a separate unit. However, when the second block of that unit occurs in the loading order, the effects of forced outages of the first block on the equivalent load duration curve (ELDC) must be removed. Thus, the recursive formula for $L_N(x)$ is used to calculate $L_{N-1}(x)$, where the unit removed is the first block of the unit considered. Then the energy for the second block is determined from that ELDC because outages of the first block of a unit do not affect the energy generated by the second block. That is, when a unit goes on forced outage, the entire unit is forced out (the equivalent full forced outage rate is used to account for partial outages). Next, the effect of a single unit consisting of the combined capacities of the two blocks is used to generate the new ELDC. If this approach were not used, the separate blocks would appear to the system as if they were individual units. This would result in incorrect estimates of energy generated not only for the unit in question but all units following in the loading order. In addition, the reliability calculations would be in error; for example, the system reliability consequences of a 1000 MW(e) unit with a 10% forced outage rate are far different from ten 100 MW(e) units, each with a 10% forced outage rate.

6.5.6.4. Technologies with fixed energy supply

Hydroelectric energy is often available only to a limited extent, and capacity factors for hydroelectric units are therefore fixed to the degree that water availability can be predicted. Since operating costs of hydroelectric plants are generally very low, simply placing a hydroelectric unit in a probabilistic simulation would generally call for more generation than is available. Therefore, various approximations are used to represent hydroelectric units or other types of unit with a fixed energy supply. The WASP model simulates system operation of hydroelectric capacity by dividing total hydroelectric capacity into two general categories. The base hydroelectric is that portion of total capacity that is expected to generate continuously at full power during a simulation period (this could represent the minimum flow conditions for a system's combined hydroelectric capability). The second portion of the hydroelectric capacity, or peaking hydroelectric, specifies both capacity and energy. The simulation model then loads the peaking hydroelectric in the appropriate position in the loading order so that exactly the right amount of energy is used. This usually means that peaking hydroelectric and a thermal unit share two positions in the loading order. This approximation for hydroelectric plant is reasonable from both the energy and economic points of view for a long-run optimization model. Chapter 8 discusses hydroelectric energy more fully.

Since various types of hydroelectric facilities have different energy storage capability, models must deal with the timing of the capacity and energy availability. The WASP-III model (Chapter 11) has approximations to represent four types of reservoir: run-of-river, daily, weekly and seasonal regulation. The WASP model calculates the base and peak energy for each type of plant based on input values of inflow energy, installed capacity and regulating volume of the reservoir. Different approximations are used for these hydroelectric plants in order to use the base-peak representation described above.

6.5.6.5. Spinning reserve

As discussed in Section 6.3, spinning reserve can alter the economic loading order. Spinning reserve is accounted for in the WASP model by associating a fast spinning reserve capability with the first (base) block of capacity for a generating unit. When the second (peak) block of capacity for that unit is loaded, the generating system's spinning reserve drops by the amount contributed by the base block for that generating unit. A system spinning reserve goal is set depending on the load and/or the size of the largest operating quantity of capacity from a single unit. The economic loading order is followed whenever the system spinning reserve goal is achieved. When the goal cannot be achieved by following the economic loading order, additional base blocks of capacity are loaded to build up the spinning reserve. In this way an approximation to a loading order subject to spinning reserve constraints is obtained. It is important to note that the production cost for the generating system can be significantly increased by imposing severe spinning reserve constraints. In general, the economic loading order results in loading the peak block of a generating unit immediately after the base block. This is because the average incremental heat rate for the peak block is usually lower than the average heat rate for the base block, and the peak block is therefore more economic to load than the base block.

6.5.6.6. 'Must-run' units

Some generating units cannot be shut down overnight or must continue operation because of area stability or for other reasons. Such 'must-run' units can be accommodated in a production cost simulation by specifying the loading order or at least specifying exceptions to strict loading order rules, such as the economic loading order or the economic loading order subject to spinning reserve constraints.

6.5.6.7. Firm purchases and sales

Utilities often have arrangements with neighbouring utilities for exchanges of energy at times beneficial to both parties. For example, the marginal fuel in winter for one utility might be coal at the same time when a neighbouring utility is using oil as marginal fuel. In such a case it may be advantageous for the second utility to buy power from the first. Accounting for such arrangements in production cost models through modification of the load duration curve is usually the preferred method. Purchases and sales are usually not constant around the clock, so the modifications must be to the chronological load data, before formation of the load duration curve. To determine which generating units are providing energy for sales, two production cost simulations are needed: one with the sales and one without. The generation devoted to the sales can then be determined by subtraction. A less preferred approximation for treating purchased power is to use a fictitious generating unit.

6.5.6.8. Emergency inter-ties

Utilities often have sufficient interconnection of transmission systems with neighbours for a significant quantity of emergency power to be available in addition to firm purchases or sales and economy purchases or sales. Thus, the reliability of the generating system can be significantly improved if this emergency inter-tie power is included. Actual LOLP or unserved energy may be much lower for the interconnected system than for the isolated generating system. One way to account for this effect in a system expansion analysis is to include very reliable capacity with very high operating costs so that it occupies the final position in the loading order. An alternative is to analyse the isolated system and account for the effects of inter-ties through unserved energy cost or by changing LOLP, reserve margin, or other reliability constraints accordingly.

6.5.6.9. Energy storage

Energy storage as used here excludes standard hydroelectric units. A pumped storage plant with an upper and lower reservoir and which requires pumping energy from the system is one example of an energy storage technology.

Technologies involving energy storage present a complication for models using load duration curves rather than chronological load data. The basic problem is proper representation of the timing of the energy drawn from storage and the timing of the generation that is stored. Adjacent points on a load duration curve could represent an hour from the middle of the night on a weekday and a daytime hour at the weekend. A generator based on daily storage could be expected to be storing energy at one point of the load duration curve and generating at the next. In general, however, the use of stored energy can be expected at times of relatively high loads and the collection of stored energy can be expected at times of relatively low loads. This reasonable assumption allows approximations for energy storage to be made (this was used in WASP-II; the present version, WASP-III, does not explicitly include storage options). Caution must be exercised, however, because the assumption that all storing (pumping for pumped storage) occurs at the absolute lowest loads in a time period and that all generation occurs at the highest loads in a time period may result in an overestimate of the benefits of adding a storage technology to a generating system, especially if long time periods (e.g. seasons) are used. Similarly, for existing storage generators, such an approximation can lead to more operation than is feasible and, therefore, to an underestimate of the operating costs.

6.5.7. Accuracy tradeoffs and recent innovations

Needless to say, there are tradeoffs between accuracy and computer time in carrying out the probabilistic simulation. In the more complicated simulations there may be dozens of generating units, each with multiblock representation. The most desirable situation for a probabilistic simulation would be to have:

(a) A time interval less than or equal to the shortest non-zero scheduled maintenance period for any generating unit in the system;

(b) Separate simulation of several hydroelectric possibilities, e.g. dry year or normal year;
(c) Multiblock representation of units;
(d) Appropriate treatment of spinning reserve and economic dispatch;
(e) Accurate representation of the ELDC so that faith can be placed in capacity factors of small units and reliability results.

Clearly, when analysing thousands of possible system configurations over long planning horizons, compromises must be made. For example, as already mentioned, WASP treats scheduled maintenance using the derating technique.

Analysts must examine each individual problem to determine what approximations are appropriate. For long-run expansion analysis, reasonable approximations may result in large errors for the operating costs or system reliability for a particular short time period. One approach to this problem is to examine the best solutions from the long-run models in detail using more restrictive assumptions or a more detailed production cost and reliability model.

Because applications of probabilistic simulation have been reasonably successful in representing electric generation systems for planning purposes, significant effort has focused on methods for improving accuracy and/or reducing computing time while maintaining acceptable accuracy. Numerical representation of the ELDC can lead to errors after numerous convolutions and deconvolutions because of truncation and round-off errors. WASP uses a Fourier series to represent the ELDC. However, inaccuracies can creep into the calculations, depending on the number of Fourier coefficients used, and computation time is still significant [22].

A recent innovation is representation of the ELDC using analytical representations (polynomial expansions) [23, 24]. The cumulant method, or method of moments, using a Gram-Charlier or Edgeworth expansion, significantly reduces computational effort, but some questions remain concerning accuracy in various circumstances [25, 26]. As further experience has been gained, methods to overcome some of these inaccuracies have been developed [26]. Other innovative approaches and improvements in existing techniques for calculating production costs and reliability will undoubtedly appear as analysts continue to study this topic (Appendix C reviews some recent developments in more detail).

6.6. COMPARISON OF PRODUCTION COST ANALYSIS AND SCREENING CURVES

In the initial stages of a generation expansion study, many more alternatives are often available than can be reasonably considered in detail. Screening curves provide a simple method for eliminating from further consideration those alternatives which are significantly less economic. The screening curve method only provides rough approximations and is not appropriate for evaluations requiring reasonable accuracy.

Production cost analysis is described in Section 6.5 as a method designed to handle details of system operations. The concept of screening curves is described in this section as a simplified approach for quick examination of system optimization strategies. Neither method satisfies all the desired properties for system optimization studies, but both methods are useful at certain stages of expansion studies. Screening curves are most appropriate for initial scoping efforts, while production cost simulations are more useful for detailed examination of operating costs and for calibration tests of simplified representations.

6.6.1. Screening curve method

The screening curve method combines simplified representations of generation costs and system load projections in order to approximate the optimum mix of generating technologies. The basic approach is to construct cost curves for each technology and then to match the points of intersection with corresponding load points to determine the most cost-effective operating regimes and capacities for each technology. The technique captures the major tradeoffs between capital costs, operating costs and levels of use for various types of generating capacity in a system. It recognizes, for example, that the low capital/high fuel cost characteristics of combustion turbines are preferable to high capital/low fuel costs of nuclear units for applications requiring small amounts of annual generation. Most important, this method requires only minimal technical and analytical inputs while it quickly provides simplified estimates of optimal technology mixes.

It is important to be aware of the limitations associated with screening curves. Screening curve analysis is not an adequate substitute for detailed production cost or expansion planning analysis. Important factors such as forced outages, unit sizes and system reliability are not treated directly with screening curves [27]. The limitations of screening curves, and methods for dealing with them, are discussed with the examples and comparisons in this section.

The screening curve method expresses the total energy production cost for a generating unit, including all capital and operating expenses, as a function of the capacity factor for the period of interest.(Annual time periods are generally used for screening curve studies, but other period lengths are possible. Implications for various time periods are discussed later.) The following equation defines the cost curves of interest for this approach:

$$\text{Total cost} = (\text{annualized fixed costs}) + (\text{variable costs} \times \text{capacity factor} \times \text{hours per year})$$

Figure 6.14 illustrates a simple case where annualized fixed costs are represented by the y-axis intercept, and variable costs (including fuel and variable O&M costs) are shown as the slope of the line. The combined costs are expressed per unit of capacity ($/kW·a) so variable costs (expressed per kW·h) must be multiplied by

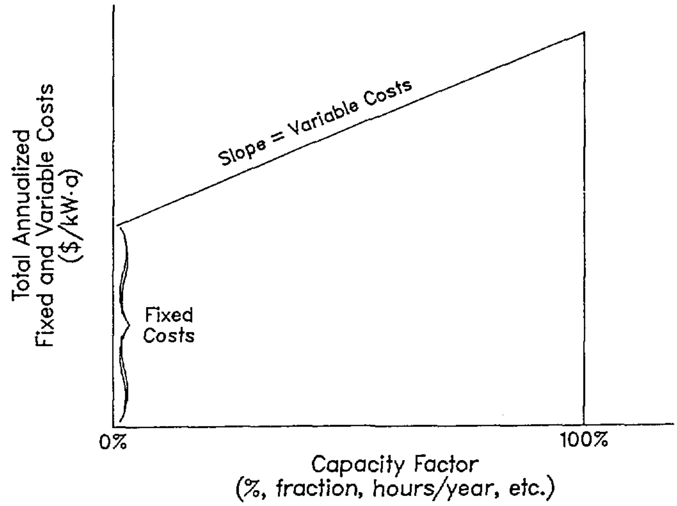

FIG. 6.14. Cost representation for screening curve method.

the appropriate capacity factor and hours per year prior to the addition by fixed costs.

To further demonstrate this step in the screening curve approach, a hypothetical case is given below with five potential generating alternatives. Cost curves are derived and then combined with a cumulative load curve to estimate an optional plant mix.

First, assume that the cost data shown in Table 6.XVII are representative of the choices for system capacity. Since a period length of one year is used for this example, the capital portion of fixed costs must be annualized. Assume that the capital recovery factor is 5% (no inflation). Total fixed costs can then be obtained by multiplying the capital costs by 0.05 and summing the result with fixed O&M costs. Variable costs are derived by multiplying average heat rates by fuel costs and then summing with variable O&M costs[12]. Table 6.XVIII shows the costs that result from these manipulations. The cost characteristics contained in Table 6.XVIII can be diagrammed for comparison as shown in Figure 6.15, which indicates that two of the hypothetical options are not competitive at any point in the range of capacity factors. The 400 MW oil unit and 200 MW coal unit display higher combined costs than the alternatives. The other three alternatives have distinct ranges of annual operation for which they provide the least-cost energy source.

Boundary points for each range can be found by selecting the linear cost functions for two technologies and solving for the capacity factor which results

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[12] Fuel cost calculations require minor changes in units to coincide with the mills/kW·h used for variable O&M costs.

TABLE 6.XVII. HYPOTHETICAL COST DATA

Technology/ size (MW)	Capital cost ($/kW(e))	Fixed O&M ($/kW·a)	Variable O&M (Mills/kW·h)	Annual ave. heat rate (10^3 J/kW·h)	Fuel cost ($/$10^9$ J)
Coal/600	752	16.20	0.21	10021	1.42
Coal/200	1054	35.64	0.46	10148	1.42
Oil/400	680	15.44	0.20	9842	4.74
Nuclear/1000	1488	13.93	0.18	10807	0.57
Gas turbine/50	160	5.40	0.69	14586	5.92

TABLE 6.XVIII. FIXED AND VARIABLE COSTS FOR HYPOTHETICAL EXAMPLE

Technology/size (MW)	Fixed cost ($/kW·a)	Variable (Mills/kW·h)
Coal/600	53.80	14.44
Coal/200	88.34	14.87
Oil/400	49.44	46.85
Nuclear/1000	88.33	6.34
Gas turbine/50	13.40	87.04

in equal costs. For example, the point at which total costs are equivalent for gas turbines and 600 MW coal units is found by:

$$\text{Total cost (gas turbine)} = 13.40\ \$/\text{kW}\cdot\text{a} + \frac{87.04\ \text{mills/kW}\cdot\text{h}}{1000\ \text{mills/\$}}\quad 8760\ \text{h/a}\cdot\chi$$

$$\text{Total cost (600 MW coal)} = 53.80\ \$/\text{kW}\cdot\text{a} + \frac{14.44\ \text{mills/kW}\cdot\text{h}}{1000\ \text{mills/\$}}\quad 8760\ \text{(h/a)}\cdot\chi$$

where χ is the capacity factor expressed as a fraction of time. Equating the two cost totals and solving for χ yields the following result:

$$\chi = \left(\frac{53.80 - 13.40}{87.04 - 14.44}\right)\left(\frac{1000}{8760}\right) = 0.0635$$

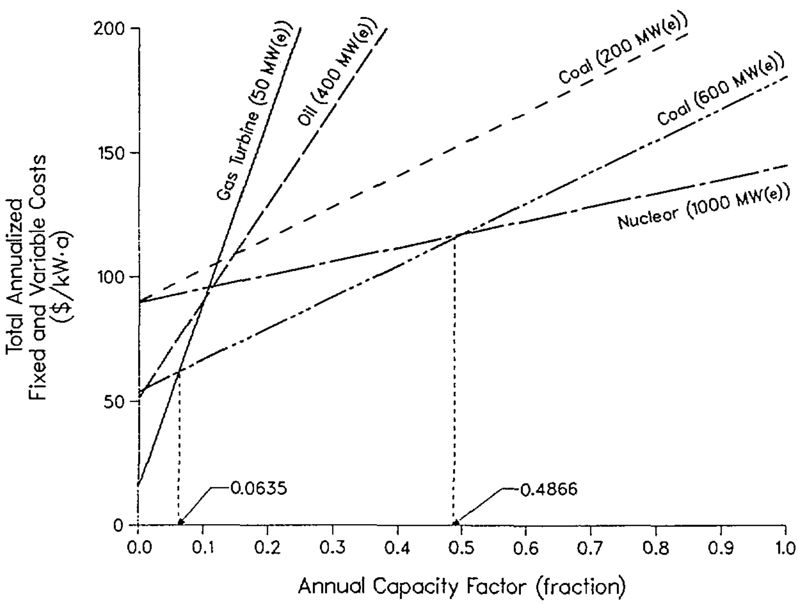

FIG. 6.15. Graphic comparison of fixed and variable cost characteristics for hypothetical example.

Thus, for capacity factors between zero and 0.0635, gas turbines provide the cheapest source of energy. Similarly, the critical point between 600 MW coal units and 1000 MW nuclear units is at a capacity factor of 0.4866. Tradeoffs between fixed and variable costs become apparent through these examples and the graphic procedure.

The diagram in Figure 6.15 is useful for determining optimal operating ranges[13] for generating options, but for system expansion studies, optional mixes of capacity are of greater interest. The second step in screening curve analysis provides the necessary translation.

As shown in Figure 6.16, points of intersection from the cost curves are mapped directly onto the cumulative load duration curve. The two non-competitive technologies have been omitted from this illustration. Assume that the load curve can be represented by the following equation:

$$Y = 1.0 - 2.68697X + 11.21611X^2 - 23.72454X^3 + 21.74757X^4 - 7.25159X^5$$

[13] The operating ranges are only approximations to optimal modes of generation. Factors which are discussed later in this section interfere with precise determinations of optimal conditions.

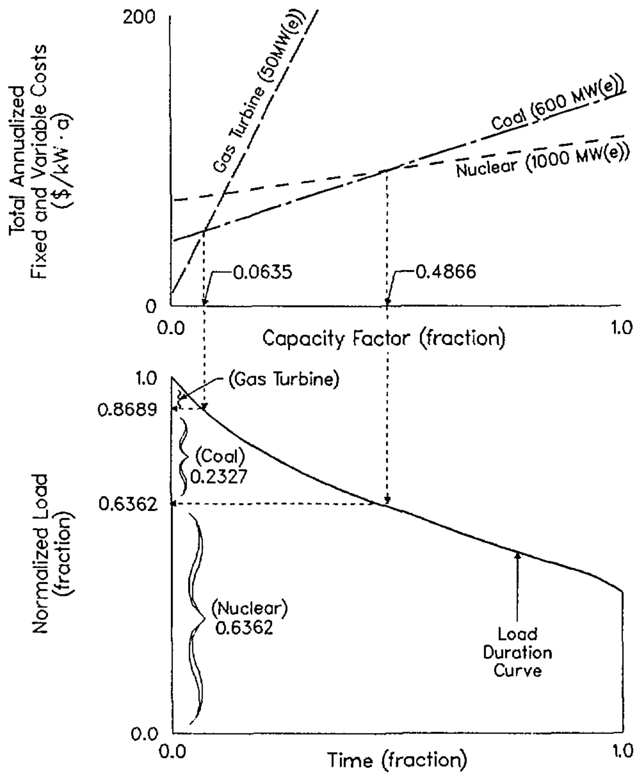

FIG. 6.16. Determination of plant load factor by screening curve method.

where Y is the normalized load and X is normalized time. Substituting previously determined capacity factors into this equation provides the following points of intersection with normalized loads:

for $X_1 = 0.0635$ $\quad Y_1 = 0.8689$

$X_2 = 0.4866$ $\quad Y_2 = 0.6362$

Simple subtraction is used to determine the relative intervals between these points of the vertical axis. Since the vertical axis corresponds to load magnitudes, the ranges derived for each technology are interpreted as if they were relative capacities. Table 6.XIX shows the results.

Relative capacity mixes are estimates rather than absolute capacities. If no forced outages were associated with generating units, the absolute load duration curve (expressed in MW rather than fractions of peak load) could be used directly to obtain the number of megawatts required for each technology. Instead, reserve margin and other factors must be considered.

TABLE 6.XIX. RESULTS OF SCREENING CURVE ANALYSIS

Technology/size (MW)	Implied best capacity factor range (fraction)	Normalized load range (fraction)	Implied best mix of capabilities (fraction)
Gas turbine/50	0.0–0.0635	0.8689–1.0	0.1311
Coal/600	0.0635–0.4866	0.6362–0.8689	0.2327
Nuclear/1000	0.4866–1.0	0.0–0.6362	0.6362

6.6.2. Comparison of screening curves with production cost analysis

The factors affecting energy production from generating units in a system were described in Section 6.3. Methods of dealing with these factors in production cost analysis are discussed in Section 6.5. The object of Section 6.6 is to show how screening curves and production cost methods differ with respect to these factors.

The following topics pose potential problems for screening curve applications.

Unit availability (forced outage rates and maintenance)
Discrete unit sizes
Existing capacity
Unit dispatch factors (minimum load, spinning reserve, startup costs, variable heat rates)
System reliability
Dynamic factors (load growth, economic trends)
Method of interpreting long-term sequence of short-term results

The problem of recognizing outage effects for generating units was alluded to in the example given in Section 6.6.1. If units were perfectly reliable and had no maintenance requirements, then the optimal capacities could be obtained direct (in MW) from an absolute load duration curve. (Even in this case the other limitations of screening curves would distort the optimal solution.) Total system capacity would just equal the system peak load. However, since scheduled and forced outages do occur, total installed capacity must include a reserve margin. The magnitude of reserves may be determined in many ways including fixed criteria, system reliability analysis or criteria based on the largest generating unit. Regardless of the method for determining reserves, capacities derived from the screening curve approach must be increased sufficiently to cover the additional requirement.

One approach is simply to maintain the relative mix determined by screening curves but increase the capacity in each category sufficiently to meet a predetermined reserve. This method guarantees that a specific reserve criterion can be met but does not ensure that it is accomplished economically. A technology originally screened to operate with capacity factors between 20% and 30% might be required to operate between 25% and 40% owing to outages of other units. The shift in operation changes the complexion of the original screening curve solution and means that some of the capacity assigned to this technology should probably come from another source better suited to the higher capacity factor.

In contrast, production cost methods usually treat the effects of planned and unplanned outages explicitly. Provisions are usually made to simulate maintenance schedules by calculating production costs at short enough intervals to exclude entirely the units being maintained in each period. The use of short time intervals is not very helpful in conjunction with screening curves because of difficulties in interpreting different capacity mixes that would result for multiple time periods in an annual simulation. Optimal capacity mixes for individual periods are not very useful when plant lifetimes are on the order of 30 years or more. The objective of long-term system optimization is to determine technology mixes that provide minimal costs in the long run, even though costs for a particular year or a period within a year may not be the lowest possible.

Similarly, forced outage rates are often treated explicitly in production cost analysis but not in the screening curve approach. Many production cost simulations treat forced outages probabilistically so that the energy generation assigned to each unit is carefully weighted by the expected outages for that unit as well as for combinations of outages for other units (Section 6.5 describes the methods in greater detail). As previously mentioned, screening curve methods must approximate the effects of forced outages by adopting a specific reserve requirement (usually a fixed percentage of peak loads). This requirement must then be allocated among the categories of generating options by some kind of heuristic algorithm.

To summarize the approaches to planned and forced outages, production cost methods generally provide accurate estimates of the cost effects due to outages, while screening curves tend to distort the cost effects and consequent implications for optimum capacity mixes. Nevertheless, some insights into capacity optimization are yielded by screening curve methods, whereas production cost simulations only deal with prespecified system configurations. Production cost techniques provide only limited insights into the system optimization problem.

Discrete unit sizes present another difficulty with screening curves. The procedure operates over a continuum of capacity factors and capacity mixes. The method is very unlikely to produce results that directly translate into integer multiples of available unit sizes. The example given in Section 6.6.1 can be used to demonstrate this point. If the total capacity requirement is 2000 MW, then the proportions of capacity would translate into 262.2 MW of 50 MW gas turbines, 465.4 MW of 600 MW coal units and 1272.4 MW of 1000 MW nuclear units. Clearly,

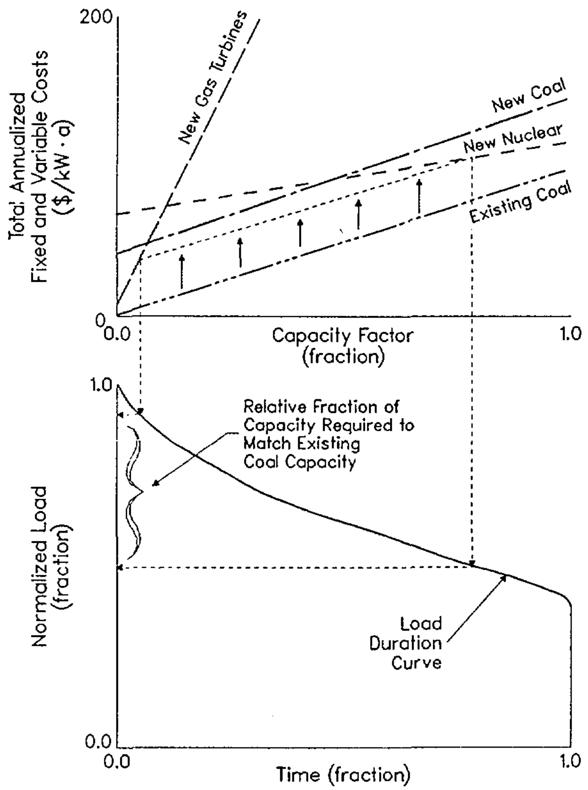

FIG. 6.17. Method for treating existing capacity by screening curve.

some adjustments would be necessary to obtain a system composed of allowable unit sizes. The optimal strategy for shifting amounts of capacity or overbuilding in selected categories of generation is not likely to be apparent for complex systems. Production cost simulations do not have this difficulty as they usually treat specific unit sizes for a predefined utility system.

Screening curve studies also tend to encounter difficulties in treating the effects of existing capacity. The method, as outlined in Section 6.6.1, utilizes cost curves that assume all capacity is new. If, for example, there already exists more capacity of a particular technology than prescribed by screening curves, the original solution must be altered. One method of accommodating existing capacity is illustrated in Figure 6.17. First, a cost curve for existing capacity is included, similar to those for new capacity except that fixed cost components (vertical axis intercept) are omitted. Then, the curve is moved upward, parallel to its original slope, until a position is reached which provides the correct capacity value when mapped against the load duration curve [28, 29].

The approach shown in Figure 6.17 is reasonably straightforward if only one type of existing capacity requires treatment, but may become much more difficult with two or more existing technologies. If there are areas of overlap for existing capacity adjustments, many interactions may be necessary to obtain the correct capacities for each option. As the cost curve for one technology is adjusted upward, it can effectively reduce the capacity factor range and corresponding capacity already calibrated for another technology. Analytical solution methods are possible in treating the more complex screening curve problem [28, 29] but the primary advantage of screening curves (their simplicity) is reduced and other problems discussed in this section remain unsolved.

Characteristics of power plants affecting unit dispatch priorities are difficult to treat with screening curves. Production cost techniques are often designed to treat the effects of minimum unit load restrictions, startup costs, variations in heat rates (with changes in output), and spinning reserve requirements. Each of these characteristics influences operating costs and the relative attractiveness for capacity choices. However, the simplified representations preclude direct treatment of the dispatch factors.

System reliability encompasses a broad range of concepts, which are discussed in detail in Chapter 7. The implications for screening curves are briefly mentioned here in order to characterize this simplified approach in perspective with system planning. It has already been pointed out that there are difficulties in dealing with unit availabilities with screening curves. Even simple reserve margins are difficult to allocate efficiently between technology options but, more important, reserve margins are being rapidly replaced by more comprehensive reliability criteria for system expansion planning. In many cases, reliability calculations are included directly with production cost simulations since many of the probabilistic concepts and treatments are analogous.

Screening curves, on the other hand, are rather insensitive to the key parameters affecting system reliability. Unit sizes, forced outage rates and maintenance requirements are of particular interest since they directly influence reliability but are not recognized in screening curve analyses. The effects of unit sizes on fixed and variable costs are treated with reasonable accuracy in the screening curve approach, but the effects on reliability are omitted. Not only do two 100 MW units have different cost characteristics from a single 200 MW unit; they also have different implications for the system's ability to meet loads in view of forced outages and scheduled maintenance. Differences such as these are not always apparent in screening curve results.

Screening curves are most suitable for examining conventional generating alternatives such as steam units fuelled by nuclear, coal, oil and gas sources. Other options such as hydroelectric pumped storage and wind generation are not as easily accommodated. While conventional technologies are usually available except for planned outages and unexpected failures, other technologies may have distinct patterns or schedules of availability. Pumped storage, for example, cannot be readily optimized with the screening curve method that uses cumulative load duration curves. The availability of pumped storage generation depends on time-of-day and seasonal patterns that reflect overall system operations in response to loads. Similarly, hydroelectric and wind generation are both characterized by constraints on the timing and quantity of energy availability. Such constraints are not readily treated with screening curve procedures.

The final difficult area to be identified involves dynamic factors such as load growth, long-term versus short-term optimal solutions, and recognition of time variations in the optimal capacity mix. Chapter 10 discusses methods for dealing with these and other complex issues in detailed long-range planning models. Production cost models do not encounter these problems since they are not intended to provide optimal expansion strategies but only production costs (and perhaps reliability calculations) for predefined configurations. Screening curve methods are intended to be applied to long-term expansion problems, so load growth and the other dynamic factors mentioned above are of concern.

As load growth and other system changes occur with time, the optimal plant mix also changes. Difficulties arise in (a) selecting an appropriate time horizon for basing capacity expansion plans and (b) finding a choice of technologies and construction schedule that minimizes costs for the entire planning period. The first problem is encountered both in the screening curve approach and in long-term optimization models. Short time horizons (such as a few years) tend to favour low capital/high operating cost technologies while allowing more immediate responses to system trends. However, after a moderately long period (15 to 30 years, for example) the system composition may have diverged significantly from the long-term optimal. Uncertainties in long-term projections need to be balanced against potential long-term cost savings.

The second problem is particularly difficult for the screening curve approach if the planning horizon covers a substantial period of time. In expansion analysis, it is important to account not only for load growth but also for the time value of money. The optimum plant mix will change from one period to the next (year to year if annual periods are used) and the differences may be difficult to reconcile. Detailed methods described in Chapter 10 recognize this problem and use a variety of simulation techniques to incorporate dynamic factors and time horizons. Screening curves are more restrictive since they produce 'snapshot' estimates of capacity mixes.

6.6.3. Summary

In spite of the drawbacks identified for screening curve analysis, the technique provides a useful tool when properly applied. Screening curves are especially useful as aids for narrowing the range of possible technology alternatives that need to be considered in more detailed analysis. A major difficulty with long-range optimization models is that they quickly become unmanageable as the number of options increases. Screening curves provide a straightforward and rapid method for determining which technologies are potentially competitive with other energy sources. The rough estimates of capacity mix also provide useful guidelines for scoping and examining detailed simulations.

In comparison with production cost analysis, screening curves do not treat many of the important factors that affect generation costs. Production cost methods can provide reasonably accurate estimates of costs as affected by unit performance parameters, cost characteristics and complex operating considerations. However, computational requirements of production cost calculations preclude their full use in comprehensive long-term optimization models. As such, the screening curve method is especially useful for reducing the excessive size of expansion studies in the earlier stages of investigation, while production cost techniques are more useful in the later stages of expansion analysis when cost assumptions and approximations have to be reviewed for accuracy.

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