SECTION 8

GENERATION OF ELECTRIC POWER

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MAJOR PARAMETER DECISIONS

The major parameter decisions that must be made for any new electric power-generating plant or unit include the choices of energy source (fuel), type of generation system, unit and plant rating, and plant site. These decisions must be based upon a number of technical, economic, and environmental factors that are to a large extent interrelated (see Table 8.1). Evaluate the parameters for a new power-generating plant or unit.

Calculation Procedure

1. Consider the Energy Source and Generating System

As indicated in Table 8.2, a single energy source or fuel (e.g., oil) is often capable of being used in a number of different types of generating systems. These include steam cycles, combined steam- and gas-turbine cycles (systems where the hot exhaust gases are delivered to a heat-recovery steam generator to produce steam that is used to drive a steam turbine), and a number of advanced technology processes such as fuel cells (i.e., systems having cathode and anode electrodes separated by a conducting electrolyte that convert liquid or gaseous fuels to electric energy without the efficiency limits of the Carnot cycle).

Similarly, at least in the planning stage, a single generic type of electric-power generating system (e.g., a steam cycle) can be designed to operate on any one of a number of fuels. Conversion from one fuel to another after plant construction does, however, generally entail significant capital costs and operational difficulties.

As Table 8.3 indicates, each combination of energy source and power-generating-system type has technical, economic, and environmental advantages and disadvantages that are unique. Often, however, in a particular situation there are other unique considerations that make the rankings of the various systems quite different from the typical values listed in Table 8.3. In order to make a determination of the best system, it is necessary to quantify and evaluate all factors in Table 8.3 (see page 8.4). Generally, this involves a complicated

TABLE 8.1 Major Parameter Decisions for New Plant

Parameter	Some alternatives
Energy source or fuel	Common fossil fuels (coal, oil, and natural gas) Nuclear fuels (uranium and thorium) Elevated water (hydroelectric) Geothermal steam Other renewable, advanced technology, or nonconventional sources
Generation system type	Steam-cycle (e.g., steam-turbine) systems (with or without cogeneration team for district heating and industrial steam loads) Hydroelectric systems Combustion-turbine (e.g., gas-turbine) systems Combined-cycle (i.e., combined steam- and gas-turbine) systems Internal-combustion engine (e.g., diesel) systems Advanced technology or nonconventional sources
Unit and plant rating	Capable of serving the current expected maximum electrical load and providing some spinning reserve for reliability and future load growth considerations Capable of serving only the expected maximum electrical load (e.g., peaking unit) Capable of serving most of the expected maximum load (e.g., using conservation or load management to eliminate the load that exceeds generation capacity)
Plant site	Near electrical load Near fuel source Near water source (water availability) Near existing electrical transmission system Near existing transportation system Near or on existing electrical-generation plant site

TABLE 8.2 Generic Types of Electric-Generating Systems

Energy source or fuel	Approximate percentage of total electric generation	Steam cycle 85 percent	Hydroelectric 13 percent	Combined steam- and gas-turbine cycle 1 percent	Combustion turbines 1 percent	Internal combustion engine (diesel) 1 percent	Photovoltaic	Wind turbine	Fuel cell	Magneto hydrodynamic	Thermoelectric	Thermionic	Open-steam or closed-ammonia cycle
Coal	44	X							X	X	X	X	
Oil	16	X		X	X	X			X	X	X	X	
Natural gas	14	X		X	X				X	X	X	X	
Elevated water supply	13		X										
Nuclear fission (uranium or thorium)	13	X											
Geothermal	0.15	X											
Refuse-derived fuels		X											
Shale oil		X		X	X				X	X	X	X	
Tar sands		X		X	X	X			X	X	X	X	
Coal-derived liquids and gases		X		X	X	X			X	X	X	X	
Wood		X											
Vegetation (biomass)		X											
Hydrogen		X				X			X	X	X	X	
Solar		X					X						
Wind								X					
Tides			X										
Waves			X										
Ocean thermal gradients													X
Nuclear fission			X										

TABLE 8.3 Comparison of Energy Source and Electrical-Generating Systems

Energy Source (fuel) and generation-system type	Fuel cost	System efficiency	Capital cost, \$/kW	System operation and maintenance (excluding fuel) costs, \$/MWh	Largest available unit ratings	System reliability and availability	System complexity	Fuel availability	Cooling water requirements	Major environmental impacts
Coal-fired steam cycle	Intermediate	High	Very high	Low to medium	Large	High	Very high	Best	Large	Particulars, SO_2 and oxides of nitrogen (NO_x) in stack gases; disposal of scrubber sludge and ashes
Oil-fired steam cycle	Highest	High	High	Lowest	Large	Very high	High	Fair	Large	SO_2 and NO_x in stack gases; disposal of scrubber sludge
Natural-gas–fired steam cycle	High	High	High	Lowest	Large	Very high	High	Fair	Large	NO_x in stack gases
Nuclear	Low	Intermediate	Highest	Medium	Largest	High	Highest	Good	Largest	Safety; radioactive waste disposal
Oil-fired combustion engine	Highest	Low	Lowest	Highest	Smallest	Lowest	Moderate	Fair	Smallest	SO_2 and NO_x in stack gases
Natural-gas–fired combustion turbine	High	Low	Lowest	Highest	Smallest	Lowest	Moderate	Fair	Smallest	NO_x in stack gases
Oil-fired combined cycle	Highest	Very high	Intermediate	Medium	Intermediate	Medium	Moderate	Fair	Moderate	SO_2 and NO_x in stack gases
Natural-gas–fired combined cycle	High	Very high	Intermediate	Medium	Intermediate	Medium	Moderate	Fair	Moderate	NO_x in stack gases
Hydroelectric	Lowest	Highest	Intermediate to highest	Low	Large	Highest if water is available	Lowest	Limited by area	Small	Generally requires construction of a dam
Geothermal steam	Low	Lowest	Intermediate	Medium	Intermediate	High	Low	Extremely limited by area	Low	H_2S emissions from system

tradeoff process and a considerable amount of experience and subjective judgment. Usually, there is no one system that is best on the basis of all the appropriate criteria.

For example, in a comparison between coal and nuclear energy, nuclear energy generally has much lower fuel costs but higher capital costs. This makes an economic choice dependent to a large extent on the expected capacity factor (or equivalent full-load hours of operation expected per year) for the unit. Coal and nuclear-energy systems have, however, significant but vastly different environmental impacts. It may well turn out that one system is chosen over another largely on the basis of a subjective perception of the risks or of the environmental impacts of the two systems.

Similarly, a seemingly desirable and economically justified hydroelectric project (which has the additional attractive features of using a renewable energy source and in general having high system availability and reliability) may not be undertaken because of the adverse environmental impacts associated with the construction of a dam required for the project. The adverse environmental impacts might include the effects that the dam would have on the aquatic life in the river, or the need to permanently flood land above the dam that is currently being farmed, or is inhabited by people who do not wish to be displaced.

2. Select the Plant, Unit Rating, and Site

The choice of plant, unit rating, and site is a similarly complex, interrelated process. As indicated in Table 8.3 (and 8.9), the range of unit ratings that are commercially available is quite different for each of the various systems. If, for example, a plant is needed with a capacity rating much above 100 MW, combustion turbine, diesel, and geothermal units could not be used unless multiple units were considered for the installation.

Similarly, the available plant sites can have an important impact upon the choice of fuel, power-generating system, and rating of the plant. Fossil-fuel or nuclear-energy steam-cycle units require tremendous quantities of cooling water [50.5 to 63.1 m^3/s (800,000 to 1,000,000 gal/min)] for a typical 1000-MW unit, whereas gas-turbine units require essentially no cooling water. Coal-fired units rated at 1000 MW would typically require over 2.7 million tonnes (3 million tons) of coal annually, whereas nuclear units rated at 1000 MW would typically require only 32.9 tonnes (36.2 tons) of enriched uranium dioxide (UO_2) fuel annually.

Coal-fired units require disposal of large quantities of ash and scrubber sludge, whereas natural-gas-fired units require no solid-waste disposal whatsoever. From each of these comparisons it is easy to see how the choice of energy source and power-generating system can have an impact on the appropriate criteria to be used in choosing a plant site. The location and physical characteristics of the available plant sites (such as proximity to and availability of water, proximity to fuel or fuel transportation, and soil characteristics) can have an impact on the choice of fuel and power-generating system.

3. Examine the Alternatives

Each of the more conventional electric-power generating systems indicated in Table 8.3 is available in a variety of ratings. In general, installed capital costs (on a dollars per kilowatt basis) and system efficiencies (heat rates) are quite different for the different ratings. Similarly, each of the more conventional systems is available in many variations of equipment types, equipment configurations, system parameters, and operating conditions.

For example, there are both pulverized-coal and cyclone boilers that are of either the drum or once-through type. Steam turbines used in steam cycles can be of either the tandem-compound or cross-compound type, with any number of feedwater heaters, and be either of the condensing, back-pressure, or extraction (cogeneration) type. Similarly, there are a number of standard inlet and reheat system conditions (i.e., temperatures and pressures). Units may be designed for base-load, intermediate-load, cycling, or peaking operation. Each particular combination of equipment type, equipment configuration, system parameters, and operating conditions has associated cost and operational advantages and disadvantages, which for a specific application must be evaluated and determined in somewhat the same manner that the fuel and electrical-generation system choice is made.

4. Consider the Electrical Load

The electrical load, on an electric-power system of any size generally fluctuates considerably on a daily basis, as shown by the shapes of typical daily load curves for the months April, August, and December in Fig. 8.1. In addition, on an annual basis, the system electrical load varies between a minimum load level, below which the electrical demand never falls, and a maximum or peak, load level which occurs for only a few hours per year. The annual load duration curve of Fig. 8.1*a* graphically shows the number of hours per year that the load on a particular power system exceeds a certain level.

For example, if the peak-power system load in the year (100 percent load) is 8100 MW, the load duration curve shows that one could expect the load to be above 70 percent of the peak (i.e., above $0.7 \times 8100 \text{ MW} = 5760 \text{ MW}$) about 40 percent of the year. The minimum load (i.e., load exceeded 100 percent of the time) is about 33 percent of the peak value.

Typically, for U.S. utility systems the minimum annual load is 27 to 33 percent of the peak annual load. Generally, the load level exceeds 90 percent of the peak value 1 to 5 percent of the time, exceeds 80 percent of the peak value 5 to 30 percent of the time, and exceeds 33 to 45 percent of the peak 95 percent of the time. Annual load factors [(average load/peak annual load) $\times$ 100 percent] typically range from 55 to 65 percent.

The frequency of a system fluctuates as the load varies, but the turbine governors always bring it back to 60 Hertz. The system gains or loses a few cycles throughout the day due to these fluctuations. When the accumulated loss or gain is about 180 cycles, the error is corrected by making all the generators turn either faster or slower for a brief period.

A major disturbance on a system, or contingency, creates a state of emergency. Immediate steps must be taken to prevent the contingency from spreading to other regions. The sudden loss of an important load or a permanent short-circuit on a transmission line constitutes a major contingency.

If a big load is suddenly lost, all the turbines begin to speed up and the frequency increases everywhere on the system. On the other hand, if a generator is disconnected, the speed of the remaining generators decreases because they suddenly have to carry the entire load. The frequency then starts to decrease at a rate that may reach 5 Hz/s, and no time must be lost under these conditions. Therefore, if conventional methods are unable to bring the frequency back to normal, some load must be dropped. Such load shedding is done by frequency-sensitive relays that open selected circuit breakers as the frequency falls.

Related Calculations. Generally, considerable economic savings can be obtained by using higher capital cost, lower operating cost units (such as steam-cycle units) to serve the base load (Fig. 8.1) and by using lower capital cost, higher operating cost units (such as combustion turbines) to serve the peaking portion of the load. The intermediate load range is generally best served by a combination of base-load, peaking, combined-cycle, and hydroelectric units that have intermediate capital and operating costs and have design provisions that reliably permit the required load fluctuations and hours per year of operation.

The optimum combination or mix of base-load, intermediate-load, and peaking power-generating units of various sizes involves use of planning procedures and production cost vs. capital cost tradeoff evaluation methods.

	April	August	December	Annual
Load factor	0.667	0.586	0.652	0.623
Min. load / peak load factor	0.371	0.378	0.386	0.330

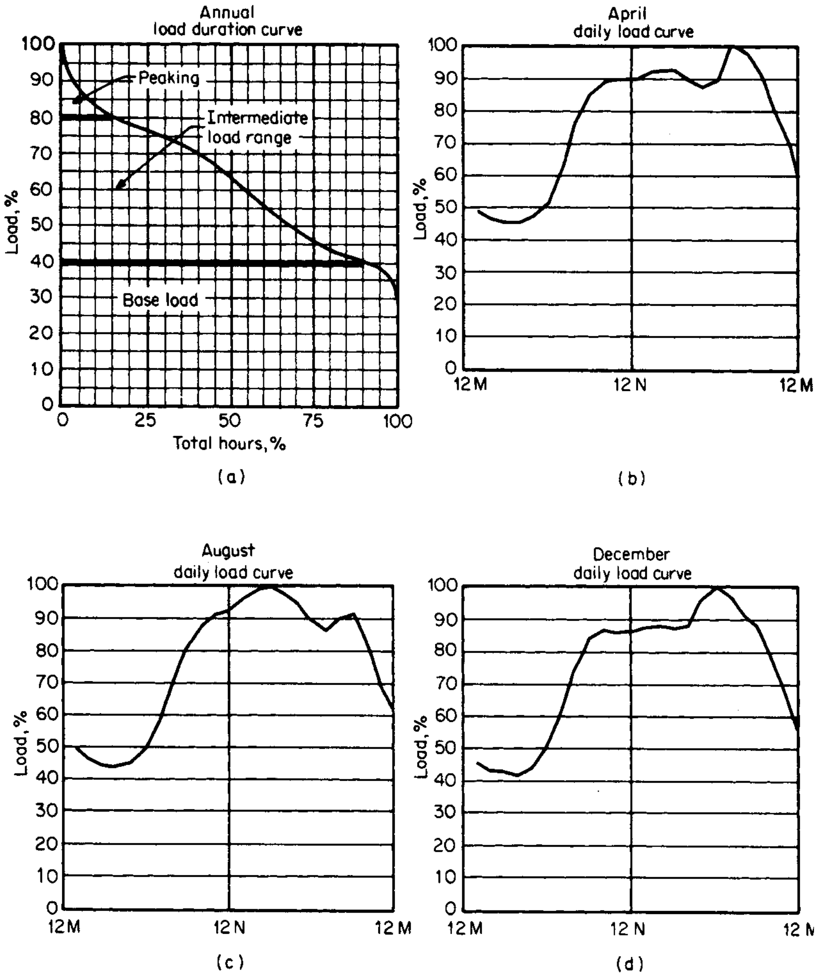

FIGURE 8.1 Examples of annual load duration and daily load curves for a power system.

OPTIMUM ELECTRIC-POWER GENERATING UNIT

Determine the qualities of an optimum new electric-power generating unit to be applied to an existing utility system. (Table 8.4 is a summary of all the necessary steps in making this kind of determination.)

TABLE 8.4 Steps to Determine the Optimum New Electric-Power Generating Unit

Step 1	Identify all possible energy source (fuel) and electric-generation-system combination alternatives.
Step 2	Eliminate alternatives that fail to meet system commercial-availability criteria.
Step 3	Eliminate alternatives that fail to meet energy source (fuel) commercial-availability criteria.
Step 4	Eliminate alternatives that fail to meet other functional or site-specific criteria.
Step 5	Eliminate alternatives that are always more costly than other feasible alternatives.
Step 5*a*	Calculate the appropriate annual fixed-charge rate.
Step 5*b*	Calculate fuel costs on a dollars per million Btu basis.
Step 5*c*	Calculate the average net generation unit heat rates.
Step 5*d*	Construct screening curves for each system.
Step 5*e*	Use screening-curve results to choose those alternatives to be evaluated further.
Step 5*f*	Construct screening curves for feasible renewable and alternative energy sources and generation systems and compare with alternatives in Step 5*e*.
Step 6	Determine coincident maximum predicted annual loads over the entire planning period.
Step 7	Determine the required planning reserve margin.
Step 8	Evaluate the advantages and disadvantages of smaller and larger generation-unit and plant ratings.
Step 8*a*	Consider the economy-of-scale savings associated with larger unit and plant ratings.
Step 8*b*	Consider the operational difficulties associated with unit ratings that are too large.
Step 8*c*	Take into account the range of ratings commercially available for each generation-system type.
Step 8*d*	Consider the possibility of jointly owned units.
Step 8*e*	Consider the forecast load growth.
Step 8*f*	Determine the largest unit and plant ratings that can be used in generation expansion plans.
Step 9	Develop alternative generation expansion plans.
Step 10	Compare generation expansion plans on a consistent basis.
Step 11	Determine the optimum generation expansion plan by using an iterative process.
Step 12	Use the optimum generation expansion plan to determine the next new generation units or plants to be installed.
Step 13	Determine the generator ratings for the new generation units to be installed.
Step 14	Determine the optimum plant design.
Step 15	Evaluate tradeoff of annual operation and maintenance costs vs. installed capital costs.
Step 16	Evaluate tradeoffs of thermal efficiency vs. capital costs and/or operation and maintenance costs.
Step 17	Evaluate tradeoff of unit availability (reliability) and installed capital costs and/or operation and maintenance costs.
Step 18	Evaluate tradeoff of unit rating vs. installed capital costs.

Calculation Procedure

1. Identify Alternatives

As indicated in Table 8.2, there are over 60 possible combinations of fuel and electric-power generating systems that either have been developed or are in some stage of development. In the development of power-generating expansion plans (to be considered later), it is necessary to evaluate a number of installation sequences with the various combinations of fuel and electric-power generating systems with various ratings. Even with the use of large computer programs, the number of possible alternatives is too large to reasonably evaluate. For this reason, it is necessary to reduce this large number of alternatives to a reasonable and workable number early in the planning process.

2. Eliminate Alternatives That Fail to Meet System Commercial Availability Criteria

Reducing the number of alternatives for further consideration generally begins with elimination of all of those systems that are simply not developed to the stage where they can be considered to be available for installation on a utility system in the required time period. The alternatives that might typically be eliminated for this reason are indicated in Table 8.5.

3. Eliminate Alternatives That Fail to Meet Energy-Source Fuel Commercial Availability Criteria

At this point, the number of alternatives is further reduced by elimination of all of those systems that require fuels that are generally not commercially available in the required quantities. Alternatives that might typically be eliminated for this reason are also indicated in Table 8.5.

4. Eliminate Alternatives That Fail to Meet Other Functional or Site-Specific Criteria

In this step those alternatives from Table 8.2 are eliminated that, for one reason or another, are not feasible for the particular existing utility power system involved. Such systems might include wind (unless 100- to 200-kW units with a fluctuating and interruptible power output can suffice), geothermal (unless the utility is located in the geyser regions of northern California), conventional hydroelectric (unless the utility is located in a region where elevated water is either available or can feasibly be made available by the construction of a river dam), and tidal hydroelectric (unless the utility is located near one of the few feasible oceanic coastal basin sites).

Table 8.5 is intended to be somewhat representative of the current technology. It is by no means, however, intended to be all-inclusive or representative for all electric-power

TABLE 8.5 Systems That Might Be Eliminated

Reason for elimination	Systems eliminated
Systems are not commercially available for installation on a utility system.	Fuel-cell systems Magnetohydrodynamic systems Thermoelectric systems Thermionic systems Solar photovoltaic or thermal-cycle systems Ocean thermal gradient open-steam or closed-ammonia cycle systems Ocean-wave hydraulic systems Nuclear-fusion systems
Energy source (fuel) is not commercially available in the required quantities.	Shale oil Tar sands Coal-derived liquids and gases Wood Vegetation Hydrogen Refuse-derived fuels
Systems typically do not satisfy other functional, feasibility, or site-specific criteria.	Wind Geothermal Conventional hydroelectric Tidal hydroelectric

generating installation situations. For example, in certain situations the electric-power generating systems that are used extensively today (such as coal and oil) may be similarly eliminated for such reasons as inability to meet government clean-air and/or disposal standards (coal), fuel unavailability for a variety of reasons including government policy (oil or natural gas), lack of a site where a dam can be constructed without excessive ecological and socioeconomic impacts (hydroelectric), or inability to obtain the necessary permits and licenses for a variety of environmental and political reasons (nuclear).

Similarly, even now, it is conceivable that in a specific situation a number of those alternatives that were eliminated such as wind and wood, might be feasible. Also, in the future, several of the generating systems such as solar photovoltaic might become available in the required ratings or might be eliminated because of some other feasibility criterion.

It should be emphasized that for each specific electric-generating-system installation it is necessary to identify those energy alternatives that must be eliminated from further consideration on the basis of criteria that are appropriate for the specific situation under consideration.

5. Eliminate Alternatives That Are Always More Costly Than Other Feasible Alternatives

In this step those remaining fuel and electric-power generating system alternatives from Table 8.2 are eliminated from further consideration that will not, under any reasonable foreseeable operational criteria, be less costly than other feasible alternatives.

Typically, the elimination of alternatives in this stage is based on a comparison of the total power-generating costs of the various systems, considering both the fixed costs (i.e., capital plus fixed operation and maintenance costs) and the production costs (fuel costs plus variable operation and maintenance costs) for the various systems.

This comparison is generally made by means of *screening curves,* such as those in Figs. 8.2 through 8.4. For each combination of fuel and electric-power generating system

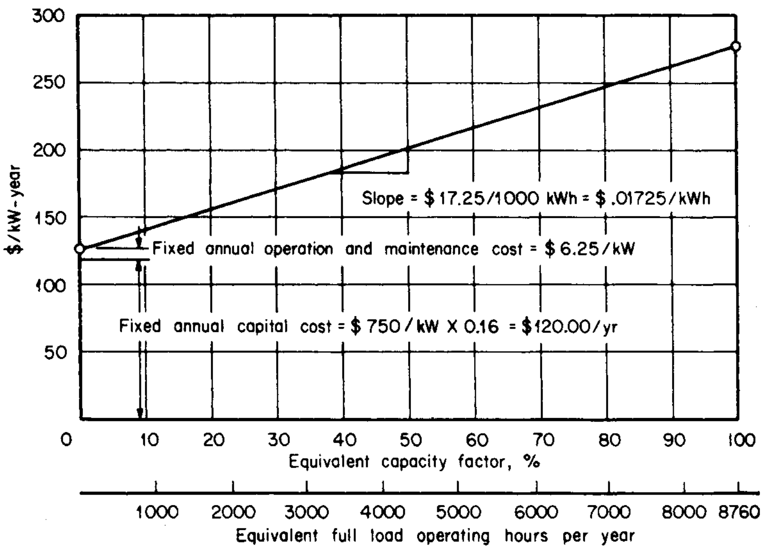

FIGURE 8.2 Construction of a screening curve for a coal-fired steam-cycle unit.

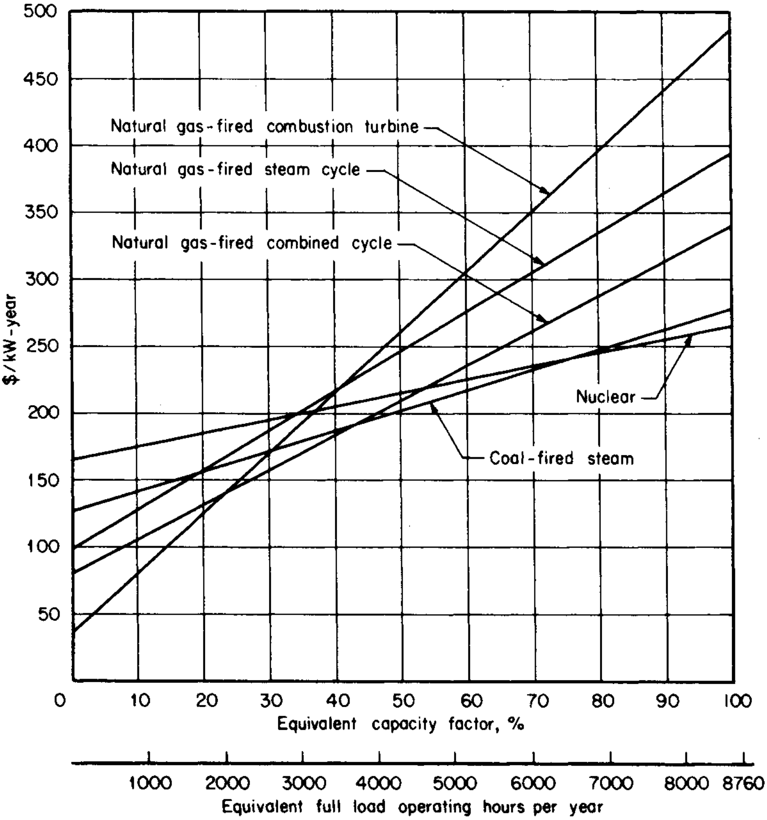

FIGURE 8.3 Screening curves for electric-generation-system alternatives based on assumption of availability of natural gas.

still under consideration, the annual operation costs per installed kilowatt (dollars per year per kilowatt) is plotted as a function of capacity factor (or equivalent full-load operation hours per year).

ANNUAL CAPACITY FACTOR

Determine the annual capacity factor of a unit rated at 100 MW that produces 550,000 MWh per year.

Calculation Procedure

1. Compute Annual Capacity Factor as a Percentage

The factor is

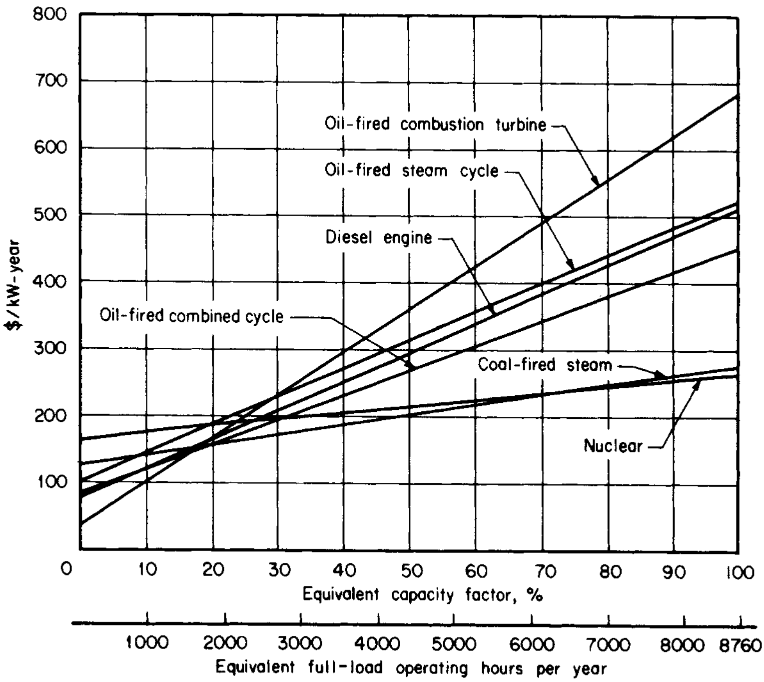

FIGURE 8.4 Screening curves for electric-generation-system alternatives based on assumption that natural gas is unavailable.

$$\left(\frac{550{,}000 \text{ MWh/100 MW}}{8760 \text{ h/yr}}\right) 100 \text{ percent} = 68.2 \text{ percent}$$

2. Compute Annual Capacity Factor in Hours per Year

The factor is (68.2/100)(8760 h/yr) = 5550 h/yr.

ANNUAL FIXED-CHARGE RATE

Estimate the annual fixed rate for an investor-owned electric utility.

Calculation Procedure

1. Examine the Appropriate Factors

As shown in Table 8.6, the annual fixed-charge rate represents the average, or "levelized," annual carrying charges including interest or return on the installed capital, depreciation or return of the capital, tax expense, and insurance expense associated with the installation of a particular generating unit for the particular utility or company involved.

TABLE 8.6 Typical Fixed-Charge Rate for Investor-Owned Electric Utility

Charge	Rate, percent
Return	7.7
Depreciation	1.4
Taxes	6.5
Insurance	0.4
Total	16.0

Related Calculations. Fixed-charge rates for investor-owned utilities generally range from 15 to 20 percent; fixed-charge rates for publicly owned utilities are generally about 5 percent lower.

FUEL COSTS

Calculate fuel costs on a dollars per megajoule (and million Btu) basis.

Calculation Procedure

1. Compute Cost of Coal

On a dollars per megajoule (dollars per million Btu) basis, the cost of coal at \$39.68/tonne (\$36/ton) with a heating value of 27.915 MJ/kg (12,000 Btu/lb) is (\$39.68/tonne)/[(1000 kg/tonne)(27.915 MJ/kg)] = \$0.001421/MJ = \$1.50/million Btu.

2. Compute the Costs of Oil

On a dollars per megajoule basis, the cost of oil at \$28 per standard 42-gal barrel (\$0.17612/L) with a heating value of 43.733 MJ/kg (18,800 Btu/lb) and a specific gravity of 0.91 is (\$0.17612/L)/[(43.733 MJ/kg)(0.91 kg/L)] = \$0.004425/MJ = \$4.67/million Btu.

3. Compute the Cost of Natural Gas

On a dollars per megajoule basis, natural gas at \$0.1201/m^3 (\$3.40 per thousand standard cubic feet) with a heating value of 39.115 MJ/m^3 = 1050 Btu/1000 ft^3 costs (\$0.1201/m^3)/(39.115 MJ/m^3) = \$0.00307/MJ = \$3.24/million Btu.

4. Compute Cost of Nuclear Fuel

On a dollars per megajoule basis, nuclear fuel at \$75.36/MWday costs (\$75.36/MWday)/[(1.0 J/MWs)(3600 s/h)(24 h/day)] = \$0.00087/MJ = \$0.92/million Btu.

AVERAGE NET HEAT RATES

A unit requires 158,759 kg/h (350,000 lb/h) of coal with a heating value of 27.915 MJ/kg (12,000 Btu/lb) to produce 420,000 kW output from the generator. In addition, the unit has electric power loads of 20,000 kW from required power-plant auxiliaries, such as boiler feed pumps. Calculate the average net generation unit rate.

Calculation Procedure

1. Define the Net Heat Rate

The average net heat rate (in Btu/kWh or J/kWh) of an electric-power generating unit is calculated by dividing the total heat input to the system (in units of Btu/h or MJ/h) by the net electric power generated by the plant (in kilowatts), taking into account the boiler, turbine, and generator efficiencies and any auxiliary power requirements.

2. Compute the Total Heat Input to Boiler

Total heat input to boiler equals (158,759 kg/h)(27.915 MJ/kg) = 4.43×10^6 MJ/h = 4200×10^6 Btu/h.

3. Compute the Net Power Output of the Generating Unit

Net generating-unit power output is 420,000 kW − 20,000 kW = 400,000 kW.

4. Determine the Net Heat Rate of the Generating Unit

The net generating unit heat rate is (4.43×10^6 MJ/h)/400,000 kW = 11.075 MJ/kWh = 10,500 Btu/kWh.

CONSTRUCTION OF SCREENING CURVE

A screening curve provides a plot of cost per kilowattyear as a function of capacity factor or operating load. An example is the screening curve of Fig. 8.2 for a coal-fired steam-cycle system, based on the data in Table 8.7 (see pages 8.16 and 8.17). Assume the total installed capital cost for a 600-MW system is \$450 million and the fixed-charge rate is 16 percent. In addition, assume the total fixed operation and maintenance cost is \$3,750,000 per year for the unit. Verify the figures given in Fig. 8.2.

Calculation Procedure

1. Determine the Fixed Annual Capital Cost

The installed cost per kilowatt is (\$450 × 10^6)/600,000 kW = \$750/kW. Multiplying by the fixed-charge rate, we obtain the fixed annual cost: (\$750/kW)(0.16) = \$120/kWyr.

2. Compute Fixed Operation and Maintenance Costs

Fixed operation and maintenance cost on a per-kilowatt basis is (\$3,750,000/yr)/ 600,000 kW = \$6.25/kWyr.

3. Compute Cost per Year at a Capacity Factor of Zero

The cost in dollars per year per kilowatt at a capacity factor of zero is \$126.25/kWyr, which is the sum of the annual fixed capital cost, \$120/kWyr, plus the annual fixed operation and maintenance cost of \$6.25/kWyr.

4. Determine the Fuel Cost

Coal at \$39.68/tonne with a heating value of 27.915 MJ/kg costs \$0.001421/MJ, as determined in a previous example. With an average unit heat rate of 11.075 MJ/kWh, the fuel cost for the unit on a dollars per kilowatthour basis is (\$0.001421/MJ)(11.075 MJ/kWh) = \$0.01575/kWh.

With a levelized variable operation and maintenance cost for the system of \$0.00150/kWh (Table 8.7), the total variable production cost for the coal-fired steam-cycle unit is \$0.01725/kWh (i.e., the fuel cost, \$0.01575/kWh, plus the variable operation and maintenance cost of \$0.00150/kWh, or \$0.01725/kWh). Hence, the total annual fixed and variable costs on a per-kilowatt basis to own and operate a coal-fired steam-cycle system 8760 h per year (100 percent capacity factor) would be \$126.25/kWyr + (\$0.01725/kWh)(8760 h/yr) = 126.26/kWh + \$151.11/kWyr = \$277.36/kWyr.

Related Calculations. As indicated in Fig. 8.2, the screening curve is linear. The *y* intercept is the sum of the annual fixed capital, operation, and maintenance costs and is a function of the capital cost, fixed-charge rate, and fixed operation and maintenance cost. The slope of the screening curve is the total variable fuel, operation, and maintenance cost for the system (i.e., \$0.01725/kWh), and is a function of the fuel cost, heat rate, and variable operation and maintenance costs.

Table 8.7 shows typical data and screening curve parameters for all those combinations of energy source and electric-power generating system (listed in Table 8.2) that were not eliminated on the basis of some criterion in Table 8.5. Table 8.7 represents those systems that would generally be available today as options for an installation of an electric-power–generating unit.

Figure 8.3 illustrates screening curves plotted for all non-oil-fired systems in Table 8.7. For capacity factors below 23.3 percent (2039 equivalent full-load operating hours per year), the natural-gas–fired combustion turbine is the least costly alternative. At capacity factors from 23.3 to 42.7 percent, the natural-gas–fired combined-cycle system is the most economical. At capacity factors from 42.7 to 77.4 percent, the coal-fired steam-cycle system provides the lowest total cost, and at capacity factors above 77.4 percent, the nuclear plant offers the most economic advantages. From this it can be concluded that the optimum generating plan for a utility electric power system would consist of some rating and installation sequence combination of those four systems.

Steam-cycle systems, combined-cycle systems, and combustion-turbine systems can generally be fired by either natural gas or oil. As indicated in Table 8.7, each system firing with oil rather than natural gas generally results in higher annual fixed capital cost and higher fixed and variable operation, maintenance, and fuel costs. Consequently, oil-fired systems usually have both higher total fixed costs and higher total variable costs than natural-gas–fired systems. For this reason, firing with oil instead of natural gas results in higher total costs at all capacity factors.

In addition, as indicated in Table 8.3, the fact that oil-fired systems generally have more environmental impact than natural-gas systems means that if adequate supplies of natural gas are available, oil-fired steam cycles, combined cycles, and combustion-turbine systems would be eliminated from further consideration. They would never provide any benefits relative to natural-gas–fired systems.

If natural gas were not available, the alternatives would be limited to the non-natural-gas–fired systems of Table 8.7. The screening curves for these systems are plotted in Fig. 8.4. From the figure, if natural gas is unavailable, at capacity factors below 16.3 percent oil-fired combustion turbines are the least costly alternative. At capacity factors from 16.3 to 20.0 percent, oil-fired combined-cycle systems are the most economical. At capacity factors from 20.0 to 77.4 percent a coal-fired steam-cycle system provides the lowest total cost, and at capacity factors above 77.4 percent nuclear is the best.

If any of those systems in Table 8.5 (which were initially eliminated from further consideration on the basis of commercial availability or functional or site-specific criteria) are indeed possibilities for a particular application, a screening curve should also be constructed for those systems. The systems should then be evaluated in the same manner as the systems indicated in Figs. 8.3 and 8.4. The screening curves for renewable energy

TABLE 8.7 Data Used for Screening Curves of Figs. 8.2 through 8.4

System	Total installed capital cost, millions of dollars	Unit rating, MW	Installed capital cost, $/kW	Annual levelized fixed-charge rate, percent	Annual fixed capital cost, $/kWyr	Total annual fixed O&M cost, millions of dollars per year	Annual fixed O&M costs, $/kWyr	Annual fixed capital, O&M costs, $/kWyr
Coal-fired steam cycle	450.0	600	750	16	120.00	3.75	6.25	126.25
Oil-fired steam-cycle	360.0	600	600	16	96.00	3.30	5.50	101.50
Natural-gas–fired steam cycle	348.0	600	580	16	92.80	3.00	5.00	97.80
Nuclear	900.0	900	1000	16	160.00	5.13	5.70	165.07
Oil-fired combined cycle	130.5	300	435	18	78.30	1.275	4.25	82.55
Natural-gas–fired combined cycle	126.0	300	420	18	75.60	1.20	4.00	79.60
Oil-fired combustion turbine	8.5	50	170	20	34.00	0.175	3.50	37.50
Natural-gas–fired combustion turbine	8.0	50	160	20	32.00	0.162	3.25	35.25
Diesel engine	3.0	8	375	20	75.00	0.024	3.00	78.00

*$/t = $/ton × 1.1023
$/L = ($/42-gal barrel) × 0.00629
$/m³ = ($/MCF) × 0.0353
†MJ/kg = (Btu/lb) × 0.002326
MJ/m³ = (Btu/SCF) × 0.037252
‡MJ/t = (million Btu/ton) × 1163
MJ/m³ = (million Btu/bbl) × 6636
MJ/m³ = (million Btu/MCF) × 37.257
MJ/MWday = (million Btu/MWday) × 1055

§$/MJ = ($/million Btu) × 0.000948
¶MJ/kWh = (Btu/kWh) × 0.001055
J/kWh = (Btu/kWh) × 1055

Fuel costs* $/standard unit	Fuel energy content†	Energy content per standard unit,‡ millions Btu per standard unit	Fuel cost,§ dollars per million Btu	Average net heat rate for unit,¶ Btu/kWh	Fuel cost, $/kWh	Levelized variable O&M costs, $/kWh	Total variable costs (fuel + variable O&M cost), $/kWh
$36/ton	12,000 Btu/lb	24 million Btu/ton	1.50	10,500	0.1575	0.00150	0.01725
$28/bbl	18,800 Btu/lb with 0.91 specific gravity	6 million Btu/barrel	4.67	10,050	0.04693	0.00130	0.04823
$3.40/ 1000 ft^3 (MCF)	1050 Btu per standard cubic foot (SCF)	1.05 million Btu/MCF	3.24	10,050	0.03256	0.00120	0.03376
$75.36/ MWday		81.912 million Btu/MWday	92	11,500	0.01058	0.00085	0.01143
$28/bbl	18,800 Btu/lb with 0.91 specific gravity	6 million Btu/barrel	4.67	8,300	0.03876	0.00350	0.04226
$3.40/ MCF	1050 Btu/ SCF	1.05 million Btu/MCF	3.24	8,250	0.02673	0.00300	0.02973
$28/bbl	18,800 Btu/lb with 0.91 specific gravity	6 million Btu/barrel	4.67	14,700	0.06865	0.00500	0.07365
$3.40/ MCF	1050 Btu/SCF	1.05 million Btu/MCF	3.24	14,500	0.04698	0.00450	0.05148
$28/bbl	18,800 Btu/lb with 0.91 specific gravity	6 million Btu/bbl	4.67	10,000	0.04670	0.00300	0.04970

sources such as hydroelectric, solar, wind, etc. are essentially horizontal lines because the fuel, variable operation, and maintenance costs for such systems are negligible.

NONCOINCIDENT AND COINCIDENT MAXIMUM PREDICTED ANNUAL LOADS

For a group of utilities that are developing generating-system expansion plans in common, the combined maximum predicted annual peak loads used in generating-system expansion studies should be the coincident maximum loads (demands) expected in the year under consideration. Any diversity (or noncoincidence) in the peaks of the various utilities in the group should be considered. Such diversity, or noncoincidence, will in general be most significant if all the various utilities in the planning group do not experience a peak demand in the same season.

Assume the planning group consists of four utilities that have expected summer and winter peak loads in the year under consideration, as indicted in Table 8.8. Determine the noncoincident and coincident annual loads.

Calculation Procedure

1. Analyze the Data in Table 8.8

Utilities A and D experience the highest annual peak demands in the summer season, and utilities B and C experience the highest annual peak demands in the winter season.

2. Compute Noncoincident Demands

Total noncoincident summer maximum demand for the group of utilities is less than the annual noncoincident maximum demand by [1 − (8530 MW/8840 MW)](100 percent) = 3.51 percent. The total noncoincident winter maximum demand is less than the annual noncoincident maximum demand by [1 − (8240 MW/8840 MW)](100 percent) = 6.79 percent.

3. Compute Coincident Demands

If the seasonal diversity for the group averages 0.9496 in the summer and 0.9648 in the winter, the total coincident maximum demand values used for generation expansion

TABLE 8.8 Calculation of Coincident Maximum Demand for a Group of Four Utilities

	Maximum demand, MW		
	Summer	Winter	Annual
Utility A	3630	3150	3630
Utility B	2590	2780	2780
Utility C	1780	1900	1900
Utility D	530	410	530
Total noncoincident maximum demand	8530	8240	8840
Seasonal diversity factor	0.9496	0.9648	
Total coincident maximum demand	8100 MW	7950 MW	8100 MW*

*Maximum of summer and winter.

planning in that year would be (8530 MW)(0.9496) = 8100 MW in the summer and (8240 MW)(0.9648) = 7950 MW in the winter.

REQUIRED PLANNING RESERVE MARGIN

All utilities must plan to have a certain amount of reserve generation capacity to supply the needs of their power customers in the event that a portion of the installed generating capacity is unavailable.

Reserve generating capability is also needed to supply any expected growth in the peak needs of electric utility customers that might exceed the forecast peak demands. In generating-system expansion planning such reserves are generally identified as a percentage of the predicted maximum annual hourly demand for energy.

Compute the reserve capacity for a group of utilities (Table 8.8) having a predicted maximum hourly demand of 8100 MW.

Calculation Procedure

1. Determine What Percentage Increases Are Adequate

Lower loss-of-load probabilities are closely related to higher planning reserve margins. Experience and judgment of most utilities and regulators associated with predominantly thermal power systems (as contrasted to hydroelectric systems) has shown that planning reserves of 15 to 25 percent of the predicted annual peak hourly demand are adequate.

2. Calculate Reserve and Installed Capacity

The range of additional reserve capacity is (0.15)(8100) = 1215 MW to (0.25)(8100) = 2025 MW. The total installed capacity is, therefore, 8100 + 1215 = 9315 MW to 8100 + 2025 = 10,125 MW.

Related Calculations. The reliability level of a particular generation expansion plan for a specific utility or group of utilities is generally determined from a loss-of-load probability (LOLP) analysis. Such an analysis determines the probability that the utility, or group of utilities, will lack sufficient installed generation capacity on-line to meet the electrical demand on the power system. This analysis takes into account the typical unavailability, because of both planned (maintenance) outages and unplanned (forced) outages, of the various types of electric-power generating units that comprise the utility system.

For generating-system expansion planning a maximum loss-of-load probability value of 1 day in 10 years has traditionally been used as an acceptable level of reliability for an electric-power system. Owing primarily to the rapid escalation of the costs of power-generating-system equipment and to limits in an electrical utility's ability to charge rates that provide for the financing of large construction projects, the trend recently has been to consider higher loss-of-load probabilities as possibly being acceptable.

Planning for generating-system expansion on a group basis generally results in significantly lower installed capacity requirements than individual planning by utilities. For example, collectively the utilities in Table 8.8 would satisfy a 15 percent reserve requirement with the installation of 9315 MW, whereas individually, on the basis of total annual noncoincident maximum loads, utilities would install a total of 10,166 MW to retain the same reserve margin of 15 percent.

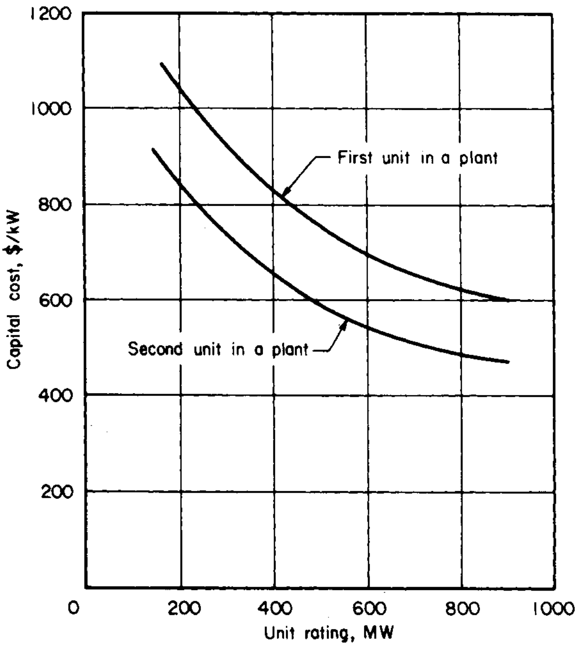

FIGURE 8.5 Typical capital costs vs. unit-rating trend for first and second coal-fired steam-cycle units.

Generating-expansion planning by a group also requires a certain amount of joint planning of the electrical transmission system to ensure that the interconnections between the various utilities in the planning group have sufficient capacity to facilitate the seasonal transfer of power between the utilities. This enables each utility in the planning group to satisfy the applicable reserve criteria at all times of the year.

For all types of electric-power generating units, it is generally the case that smaller unit ratings have higher installed capital costs (on a dollar per kilowatt basis) and higher annual fixed operation and maintenance costs (on a dollar per kilowatthour basis), with the increase in the costs becoming dramatic at the lower range of ratings that are commercially available for that type of electric-power generating unit. Figs. 8.5 and 8.6 illustrate this for coal-fired steam units. Smaller generating units also generally have somewhat poorer efficiencies (higher heat rates) than the larger units.

The installation of generating units that are too large, however, can cause a utility to experience a number of operational difficulties. These may stem from excessive operation of units at partial loads (where unit heat rates are poorer) or inability to schedule unit maintenance in a manner such that the system will always have enough spinning reserve capacity on-line to supply the required load in the event of an unexpected (forced) outage of the largest generation unit.

In addition, it is not uncommon for large units to have somewhat higher forced-outage rates than smaller units, which implies that with larger units a somewhat larger planning reserve margin might be needed to maintain the same loss-of-load probability.

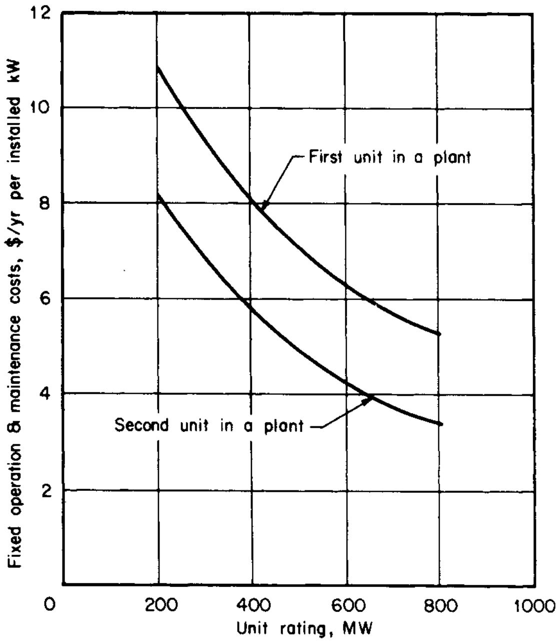

FIGURE 8.6 Typical fixed operation and maintenance costs vs. unit-rating trend for first and second coal-fired steam-cycle units.

RATINGS OF COMMERCIALLY AVAILABLE SYSTEMS

The ratings of the various system types indicated in Table 8.7 are typical of those that are commonly available today. Actually, each of the various systems is commercially available in the range of ratings indicated in Table 8.9. Evaluate the different systems.

Calculation Procedure

1. Consider Nuclear Units

Nuclear units are available in tandem-compound turbine configurations (Fig. 8.7*a*) where a high-pressure (HP) turbine and one to three low-pressure (LP) turbines are on one shaft system driving one generator at 1800 r/min in ratings from 500 to 1300 MW.

2. Consider Fossil-Fuel Units

Steam units fired by fossil fuel (coal, oil, or natural gas) are available in tandem-compound 3600-r/min configurations (Fig. 8.7*b*) up to 800 MW and in cross-compound turbine configurations (Fig. 8.7*c*) where an HP and intermediate-pressure (IP) turbine are on one shaft driving a 3600-r/min electric generator. One or more LP turbines on a second shaft system drive an 1800-r/min generator in ratings from 500 to 1300 MW.

TABLE 8.9 Commercially Available Unit Ratings

Type	Configuration*	Rating range
Fossil-fired (coal, oil, natural gas) steam turbines	Tandem-compound	20–800 MW
	Cross-compound	500–1300 MW
Nuclear steam turbine	Tandem-compound	500–1300 MW
Combined-cycle systems	Two- or three-shaft	100–300 MW
Combustion-turbine systems	Single-shaft	<1–110 MW
Hydroelectric systems	Single-shaft	<1–800 MW
Geothermal systems	Single-shaft	<20–135 MW
Diesel systems	Single-shaft	<1–20 MW

*See Fig. 8.7.

Related Calculations. Combined-cycle systems are generally commercially available in ratings from 100 to 300 MW. Although a number of system configurations are available, it is generally the case that the gas- and steam-turbine units in combined-cycle systems drive separate generators, as shown in Fig. 8.7*d*.

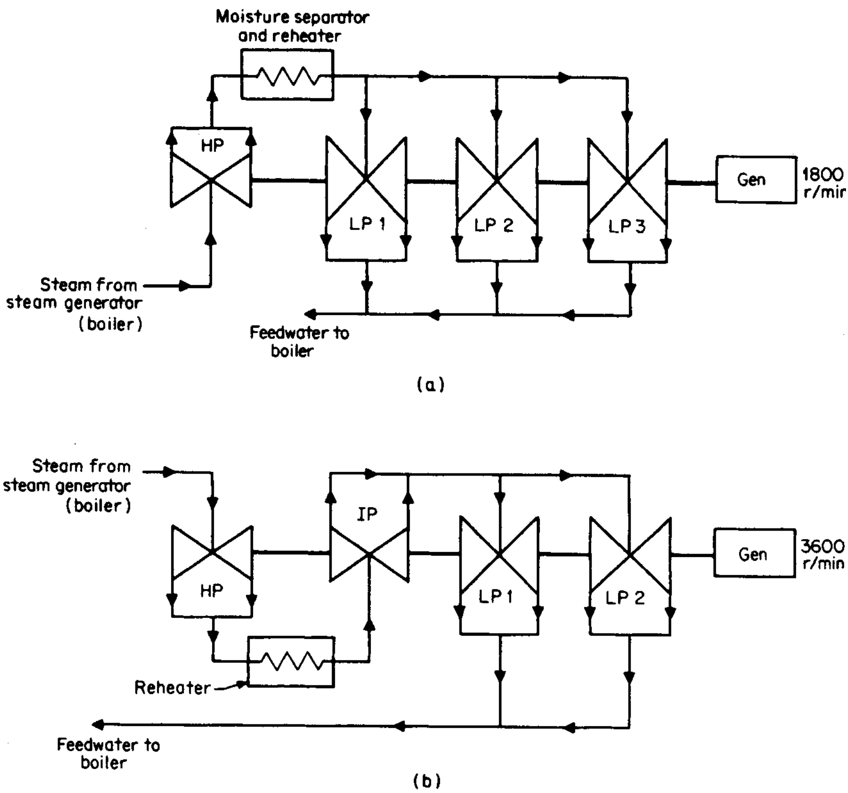

FIGURE 8.7 Various turbine configurations.

Because nuclear and larger fossil-fired unit ratings are often too large for a particular company or electric utility to assimilate in a single installation, it has become common for the smaller and medium-size utilities to install and operate these types of units on a joint, or pool, basis. In this arrangement, one utility has the responsibility for installation and operation of the units for all of the partners. Each of the utilities pays a percentage of all capital and operation costs associated with the unit in accordance with the ownership splits.

Such an arrangement enables all of the owners of the unit to reap the benefits of the lower installed capital costs (dollars per kilowatt) and lower operation costs (dollars per kilowatthour) typical of larger-size units. The operational difficulties associated with having too much of an individual company's total installed capacity in a single generating unit are minimized.

For a number of technical and financial reasons (including excessive fluctuations in reserve margins, uneven cash flows, etc.) utilities find it beneficial to provide for load growth with capacity additions every 1 to 3 years. Hence, the rating of units used in a generating-system expansion plan is to a certain extent related to the forecast growth in the period.

HYDROPOWER GENERATING STATIONS

Hydropower generating stations convert the energy of moving water into electrical energy by means of a hydraulic turbine coupled to a synchronous generator. The power that can be extracted from a waterfall depends upon its height and rate of flow. Therefore, the size and physical location of a hydropower station depends on these two factors.

The available hydropower can be calculated by the following equation:

$$P = 9.8 \times q \times h$$

where

P = available water power (kW)

q = water rate of flow (m^3/s)

h = head of water (m)

9.8 = coefficient used to take care of units

The mechanical power output of the turbine is actually less than the value calculated by the preceding equation. This is due to friction losses in the water conduits, turbine casing, and the turbine itself. However, the efficiency of large hydraulic turbines is between 90 and 94 percent. The generator efficiency is even higher, ranging from 97 to 99 percent, depending on the size of the generator.

Hydropower stations can be divided into three groups based on the head of water:

1. High-head development
2. Medium-head development
3. Low-head development

High-head developments have heads in excess of 300 m, and high-speed turbines are used. Such generating stations can be found in mountainous regions, and the amount of impounded water is usually small. Medium-head developments have heads between 30 m and 300 m, and medium-speed turbines are used. The generating station is typically fed by a large reservoir of water retained by dikes and a dam. A large amount of water is usually impounded behind the dam. Low-head developments have heads under 30 m, and low-speed turbines are used. These generating stations often extract the energy from flowing rivers, and no reservoir is provided. The turbines are designed to handle large volumes of water at low pressure.

LARGEST UNITS AND PLANT RATINGS USED IN GENERATING-SYSTEM EXPANSION PLANS

The group of utilities in Table 8.8 is experiencing load growth as shown in Table 8.10. Determine the largest nuclear and fossil unit ratings allowable through year 15 and beyond.

Calculation Procedure

1. Select Unit Ratings

Generally the largest unit installed should be 7 to 15 percent of the peak load of the utility group. For this reason, in Columns 5 and 7 of Table 8.10, 900-MW nuclear and 600-MW fossil units are selected through year 15. Beyond year 15, 1100-MW nuclear and 800-MW fossil were chosen.

2. Determine the Ratings for 1 Percent Growth per Year

For lower annual load growth of 1 percent per year instead of 2.1 to 3.2 percent as indicated, financial considerations would probably encourage the utility to install 600-MW nuclear and 300- to 400-MW fossil units instead of the 600- to 1100-MW units.

ALTERNATIVE GENERATING-SYSTEM EXPANSION PLANS

At this point, it is necessary to develop numerous different generating-system expansion plans or strategies. The development of two such plans or strategies is indicated in Table 8.10. The plans should be based upon the forecast maximum (peak) coincident hourly electrical demand (load) for each year in the planning period for the group of utilities that are planning together. The planning period for such studies is commonly 20 to 40 yr.

If the installed capacity for the group of utilities is initially 9700 MW, Columns 5 and 7 might be representative of two of the many generating-system expansion plans or strategies that a planner might develop to provide the required capacity for each year in the planning period. Determine the total installed capacity and percentage reserve for Plan B.

Calculation Procedure

1. Compute the Installed Capacity in Year 6

The total installed capacity in year 6 is 9700 MW initially, plus a 300-MW combined-cycle unit in year 2, plus a 900-MW nuclear unit in year 3, plus a 50-MW natural-gas–fired combustion-turbine unit in year 5, plus a 600-MW coal-fired steam unit in year 6 = 11,550 MW. This exceeds the required installed capacity of 11,209 MW.

2. Compute the Reserve Percentage

The percentage reserve is [(11,550 MW/9,747 MW) − 1.0](100 percent) = 18.5 percent, which exceeds the targeted planning reserve level of 15 percent.

Related Calculations. The excess of the actual reserves in a given generating-system expansion plan over the targeted planning reserve level increases the total cost of the plan but also to some degree improves the overall reliability level. It therefore needs to be considered in the comparison of generating-system plans.

The generating-system expansion plans developed usually contain only those types of electric-power generating systems, that were found in the screening curve analysis to yield minimum total annual cost in some capacity factor range. For example, if natural gas is available in sufficient quantities over the planning period, the types of electric-power generating systems used in the alternative generating-system expansion plans would be limited to nuclear units, coal-fired steam-cycle units, and natural-gas–fired combined-cycle and combustion-turbine units, as indicated in Table 8.10.

After a number of different generating-system expansion strategies are developed, the plans must be compared on a consistent basis so that the best plan to meet a given reliability index can be determined. The comparison between the various generating-system expansion plans is generally performed by calculating for each plan the production and investment costs over the life of the plan (20 to 40 yr) and then evaluating those costs using discounted revenue requirements (i.e., present worth, present value) techniques (see Sec. 19).

The production costs for each generating-system expansion plan are generally calculated by large computer programs that simulate the dispatching (or loading) of all the units on the entire power system, hourly or weekly, over the entire planning period. These programs generally employ a probabilistic technique to simulate the occasional unavailability of the various units on the power system. In addition, load forecast, economic, and technical data for each existing and new unit on the power system and for the power system as a whole (as indicated in the first four columns of Table 8.11) are required.

The investment costs for each plan are generally calculated by computer programs that simulate the net cash flows due to the investments in the various plans. Annual book depreciation, taxes, insurance, etc., appropriate for the particular utility involved, are considered. These programs generally require the economic data and corporate financial model data indicated in the last column of Table 8.11.

To determine the optimum generating-system plan over the planning period, sufficient generating-system expansion plans similar to those indicated in Table 8.10 must be developed and evaluated so that all of the reasonable combinations of electric-power–generating-system types, ratings, and installation timing sequences are represented. Even with the use of large computer programs, the number of possible alternative plans based on all combinations of plant types, ratings, etc. becomes too cumbersome to evaluate in detail. It is generally the case, therefore, that generating-system planners use an iterative process to determine the optimum plan.

For example, early in the evaluation process, a smaller number of alternative plans is evaluated. On the basis of a preliminary evaluation, one or more of those plans are modified in one or more ways and reevaluated on a basis consistent with the initial plan to determine if the modifications make the plan less than optimum.

As indicated in Table 8.12, it takes a number of years to license and construct a new power plant. The initial years of the various alternative generating-system expansion plans represent new power-generating facilities for which the utility is already committed. For this reason, the initial years of all of the alternative generating-system plans are generally the same.

TABLE 8.10 Two Alternative Generation Expansion Plans Developed for a Utility

Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8
				Generating-system expansion Plan A		Generating-system expansion Plan B	
Year	Forecast annual growth in peak load coincident, percent yr	Forecast maximum or peak coincident demand or load, MW	Required installed capacity with 15 percent minimum reserve margin, MW	Capacity installation, MW	Total installed capacity, MW	Capacity installation, MW	Total installed capacity, MW
0 (current year)		8,100		9700	9,700	9700	9,700
1	3.2	8,359	9,613	—	9,700	—	9,700
2	3.2	8,627	9,921	600 C	10,300	300 CC	10,000
3	3.2	8,903	10,238	50 CT	10,350	900 N	10,900
4	3.2	9,188	10,566	900 N	11,250	—	—
5	3.2	9,482	10,904	—	11,250	50 CT	10,950
6	2.8	9,747	11,209	50 CT	11,300	600 C	11,550
7	2.8	10,020	11,523	300 CC	11,600	50 CT	11,600
8	2.8	10,301	11,846	600 C	12,220	300 CC	11,900
9	2.8	10,589	12,177	50 CT	12,250	900 N	12,800
10	2.1	10,811	12,433	900 N	13,150	—	—
11	2.1	11,038	12,694	—	13,150	50 CT	12,850
12	2.1	11,270	12,961	—	13,150	600 C	13,450

13	2.1	11,507	13,233	300 CT	13,450	—	—
14	2.5	11,795	13,564	600 C	14,050	300 CC	13,750
15	2.5	12,089	13,903	—	—	900 N	14,650
16	2.5	12,392	14,250	1100 N	15,150	—	—
17	2.5	12,701	14,607	—	15,150	50 CT	14,700
18	2.7	13,044	15,001	50 CT	15,200	800 C	15,500
19	2.7	13,397	15,406	300 CC	15,500	300 CC	15,800
20	2.7	13,758	15,822	800 C	16,300	50 CT	15,850
21	2.7	14,130	16,249	50 CT	16,350	1100 N	16,950
22	2.7	14,511	16,688	800 C	17,150	—	—
23	3.0	14,947	17,189	50 CT	17,200	800 C	17,750
24	3.0	15,395	17,704	1100 N	18,300	—	—
25	3.0	15,857	18,235	—	—	1100 N	18,850
26	3.0	16,333	18,782	800 C	19,100	—	—
27	3.0	16,823	19,346	1100 N	20,200	800 C	19,650
28	3.0	17,327	19,926	—	—	300 CC	19,950
29	3.0	17,847	20,524	800 C	21,000	1100 N	21,050
30	3.0	18,382	21,140	800 C	21,800	800 C	21,850

Key: N = nuclear steam-cycle unit, C = coal-fired steam-cycle unit, CC = natural-gas–fired combined-cycle unit, and CT = natural-gas–fired combustion turbine.

TABLE 8.11 Data Generally Required for Computer Programs to Evaluate Alternative Expansion Plans

Load-forecast data	Data for each existing unit	Data for each new unit	General technical data regarding power system	Economic data and corporate financial model data
Generally determined from an analysis of historical load, energy requirement, and weather-sensitivity data using probabilistic mathematics	Fuel type	Capital cost and/or levelized carrying charges	Units required in service at all times for system area protection and system integrity	Capital fuel and O&M costs and inflation rates for various units
Future annual load (MW) and system energy requirements (MWh) on a seasonal, monthly, or weekly basis	Fuel cost	Fuel type	Hydroelectric unit type and data—run of river, pondage, or pumped storage	Carrying charge or fixed-charge rates for various units
Seasonal load variations	Unit incremental heat rates (unit efficiency)	Fuel costs	Minimum fuel allocations (if any)	Discount rate (weighted cost or capital)
Load-peak variance	Unit fuel and startup	Unit incremental heat rates	Future system load data	Interest rate during construction
Load diversity (for multiple or interconnected power systems) Sales and purchases to other utilities	Unit maximum and minimum rated capacities	Unit fuel and startup costs	Data for interconnected company's power system or power pool	Planning period (20–50 yr)
Seasonally representative load-duration curve shapes	Unit availability and reliability data such as partial and full forced outage rates	Unit availability and reliability data such as mature and immature full and partial forced-outage rates and scheduled outages	Reliability criteria such as a spinning reserve or loss-of-load probability (LOLP) operational requirements	Book life, tax life, depreciation rate and method, and salvage value or decommissioning cost for each unit
	Scheduled outage rates and maintenance schedules	Unit commercial operation dates	Limitations on power system ties and interconnections with the pool and/or other companies	Property and income tax rates
	O&M (fixed, variable, and average)	Unit maximum and minimum capacities	Load management	Investment tax credits
	Seasonal derating (if any) and seasonal derating period	Sequence of unit additions	Required licensing and construction lead time for each type of generation unit	Insurance rates
	Sequence of unit retirements (if any)	Operation and maintenance costs (fixed and variable)		
	Minimum downtime and/or dispatching sequence (priority) of unit use	Time required for licensing and construction of each type of unit		

TABLE 8.12 Time Required to License and Construct Power Plants in the United States

Type	Years
Nuclear	8–14
Fossil-fired steam	6–10
Combined-cycle units	4–8
Combustion turbine	3–5

The resulting optimum generating-system expansion plan is generally used, therefore, to determine the nature of the next one or two power-generating facilities after the committed units. For example, if Plan A of Table 8.10 is optimum, the utility would already have to be committed to the construction of the 600-MW coal-fired unit in year 2, the 50-MW combustion turbine in year 3, and the 900-MW nuclear unit in year 4. Because of the required lead times for the units in the plan, the optimum plan, therefore, would in essence have determined that licensing and construction must begin shortly for the 50-MW combustion turbine in year 6, the 300-MW turbine combined-cycle unit in year 7, the 600-MW coal-fired unit in year 8, and the 900-MW nuclear unit in year 10.

GENERATOR RATINGS FOR INSTALLED UNITS

After determining the power ratings in MW of the next new generating units, it is necessary to determine the apparent power ratings in MVA of the electric generator for each of those units. For a 0.90 power factor and 600-MW turbine, determine the generator rating.

Calculation Procedure

1. Compute the Rating

Generator rating in MVA = turbine rating in MW/power factor. Hence, the generator for a 600-MW turbine would be rated at 600 MW/0.90 = 677 MVA.

Related Calculations. The turbine rating in MW used in the preceding expression may be the rated or guaranteed value, the 5 percent over pressure value (approximately 105 percent of rated), or the maximum calculated value [i.e., 5 percent over rated pressure and valves wide open (109 to 110 percent of rated)] with or without one or more steam-cycle feedwater heaters out of service. This depends upon the manner in which an individual utility operates its plants.

OPTIMUM PLANT DESIGN

At this point, it is necessary to specify the detailed design and configuration of each of the power-generating facilities. Describe a procedure for realizing an optimum plant design.

Calculation Procedure

1. Choose Design

Consider for example, the 600-MW coal-fired plant required in year 8; a single design (i.e., a single physical configuration and set of rated conditions) must be chosen for each component of the plant. Such components may include coal-handling equipment, boiler, stack-gas cleanup systems, turbine, condenser, boiler feed pump, feedwater heaters, cooling systems, etc. for the plant as a whole.

2. Perform Economic Analyses

In order to determine and specify the optimum plant design for many alternatives, it is necessary for the power-plant designer to repeatedly perform a number of basic economic analyses as the power-plant design is being developed. These analyses, almost without exception, involve one or more of the following tradeoffs:

a. Operation and maintenance cost vs. capital costs

b. Thermal efficiency vs. capital costs and/or operation and maintenance (O&M) costs

c. Unit availability (reliability) vs. capital costs and/or O&M costs

d. Unit rating vs. capital cost

ANNUAL OPERATION AND MAINTENANCE COSTS VS. INSTALLED CAPITAL COSTS

Evaluate the tradeoffs of annual O&M costs vs. installed capital for Units A and B in Table 8.13.

TABLE 8.13 Evaluation of Annual O&M Costs vs. Installed Capital Costs

Cost component	Unit A	Unit B
Net unit heat rate	10.55 MJ/kWh (10,000 Btu/kWh)	10.55 MJ/kWh (10,000 Btu/kWh)
Unit availability	95 percent	95 percent
Unit rating	600 MW	600 MW
Installed capital costs	$\$450 \times 10^6$	$\$455 \times 10^6$
Levelized or average fixed-charge rate	18.0 percent	18.0 percent
Levelized or average annual O&M cost (excluding fuel)	$\$11.2 \times 10^6$/yr	$\$9.7 \times 10^6$/yr
For Unit A:		
Annual fixed capital charges = $(\$450 \times 10^6)(18/100)$	=	$\$81.00 \times 10^6$/yr
Annual O&M cost (excluding fuel)	=	$\$11.20 \times 10^6$/yr
Total annual cost used for comparison with Unit B	=	$\$92.20 \times 10^6$/yr
For Unit B:		
Annual fixed capital charges = $(\$455 \times 10^6)(18/100)$	=	$\$81.90 \times 10^6$/yr
Annual O&M cost (excluding fuel)	=	$\$9.70 \times 10^6$/yr
Total annual cost used for comparison with Unit A	=	$\$91.60 \times 10^6$/yr

Calculation Procedure

1. Examine Initial Capital Costs

Units A and B have the same heat rate [10.550 MJ/kWh (10,000 Btu/kWh)], plant availability (95 percent), and plant rating (600 MW). As a result, the two alternatives would also be expected to have the same capacity factors and annual fuel expense.

Unit B, however, has initial capital costs that are \$5 million higher than those of Unit A but has annual O&M costs (excluding fuel) that are \$1.5 million less than those of Unit A. An example of such a case would occur if Unit B had a more durable, higher capital-cost cooling tower filler material [e.g., polyvinyl chloride (PVC) or concrete] or condenser tubing material (stainless steel or titanium), whereas Unit A had lower capital-cost wood cooling-tower filler or carbon steel condenser tubing.

2. Analyze Fixed and Annual Costs

For an 18 percent fixed-charge rate for both alternatives, the annual fixed charges are \$900,000 higher for Unit B (\$81.9 million per year vs. \$81.0 million per year). Unit B, however, has annual O&M costs that are \$1.5 million lower than those of Unit A. Unit B, therefore, would be chosen over Unit A because the resulting total annual fixed capital, operation, and maintenance costs (excluding fuel, which is assumed to be the same for both alternatives) are lower for Unit B by \$600,000 per year. In this case, the economic benefits associated with the lower annual operation and maintenance costs for Unit B are high enough to offset the higher capital costs.

THERMAL EFFICIENCY VS. INSTALLED CAPITAL AND/OR ANNUAL OPERATION AND MAINTENANCE COSTS

Table 8.14 describes two alternative units that have different thermal performance levels but have the same plant availability (reliability) and rating. Unit D has a net heat rate (thermal performance level) that is 0.211 MJ/kWh (200 Btu/kWh) higher (i.e., 2 percent poorer) than that of Unit C but has both installed capital costs and levelized annual O&M costs that are somewhat lower than those of Unit C. Determine which unit is a better choice.

Calculation Procedure

1. Compute the Annual Fixed Charges and Fuel Cost

If the two units have the same capacity factors, Unit D with a higher heat rate requires more fuel than Unit C. Because Unit D has both installed capital costs and levelized annual operation and maintenance costs that are lower than those of Unit C, the evaluation problem becomes one of determining whether the cost of the additional fuel required each year for Unit D is more or less than the reductions in the annual capital and O&M costs associated with Unit D.

The simplest method of determining the best alternative is to calculate the total annual fixed charges and fuel costs using the following expressions:

Annual fixed charges (dollars per year) $=$ TICC $\times$ FCR/100, where TICC $=$ total installed capital cost for Unit C or D (dollars) and FCR $=$ average annual fixed-charge rate (percent/yr).

TABLE 8.14 Evaluation of Thermal Efficiency vs. Installed Capital Costs and Annual Costs

Cost components	Unit C	Unit D
Net unit heat rate	10.550 MJ/kWh (10,000 Btu/kWh)	10.761 MJ/kWh (10,200 Btu/kWh)
Unit availability	95 percent	95 percent
Unit rating	600 MW	600 MW
Installed capital cost	$\$450 \times 10^6$	$\$445 \times 10^6$
Levelized or average fixed-charge rate	18.0 percent	18.0 percent
Levelized or average annual O&M costs (excluding fuel)	$\$11.2 \times 10^6$/yr	$\$11.1 \times 10^6$/yr
Levelized or average capacity factor	70 percent	70 percent
Levelized or average fuel cost over the unit lifetime	$1.50/million Btu ($0.001422/MJ)	$1.50/million Btu ($0.001422/MJ)
For Unit C:		
Annual fixed capital charges = ($\$450 \times 10^6$)(18/100)		= $\$ 81.00 \times 10^6$/yr
Annual O&M cost (excluding fuel)		= $\$ 11.20 \times 10^6$/yr
Annual fuel expense		
= (10.550 MJ/kWh)(600,000 kW)(8760 h/yr)(70/100)($0.001422/MJ)		= $\$55.19 \times 10^6$/yr
[= (10,000 Btu/kWh)(600,000 kW)(8760 h/yr)(70/100)($\$1.50/10^6$ Btu)]		
Total annual cost used for comparison with Unit D		= $\$147.39 \times 10^6$/yr
For Unit D:		
Annual fixed capital charges = ($\$445 \times 10^6$)(18/100)		= $\$80.10 \times 10^6$/yr
Annual O&M cost (excluding fuel)		= $\$11.10 \times 10^6$/yr
Annual fuel expense		
= (10.761 MJ/kWh)(600,000 kW)(8760 h/yr)(70/100)($0.001422/MJ)		= $\$56.29 \times 10^6$/yr
[= (10,200 Btu/kWh)(600,000 kW)(8760 h/yr)(70/100)($\$1.50/10^6$ Btu)]		
Total annual cost used for comparison with Unit C		= $\$147.49 \times 10^6$/yr

Annual fuel expense (dollars per year) = HR × rating × 8760 × CF/100 × FC/10^6, where HR = average net heat rate in J/kWh (Btu/kWh), rating = plant rating in kW, CF = average or levelized unit capacity factor in percent, and FC = average or levelized fuel costs over the unit lifetime in dollars per megajoule (dollars per million Btu). The calculated values for these parameters are provided in Table 8.14.

2. *Make a Comparison*

As shown in Table 8.14, even though the annual fixed charges for Unit C are \$900,000 per year higher (\$81.0 million per year vs. \$80.10 million per year) and the annual O&M costs for Unit C are \$100,000 per year higher (\$11.2 million per year vs. \$11.1 million per year), the resulting total annual costs are \$100,000 per year lower for Unit C (\$147.39 million per year vs. \$147.49 million per year). This stems from the annual fuel expense for Unit C being \$1.10 million per year lower than for Unit D (\$55.19 million per year vs. \$56.29 million per year) because the heat rate of Unit C is 0.2110 MJ/kWh (200 Btu/kWh) better. In this case, the Unit C design should be chosen over that of Unit D because the economic benefits associated with the 0.2110 MJ/kWh (200 Btu/kWh) heat-rate improvement more than offsets the higher capital and O&M costs associated with Unit C.

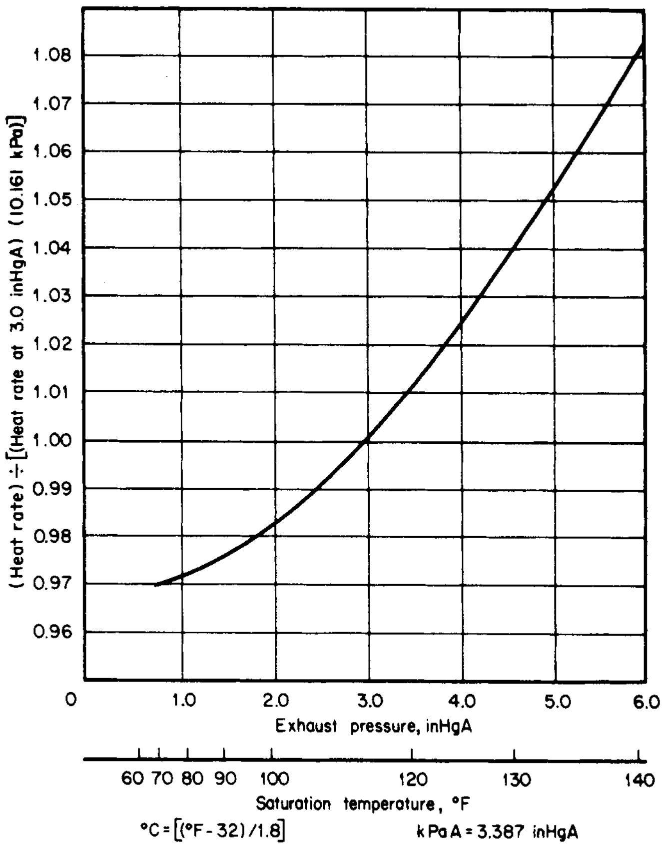

FIGURE 8.8 Typical heat rate vs. exhaust pressure curve for fossil-fired steam-cycle units.

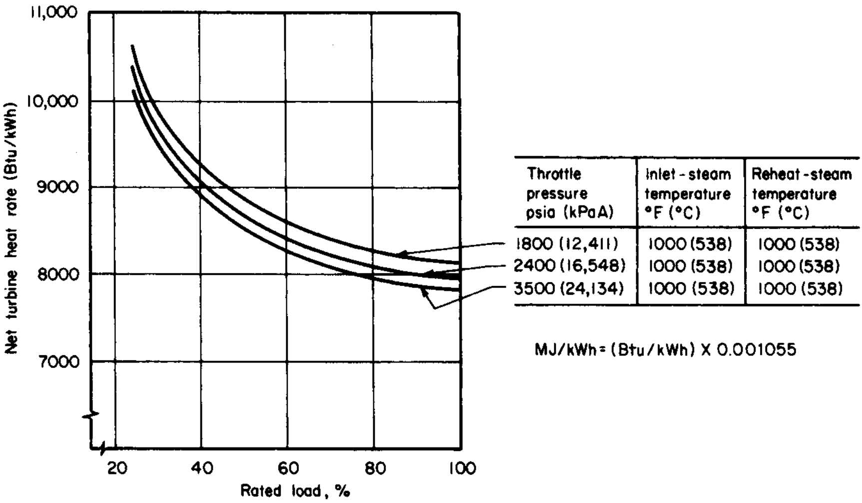

FIGURE 8.9 Fossil-fired steam-cycle unit turbine heat rates at 7.6-cmHgA exhaust pressure vs. percent-rated load.

Related Calculations. The heat rate for a steam-cycle unit changes significantly with the turbine exhaust pressure (the saturation pressure and temperature provided by the cooling system) as shown in Fig. 8.8; with the percentage of rated load (amount of partial load operation of the unit) as shown in Fig. 8.9; with the choice of throttle (gauge) pressure of 12,411 kPa (1800 psig) vs. a gauge pressure measured at 16,548 kPa (2400 psig) vs. 24,132 kPa (3500 psig) as shown in Fig. 8.9 and Table 8.15; with throttle and reheater temperature and reheater pressure drop; and with a number of steam-cycle configuration and component performance changes as shown in Table 8.16. Therefore it is necessary for the power-plant designer to investigate carefully the choice of each of these parameters.

For example, as shown in Fig. 8.8, a change in cooling-tower performance (such as a change in the cooling-tower dimensions or a change in the rated circulating water flow) that increases the turbine-exhaust saturation temperature from 44.79°C to 48.62°C would cause the turbine-exhaust saturation pressure to rise from an absolute pressure of

TABLE 8.15 Effect of Steam-Condition Changes on Net Turbine Heat Rates

Steam condition	Percent change in net heat rate			
Throttle pressure, psi	1800	2400	3500	3500
Number of reheats	1	1	1	1
Throttle pressure (change from preceding column)		1.9–2.1	1.8–2.0	1.6–2.0
50°F Δ throttle temperature	0.7	0.7–0.8	0.8–0.9	0.7
50°F Δ first reheat temperature	0.8	0.8	0.8	0.4
50°F Δ second reheat temperature				0.6
One point in percent Δ reheated pressure drop	0.1	0.1	0.1	0.1
Heater above reheat point	0.7	0.6	0.5–0.6	

kPa = psi × 6.895
Δ°C = ΔF/1.8

TABLE 8.16 Effect of Steam-Cycle Changes on Net Turbine Heat Rates

	Change in net heat rate*	
Cycle configuration	Percent	Btu/kWh†
1. Extraction line pressure drops of 3 percent rather than 5 percent (constant throttle flow)	−0.14	−11
2. Bottom heater drains flashed to condenser through 15°F drain cooler rather than 10°F‡	+0.01–0.02	+1–2
3. Change deaerator heater to closed-cascading type with a 5°F temperature difference (TD) and a 10°F drain cooler	+0.24	+19
4. Make all drain coolers 15°F rather than 10°F	+0.01	+1
5. Reduce demineralized condenser makeup from 3 percent to 1 percent	−0.43	−35
6. Make top heater 0°F TD rather than −3°TD (constant throttle flow)	+0.01	+1
7. Make low-pressure heater TDs 3°F rather than 5°F	−0.11	−9
8. Eliminate drain cooler on heater 7	+0.08	+6.1

*+, is poorer
†MJ/kWh = (Btu/kWh) × 0.001055
‡Δ°C = Δ°F/1.8

9.48 kPa (2.8 inHg) to 11.52 kPa (3.4 inHg), which, as indicated in Fig. 8.8, would increase the heat-rate factor from 0.9960 to 1.0085 (i.e., a change of 0.0125 or 1.25 percent). For a net turbine heat rate of 8.440 MJ/kWh (8000 Btu/kWh), this results in an increase of 0.106 MJ/kWh (100 Btu/kWh); that is, (8.440 MJ/kWh)(0.0125) = 0.106 MJ/kWh.

From Fig. 8.9, operation of a unit at a gauge pressure of 16,548 kPa/538°C/538°C (2400 psig/1000°F/1000°F) at 70 percent of rated load instead of 90 percent would increase the net turbine heat rate by 0.264 MJ/kWh (250 Btu/kWh) from 8.440 MJ/kWh (8000 Btu/kWh) to 8.704 MJ/kWh (8250 Btu/kWh).

From Table 8.15 and Fig. 8.9, a change in the throttle gauge pressure from 16,548 kPa (2400 psig) to 12,411 kPa (1800 psig) would increase the heat rate from 0.160 to 0.179 MJ/kWh (152 to 168 Btu/kWh), that is, from 1.9 to 2.1 percent of 8.440 MJ/kWh (8000 Btu/kWh).

REPLACEMENT FUEL COST

Table 8.17 describes the pertinent data for two alternatives that have the same net unit heat rate and rating. Unit F, however, has an average unit availability about 3 percent lower than Unit E (92 vs. 95 percent). The capacity factor for each unit is 70 percent. Determine the replacement fuel cost.

Calculation Procedure

1. Analyze the Problem

Because the ratings and heat rates are the same, it is convenient, for evaluation purposes, to assume that a utility would attempt to produce the same amount of electric power with either unit throughout the year. However, because of its lower plant availabil-

TABLE 8.17 Evaluation of Reliability vs. Installed Capital and O&M Costs

	Unit E	Unit F
Net unit heat rate	10.550 MJ/kWh (10,000 Btu/kWh)	10.550 MJ/kWh (10,000 Btu/kWh)
Unit availability	95 percent	92 percent
Unit rating	600 MW	600 MW
Installed capital cost	$\$450 \times 10^6$	$\$440 \times 10^6$
Levelized or average fixed charge rate	18 percent	18 percent
Levelized or average annual O&M cost (excluding fuel)	$\$11.2 \times 10^6$/yr	$\$12.0 \times 10^6$/yr
Desired levelized or average capacity factor	70 percent	70 percent
Actual levelized or average capacity factor	70 percent	67.8 percent
For Unit E:		
Annual fixed capital charges $= (\$450 \times 10^6)(18/100)$		$= \$81.00 \times 10^6$/yr
Annual O&M cost (excluding fuel)		$= \$11.20 \times 10^6$/yr
Total annual cost used for comparison with Unit F		$= \$92.20 \times 10^6$/yr
For Unit F:		
Annual fixed capital charges $= (\$440 \times 10^6)(18/100)$		$= \$79.20 \times 10^6$/yr
Annual O&M cost (excluding fuel)		$= \$12.00 \times 10^6$/yr
Replacement energy required for Unit F as compared with Unit E $= (600\text{ MW})(8760\text{ h/yr})(70/100)[1 - (92\text{ percent}/95\text{ percent})]$ $= (600\text{ MW})(8760\text{ h/yr})(70 - 67.789)/100$ $= 116{,}210$ MWh/yr		
Replacement energy cost penalty for Unit F as compared with Unit E $= (116{,}210\text{ MWh/yr})(\$15/\text{MWh})$		$= \$\ 1.74 \times 10^6$/yr
Total annual cost used for comparison with Unit E		$= \$92.94 \times 10^6$/yr

ity. Unit F would in general be expected to produce about 3 percent less electric power than Unit E. As a result, during a total of 3 percent of the year when Unit F would not be available, as compared with Unit E, the utility would have to either generate additional power or purchase power from a neighboring utility to replace the energy that Unit F was unable to produce because of its unavailability.

The difference between the cost of either the purchased or generated replacement power and the cost to generate that power on the unit with the higher plant availability represents a replacement energy cost penalty that must be assessed to the unit with the lower power availability (in the case, Unit F).

2. Calculate the Replacement Energy Cost

The replacement energy cost penalty is generally used to quantify the economic costs associated with changes in plant availability, reliability, or forced outage rates. The replacement energy cost penalty is calculated as follows: replacement energy cost penalty $=$ RE $\times$ RECD, in dollars per hour, where RE $=$ replacement energy required in MWh/yr and RECD $=$ replacement energy cost differential in dollars per megawatthour.

The value of RECD is determined by RECD $=$ REC $-$ AGC_{ha}, where REC $=$ cost to either purchase replacement energy or generate replacement energy on a less efficient or more costly unit, in dollars per megawatthour, and AGC_{ha} $=$ average generation cost of the unit under consideration with the highest (best) availability, in dollars per megawatthour. The average generation cost is calculated as $AGC_{ha} = HR_{ha} \times FC_{ha}/10^6$, where HR_{ha} = heat rate of the highest availability unit under consideration in J/kWh (Btu/kWh) and FC_{ha} = the average or levelized fuel cost of the highest availability unit under consideration in dollars per megajoule (dollars per million Btu).

The replacement energy, RE, is calculated as follows: $RE = \text{rating} \times 8760 \times [(DCF/100)(1 - PA_{la}/PA_{ha})]$, where rating = the capacity rating of the unit in MW, DCF = desired average or levelized capacity factor for the units in percent, PA_{la} = availability of unit under consideration with lower availability in percent, and PA_{ha} = availability of unit under consideration with higher availability in percent.

Implied in this equation is the assumption that the actual capacity factor for the unit with lower availability (ACF_{la}) will be lower than for the unit with higher availability as follows: $ACF_{la} = DCF \times (PA_{la}/PA_{ha})$.

As shown in Table 8.17, even though the annual fixed charges for Unit E were \$800,000 per year higher (\$81.00 million vs. \$79.20 million per year), the total resulting annual costs for Unit E were \$740,000 lower (\$92.20 million vs. \$94.94 million per year) because Unit F had a \$1.74 million per year replacement energy cost penalty and operation and maintenance costs that were \$800,000 per year higher than Unit E.

Related Calculations. It generally can be assumed that the replacement energy (either purchased from a neighboring utility or generated on an alternate unit) would cost about \$10 to \$20 per megawatthour more than energy generated on a new large coal-fired unit. In the example in Table 8.17, a value of replacement energy cost differential of \$15/MWh was used.

CAPABILITY PENALTY

Compare the capability (capacity) penalty for Units G and H in Table 8.18. Unit G has a rated capacity that is 10 MW higher than that of Unit H.

Calculation Procedure

1. Analyze the Problem

To achieve an equal reliability level the utility would, in principle, have to replace the 10 MW of capacity not provided by Unit H with additional capacity on some other new unit. Therefore, for evaluation purposes, the unit with the smaller rating must be assessed what is called a capability (capacity) penalty to account for the capacity difference. The capability penalty, CP, is calculated by: $CP = (\text{rating}_l - \text{rating}_s) \times CPR$, where rating_l and rating_s are the ratings of the larger and smaller units, respectively, in kW, and CPR = capability penalty rate in dollars per kilowatt.

2. Calculate the Capability Penalty

For example, if the units have capital costs of approximately \$500/kW, or if the capacity differential between the units is provided by additional capacity on a unit that would cost \$500/kW, the capability penalty assessed against Unit H (as shown in Table 8.18) is \$5 million total. For an 18 percent fixed-charge rate, this corresponds to \$900,000 per year.

Note that the annual operation and maintenance costs are the same for both units. In this case, those costs were not included in the total annual costs used for comparison purposes.

As shown in Table 8.18, even though alternative Unit H had a capital cost \$2 million

TABLE 8.18 Evaluation of Unit Rating vs. Installed Capital Costs

	Unit G	Unit H
Unit rating	610 MW	600 MW
Net unit heat rate	10.550 MJ/kWh (10,000 Btu/kWh)	10.550 MJ/kWh (10,000 Btu/kWh)
Unit availability	95 percent	95 percent
Installed capital cost	$\$450 \times 10^6$	$\$448 \times 10^6$
Levelized or average fixed-charge rate	18 percent	18 percent
Levelized or average annual O&M cost (excluding fuel)	$\$11.2 \times 10^6$/yr	$\$11.2 \times 10^6$/yr
Capability penalty rate	\$500/kW	\$500/kW
For Unit G:		
Annual fixed capital charges		
$= (\$450 \times 10^6)(18/100)$		$= \$81.00 \times 10^6$/yr
Total annual cost used for comparison with Unit H		$= \$81.00 \times 10^6$/yr
For Unit H:		
Annual fixed capital charges		
$= (\$448 \times 10^6)(18/100)$		$= \$80.64 \times 10^6$/yr
O&M costs same as alternate Unit G		
Total capability penalty for Unit H as compared with Unit G		
$= (610\text{ MW} - 600\text{ MW})(1000\text{ kW/MW})(\$500/\text{kW})$		
$= \$5.00 \times 10^6$/yr		
Annual capability penalty		
$= (\$5.0 \times 10^6)(18/100)$		$= \$\ 0.90 \times 10^6$/yr
Total annual costs used for comparison with Unit G		$= \$81.54 \times 10^6$/yr

lower than alternative Unit G, when the capability penalty is taken into account, alternative Unit G would be the economic choice.

Related Calculations. Applying the evaluation techniques summarized in Tables 8.13 through 8.18 sequentially makes it possible to evaluate units that fall into more than one (or all) of the categories considered and thereby to determine the optimum plant design.

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