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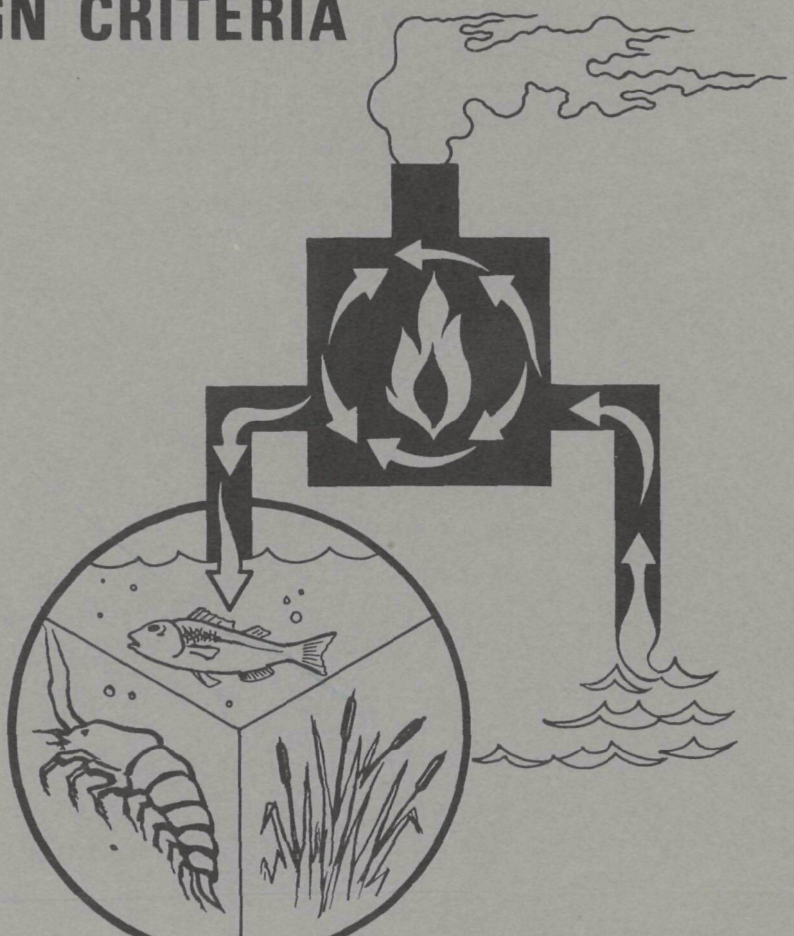
A SURVEY OF ALTERNATE METHODS FOR COOLING CONDENSER DISCHARGE WATER

OPERATING CHARACTERISTICS AND DESIGN CRITERIA



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A SURVEY OF ALTERNATE METHODS

FOR COOLING CONDENSER DISCHARGE WATER

OPERATING CHARACTERISTICS AND DESIGN CRITERIA

by

DYNATECH R/D COMPANY
A Division of Dynatech Corporation
Cambridge, Massachusetts 02139

for the

WATER QUALITY OFFICE
ENVIRONMENTAL PROTECTION AGENCY

Project No. 16130 DHS

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TABLE OF CONTENTS

TABLE OF CONTENTS (CONCLUDED)

Section 1
INTRODUCTION

1.1 Overall Program Goals

In December, 1968, Dynatech R/D Company undertook a program for the Federal Water Pollution Control Administration with the ultimate aim of performing a survey and economic analysis of alternate methods for cooling condenser discharge water from thermal power plants. The first phase of this program was to consist of a systematic gathering of present state-of-the-art information in the areas of:

1. Large-scale heat rejection equipment;
2. Power plant operating characteristics; and
3. Total community considerations.

This report will document the results of Task II, Phase I, of this program.

1.2 Scope of Task II

The second task of this program is concerned with gathering information relating to selection, design, and optimization of the power plant itself. In order to understand the scope and relevance of Task II, it is necessary to review the thrust of the entire program.

As stated above, the first phase of the investigation is intended to survey the state-of-the-art in the areas of large-scale heat rejection equipment, power plant characteristics, and the integration of the power plant with the community which it serves. Whereas these areas are dealt with separately for the sake of an orderly investigation, a proper understanding of the problem of thermal pollution and its solutions as related to electric power generation comes only from a consideration of these three areas as they relate to one another.

1.2.1 Task I and Task II

The initial task, as reported in July, 1969[136] presented, in detail, considerations of alternative methods of transferring large quantities of rejected heat to the atmosphere. However, the technological and economic aspects of this heat rejection process were discussed in isolation from power plant considerations, except insofar as the unit capacities (amount of heat to be rejected), process side temperature (temperature of condenser discharge water), and ambient conditions (atmospheric dry-bulb and wet-bulb temperatures) were chosen to be typical of present or projected power plant operating conditions.

The results of an analysis of this kind leads to the conclusion that for a given heat load and ambient conditions, the size of the heat transfer equipment, and, as a result, its cost, can always be reduced by raising the process side temperature. It is part of the scope of Task II to relate back to the analysis and conclusion of Task I and to put this conclusion in a proper perspective.

A brief discussion here will serve to illustrate the importance of this relationship. Figure 1.1 presents a plot of unit cost versus heat rejection temperature. Line A represents the cost of the heat transfer equipment and shows the cost decreasing with increasing temperature. Line B indicates a possible total power plant cost (including heat rejection equipment) which might be typical if an existing plant, designed to operate at the lowest condensing temperature available with once-through cooling, is forced to operate in conjunction with a cooling unit at higher condensing temperatures. As is well known, if the heat rejection temperature is raised, the operating point of the plant is shifted, with the net result being an increase in the amount of heat rejected and a decrease in the net output power.

If, however, one starts with the constraint that once-through cooling is not permissible, and the technological and economic restrictions and operating characteristics are included in the total optimization process, then the power plant cycle and the resultant cost curve will be affected. A possible result is suggested by Line C in Figure 1.1. The result of including the heat rejection system in the

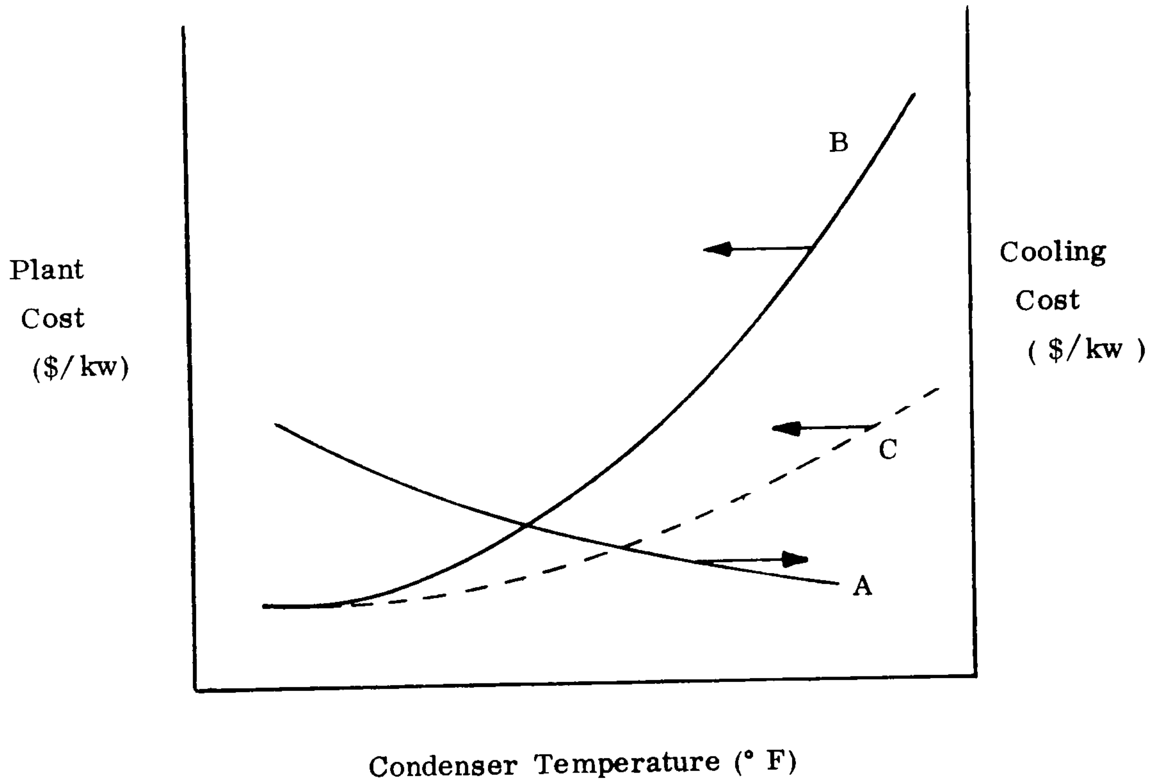

Figure 1.1

Plant and Cooling Cost Comparison

overall system optimization may not result in a shift in the cost minimum to a new operating point but the absolute level of the cost curve should be shifted down.

1.2.2 Task II and Task III

In addition to providing sufficient information to relate the results of Tasks I and II together in a total system picture, it is necessary to anticipate the need to relate Task II to the overall community considerations of Task III. That is, when the means by which the power producing section of the community might be integrated with other sections with a need (or at best a possible use) for thermal energy input, it will be found that most applications require that the energy be available at temperatures which are considerably in excess of normal power plant condenser temperatures. Operation at these temperatures will clearly cause the power plant to operate inefficiently in the classical, thermodynamic sense. However, if a source of environmental deterioration is eliminated by such a scheme, then the traditional definitions of efficiency may be replaced by some evaluation of "quality of life" which will dictate this new operating condition.

Here again, if an existing power plant, designed with conventional parameters in mind, were forced to operate at these conditions, the operating cost would be extremely high and the rated capacity would probably not be attainable. However, if a plant is designed and optimized from the beginning with these constraints in mind, the total system will operate in a more efficient way.

1.3 Topics Under Consideration

In this task, we will try to consider the fundamental governing criteria which determine how power plants are designed and optimized. These criteria are both technical and economic, and many of them are decoupled from the question of heat rejection and the resultant effect on the environment. That is, no matter what constraints are placed on the plant in the way of water use regulations or what decisions are reached concerning the trade-offs between once-through cooling, towers, or air rejection, some of the basic design decisions may well be unaffected. In the following discussion, we have tried to focus on those technical and economic considerations which affect and are affected by the process of heat rejection.

This report has been divided into two sections. In Section 2, the whole question of power plant considerations will be considered. This will include questions of establishment of need, capacity determination, fuel selection, siting, capacity factor and fixed charge rates. The process of answering these questions may be thought of as a system planning study, in which the requirement for detailed design and optimization are established. These initial design considerations are often overriding in determining how the power generation section of the community will operate and therefore must be thoroughly understood by FWQA.

Section 3 will deal with detail plant design and optimization, which may be considered as the process of satisfying the needs established in the system planning study.

Although this two-step method of presentation of the design process is somewhat indicative of actual practice, there is really no clear separation of the two processes. System planning is done with expected results of the detailed design and there are often changes in plans due to results of detail study. The mechanism and consequences of this feedback vary drastically with individual plants and are therefore difficult to generalize, although an attempt has been made in Section 3.

Section 2

POWER PLANT SELECTION CONSIDERATIONS

2.1 Introduction

The selection of the design for a new power plant is influenced by many factors. The relative importance of these factors will vary according to geographical location, local legislation, ownership, source of finance, and other circumstances. The selection considerations discussed below are some of the more general criteria and procedures used today. It should be emphasized that the different criteria are not considered separately but rather that many different combinations need be considered in order to provide a power plant design which is not only economical but also as beneficial as possible to the community which it serves.

2.2 Initiation

At the present time, in this country, thermal power plants are being initiated which will require up to ten years for completion. These long-term planning requirements necessitate accurate prediction of future power needs. Power consumption in the United States has grown exponentially in the past. As shown in Figure 2.1, this growth is expected to continue. Thermal power station requirements could, in fact, be greater than these projections with the advent of the electric car or other major electric power consumer. They could, of course, be less with advances in state of the art of direct energy conversion, but this is unlikely for the next several decades. One interesting note is that power company predictions in the past have always been conservative; i.e., more electricity has been needed than was predicted.

In the past, initiation of a new power plant sometimes took the form of a memorandum from the chief engineer at an existing facility to its management stating that with the expected load increases, the existing generating capacity would become inadequate at some future date. At present, with the extended construction

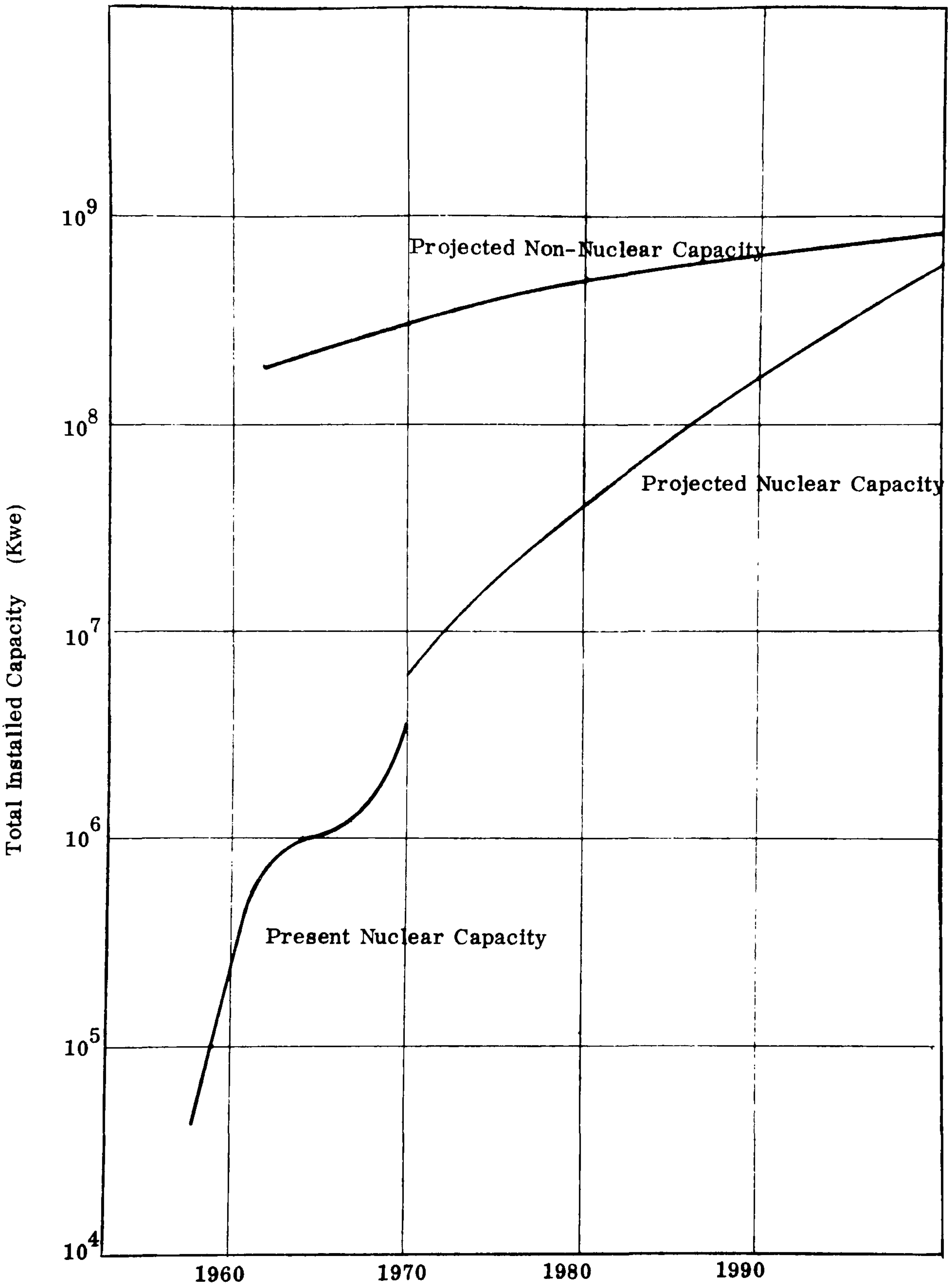

Figure 2.1
Projected Electric Utility Generating Capacity (From Ref. 114)

times necessary for the larger plants, power company management must be aware well in advance of the future generating needs of the system. Also, due to the large interconnected grid systems now in use in the United States, the different company managements must be aware of other system needs and plans. Thus, the decision to build a new plant nowadays is the result of careful planning of both the people within a power system and the people representing various neighboring power systems.

2.3 Unit Capacity Selection

2.3.1 Growth

The development of the thermal power station from its beginning in the late 1800's to the present can be roughly divided into five successive phases. The initial phase was characterized by manually fired, fire-tube and combined fire-tube smoke-tube boilers. This permitted only very small capacities (5 Mw) and steam pressures (200 psi) and lasted until about 1900. Sectional and vertical water-tube boilers with fixed and restricted movement grates of many different designs marked the second phase of development, which lasted until about 1925. Capacities increased to about 30 Mwe and pressure to about 500 psi during this phase. The grating and material problems of the first two phases were overcome partly in the third phase with the introduction of pulverized coal firing. With pulverized coal fired radiant boilers, steam pressure and temperature continued to increase to the 2000 psi and 1000°F range with 100-200 Mwe units until the 1950's. Present day supercritical fossil plants represent the fourth phase of development. At times during this phase pressures up to 5000 psi and temperatures up to 1200°F have been used, but the high cost of austenite steels necessary for these values has caused a general falling back to the 3500 psi and 1050°F range for modern fossil fueled plants of up to 1000 Mwe. The fifth phase is, of course, the present nuclear power plant era. Due to imposed limitations and economic considerations, to be explained, the steam conditions for present day nuclear power plants are in the range of those of the third stage of development of the fossil fueled plant. Even with these less advanced steam conditions, nuclear plants of over 1000 Mwe are being planned.

The heat rate of fossil fueled plants is not expected to be improved much in the near future. This is due to what are considered stabilized maximum steam conditions with present day materials. Unit size, on the other hand, is expected to continue to increase although there appear to be limits on this also. Average and maximum sizes of new fossil fueled units are shown in Figures 2.2 and 2.3. It is noted that while average unit size continues to increase, the maximum unit size appears to have leveled off. Total plant capacity has shown a similar increase as shown by some specific examples in Figure 2.4.

The trend toward larger units, both fossil and nuclear, is explained by the lower specific cost of a power station as unit size is increased, as shown in Figures 2.5 and 2.6. This trend is expected to be more pronounced with nuclear plants since capital costs of nuclear plants fall off more rapidly with increased rating than do capital costs of fossil plants. (Ref. 86). The choice between nuclear fuel and fossil fuel is discussed more fully in the next section.

2.3.2 Limitations

The problems to be solved in increasing turbine-unit size depend on whether the purchaser wishes to have a tandem-compound (single shaft) or a cross-compound machine (double shaft). Maximum size of a tandem-compound turbine is approximately 800 Mwe at present, while cross-compound machines have been built with capacities over 1000 Mwe and are available up to 1500 Mwe. The main problem faced by the turbine manufacturer is the length of blade in the last stage of the low-pressure turbine. In 1968 blades having a maximum length of 33.5 in. were designed for use in 3600 rpm turbines, and 52 in. was the maximum designed length for 1800 rpm use.

Another possible limit on turbo-generator unit size is transport weight limits for generators. Direct contact hydrogen and water cooling of rotor and stator have reduced the specific weight of generators considerably over the past ten years, yet cartridge stator assembly has been necessary for some of the recent large units. Stator site winding has been avoided for the large units due to the increased cost, but could become a necessity as unit size continues to grow.

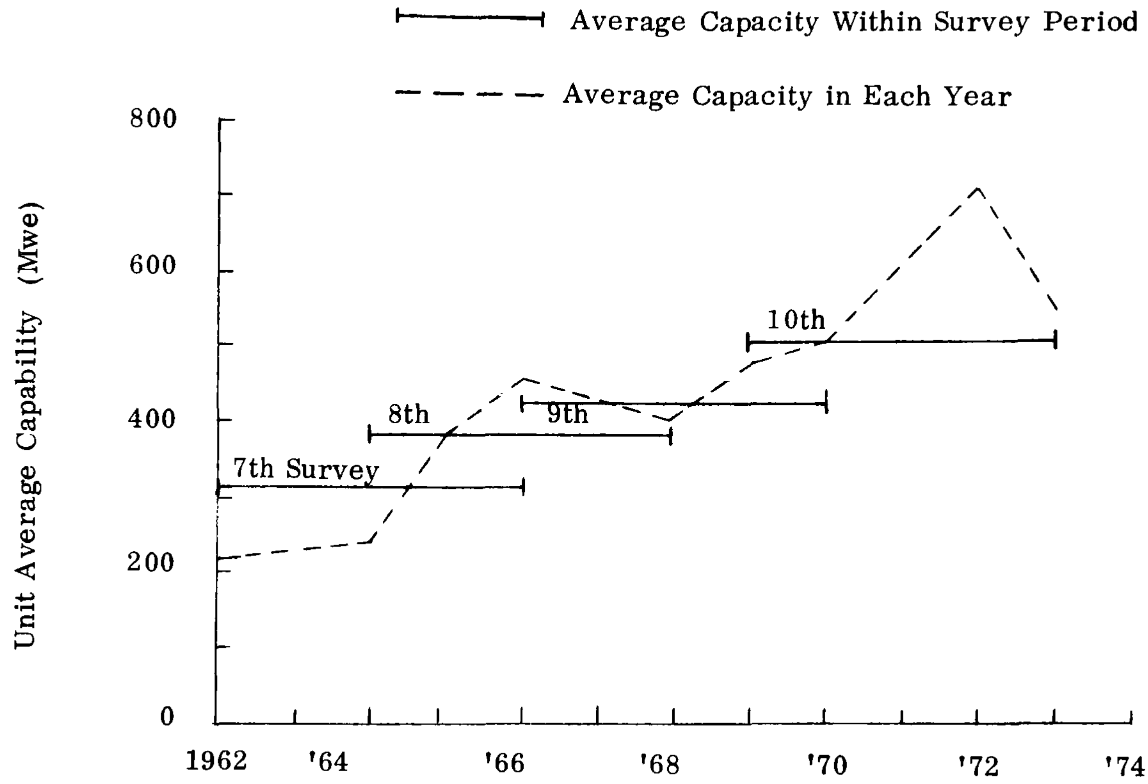

Figure 2.2

Growth of Average Size of Fossil Plants (Ref. 63)

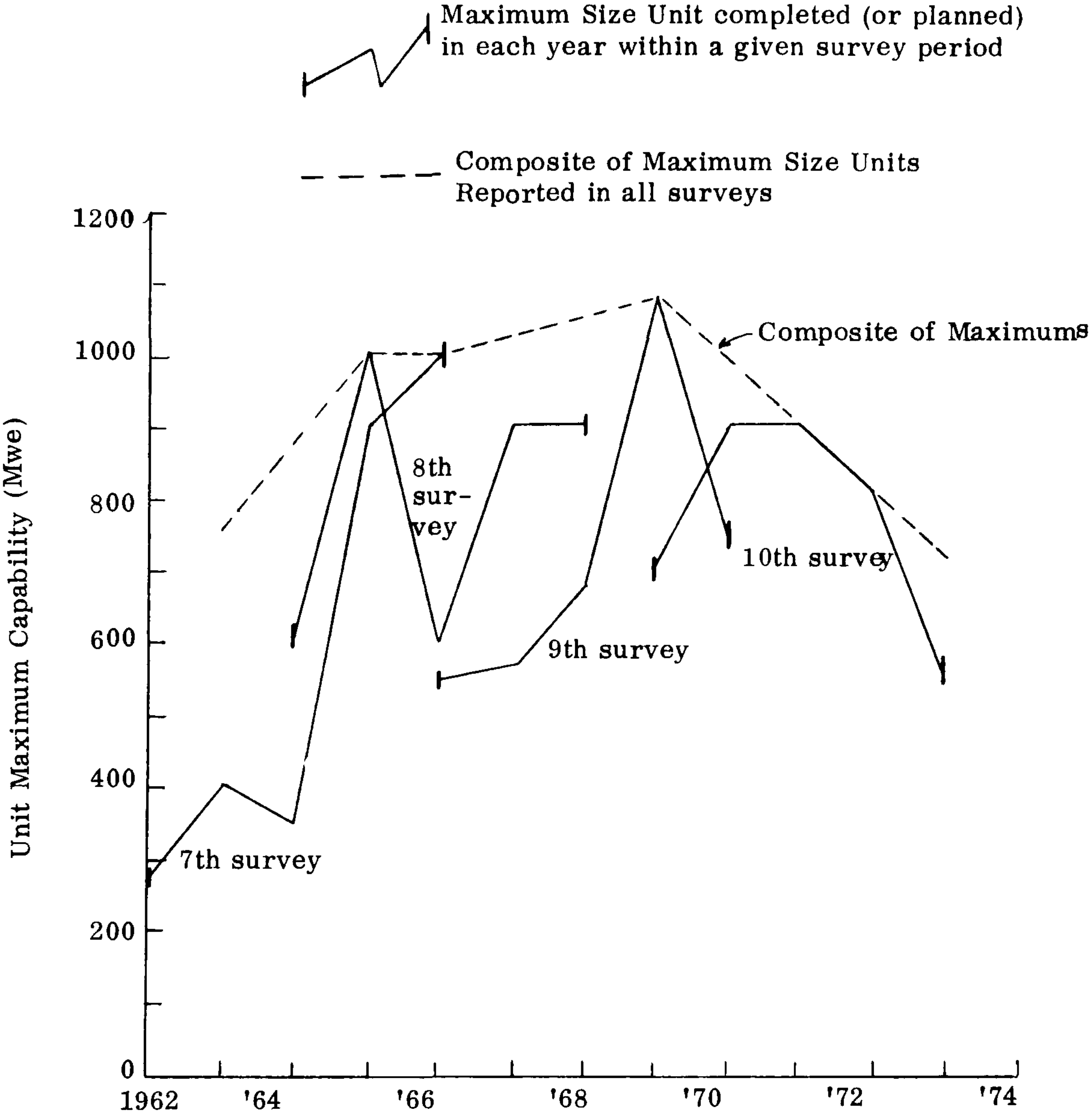

Figure 2.3

Growth and Decline of Maximum Size of New Fossil Units (Ref. 63)

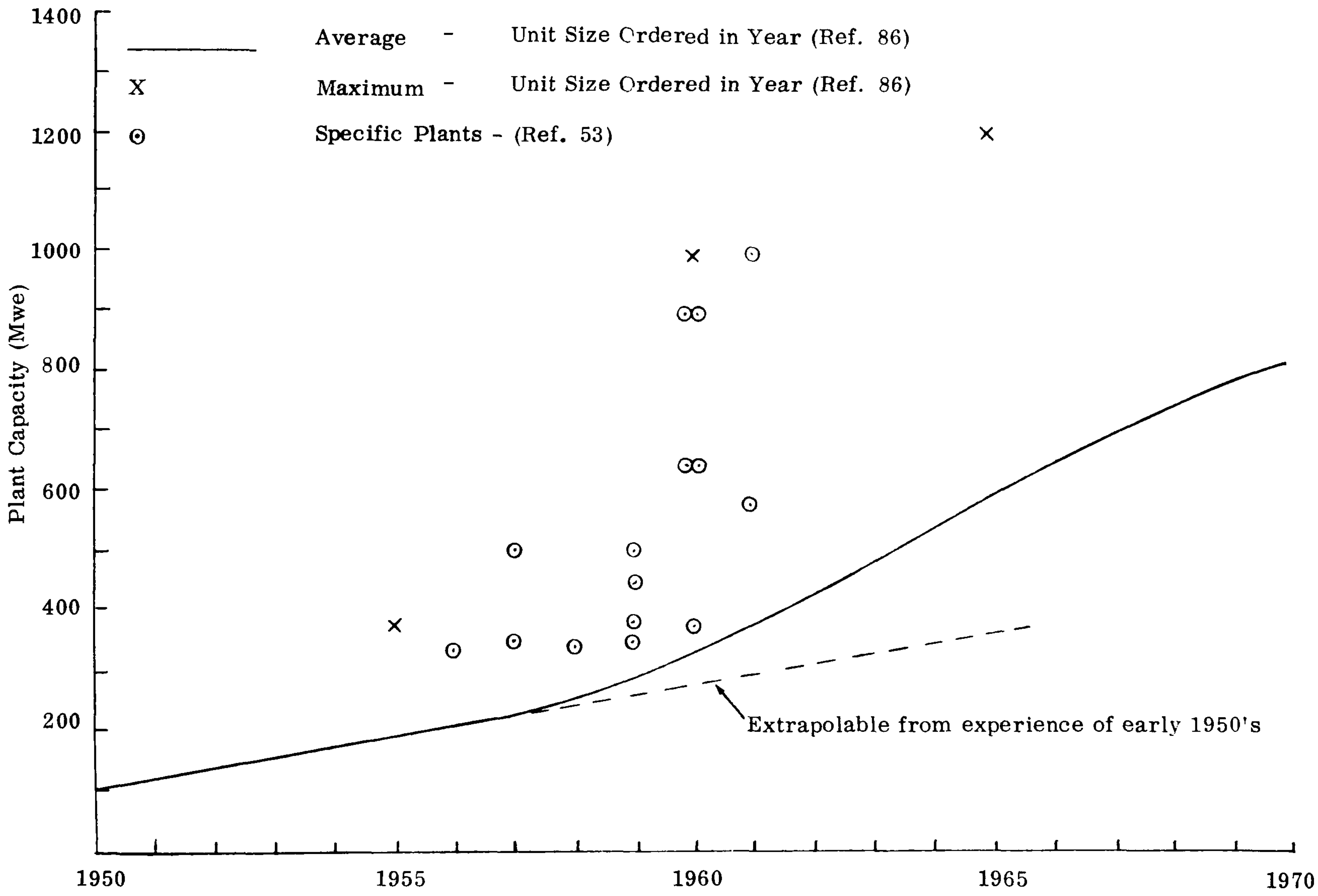

Figure 2.4

Growth of Average and Maximum Size of Fossil Plants

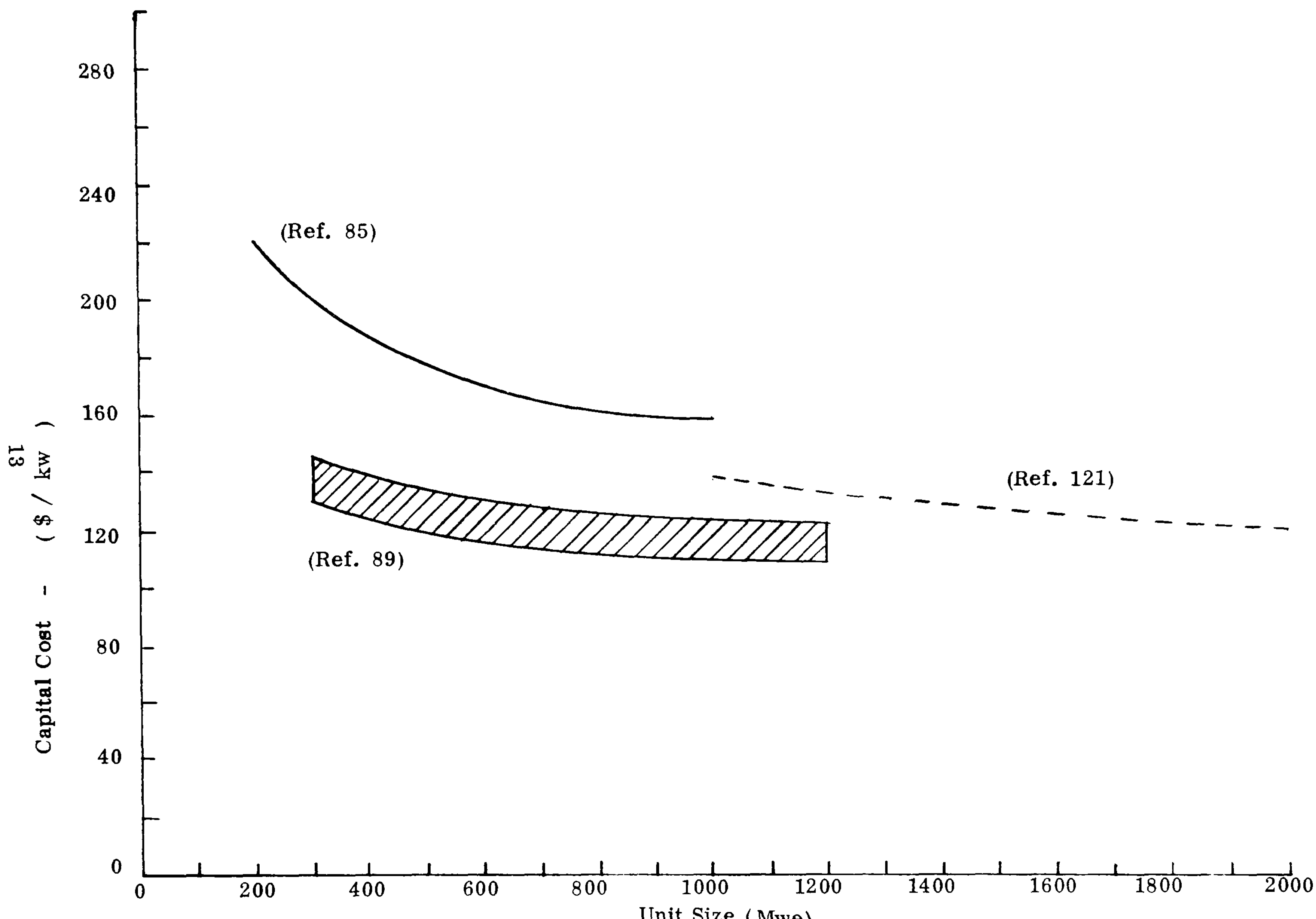

Figure 2.5

Capital Cost for Fossil Plants

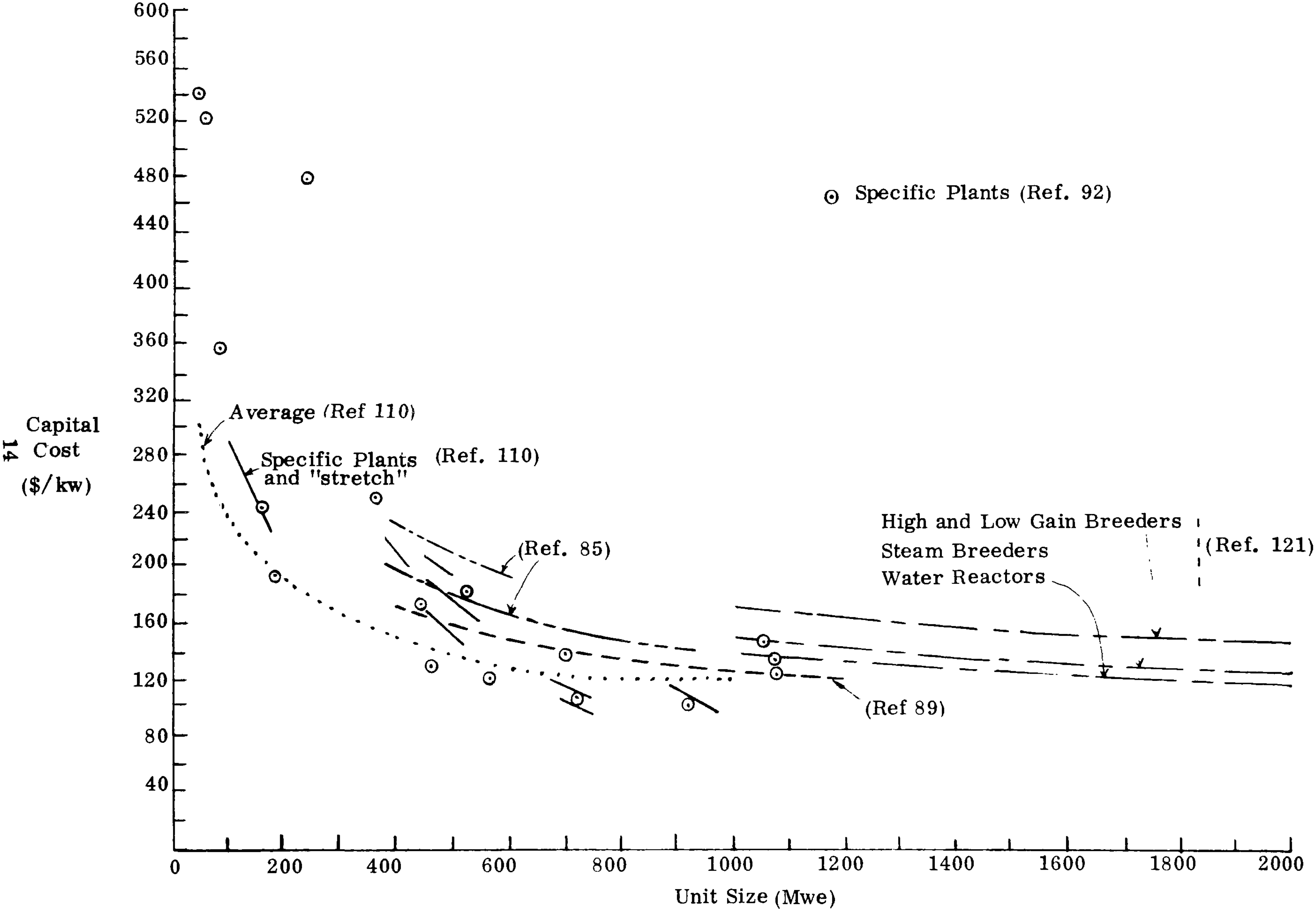

Figure 2.6

Capital Cost for Nuclear Plants

A third limit on turbo-generator size could be turbine shaft strength. The strength and proportion of these shafts are determined not only by their ability to transmit full load torque and at the same time support their weights and give acceptable critical speeds, etc., but also by their capability to withstand severe transient loads under short circuit conditions. On large turbo-generators the initial short circuit torque in the air gap can be of the order of ten to fifteen times the normal full load torque of the machine. The torque transmitted to the rotor shafts is generally smaller due to torsional elasticity, with the largest torque (four to six times full load torque) occurring at the coupling between turbine and generator, and diminishing to about twice full load torque at the high pressure-low pressure coupling in a tandem compound unit.

Boiler sizes have grown continually in the past but there does appear to be a future limit on coal burning unit size. A single steam generating furnace for a 1070 Mwe unit has been put in service in the U.S., and manufacturers are willing to offer single boilers with a divided furnace having an output of 1200 Mwe for coal firing. Capacities can easily be increased further if oil or natural gas are burned, since the limitation on size for coal units is principally one of length of soot blower. Blowers have not yet been produced in the United States which can satisfactorily deal with furnace widths much in excess of 100 ft.

Steam conditions for most present day nuclear plants, as has been noted, approximate those used in fossil-fueled plants of thirty to forty years ago. While these conditions result in lower thermal efficiency and thus have limited the application of nuclear power, two important points have often been disregarded:

1. The steam-temperature limitations of present day light-water power reactors are as much a result of economic optimization as they are of technological limits.

2. Limitations on the pressure and temperature of the steam cycle affect only the efficiency of the steam cycle itself, whereas the only meaningful comparison is one based on overall plant efficiency. On this basis, the nuclear plant fares somewhat better, since the fossil plant incurs additional inefficiencies in the furnace/boiler units. That is, in spite of the

extensive use of stack gas recuperators, some of the energy released in the combustion of the fossil fuel is lost to hot stack gases. In a nuclear reactor, all of the energy liberated in the fission reaction is transferred to the steam cycle.

This is not to say that technological considerations do not limit nuclear plant design. The major obstacle in improving steam conditions in nuclear plants is still the development of suitable materials--the same major obstacle faced in fossil plant design.

Present day steam cycles in nuclear plants can be divided into two categories; superheated- and saturated-steam cycles. The most common cycle at the present time, and for the immediate future, is the saturated steam cycle, such as used in the Oyster Creek (Ref. 102) and Connecticut Yankee (Ref. 86) plants. Superheated-steam plant designs can be divided into three main groups:

1. Boiling water integral-superheat plants such as Bonus and Pathfinder (Ref. 108);
2. Plants that use other-than-water-coolants in a primary loop to superheat steam in a secondary loop, such as the liquid-metal Fermi plant, the organic cooled Piqua plant, and the gas-cooled Peach Bottom plant; (Ref. 115)
3. Nuclear plants using fossil fuel fired superheaters such as the plants at Elk River and Indian Point (Ref. 115).

While all three types of nuclear superheat plants promise higher thermal efficiencies in the future, the large (> 400 Mwe) nuclear plants built and on the drawing boards today are saturated steam cycle plants. The reason that nuclear superheat is more difficult and expensive to obtain than fossil fuel superheat is the materials that are required. Besides the high temperature requirement for both nuclear and fossil superheat, in a nuclear plant there is the desire to maintain a minimum neutron absorption cross section, and also the requirement that the material can withstand high neutron fluxes for the fuel lifetime. For these reasons, the maximum steam temperature for present day large reactors (BWR and PWR) is about 550° or less.

To achieve better efficiencies and the low steam temperatures in nuclear plants, the incentive has been to operate at the highest possible pressure, which is the saturation pressure. This causes a major limitation of excessive moisture in the later stages of the turbine. For a saturated steam cycle with no means of moisture removal or reheat, initial steam pressures as low as 50 psig may be necessary to keep the moisture at 1.5" Hg exhaust pressure within the acceptable range of 8-12% (Ref. 115). For this reason, nuclear saturated steam plants usually use at least one stage of moisture separation, whereby steam is extracted from the turbine after partial expansion. Often the steam is reheated immediately following moisture separation, resulting in low pressure superheated steam being returned to the turbine. Reheat is usually accomplished with either the primary coolant, or with steam extracted from the reactor or steam generator. The main purpose of reheat in both nuclear and fossil plants is to reduce the moisture in the turbine exhaust --this then allows higher initial steam pressure and higher thermal efficiency.

Many other factors affect plant capacity choice, such as location and community considerations, and they are discussed in the following sections.

2.4 Fuel Selection

There are two major factors that must be considered in choosing between nuclear and fossil fuel for a new thermo-electric plant. The first is economics and the second is public concern. Economics, it will be shown, tends to favor nuclear power in the future. Public concern, on the other hand, often tends to disfavor nuclear power for a number of reasons: thermal pollution, radiation poisoning, or "bomb" possibility.

The absolute economics of nuclear power are difficult to determine or to project since the price of plutonium and enriched uranium is set by the Federal government. The general comparison between nuclear and fossil fueled plants is one of higher capital cost and lower operating costs for nuclear plants than for fossil plants. This statement needs considerable qualification and any comparison is dependent on numerous factors as will be shown below. Also, any really valid economic comparison between nuclear and fossil fueled plants should be based on a comparison of the present worth of all future revenue requirements for a plant. The present worth concept is necessary to account for the difference in timing of both investments and expenses.

The capital cost of both nuclear and fossil plants depends on two major variables: time, with regard to technological advances and other economic factors, and size. The change in capital costs with time is almost impossible to separate from the size variable. Even when separated from the size effect, it is difficult to quantify. As part of the consideration of the effect of time are the factors of state of technology, interest rate, labor and material costs, and site location as reflecting land costs and community considerations. Figure 2.8 is indicative of the variation in the specific capital cost of fossil fueled plants over the past two decades. While the ordinate of this figure is specific cost, average plant capacity varied for the different years and thus affects the changes with time.

Both nuclear and fossil plant specific capital costs decrease with increased size as was shown in Figures 2.5 and 2.6, with nuclear cost decreasing more rapidly than fossil. The steeper slope of the nuclear curve is due to the large amount of fixed-cost investment in a nuclear plant; that is, that minimum investment required independent of size; e.g., fuel handling systems, chemistry facilities, certain amounts of shielding and containment. There is proportionally more of this base investment in a nuclear plant than in a fossil-fuel plant. A recent paper[89] shows the capital costs of the two types of plants to become equivalent in the 1200 to 1600 Mwe range, as shown in Figure 2.9.

Fuel cost for fossil fueled plants tends to vary considerably with different locations in the United States,while nuclear fuel cost is essentially constant everywhere as fixed by the government. A continuous national survey of new fossil fueled plants in the United States shows, Figure 2.10, a general increase in fossil fuel price over the last two decades, but this may be misleading. The use of unit trains and coal pipes in the past few years has reduced fossil fuel costs in some areas of the country.

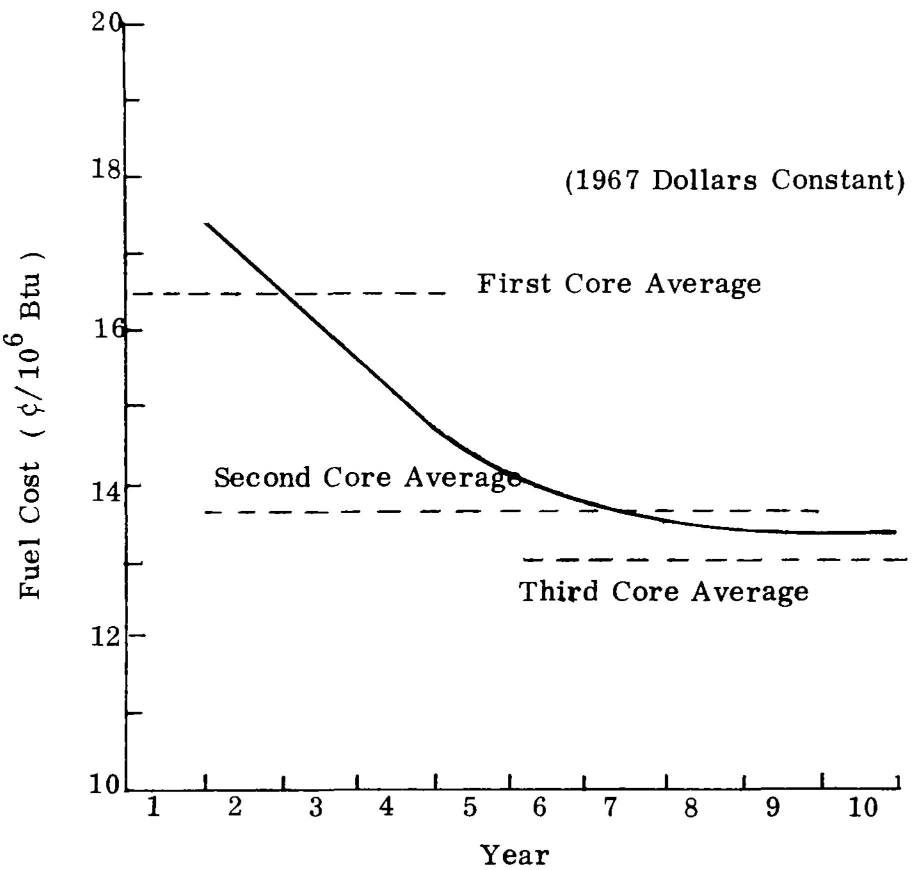

Figure 2.7

Nuclear Fuel Costs 1971-1980 (Ref. 89)

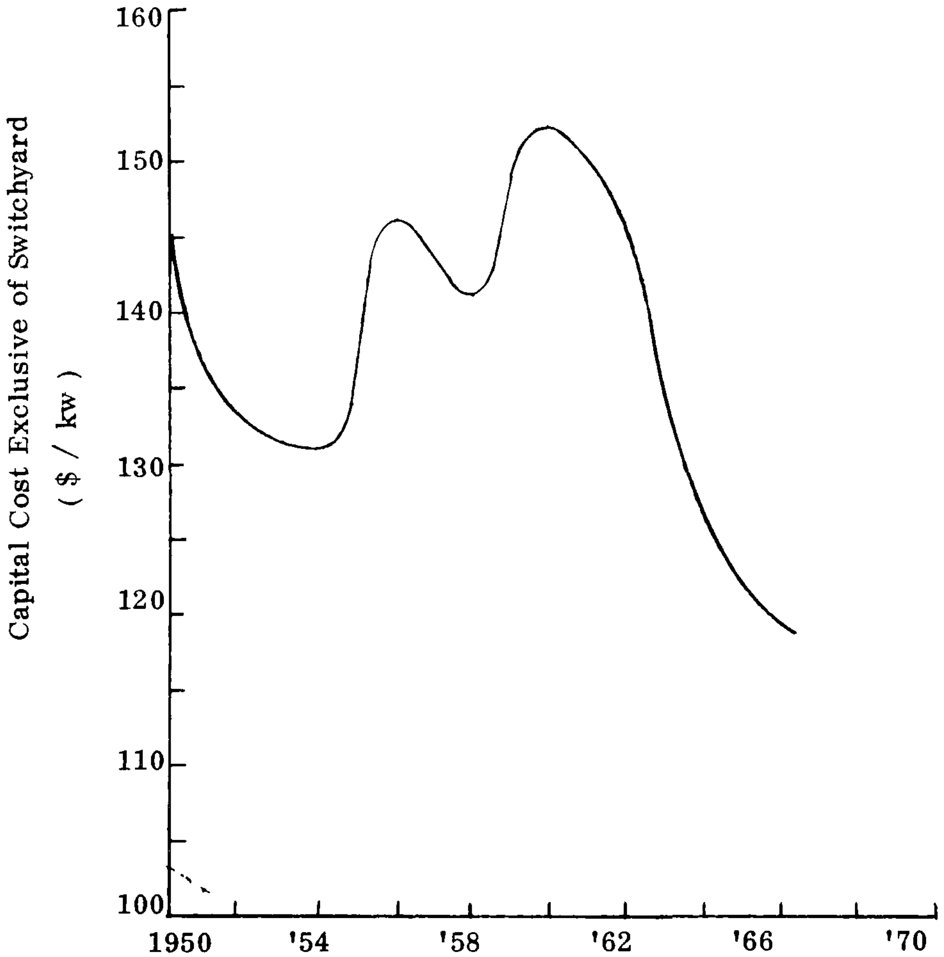

Figure 2.8

Capital Cost of Fossil Plants (Ref. 64)

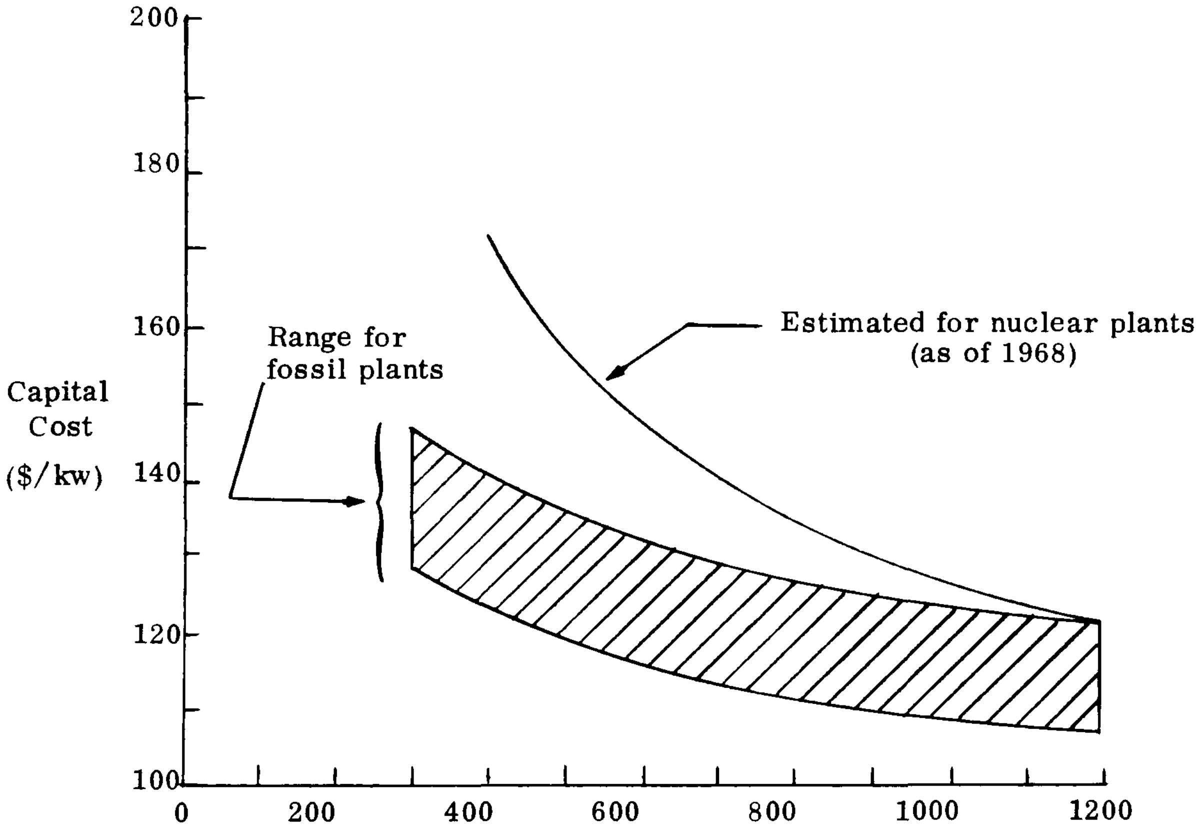

Figure 2.9
Capital Cost for Nuclear and Fossil Plants (Ref. 89)

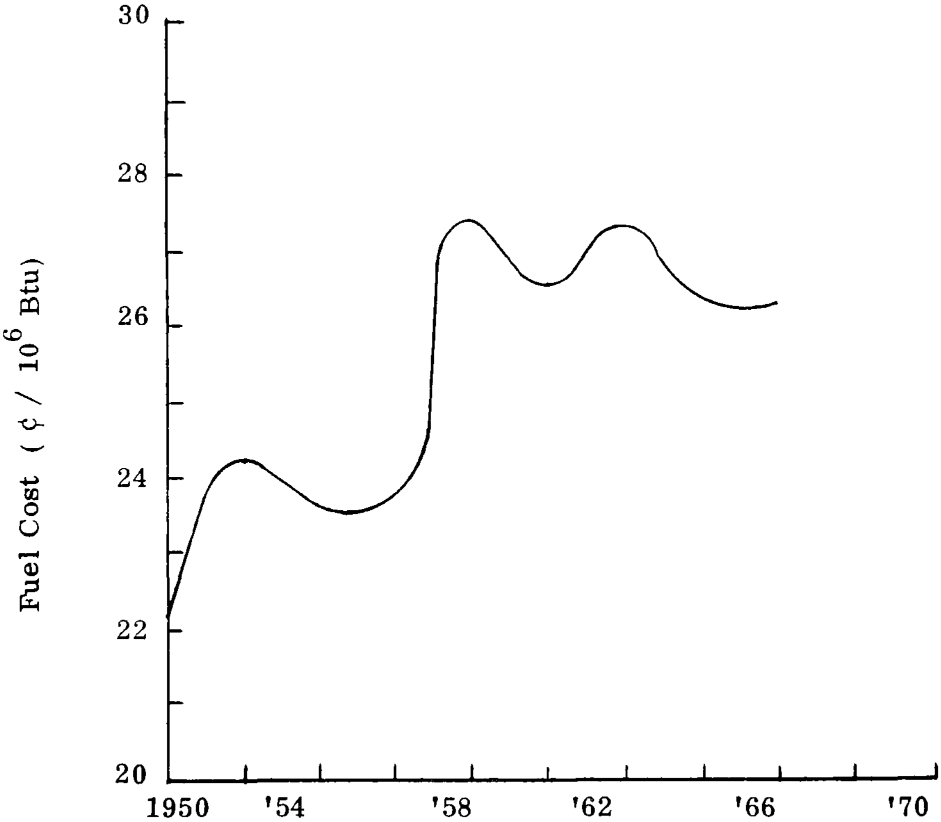

Figure 2.10
Fossil Fuel Costs (Ref. 64)

Figure 2.7 shows predicted nuclear fuel cost for the next decade. For a comparison of fuel costs as a per cent of the price of the power produced, the generally lower thermal efficiency of nuclear plants, as compared to fossil plants, must be considered. Figure 2.11 shows projected nuclear costs in the units of mills/kwhr, which therefore reflects projected nuclear thermal efficiency.

A comparison of total energy costs, sometimes called "bus-bar" energy cost, is shown in Figure 2.12. As was mentioned previously, many factors affect this cost, some of the more important being location, interest rate, capacity factor, and community consideration.

An interesting example of interest rate affecting the type of nuclear plant built is the tendency to build gas-cooled reactors in England and Germany and heavy water reactors in Canada. Both these countries have public power systems and resulting lower interest rates than the United States. This, therefore, allows both countries to build reactor types which require more capital investment (gas-cooled and heavy water versus boiling water and pressurized water as built in the U. S.), but which use a less expensive fuel (natural uranium versus enriched uranium in the U. S.).

Public concern over nuclear power plants has, in the past, centered on the "bomb" possibility and radiation poisoning. Before the power companies launched large scale public relations campaigns, many people associated nuclear power plants with atomic bombs, and thought that if an accident occurred a nuclear blast would result. The public now generally accepts that this will not happen, but there is still much concern over radiation poisoning from a nuclear plant. This concern is focused on two main types of radioactive release--the "normal" radiation release from a nuclear power plant or fuel reprocessing plant, and the possibility of large scale radioactive release caused by an accident. The Atomic Energy Commission regulates the first type of release to keep it within "acceptable" limits, and requires many redundant design safety features to be incorporated in a nuclear plant to try to prevent a major accident from occurring. Nevertheless, there are still many people who think nuclear power is acceptable, but that it should be built "in another town."

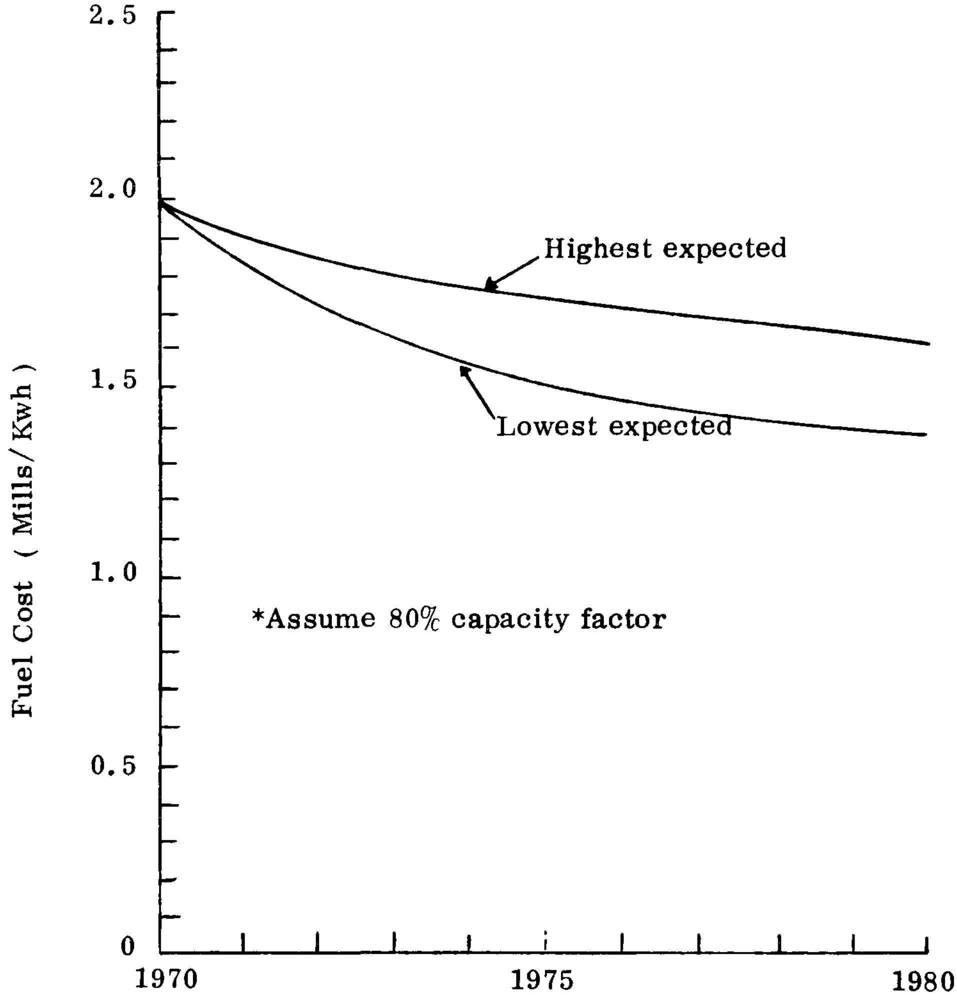

Figure 2.11

Projected Range of Nuclear Fuel Costs (Ref. 110)
(Including Capital Charges On Fuel Inventory)

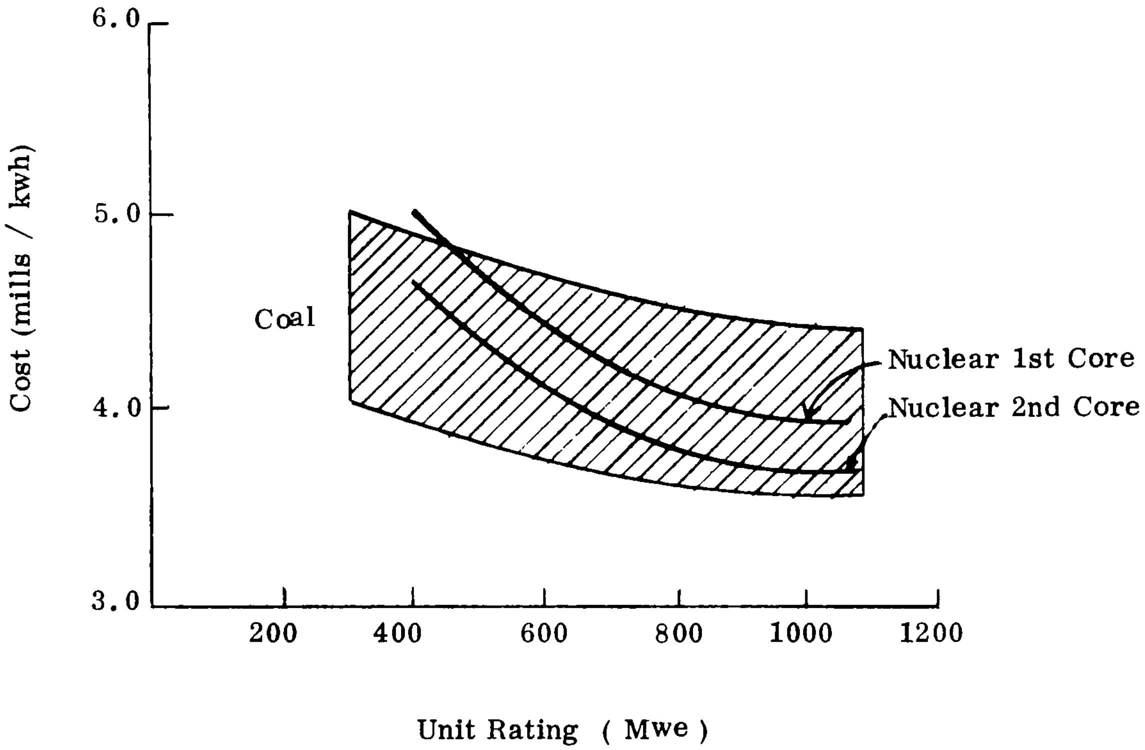

Figure 2.12

Total Power Generating Cost (Ref. 89)

More recently, public and official concern has been directed toward the increased heat rejection (and hence, increased thermal pollution) required for a nuclear plant as compared to a fossil plant. This is due directly to lower overall plant efficiencies (or higher heat rates) as was discussed briefly in an earlier section (Sections 2.3.1 and 2.3.2).

Efficiencies for modern plants are still subject to considerable variation depending upon the individual design constraints, but typical values are in the following ranges:

Fossil -	38-40%
Nuclear, light water -	30-33%
Nuclear, gas-cooled -	37-39%

Although this suggests that gas-cooled, nuclear plants may be built with efficiencies comparable to the best fossil plants, economic factors described in the previous paragraph (high initial cost vs. lower operating costs) tend to dictate against their use in the United States. Therefore, the usual comparison of efficiencies between fossil and nuclear is based on the light-water nuclear units which must reject up to 50% more heat than well-designed fossil plants of equal capacity. The efficiency of nuclear plants can be, and is being increased, but the high capital cost and low fuel cost of nuclear power does not result in as much of an economic incentive for this increase as it does in fossil fueled plants. Power companies must consider all of the above given factors and more when deciding on the type of power plant to build. In 1967 nuclear power accounted for less than 0.5% of the national electrical output. It is projected that it will account for about 35% by 1980 and 85% by 2030.

2.5 Site Selection

The trend toward larger power generating plants in the United States is well established, and associated with this trend is the increasing problem of finding satisfactory locations for these plants. A number of technical and economic factors must be considered in selecting a power plant site whether it is nuclear or fossil-fueled. The principal factors involved are an adequate means of dissipating waste heat, means for transportation of heavy equipment and/or fuel to the site, proximity to load or load transmission availability, adequacy of soil conditions for the type of construction contemplated, the availability of construction and operating labor, and community consideration. Nuclear power plants have the added special aspect of safety requirements as mentioned in the previous section.

The cooling requirements for a nuclear plant are normally significantly greater than for a fossil-fueled plant as discussed in the previous section. In the case of once-through cooling, this means that for a comparable water temperature rise across the condenser (or maximum condenser discharge temperature because of water use regulations), the nuclear plant requires a significantly higher flow rate (see Figure 2.13). While the use of a cooling tower can significantly reduce the flow rate requirements (both because of the evaporative mode of cooling and higher permissible condenser water temperature rises), the total water usage (as measured by required make-up water) is still higher for the case of the nuclear plant.

Transportation requirements for fuel for a fossil fuel plant usually represent a significant portion of the capital and operating costs. A 1000 Mwe coal burning plant may use up to 5000 tons of coal per day depending on the type of coal. This is equivalent to approximately 70 train car loads per day which do not require such large transportation facilities for operation, but usually require larger capacity transportation facilities for construction than do fossil fueled plants. A 5000 Mwe boiling water reactor has a pressure vessel that is 19 feet in diameter and weighs approximately 500 tons. Thus, water access is desirable in many cases and essential in some cases to bring the reactor pressure vessel to the site.

Transportation of spent nuclear fuel can be accomplished by truck, but it is usually more desirable to have rail access to a nuclear plant for this purpose.

The space requirements for power plants can be quite large. The minimum total area required for a large (1000 Mwe or larger) coal fired station is on the order of 150 - 200 acres.[112] This includes space for 40 to 50 days coal storage, ash-disposal basin and switching as well as all other station features. A nuclear plant of similar capacity with an above-ground reactor containment structure requires a minimum space of about half that for the fossil plant. It should be emphasized that these figures are minimum sizes and that most nuclear and fossil plants are located on considerably larger sites, some over 1,000 acres.

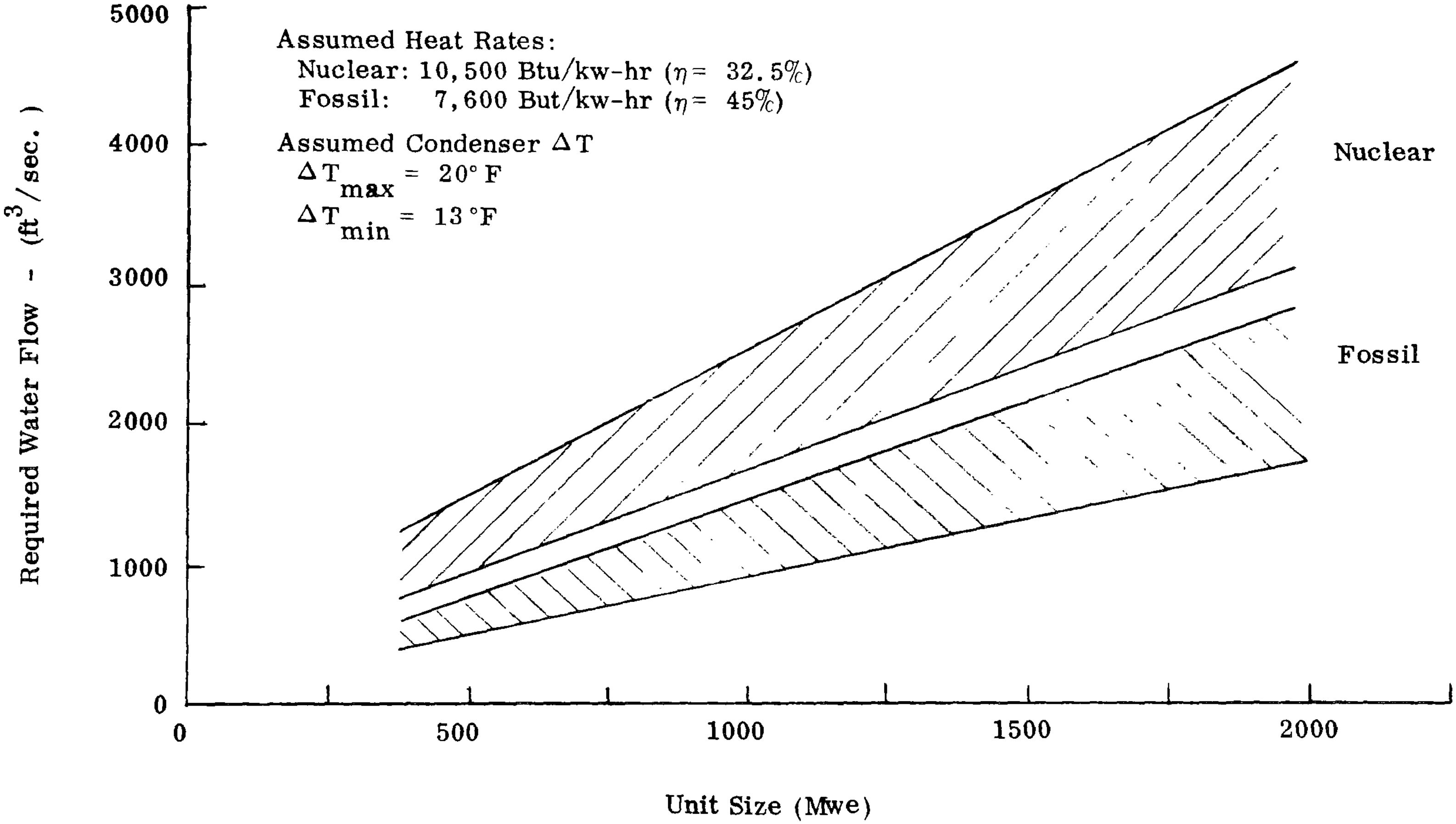

Figure 2.13

Condensor Cooling Water Requirements (Ref. 112)
(for once-through cooling)

The locating of a nuclear power plant at or near a load center (city) is highly dependent on community consideration. The advantages of siting a nuclear plant in a city include: freedom from atmospheric pollution and coal dust nuisance, elimination of large fuel storage space, availability of waste heat for space heating, and the elimination of great lengths of objectionable overhead transmission or costly underground cable. The potential drawbacks, as mentioned in the previous section, are: routine radioactive effluents, accident danger, and increased thermal pollution. The much considered abatement of thermal pollution to rivers and estuaries by use of cooling towers is not as easily accomplished with a power plant located in a city. Aside from the excessive cost of the land required for a cooling tower at a city site, secondary pollution, as described in the Task I report, must be considered as well as the appearance of the typical cooling tower.

Increased cooperation with local and state agencies and with conservationist groups has become a necessary policy for power companies recently. This cooperation is necessary in order to solve power-reactor siting problems at an early stage of planning. There have been instances, such as the proposed 325 Mwe nuclear plant at Bodega Bay, California, for which the construction application to the AEC was withdrawn after $4 million had been spent at the site (Ref. 101).

2.6 Plant Capacity Factor

Plant capacity factor is an important consideration in power plant design in that it enters strongly into the optimization process, as will be seen in Section 3. Capacity factor is usually defined as the ratio of the average load on a machine, plant, or system for a given period of time (commonly one year) to the capacity of the machine or equipment. For evaluation purposes it is usually desirable to base the capacity factor on the maximum guaranteed capability of the unit or units considered.

When new units are installed, they are usually the largest and most efficient in their connected system and are therefore run continuously at maximum capability to provide the base load of the system. As the years go by, and newer and more efficient units are installed in the system, the aging units gradually shift from base-load to peak-load service, and in their final years may run only during the seasonal peaks or during emergency outages of other units. In design, a high expected capacity factor not only allows more capital expenditure for a more efficient plant, but fuel costs can be reduced due to larger yearly consumption.

Lifetime capacity factor is determined by estimates of load duration of the plant each year for the life of the plant. These estimates are made in the form such as shown in Table 2.1 or in the form of curves such as Figure 2.14. Table 2.1 and Figure 2.14 both result in approximately the same average lifetime capacity factor. Another means of presenting the equivalent information is a plot of expected annual generation vs. time. This is shown in Figure 2.15 for a nominal 300 Mwe plant with the load duration curves of Figure 2.14.

Table 2.1
LOAD DURATION
Hours Per Year at Various Outputs

Output % of Maximum Capacity	Plant Life - Years		
	0 - 10	10 - 20	20 - 30
100	5150	2200	1100
80	1750	1850	1250
60	800	1700	1850
35	700	1500	1700
0	360	1510	2860

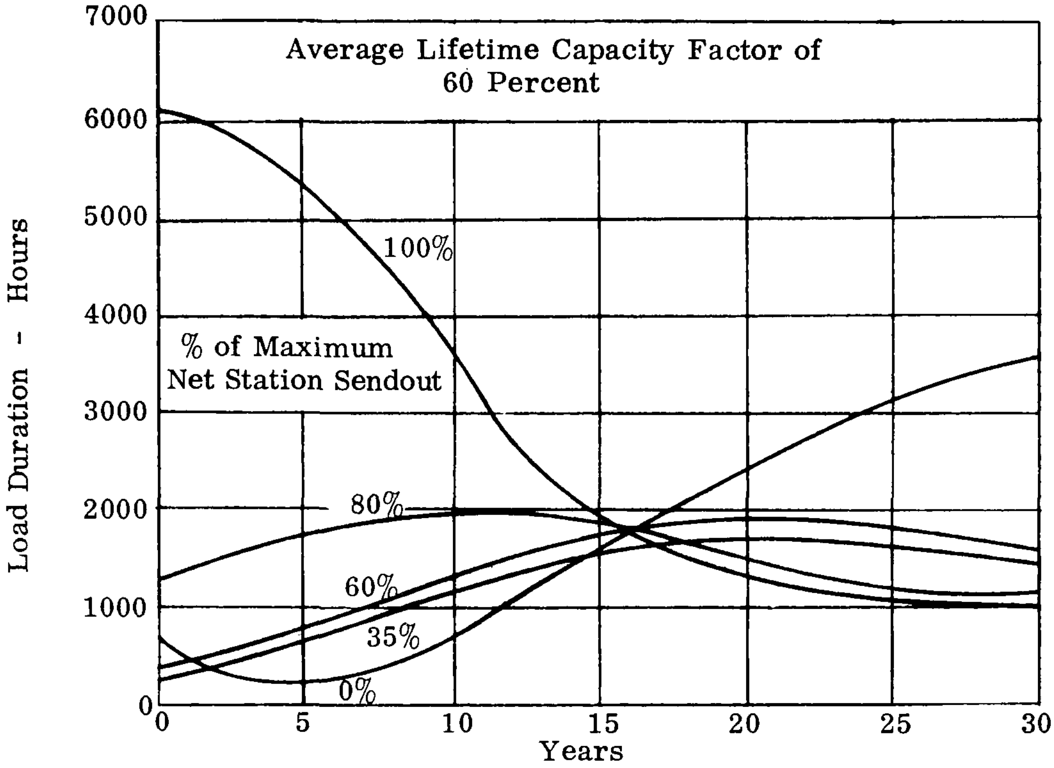

Figure 2.14

Projected Division of Hours for Each Year at Various Loads

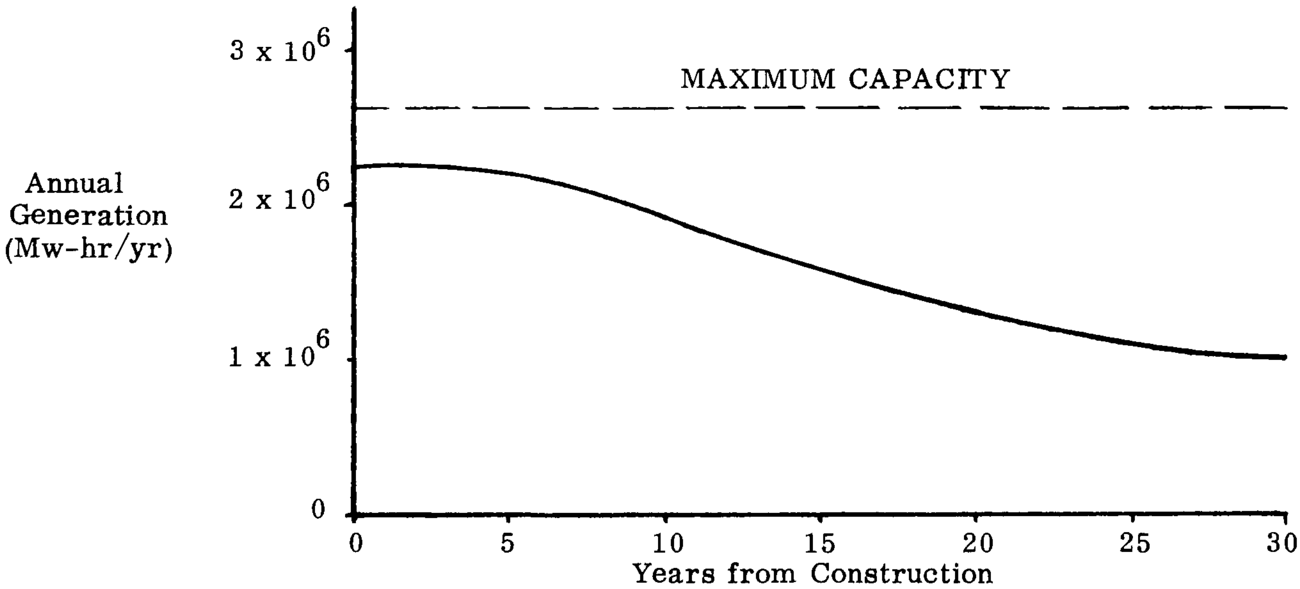

Figure 2.15

Projected Annual Generation for 300 Mwe Plant with
Average Lifetime Capacity Factor of 60% (from Figure 2.14)

Load duration tables or curves for a new plant are prepared by a utility from data on present operating units and expected load increases. The expected loading of a new plant is usually estimated for a specific type of plant with the idea of providing a base for economic optimization, as will be seen in Section 3. Also for optimization purposes, the load duration estimates are usually broken down further into percents of time at various condenser pressures, as is shown in Table 2.2.

Table 2.2

DIVISION OF HOURS AT VARIOUS CONDENSER PRESSURES

Percent of Maximum Net Station Sendout	Percent of Time at Condenser Pressure (in. Hg abs.) 1.0	1.5	2.0
100	30	30	40
80	40	30	30
60	55	30	15
35	70	30	0

2.7 Fixed Charge Rate

An annual fixed charge rate can be defined as the fraction of original cost which must be paid each year for the use of capital, for amortization of the investment, and for the payment of other charges incidental to the acquisition or use of the invested capital. Carrying charges are used to determine the yearly capital costs on items of equipment. The major items which make up carrying charges used for economic evaluation by privately owned electric utilities are:

1. Depreciation
2. Return on capital
3. Federal Income Tax
4. State and local taxes
5. Insurance.

There are numerous means by which depreciation may be calculated such as the straight line, the sum-of-the-year-digits, and the sinking-fund methods. Simple straight-line depreciation is most often used by power utilities with occasional use of two methods at the same time; the straight line method used for rate of return calculations and a more rapid depreciation, such as the sum-of-the-year-digits method used for income tax purposes. Normal straight-line depreciation is usually taken as 3.0% or 3.33% corresponding to expected lives of 33 and 30 years respectively.

Return on capital and Federal Income tax are usually fixed percentages of the value of the depreciated utility plant and as such decline as the original investment is amortized. State and local taxes and insurance can either be considered as fixed percentages of the original investment or treated as percentages of the depreciated value of the utility. Figure 2.16 shows typical annual fixed charges made up of the following:

1. Straight-line depreciation at the rate of 3.33 percent of the initial investment per year, with zero salvage value at the end of the 30-year life.

2. Rate of return of 6.25 percent of the annual average unrecovered investment.

3. Federal Income Tax rate of 4.15 percent of the annual average unrecovered investment. This is based on a debt-equity ratio of 50 percent.

4. Property Tax rate and insurance of 3.31 percent of the unrecovered investment at the beginning of each year.

The large variation in fixed charge rate as the investment is amortized makes it difficult to select a year or group of years which may be considered for evaluation purposes, especially if present worth evaluation is used. The means by which this variation is accounted for is discussed in Section 3.

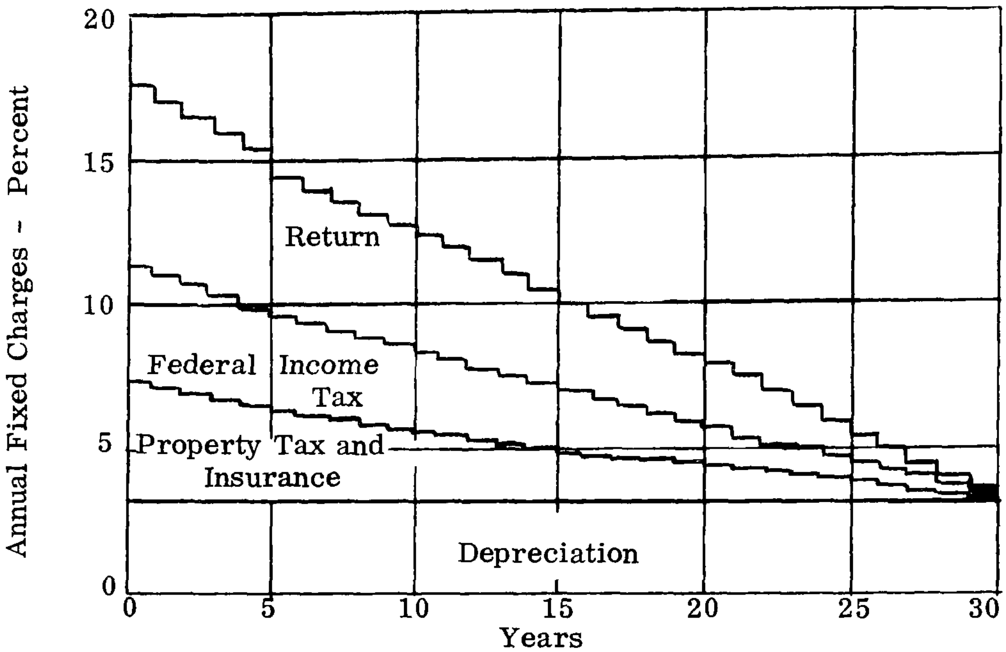

Figure 2.16

Typical Fixed Charges

Section 3

DETAILED DESIGN AND OPTIMIZATION

3.1 Introduction

The design and construction of power plants using other than once-through cooling will become increasingly important in the near future. To evaluate the economics of these future plants it is first necessary to have an understanding of the techniques used in the design and optimization of present day power plants. The cost of various types of heat rejection equipment was discussed in the Task I Report and will not be covered again in this report; rather the report will focus on the other main components of a power plant.

The economic incentive for power plant optimization is considerable. For a utility with a steam unit capacity of approximately 2500 Mw, such as the Department of Water and Power of Los Angeles, the annual fuel bill is about $35 million, which represents only about 20 percent of the total power system budget (Ref. 26). Because of this, it is apparent that a 1/2 or 1 percent reduction in either heat rate or capital cost represents substantial savings. A non-economic consideration for improving the efficiency of a power plant is that the higher the efficiency of a plant, the less waste heat must be rejected to the environment per unit of electricity produced.

In Section 2, overall plant selection was considered and some discussion of the selection of an optimum plant size was included. That type of preliminary design study may be considered system planning, which is most often done by the power utilities themselves. They define their power requirements and other general parameters, such as expected load duration, in the system planning phase of power plant design.

This section describes the detailed design and optimization that follows a system planning study. The two phases are, of course, never completely distinct, since the considerations and results of each phase have some influence on the other phases.

The order of consideration of the parameters for optimization is as follows: first, to select the initial pressure and temperature and reheat temperature; second, to consider the number and temperature of feedwater heaters; and third, to consider the effect of various condensers. Less important parameters such as maintenance and controls are then studied and the whole plant re-evaluated in terms of the successive design changes. These progressive steps in the detailed design and optimization procedure have been followed in the sections of this chapter.

The differences between nuclear and fossil plants have been de-emphasized in this chapter. The economics of nuclear plants are more complex than fossil plant economics and have been clouded by influences such as AEC support of nuclear fuel prices, the tendency of manufacturers to bid low to get into the market, and the fact that each new nuclear plant has usually incorporated some advancement in the state of the art and is thus somewhat of a "first". However, the design and optimization procedure is the same for both nuclear plants and fossil plants, and therefore the procedure as explained in this chapter should be equally valid for both types of plants. We also have included nuclear turbine costs in the appendix, which may be used in the same fashion as fossil turbine costs.

Detailed economic optimization of present day power plants is often done with the use of a computer. The computer programs that are used range from ones that are very much simple trial and error, to ones that are very sophisticated. The details of these programs will not be covered in this report, but rather a more general approach will be taken.

3.2 Basic Cycle Optimization

The most important cost optimization procedure used in power plant design after a system planning study, is the determination of the initial pressure and temperature and the reheat temperature(s) of the unit. Also of initial importance is the type of turbine to be used, e.g., cross compound or tandem compound and the length of the last stage of blades.

It has been found in the past that somewhat specific ranges for the above parameters represent probable ranges within which the most economical values will be found. In order to shorten the description of these parameter ranges we will limit our consideration to units of greater than 200 Mwe.

For large steam units of greater than 200 Mwe the values of initial pressure and temperature and reheat temperature that are usually considered are given in Table 3.1.

Table 3.1

Initial Pressure, psi	1800,	2400,	3500	
Initial Temperature, °F	1000,	1025,	1050,	1100
Reheat Temperature, °F	1000,	1025,	1050	

The possible combinations of the variables in Table 3.1 are over 100 if a second reheat is considered. If this is multiplied by the possible kinds of turbines for each pressure and temperature (approximately 20), then the total number of possible alternatives exceeds 2000. Obviously, detailed cost calculations cannot be performed for 2000 alternatives, except possibly by computer. Therefore, some sort of limiting approximations are necessary. These approximations are the result of past experience in power plant design and a general knowledge of the costs as functions of the various parameters. For example, for a plant with an expected high lifetime capacity factor only higher pressures will be considered.

The final selection of the optimum power plant is done by calculating the present worth of all future revenue requirements* for various alternatives and selecting the lowest. The present worth concept discounts the value of money needed in the future (fuel cost, etc.) relative to initial revenue requirements (capital expenditures), as will be explained in Section 3.2.3. To calculate the present worth of the various alternatives requires the calculation of the capital charges per year and the operating costs per year for the various alternatives. The details of these procedures are described in the following two sections, and the means of converting to present worth described in the third section.

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*Approximately 80% of power companies in the United States use this method.

3.2.1 Capital Costs

The calculation of yearly capital charges requires first a calculation of the initial investment costs. The fixed charge rates, as described in Section 2.7, are then applied to the initial investment cost to give the capital charges per year.

The investment required for a steam power plant varies greatly with location, fuel, particular requirements, desired heat rate, and numerous other factors. Figure 3.1 shows the type of variation in cost encountered for steam power plants in this country.

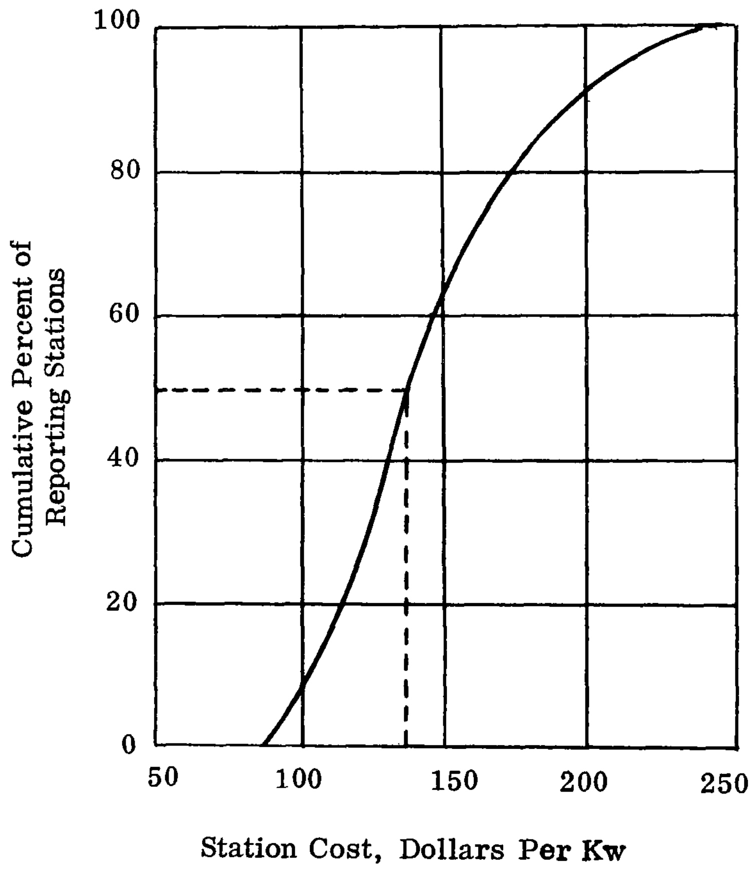

Figure 3.1
Cumulative Frequency Distribution of Station Cost (From Ref. 51a)

To understand the reasons for this large variation, it is necessary to examine the costs of the various components that make up a steam power plant. The largest source of data on steam power plant costs are the reports of the utilities to the Federal Power Commission. The FPC has established a Uniform System of Accounts (Ref. 4a) that the utilities use for reporting costs. Some of the important accounts of the system are specified as follows:

For Fossil-Fueled Plants:

Account 310. Land and Land Rights

This account includes the cost of land and land rights employed in connection with steam-power generation.

Account 311. Structures and Improvements

This account includes the cost in place of structures and improvements used and useful in connection with steam-power generation. (Note: Also includes steam-production roads and railroads.)

Account 312. Boiler-Plant Equipment

This account includes the cost installed of furnaces, boilers, coal and ash handling, coal-preparing equipment, steam and feedwater piping, boiler apparatus and accessories used in the production of steam, mercury, or other vapors, to be used primarily for generating electricity. (Note: Includes the feedwater heaters, boiler feed pumps, and all other equipment associated with the feedwater system. Also, when the system for supplying boiler or condenser water is elaborate, as when it includes a dam, reservoir, canal, pipe line, or cooling pond, the cost of such special facilities shall be charged to a subdivision of Account 311.)

Account 314. Turbine-Generator Units

This account includes the cost installed of main turbine-driven units and accessory equipment used in generating electricity by steam. (Note: Also includes the condensers and circulating-water system. Also cooling system including towers, pumps, tanks, and piping.)

Account 315. Accessory Electrical Equipment

This account includes the cost of auxiliary generating apparatus, conversion equipment, and equipment used primarily in connection with the control and switching of electric energy produced by steam power, and the protection of electric circuits and equipment, except electric motors used to drive equipment included in other accounts. Such motors shall be included in the account in which the equipment with which it is associated is included. (Note: Does not include transformers and other equipment used for changing the voltage or frequency of electric energy for the purpose of transmission or distribution.)

Account 316. Miscellaneous Power-Plant Equipment

This account includes the cost installed of miscellaneous equipment in and about the steam-generating plant devoted to general station use, which is not properly includable in any of the foregoing steam-power-production accounts.

Account 353. Station Equipment

This account includes the cost installed of transforming, conversion, and switching equipment used for the purpose of changing the characteristics of electricity in connection with its transmission or for controlling transmission circuits.

For Nuclear Plants:

For nuclear plants, similar accounts are defined. These are:

Account 320: Land and Land Rights
Account 321: Structures and Improvements
Account 322: Reactor Plant Equipment
Account 323: Turbogenerator Units
Account 324: Accessory Electric Equipment
Account 325: Miscellaneous Power Plant Equipment

Similar to the case of fossil plants, condensers and cooling systems including towers are part of Account 322. However, ponds, reservoirs, dams, etc. are included as a subsection of Account 321, Structures and Improvements.

Figure 3.2 shows typical relative magnitudes of the various costs according to the FPC accounts. Specific FPC data, however, must be used with discretion because there are some items that have not been clearly defined. The most important of these is "installed generating capacity" which some utilities consider to mean the nameplate rating while others report maximum unit capability. The difference can be as much as 25 percent.

Because some of the accounts specified by the FPC are so broad, it is nearly impossible to use their statistics to establish detailed patterns of station component costs. However, since these accounts are so widely used and there is a large body of data classified according to the system, it is beneficial to examine them further.

For optimization purposes it is generally sufficient to examine the changes in boiler-plant equipment costs and turbine-generator equipment costs with size and steam conditions. Overall capital costs as functions of size were discussed in Section 2, and therefore in this section the emphasis will be on variation of costs with steam conditions. Unit size, however, is still an important parameter is the discussion. Table 3.2 shows some 1963 costs broken down into component costs. It is seen that the major cost changes with steam conditions occur for the boiler plant equipment costs and the turbine plant equipment costs, and that other costs, such as transmission costs, although large, do not vary significantly with steam conditions.

To understand the reasons for these cost variations with steam conditions it is first necessary to break down the boiler plant equipment costs and turbine generator equipment costs further. Table 3.3 shows approximate cost percentages for the various components of these two cost accounts. In the next two sections turbine generator costs and boiler costs are discussed in more detail.

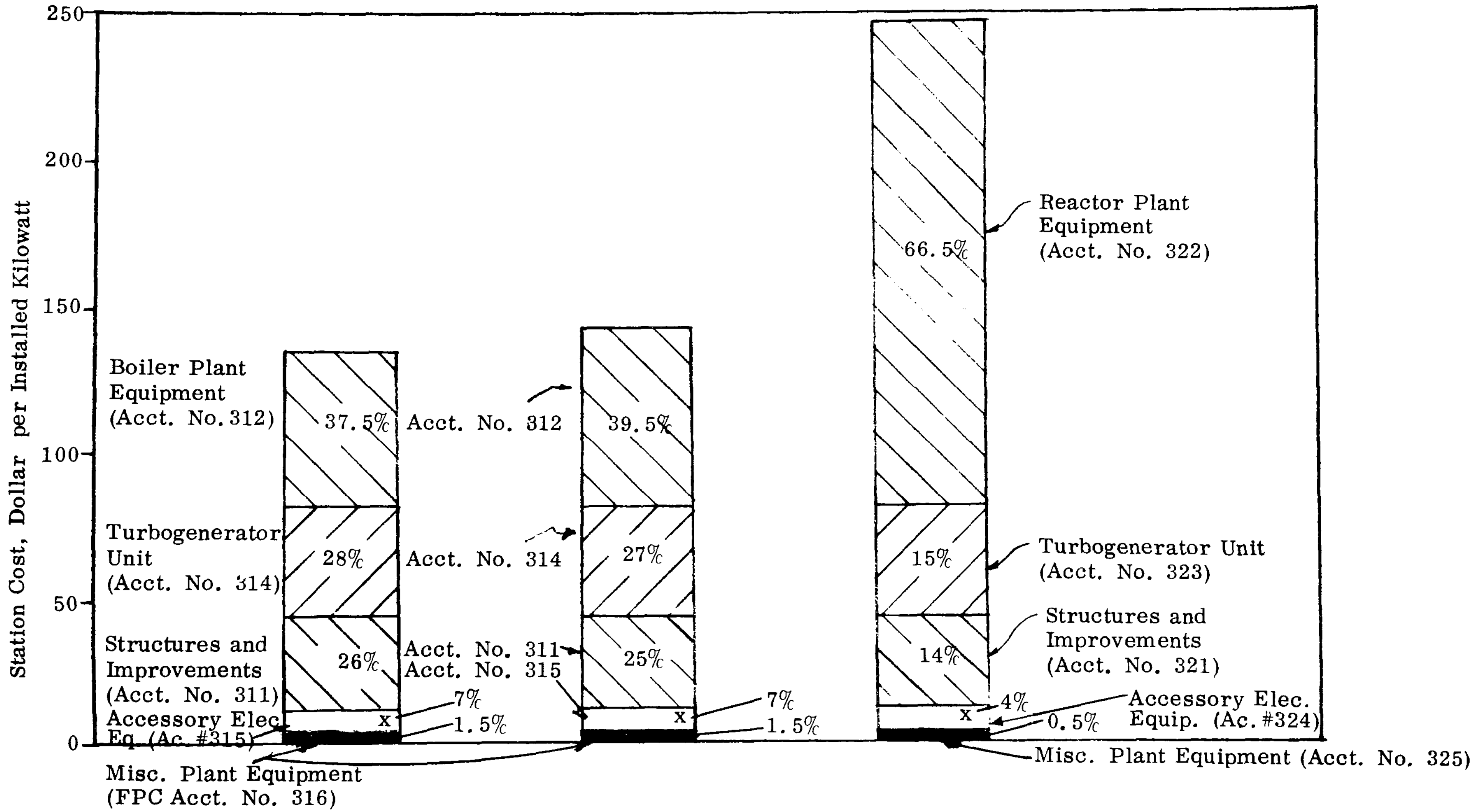

Figure 3.2

Typical Distribution of Station Costs According to FPC Accounts for Coal-Fired, Gas or Oil-Fired, and Nuclear Plants (from Ref. 16a)

POWER STATION CAPITAL COST (THOUSANDS)

Nameplate	300 Mw TC4F 3600 RPM			400 Mw TC4F 3600 RPM			500 Mw CC2F 3600/1800 RPM			600 Mw CC2F 3600/3600 RPM		
Pressure, psig	2400	3500	3500	2400	3500	3500	2400	3500	3500	2400	3500	3500
Temperature, F	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
First Reheat, F	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Second Reheat, F			1000			1000			1000			1000
310 Land and Land Rights	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200
311 Structures and Improvements	2,860	2,860	2,860	3,015	3,015	3,015	3,510	3,535	3,510	3,790	3,790	3,790
312 Boiler Plant Equipment	15,590	16,228	16,612	19,907	20,638	21,149	23,959	25,179	25,504	27,730	28,943	29,578
314 Turbine Generator Equipment	8,408	8,541	8,917	10,520	10,431	10,809	13,238	13,154	13,566	14,983	14,886	15,340
315 Accessory Electrical Equipment	1,204	1,204	1,204	1,277	1,277	1,277	1,565	1,565	1,565	1,655	1,655	1,655
316 Miscellaneous Power	414	414	414	417	417	417	443	443	443	475	475	475
353 Transmission												
Transformers	320	320	320	415	415	415	490	490	490	590	590	590
General Items	4,345	4,414	4,478	4,735	4,800	4,868	5,388	5,478	5,540	5,922	5,981	6,077
Contingency	1,609	1,669	1,695	1,964	2,007	2,050	3,407	2,456	2,482	2,705	2,780	2,895
TOTAL COST	$34,950	$35,850	$36,700	$42,450	$43,200	$44,200	$51,200	$52,500	$53,300	$58,050	$59,300	$60,500
$/kw net output	$114.97	$119.18	$121.74	$103.79	$106.60	$108.67	$ 98.79	$102.81	$103.69	$ 95.35	$ 98.42	$100.05

Table 3.2

1963 POWER PLANT COSTS (FROM REFERENCE 65)

Table 3.3

TYPICAL BREAKDOWN OF BOILER PLANT EQUIPMENT COSTS AND TURBINE GENERATOR EQUIPMENT COSTS
(after Ref. 16a)

Account 312. Boiler Plant Equipment

Boiler	55
Piping	15
Fuel Handling System	13
Feedwater System	9
Draft System	5
Ash Handling System	3
	100%

Account 314. Turbine Generator Equipment*

Turbine Generator	75
Condenser	10
Condenser Supply System	15
	100%

*Cost breakdown typical for a once-through cooling system.

3.2.1.1 Turbine Generator Costs

Turbine generator costs are one of the more well defined components of steam station costs. The manufacturers of this equipment publish prices for a large number of "standard" units including price modifications for various steam conditions. Table 3.4 is a recent Westinghouse price list for various large steam turbines, and are base, uninstalled prices. The actual selling price is obtained by the use of a common multiplier (quoted as 0.54 in March, 1970), i.e., the price of a 175,000 kw, TC2F-25* is $9,800,000 x 0.54 = $5,292,000 or $5,292,000/175,000 kw = 30.24 dollars/kw.

The full Westinghouse price list and portions of the General Electric price list have been included in the Appendix. Prices for the two company's turbines are identical (as is the multiplier) on an equal power basis with slightly different designs (last stage blade lengths) used. The price multiplier applies not only to the base turbine prices but also to all the accessory prices given in the Appendix.

It should be noted that in Table 3.4 there is a cost reduction between similar units in going from 2400 psi to 3500 psi, which is contrary to general power station costs as functions of pressure. This decrease in cost for the turbine is more than compensated for by increased boiler cost, and also by the increased cost of a second reheat, a usual addition to supercritical units.

The condenser system, which comprises about 25 percent of the turbine generator system cost will be discussed in Section 3.4

3.2.1.2 Boiler Plant Costs

Boiler costs are one of the most difficult component costs to obtain. The difficulty is that there are many variables, such as fuel type, that have a significant effect on the overall cost and that are not in standard use throughout the industry. Boiler manufacturers do not publish prices, and it is necessary for utility companies to submit detailed design requirements to the manufacturers to obtain cost estimates.

*Numbers after turbine type are length of last stage blades (in inches).

Table 3.4

(From Westinghouse - See Appendix)

Steam Turbine Generator Units

Condensing Non-Reheat and Reheat Double Flow 25-Inch Last Row Blades and Larger

Condensing Reheat Units

Basic List Prices

Prices—in Thousands of Dollars—Include Freight and Installation Services

Basic Unit Turbine Rating, Kw	Generator Rating, Kva	Turbine Exhaust Ends	Basic List Price
Tandem Compound—3600 Rpm			
175,000	210,000	2-25"	$ 9,800
225,000	270,000	2-28.5"	12,200
250,000	300,000	2-31"	13,300
250,000	300,000	4-23"	13,400
350,000	420,000	4-25"	16,200
450,000	540,000	4-28.5"	20,600
500,000	600,000	4-31"	23,000
500,000	600,000	6-25"	23,000
650,000	780,000	6-28.5"	28,600
750,000	900,000	6-31"	32,800
Cross Compound—3600/3600 Rpm			
250,000	300,000	4-23"	15,800
350,000	420,000	4-25"	18,550
400,000	480,000	6-23"	20,500
450,000	540,000	4-28.5"	22,800
500,000	600,000	4-31"	25,000
500,000	600,000	6-25"	25,000
650,000	780,000	6-28.5"	30,400
700,000	840,000	8-25"	31,200
750,000	900,000	6-31"	34,700
900,000	1,080,000	8-28.5"	40,000
1,000,000	1,200,000	8-31"	43,800
Cross Compound—3600/1800 Rpm			
400,000	480,000	2-40"	21,200
500,000	600,000	2-44"	24,800
700,000	840,000	2-52"	33,100
800,000	960,000	4-40"	37,000
1,000,000	1,200,000	4-44"	43,200
1,200,000	1,440,000	6-40"	51,200
1,400,000	1,680,000	4-52"	57,000
1,500,000	1,800,000	6-44"	61,800

Pricing for Units with Capability other than Listed

1. Add or deduct turbine capability at **$9.00/kw** for each kw more or less than listed in table for base machine of the type desired.
2. Add generator capability at **$10.00/kva** for each kva more than listed in table for base generator rating.
3. Deduct generator capability at **$10.00/kva** for each kva less than listed in table for base generator ratings down to 150,000 kva.
4. For further kva reductions lower than 150,000 kva, **deduct $12.00/kva.**

Price Additions for Pressure (Psig)

Prices—in Thousands of Dollars

Turbine Rating, Kw	Initial Pressure Range, Psig② 1250-1450	1600-1800	2200-2400	3200-3500	4100-4500
150,000	$ 120	$ 0	$ 120	$540	$1,200
200,000	300	0	0	300	1,000
300,000	540	120	0	120	800
400,000	840	300	0	0	600
500,000	1,200	540	120	0	700
600,000	1,620	840	300	0	800
700,000	......	1,200	540	0	900
800,000	......	1,620	840	0	1,000
900,000	......	2,100	1,200	0	1,100
1,000,000	......	......	1,620	0	1,200
1,100,000	......	......	2,100	0	1,300
1,200,000	......	......	2,640	0	1,400
1,300,000	......	......	3,240	0	1,500
1,400,000	......	......	3,900	0	1,600
1,500,000	......	......	4,620	0	1,700

②For pressures between those listed above, use the adjoining pressure range which results in the higher price.

Table F: Price Additions for Temperature (°F)

Prices—in Thousands of Dollars

Turbine Rating, Kw	Initial Temperature Range 826-900	901-950	951-1000	1001-1050	1051-1100	First Reheat Temperature Range 826-900	901-950	951-1000	1001-1025	1026-1050	Second Reheat Temperature Range 1000	1001-1025	1026-1050
150,000	−$ 60	−$ 40	$0	$180	$ 480	−$ 60	−$ 40	$0	$300	$500	$1,600	$1,800	$2,000
200,000	− 90	− 60	0	180	480	− 90	− 60	0	300	500	1,600	1,800	2,000
300,000	− 120	− 80	0	240	480	− 120	− 80	0	300	500	1,600	1,800	2,000
400,000	− 150	− 100	0	300	600	− 150	− 100	0	300	500	1,600	1,800	2,000
500,000	− 180	− 120	0	360	720	− 180	− 120	0	300	500	1,700	1,900	2,100
600,000	− 210	− 140	0	420	840	− 210	− 140	0	320	520	1,800	2,000	2,220
700,000	......	......	0	480	960	......	......	0	340	540	1,900	2,100	2,340
800,000	......	......	0	540	1,080	......	......	0	360	560	2,000	2,200	2,460
900,000	......	......	0	600	1,200	......	......	0	380	580	2,100	2,300	2,580
1,000,000	......	......	0	660	1,320	......	......	0	400	600	2,200	2,400	2,700
1,100,000	......	......	0	720	1,440	......	......	0	420	620	2,300	2,500	2,820
1,200,000	......	......	0	780	1,560	......	......	0	440	640	2,400	2,600	2,940
1,300,000	......	......	0	840	1,680	......	......	0	460	660	2,500	2,700	3,060
1,400,000	......	......	0	900	1,800	......	......	0	480	680	2,600	2,800	3,180
1,500,000	......	......	0	960	1,920	......	......	0	500	700	2,700	2,900	3,300

Prices effective August 9, 1969; subject to change without notice.

Babcock and Wilcox have, however, made some estimates of general cost differentials for variations of pressure, temperature, fuel type, and unit size. These differentials, for three pressures (1800, 2400, and 3500 psig) three reheat schedules (1000/1000° F, 1050/1025° F, and 1000/1000/1000° F) and two capacities (300 Mw; 2100×10^3 lb/hr and 500 Mw; 3400×10^3 lb/hr) are shown in Table 3.5 for coal-fired units. Simple, additive corrections for going to gas-fired or oil-fired are given below.

Table 3.5

BOILER COST DIFFERENTIALS* FOR COAL-FIRED UNITS
(figures in $/kw)

	1000/1000° F 300 Mw	1000/1000° F 500 Mw	1050/1025° F 300 Mw	1050/1025° F 500 Mw	1000/1000/1000° F 300 Mw	1000/1000/1000° F 500 Mw
1800 psig	-2.69	not available	-1.75	not available	not available	not available
2400 psig	0. (base)	-1.68	+0.94	-0.82	+1.35	-0.36
3500 psig	+0.90	-0.78	+1.84	+0.08	+2.25	+0.54

*Cost differentials (delivered and erected) including burning equipment, forced draft fans, structural steel, air heaters, insulation, lagging and casing, flues and ducts, and soot blowing equipment; excluding high pressure leads and feedwater system (Courtesy of Babcock and Wilcox).

The corresponding cost differentials for oil-fired or gas-fired units are obtained for any specific pressure, reheat schedule, and unit size simply by adding the additional savings noted below. These savings differ slightly with unit size.

Table 3.5a

ADDITIONAL SAVINGS FOR DIFFERENT FUELS

	300 Mw	500 Mw
Oil-fired	-11.26	-11.22
Gas-fired	-12.43	-12.46

Therefore, the total differential cost for a gas-fired, 3500 psig, 1000/1000/1000°F, 300 Mw unit is

$$\Delta\ \$/\text{kw} = \underset{\text{(Table 3.5)}}{+2.25} \quad \underset{\text{(Table 3.5a)}}{-12.43}$$

$$= -10.18\ \$/\text{kw}$$

while for a 500 Mw unit of the same type

$$\Delta\ \$/\text{kw} = \underset{\text{(Table 3.5)}}{+0.54} \quad \underset{\text{(Table 3.5a)}}{-12.46}$$

$$= -11.92\ \$/\text{kw}$$

3.2.1.3 Example

For use in explaining the optimization procedure in the following sections we have chosen an example from the literature (Ref. 40a). The example includes estimates of costs for various steam conditions for a 300 Mw new unit in 1963. These cost estimates were based on book prices for turbine generator units and preliminary cost data from manufacturers of other equipment. The total plant costs for the various units are shown in Table 3.6. It is noted that the costs in Table 3.6 are considerably higher than the costs for the 300 Mw units shown in Table 3.2. This is due to the use of book prices and preliminary estimates for the costs shown in Table 3.6 whereas the costs in Table 3.2 were based on competitive prices.

The nine sets of steam conditions and turbine types shown in Table 3.6 will also be used as examples in the next sections on operating costs.

Table 3.6

COST DATA FOR VARIOUS ALTERNATIVE STEAM CONDITIONS AND TURBINE TYPES (from Ref. 40a)

Alternate Number	Steam Conditions	Turbine Type	Initial Station Cost,* $/kw	Maximum Net Station Sendout (at 1.5 in. Hg) kw
1	2400 psig, 1000/1000 F	TC4F-26	128.96	303,700
2	2400 psig, 1050/1000 F	TC4F-26	131.19	302,700
3	3500 psig, 1000/1000 F	TC4F-26	133.98	299,330
4	3500 psig, 1000/1000/1000 F	TC4F-26	138.68	299,980
5	3500 psig, 1000/1025/1050 F	TC4F-26	140.94	299,980
6	3500 psig, 1000/1000 F	TC4F-29	134.71	302,330
7	3500 psig, 1000/1000 F	CC4F-29	136.32	302,330
8	3500 psig, 1000/1000 F	CC2F-38	135.65	301,330
9	3500 psig, 1000/1000 F	CC2F-43	138.47	305,330

*$/kw based on maximum net station sendout at 1.5 in. Hg. abs.

3.2.2 Operating Costs

The analysis of how comparative operating costs for a variation of alternative power plants will consider only the fuel costs. Other operating costs such as labor and maintenance will be deferred to Section 3.5. This restriction is usually imposed on the basic cycle optimization procedures in practice, since the fuel costs represent the dominant portion of the operating costs. Furthermore, changes in the basic cycle affect the fuel costs to a much greater extent than that to which they affect the other operating costs.

In order to compute the fuel costs for the various alternative cycles, the following information is required:

1. the heat rate (efficiency) for cost cycle (Appendix)
2. the projected load duration curves (Figure 2.14)
3. the associated projected condenser pressure curves (Table 2.2)
4. the criterion by which the loads are distributed among the plants within the particular utility system.

With this information, the comparison and selection procedure consists of the following steps:

1. Quantify the criterion for load distribution in the utility system (this sets the basis for comparison).
2. Compute the expected loadings of the alternatives.
3. Calculate the expected fuel consumption over the life of the plant.
4. Calculate the present worth of the future fuel costs.

In order to perform these steps, it is necessary to make projections of future fuel costs. Nuclear and fossil fuel costs were discussed in Section 2 and past fuel costs are shown in Figures 2.7 and 2.10. The common assumptions are either that the cost will remain constant or that it will increase linearly at some assumed rate given the life of the plant. The entire procedure will be illustrated by means of a sample computation based on the selection of a 300 Mwe (nominal) unit from among the alternatives tabulated in Table 3.6 to meet the projected load duration tabulated in Table 2.1 and Table 2.2.

3.2.2.1 Plant Loading Criterion

There are two commonly used criteria for determining how the total system load is assigned to the individual units within the system. These are:

1. All units operating at equal Incremental Heat Rates

or 2. All units operating at equal Incremental Running Rates

These terms are defined as follows:

(a) Incremental Heat Rate (IHR)

The incremental heat rate is the additional amount of energy input required to obtain a unit change in power output, expressed in (Btu/hr-kw). The heat rate (HR) relates the energy input (Q_{IN}) to the plant output (KW) as

$$HR \equiv \frac{Q_{IN}}{KW}$$

Therefore, the incremental heat rate (IHR) can be expressed mathematically as:

$$IHR \equiv \frac{\Delta Q_{IN}}{\Delta KW} = \frac{\Delta (HR \times KW)}{\Delta KW}$$

$$= KW \frac{\Delta (HR)}{\Delta (KW)} + HR$$

Therefore, curves of incremental heat rate vs. load are readily constructed from the normal unit rating curves of heat rate vs. load. These are shown in Figures 3.3 and 3.4.

(b) Incremental Running Rate (IRR)

The incremental running rate is the additional cost to obtain a unit increase in plant output. This is computed simply as the fuel cost (in \$/Btu) times the incremental heat rate. These curves correspond to the absolute and incremental heat rate curves of Figures 3.3 and 3.4 and are shown in Figures 3.5 and 3.6.

The absolute heat rate curves, from which the others are obtained, are computed from the turbine heat rate tables included in the Appendix. In order to give meaningful comparisons between plants, however, the turbine heat rate must be connected to a net plant heat rate (NHR). This is given by:

$$\text{Plant NHR} = \frac{\text{turbine heat rate}}{\eta_{\text{boiler}} \left\{ 1 - \frac{\%\ \text{Auxiliary Power}}{100} \right\}}$$

where η = boiler efficiency

Boiler efficiencies range from 88% to 91% and are normally considered constant for optimization computations.

Figures 3.3 and 3.4 show absolute and incremental plant net heat rates at 1.5 in Hg abs condenser pressure for the nine cases of the example of the preceding section. Figures 3.5 and 3.6 show the incremental running rate curves for the same cycles for a fuel cost of 35.0 cents per million Btu. These curves have the same shape and general characteristics as the incremental heat rate curves of Figures 3.3 and 3.4, except that the "hooks" at the lower ends have been eliminated.

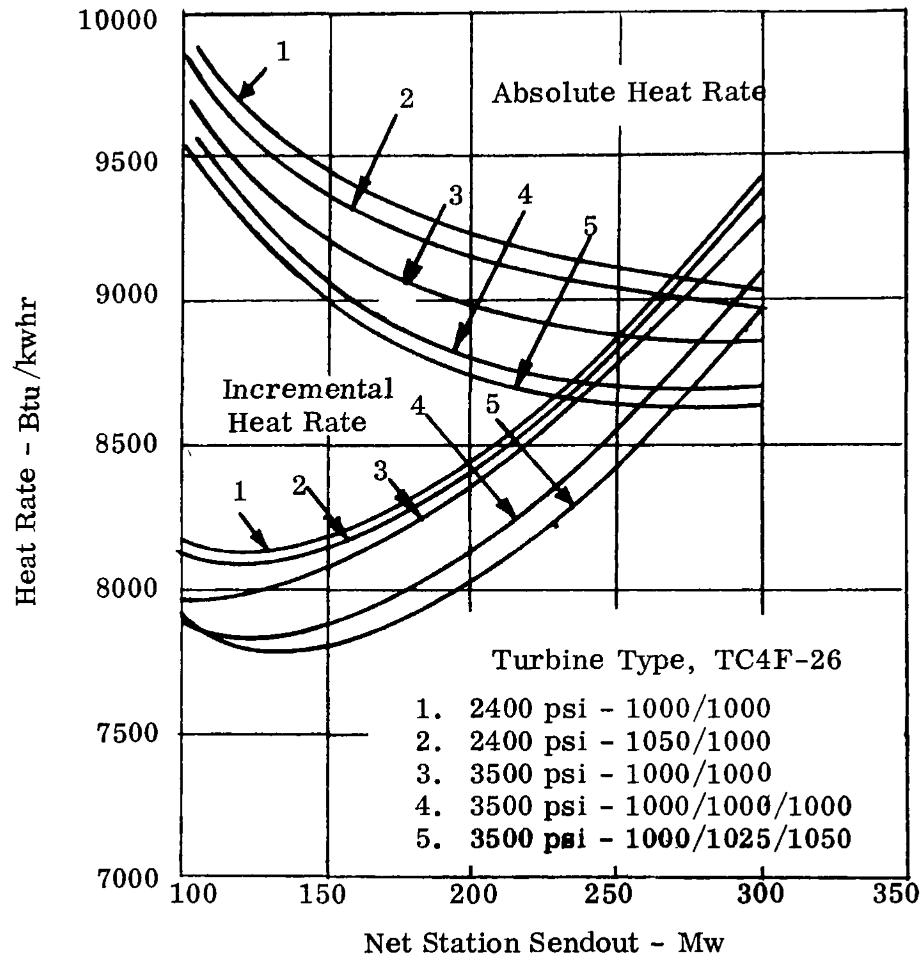

Figure 3.3

Absolute and Incremental Heat Rates at 1.5" Hg Condenser Pressure. Variation with Pressure and Temperature

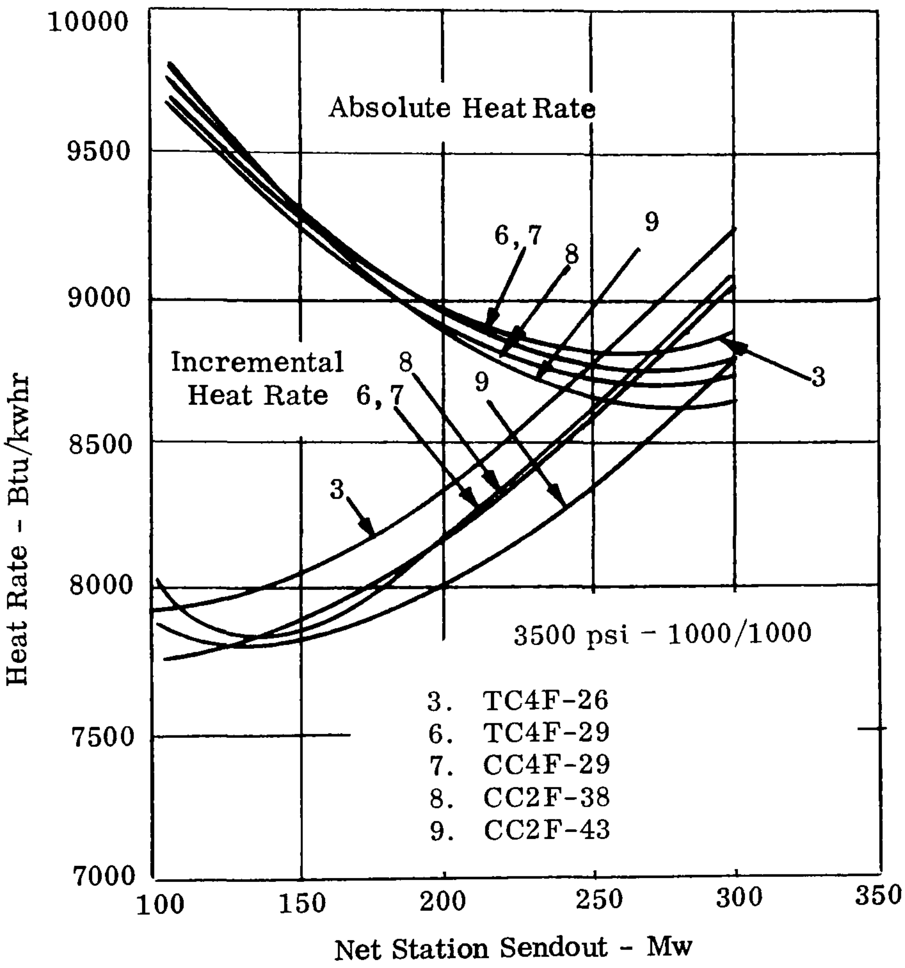

Figure 3.4

Absolute and Incremental Heat Rates at 1.5" Hg Condenser Pressure. Variation with Turbine Type

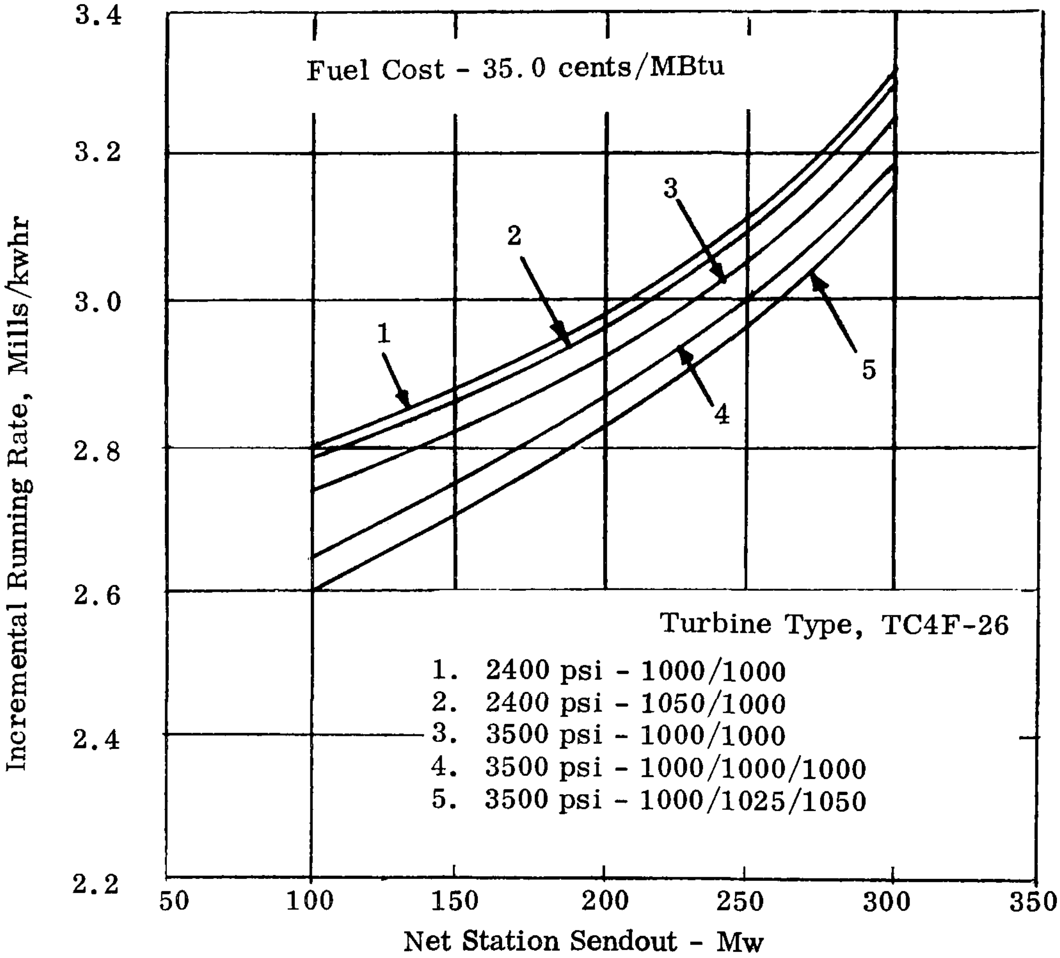

Figure 3.5

Incremental Running Rates Corresponding to Incremental Heat Rates Shown in Figure 3.3

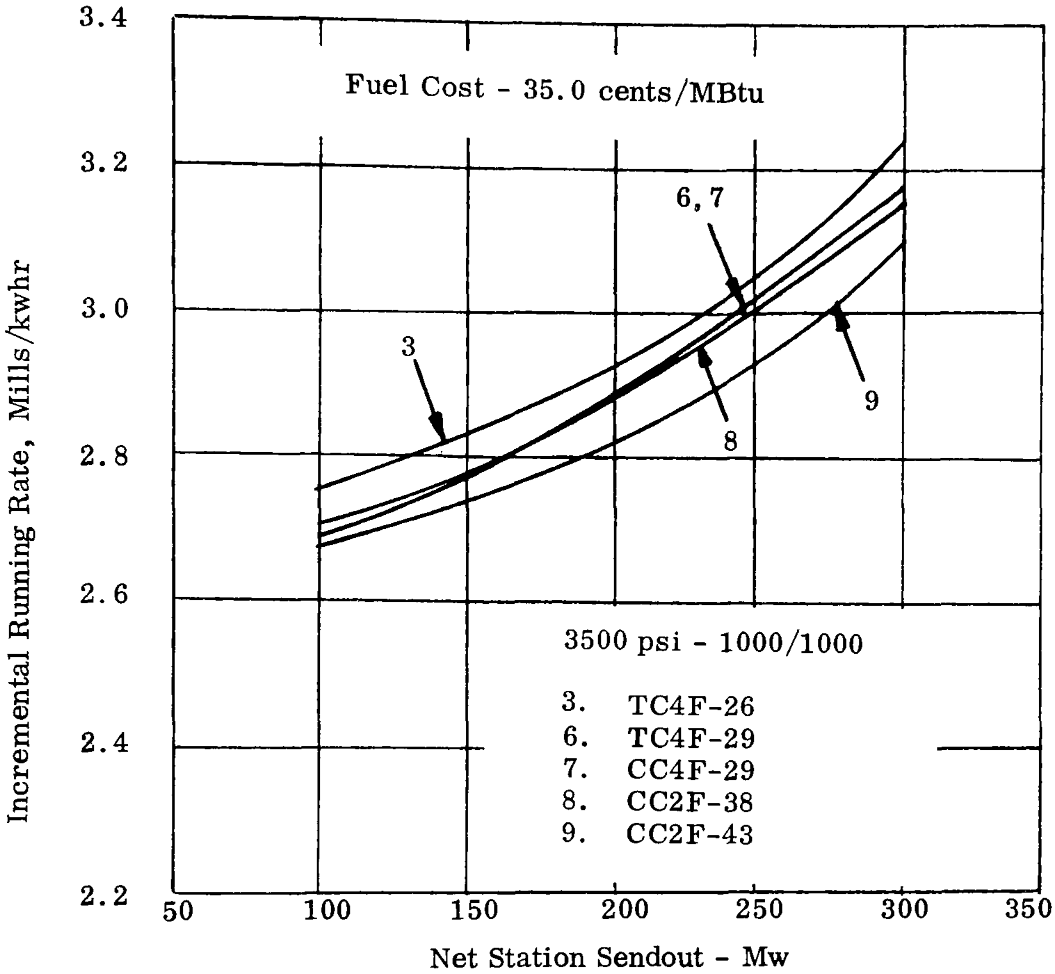

Figure 3.6

Incremental Running Rates Corresponding to Incremental Heat Rates Shown in Figure 3.4

The criterion which will be adopted here is that a utility system will run all of its individual plants at equal running rates. It is clear that this represents a minimum cost solution. Consider, for example, two plants one operating at a higher IRR than the other. If the load on the first plant is reduced ΔKW_1, this will result in a cost savings of $\Delta KW_1 \times IRR_1$. This load can then be picked up by the other plant at a cost of $\Delta KW_1 \times IRR_2$. This results in a net savings of $\Delta KW_1 (IRR_1 - IRR_2)$.

This suggests that the appropriate way to compare the alternative cycles listed in Table 3.6 is at equal incremental running rates. This is done in the following way.

1. A base unit is arbitrarily chosen (in this example we chose #1 from Table 3.6 -- a 2400 psi, 1000/1000° F, TC4F-26) and is run so as to meet the projected load duration curves of Tables 2.1 and 2.2. The incremental running rates for that unit under those loads are tabulated.

2. One-by-one, each of the alternatives is run for the same time periods at the same incremental running rates. This will result in different total outputs.

3. The final fuel cost is then evaluated two ways:

   (i) at the reference capacity factor (Tables 2.1 and 2.2)

   (ii) at the "evaluated capacity factor" which results from running the other units at the base IRR.

3.2.2.2 Computation of Base Unit Incremental Running Rates

The load duration curves of Figure 2.14 and their tabular approximations (Table 2.1) are given in terms of percent of maximum station send-out. This maximum send-out will be evaluated at a condenser pressure of 1.5 in. Hg (the difference at 1.0 or 2.0 in. Hg are slight) and these are tabulated in Figure 3.6.

For the base costs

	Max. Send-out	=	302,700 kw
Therefore,	80%	=	242,160 kw
	60%	=	181,620 kw
	35%	=	105,945 kw

and these send-outs correspond to incremental running rates (Figure 3.5) of

Max. Send-out	~	IRR = 3.310
80%	~	IRR = 3.077
60%	~	IRR = 2.917
35%	~	IRR = 2.812

These conversions make possible the construction of Incremental Running Rate Duration curves corresponding to the load duration curves of Figure 2.14 and Table 2.1. These are shown in Figure 3.7 and Table 3.7.

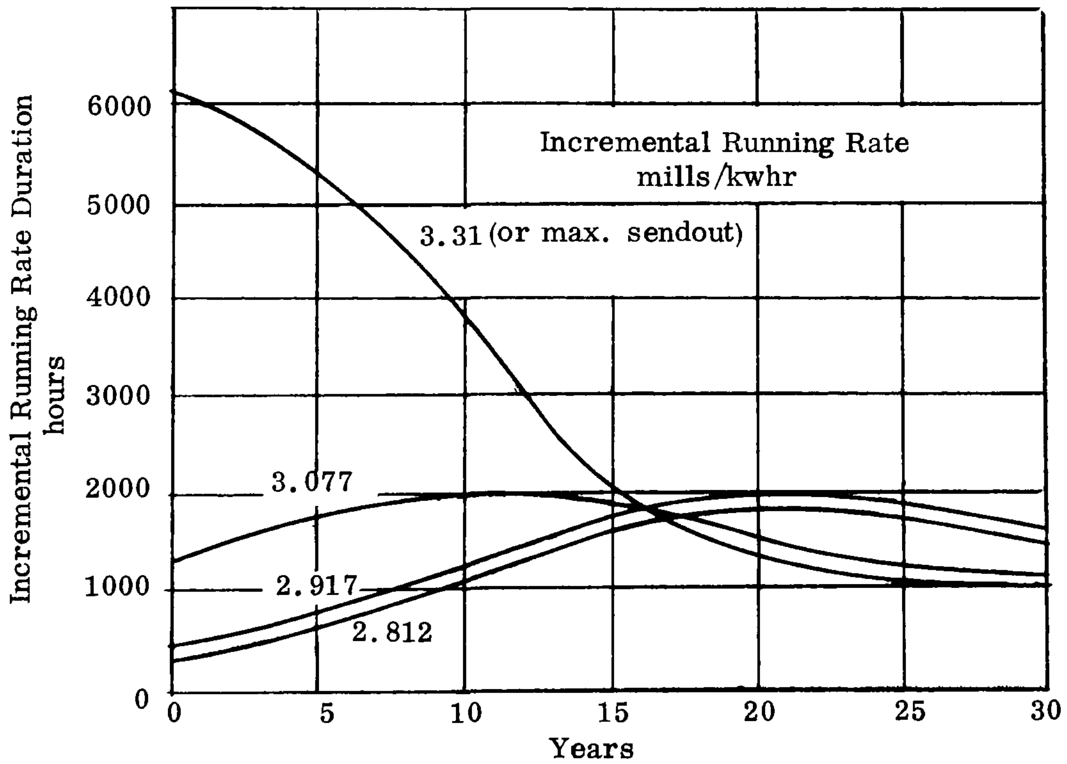

Figure 3.7

Division of Hours at Various Incremental Running Rates. Produces 60% Capacity Factor for Case 1, 2400 psi, 1000/1000 F, TC4F-26.

Table 3.7

INCREMENTAL RUNNING RATE DURATION - HOURS PER YEAR AT VARIOUS INCREMENTAL RUNNING RATES

Incremental Running Rates	Years 0 - 10	10 - 20	20 - 30
3.31	5150	2200	1100
3.08	1750	1850	1250
2.92	800	1700	1850
2.81	700	1500	1700

The evaluation of the alternative units then proceeds by evaluating the loading and lifetime capacity factors for the other units when run at same incremental running rates for the same duration.

This computation is performed as follows: Consider unit #4 (3500 psig, 1000/1000/1000° F, TC4F-26). The send-out at each of the incremental running rates is obtained from Curve #4 on Figure 3.5. An extrapolation of the curve to an IRR = 3.31 clearly exceeds the maximum unit capacity, so those hours are credited with the maximum available send-out although this results in a lower IRR.

Send-out at max. capacity: 299,980 kw

$$\Sigma\, KW_{max} = 299{,}980\text{ kw}\left\{\overbrace{5150\,\frac{\text{hrs}}{\text{yr}} \times 10\text{ yrs}}^{0\,-\,10} + \overbrace{2200\,\frac{\text{hrs}}{\text{yr}} \times 10\text{ yrs}}^{10\,-\,20} + \overbrace{1100\,\frac{\text{hrs}}{\text{yr}} \times 10\text{ yrs}}^{20\,-\,30}\right\}$$

$$= 299{,}980 \times 84{,}500\text{ kw-hr}$$

$$= 25{,}350{,}000\text{ mw-hr}$$

Send-out (at IRR = 3.077) = 271,000 kw

$$\Sigma\, KW_{3.077} = 272{,}000 \left\{\overbrace{1750\,\frac{\text{hrs}}{\text{yr}} \times 10\text{ yrs}}^{0\,-\,10} + \overbrace{1850\,\frac{\text{hrs}}{\text{yr}} \times 10\text{ yrs}}^{10\,-\,20} + \overbrace{1250\,\frac{\text{hrs}}{\text{yr}} \times 10\text{ yrs}}^{20\,-\,30}\right\}$$

$$= 13{,}400{,}000\text{ mw-hr}$$

Send-out (at IRR = 2.917) = 223,000 kw

$$\Sigma KW_{2.917} = 223{,}000 \left\{ \overbrace{800 \frac{hrs}{yr} \times 10 \text{ yrs}}^{0-10} + \overbrace{1700 \frac{hrs}{yr} \times 10 \text{ yrs}}^{10-20} + \overbrace{1850 \frac{hrs}{yr} \times 10 \text{ yrs}}^{20-30} \right\}$$

$$= 9{,}120{,}000 \text{ mw-hr}$$

Send-out (at IRR = 2.812) = 180,500 kw

$$\Sigma KW_{2.812} = 180{,}500 \left\{ \overbrace{700 \frac{hrs}{yr} \times 10 \text{ yrs}}^{0-10} + \overbrace{1500 \frac{hrs}{yr} \times 10 \text{ yrs}}^{10-20} + \overbrace{1700 \frac{hrs}{yr} \times 10 \text{ yrs}}^{20-30} \right\}$$

$$= 7{,}050{,}000 \text{ mw-hr}$$

The total lifetime send-out is obtained by summing each of these

$$\Sigma KW_{tot} = \Sigma KW_{max} + \Sigma KW_{3.077} + \Sigma KW_{2.917} + \Sigma KW_{2.812}$$

$$= 54{,}026{,}460 \text{ mw-hr}$$

The average lifetime capacity factor is given by

$$\text{Cap. Factor} = \frac{\Sigma KW_{tot}}{\Sigma KW_{max}}$$

$$\Sigma KW_{max} = 299{,}980 \times 8760 \frac{hrs}{yr} \times 30 \text{ yrs}$$

$$= 78{,}500{,}000 \text{ mw-hr}$$

$$\text{Cap. Factor} = \frac{54{,}026{,}460}{78{,}500{,}000}$$

$$= 68.53$$

These results, as well as those for all of the other alternatives are tabulated in Table 3.8.

Table 3.8

EVALUATED CAPACITY FACTORS FOR ALTERNATE UNIT DESIGNS
LOADED AT EQUAL INCREMENTAL RUNNING RATES

Alternate Number	Steam Conditions	Turbine Type	Net Station Sendout, kilowatts At Equal Incremental Running Rates				No. 3 Unit Lifetime Calculated Generation, Mwhr	Evaluated Lifetime Average Capacity Factor, percent
	(Incremental Running Rate, mills/kw hr)	(See Note Below)	(3,310)	(3.077)	(2.917)	(2.812)		
1	2400 psig, 1000/1000 F	TC4F-26	302,700	242,160	181,620	105,945	48,228,750	60.63
2	2400 psig, 1050/1000 F	TC4F-26	302,700	248,000	189,000	121,000	49,394,100	62.09
3	3500 psig, 1000/1000 F	TC4F-26	299,330	256,000	200,500	144,000	50,862,960	64.66
4	3500 psig, 1000/1000/1000 F	TC4F-26	299,980	272,000	223,000	180,500	54,026,460	68.53
5	3500 psig, 1000/1025/1050 F	TC4F-26	299,980	279,000	231,000	192,000	55,138,740	69.94
6	3500 psig, 1000/1000 F	TC4F-29	302,330	274,000	216,500	176,000	53,866,710	67.80
7	3500 psig, 1000/1000 F	CC4F-29	302,330	274,000	216,500	176,000	53,866,710	67.80
8	3500 psig, 1000/1000 F	CC2F-38	301,330	278,500	220,500	176,000	54,170,130	68.41
9	3500 psig, 1000/1000 F	CC2F-43	305,330	298,500	248,000	199,000	57,501,300	71.66

Note: Incremental running rates correspond to loading of Alternate 1 at 100, 80, 60 and 35 percent of maximum net station sendout at 1.5 in. Hg abs.

It is now possible to compute the total fuel requirements for each alternative. For Unit 4 (3500 psig, 1000/1000/1000° F, TC4F-26):

1. From Table 3.7 we see that the incremental running rate durations for the fifth year are

   5150 hours @ Maximum Send-out
   1750 hours @ 3.08 IRR
   800 hours @ 2.92 IRR
   700 hours @ 2.81 IRR

2. From Table 3.8, this corresponds to output of

   299.98 Mwe for 5150 hours
   272.0 Mwe for 1750 hours
   223.0 Mwe for 800 hours
   180.5 Mwe for 700 hours

3. If the load duration breakdown of Table 2.2, into various condenser pressures is assumed to apply, then the loading can be broken down further as shown in Table 3.9

Table 3.9

HOURS OF OPERATION PER YEAR AT THE GIVEN OUTPUT AND CONDENSER PRESSURE FOR THE 3500 PSI, 1000/1000/1000 F; TC4F-26 UNIT DURING THE FIFTH YEAR

Power Output	Condenser Pressure (in. Hg abs)		
Mwe	1.0	1.5	2.0
299.98	1545	1545	2060
272.0	700	525	525
223.0	440	240	120
180.5	490	210	0

4. From the heat rate tables, the turbine heat rates are obtained for the various loads and condenser pressures and the corresponding net plant heat rates are calculated from Equation 3.2). The total fuel cost for the year is then given by

$$TFC = SFC\ \Sigma\ (HR \times KW \times T)_i \tag{3.3}$$

where

TFC	=	total fuel cost for the year (\$/yr)
SFC	=	specific fuel cost (\$/Btu)
HR	=	heat rate at specific kw and condenser pressure (Btu/kwhr)
KW	=	power output (kw)
T	=	time per year at kw output (hours/yr)

The summation is taken for all the values of Table 3.9.
Numerically for Unit #4, this becomes:

$$TFC = 0.35 \times 10^{6} \frac{\$}{\text{Btu}} + \left\{ 299.98 \times 10^{3}\ \text{kw} \left[\overbrace{1545 \frac{\text{hrs}}{\text{yr}} \times 8728 \frac{\text{Btu}}{\text{kw-hr}}}^{1.0\ \text{in Hg}} + \overbrace{1545 \times 8753}^{1.5\ \text{in Hg}} + \overbrace{2060 \times 8804}^{2.0\ \text{in Hg}} \right] \right.$$

$$+ 272.0 \times 10^{3}\ \text{kw} \left[700 \frac{\text{hrs}}{\text{yr}} \times - - - -- - - - - \right.$$

$$+ 223.0 \times 10^{3}\ \text{kw} \left[440 \frac{\text{hrs}}{\text{yr}} \times - - - - - - - - \right.$$

$$\left. + 180.5 \times 10^{3}\ \text{kw} \left[490 \frac{\text{hrs}}{\text{yr}} \times - - - - - - - - \right] \right\}$$

$\cong 7.1 \times 10^{6}$ \$/yr for the fifth year.

In the next section it will be seen how the present worth of fuel cost for all the years is calculated.

3.2.3 Present Worth Evaluation

Since differing yearly costs are encountered for various power plant design alternatives, the problem of evaluating the relative importance of each year's costs arises. It is generally considered by economists that a sum of money to be realized or spent at some future time has less value than the same sum at present. This is because of the earning power of money in terms of interest.

The relationship between the value of an amount of money in the future to an amount at present is expressed by "present worth" equations. In this section, interest compounded on an annual basis will be considered. With this interest, the present worth of a sum of money at some future time is expressed as

$$PW = \frac{S}{(1 + r)^n} \tag{3.4}$$

where
- PW = present worth, dollars
- S = sum of money in the future, dollars
- r = interest rate per year
- n = number of years

Since overall power generating costs are a sum of fixed charges and operating costs, and these costs are considered on a per power output basis (mill/kwhr), the required revenue rate for a year may be expressed as

$$R_i = \frac{C_i \times I + TFC_i + O_i}{KWHR_i} \tag{3.5}$$

where
- R_i = required electrical rate for the year i (dollars/kwhr)
- C_i = fixed charge rate for the year i (%) (Figure 2.16)
- I = total initial investment (dollars) (Table 3.6)
- TFC_I = total fuel cost for the year i (dollars) (Equation 3.3)
- O_i = total operating costs (exclusive of fuel) for the year i (dollars) (if available)
- $KWHR_i$ = total plant net generation for the year i (kwhr) (as in Equation 3.3)

Therefore, based on present worth, the combined required electrical rate is written as

$$R_{PW} = \frac{\sum_{i=1}^{n} \left[\left(C_i \times I + TFC_i + O_i \right) / (1 + r)^i \right]}{\sum_{i=1}^{n} (KWHR)_i} \tag{3.6}$$

The present worth of revenue requirements for the nine cases of our example have been calculated and are shown in Table 3.10. The load duration data and fixed charge rates of Sections 2.6 and 2.7 were used and a constant fuel cost of 35¢/ million Btu was assumed. Operating and maintenance costs (exclusive of fuel) of 300,000 \$/yr were assumed for each unit. The revenue requirements are given in Table 3.10 for the evaluated capacity factors of Table 3.8. It is seen that the unit with the lowest revenue requirement is the 3500 psig, 1000/1000° F CC2F-43 (#9). Since not all possible combinations of pressure, flow arrangement, reheat temperatures, and blade length were evaluated, this may not represent an absolute minimum. In fact, examination of Units 3, 4, and 5 suggests that a different reheat temperature, namely a 3500 psig, 1000/1025/1050° F CC2F-43 would have even lower revenue requirements.

An alternative method of comparison is to evaluate all of the alternate units at the base capacity factor (60.63% for the 2400 psig, 1000/1000° F TC4F-26). This results in essentially the same lifetime send-out for all units and is more appropriate if system planners feel that any additional capacity would not be usable. On this basis the most economical unit evaluated was the base unit (2400 psig, 1000/ 1000° F TC4F-26). An examination of Units 3 and 6 suggests that a unit with 29 inch plates would be superior (2400 psig, 1000/1000° F TC4F-29).

Table 3.10

PRESENT WORTH OF REVENUE REQUIREMENTS OF THE VARIOUS ALTERNATIVES

Alternate Number	Steam Conditions	Turbine Type	Unit Revenue Requirements Mills/kwhr At Evaluated Capacity Factor	At 60.63% Capacity Factor
1	2400 psig, 1000/1000 F	TC4F-26	3.041	3.041
2	2400 psig, 1050/1000 F	TC4F-26	3.006	3.054
3	3500 psig, 1000/1000 F	TC4F-26	2.937	3.067
4	3500 psig, 1000/1000/1000 F	TC4F-26	2.838	3.085
5	3500 psig, 1000/1025/1050 F	TC4F-26	2.810	3.096
6	3500 psig, 1000/1000 F	TC4F-29	2.841	3.062
7	3500 psig, 1000/1000 F	CC4F-29	2.855	3.074
8	3500 psig, 1000/1000 F	CC2F-38	2.824	3.064
9	3500 psig, 1000/1000 F	CC2F-43	2.754	3.084

3.3 Feedwater Heaters

The optimum number of feedwater heaters and the final feedwater temperature are considered to be the most important cycle parameters after the initial pressure and temperature and reheat temperature have been established.

In a regenerative feedwater heating cycle the transfer of heat from extraction steam to feedwater takes place in feedwater heaters. Feedwater heaters are divided into two basic categories: 1) open, or contact, heater in which the steam and water mix in direct contact and 2) closed heaters in which no mixing occurs. Open feedwater heaters are more effective since there is no available heat loss, but they are also more expensive since a feedwater pump is required between each heater.

A complete discussion of the basic thermodynamics of the feedwater cycle is beyond the scope of this report, but Bartlett (Ref. 16a) contains a good introduction to the feedwater heating cycle which we have included here for convenience.

> "The maximum number of feedwater heaters which can be economically justified is limited by diminishing performance gains, cost of extra heaters, turbine design limitations, and turbine-room space limitations. Usually economic appraisals lead to the following pattern of heater application.
>
> | | |
> |---|---|
> | 20,000 - 50,000 kw | 4 or 5 heaters |
> | 50,000 - 100,000 kw | 5 or 6 heaters |
> | 100,000 - 200,000 kw | 5, 6, or 7 heaters |
> | Over 200,000 kw | 6, 7, or 8 heaters |
>
> In locating heaters in the feedwater heating cycle of a nonreheat unit, it is desirable to have the feedwater enthalpy rise for each heater as nearly equal as the design of the turbine will permit. This arrangement not only provides for optimum heater performance but also facilitates duplication. A complete exposition, justifying the assumption of equal rises as the basis of optimum heater arrangement, may be found in Salisbury (Ref. 67a).
>
> For single-reheat cycles the use of essentially equal feedwater enthalpy rises is desirable for heaters which extract below the reheat point. The special conditions existing at and above the reheat point require that heaters extracting in this region receive individual attention.
>
> The heater extracting at the reheat point provides optimum cycle performance when designed with a feedwater enthalpy rise approximately 1.8 times the average of the lower-pressure heaters.
>
> Double reheat cycles should provide for extraction from both reheat points and from one intermediate point in between the two reheats. The heater extracting from the second reheat point and the low-pressure heaters may be treated in the same manner as the heater extracting at the reheat point and low-pressure heaters of a single-reheat cycle. The heater extracting from the high-pressure reheat point should take about two-thirds and the intermediate heater about one-third of the total feedwater enthalpy rise above the heater extracting from the second reheat point.
>
> The ideal of equal feedwater enthalpy rises for the heaters of a nonreheat cycle and those of reheat cycles extracting below the reheat point is impossible to attain in actual practice because of the limited number of stages in the turbine. Deviations from the equal-rise ideal of as much as 10 to 20 percent do not affect the heat rate appreciably.

Besides the reheat points, turbines often have other natural extraction points at the crossovers. Since extraction steam can often be removed at these points with little drop in pressure, gains in performance can sometimes be realized by deliberately adjusting the cycle to take advantage of them, even though from an equal-rise point of view it may not be the most desirable arrangement.

The lowest-pressure heater often merits special consideration. The equal-rise concept often results in extraction steam for this heater of such great specific volume that it becomes difficult to provide for its removal from the turbine stage and exhaust hood. An equally important consideration is the reduction in the feedwater enthalpy rise of the bottom heater at partial loads, resulting in the heater "cutting out of service". These factors usually result in the provision for a somewhat larger feedwater enthalpy rise for this heater than for those above it.

An improvement in heat rate may nearly always be obtained by increasing the number of feedwater heaters. To obtain maximum benefit from additional heaters, however, all the heaters should be rearranged so as to optimize the heater enthalpy rises as nearly as possible.

Improving the effectiveness of the feedwater heating-cycle components is usually an economical way of improving over-all performance. Losses due to high terminal differences, large extraction-line pressure drops, and multiple cascading of heaters without drain coolers can reach considerable proportions."

There are numerous methods available for estimating the effects of changes in feedwater heating-cycles components on performance (cf Ref. 16a). In general, however, the present practice is to prepare, with the use of a computer, numerous heat balances (such as shown on page 5 of GET-2050B, included in the appendix) with various numbers and sizes of feedwater heaters. The optimum size and number is then easily chosen with economic considerations similar to those in the preceding section.

3.4 Condenser System

One of the major components of the power plant is the condenser with its associated piping, pumps, controls, and instrumentation. As indicated in Table 3.3, the cost of the condensing system can account for up to 25% of the turbine-generator costs. More important, however, is the influence of the condenser on the overall cycle performance, system efficiency, and, hence, total operating costs. Furthermore, it is in the condenser where the required heat rejection from the cycle is carried out, that the interface between the power generating system and the environment occurs. It is here that the restrictions on peak water temperature and permissible amount of water consumption are felt on the power generation system.

In order to describe the available options and trade-offs for system optimization, it is useful to describe the conventional, single-pressure condenser. More recent advances will then be discussed with reference to this base system.

3.4.1 The Single-Shell Condenser

The simplest type of condenser concepts of a single shell in which turbine exhaust steam condensers on the outside of tubes. Cooling water is pumped through the tubes and discharged at an elevated temperature to accomplish the necessary heat rejection. Figure 3.8 gives a simplified sketch of the temperature distributions through the condenser.

The steam-side operates essentially at constant temperature and pressure at its saturation condition. The water temperature rise and the condensing temperature level are set by the load imposed on the condenser and the condenser size. In the nomenclature of Figure 3.8, the governing equations are

Water Temperature Rise:

$$T_{w2} - T_{w1} = \frac{Q}{W C_p} \tag{3.7}$$

Condensing Temperature:

$$\frac{T_{w2} - T_{w1}}{\ell n \left\{ \frac{T_c - T_{w2}}{T_c - T_{w1}} \right\}} = \frac{Q}{UA} \tag{3.8}$$

where U is the overall heat transfer coefficient. (The following tradeoffs will be discussed from the point of view of U = constant.)

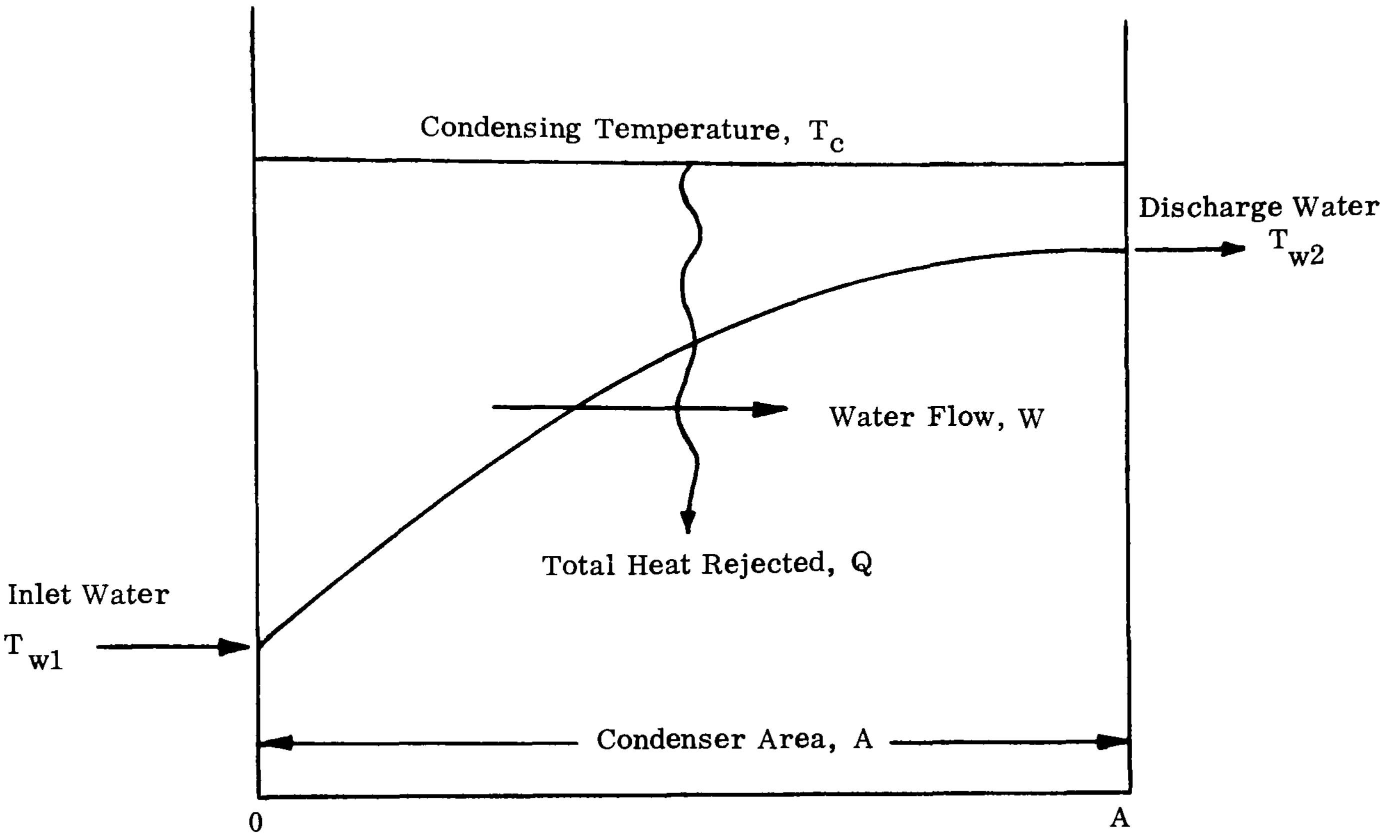

Figure 3.8

Temperature Distribution in a Single-Pressure Condenser

The condensers are normally sized such that the terminal temperature difference (T_c - T_{w2}) is about 5° F. It is possible to build a larger condenser (increase A) to reduce this temperature difference but a large area increase is required for a slight additional reduction in T_c and the choice of 5° F as a design point represents a sensible economic choice.

The obvious alternative is to increase the water flow. For a given heat load and inlet water temperature, this will reduce the water temperature rise (Equation 3.7) and, if the criterion of a 5° F terminal temperature difference is maintained, will reduce the attainable condensing temperature by a like amount. The benefit of increased water flow must be weighed against the following factors:

1. Water velocities in the tubes must be kept below 7 ft/sec, because of tube life considerations. Hence, very high water flows require a condenser design with a large number of short tubes which sometimes produces an awkward geometry with which to interface the turbine.

2. The pumping costs increase with increased water flow.

3. The increased use of water may be inconsistent with environmental protection.

4. If the condenser utilizes once-through cooling, the above considerations are probably sufficient. If, however, the condenser cooling water is supplied by a cooling tower, the increased flow is reflected in increasingly severe tower requirements and tower costs.

Since 1965, the use of dual pressure condensers has permitted a lowering of the effective condensing pressure and temperature with the resulting improvement in heat rate while using essentially the same cooling water. An examination of Figure 3.8 suggests the solution. It is clear that the low temperature water which is available in the inlet portion of the condenser is not being utilized efficiently. The condensing temperature is set with respect to the <u>highest</u> (or exit) cooling water temperature. Clearly, at least some of the turbine exhaust could be expanded to to a lower temperature and pressure rise closely approaching the coolest (or inlet) water temperature. This splitting of the steam flow is further facilitated in the larger size turbines which have multiple exhaust flows anyway.

3.4.2 The Multi-Pressure Condenser

A diagram similar to Figure 3.8 can be drawn for a dual pressure condenser and is shown as Figure 3.9. The extension to multi-pressure (three or more stages) is obvious. Structurally, the unit can be thought of as two separate condenser shells, although the actual design is often a single shell with a pressure tight partition separating the high pressure condensing region (B) from the lower pressure region (A).

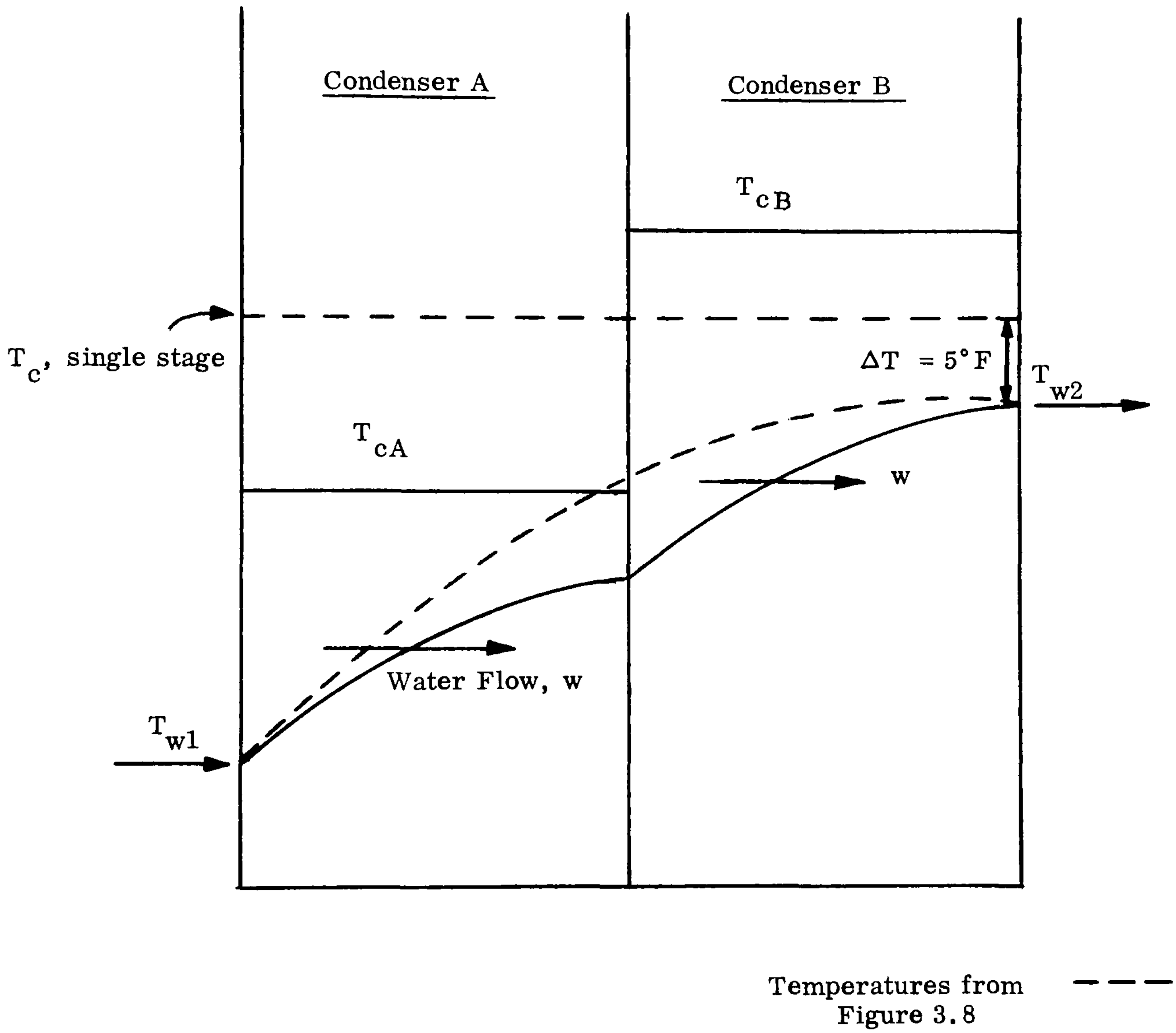

Figure 3.9

Temperature Distribution in a Dual Pressure Condenser

While part of the steam is expanded to a lower pressure and temperature ($T_{cA} < T_c$), the remainder is discharged at a somewhat higher temperature ($T_{cB} > T_c$). The net effort can be to improve the heat rate as illustrated in the following comparison excerpted from Reference 45.

SINGLE VERSUS MULTIPRESSURE CONDENSING

A representative comparison of single versus multipressure condensing performance is afforded by the diagram shown in Figures 3.10 and 3.11. These describe the full capability overpressure performance of the low pressure end of the heat cycle serving a 500 Mw supercritical unit. Figure 3.10 presents the details of conventional single pressure condensing operation. A turbine back pressure of 2 in. of mercury absolute, corresponding to a year round average circulating water inlet of 74 F, has been assigned at each of the two condenser sections. Although not indicated, condenser water sides are arranged for two pass flow of circulating water, which is routed in parallel to both condensing sections.

Figure 3.11 assumes the single pass flow of cooling water through each condenser section. Coolant is routed in series to one, and then the other section. Full coolant flow through the first tube section, at an inlet temperature equal to the 74 F assumed for the parallel flow case, is seen to <u>reduce</u> turbine <u>back pressure</u> from 2.0 to 1.55 in Hga. Circulating coolant supply to the second tube bank, although at twice the rate established for the parallel flow scheme, arrives at the tube sheet at 84 F after performing the condensing duty required at the first condenser shell. Calculated performance at the second series oriented section, therefore, produces an exhaust of 2.2 in. Hga, or 0.2 in. <u>above</u> the parallel flow case.

The plant utilizes condensing type auxiliary turbines for main feed pump drive. For the multipressure condensing arrangement, drive turbine condensate along with the colder condensate collected at the lower exhaust pressure shell, are fed into the hotwell of the higher operating pressure section. By heating these cascaded flows to saturation

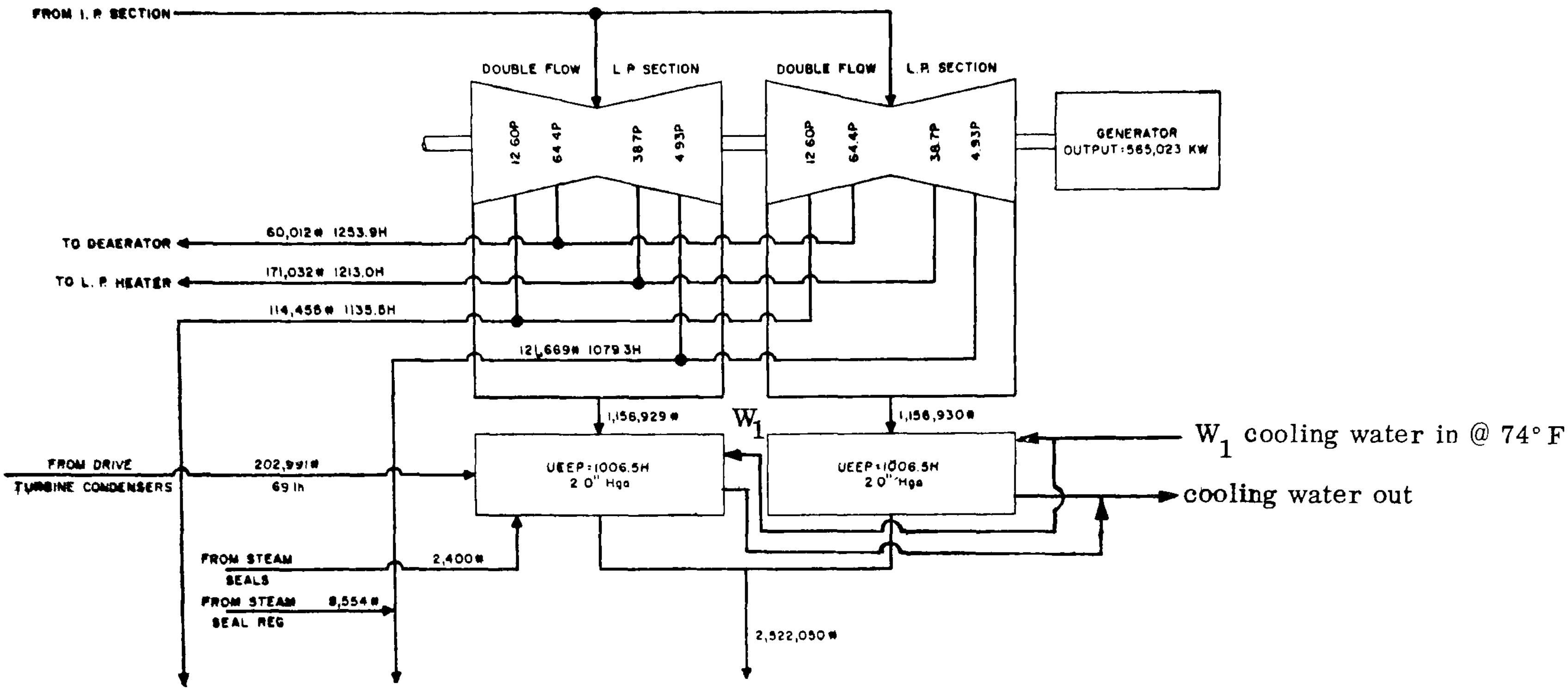

Figure 3.10

Low Pressure Cycle Performance for 500 Mw Unit Employing Single Pressure Condenser (Parallel Flow Arrangement) (Ref. 45)

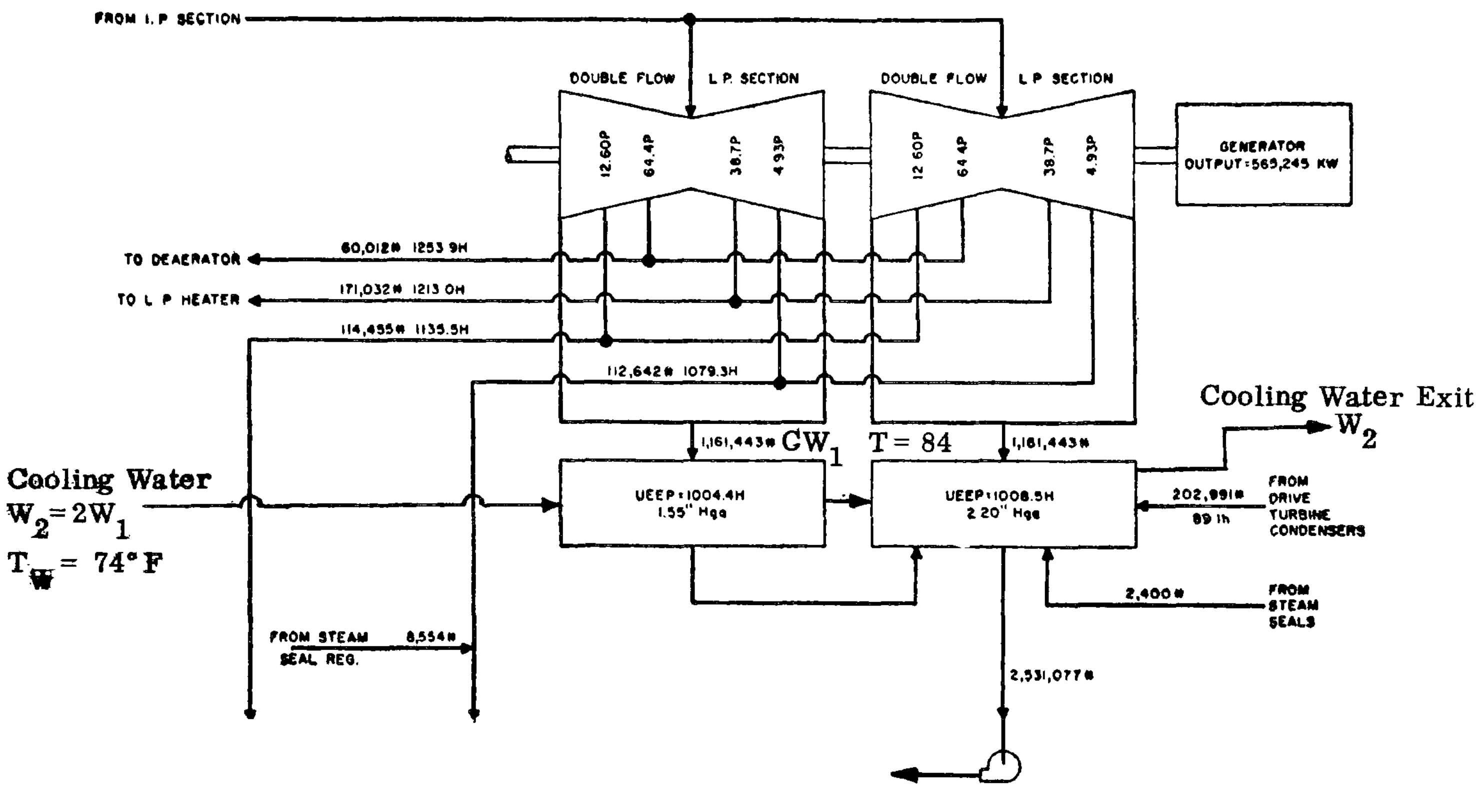

Figure 3.11

Low Pressure Cycle Performance for 500 Mw Unit Employing Dual-Pressure Condenser (Series Flow Arrangement)(Ref. 45) at 2.2 in. Hga, heat that would normally be rejected to the circulating water is recovered. This cycle advantage makes its appearance in the increased enthalpy of condensate delivered to the first feedwater heater, where a decreased demand for final extraction stage bleed steam(112,642 lb/hr in Fig. 3.11 vs. 121,669 lb/hr in Fig. 3.10) makes an incremental addition to turbine-generator output.

Overall thermal advantage favoring the multipressure series flow condensing arrangement is shown to be a 222 kw increase in turbine gross capability at cycle heat input identical to the single condensing pressure case (565,245 kw vs. 565,023 kw). For this particular illustration, the multipressure condensing design must be assigned both cycle efficiency and unit capability credits over the competing design.

It is of significant importance to reveal that the unit chosen to illustrate series versus parallel flow condensing performance was one that had been previously optimized for single exhaust pressure, parallel flow operation. No attempt was made, in the case of the dual pressure condenser arrangement, to individually proportion tube dimensions and heat transfer surface at each condensing section to best meet expected dual pressure operating conditions. Despite differences in volumetric flow loadings produced by unequal condensing pressures, exhaust blade length studies were not undertaken to determine if a change in last stage blading in either turbine exhaust might improve the economics of multipressure condensing. Finally, variations in circulating water flow, which in some applications might significantly affect coolant system investment costs and water pumping power requirements were not considered. Coolant flow, as optimized for the parallel flow arrangement, was assumed equal in each case.

Because the coolant temperature approaches the higher of the two condensing temperatures in the dual pressure system rather than an average condensing steam temperature, multipressure condensing offers the possibility of reducing coolant flow, while maintaining the thermal performance of the single-pressure condenser plants. Where site or plant characteristics place a premium cost on coolant flow quantity, this advantage can be of decisive importance. Cooling tower installations are a case in point. Increased coolant temperature rise, at reduced coolant flow rate through the main condensers increases tower range and reduces tower flow loading. Both factors will contribute to a reduction in cooling tower first cost.

3.4.3 Condenser Costs

While a detailed review of condenser cost trade-offs is beyond the scope of this section, the approximations used to compute these costs in the optimization program developed under another task in this study (Ref. 14a) are presented here for convenience of reference. Nearly all power plant condensers are of the shell-and-tube type and their cost is nearly proportional to the amount of heat transfer surface. A curve-fit approximation to the information continued in References 137, 138, and 139 is given by:

$$\mathrm{CONCST} = 20\ (1.05 \times \mathrm{ACOND})^{0.9} \tag{3.9}$$

where CONCST ~ condenser cost (dollars)

ACOND ~ heat transfer surface area (ft^2)

For dual pressure condensers, the capital cost of the condenser itself may still be approximated by this relationship. However, the real savings in using a dual pressure unit come from the improved heat rates attainable with these units. The computation of the available increases in cycle efficiency are quite complex (see, for example, the discussion of the third paragraph under "SINGLE VERSUS MULTI-PRESSURE CONDENSING") and cannot be included here. If the appropriate heat rate curves are available, they are used in place of Figures 3.3 through 3.6, for the computation of fuel costs (Sections 3.2.2 and 3.2.3).

3.5 Operational Considerations

"Operational considerations" in power plant design could be interpreted to mean almost all portions of the design. In this section operational considerations are meant to mean those portions of the design of a power plant that directly affect the facility of operation and control of the plant after it has gone "on line." Instrumentation and control, plant maintenance, and plant layout are the main areas of operational design that are discussed.

3.5.1 Instrumentation and Control

Because of the many different types and complexity of the controls used in today's power plants, a complete description would fill numerous volumes. Therefore a rather simple approach is necessary here with the details left to the references. (References 18, 19, 21, 22, and 26 are recommended as an entrance to the field.)

During the 1950's change from pneumatic control to electric control in power plants began on a large scale. In the early stages of this transition, many of the systems built were combination pneumatic and electric and are still in use today.

Most power companies today use electronic computing and data logging systems, but many companies have developed the policy of "wait and see" with regard to the present use of computers for full control of operation of large units. This is thought to be due to two factors:

1. Computer equipment is very costly.
2. Early computer controlled units have not functioned satisfactorily.

The large number of interpret and control functions necessary in a power plant is the main reason that automatic control is desired, while the type and amount of sensing required has been a drawback. There has been considerable difficulty in purchasing sensing devices sufficiently reliable to give proper signals to the electronic equipment. Proponents of computer control claim that this disadvantage will be overcome as manufacturers gain operating experience with plants in operation. Further automation of control in power plants will most probably occur in the future, but the rate of change does not seem to be large at present.

3.5.2 Power Plant Layout

The design of the layout of a power plant occurs in parallel with the theoretical analysis of performance, and is the most practical side of the overall design. Layout design is essentially a trial and error process incorporating both logic and past experience and, as such, it constitutes a substantial part of the engineering cost of the whole project. The peak of layout design does not coincide with the peaks of analytical design and detailed plant design, as will be seen, yet the analysis, layout, and details must be in final agreement. This represents the major difficulty in layout design.

To understand where layout design fits into the overall design picture, the overall design may be considered to occur in six phases (Ref. 117), with the major decisions on the plant layout being made in only one of the phases. This general description is equally applicable to both fossil and nuclear plants. The phases considered are:

1. Initial Description -- Economic and political decisions as to type of reactor, site, etc.
2. Engineering Performance Study -- Approximate power and safety calculations to determine reactor size necessary.
3. Economic Project Evaluation -- Decision whether to design and build is made.
4. Project Design -- Engineering study for specific site and reactor size. Main stage of decision on layout and dimensions of major components. Civil construction begins at end of phase.
5. Plant Design -- Plant design proceeds by manufacturing specialists. Main stage of engineering analysis.
6. Detail Design -- Detail plant component design drawings by manufacturers. Detailed layout drawings completed. Differences between final detailed layout and the layout form of phase 4 are adjusted.

Although it is possible for layout design to continue through phases 5 and 6, the pressure to start construction early usually requires that the bulk of the layout work be completed in phase 4.

The objectives in plant layout design are to evaluate the proper trade-offs between the use of minimum space and the provision of easy access to critical components. In both fossil and nuclear plants, the major problems are concerned with the logistics of fuel. In a fossil plant, particularly a coal-fired plant, the sheer bulk of the fuel which must be transported to and stored at the plants present serious problems in access route and switchyard layout. Similarly, an enormous amount of ash must be removed from the furnaces, cooled, and ultimately disposed of. Finally, the flue gas stacks themselves must be considered and located in such a way that they do not interfere with plant operation (particularly in the case of cooling towers and transmission lines).

In the case of nuclear plants, fuel handling is a problem, not because of the bulk but because of the potential hazards. Once inside the reactor containment vessel, the hazard is virtually eliminated but during transport of the fuel elements to the plant and during removal of spent cores the access routes and handling equipment and techniques must be laid out with extreme caution. Since shielding must be provided throughout these routes, their cost per unit length is extremely high and plant layout must shorten them whenever possible.

Other than the above considerations, the layout of plant buildings depends as much on local geography as it does on the internal layout of each building. Layout of the reactor itself can be said to be determined by (Ref. 117):

shape and size of core and containment;
coolant circulation and steam generation system;
shielding;
fuel-handling and core-control systems;
site layout and foundation conditions;
method of erection of heavy parts;

One of the most important maintenance projects in power generation is the major overhauls of the equipment during outage periods. Usually the most costly item is the downtime of the equipment itself. This cost is evaluated on the basis of the incremental cost of power generation with the equipment being used for replacement during the outage. The replacement of a 500 Mwe plant (equivalent heat rate of 9000) with an older out of date plant having twice the heat rate would cost $18,000 per day (fuel at 20¢/m Btu). This is over and above the actual cost of the maintenance work.

The large replacement cost of generating capacity justifies using many men during a unit outage, yet, comparatively few men are needed for normal maintenance. Thus, it can be very advantageous for large power company groups to use revolving work crews. Otherwise men unfamiliar with an operation must be used during a period in which time is very expensive.

The cost of operation and maintenance, while small compared to capital cost and fuel cost, is not negligible in the economics of a power plant. However, because of wide variations in labor costs, utility policies, plant designs, and other variables, they are nearly impossible to generalize quantitatively. A reasonable rule-of-thumb is that O&M costs are of the order of 5 to 15% of total generating costs, with 5-10% perhaps more appropriate for fossil-fired plants while 10-15% is required for nuclear plants. It appears that the increased costs for nuclear plants are related to the more serious safety requirements and the generally higher wage-scales for nuclear plant personnel who tend to be more technically specialized.

Table 3.11 presents some comparative cost breakdowns from the Oyster Creek plant which might be considered typical, although in no sense definitive for a given installation.

Table 3.11

COMPARISON OF POWER-GENERATING COSTS FOR NUCLEAR AND FOSSIL-FUEL PLANTS (from Ref. 115*)

	Fossil-fuel Plant (mills/kwhr)	Nuclear Plant (mills/kwhr)
Capital Cost	1.57	2.04
Fuel Cost	2.35	1.66
Operating and Maintenace	0.42	0.55
Total	4.34	4.25

*From report on Oyster Creek Nuclear Electric Generating Station 515 Mwe Plant; Annual Costs for years 1 to 5.

Projected revenue requirements for the Oyster Creek Nuclear Station over the plant lifetime shows some minor changes in this cost distribution with the O&M percentage increasing as the plant ages.

Table 3.12

PROJECTED REVENUE REQUIREMENTS FOR OYSTER CREEK NUCLEAR STATION (from Ref. 119) (figures in mills/kwhr)

	Years of Operation					
	0-5	6-10	11-15	16-20	21-25	26-30
Plant Fixed Charges	1.67	1.57	1.46	1.45	1.66	1.84
Working Capital	0.20	0.35	0.39	0.42	0.48	0.54
Fuel Cycle	1.64	1.28	1.23	1.23	1.23	1.23
O&M	0.51	0.51	0.51	0.54	0.67	0.80
Total	4.02	3.71	3.59	3.64	4.04	4.41

Section 4

SUMMARY AND CONCLUSIONS

Summary of Results

The central question which this total study hopes to deal with is how the additional design requirement of cooling water use restrictions will affect the technical and economic aspects of power generation. In order to find a real "optimum" solution to this question it is necessary to consider both the technology and cost of the heat rejection equipment, and to consider the design and optimization of the power plant itself. The basic premise, as illustrated in Figure 1.1, is that a plant which is optimized from the outset on the basis of some water use restrictions will be more efficient (or less costly) than a plant, originally designed in the absence of water use considerations, and then retro-fitted with cooling equipment to meet the requirements.

The actual performance of this total optimization requires cost and performance information not only for the cooling equipment which was made available in the Task I Report (Ref. 136), but also for the power plant. This report has attempted to present not only the necessary cost/performance information required for power plant optimization, but also the computational techniques which are presently used by power plant designers to arrive at what they consider to be the most economic solution.

Within this framework two considerations are paramount. First, there are a number of considerations which can dominate the total design process in terms of plant selection and which are very difficult to quantify. These considerations are reviewed in Section 2 in a qualitative discussion. They include plant size, type of thermodynamic cycle, fuel, site location, and future system demands. In the optimization program, which will be developed and presented in a later report, the determination of each of these considerations will be left as an input specification. That is, the plant size, cycle choice (heat rate vs. operating point), fuel choice, site data, and anticipated load factors will be taken as given and will not be part of the optimizable parameters.

Second, there are aspects of the cost-performance information which, although legitimately part of the optimization process, are not includable for the following reasons:

1. A detailed optimization of an operating power plant is an enormous task. As discussed in Section 3, it is done through the computation of extremely detailed heat balances where differences of a fraction of a percent are considered definitive. Clearly, computations of this size and precision cannot be generalized within the scope of this study and perhpas cannot be generalized at all.

2. A counter-consideration, however, is that while it is true that a detailed optimization is not possible, it is also probably not necessary in order to obtain the result which we seek. That is, we are interested only in the parametric variation which would be affected by water use restrictions and choice of heat rejection equipment. As a first approximation, although this is not necessarily true in any specific installation, it may be assumed that the major power plant design decision which will be affected is the choice of the turbine-generator and condenser components.

Therefore, Section 3 has focussed on the cost performance information for turbine-generators and on the economic computations which must be used to select the optimum turbine-generator unit for a given set of design conditions. The other aspects of the plant design and plant economics have been reviewed in as much detail as was available but have not been quantified for use in the optimization program.

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27 Abstract

This report is part of a larger study to perform a technical and economic survey of alternate methods for cooling condenser discharge water from thermal power plants. The task reported on in this document investigates the criteria by which the power plants themselves are designed and optimized. These criteria are both technological and economic.
The initial section reviews the general aspects of power plant selection. These include questions such as how the procedure of procuring a new plant is initiated, how the plant size is determined, what factors influence the choice of fuel and site location, and how the plant capacity factor and fixed charge rate are calculated.
There follows a detailed review of design and cost optimization procedures. This includes a review of capital costs for the turbine-generator units and for the boilers. Operating costs are computed based on constant incremental running rates. A worked example is presented and carried to the point of a "present worth" evaluation. A brief discussion of the use of feed-water heaters, single- and multi-pressure condensers is provided. Some operational considerations including instrumentation and control and plant layout are discussed briefly. A separately bound Appendix includes a Heat Rate Table for General Electric turbines, and Westinghouse and General Electric price lists for both conventional and nuclear turbine-generator units.

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