ECONOMICS OF CONVERSION OF FOSSIL FUELS TO ELECTRICITY

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INTRODUCTION

The conversion of fossil fuels to electricity has traditionally been accomplished in the following sequence of processes: conversion to heat by combustion; conversion to mechanical energy through thermodynamic processes; conversion to electricity by dynamo-electric processes. Although more direct methods* are available, this paper will consider the economics of only this traditional conversion sequence. Since most of the electrical energy produced in the United States is generated by the Electric Utility Industry (91.5 percent in 1963), the economics will be discussed in terms of that industry. In other industries electricity is frequently a by-product of other thermal processes. The economics is special and diverse, and although it is of great significance to the industries involved, it is not fundamental to an over-all view of the conversion of fuel to electricity.

Figure 1 shows the historical trend of generating capacity of the electric utility industry in the continental United States and projections into the future. A band is used for the nuclear projection to cover the range of current forecasts by various industry groups. A significant point to be noted from this figure is that although nuclear capacity is expected to become increasingly important after 1970, fossil fired thermal capacity still shows impressive growth. This indicates that conversion of fossil fuels will for many years continue to be the major source of electric energy.

In the electric utility industry, power cost is commonly considered to consist of three components: fixed charges on investment, fuel, and operation and maintenance. The fixed charge component is actually the revenue requirement, expressed as a level percentage of first cost of plant to cover return, depreciation, Federal Income Tax, and other taxes and insurance. The fuel component is the product of conversion efficiency and fuel price and includes a charge for fuel inventory. Operation and maintenance includes the cost of labor, materials, and supplies. Table I illustrates the calculation of total power cost from a typical modern steam unit.

It should be noted that these costs would not be realized in an actual electric utility system because of the practical requirements of part load operation (which increases heat rate) and reserve capacity (which increases effective investment cost). These points will be discussed in more detail later.

The economics of energy conversion can best be discussed in terms of the actual apparatus that produces practical renditions of the processes involved. Accordingly, the discussion to follow will consider power cost components of: diesel engine plants, gas turbine plants, steam electric plants, and combination cycle plants.

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* The fuel cell accomplishes the conversion to electricity in a single step. Thermionic, thermoelectric and magnetohydrodynamic (MHD) methods require two steps: combustion to produce heat; and then direct conversion to electricity.

TABLE I

Investment, $/kw		110
Fixed Charges, mills/kwh (12% F.C., 80% Cap. Factor)		1.89
Operation and Maintenance, mills/kwh		0.25
Fuel Cost, Burn-up, mills/kwh (8800 Btu/kwh, 25¢/M Btu)	2.20	
Fuel Cost, Inventory, mills/kwh (90 days inventory at 10%)	0.07	
Total Fuel Component, mills/kwh		2.27
Total Power Cost, mills/kwh		4.41

PLANT INVESTMENT COMPONENT OF POWER COST

In order to translate plant investment into a power cost component, the fixed charge rate on investment and the capacity factor at which the plant operates, must be considered. Fixed charge rates vary from 10% per year to 15% per year, depending on the type of financing, i.e. the proportion of bonds, preferred stock and common stock; earnings permitted by the regulating commissions; rate of depreciation; and state and local taxes.

Internal Combustion Plants

Diesel-engine generator plants vary over a wide range in installed costs, depending on type of engine, speed, size and type of service for which intended. They may be installed for as low as $85/kw for sets designed for short time peaking service to as high as $200/kw for sets designed for heavy duty, full time base-load service.

Gas turbine generator plants also vary over a wide range in installed costs depending somewhat on rating but to a greater extent on the design efficiency. A relatively low efficiency simple cycle gas turbine plant for peaking service may be installed for as low as $70/kw, while a 2-shaft machine with regenerative cycle may be as high as $150/kw.

Steam Electric Plants

The installed cost per kw of steam electric stations has shown outstanding progress over the years, in spite of inflationary trends. This has been largely the result of the combined efforts of electric utility engineers, consulting engineers and equipment manufacturers who have displayed great courage and ingenuity in successfully applying ever increasing ratings. (Fig. 7) The downward trend in station costs per kw is also attributable to adoption of the unit system (1 boiler, 1 turbine-generator, 1 step-up transformer bank) and continued effort toward design simplification throughout the plant. Fig. 4 shows the downward trend in $/kw versus size, including the effect of typical steam conditions for the size of unit being considered. The indicated band will account for difference in site conditions, plant design concepts and local construction costs. Table II shows the relative installed costs of the major equipments in a typical steam-electric plant.

TABLE II

Site and Structure (Boiler)	16%
Steam Generator (Boiler) and Draft Equipment	25
Feedwater System and Piping	10
Turbine Generator	22
Condenser and Circulating Water System	8
Electrical Equipment	5
Coal Handling	6
Step-Up Transformer and High Yard Equipment	8
	100%

Other design factors influence the installed cost: a plant designed for oil or gas firing will reduce plant costs by $15 - $25 per kw; the range from an all indoor plant to the full outdoor design in the order of $5 - $10/kw; a wet type cooling tower where a moderate water supply is available adds $5 - $10/kw over the more conventional river, lake or ocean source; and a dry type cooling tower--for locations with minimum cooling water--will add $20 - $30/kw.

Steam Generators (Boilers)

Steam generator equipments offer the designer a real challenge to arrive at an optimized product after due consideration of many parameters. The greatest single unknown is the quality of fuel, in the case of coal, that will be burned throughout the life of the equipment and with which it is expected to meet the rated output. Over the years, the cost per unit of output has steadily decreased, primarily by taking advantage of the increased knowledge, gained through design and operating experience, pertaining to the many factors which can be utilized to increase the compactness of the equipment.

Higher temperatures and pressures permitted by modern metallurgy, reduce the required steam flow per kw of plant output. Increased knowledge of water treatment, of water circulation characteristics, of gas distribution in the pressurized furnace and the adoption of intermediate furnace walls, or twin furnaces, all contribute to compactness. At the higher pressures, use of forced circulation and elimination of the steam drum both contribute to reduction in materials.

Today, single steam generator equipments are being designed for flows approaching 8,000,000 #/hr--corresponding to a station output about 1200 mw.

Turbine Generators

The turbine designer has kept pace with the rapid increase in ratings, still showing a continued decrease in unit investment by arriving at designs with more and more compactness. A high rated turbine must pass high steam flow and the required orifice areas are obtained by longer buckets on larger wheels and in the lower pressure area of the turbine by providing multiple flow paths. These design features impose greater forces on the main casing flanges, greater centrifugal and bending forces on the wheels and buckets and greater spans between bearings. These and many other requirements are successfully met by the use of new alloy metals and design ingenuity--all resulting in higher outputs per unit of equipment.

High speed, 3600 rpm, turbines are applied for almost all modern high-pressure, high-temperature, steam conditions. Tandem turbines--one turbine and one generator--are today on order in ratings up to 700 mw. For still larger ratings the cross compound turbine is applied where two turbines are used in series in the steam path and each turbine has its corresponding generator. The high-pressure 3600 rpm turbine exhausts into a low-pressure 1800 rpm turbine where sufficient orifice area for the very high steam flows to the condenser is more readily obtained. Cross compound set ratings as high as 1130 mw are on order.

In nuclear fueled plants, where the steam conditions are appreciably lower than in fossil fueled plants, 1800 rpm tandem turbine-generator set ratings of 750 mw are on order.

While steam generators and turbines have been increasing in rating, the associated generators have also been keeping pace. As a first step, air has been replaced by hydrogen as a cooling medium in the generator casing. The latest development for the larger ratings was the introduction of the conductor-cooled generator where the rotor is designed so that hydrogen gas is in direct contact with the rotor conductors and where the armature bars are arranged for gas, oil or water to be in direct contact with the conductors for removal of heat loss. These design techniques have permitted spectacular increases in rating from the same physical size equipment.

Combined Cycle Plants

Some attention has been given to the combined gas turbine - steam turbine cycle where a conventional steam electric plant is essentially topped by a simple cycle gas turbine generator set, and the exhaust gases are used for combustion in the steam generator. Such a plant with output in the order of 250,000 kw is in successful operation, using gas as the fuel. Although this kind of plant requires added investment per kw, this is more than offset by the gain in efficiency. The widespread application of combined gas turbine - steam turbine plants awaits the development of successful coal firing.

Several years ago, when conventional units were in the 100,000 kw range and with heat rates 10,000 Btu/kwh or higher, plants with mercury cycle topping and heat rates of 9000 Btu/kwh received some interest. Since that time, however, the progress in heat rates of conventional cycles has reached the point where the mercury cycle practically cannot be justified because the heat rate gain is more than offset by the extra investment in plant equipment.

FUEL COMPONENT OF POWER COST

Although the inventory component of fuel cost is not negligible, it is sufficiently small that it can be ignored in a discussion of comparative fossil fuel conversion economics. The burn-up component, as noted earlier, is a function of efficiency and fuel price.

Diesel Engine Plants

The diesel engine in this country dates from about the year 1900. Since that time, the use of diesel engines has expanded tremendously, although for electric utility application, their use is limited by small unit size and inability to burn coal. Oil and gas fired diesel engines accounted for about 1.5 percent of total capacity in 1963. In recent years, there has been some application of small high-speed diesel engines for emergency and peaking service on large utility systems, but the major application is in base load service on small municipal systems. By the use of high cylinder pressures and temperatures, it is possible to obtain heat rates as low as 9500 Btu per kwh as indicated in Figure 2. As will be explained later, the heat rates in this figure are all based on the "higher heating value" of the fuel, and hence vary somewhat with the nature of the fuel.

Gas Turbine Plants

The first gas turbine used for electric power generation in this country was installed in 1949. Gas turbines are inherently simple machines of low first cost and their primary application in utility systems is for peaking and emergency standby service. Unit sizes are large enough to be practical for large utilities. Coal firing is not feasible, but gas turbines can handle a wide variety of oil and gas fuels. The major heat loss in the gas turbine cycle is the exhaust; and where no attempt is made to recover this heat, efficiencies are relatively low. Heat rates in the range of 14,500 - 16,500 Btu per kwh are typical, as shown in Figure 2. Where regenerators are used for exhaust heat recovery, heat rates as low as 13,000 Btu per kwh may be achieved. The use of higher firing temperatures (above 1600 F) will in the future reduce gas turbine heat rates.

Steam Electric Plants

The first central electric generating stations, built just prior to the turn of the century, consisted of boilers supplying saturated steam to reciprocating steam engines driving slow-speed generators. By 1910, the steam turbine was rapidly supplanting the reciprocating engine because of its greater simplicity and higher efficiency.

Figure 3 shows, schematically, a modern steam cycle. In considering the efficiency of such a cycle, it may be noted that the major source of boiler losses is in the heat contained in the gases discharged through the stack. In the 1920's, the introduction of economizers and air preheaters gave a substantial reduction in this loss by using the stack heat to preheat incoming air and feedwater. A second factor in boiler efficiency progress was the introduction of pulverized coal firing which greatly increased combustion efficiency. Other important developments have made it possible to maintain high efficiency at partial load. Some of these are control of gas flow by baffling and recirculation, and steam temperature control through de-superheating, differential firing, and burner angle control. Modern coal fired boilers have full load efficiencies of 90 percent or more.

Another major loss occurs in the condenser where heat in the turbine exhaust steam is rejected to the cooling water. This loss is substantially reduced by regenerative feedwater heating, accomplished by extracting steam from various stages of the turbine. This device has been universally used for over 30 years. A more recent cycle development is the use of reheat. After expanding partially through the turbine, steam is returned to the boiler and reheated to approximately initial temperature for re-entry to the turbine. Nearly all large steam plants going into service today incorporate this feature which improves the cycle efficiency 4 to 5 percent. A few plants have used a second reheat which provides an additional gain of about 2 percent.

Over the years, turbines have been designed in larger and larger ratings incorporating these cycle improvements, while at the same time, there has been steady improvement in turbine mechanical efficiency brought about by closer control of running clearances and leakages, advanced aerodynamic design of buckets and improved nozzle design.

Figure 2 shows today's net station heat rates for steam plants with steam conditions typical for the sizes shown. This ranges from 850 psig throttle pressure and 900°F temperature for the smaller units to 3500 psig, 1000°F initial and 1050°F reheat for the larger sizes. The approximate historical trend of best station heat rates is given in Figure 8.

Heating Value of Fuels

In the combustion of hydro-carbon fuels where water is a product, it is necessary to consider what are called the "higher" and "lower" heating values of the fuels. In practical thermodynamic machinery, the exhaust temperature is such that the product water is in the form of vapor. The heat of vaporization represents heat that, while produced in combustion, is not available to the machine or process. It has become customary to subtract this heat of vaporization from the total heating value of the fuel and refer to it as the "lower heating value". The total heat, as would be determined by bomb calorimeter, is called the "higher heating value". The thermal efficiency, or heat rate, of a generating plant thus depends upon which heating value is used in its determination. The situation is further complicated by the fact that the ratio of higher heating value to lower heating value is not the same for all fuels. Typical values are as follows:

Fuel	Ratio $\frac{HHV}{LHV}$
Coal	1.03
Oil	1.06
Natural Gas	1.11

In European practice, lower heating value is most commonly used; whereas in this country, higher heating value is the usual rule. An exception to this is in the diesel industry where HHV is used in quoting efficiency for oil fuel and LHV for gas fuel.

Operation and Maintenance Component of Power Costs

Diesel plants and gas turbine plants comprise relatively small ratings with resulting higher operation and maintenance costs than are experienced in steam electric plants. Furthermore, type of fuel, service conditions, and annual capacity factors vary widely. In general, however, typical costs for a diesel or gas turbine plant will be in the range of 0.5 to 5.0 mills/kwh for a capacity factor of 80%.

For steam electric plants, Figure 5 shows typical operation and maintenance costs for coal firing. Gas and oil fired plants have slightly lower costs.

Generation System Economics

From the foregoing discussion of investment cost, heat rates, and operation and maintenance costs for the different types of plants, it will be seen that a wide range in power costs per kwh is inevitable. Even considering only one type of generating plant, costs will vary considerably because of differences in fuel and construction costs in different parts of the country. But beyond these considerations of the cost of power generated in a single plant or unit is the question of total system cost which determines the impact of electric energy on the nation's economy.

The first factor that influences total system generating cost is the nature of the load. In a 24-hour period, the magnitude of load on a typical electric utility system varies through a two to one range. In a year this variation is three to one, or more. Figure 6 is a typical annual load duration curve. It shows that the top 20 percent of the load exists for only about 6 percent of the time. Generating cost for this component of load is very high because of the fixed investment charge which is distributed over only a few kwh. At the other extreme is the bottom 30 percent of the load which exists 100% of the time. This is the base load which may be generated at minimum cost. As noted earlier, part load efficiency of generating units is important because of the fluctuating nature of the load, and because excess capacity must always be kept in operation to provide a high degree of service continuity in the event of sudden equipment breakdown. In addition to this so-called "spinning reserve", it is necessary to have some capacity in cold standby for long-time outages, and to permit units to be withdrawn from service for maintenance and inspection. In general, electric utility systems have installed capacity representing 110 to 120 percent of anticipated peak load. This imposes an investment cost burden beyond that calculated for power conversion cost of a single unit.

The second factor influencing total system cost is growth. The industry has historically grown at the rate of about 7 percent per year. In the past, this growth, together with the shape of the load duration curve, has very neatly fitted the pattern of progress in generating unit efficiency so as to eliminate the problem of obsolescence: new efficient units could always operate at high load factor in the bottom of the load curve while older, less efficient units performed the short time peaking function. Today, the growth continues, and the load duration curve remains about the same, but progress in efficiency improvement has slowed. This gives an opportunity to apply special forms of peaking generation whose operating characteristics and low investment cost are ideally suited for the short duration peak load. Pumped storage hydro and gas turbines are beginning to find wide application for this bulk peaking service.

One might ask whether the introduction of nuclear power does not constitute the beginning of another technological cycle wherein progress in reducing fuel cost will again prove to be compatible with load growth and the shape of the load curve. This could be the case--but today there exist forms of peaking generation that were not available 60 years ago. And economic studies indicate that optimum system design must include peaking generation as well as the most advanced forms of base load units.

This brings up the third major factor in generation system economics: the emergence of new methods of system design analysis using simulation techniques in digital computers. It is now possible to analyze the performance and economics of alternate 20-year plans for generation system expansion with a high degree of accuracy and at reasonable cost. These methods are gaining wide acceptance and will perform an important service in keeping the future cost of electric power as low as possible.

In conclusion, there will be continued progress in the economics of converting fossil fuels to electricity, but probably at a less spectacular rate than in previous years. There is still opportunity for lower investment costs through design simplification and the application of still larger units. These same factors, together with automation, will result in lower operation and maintenance costs. Similarly, it is expected that modest improvements in conversion efficiency will be realized. Thus, there seems to be little doubt but that fossil fueled generating plants will continue to contribute in a major way to low total system generating costs in the future.

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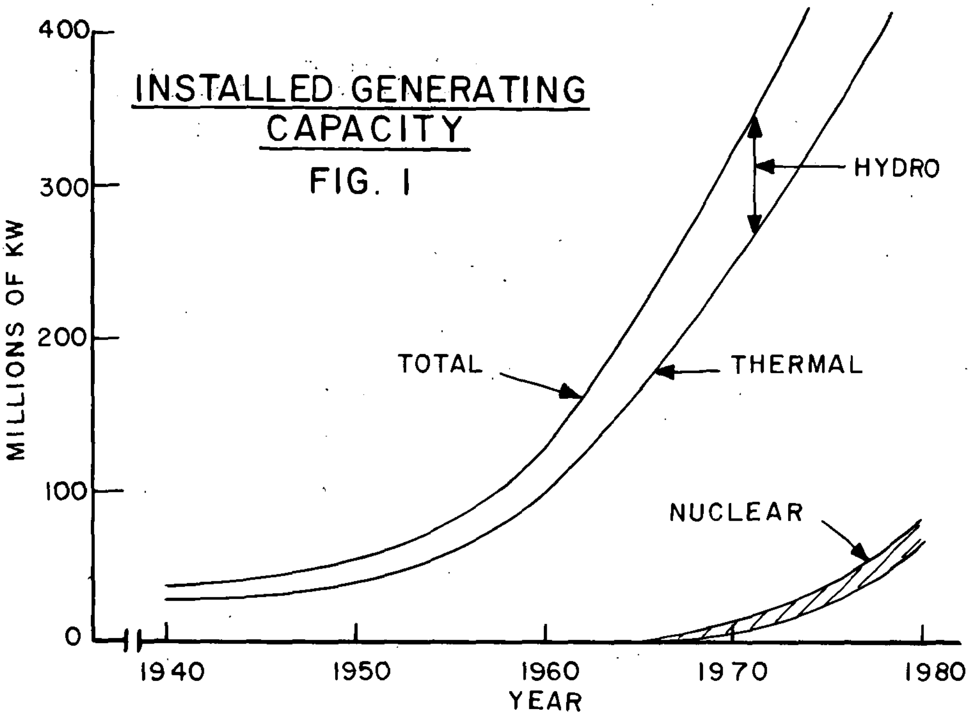
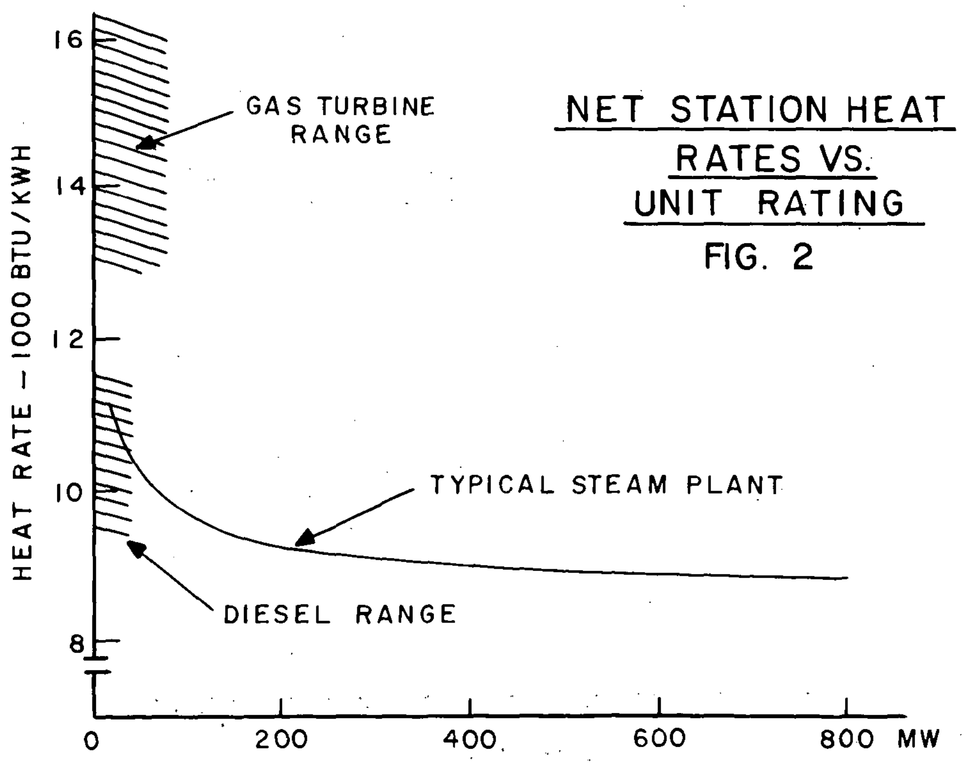
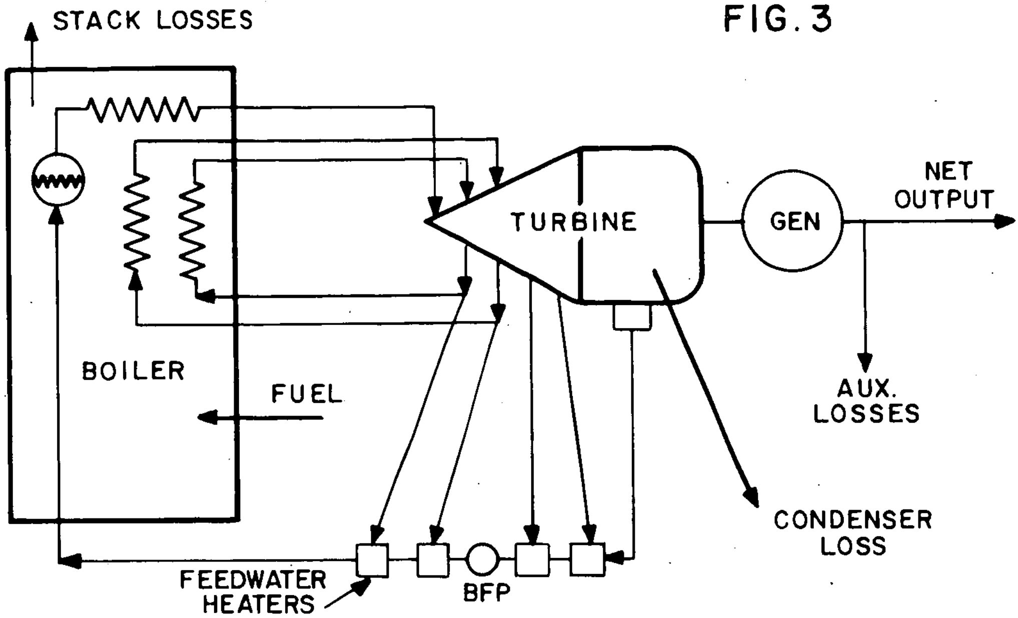

INSTALLED GENERATING CAPACITY
FIG. 1
MILLIONS OF KW
400
300
200
100
0
HYDRO
TOTAL
THERMAL
NUCLEAR
1940
1950
1960
1970
1980
YEAR


NET STATION HEAT RATES VS. UNIT RATING
FIG. 2
HEAT RATE — 1000 BTU/KWH
16
14
12
10
8
GAS TURBINE RANGE
TYPICAL STEAM PLANT
DIESEL RANGE
0
200
400
600
800 MW

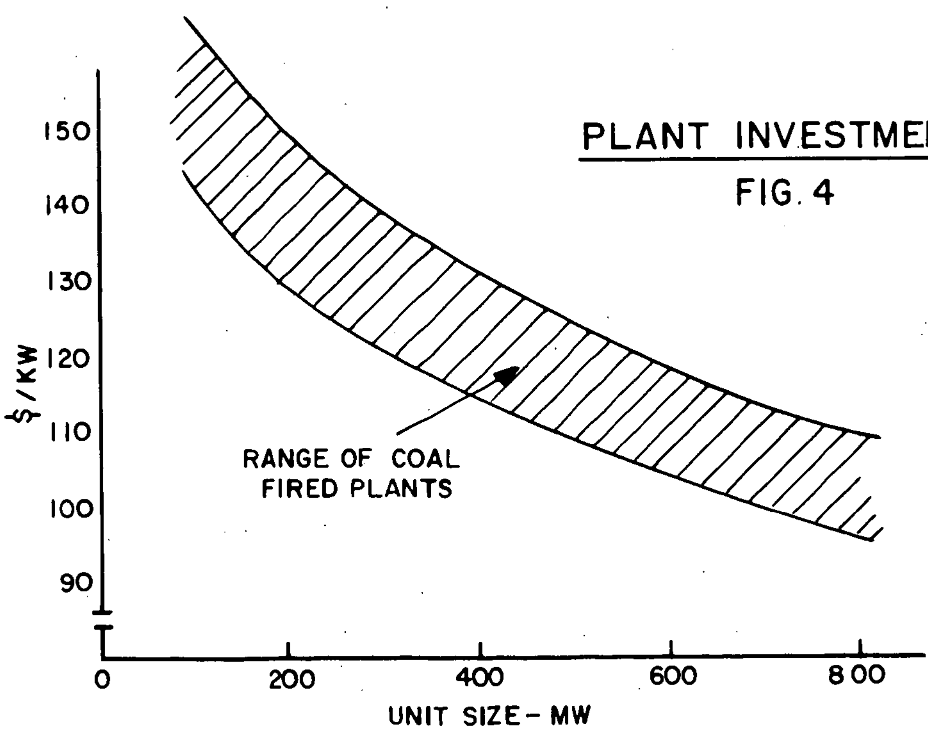
STEAM CYCLE DIAGRAM

FIG. 3

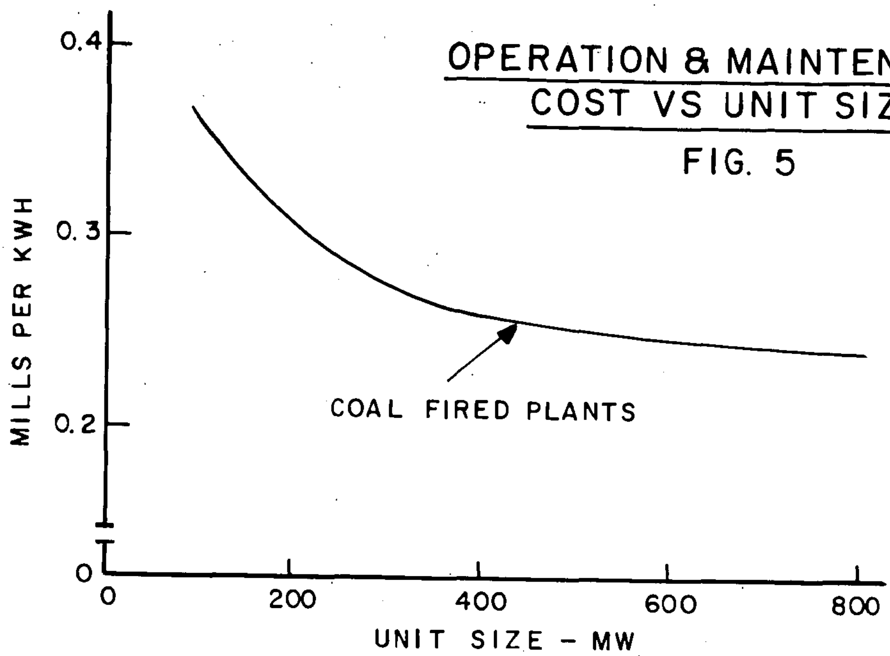


PLANT INVESTMENT

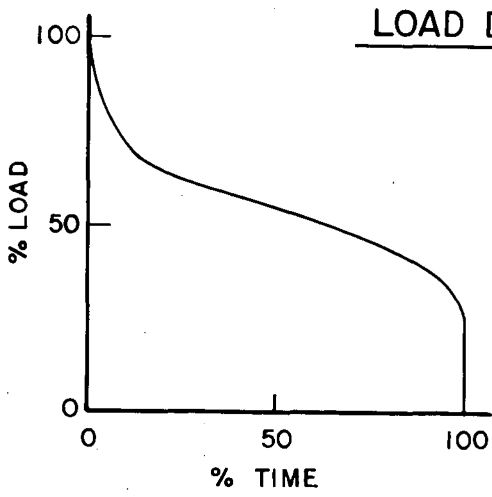
FIG. 4



OPERATION & MAINTENANCE
COST VS UNIT SIZE
FIG. 5

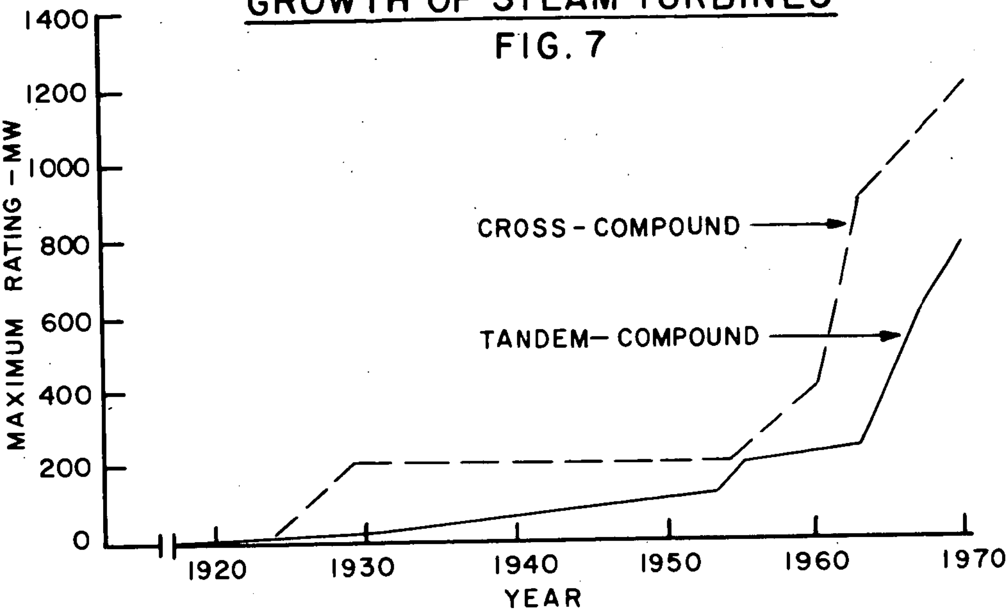


LOAD DURATION CURVE
FIG. 6



GROWTH OF STEAM TURBINES

FIG. 7



TREND OF BEST NET STATION HEAT RATE

FIG. 8