Cairo University/Massachusetts Institute of Technology

Technological Planning Program

GENERATION CAPACITY PLANNING FOR THE EGYPTIAN ELECTRIC POWER SYSTEM

RESEARCH TEAM

Cairo University	M.I.T.	Ministry of Electricity
H. Anis	M. Weitzman	E. El-Sharkawi
M. El Kolaly		H. El-Shaer
		M. Swidan

PROJECT ON

THE LONG TERM INVESTMENT PLANNING FOR

THE EGYPTIAN ELECTRIC POWER SYSTEM

PRINCIPAL INVESTIGATORS

Cairo University:	M.S. Abou Hussein S. El-Sobki
M.I.T.	M. Weitzman J. Kirtley
Ministry of Electricity:	M.M. Abaza

PREFACE

This report is one of a series of publications which describe various studies undertaken under the sponsorship of the Technology Adaptation Program at the Massachusetts Institute of Technology.

The United States Department of State, through the Agency for International Development, awarded the Massachusetts Institute of Technology a contract to provide support at M.I.T. for the development, in conjunction with institutions in selected developing countries, of capabilities useful in the adaptation of technologies and problem-solving techniques to the needs of those countries. This particular study describes research conducted in conjunction with Cairo University, Cairo, Egypt.

In the process of making this TAP supported study some insight has been gained into how appropriate technologies can be identified and adapted to the needs of developing countries per se, and it is expected that the recommendations developed will serve as a guide to other developing countries for the solution of similar problems which may be encountered there.

Fred Moavenzadeh

Program Director

TABLE OF CONTENTS

	Page
INTRODUCTION	1
I. INVESTMENT CRITERIA FOR LUMPY CAPACITY EXPANSION	3
II. PREINVESTMENT SURVEY FOR CAPACITY EXPANSION	20
Introduction	21
Methodology	30
Computation and Results	37
Summary of Results	48
Parametric Analysis of Recovery Cost Study	50
Conclusions	76
References	78
III. OPTIMAL MIXING OF STEAM AND GAS TURBINE POWER PLANTS	79
The Need for Mixing	80
Gas Turbine vs. Steam Plants	82
Load Duration Curve	84
Models of Power Plants Mixture	87
Estimation of Cost Parameters	89
Simplex Model	92
Realistic Model	95
Comparison Between the Simplex and Realistic Models	104
Effect of the Number of Operating Units and Their Technical Minimum	105
Conclusions and Recommendations for Further Studies	107
References	108

INTRODUCTION

The objective of the project on long-term investment planning for the Egyptian electric power system is to provide Egypt with trained personnel and modern techniques for the economic assessment of electric power generation, transmission, and distribution. In July 1977 participants from Cairo University, M.I.T., and the Egyptian Ministry of Electricity met to discuss implementation of the first phase of study for long-term investment planning. This Phase I research strategy consisted primarily of two projects: a preinvestment survey for investment planning, and a study of the optimum mixture of power station types for variable demand. The results of Phase I, concluded in August 1978, are compiled in this report.

Section 1 addresses the problem of establishing priorities for capacity expansion when some of the projects are large. Assigning priorities to projects for capacity expansion on the basis of capacity costs alone would not be reasonable since a large project having low unit costs may deserve a low scheduling priority because its full capacity could not be immediately utilized. To determine which individual projects should be undertaken and when, the investment strategy for all projects must be mapped out beforehand. The problem is formulated as establishing project priorities so as to minimize the discounted value of all costs incurred in expanding capacity, subject to the condition that projects are selected when no excess capacity exists in the system. Then, defining the "recovery cost" of each project to be the payment per unit output which would let the project break even, it is shown in Section 1 that a necessary and sufficient condition for an optimal solution is to always select that project with lowest recovery cost as the next to be undertaken.

In Section 2, Weitzman's method (outlined in Section 1) is used to

compare recovery costs for projected Egyptian oil, gas turbine, and nuclear plants. Various possible values for interest rates, fuel price escalation rates, and demand were considered in evaluating conditions which would affect the results. It was found that recovery costs per unit output of the gas turbine plants are notably higher than those of steam and nuclear plants, given that the gas turbine is base-loaded. If the gas turbine is run 4050 hours per year or less, it would have a lower recovery cost than that of the steam plants considered. The nuclear plant recovery cost is very sensitive to the interest rate. Analysis showed that the recovery cost of the nuclear plant, at 7.8% interest rate, is greater than that of the steam plants considered.

Section 3 discusses what proportion of the electrical generating equipment should be gas turbine as opposed to steam. The demand for electricity varies - daily, weekly, and seasonally. Steam generator plants are relatively cheap per kilowatt when used at near full capacity, and relatively expensive at low capacity utilization. Gas turbine plants are relatively expensive per peak kilowatt, and relatively cheaper per kilowatt at low output, since the output can be easily and cheaply varied.

The basic question is this: Given the pattern of demand fluctuation, what is the least cost combination of power station types? The solution lies in minimizing a cost function based on capital and running costs of generation. A single decision variable is used to represent the steam plant capacity required in a mixed system to meet known demand. The model can be made more complex by including startup and shutdown costs. Results show that in north Egypt the optimum capacity share of steam plant in a mixed steam and gas turbine system is 82% of total capacity.

GENERATION CAPACITY PLANNING FOR THE EGYPTIAN ELECTRIC POWER SYSTEM

SECTION I

INVESTMENT CRITERIA FOR LUMPY CAPACITY EXPANSION

M. WEITZMAN

Investment Criteria for Lumpy Capacity Expansion

M.L. Weitzman

Summary

Suppose that capacity must be expanded over time in some industry or sector. If all capacity expanding projects are small, it is easy to rank them. The next project to be undertaken should have the lowest cost per unit of capacity. When some investments are large, this simple criterion no longer works. A large project might have low unit costs and yet be undesirable because its huge capacity could only be fully utilized at some future time. The standard approach to investment planning based on an individual evaluation of separate projects doesn't normally work when there are indivisibilities. To determine if and when an individual project should be untertaken, the entire investment strategy must be mapped out in unison. This can be a very messy combinatoric problem, especially if repetitive strategies are disallowed because some ways of increasing capacity are uniquely tied to geographic or other conditions.

Surprisingly enough, it turns out that even when investment projects are big and lumpy, the project analysis approach can be made to work. This is a tremendous simplification, since investment priorities can be ranked by the simple expedient of calculating a single cost-like number for each project. The present paper is concerned with explaining this result, which provides a rigorous theory of investment criteria for choosing among large scale projects.

Introduction

The present paper can be viewed as an exercise in trying to strongly characterize an optimal policy for expanding capacity when investments must be

made in discrete or lumpy projects. Although the theory is developed at an abstract level, perhaps the easiest way to convey its flavor is by starting with a specific example.

Suppose planners are considering the best way to expand electricity generation in some country or region. A more or less steady expansion of the system is contemplated, far into the future. Assume that all electricity must be domestically produced (later we consider the possibilities of exports or imports).

Generating capacity is expanded by investing in individual projects. There may be many alternatives of various sizes. Some projects are repeatable - like thermal or perhaps nuclear power plants of various sizes. Other projects, frequently very large ones, are by their very nature once and for all investments because they are tied to a specific location. Hydro-electric installations readily come to mind. Many of the newer exotic technology projects are also non-repeatable - harnessing tidal flows (Fundy, Britainy), diverting water into natural depressions (Quattara), etc.

The basic question is: which project should be undertaken next? This question is more difficult to answer then might be supposed. Among small projects it would suffice to develop next that generating source offering the lowest (present discounted) cost per rated kilowatt of capacity. But when a project is large, initial excess capacity is almost inevitable. Nor is it clear how to correct the "lowest cost per kilowatt" formula for excess capacity. Indeed, there is no reason to expect that one lumpy investment project may be analyzed in isolation from the alternatives by assigning to it a single number which can meaningfully be compared with the other assigned numbers. In a world of lumpy projects, optimal investment strategies can usually only be

analyzed as an entire (mixed integer) programming problem formulated over some large time horizon. The solution typically involves a complicated interdependence[1] among all the projects which defies any simple analysis. Such problems are combinatoric in nature and they are frequently difficult or expensive to solve.

Of course, if the least cost capacity expansion problem has special features, these may be advantageously utilized in characterizing and finding an optimal solution. Thus, for example, in the Chenery-Manne capacity expansion model,[2] infinite repeatability of all projects and a linearly growing demand limits the strategy space to capacity expansion of one size plant only. An optimal strategy is easily found by locating that size plant which gives lowest present discounted cost when it alone is always expanded to meet new demand. The situation is fundamentally different when non-repetitive projects are considered, and a seemingly messy combinatoric problem immediately emerges.

The basic conclusion of the present paper is that under certain assumptions it is possible to assign each project a "recovery cost" which gives a correct ordinal ranking of when it should be undertaken relative to the other projects. Thus, all the advantages of a single rate of return criterion apply in an unfamiliar context. That project should be next undertaken which has the lowest recovery cost. The formula giving a project's recovery cost is a relatively straightforward adjustment of the cost per kilowatt which takes account of the project's size; it is easy to apply and has an elementary economic interpretation.

While the conclusions of the present paper are based on a simplified model, it is hoped they may be of some use in a wider context. For example,

the notion of recovery cost might prove helpful in providing a rough screening criterion for large projects technically not covered by this paper's formal model.

The Model

We consider a planning situation where the demand for a certain commodity is prescribed at each time and must always be fulfilled. For analytic convenience, the fixed final demand schedule $D(t)$ is taken to be a linear function of time:

$$D(t) = A + Bt. \tag{1}$$

Formula (1) might be defended as a first order approximation holding for at least the near future. It represents a key assumption which greatly simplifies the analysis.

Demand is met by investing in discrete projects which expand capacity. A typical pattern of capacity expansion is depicted in Fig. 1.

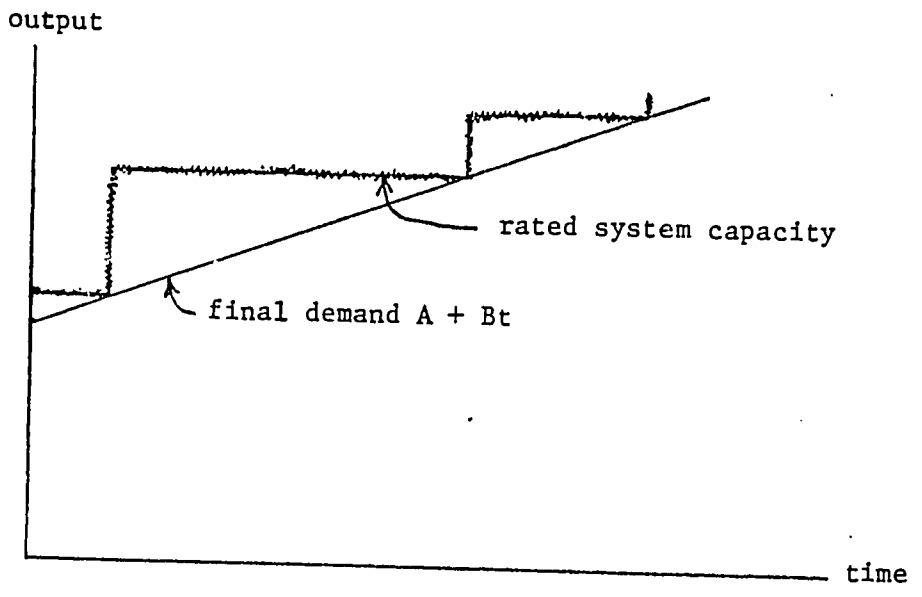


FIGURE 1

Let there be a total of n different projects. The first m of these are unique and non-repeatable. Projects m+1 through n are repeatable and can be invested in over and over again.

Let project i ($1 \leq i \leq n$) have a full capacity output of K_i. Without significant loss of generality, we allow projects to begin producing only when no excess capacity exists in the system (all previous projects are producing at full capacity). If project i is chosen to increase the rated capacity of the system by coming on line at T (a time when there is zero excess capacity in the system), it is restricted to do so according to the following prearranged production schedule. At time t, $T \leq t \leq T + \frac{K_i}{B}$, the output of project i is $B(t-T)$, leaving excess capacity $K_i - B(t-T)$. At time $T + \frac{K_i}{B}$, the output of project i reaches its full rated capacity level, K_i, and it remains there forever (every capacity expanding project is assumed for simplicity to be infinitely durable). Thus, the output stream of project i coming on line at time T would look as follows:

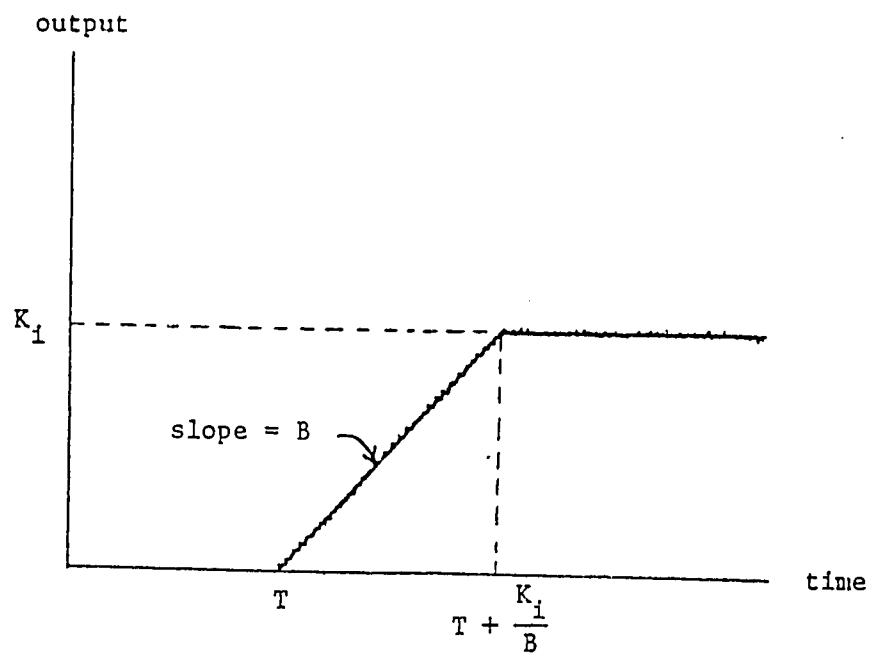


FIGURE 2

If project i is chosen to begin coming on line at T, it forces outlays to be made at time t as given by the project cost function $F_i(t-T)$. When $t<T$, project i is in the primary construction phase. It is during this phase that are incurred the major construction costs associated with creating an installation of size K_i. At times from T to $T + \frac{K_i}{B}$, basic overhead installations have already been completed and secondary capacity is filled in according to the prescribed linear schedule. Finally, for times after $T + \frac{K_i}{B}$, all construction has been completed and the only outlays are variable operating costs.

To use an example from hydro-electric generation, the first phase would be concerned with constructing a dam and creating the basic overhead for a transmission system and other installations. The second phase would involve filling in the existing system with more generators and transmission lines until full capacity is reached. At that time the third phase begins, with full capacity operating costs being the only outlays. For a small thermal plant, the second phase is of minor consequence, the first and third phases being dominant.

Optimal Capacity Expansion

The basic problem is to schedule capacity expanding projects to come on line meeting final demand at minimum present discounted cost. Let the hth plant installed (h=1,2,...) be a project of type j(h) and let it begin operating at time T_h. Mathematically, the problem is to introduce projects in the optimal order j*(1), j*(2),... which minimize

$$\int_0^\infty \sum_{h=1}^{\infty} F_{j(h)}(t-T_h) \; e^{-rt} \, dt, \qquad (2)$$

subject to $$T_1 = \bar{T}_1 \tag{3}$$

$$T_{h+1} = T_h + \frac{K_{j(h)}}{B} \tag{4}$$

for $i=1,\ldots, m$, and $\ell \neq h$, $\quad j(h) = i \Rightarrow j(\ell) \neq i$. (5)

The objective function (2) is the present discounted value of all costs incurred in expanding capacity. Time T_1 (= $\bar{T}_1$, given) is the first time when no excess capacity exists in the system and a new plant must begin operating. Thereafter, as expressed by equation (4), new capacity comes on line at times when the old capacity just exactly covers demand. Condition (5) precludes using any of the non-repeatable projects $i=1,\ldots, m$ more than once. Note that we are implicitely assuming there is enough start up time to complete project $j^*(h)$ before time T_h. So long as there is at least one repeatable project, a solution of (2)-(5) must exist.

Because projects are indivisible, problem (2)-(5) possesses a complicated combinatoric structure which seemingly defies easy solution. Surprisingly, it turns out that the model as it is formulated has enough structure to induce a very simple characterization of an optimal solution. A "recovery cost" is assigned to each project. That project is next undertaken which has the lowest recovery cost among all remaining alte· ·ves. Thus, we have the unexpected result that lumpy projects can be meaningfully ranked as investment priorities.

Many of the underlying assumptions of formulation (2)-(5) -- arithmetic growth of demand, infinite project lifetime, etc. -- may appear to be un-

realistic. Yet the model as a whole captures enough essential aspects of reality that its solution is likely to be relatively robust over the near future. What we are really interested in knowing is not so much the complete solution to an infinite horizon problem, so much as the identification of the next project, or the next few, to be built (after that, the data will change anyway). Identifying the next few projects to be built is easily and quickly done for the model (2)-(5). The optimality of this choice is unlikely to be much sensitive to the shortcomings of the present formulation. In other words, my feeling is that if a more complicated and realistic model were constructed, the investment program for the near future obtained by numerically solving it would not differ appreciably from the present model's recommendations.

Even for complicated investment situations, the project ranking which emerges as a solution to the simplified model (2)-(5) might serve as a rough screening device or as a starting point for more sophisticated analyses, like integer programming.[3] The fact that it is possible to sharply characterize an optimal solution makes problem (2)-(5) a natural preliminary to any more general analysis. And the present model may even be a reasonable description of some situations.

Solving the Problem

Define the recovery cost of a project to be the hypothetical payment per unit of output which would make the project just break even. The recovery cost for project i, C_i, is defined as the solution to:

$$\int_0^{K_i/B} C_i \, Bs \, e^{-rs} \, ds + \int_{K_i/B}^{\infty} C_i \, K_i \, e^{-rs} ds = \int_{-\infty}^{\infty} F_i(s) \, e^{-rs} \, ds. \quad (6)$$

The right hand side of equation (6) is the total cost of project i, discounted back to the time when it first starts coming on line. The left hand side is the hypothetical discounted revenue accumulated by charging a price of C_i per unit of output (the first integral covers the expansion phase and the second full capacity operation).

Integrating out the left hand side of (6) yields the formula

$$C_i = \frac{r^2 \int_{-\infty}^{\infty} F_i(s)\, e^{-rs}\, ds}{B(1-e^{-rK_i/B})} . \tag{7}$$

Although the notion of recovery cost has intuitive appeal, the following theorem gives it a rigorous basis as a criterion for selecting among discrete projects of differing sizes.

Theorem: A necessary and sufficient condition for an optimal solution of problem (2)-(5) is the rule:

<u>always select next the project with lowest recovery cost.</u>

At time T_1, that project i^* ($=j^*(1)$) should come on line which satisfies:

$$C_{i^*} = \min_{i=1,\ldots,n} C_i . \tag{8}$$

If i^* is a non-repeatable project ($1 \le i^* \le m$), it is deleted off the list from which the next project $j^*(2)$ is selected (by the criterion of lowest recovery cost) to come on line at time $T_2 = T_1 + \frac{K_{i^*}}{B}$. Note that once a repeatable project ($i=m+1,\ldots,n$) is selected by the criterion of minimum recovery cost, it will continue to be selected by that same criterion (so

long as a project with lower recovery cost is not added to the list of available projects).

Because it is so easy to calculate recovery costs, sensitivity analysis is made especially simple. The effects on project ranking of changing such parameters as the interest rate, growth of demand, plant capacity or cost estimates is easily determined. It is also easy to say how an optimal investment strategy changes when certain projects are added to or deleted from the list of prospective candidates.

That such an elementary decision rule as (8) is optimal depends more crucially than might be supposed on the simplifying assumptions of the model. There does not seem to be available a sharp characterization of an optimal solution when, for example, demand varies non-linearly with time, projects depreciate, or the discount rate is not constant. About all that might be said of a general character in such situations is that a limiting argument could be used to show the results presented here are valid as an approximation when the stipulated preconditions are close to being met.

Proof of Optimality

For completeness, we prove the optimality of decision rule (8) from first principles. An alternative approach would be to demonstrate that (2)-(5) is a particular example of a resource pool problem and then to apply the general theory developed in Weitzman [1976] to this special case.

The following monotonicity property is important:

In an optimal policy,

$$C_{j(h)} \leq C_{j(h+1)} \tag{9}$$

for all h=1,2,...

proof: Consider an alternative policy that reverses the order of investment in projects j(h) and j(h+1) but leaves unchanged the rest of the program. That is, at time T_h project j(h+1) comes on line and at time $T_h + \frac{K_{j(h+1)}}{B}$ project j(h) comes on line - otherwise everything else remains the same. The difference in present discounted cost between the old policy and the new variation is

$$e^{-rT_h} Y_{j(h)} + e^{-r(T_h+K_{j(h)}/B)} Y_{j(h+1)}$$

$$- (e^{-rT_h} Y_{j(h+1)} + e^{-r(T_h+K_{j(h+1)}/B)} Y_{j(h)})$$

$$= e^{-rT_h}[Y_{j(h)}(1-e^{-rK_{j(h+1)}/B}) - Y_{j(h+1)} (1-e^{-rK_{j(h)}/B})], \tag{10}$$

where

$$Y_i \equiv \int_{-\infty}^{\infty} F_i(s)\ e^{-rs}\ ds. \tag{11}$$

Inequality (9) must hold because otherwise, from formulas (7) and (11), expression (10) is positive and the original policy is non-optimal.

The main body of proof now proceeds by contradiction with the selection rule based on (8). Suppose that it is optimal to choose as the first investment some project j(1)(≠i*) satisfying

$$C_{j(1)} > C_{i*} \tag{12}$$

Let the present discounted cost of this allegedly optimal policy be

$$\alpha \equiv \sum_{h=1}^{\infty} \gamma_{j(h)} e^{-rT_h}. \tag{13}$$

Equation (13) can be rewritten as

$$\alpha = \sum_{h=1}^{\infty} \frac{\gamma_{j(h)}}{1-e^{-rK_{j(h)}/B}} ((1-e^{-rK_{j(h)}/B}) e^{-rT_h}), \tag{14}$$

where, making use of (4),

$$\sum_{h=1}^{\infty} (1-e^{-rK_{j(h)}/B}) e^{-rT_h} = \sum_{h=1}^{\infty} e^{-rT_h} - \sum_{h=2}^{\infty} e^{-rT_h} = e^{-rT_1}. \tag{15}$$

It follows from the monotonicity property (9) that since project i* satisfying (12) does not come on line at time T_1 in the allegedly optimal policy, it never does. Consider an alternative policy of commencing with project i* and postponing to a starting date of $T_1 + \frac{K_{i*}}{B}$ the allegedly optional policy which had previously begun at T_1. In other words, what was policy over $[T_1,\infty)$ now becomes policy over $[T_1 + \frac{K_{i*}}{B},\infty)$ and project i* now begins at T_1. The present discounted cost of this alternative policy is

$$\alpha' \equiv e^{-rT_i} \gamma_{i*} + e^{-rK_{i*}/B} \alpha. \tag{16}$$

From (12), (9), (11), and (7),

$$\frac{Y_{i*}}{1-e^{-rK_{i*}/B}} < \frac{Y_{j(h)}}{1-e^{-rK_{j(h)}/B}} \qquad h=1,2,\ldots \tag{17}$$

Combining (17) with (14), (15),

$$\frac{Y_{i*}e^{-rT_1}}{1-e^{-rK_{i*}/B}} < \alpha,$$

which can be rewritten as

$$e^{-rT_1} Y_{i*} + e^{-rK_{i*}/B} \alpha < \alpha .$$

By (16), this implies

$$\alpha' < \alpha.$$

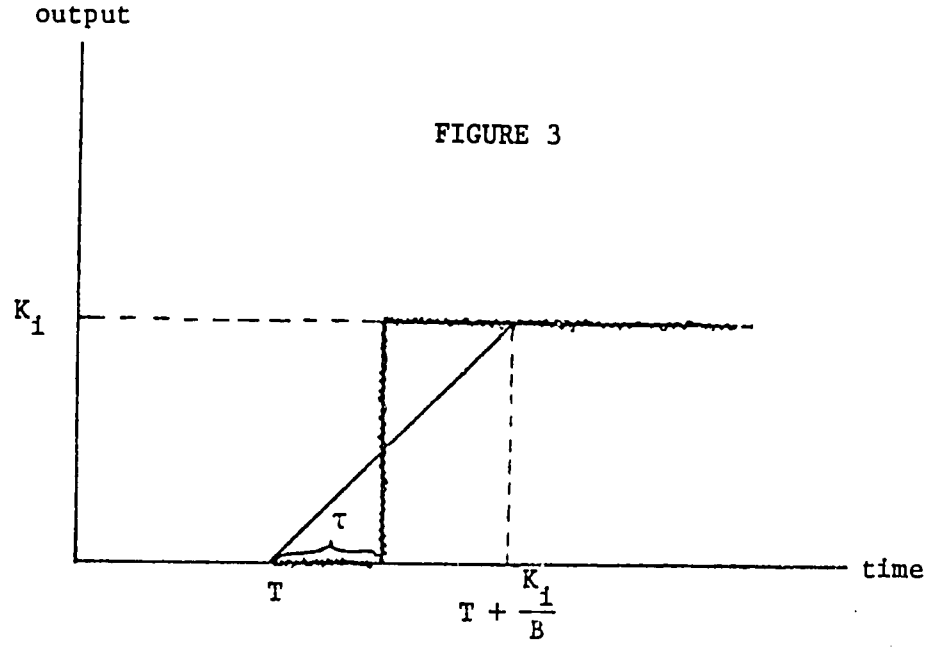
The alternative policy has lower present discounted cost than the proposed optimum, a contradiction. Hence, the supposition (12) is false. The selection rule based on (8) is a necessary condition for an optimum.

This concludes our proof of the form of an optimal policy. Strictly speaking, we have proved the necessity of the selection rule based on (8) for a project coming on line at T_1. The extension to T_h for all h is immediate. The selection rule (8) specifies a unique choice of j*(h) for each h (except in the case of ties, for which it is easy to show that how the tie is broken makes no difference to the value of the objective function). Thus, since an optimum exists, sufficiency of the selection rule based on (8) has also been demonstrated.

A Few Brief Extensions

It is easy to extend the model to cover the case where imports are available at price P and exports can be sold at price p(<P). To make the problem interesting, p should be higher than variable production costs (otherwise there is no exporting) and P should be high enough to ward off a stategy of importing everything and producing nothing domestically.

When imports and exports were disallowed, the output stream of project i coming on line at time T was as depicted in Fig. 2. Now the corresponding output stream would be as depicted in Fig. 3.



For τ periods of time, the commodity is imported to help meet final demand. Then, when plant i comes on line at time $T + \tau$, it immediately produces at full capacity, exporting the excess production over domestic demand. At time $T + \frac{K_i}{B}$, there is no excess capacity.

The time τ is selected to minimize net present discounted project costs, taking into account import costs, export revenues, and all production costs for project i coming on line with full capacity at time τ. Except for these new net present discounted costs replacing the previous $\{\gamma_i\}$ in formula (7)

and elsewhere, the analysis based on equation (8) remains the same. The effect of having import or export possibilities is generally to increase the relative desirability of large scale projects.

With a slightly different interpretation, the same analysis covers the case of a piecewise linear benefit function kinked at time t around the target demand level A + Bt. In this interpretation, the import price is the welfare loss of falling short a unit from target and the export price is the welfare gain of delivering an extra unit above target.

Some other generalizations of the model are possible, but it would be tedious to go on listing them.

Footnotes

1. See, for example, Chenery [1959].

2. See Chenery [1952] or Manne [1967].

3. See, for example, Westphal [1971].

References

Chenery, Hollis B., "Overcapacity and the Acceleration Principle", Econometrica 20, 1952, 1-28.

Chenery, Hollis B., "The Interdependence of Investment Decisions" in Abromowitz (ed.) The Allocation of Economic Resources, Stanford University Press, 1959.

Manne, Alan S., Investments for Capacity Expansion, M.I.T. Press, 1967.

Weitzman, Martin L., "The Optimal Development of Resource Pools", Journal of Economic Theory, June 1976, 351-64.

Westphal, Larry E., Planning Investments with Economies of Scale, North-Holland, 1971.

GENERATION CAPACITY PLANNING FOR THE EGYPTIAN ELECTRIC POWER SYSTEM

SECTION II

PREINVESTMENT SURVEY FOR CAPACITY EXPANSION

Research Team:

H. Anis
E. El-Sharkawi
H. El-Shaer
M. Swidan
H. El-Kolaly
M. El-Gazzar
S. Doss
K. Aly

1. INTRODUCTION:

1.1 Preliminary Considerations:

It is recognized that accurate load forecasts are the foundation for efficient usage of limited capital resources. In the way of establishing a load forecast as means of assessing the generation expansion for the coming decade, the following considerations are borne in mind:

(a) The rather erratic economical and social conditions in Egypt over the past decade rendered such accurate load forecasts difficult. There is nothing for many years that can be considered to represent a "normal" growth trend. This is attributed to the effects of the war years, dislocation of population in some areas, and economic effects of military activities and expenditures.

(b) After establishing a power policy, the process of dealing with foreign governments and financing arrangements becomes very time consuming. Therefore anticipations in this regard must be relied upon in any economical feasibility study.

(c) In setting a realistic generation expansion policy, the existing and expected limitations in the present power generation complex must be accounted for. This may be divided into two main categories,

namely, capacity limitations and expected outage rates.

1.2 Capacity Limitations:

Thermal Plants:

The sum of name plate ratings of all the existing thermal generating units together with the hydro-electric capacity gives a rather impressive total installed capacity in terms of system loads. However, the system dependable capacity is considerably less than the sum of the nameplates and the significant limitations in both steam and hydro-electric capacities must be considered carefully.

Many of the existing steam units are incapable of producing rated output for various reasons. The problems range from improper boiler design to damaged water walls, high cooling water temperature, and inadequate control systems and safety devices. Many of the boiler problems are attributed to the burning of crude oil during the war years when mazout was not available. All of these considerations are aside from any that may relate directly to thermal efficiency which has not been a primary concern to date since fuel oil has been available to the Egyptian Electricity Authority at a modest price.

Hydroelectric Plants:

The Aswan and High Dam complex facility has an extremely important role in an economical power supply. This is, however, subject to limitations. The first limitation is imposed by the

treaty between Egypt and Sudan which allocates the amount of water to be used by each country. Only a total of 55.5 billion cubic meters of water per year is allocated to Egypt.

On the other hand, the maximum nameplate rating of the High Dam is 2100 MW and Aswan is 345 MW. However, the dependable capabilities of both plants are significantly less than nameplant ratings. They have virtually never been more than ten of the twelve High Dam units available for operation at the same time , which means a true capacity of 1/50 MW. For Aswan, a true capacity of only 225 MW is usable because of the low head caused by the High Dam itself and the outage of at least one unit for maintanance.

Table (1) gives a general idea about both installed and expected generating capacities of the power station feeding the unified power system of Egypt.

Table (1)

INSTALLED AND PROJECTED GENERATING CAPACITY OF UPS POWER STATIONS

Name of Station	Installed Power Megawatts: Number and Capacity of Units	Total	Maximum Capability in Megawatts (Assuming All Generating Units in Service): 1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
1. Cairo West	3 x 87	261	150	150	150	150	150	187	224	261	261	261	261
2. Cairo South	4 x 60	240	180	240	240	240	240	240	240	240	240	240	240
3. Cairo North	2 x 30 + 1 x 20 + 2 x 10	100	75	75	75	75	75	75	75	75	36	36	0
4. El-Tebbin	3 x 15	45	28	40	40	40	40	40	40	40	40	40	40
5. Talka	3 x 12.5 + 3 x 30	127	116	116	116	116	116	116	116	116	116	116	116
6. Damanhour	2 x 15 + 3 x 65	225	195	195	195	195	195	195	195	195	195	195	195
7. El-Seyouf	2 x 26.5 + 2 x 30	113	100	100	100	100	100	100	100	100	100	100	100
8. Karmouz	4 x 16	64	30	30	45	45	45	15	0	0	0	0	0
9. Assiut	3 x 30	90	60	90	90	90	90	90	90	90	90	90	90
10. Suez(Damaged)	4 x 25	100	---	---	---	---	---	---	---	---	---	---	---
11. Kafr El-Dawar	3 x 110	330	---	---	---	110	220	220	220	330	330	330	330
12. Cairo West	1 x 87	87	---	---	---	---	87	87	87	87	87	87	87
13. Abu Qir I	2 x 150	300	---	---	---	---	---	300	300	300	300	300	300
14. Ismailia	2 x 150	300	---	---	---	---	---	---	---	300	300	300	300
15. Abu Qir II	2 x 150	300	---	---	---	---	---	---	300	300	300	300	300
16. Suez I	2 x 150	300	---	---	---	---	---	---	---	300	300	300	300
17. New Plant I	2 x 300	600	---	---	---	---	---	---	---	---	300	600	600
18. Sidi Krir I	1 x 600	600	---	---	---	---	---	---	---	---	---	---	600
Total			934	1035	1051	1161	1355	1665	1987	2734	2995	3295	3859
COMBUSTION TURBINE STATIONS*													
1. El-Max	2 x 14	28	12	24	24	24	24	24	24	24	24	24	24
2. Suez	1 x 17			17	17	17	17	17	17	17	17	17	17
3. Ismailia	1 x 23				23	23	23	23	23	23	23	23	23
4. Cairo North	1 x 23				23	23	23	23	23	23	23	23	23
5. Port Said	2 x 23								46	46	46	46	46
6. Fayum	1 x 23				23	23	23	23	23	23	23	23	23
7. Helwan	120 MW Total					120	120	120	120	120	120	120	120
8. Talka	180 MW Total					180	180	180	180	180	180	180	180
Total			12	41	110	410	410	410	456	456	456	456	456
HYDRO STATIONS**													
High Dam	12 x 175	2100***)											
Aswan	7 x 46 + 2 x 11.5	345***)		1400	1550	1700	1800	2000	2200	2360	2360	2360	2360
Total System Capability				2477	2711	3271	3568	4075	4643	5550	5811	6111	6675

*Winter Ratings.

**Hydro Capability varies as a function of load magnitude and distribution in the UPS network.

***High Dam output is usually limited to 1750 MW because units must be removed from service in pairs when under maintenance due to common penstock arrangements, and one or more units are consistently out for maintenance. Aswan capability is 260 MW due to reduced head after construction of High Dam.

1.3 Generating Capacity Outages:

In addition to any limitations in the power output capabilities of the units the high incidence of outages of many of the units must be considered in preparing future system expansion plans and schedules.

Based on statistics acquired by the Egyptian Electricity Authority for the years 1971 through 1975, a projection was made up to the year 1983. On the average, a total of 888 MW outage was forseen for the year 1983 representing 16.1% of the total installed capacity. This figure is much smaller than its 1971 - 1975 counterpart (26.6%) due to the new installed units and improved maintanance.

1.4 Load Forecast:

The Egyptian Electricity Authority has undertaken many load forecast studies for the determination of the future demand of Egypt until 1985. Most of the presently employed methods of load forecasting have been extensively studied by the planning personnel of the Egyptian Electricity Authority.

A high growth rate of peak load and energy use can be expected at first to compensate for the low and erratic growth rates that prevailed because of the war years. An initial high growth rate also can be expected in connection with the new changes in Egypt's economic policies. Using these criteria, it was forecasted that up through 1980 the load will double at

a seven year interval rate; in other words at a cumulative annual growth rate of 10.40%.

Studies undertaken by the planning group of the Studies and Research Sector of the Egyptian Electricity Authority have shown that the average rate of growth of electrical energy consumption in Egypt for the last decade excluding large industries, even though erratic on a year-by-year basis has been at an average rate of 10.44%.

Separate individual studies of the various sectors of the Egyptian economy (residential, commercial, small industrial, agricultural etc.) up through the year 1980 have indicated an expected continuation of this 10.4% growth rate. For these reasons, it is expected that such a growth rate of 10.4% will continue up through the year 1980. It is also highly improbable that such a rate can be maintained indefinetly. Therefore, it is assumed that after 1980 up through the year 1985 the normal load will grow at a rate which would cause it to double again in a little less than 8 years or at an annual cumulative rate of 9.4%.

Later in this study an analytical formulation of the growth function will be necessary to estimate the prospective cost of different power plants.

An approximate function based on the following figure can be deduced as follows:

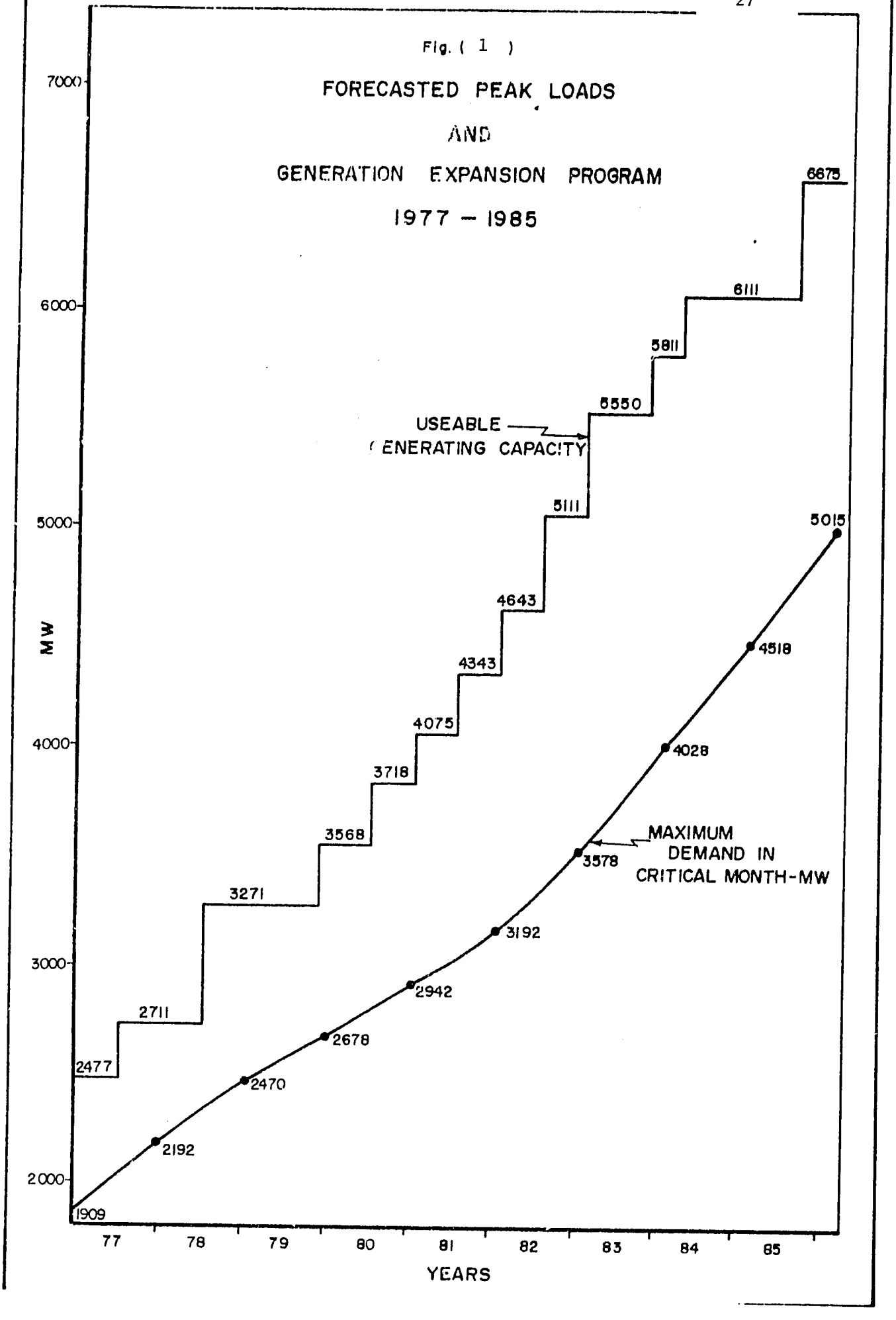
Fig. (1)

FORECASTED PEAK LOADS

AND

GENERATION EXPANSION PROGRAM

1977 – 1985



Assuming: y = growth (MW)

x = years (measured from 1976)

$$\therefore \text{ rate of growth} = \frac{dy}{dx} = 0.1\,y$$

$$dx = \frac{dy}{0.1y}$$

$$\therefore x = 10 \ln y$$

$$\therefore y = e^{0.1\,x}$$

which is obviously applicable only over the limited number of years of this study (1976 - 1985)

If B = growth rate

$$\therefore B = \frac{dy}{dx} = 0.1\,y \;\ldots\ldots\; (1.1)$$

Table (2) summarizes the original forecasted peak demands and energy requirements. It must be emphasized that regular load forecasting produced a very large rate of growth for the years 1976 through 1980 and a suppressed growth rate for the years 1980 to 1985.

Table (2)

Final Peak Demand and Energy Forecast 1976 - 1985

	76	77	78	79	80	81	82	83	84	85
Peak Demand MW	1909	2192	2470	2678	2924	3192	3578	4028	4518	5045
Energy 10^9 KWH	11.6	13.5	15.2	16.8	18.5	20.5	22.6	25.0	27.7	30.6

Fig. (1), meanwhile, gives maximum demand for the years 1977 through 1985. The annual increase of the maximum demand varied between 8.4% and 12.7% with an average cumulative growth rate for 1976 through 1985 of 11.4% and a corresponding 11.3% average compound rate for the generated energy. The study made by Sanderson and Porter (1977) accounted for an extra 5%, in estimating the maximum demand as a forecast error which may originate due to one or more of the factors mentioned earlier in this report.

1.5 Expected New Generating Plants:

Table (3) gives the scheduled commercial operation for the new generating units.

Table (3)

Estimated Dates of Commercial Operation of Generating Units

PLANT	CAPACITY MW	TYPE	DATE
Helwan	4 x 30	Gas Turbine	1979
Talkha	6 x 30	Gas Turbine	1979
Abu Qir 1st Phase	2 x 150	Steam	1980
Abu Air 2nd Phase	2 x 150	Steam	1981
Ismailia	2 x 150	Steam	1982
Suez I	2 x 150	Steam	1980
Sidi Kreir I	1 x 600	Nuclear	1985

2. METHODOLOGY:

Some means had to be sought to assess the econmical feasibility of the project aimed at expanding the generation capacity of the unified power system of A. R. Egypt. A method which adequately suits this type of analysis was developed by Prof. M. Weitzman of the Massachusetts Institute of Technology, U.S.A. The method offers relatively simple investment criteria for capacity expansion.

2.1 Identification of the Method:

The method characterizes an optimal policy for expanding capacity when investments must be made in discrete projects. As applied to power systems, the generating capacity is expanded by investing in individual projects with a number of alternatives. Distinction is made between thermal and nuclear power plants which are repeatable projects, and hydro-electric projects which are very large and are naturally tied to specific locations. The problem is to choose the project to be executed next.

The solution is complicated due to the initial excess capacity which renders the simple lowest-cost-per-kilowatt criterion ineffective. An alternative would be to analyze the investment strategy as an entire programming problem formulated over a large time scale which can be most complicated and time-consuming.

The method developed by Weitzman assigns to each project a "recovery cost" which ranks it relative to other projects.

The project with the lowest recovery cost is executed next. The formula giving the recovery cost of a project is a relatively straight forward adjustment of the cost per kilowatt which takes account of the project size.

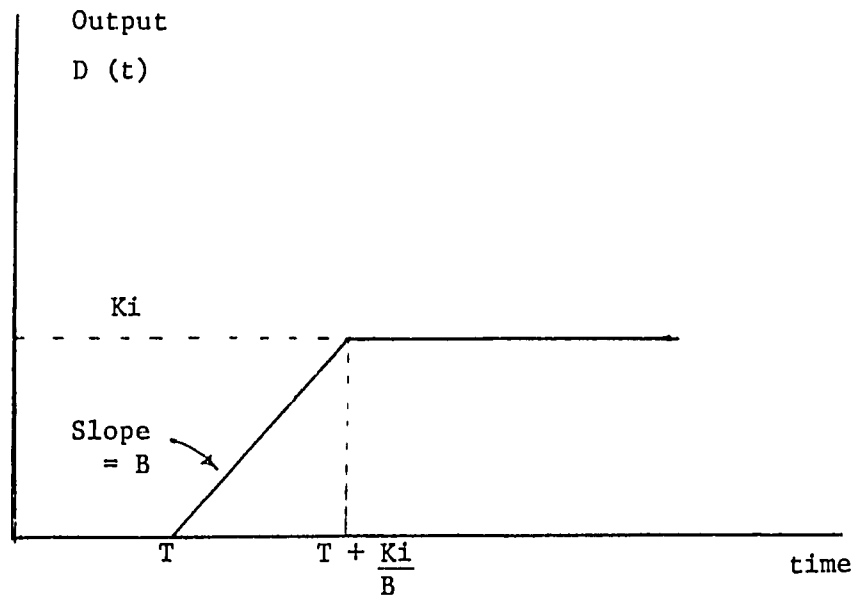
2.2 Assumptions and Analysis:

The energy demand schedule D (t) of Fig. (2) is assumed linear for the near future

$$D(t) = A + Bt \quad \ldots\ldots\ldots\ldots (2.1)$$

Let project i (one of many different projects) has a capacity of K_i. Project i is chosen to increase the rated capacity of the system by coming on line at time T when there is zero excess capacity in the system. That is, at time t, $T \leqslant t \leqslant T + \frac{Ki}{B}$, the output of project i is B (t - T), leaving excess capacity $K_i - B(t - T)$. At time $T + \frac{Ki}{B}$, the output reaches full rated capacity K_i and remains there forever.

Fig. (1.3)



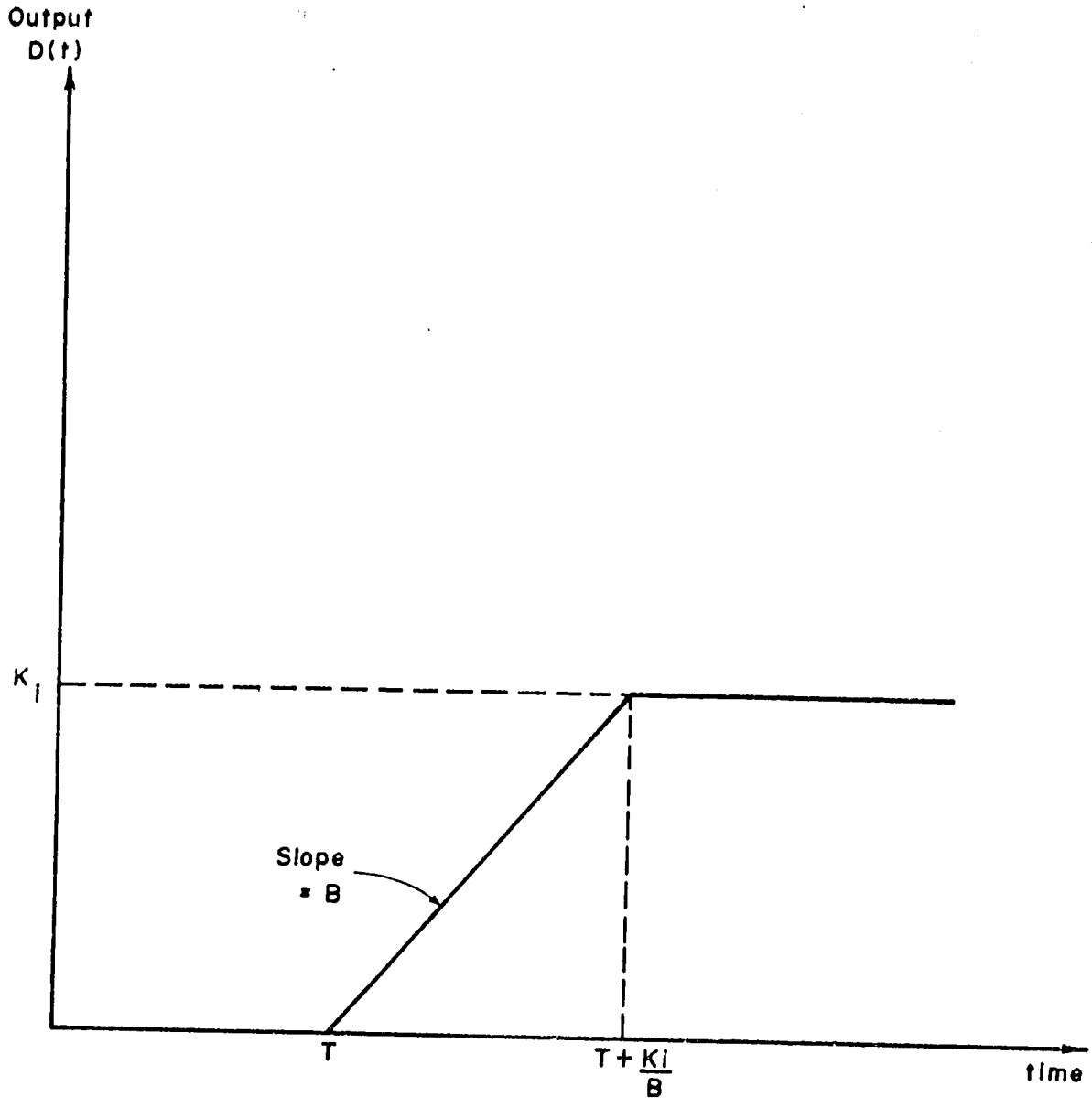


Fig. (2)

If project i is chosen to begin coming on line at T, it forces outlays to be made at time t as given by the project cost function F_i (t - T). When $t < T$, project i is in the primary construction phase. It is during this phase that are incurred the major construction costs associated with creating an installation of size K_i. At times from T to $T + \frac{Ki}{B}$, basic overhead installations have already been completed and secondary capacity is filled in according to the prescribed linear schedule. Finally, for times after $T + \frac{Ki}{B}$, all construction has been completed and the only outlays are variable operating costs.

2.3 Optimal Capacity Expansion:

The basic problem is to schedule capacity expanding projects to come on line meeting final demand at minimum present discounted cost. Let the hth plant installed be a project of type j(h) and let it begin operating at time T_h. Mathematically, the problem is to introduce projects in the optimal order which minimizes

$$\int_0^\infty \sum_{h=1} F_{j(h)}(t - T_h)\, e^{-rt}\, dt \qquad \ldots\ldots \quad (2.2)$$

Subject to

$$T_1 = \overline{T}_1 \qquad \ldots\ldots \quad (2.3)$$

$$T_{h+1} = T_h + \frac{K_{j(h)}}{B} \qquad \ldots\ldots \quad (2.4)$$

The objective function (2.2) is the present discounted value of all costs incured in expanding capacity. Time

T_1 (= $\bar{T}_1$, given) is the first time when no excess capacity exists in the system and a new plant must begin operation. Thereafter as expressed by (2.4), new capacity comes on line at times when the old capacity just exactly covers demand. The use of the non-repeatable projects more than once is precluded.

The model as it is formulated has enough structure to induce a very simple characterization of an optimal solution. A recovery cost is assigned to each project. That project is next under taken which has the lowest recovery cost among all remaining alternatives.

Thus, lumpy projects can be meaningfully ranked as investment priorities.

Even for complicated investment situations, the project ranking which emerges as a solution to the simplified model (2.2) - (2.4) might serve as a rough screening device or as a starting point for more sophisticated analysis, like integer programming. The fact that it is possible to sharply characterize an optimal solution makes problem (2.2) - (2.4) a natural preliminary to any more general analysis.

The recovery cost of a project is defined as the hypothetical payment per unit of output which would make the project just break even. The recovery cost for project i, C_i,

is defined as the solution to

$$\int_{0}^{Ki/B} C_i \, Bt \, e^{-rt} \, dt + \int_{Ki/B}^{\infty} C_i \, k_i \, e^{-rt} \, dt$$

$$= \int_{-\infty}^{\infty} F_i(t) \, e^{-rt} \, dt \quad \ldots\ldots\ldots \quad (2.5)$$

The right hand side of eq. (2.5) is the total cost of project i, discounted back to the time when it first starts coming on line. The left hand side is the hypothetical discounted revenue accumulated by charging a price of C_i per unit of output (the first integral covers the expansion phase and the second full capacity operation). Integrating out the left hand side of (2.5) yields the formula.

$$C_i = \frac{r^2 \int_{-\infty}^{\infty} F_i(t) \, e^{-rt} \, dt}{B \, (1 - e^{-rK_i/B})} \quad \ldots\ldots (2.6)$$

Although the notion of recovery cost has intuitive appeal, the following theorem gives it a rigorous basis as a criterion for selecting among discrete projects of different sizes:

"A necessary and sufficient condition for an optimal solution of problem (2.2) - (2.4) is the rule: Always select next the project with lowest recovery cost."

Equation (2.6) may be simply rewritten as

$$C_i = \frac{r^2 \cdot \gamma_i}{B\,(1 - e^{-r\ Ki/B})} \qquad \ldots\ldots\ldots\ldots (2.7)$$

Because it is so easy to calculate recovery costs, sensitivity analysis is made specially simple. The effects on project ranking of changing such parameters as the interest rate r, growth rate of demand B, plant capacity Ki or cost estimate γ_i, is easily determined.

It is also easy to say how an optimal investment strategy changes when certain projects are added to or deleted from the list of prespective candidates.

2.4 Application to Power Generation

The above formulation will be applied to various power generation plants which are intended for construction in the near future. The following remarks are made:

1 - A power plant, in general, does not begin production before its completion and commissioning. The contradiction of this fact with the hypothesis of Fig. (3) is avoided by assuming the production to follow the growth profile of Fig. (1), linearized over the construction years of the respective plant.

2 - It is realized that a power plant has a nominal life duration of 20 - 30 years but is considered, here, to be infinitely long relative to the construction years in order to satisfy Weitzman's model.

3. COMPUTATIONS AND RESULTS:

Our calculations will consider some of the new projected plants from the year 1975 to 1985.

- steam power plants:

  i. Abu Quir I & II

  ii. Abu Quir I, II, III and IV

  iii. Ismailia

  iv. Suez

- Nuclear power plants:

  Sidi-Krier

- Gas turbines plants:

  i. Talkha

  ii. Helwan

3.1 Data in Common:

A part of the data is common for different plants such as:

(a) Interest rate:

The interest rate during the construction period is taken to be 8%/year on the total cost (local and equivalent currency).

(b) Load Growth:

The predicted load growth till 1985 obeys the curve of Fig. (1).

To satisfy the foregoing model, two assumptions are made:

i. The growth rate is assumed constant at its value when the plant reaches its full capacity. This constant value according to the equation derived in section (1.4) is always equal to 10% of the demand at that date.

ii. At the time any plant is commissioned no excess capacity is assumed to exist in the system.

(c) Equivalent currency: The following rates of exchange are used.

1 U. S. Dollar = 0.7 L. E.

1 D. M. = 0.3 L. E.

1 F. F. = 0.138 L. E.

(d) Production Cost:

- The number of operating hours is taken fixed for all steam plants at 7,000 hr/year.

- load factor = 0.8

  i. for steam plants

  - Cost of fuel = 67 $/metric ton = 46.9 LE/Metric ton
  - The heat rate and operation and maintenance (O&M) costs for steam plants are given by the following table, where

Production costs = (O. & M.) cost

+ (46.9 x Heat Rate)

Table 4

Production Cost of Steam Plants

Rating MW	Heat Rate ton/MHW	O & M costs L.E./MWH	Production Cost L.E./MWH
150	0.235	4.0	15.02
300	0.230	3.8	14.59
400	0.228	3.6	14.29
500	0.226	3.5	14.10
600	0.225	3.4	13.95

ii. for gas turbines: (based on 30 MW units)

Heat rate = 0.5 metric ton/MWH

O. & M. cost = 8 L. E./MWH

Cost of fuel = 67 $/metric ton = 46.9 L.E./metric ton

Production cost = 8 + 46.9 x 0.5 = 31.45 L. E./MWH

iii. for nuclear plants

Production cost = 6.3 L. E./MWH

3.2 Calculations:

Steam plants:

i. Abu-Quir I & II:

It is composed of 2 units each of 150 MW

$\therefore$ Ki = 2 x 150 = 300 MW

Construction costs is given by the following table:

YEARS	L.C. L.E.x 10^3	E.C. L.E.x 10^3	T.C. L.E.x 10^3
1976	75	6265	6340
1977	1200	6256	7456
1978	3405	29315	32720
1979	8030	25650	33680
1980	7980	5603	13583

L.C. = local currency
T.C. = total cost

Equivalent currency (E. C.) from French Franc

B = 294.2 MW/year

$$\text{Total construction cost} = [6340\ (1.08)^4 + 7456\ (1.08)^3 + 32720\ (1.08)^2 + 33680\ (1,08) + 13583 \times 10^3$$
$$= 106,139.92 \times 10^3 \text{ L. E.}$$

$$\text{Variable cost/year} = 300 \text{ MW} \times 0.8 \text{ (load factor)} \times 7000 \text{ hr/year} \times 15.02 \text{ LE/MWH}$$
$$= 25,233.6 \times 10^3 \text{ L. E./year}$$

$$\text{Present discounted cost} = \frac{25{,}233.6 \times 10^3}{0.08} = (P.\ D.\ C.)$$

$$P.D.C. = 315{,}420 \times 10^3 \text{ L. E.}$$

Total cost: $(\gamma i) = (106{,}139.92 + 315{,}420) \times 10^3$

$$= 321{,}559.92 \times 10^3 \text{ L. E.}$$

$$C_i = \frac{r^2 \cdot \gamma_i}{B\,(1 - e^{-\frac{rKi}{B}})} = 117.06 \times 10^3 \text{ L. E./MW}$$

ii. <u>Abu-Quir I, II, III, & IV</u>

It is composed of 4 units each of 150 MW

$$K_i = 4 \times 150 = 600 \text{ MW}$$

The construction cost is given by the following table:

YEARS	L.C. in L.E. x 10^3	E.C. in L.E. x 10^3	T.C. in L.E. x 10^3
1976	75	6265	6340
1977	1205	10349	11554
1978	5575	29359	34934
1979	12755	56448	69203
1980	15200	28787	43987
1981	6540	6300	12840

Equivalent currency (E. C.) from F.F.

B = 319.2 MW /year

$$\text{Total construction cost} = 6340\ (1.08)^5 + 11554\ (1.08)^4 + 34934\ (1.08)^3 + 69203\ (1.08)^2 + 43987\ (1.08) + 12840$$

$$= 210{,}105.75 \times 10^3 \text{ L.E.}$$

$$\text{Variable cost/year} = 600 \times 0.8 \times 15.02 \times 7000$$

$$= 50{,}462.7 \times 10^3 \text{ L.E.}$$

$$\text{P. D. C.} = \frac{50{,}462.7 \times 10^3}{0.08} = 630{,}840 \times 10^3 \text{ L.E.}$$

$$\gamma_i = (210{,}105.75 + 630{,}840) \times 10^3$$

$$= 840{,}945.75 \times 10^3 \text{ L.E.}$$

$$C_i = \frac{r^2 \cdot \gamma_i}{B\ (1 - e^{-\frac{rKi}{B}})} = 120.77 \times 10^3 \text{ L. E./MW}$$

iii. Ismailia:

It is composed of 2 units each of 150 MW

$K_i = 2 \times 150 = 300$ MW

The construction cost is given by the following table:

YEARS	L.C. in L.E. x 10^3	E.C. in L.E. x 10^3	T.C. in L.E. x 10^3
1978	117	1572	1689
1979	4860	19948	24808
1980	4186	50140	54326
1981	3875	25536	29411
1982	855	3421	4276

E.C. from U. S. Dollars

$B = 357.8$ MW/year

Total construction cost $= 1689 \cdot (1.08)^4 +$

$24808\ (1.08)^3 + 54326\ (1.08)^2$

$+ 29411\ (1.08) + 4276$

$= 132{,}954.53 \times 10^3$ L.E.

Variable cost/year $= 300 \times 0.8 \times 15.02 \times 7000$

$= 25{,}233.6 \times 10^3$ L.E.

P. D. C. $= \dfrac{25{,}233.6 \times 10^3}{0.08}$

$= 315{,}420 \times 10^3$ L.E.

$\gamma_i = (315{,}420 + 132{,}954.53) \times 10^3$

$= 448{,}374.53 \times 10^3$ L.E.

$$C_i = \frac{r^2 \cdot \gamma_i}{B\left(1 - e^{-\frac{rKi}{B}}\right)}$$

$= 123.62 \times 10^3$ L.E./MW

iv- Suez:

It is formed of 2 units each of 150 MW

$K_i = 150 \times 2 = 300$ MW

Construction cost is given by the following table:

YEARS	L.C. in L.E. x 10^3	E.C. in L.E. x 10^3	T.C. in L.E. x 10^3
1977	620	6247	6867
1978	3150	17550	20750
1979	7415	60555	67970
1980	5415	6952	12467

E. C. from D. M.

$B = 294.2$ MW / year

Total construction cost $= 6867(1.08)^3 + 20750(1.08)^2 + 67970\ (1.08) + 12467$

$= 118{,}727.8 \times 10^3$ L. E.

Variable cost/year $= 300 \times 0.8 \times 15.02 \times 7000$

$= 25{,}233.6 \times 10^3$ L.E.

P. D. C. $= \dfrac{25{,}233.6 \times 10^3}{0.08}$

$= 315{,}420 \times 10^3$ L.E.

$\gamma_i = (118{,}727.8 + 315{,}420) \times 10^3$

$= 434{,}147.8 \times 10^3$ L.E.

$$C_i = \frac{r^2 \cdot \gamma_i}{B(1 - e^{-\frac{rKi}{B}})}$$

$= 120.56 \times 10^3$ L.E./MW

Nuclear Power Plants:

Sidi-Krier

K_i = 620 MW

B = 504.5 MW/year

YEARS	T. C. in L. E. x 10^3
1980	59,922
1981	41,410
1982	121,713
1983	183,968
1984	137,631
1985	63,596

Note:

In the construction cost, 5% interest was included.

$\therefore$ Total construction cost = $59{,}922\ (1.03)^3 + 41410\ (1.03)^4$

$121{,}713\ (1.03)^3 + 183968\ (1.03)^2 + 137631(1.03)$

$+ 63{,}596$

$= 649{,}600 \times 10^3$ L. E.

Variable cost/year $= 620 \times 0.8 \times 6.3 \times 7000$

$= 21{,}873.6 \times 10^3$ L.E.

P. D. C. $= \dfrac{21{,}873.6 \times 10^3}{0.08}$

$= 273{,}420.00 \times 10^3$ L.E.

γ_i $= (643{,}600 + 273{,}420.00) \times 10^3$

$= 923{,}020 \times 10^3$ L. E.

C_i $= \dfrac{r^2 \cdot \gamma_i}{B(1-e^{\frac{-rKi}{B}})}$

$= 125.05 \times 10^3$ L.E./MW

Gas turbines:

i. Talkha

It consists of 6 units each of 30 MW rating

$K_i = 6 \times 30$

$= 180$ MW

YEARS	L.C. in L.E. x 10^3	E.C. in L.E. x 10^3	T.C. in L.E. x 10^3
1978	705.1	30542 x 0.7	22,086.5
1979	810.5	6990.08 x 0.7	5,703.56

*Note: These values include 8% interest

$B = 267.8$ MW /year

$\therefore$ Total construction cost $= (22{,}084.5 + 5{,}703.56) \times 10^3$

$= 27{,}788.06 \times 10^3$ L.E.

Variable cost/year $= 180 \times 0.8 \times 31.5 \times 7000$

$= 31{,}752 \times 10^3$ L.E.

Present discount cost $= \dfrac{31{,}752 \times 10^3}{0.08}$

$= 396{,}900 \times 10^3$ L.E.

$\gamma_i = (396{,}900 + 27{,}788) \times 10^3$

$= 424{,}688 \times 10^3$ L.E.

$$C_i = \frac{r^2 \cdot \gamma_i}{B(1-e^{-\frac{rKi}{B}})}$$

$= 193.87 \times 10^3$ L.E./MW

ii. Helwan:

It consists of 4 units each of 30 MW

K_i = 4 x 30 = 120 MW

B = 267.8 MW /year

The construction cost is given by the following table and it includes 8% interest during years of construction

YEAR	L.C. in L.E. x 10^3	E.C. in L.E. x 10^3	T.C. in L.E. x 10^3
1978	779.8	21,479 x 0.7	15,815.1
1979	549.7	5,721 x 0.7	4,554.4

Total construction cost = 20,369.5 x 10^3 L.E.

Variable cost/year = 120 x 0.8 x 31.45 x 7000

= 21,134.4 x 10^3 L.E.

P.D.C. $= \frac{21,134.4 \times 10^3}{0.08}$

= 264,180 x 10^3 L.E.

γ_i = (20,369.5 + 264,180) x 10^3

= 284,549.5 x 10^3 L.E.

$C_i = \frac{r^2 \gamma_i}{B\,(1-e^{\frac{-rKi}{B}})}$

= 193.12 x 10^3 L.E./MW

4. SUMMARY OF RESULTS

The results of the above calculations can be summarized in the following table:

Table (5)

Name of Station	CAP. MW	Years	B MW/year	Ci 10^3 L.E./MW
STEAM				
ABK I & II	300	76-80	294.2	117.06
ABK I, II, III & IV	600	76-81	319.2	120.77
Ismailia	300	78-82	357.8	123.62
Suez I	300	77-80	294.2	120.56
NUCLEAR				
Sidi-Krier	620	80-85	504.5	125.05
GAS TURBINE				
Talkha	180	78-79	267.8	193.87
Helwan	120	78-79	267.8	193.12

The following conclusions may be drawn.

1. Recovery costs per output of Gas Turbine plants are notably higher than those of steam and nuclear plants. This is to be expected if a gas turbine plant is operated as a base capacity rather than as peaker. Since a gas turbine plant is known for its rapid and economical cycling ability. The contribution of the production cost to the total cost (γ_i) becomes excessive and leads to this result.

2. As an example of a comparison of a steam plant with a gas turbine one for a given growth rate (B), the ABK I & II steam and Talkha gas turbine plants are chosen. It is of interest to calculate the number of operating hours/year of the latter which equates the overall recovery costs (C_i) of both plants.

If (T) is assumed to be the break even utilization hours/year of the gas turbine plant,

Then:

$$C_i = 117.53 \times 10^3$$

$$= \frac{(0.08)^2 \left[27{,}788{,}060 + \frac{180 \times 0.8 \times 31.5\ T}{0.08}\right]}{267.8 \left[1 - e^{-\frac{0.08 \times 180}{267.8}}\right]}$$

$$T = 4050.63 \text{ hours/year}$$

It is clear that a gas turbine unit will not be economical if it runs more than 4050 hours per year.

3. It seems that the complete complex of ABK plants is comparable from a recovery cost point of view to the Nuclear plant of SIDI-KRIER. This is explained by the fact that a high growth rate of the latter is some how compensated by a reduced total cost of the former. It should, however, be borne in mind that the future availabilities of the two corresponding fuels are not identical. A possible future shortage in fossil fuel may give more credit to the choice of a nuclear plant. Later in this part, the effects of fuel price escallation are examined.

4. The method introduced by Weitzman is proven in this work to be a simple indicative means of comparing different power projects for capacity expansion.

5. PARAMETRIC ANALYSIS OF RECOVERY COST STUDY:

The foregoing section used available data in estimating a cost recovery index for each of the prospective power generation projects in Egypt. These indices formed a sound ground for assessing the economical feasibility of each project and further offered a reliable tool for comparing the prospects of each project.

In order to be able to probe into the preceding results with confidence, a parametric analysis of them would be necessary. A sensitivity evaluation of the effect of each one of the parameters involved in the above study would serve the following purposes:

1. Justification of the assumptions made throughout the recovery cost analysis.

2. Clarification of the extent of the errors that could have been created due to incomplete, or sometimes inaccurate data related to load forecast and future cost estimates.

3. Addition of great freedom in reapplying the presented techniques at different situations in time and space.

Basically, a sensitivity analysis is achieved by including small perturbation in each of the studied parameters, one at a time. The response of the objective function in question is detected and its significance is judged.

In this study, the objective function is the recovery cost (C_i) whose variables are the interest rate (r), the total cost (γ_i), plant capacity (K_i) and the growth rate of demand (B).

$$C_i = \frac{r^2 \cdot \gamma_i}{B\,[1-e^{-\frac{rKi}{B}}]} \qquad \ldots\ldots.(5.1)$$

Of these parameters a sensitivity study of only the interest rate (r) and the growth rate of demand (B) can be meaningfull. This is so since both (r) and (B) appear twice in the objective function in opposing roles.

On the other hand, it is clear that (C_i) is directly proportional to (γ_i), and that (C_i) decreases in a quasi-exponential fashion as the capacity (K_i) increases.

5-1 The Interest Rate:

As outlined earlier in this report, the interest rate (r) was taken in all computations to be 8%. This value is a realistic, yet crude estimate of that parameter. Many external factors interfere in deciding the value of (r).

Among these factors are the commercial protocols between Egypt and other developed nations, the local situation of construction work and the nature of loans from international agencies.

A relatively wider range of variation in the value of (r) is going to be speculated. Its effect is tested for values

ranging between 6% and 12%, inclusive.

The results are given in tables (6) to (12). A graphical representation of the effect of (r) on the recovery cost (C_i) is displayed in fig. (3). Over the given range of (r), the value of the recovery cost increases with the interest rate, and this increase appears linear. A verification of this linearity is made by looking upon the variation of (r) with (C_i) as regression of two statistical samples.

A linear fitting of the functions of fig. (5.1) is numerically achieved to express (C_i) in the form

$$C_i = a_i + b_i \times r \quad \text{L. E./MW} \qquad .....(5.2)$$

The results of the linear fitting are given in Table (13) for the seven studied power plants.

TABLE 6

(r = 6%)

NAME OF STATION	CAP MW	YEARS	B MW/Year	T.C.C. x 10^3 L.E.	P.D.V. x 10^3 L.E.	γ_i x 10^3 L.E.	C_i x 10^3 L.E.
STEAM							
ABK I & II	300	76-80	294.2	102,932.31	420,560	523,492.31	107.93
ABK I,II,III,IV	600	76-81	319.2	201,900.67	841,045	1,043,020.67	110.29
ISMAILIA	300	78-82	357.8	128,171.4	420,560	548,731.4	112.53
SUEZ I	300	77-80	294.2	116,008.61	420,560	536,568.61	110.63
NUCLEAR							
SIDI-KRIER	620	80-85	504.5	621,740.13	364,560	986,300.13	99.01
GAS TURBINE							
TALKHA	180	78-79	267.8	27,379.09	529,200	556,579.09	189.29
HELWAN	120	78-79	267.8	20,076.63	352,240	372,316.63	188.67

T.C.C. = Total Construction Cost

P.D.V. = Present Discount Value

TABLE 7

(r = 7%)

NAME OF STATION	CAP MW	YEARS	B MW/year	T.C.C. x 10^3 L.E.	P.D.V. x 10^3 L. E.	γ_i x 10^3 L. E.	C_i x 10^3 L.E./MW
STEAM							
ABK I & II	300	76-80	294.2	104,526.1	360,480	465,006.1	112.42
ABK I, II, III & IV	600	76-81	319.2	205,969.37	720,895.71	926,865.09	115.4
ISMAILIA	300	78-82	357.8	130,548.41	360,480	491,028.41	117.97
SUEZ I	300	77-80	294.2	117.363.95	360,480	477,843.95	115.52
NUCLEAR							
SIDI-KRIER	620	80-85	504.5	635,524.98	312,480	948,004.98	111.7
GAS-TURBINE							
TALKHA	180	78-79	267.8	27,583.57	453,600	481,183.57	191.56
HELWAN	120	78-79	267.8	20,223.06	301,920	322,143.06	190.38

T. C. C. = total construction cost.

P. D. V. = present discount value.

TABLE 8

(r = 8 %)

NAME OF STATION	CAP MW	YEARS	B MW/year	T.C.C. x 10^3 L.E.	P.D.V. x 10^3 L. E.	γ_i x 10^3 L. E.	C_i x 10^3 L.E./MW
STEAM							
ABK I & II	300	76-80	294.2	106,139.92	315,420	421,559.92	117.06
ABK I, II, III & IV	600	76-81	319.2	210,105.75	630,840	840,945.75	120.77
ISMAILIA	300	78-82	357.8	132,954.53	315,420	448,374.53	123.62
SUEZ I	300	77-80	294.2	118,727.8	315,420	434,147.8	120.56
NUCLEAR							
SIDI-KRIER	620	80-85	504.5	649,600	273,420	923,020	125.05
GAS-TURBINE							
TALKHA	180	78-79	267.8	27,788.06	396,900	424,688	193.87
HELWAN	120	78-79	267.8	20,369.5	264,180	284,549.5	193.12

T. C. C. = Total construction cost

P. D. V. = present discount value

TABLE 9

(r = 9 %)

NAME OF STATION	CAP MW	YEARS	B MW/year	T.C.C. x 10^3 L.E.	P.D.V. x 10^3 L. E.	γ_i x 10^3 L. E.	C_i x 10^3 L.E./MW
STEAM							
ABK I & II	300	76-80	294.2	107,774	280,373.33	383,147.33	121.37
ABK I, II, III & IV	600	76-81	319.2	214,310.75	560,696.67	775,007.41	126.36
ISMAILIA	300	78-82	357.5	135,389.95	280,373.33	415,763.28	129.49
SUEZ I	300	77-80	294.2	120,100.34	280,373.33	400,473.67	125.74
NUCLEAR							
SIDI-KRIER	620	80-85	504.5	663,970.72	243,040	907.010.72	139.03
GAS-TURBINE							
TALKHA	180	78-79	267.8	27,992.55	352,300	360.792.55	196.21
HELWAN	120	78-79	267.8	20,515.94	234,826.67	255,342.6	195.39

T. C. C. = total construction cost.

P. D. V. = present discount value

TABLE 10

(r = 10%)

NAME OF STATION	CAP MW	YEARS	B MW/YEAR	T.C.C. x 10^3 L.E.	P.D.V. x 10^3 L.E.	γ_i x 10^3 L.E.	C_i x 10^3 L.E.
STEAM							
ABK I & II	300	76-80	294.2	109,428.53	252,336	361,764.53	126.84
ABK I,II,III & IV	600	76-81	319.2	218,585.33	504,672	723,257.33	132.23
ISMAILIA	300	78-82	357.8	137,854.87	252,336	390,190.87	135.59
SUEZ I	300	77-80	294.2	121,481.48	252,336	373,817.48	131.07
NUCLEAR							
SIDI-KRIER	620	80-85	504.5	678,642.74	218,736	897,378.74	153.81
GAS TURBINE							
TALKHA	180	78-79	267.8	28,197.03	317,520	345,717.03	198.59
HELWAN	120	78-79	267.8	20,662.37	211,344	232,006.37	197.7

T.C.C. = Total Construction Cost

P.D.C. = Present Discount Value

TABLE 11

(r = 11%)

NAME OF STATION	CAP MW	YEARS	B MW/YEAR	T.C.C. x 10^3 L.E.	P.D.V. x 10^3 L.E.	γ_i x 10^3 L.E.	C_i x 10^3 L.E.
STEAM							
ABK I & II	300	76-80	294.2	111,103.74	229,396.36	340,500.1	131.98
ABK I,II,III & IV	600	76-81	319.2	222,930.46	458,792.73	681,723.19	138.35
ISMAILIA	300	78-82	357.8	140,349.49	229,396.36	369,745.85	141.92
SUEZ I	300	78-80	294.2	122,871.3	229,396.36	352,267.66	136.54
NUCLEAR							
SIDI-KRIER	620	80-85	504.5	693,621.76	198,850.91	892,472.67	169.29
GAS TURBINE							
TALKHA	180	78-79	267.8	28,401.52	288,654.55	317,056.06	201.01
HELWAN	120	78-79	267.8	20,808.81	192,130.91	212,939.72	200.04

T.C.C. = Total Construction Cost

P.D.C. = Present Discount Value

TABLE 12

(r = 12%)

NAME OF STATION	CAP MW	YEARS	B MW/YEAR	T.C.C. x 10^3 L.E.	P.D.V. x 10^3 L.E.	γ_i x 10^3 L.E.	C_i x 10^3 L.E.
STEAM							
ABK I & II	300	76-80	294.2	112,799.82	210,280	323,079.82	137.3
ABK I,II,III & IV	600	76-81	319.2	227,347.13	420,560	647,907.13	144.74
ISMAILIA	300	78-82	357.8	142,873.98	210,280	353,153.98	148.49
SUEZ I	300	77-80	294.2	124,269.84	210,280	334,549.84	142.17
NUCLEAR							
SIDI-KRIER	620	80-85	504.5	708,913.56	182,280	891,193.56	185.52
GAS TURBINE							
TALKHA	180	78-79	267.8	28,606	264,600	293,206	203.46
HELWAN	120	78-79	267.8	20,955.24	176,120	197,075.24	202.42

T.C.C. = Total Construction Cost

P.D.C. = Present Discount Value

TABLE 13 a

STATION	TYPE	$C_i = f(r)$
ABK I & II	STEAM	$C_i = 78.16 + 4.89\ r$
ABK I,II,III & IV	STEAM	$C_i = 75.22 + 5.74\ r$
ISMAILIA	STEAM	$C_i = 76.02 + 5.99\ r$
SUEZ I	STEAM	$C_i = 78.73 + 5.26\ r$
SIDI KRIER	NUCLEAR	$C_i = 10.81 + 14.41\ r$
TALKHA	GAS TURBINE	$C_i = 175.03 + 2.36\ r$
HELWAN	GAS TURBINE	$C_i = 174.84 + 2.29\ r$

5.1.1. Discussion

i. The recovery costs C_i for all investigated generation plants appear to be linearly dependant on r over the range of (r) between 6% and 12% inclusive.

ii. The sensitivity of the recovery cost of nuclear power plant to the change in the interest rate is the most significant being equal to about 14.41 L.E./MW/%. Next are steam power plants with approximately equal sensitivities of (4.89 - 5.99) L.E./MW/%. The least sensitive of all are gas turbine plants whose recovery costs vary with the interest rate at only about (2.29 - 2.36) L.E./MW/%.

iii. The variation of the interest rate does not alter the status of gas turbine plants being the most expensive when used to supply base loads.

iv. For the same output capacity (about 600 MW), the nuclear plant (e.g. Sidi-Krier) will be more economically effective than its steam counter part (Abu-Qir) when the interest rate

TABLE 13 b

NAME OF STATION	C_i x 10^3 L.E./MW						
	r = 6%	r = 7%	r = 8%	r = 9%	r = 10%	r = 11%	r = 12%
STEAM							
ABK I & II	107.93	112.42	117.06	121.87	126.84	131.98	137.3
ABK I,II,III & IV	110.29	115.4	120.77	126.36	132.23	138.35	144.74
ISMAILIA	112.53	117.97	123.62	129.49	135.59	141.92	148.49
SUEZ I	110.63	115.52	120.56	125.74	131.07	136.54	142.17
NUCLEAR							
SIDI-KRIER	99.01	111.7	125.05	139.08	153.81	169.29	185.52
GAS TURBINE							
TALKHA	189.29	191.56	193.87	196.21	198.59	201.01	203.46
HELWAN	188.67	190.88	193.12	195.39	197.7	200.04	202.42

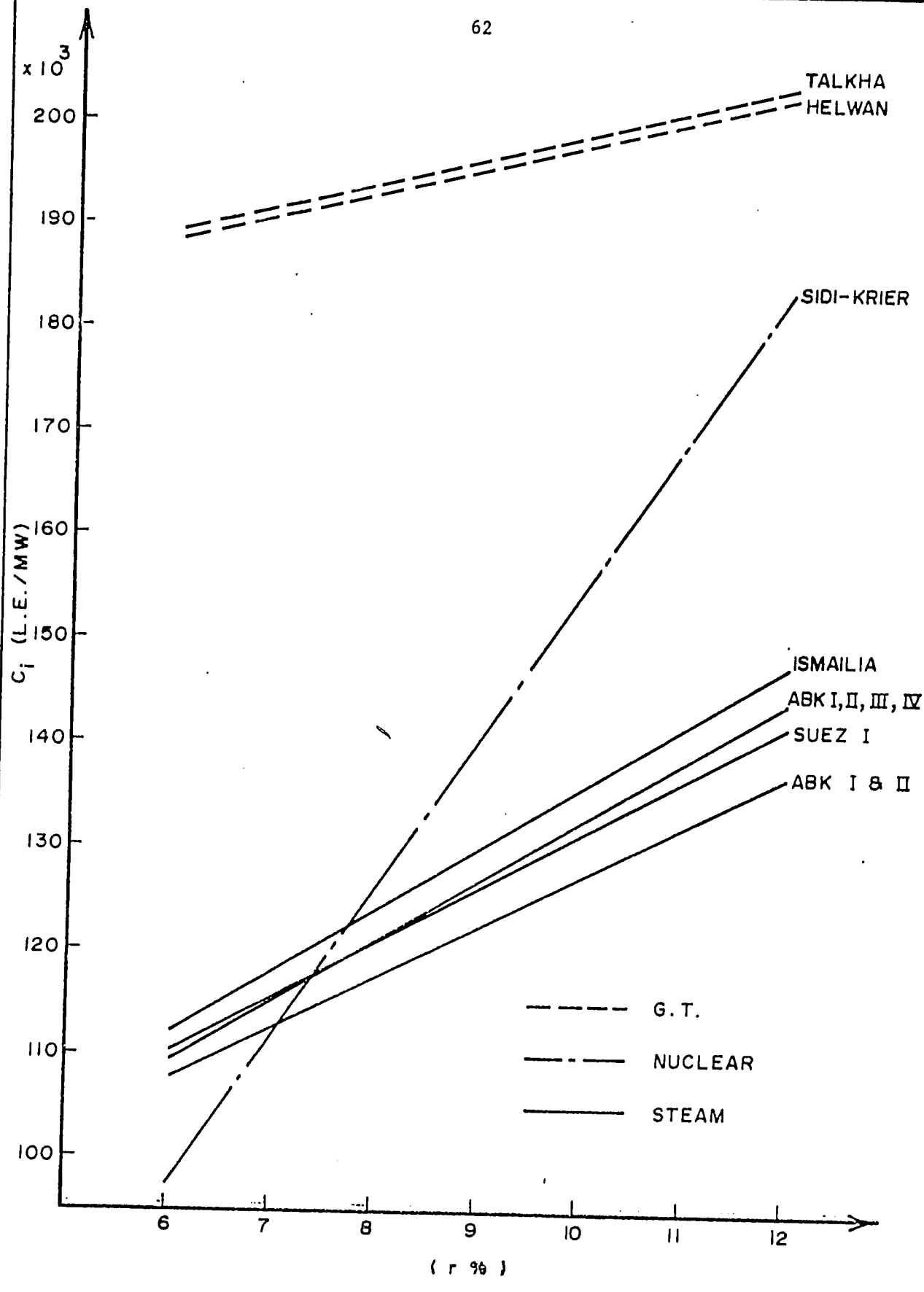


Fig. (3) EFFECT OF INTEREST RATE

goes below about 7.5%. In fact, at an interest rate of 7.75%, the recovery cost of the nuclear is more than all the investigated steam and gas turbine generating plants.

5-2 Growth Rate:

Once again, the estimate of the growth rate in the power generation projects is subject to various sources of errors reflected upon it by the inaccuracy of the load forecast. As outlined earlier in this report, inaccuracies in load forecasting stemmed from the erratic economical and social conditions in Egypt over the past two decades. The process of dealing with foreign governments to finance projects contributed to some extent to these inaccuracies.

Therefore, it becomes imperative to evaluate the sensitivity of the recovery cost of each of power generation projects to alterations in the rate of growth in demand and hence in capacity expansion.

The value of the growth rate (B) as it appears in equation (5.1) was varied over a 40% range in steps of (+ 10%, +5%, 0, -5%, -10%, -20%, -30%).

The percentage change in (B), denoted by (D), is given by:

$$D = \left(\frac{B - \bar{B}}{\bar{B}} \right) \times 100\%$$

Where $\bar{B}$ is the nominal growth rate used earlier in this

study and was taken to be always 10% of the demand by the end of the construction period.

The results are obtained in tables (14) through (19) and graphically depicted in fig. (4).

TABLE 14

D = 10%

NAME OF STATION	CAP MW	YEARS	B MW/years	C_i x 10^3 L.E./MW
STEAM				
ABK I & II	300	76-80	323.62	116.64
ABK I,II,III & IV	600	76-81	351.12	119.96
ISMAILIA	300	78-82	393.58	123.25
SUEZ I	300	77-80	323.62	120.12
NUCLEAR				
SIDI-KRIER	620	80-85	554.95	124.05
GAS TURBINE				
TALKHA	180	78-79	294.58	193.4
HELWAN	120	78-79	294.58	192.81

TABLE 15

D = 5%

NAME OF STATION	CAP MW	YEARS	B MW/years	C_i x 10^3 L.E./MW
STEAM				
ABK I & II	300	76-80	308.9	116.84
ABK I,II,III & IV	600	76-81	335.2	120.35
ISMAILIA	300	78-82	375.69	123.43
SUEZ I	300	77-80	308.9	120.33
NUCLEAR				
SIDI-KRIER	620	80-85	529.73	124.76
GAS TURBINE				
TALKHA	180	78-79	281.2	193.62
HELWAN	120	78-79	281.2	192.96

TABLE 16

D = -5%

NAME OF STATION	CAP MW	YEARS	B MW/years	C_i x 10^3 L.E./MW
STEAM				
ABK I & II	300	76-80	279.49	117.31
ABK I,II,III & IV	600	76-81	303.24	121.23
ISMAILIA	300	78-82	339.91	123.84
SUEZ I	300	77-80	279.49	120.81
NUCLEAR				
SIDI-KRIER	620	80-85	479.28	125.37
GAS TURBINE				
TALKHA	180	78-79	254.41	194.14
HELWAN	120	78-79	254.41	193.3

TABLE 17

$D' = -10\%$

NAME OF STATION	CAP MW	YEARS	B MW/years	C_i x 10^3 L.E./MW
STEAM				
ABK I & II	300	76-80	264.78	117.59
ABK I,II,III & IV	600	76-81	287.28	121.75
ISMAILIA	300	78-82	322.02	124.03
SUEZ I	300	77-80	264.78	121.1
NUCLEAR				
SIDI-KRIER	620	80-85	454.05	125.72
GAS TURBINE				
TALKHA	180	78-79	241.02	194.44
HELWAN	120	78-79	241.02	193.5

TABLE 18

D = -20%

NAME OF STATION	CAP MW	YEARS	B MW/years	C_1 x 10^3 L.E./MW
STEAM				
ABK I & II	300	76-80	235.2	118.2
ABK I,II,III & IV	600	76-81	255.3	122.9
ISMAILIA	300	78-82	286.2	124.6
SUEZ I	300	77-80	235.3	127.78
NUCLEAR				
SIDI-KRIER	620	80-85	403.5	126.5
GAS TURBINE				
TALKHA	130	78-79	214.2	195.1
HELWAN	120	78-79	214.2	193.9

TABLE 19

D = -30%

NAME OF STATION	CAP MW	YEARS	B MW/years	C_1 x 10^3 L.E./MW
STEAM				
ABK I & II	300	76-80	205.94	119.09
ABK I,II,III & IV	600	76-81	223.44	124.6
ISMAILIA	300	78-82	250.46	125.39
SUEZ I	300	77-80	205.94	122.65
NUCLEAR				
SIDI-KRIER	620	80-85	353.15	127.66
GAS TURBINE				
TALKHA	180	78-79	187.46	196.06
HELWAN	120	78-79	187.46	194.6

5.2.1 Discussion:

1. A change in the estimated growth rate (B) of generation demand requirements has little effect on the corresponding recovery cost (C_i) of the investigated generating plants. In addition, the effect is always such that (C_i) decreases as (B) increases.

2. At a rate of interest of 8%, a 10% change in (B) corresponds to a change in (C_i) of 2.4% for the nuclear power plant, 1.9 to 3.5% for steam power plants and only 1.32% for gas turbine power plants.

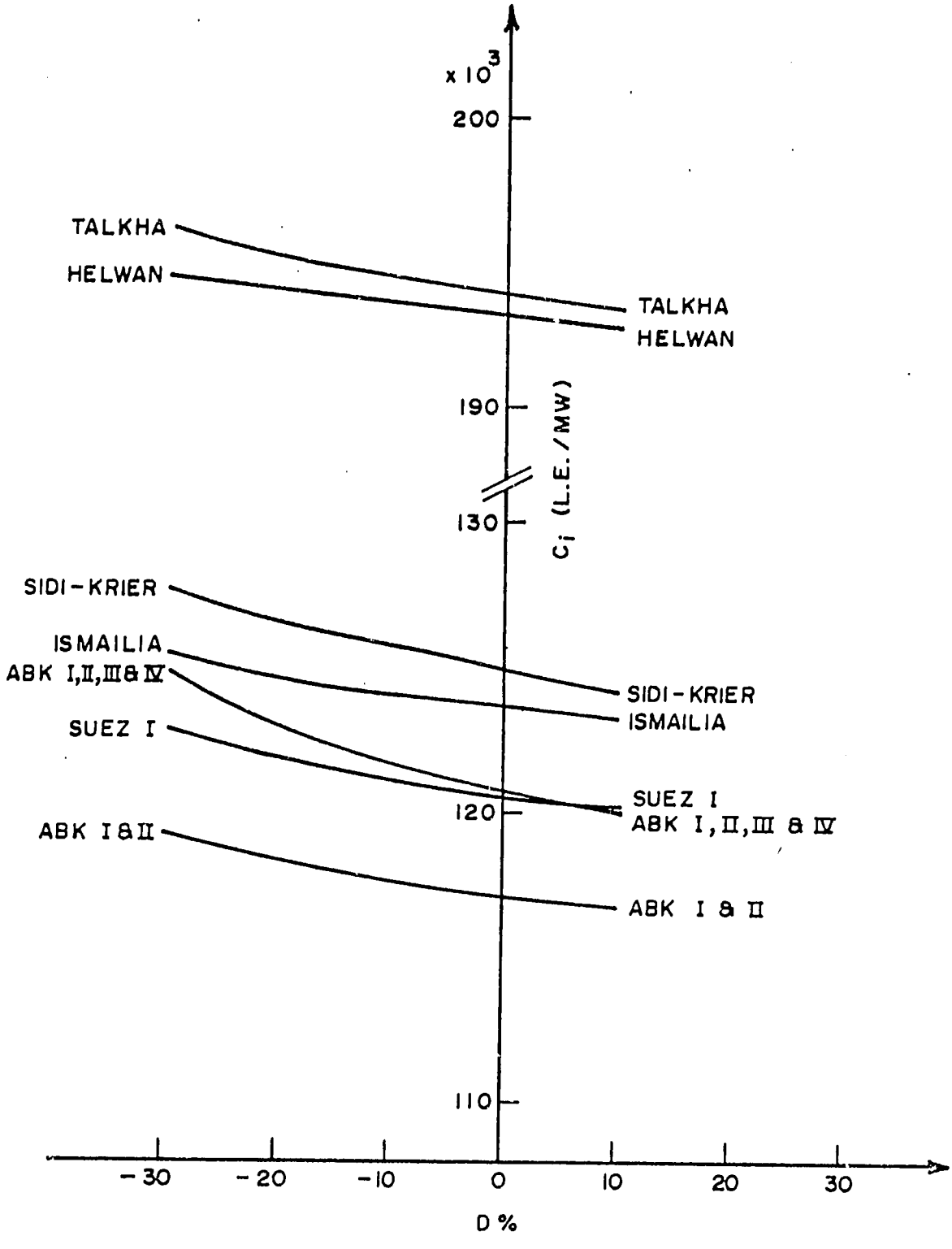


Fig. (4) EFFECT OF GROWTH RATE

5.3 Effect of Prospective Changes in Fuel Prices:

The effect of the escalation in fuel prices has been considered for a rate of 7.5%/year for fossil fuels (oil and gas) and at a rate of 6%/year for the nuclear fuel.

The effect of this escalation on the unit production cost in (L.E./MWH) in relation to the construction time for the three types of power plants, namely: Steam, gas-turbine, and nuclear is shown in Table (20).

The effect of the fuel rate increase on the recovery cost C_i (L.E./MW) at the year of commissioning is shown in Table (21).

Comparing the recovery cost C_i of Table (5) with the corresponding stations, the ranking of the different plants remained almost the same except for the nuclear plant and Ismailia steam power plant. They switched their ranks, i.e. the nuclear power plant recovery cost now lies in the middle range of steam plants. This indicates the sensitivity of the recovery cost to the fuel rate increase.

TABLE 20 a
STEAM:

YEARS	COST OF FUEL L.E./MWH	PRODUCTION COST L.E./MWH
0	11.02	15.02
1	11.85	15.85
2	12.73	16.73
3	13.69	17.69
4	14.72	18.72
5	15.82	19.82
6	17.01	21.02

TABLE 20 b
GAS TURBINES:

YEARS	COST OF FUEL L.E./MWH	PRODUCTION COST L.E./MWH
0	23.45	31.45
1	25.21	33.21
2	27.10	35.10
3	29.13	37.13
4	31.32	39.32
5	33.67	41.67
6	36.19	44.19

TABLE 20 c
NUCLEAR

YEARS	COST OF FUEL L.E./MWH	PRODUCTION COST L.E./MWH
0	5.04	6.3
1	5.34	6.60
2	5.66	6.92
3	6.00	7.26
4	6.36	7.62
5	6.74	8.00
6	7.15	8.41
7	7.58	8.84

TABLE 21

NAME OF STATION	CAP MW	YEARS	B MW/YEAR	T.C.C. x 10^3 L.E.	P.D.V. x 10^3 L.E.	γ_i x 10^3 L.E.	C_i x 10^3 L.E.
STEAM							
ABK I & II	300	76-80	214.2	106,139.92	351,330	457,469.92	127.04
ABK I,II,III & IV	600	76-81	319.2	210,105.75	742,980	953,085.75	136.87
ISMAILIA	300	78-82	357.8	132,954.53	393,120	526,074.53	145.04
SUEZ I	300	77-80	294.2	118,727.8	351,330	470,057.8	130.53
NUCLEAR							
SIDI-KRIER	620	80-85	504.5	649,600	383,656.00	1,033,256	139.98
GAS TURBINE							
TALKHA	180	78-79	267.8	27,788.06	418,446	446,234.06	203.71
HELWAN	120	78-79	267.8	20,369.5	278,964	299,333.5	203.15

T.C.C. = Total Construction Cost

P.D.C. = Present Discount Value

6. CONCLUSIONS

Based on the findings of this report the following conclusions are made:

1. This study substantiates that the "recovery cost" method introduced in this text is a simple indicative means of comparing the different power projects for capacity expansion. Due to the simplicity of this method, the optimal investment strategy is changed easily if certain projects are added to or deleted from the list of prospective candidates.

2. The highest recovery costs are those of gas-turbines. This result is only reached if the assumption is made that gas-turbines are operating as base plants. In comparing the gas-turbines with steam plants from the recovery cost point of view, it is found that there is a break even utilization hours-per-year of the gas-turbines at which they score a recovery cost equal to that of steam plants.

3. The relatively high growth rate of the nuclear power plant of Sidi-Kreir and the relatively low total cost of the complete complex of Abu-Quir power plants yields a little difference between the two projects from a recovery cost point of view. A possible future shortage in fossil fuel may however give an advantage to nuclear power plants over their steam counterpart.

4. From the interest rate point of view, the nuclear power plant of Sidi-Kreir (620 MW) has a breakeven rate with the steam plant of Abu-Quir (600 MW) at 7.5%, below which the nuclear plant will be more economical.

5. As the estimated growth rate is increased, the recovery cost decrease only slightly.

6. In view of the prospective fuel price increase the nuclear plant is expected to exchange ranks with the Ismailia steam plant giving advantage to the former in the future.

7. REFERENCES

1. R.L. SULLIVAN, Power System Planning, Mc Graw - Hill International, New York, 1977.

2. SANDERSON and PORTER, INC., System Planning Diagnostic Report, Presented for the Egyptian Electricity Authority, April 1977.

3. M. WEITZMAN, "Investment Criteria for Lumpy Capacity Expansion", Section 1, Generation Capacity Planning for the Egyptian Electric Power System.

4. H.B. CHENERY, "Overcapacity and the Acceleration Principle", Econometrica, vol. 20, pp. 1-28, 1952.

5. H.B. CHENERY, The Interdependence of Investment Decision, The Allocation of Economic Resources, Stanford University Press, 1959.

6. A.S. MANNE, Investments for Capacity Expansion; Size Location and Time-Phasing, George Allen and Unwin Ltd, London, 1967.

7. M. WEITZMAN, "The Optimal Development of Resource Pools", Journal of Economic Theory, 351-64, June 1976.

8. L.E. WESTPHAL, Planning Investments with Economics of Scale, North-Holland, 1971.

GENERATION CAPACITY PLANNING FOR THE EGYPTIAN ELECTRIC POWER SYSTEM

SECTION III

OPTIMAL MIXING OF STEAM AND GAS TURBINE POWER PLANTS

Research Team:

H. Anis
E. El-Sharkawi
H. El-Shaer
M. Swidan
H. El-Kolaly

1. The Need for Mixing:

The present trend in power systems to install generating units having a size as large as possible in comparison to the total installed capacity, involves the problem of increase in the magnitude of the reserve margin. This fact, added to the fact that the diagram of the load to be supplied has a typical sharpened shape raises the problem of the composition of the generating systems - that is, the problem of finding the optimum percentage for peak generating in respect of base generation. Peak generation may be described as having, in general, high operating costs and low capital costs.

The flexibility that peaking units provide, aids utilities in fulfilling each of their three objectives of meeting consumer demand, reliability and economical operation. The very principle of peaking power is, of course to meet unexpected or unscheduled high demands by consumers as well as anticipated peaks.

The fact that peaking power is generally acquired in relatively small separate units enhances overall system reliability, since the loss of any single plant will have minimum effect on the entire system. Finally, the incorporation of a calculated amount of peaking power can reduce the overall cost of generation in a number of ways.

First, because the installed cost of peaking plants per 1 MW is substantially less than that of high-efficiency base load units, utilities can realize a substantial savings in capital expenditures by including in their total capacity a percentage of units specifically designed for peaking use. This capital saving can result in an overall saving compared to using base load units at low capacity factors in spite of the high specific fuel cost of the peaking unit.

Second, the addition of peaking plants as a utility's requirements can make it possible to use the existing base plants more efficiently when an utility reaches the point where it must expand, it may go basically in one of two directions. It may add another base plant equal to its additional requirement (at a large capital expenditure) and "semi-retire" its old base equipment to peaking duty. In time, this unit will be operating at a capacity factor low enough to make its operation more costly than a peaking unit. The alternative is to meet the additional demand with a mix of base and peaking units purchased in accordance with a predetermined plant to maintain a certain percentage of total capacity in peaking plants. Such a mix will ensure that the base plants most suited for continuous duty will be used solely in that manner, the way in which their high capital cost is usually justified.

An additional benefit of this mixing approach is that, by adding low-cost peaking units to meet small increases in demand, the purchase of base load units can often be deferred until demand is such as to justify buying a larger unit than could otherwise be used efficiently. Effort must therefore be made to establish the

optimum mixture between the gas turbine and steam power plants to meet a certain load such as that of lower Egypt.

It is to be realized that the value of the mixing ratio provided by this study may be taken as a guide line in the way of choosing plant capacities. The final choice is governed by other factors, in addition, such as the availability of the nearest standard unit capacity as well as special agreements with foreign governments.

2. GAS TURBINES VERSUS STEAM PLANTS:

Gas turbines have seen their most extensive use within the utility industry, in the field of peaking duties. Because a peaking unit supplies only a small part of total system energy, the qualities of short delivery time, rapid cycling capability and low capital cost take precedence over low operating cost. It is a characteristic of the gas turbine, that its disadvantages are maximized and its disadvantages are minimized in such an application. The result is that the simple cycle engine used singly or in combination has become an industry standard for peaking use.

Like any engine, the gas turbine operates by using a working fluid to convert heat energy from fuel into mechanical energy. The engine harnesses the mechanical energy and puts it to use.

The gas turbine is distinguished from the familiar steam turbine by three major differences:

1. The gas turbine is an internal combustion engine, unlike the steam turbine in which fuel is burned in an external boiler.

2. The G. T. uses a different working fluid like the steam turbine, the G. T. name refers to its working fluid - some type of gaseous substance (usually atmospheric air and products of combustion). A common misconception with the G. T. is that its name refers to the fuel that the engine uses, for example, natural gas. Because of its misconception, the name "combustion turbine" is sometimes preferred.

3. The G. T. operates at high temperatures and low pressures, while the steam turbine generally operates at high pressures and moderate temperatures.

There exists a number of gas turbine cycle variations. The most common of these is the "simple cycle". The typical simple cycle gas turbine engine consists of three major components: compressor, combustion system, and a turbine which is mechanically coupled to the compressor. Power is developed in the turbine section, and drives both the compressor and an external load at constant speed.

3. Load Duration Curve:

Since the problem of mixture between steam and gas turbine plants arises primarily in lower (northern) Egypt, it is this portion of the country that this work will study.

A representative daily load curve of the prospective generation (steam and gas) in lower Egypt is the difference between the daily demand and the daily supply of power from upper (southern) Egypt to lower Egypt. These two curves are given in Fig. (1) and the resultant daily curve of prospective generation demand is given in Fig. (2). It must be noted that the power supply from upper to lower Egypt is produced by hydro-electric plants, namely, the High Dam. Such a supply is intended to form a compound of base and peak powers as shwon in Fig. (1), the base being at a 700 MW level.

The curve gives a clear picture of the percentage of time that each type of capacity is in operation, and it makes readily apparent the fact that base load generation supplies the major portion of energy throughout the year by far. Similarly, it is evident that peaking capacity is the source of little of the annual energy produced. The greatly differing usage rates of the two categories dictate the divergent characteristics required of the generation facilities used to provide the two types of power.

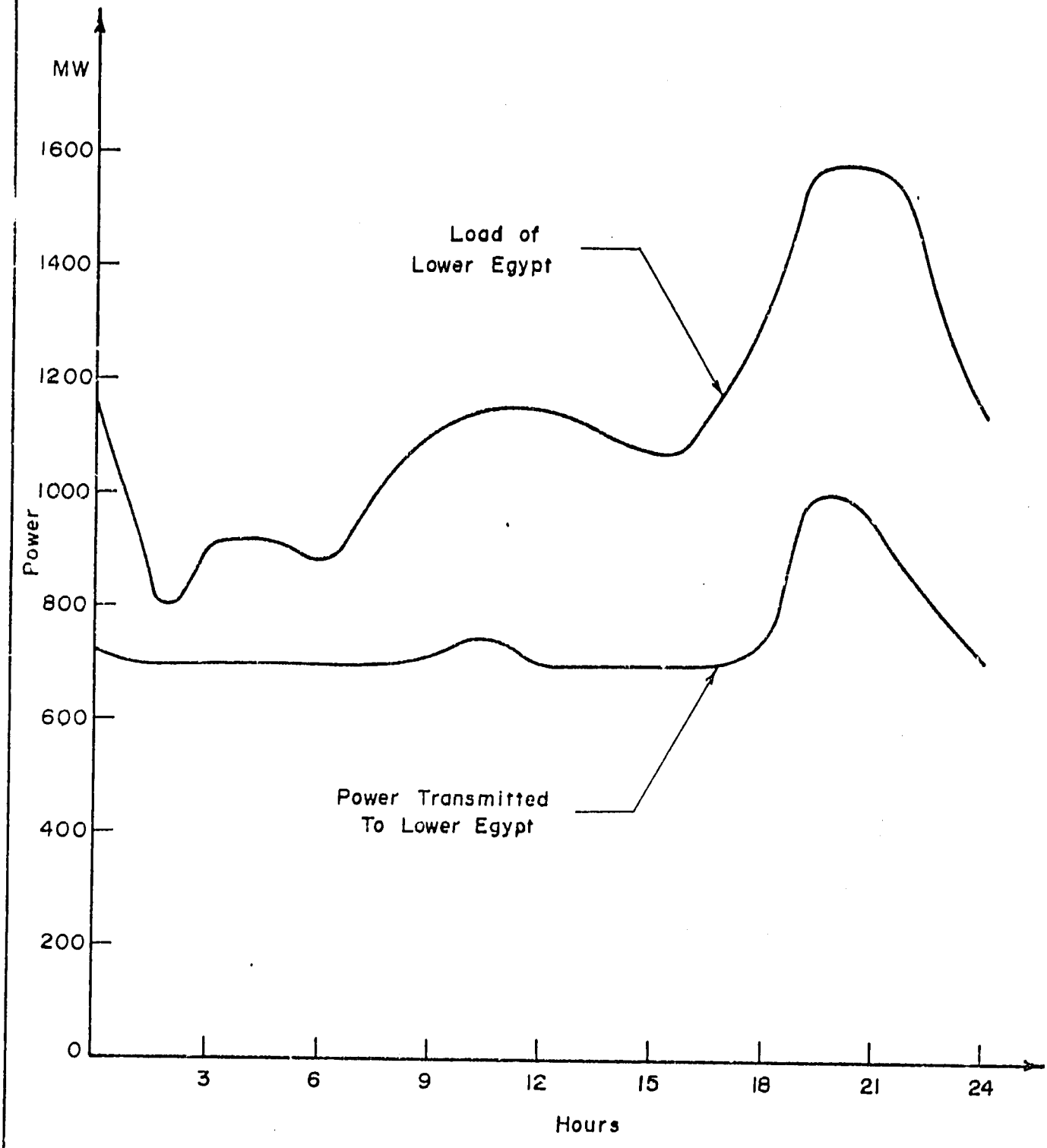


Fig. (1) LOAD CURVES

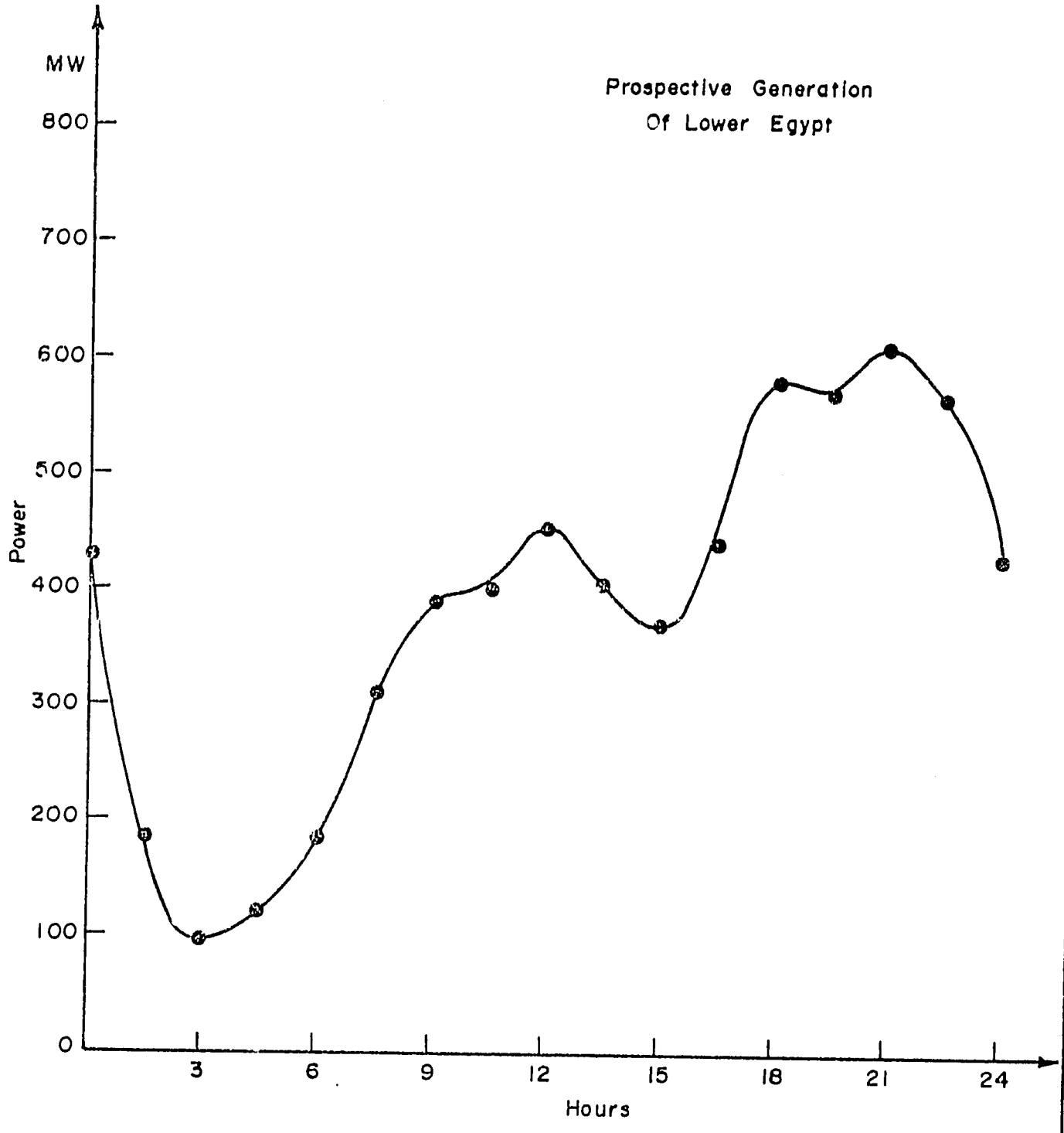


Fig. (2) LOAD CURVE

The fact that base load units are in operation such a high percentage of the time makes low operating cost an overriding consideration. On the other hand, since peaking units are in use relatively little their operating cost is relatively important with the capital cost of the equipment itself being the significant factor in the overall cost of ownership.

The load duration curve of lower Egypt, based on Fig. (2) is given in Fig. (3) . It is this curve that this study is concerned with. The curve is plotted with its ordinate normalized to the total power generation capacity of lower Egypt (steam and gas).

4. MODELS OF POWER PLANTS MIXTURE:

It is assumed that the annualized cost of any of the two plants (steam and gas) per unit installed capacity is composed of two parts one dependent on the operating time and the other is not. For steam plants such a cost takes the form.

$$C_s = \alpha + a T \quad .....(L.E./MW/year)$$

where T is the number of operating hours/year. For the gas turbine plant, this is given by

$$C_g = \beta + b T \quad .....(L.E./MW/year)$$

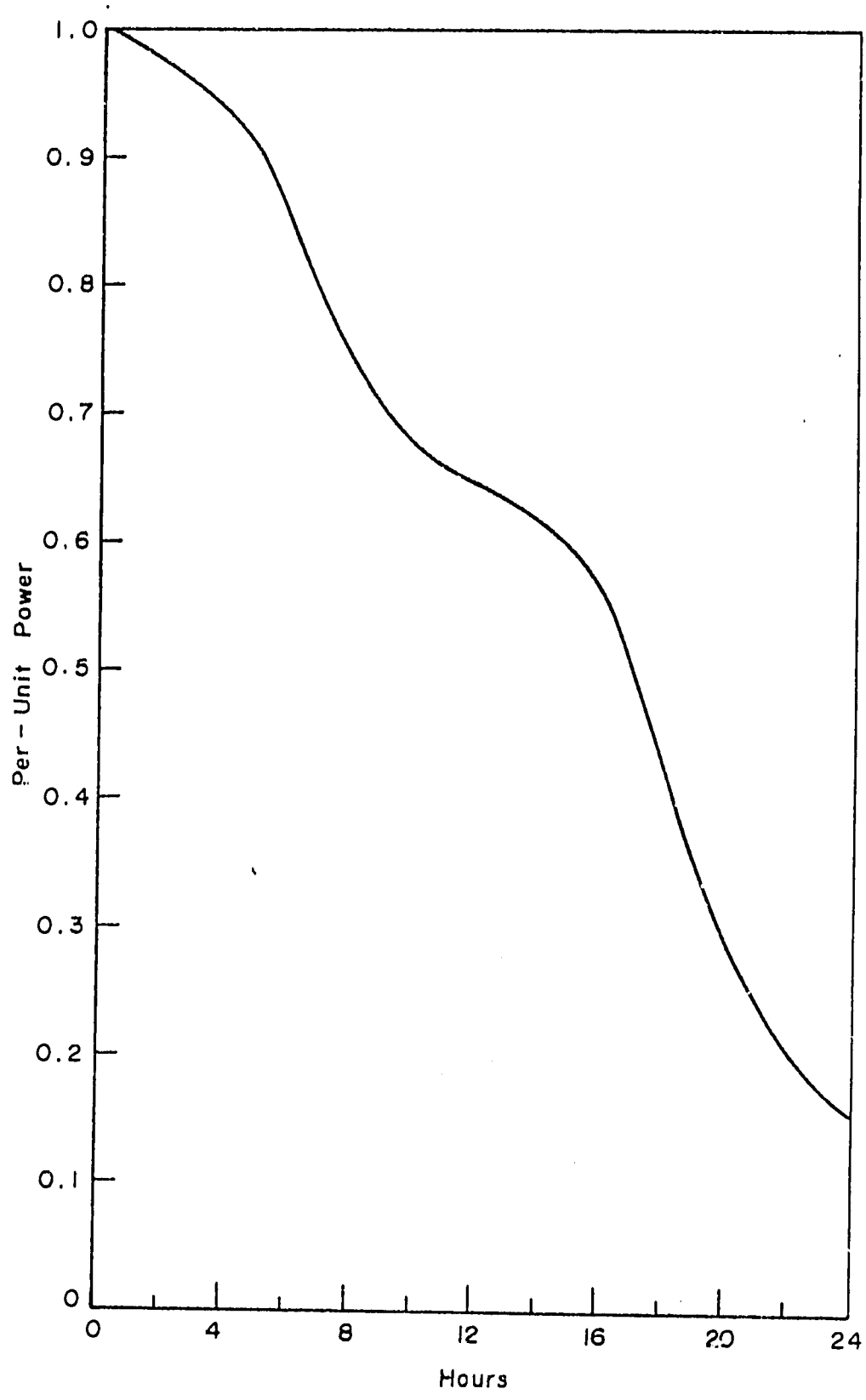


Fig. (3) LOAD DURATION CURVE

5. Estimation of Cost Parameters:

i. Steam Plants

α = annualized cost/MW including operational cost independent of output for steam units.

No. of operating years = 30

Construction cost/KW = 332 L. E.

Annualized construction cost (assuming 10% interest rate) $= \dfrac{332 \times 0.1 \times 10^3}{1 - e^{-(0.1 \times 30)}}$

= 34,940 L. E./MW/year

Operation & Maintanance cost/MWH = 4 L. E.

No. of operating hours/year = 7000

O. & M. cost/MW/year = 4 x 7000

= 28,000 L.E./MW

$\therefore$ $\boxed{\alpha = 62{,}940 \text{ L. E. /MW/year}}$

a = running cost/MWH for steam units.

International fuel cost = \$ 67/metric ton

Heat rate for steam units used = 0.235 tons/MWH

$\therefore$ a = 0.235 x 67 x 0.7

a = 11.02 L. E./MWH

ii. Gas Turbine Plants

β = annualized cost/MW including operational cost independent of output.

No. of operating years for G. T. = 20

Construction cost of Talkha G. T. (180 MW) = $27,788 \times 10^3$ L. E.

Annualized construction cost $= \dfrac{27,788 \times 10^3 \times 0.1}{180\,[1 - e^{-0.1 \times 20}]}$

= 17,854 L. E./MW/year

O. & M. cost/MWH = 8 L. E.

No. of operating hours = z

O. & M. cost/MW/year = 8z L. E.

According to gas turbine manufacturers z may be practically taken as 2200 hr/year

= 17,854 + 8 x 2200 = 35,454 L. E./MW/year

b = running cost/MWH for G. T.

International fuel cost = \$ 67/ton

Heat rate = 0.5

b = 0.5 x 67 x 0.7

b = 23.45 L. E./MWH

The break even number of hours, above which steam plants are more economical to be used and below which gas turbine plants are more economical, is given by the intersection of the above two equations. This gives:

$$T^* = \frac{\alpha - \beta}{b - a} \text{ hours/year}$$

= 2211 hours/year, or 6.14 hours/day

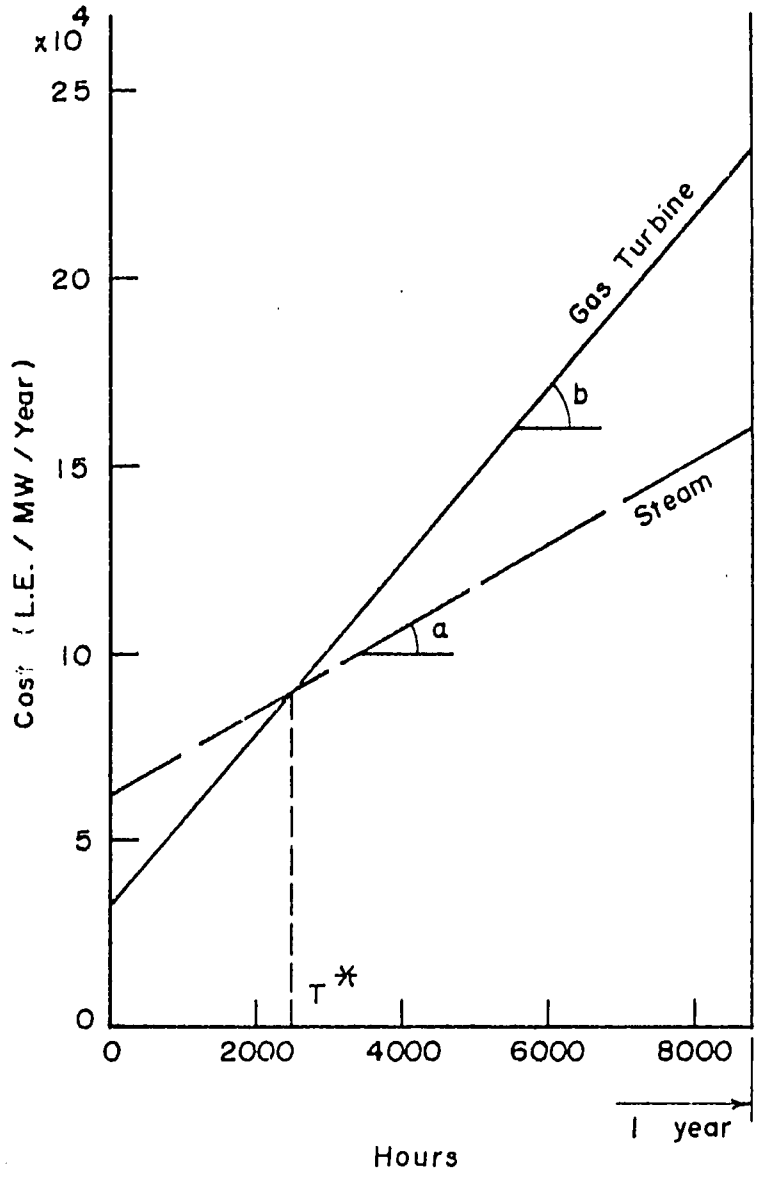


Fig. (4) COST PARAMETERS

This is displayed in Fig. (4). The number of operating hours T* corresponds on the load duration curve of Fig. (3) to a ratio of steam plant capacity to total capacity of 0.84.

6. Simplex Model:

The problem is firstly modelled by its load duration function [Fig. (5)] characterized by its base power d, total power D and a variable steam plant capacity x. When the demand falls below x only steam units operate. Above x, a mixture of steam and gas turbine units operate.

Let $F(t)$ = load duration curve

$\phi(y)$ = inverse of load duration curve.

D = capacity of combined steam and gas turbines.

$D - x$ = capacity of gas turbine units

α = annualized cost/MW including operational cost independent of output for steam units.

a = running cost/MWH for steam units

β = annualized cost/MW for G. T. units including the operational cost independent of output.

b = running cost/MWH for G. T. units

$c(x)$ = Total cost function

From the above assumption we can put the total cost equal to

$$c(x) = \beta(D - x) + \alpha x + b \int_{\phi(D)}^{\phi(x)} (y - x) \, . \, d\phi + a \int_{\phi(x)}^{\phi(D)} x \, d\phi + a \int_{\phi(d)}^{\phi(x)} y \, d\phi \quad \ldots\ldots\ (1)$$

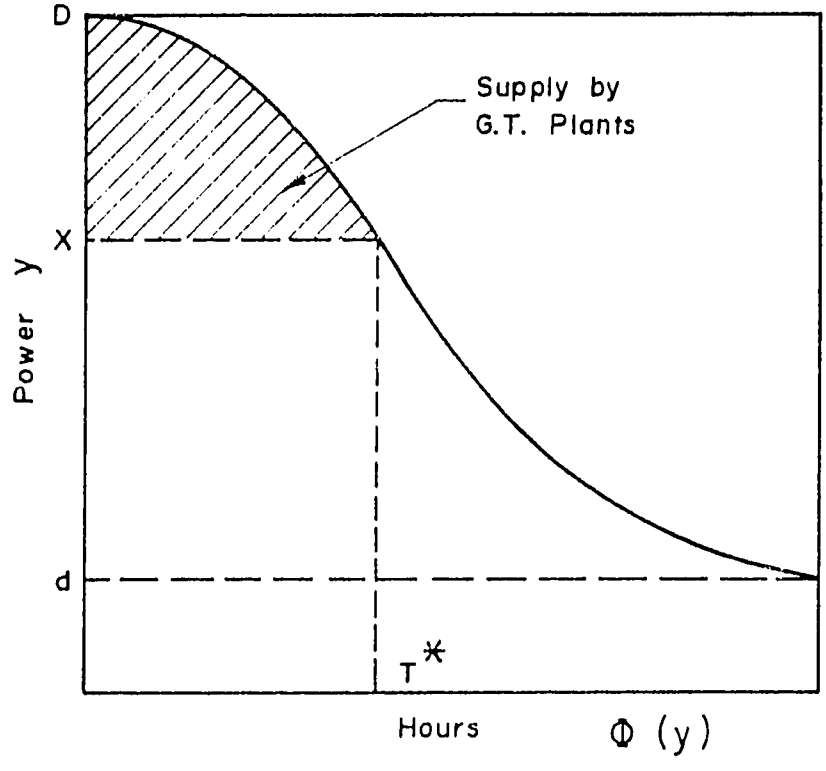


Fig. (5) SIMPLEX MODEL

$$\frac{d\ C\ (x)}{dx} = -\ \beta + \alpha - b\int_{\phi(x)}^{\phi(D)} d\phi + a\int_{\phi(x)}^{\phi(D)} d\phi$$

$$-a\ .\ x\ .\ \phi'(x) + a.\ x.\phi'(x) = 0$$

Then, $$\boxed{\frac{\alpha - \beta}{b - a} = \int_{\phi(x)}^{\phi(D)} d\ \phi = \phi\ (x)}$$

Since,

i. $$\int_{\phi(x)}^{\phi(D)} x\ .\ d\ \phi = x\ .\int_{\phi(x)}^{\phi(D)} d\phi = x\ [\phi\ (D) - \phi\ (x)]$$

$$\therefore\ \frac{d}{dx}\int_{\phi(x)}^{\phi(D)} x\ d\phi = [\phi(D) - \phi\ (x)] - x\phi'\ (x)$$

$$= \int_{\phi(x)}^{\phi(D)} d\phi - x\ \phi'$$

ii. $$\int_{\phi(d)}^{\phi(x)} y\ d\phi = \int_{\phi(d)}^{\phi(x)} x\ .\ \frac{d\ \phi\ (x)}{dx}\ .\ dx$$

$$= \int_{d}^{x} x\ .\ \phi'\ (x)\ .\ dx$$

$$\frac{d}{dx}\int_{\phi(d)}^{\phi(x)} yd\ \phi(y) = x\ .\ \phi'\ (x)$$

iii. $$\int_{\phi(x)}^{\phi(D)} (y - x)\ .\ d\phi = (i) - (ii)$$

$$\frac{d}{dx}\int_{\phi(x)}^{\phi(D)} (y-x)\ d\phi = \int_{\phi(x)}^{\phi(D)} d\ \phi$$

The result given by the simplex model is identical to the deduction given earlier. A value of x of 0.84 is deduced from the load duration curve meaning that gas turbine plants should have a capacity of only 16% of the total installed capacity. This again means 2211 hours/year operation hours for gas turbines.

7. Realistic Model:

The simplex model ignored some facts which could influence the results. A more realistic model is set which accounts for the following [Fig. (6)] :-

1. The thermal efficiency of steam units varies with the loading Accordingly, the running cost (a) of the unit is no longer constant but rather varies with the per unit loading (y/x). This variation as supplied by manufactruers is plotted in Fig. (7). It reads:

$$a = 17 - 7.5\ (y/x) \qquad 0 < y/x < .8$$

$$a = 5 + 7.5\ (y/x) \qquad .8 < y/x < 1$$

2. There exists a minimum level of loading for steam units below which a complete shut down of the unit is technically recommended. In Fig. (6) , this minimum is indicated by mx ($m < 1$). A unit when shut down, and depending on the period of shut down, incurs an extra cost of shut down/start-up. Based on data supplied by steam turbine manufacturers, the shut down/start-up cost is plotted in Fig. (8) as a function of shut down time. The shut down/start-up cost is the sum of the shut down/start-up cost of the successively shut down units. The shut down time of each unit is deduced from the load duration curve.

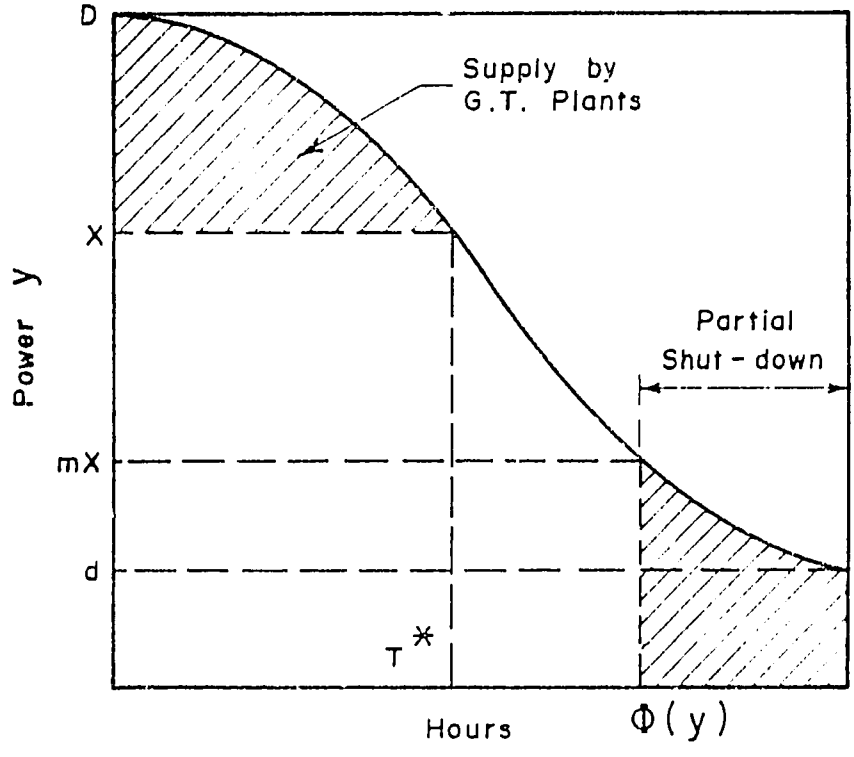
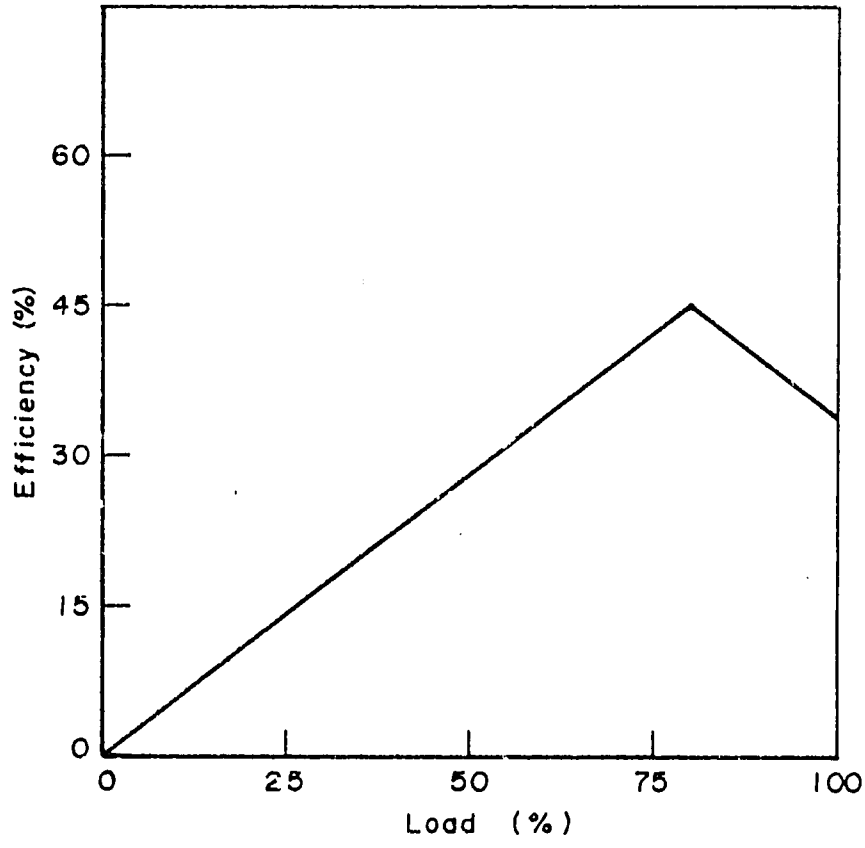


Fig. (6) REALISTIC MODEL



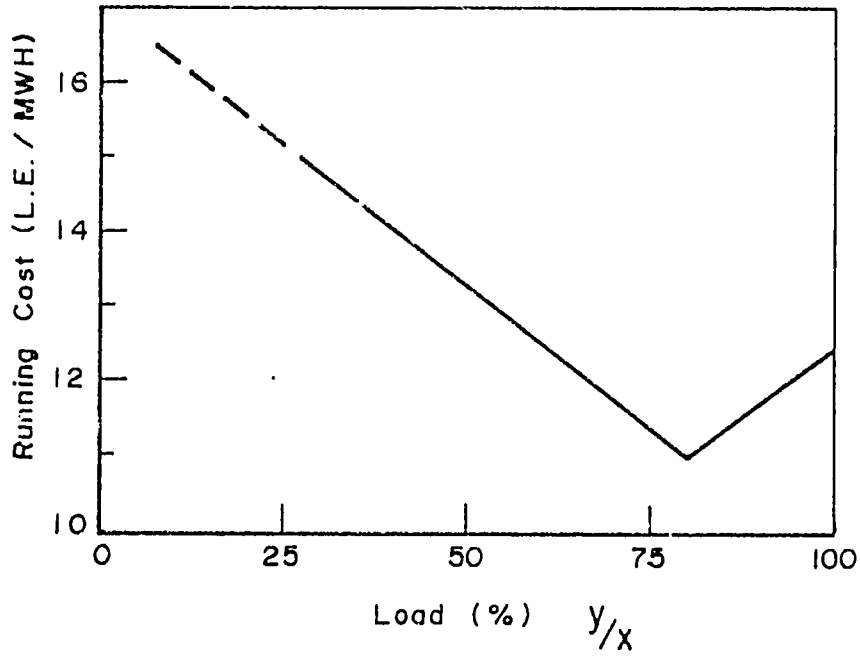


Fig. (7) RUNNING COST OF STEAM UNITS

Let $\phi(y)$, x, d, D, α, β, and b be as defined in section (7.2) and let:

y/x = utilization rate of steam for (in per unit)

a(y/x) = running cost/MWH for steam units as a function of the utilization rate.

W = shut down cost of steam plants

c (x) = total cost function

m = Technical minimum loading (in per unit)

In this model we assume that the G. T. is used only as peaker.

$$c(x) = \beta (D - x) + \alpha x + \int_{\phi D}^{\phi x} (y - x) \, d\phi(y)$$
$$+ a(1) \cdot \phi(x) \cdot x + \int_{\phi(x)}^{\phi(mx)} a(y/x) \cdot y \cdot d\phi(y)$$
$$+ a(m) \int_{\phi(mx)}^{\phi(d)} y \, d\phi(y) + W$$

To estimate the shut down/start up cost, units of 25 MW capacity were realistically assumed to be shut down successively as the load goes below y = mx. The number of shut down units is then

$$n = (mx - d)/25$$

The total annual shut down/start up cost is

$$W = 365 \sum_{i=1}^{n} S(\phi_i)$$

where, ϕ is the average number of shut down hours /day of the ith unit to be shut down.

S is the cost of shut down as given by Fig. (8).

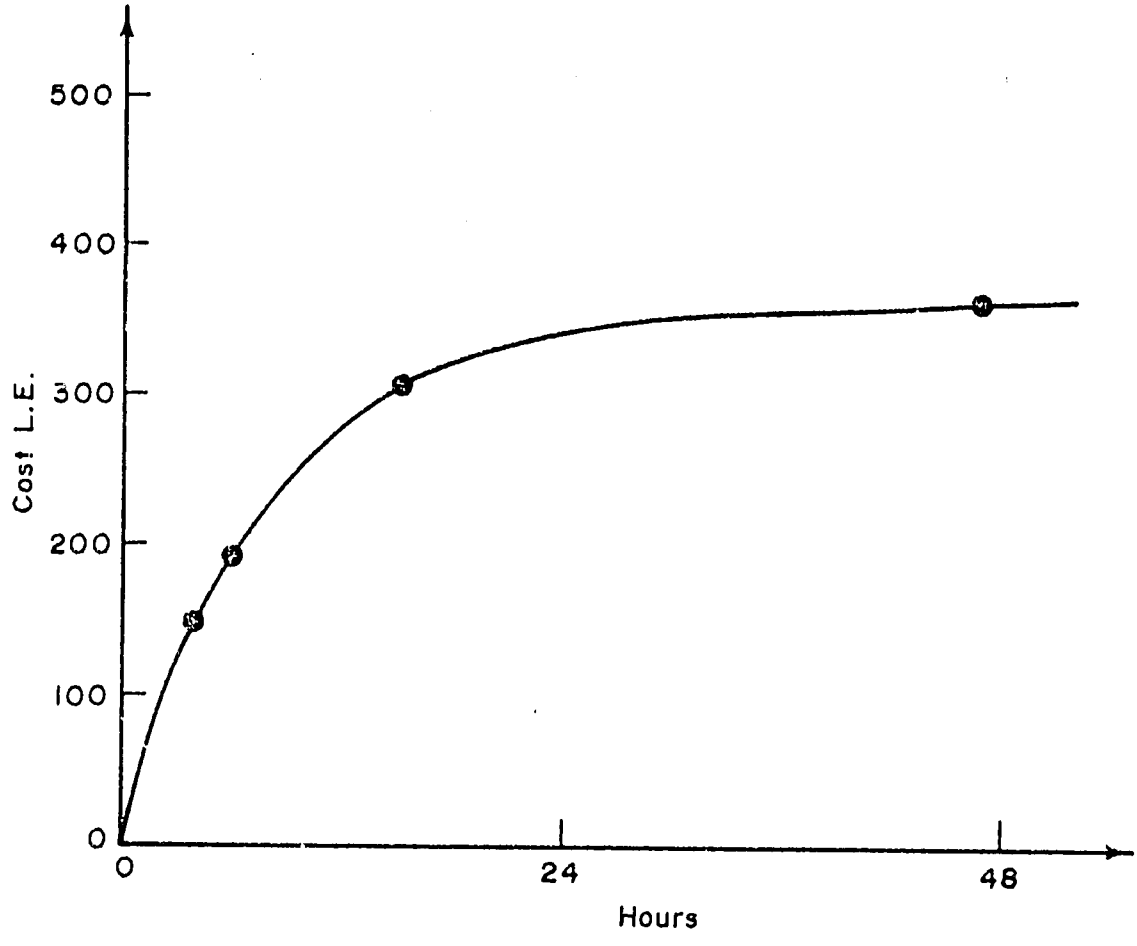


Fig. (8) START-UP COST OF A TYPICAL 25 MW UNIT

7.1 Application of the Realistic Model:

In view of the complexity of the cost function C (x) the differential approach is dispensed with. An alternative is a numerical algorithm which minimizes that function directly.

Fig. (9) outlines the numerical algorithm which includes two major subroutines:

1. A subroutine to replace the load duration curve by a fitted polynomial and makes it accessible to the optimization technique.

2. A direct optimization technique based on the Rosenbrock's rotating axes climbing method.

7.2 Results:

Fig. (10) depicts the variation of the total annualized cost of a mixture of gas turbine and steam power plants. The technical minimum loading is taken in Fig. (10) to be m = 40%. The optimal mixing ratio was computed to be

$$x = 0.8181$$

at a minimum total cost of

$$\text{L.E. } 78.5 \times 10^6/\text{year}$$

The corresponding optimum number of operating hours/year for gas turbines are deduced from the load duration curve to be

$$T^* = 2336 \text{ hours/year}$$

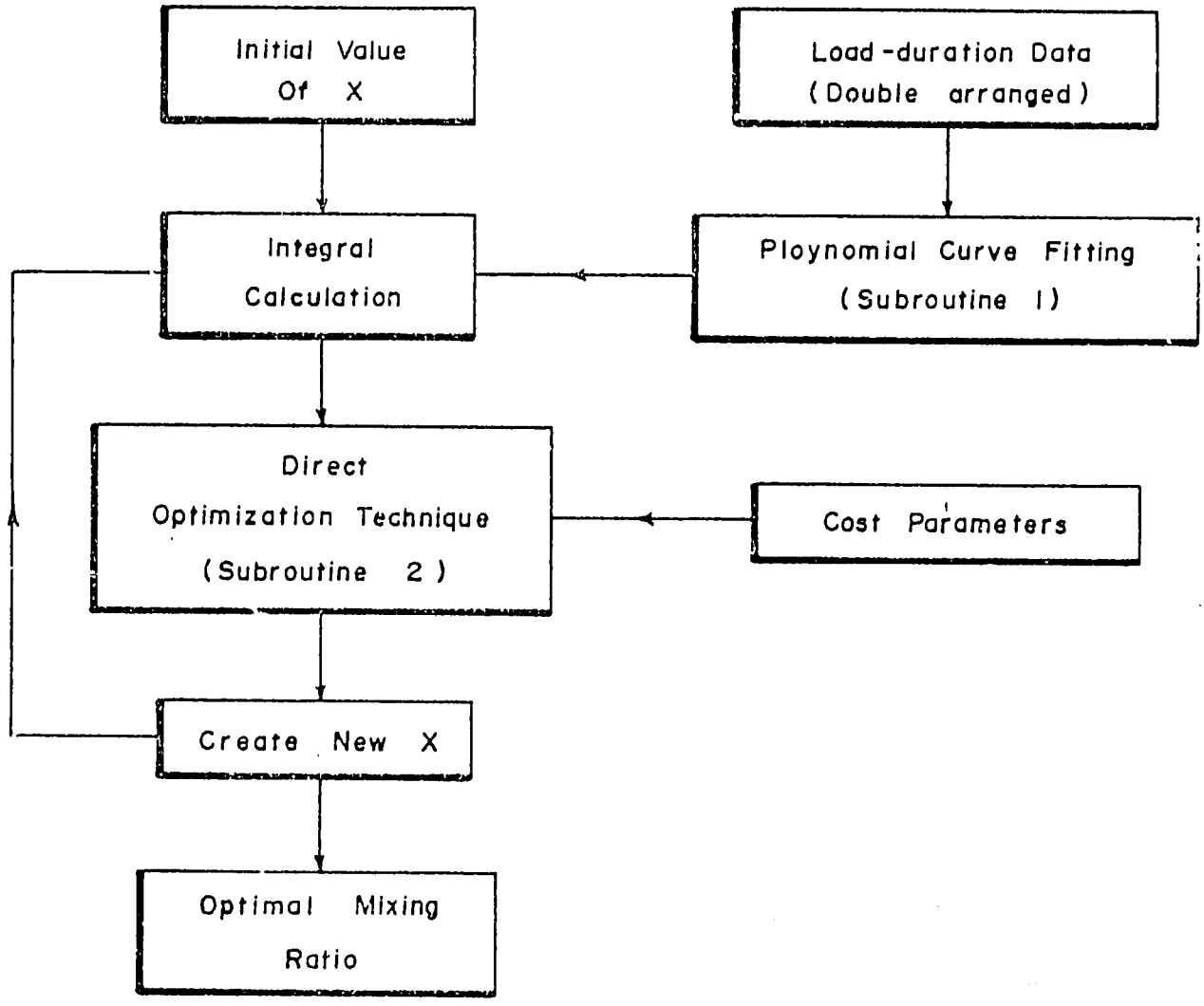


Fig. (9) FLOW CHART FOR COMPUTING OPTIMAL MIXING RATIO OF POWER PLANTS

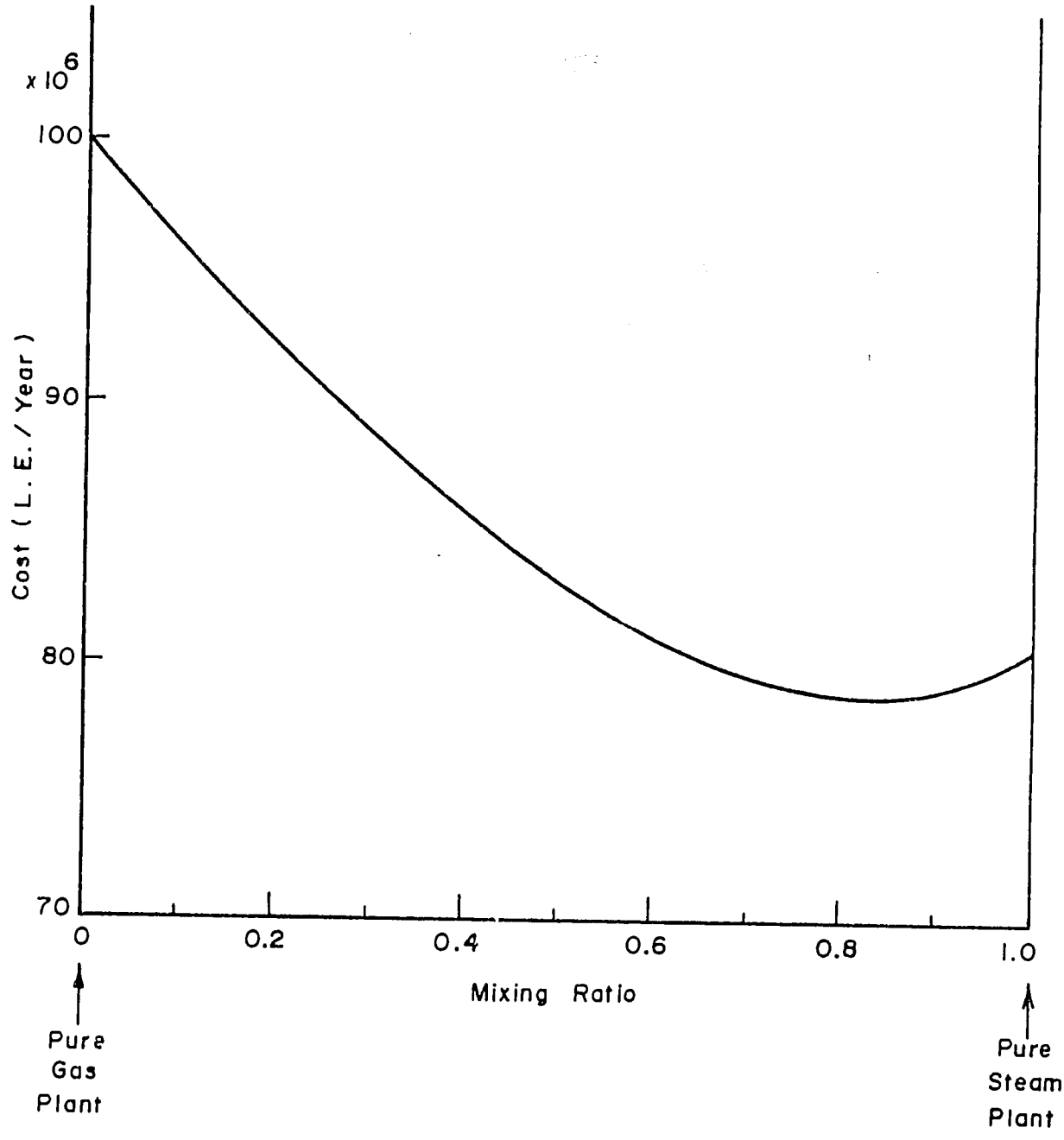


Fig. (10) COST FUNCTION

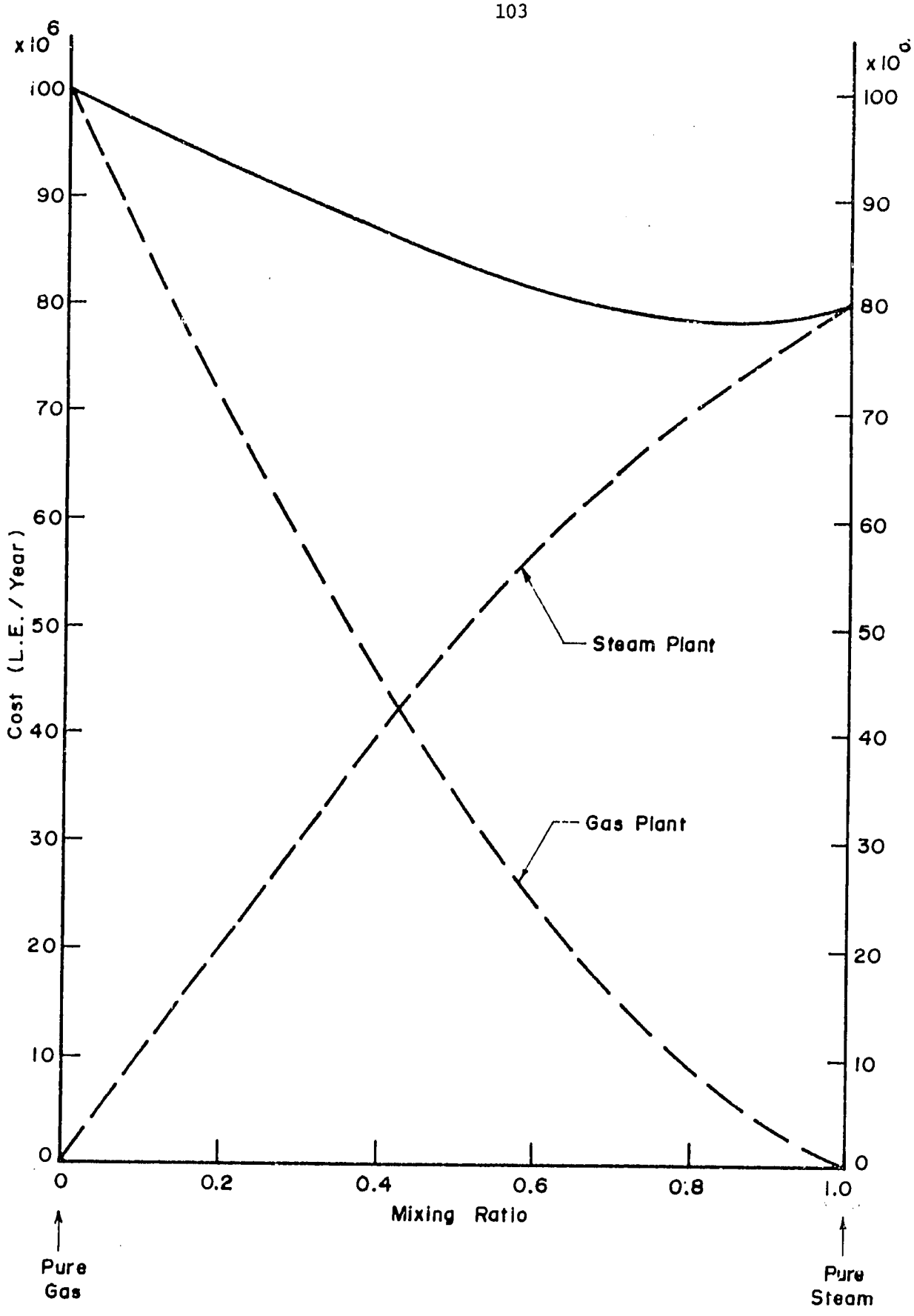


Fig. (11) COST COMPONENTS

Fig. (11) shows the variation of the individual cost components of gas turbines and steam plants with the mixing ratio.

8. Comparison Between the Simplex and Realistic Models

To examine the accuracy of the Simplex model, described in section (6), an exact model was developed which took into consideration the running costs of the steam units as a non-linear function of the generated output. The start-up costs as a function of the shutdown period were also accounted for. Both models were applied to a sample case of the operating conditions for the Northern Egypt power system, as described in section(1.2). In this sample case the hydro-resources were utilized for a fixed pattern, as mentioned in section (3).

Fig. (10) illustrated the variation in the operation costs/ annum as a function of the mixing ratio (available power of steam generation given in per unit of maximum demand). From the figure it is noted that the lowest production costs are achieved for a mixing ratio of about 0.82 p.u., i.e. the gas units capacity yielding minimum total cost is about 0.18 p.u. From the assumed load duration curve for the sample case study the corresponding annual duration for the gas units will be about 2336 hours/year. The corresponding figure for the simple model discussed in sec. (6) was about 2211 hours/year, which indicates an inaccuracy of the simple model of about 5.7%. This difference is attributed to the following factors:

(a) The non-linearity in the heat rate of the units as a function of the generated output power.

(b) The variable costs of start-up as a function of total shut-down period of steam generating units.

9. Effect of the Number of Operating Units and their Technical Minimum:

The results shown in Figs. (10) and (11) were obtained for the case of keeping the steam units at or above their technical minimum of 0.4 p.u. of their ratings. Below that level the unit is assumed to be shut-down.

In order to test the sensitivity of the production costing to such a value, the procedure was repeated for a variable minimum loading of the steam units between 0.4 and 0.8 p.u. of their rated power. This, in effect, means varying the number and duration of operating units.

Fig. (12) illustrates the above effect. It appears, as the minimum loading is increased towards 0.8, that this economic way of unit dispatching resulted in a total saving in production cost of 1.5%.

It must be pointed out that as the minimum loading is increased so does the number of shut down units. This frequent shut down, in the long run, has an adverse effect on the life span of the steam units.

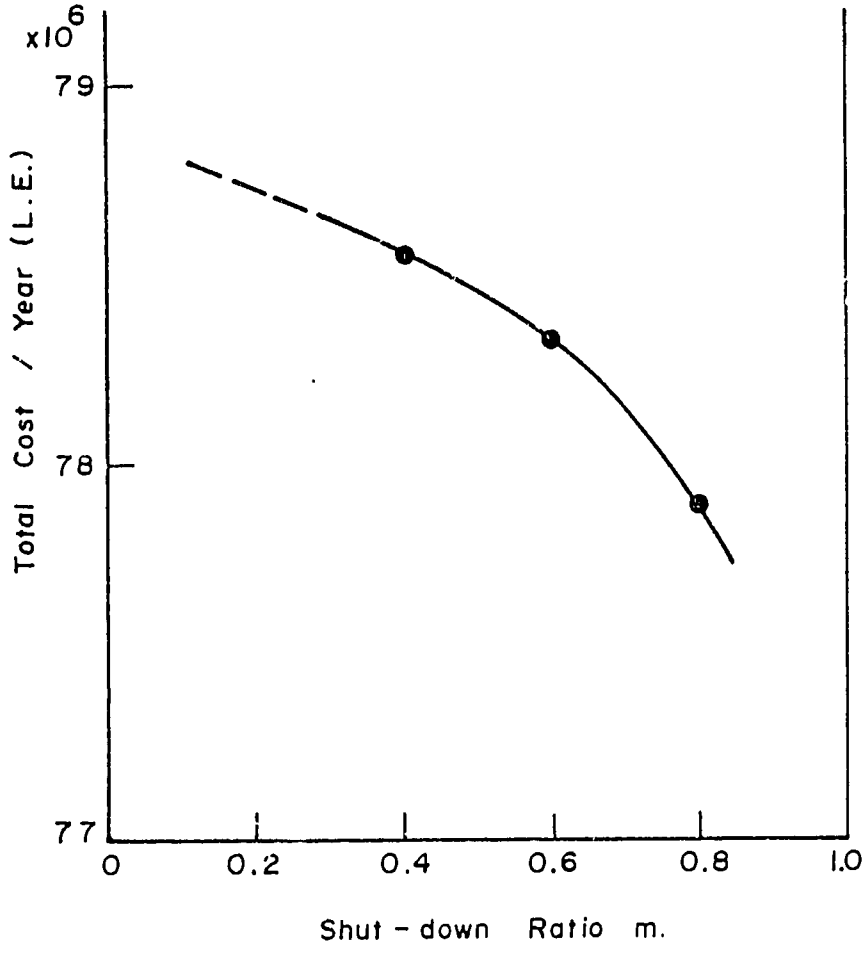


Fig. (12) EFFECT OF SHUT-DOWN RATIO

10. CONCLUSIONS AND RECOMMENDATIONS FOR FURTHER FUTURE STUDIES:

1. A model of a combination of gas-turbines and steam power plants to feed Northern Egypt indicates that the optimum capacity share of steam plant should be about 82% of the total capacity.

2. The realistic model developed in the study to produce the mixing ratio of gas-turbine and steam plants can be constituted by a simplified model which gives a fairly acceptable estimate of the above ratio.

3. The overall cost of a mixture between gas-turbines and steam power plants is much less sensitive to the mixing ratio at the optimum value of that ratio that it is at the extreme limits where the system is either fed chiefly by steam plants or gas-turbines.

4. It is clear from the results that the hydro-resources utilization pattern would affect the optimal solution. It is, therefore, recommended that this analysis be reapplied to different hydro-resources operational patterns.

5. Recent econmical studies carried out in Egypt show the feasibility of "pumping storage" schemes on the Gulf of Suez of large capacities. It is recommended to expand the realistic model of power plant mixing to include pumping storage as additional peak-shaving generation. This is expected to affect the utilization ratio of gas turbine plants.

11. References

1. G. Manzoni, P.L. Noferi and M. Valtorta, "Planning Generating Units for Peak-Load in Power Systems Relevant Parameters and their Relative Influence", Cigre, 1970 Session.

2. G. Manzoni, P.L. Noferi and M. Valtorta, "Planning Thermal and Hydraulic Power Systems Relevant Parameters and their Relative Influence". Ciger 1972 Session.

3. L.Paris, L.Salvaderi, "Pumped-Storage Plant Basic Characteristics: Their Effect on Generating System Reliability", American Power Conference, Chicago 1974.

4. Sanderson and Porter, INC., System Planning Diagnostic Report, Presented for the Egyptian Electricity Authority, April 1977.

5. L.E. Westphal, Planning Investments with Economics of Scale, North-Holland, 1971.