PUBLIC POWER CORPORATION

GREECE

SECOND

INTERIM REPORT

ON

ELECTRICITY TARIFFS

BY

D. J. BOLTON, M.Sc., M.I.E.E.

Consulting Engineers:
KENNEDY & DONKIN
Alliance House,
12, Caxton Street,
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Contents

1 INTRODUCTION

1.1 Origin and Terms of Reference

On February 20th, 1963, the Firm were asked by the Public Power Corporation of Greece to make recommendations on their electricity tariffs and to prepare a new rate structure. Although no formal terms of reference were laid down, it was made clear that the problem was two-fold. Namely, to formulate a tariff which would be appropriate to a number of new large industrial loads expected to arise, and to design a single rate structure for the whole of Greece which would replace the two sets of tariffs now operating.

1.2 First Visit to Athens and Interim Report

Mr. Bolton paid a seven week visit to Athens in May and June 1963. Following this an Interim Report was submitted in August 1963, covering the ground indicated at Section (1.4) below. No attempt is made in the present document to summarise the work of this Report, although for convenience there is a certain amount of recapitulation of the recommendations. The data and calculations of this Interim Report are basic to the whole tariff survey, and a familiarity with it will be assumed throughout the present document.

1.3 Second Visit to Athens and Second Interim Report

Mr. Bolton paid a second visit to Athens in May and June 1964, but only part of this period was spent on the tariff survey. The conclusions and recommendations resulting from the work of this visit are presented herewith. Since the total programme has not been completed it is not possible to submit a final report. Hence the present document is submitted under the title "Second Interim Report". But where the term "Interim Report" appears without qualification, it must be understood that this refers to the first Interim Report.

1.4 Survey of Ground to be Covered

The work comprised in the complete tariff programme falls into three sections, as follows:-

(a) Analysis of the costs, present and future, including appropriate provision for depreciation and an adequate return on the capital employed. Establishment of a relationship between these costs and the various electrical services, and their allocation to different sectors of the supply system. Expression of the results in the form of Cost Formulae.

(b) Formulation of tariffs for high tension supply to industrial consumers in two groups, namely:- A, large-scale; and B, medium-scale. The latter have to take the place of the six two-part maximum-demand tariffs which now operate in the two areas of the Corporation's supply.

(c) Formulation of tariffs for low tension supply to residential, commercial, rural and small power consumers.

The Interim Report covered section (a) and the first part of section (b). The present document covers the remainder of section (b). It also includes recommendations for the preparatory work to be carried out in order to cover section (c) and thus complete the work.

1.5 Supply to Aluminium Industry

Three years before the first of the above-mentioned visits to Athens a long-term contract was entered into for the bulk supply of electricity to a group of French aluminium producers. This was not dealt with in the Interim Report because it was understood that the matter was already settled and did not admit of further action.

During the second visit the matter was raised again, and at the request of the Greek Government a separate report was submitted to the Government on the terms of this Contract. This Aluminium Report was dated 21st June, 1964, and whilst its contents do not form part of the present document, it is an essential element in the total tariff survey. This aluminium supply is much the largest of the new large-scale loads which the Corporation is hoping to attract; and whilst the terms of the supply put it into a class by itself which does not form part of the normal tariff schedule, its financial results inevitably affect the Corporation's total finances. This effect, therefore, cannot be dissociated from the total consideration.

1.6 Data Employed

The data made use of in the Interim Report consisted of the Annual Reports, Accounts and engineering statistics up to and including the calendar year 1962. During the 1964 visit the corresponding statistics for the year 1963 were made available and have been made use of in the present document.

The Interim Report also made use of the ten-year forecast that had been prepared for the period 1963 to 1972. It is understood that no formal revision has been made of this forecast. Moreover, whilst any forecast is necessarily subject to revision as the earlier years become replaced by factual results, none of the modifications up to date appear likely to upset the forecast from the financial planning aspect. In general, therefore, the ten-year forecast figures continue to be employed in the present document.

2 COSTS AND COST FORMULAE

2.1 Target Years

In the Interim Report a particular year in the forward estimate was made the "target" of the cost exercise, namely 1966. The same plan is followed in the present document, but (having regard to the fact that it is compiled a year later) a secondary target is made for a later year, 1972. This is the final year of the ten-year forecast and is probably the most distant year for which estimates can be made with any confidence. There is another reason for choosing these two dates. The year 1966 is likely to be the first during which all the new tariffs will be fully operative. Once they are introduced it is reasonable to hope that they will be able to operate with little or no alteration until the later date (1972). Thus these two target years represent an appropriate time range for the tariff calculation.

2.2 Physical and Financial Costs

The total costs of supply are in two categories which may be called physical and financial. The former are "factual" costs which are necessarily and immediately incurred. They take the form of expenditure on materials, wages, salaries, rents, administration costs etc. The latter category covers the capital charges and allocations, namely, depreciation provision and interest or capital yield. They are not actual or specific since they depend on some assumption or hypothesis such as length of asset life or appropriate capital yield. They lack the immediacy of physical payments and can on occasion be deferred or anticipated.

It may be objected that interest payments are factual and a necessary concomitant of particular loans. This is correct as regards the interest which appears in the annual accounts, but it is not true of the interest element which enters into the cost calculation. The distinction is particularly important in the Corporation's case because a large part of their investment is free of interest.

If the cost formula only included the factual interest it would not cover the true cost of giving the supply, and the tariffs based thereon would not secure an adequate revenue. It has therefore been recognised, by the Corporation and the Government alike, that the revenues secured must be sufficient to give an appropriate yield on the whole value of the net capital made use of, irrespective of whether this capital is derived from loans, gifts or accrued savings. If this were not done, it would mean that national resources were being used up at prices which were insufficient to replace them.

In order to make the above distinction clear, the word "interest" is used to denote the factual payments shown in the annual accounts, and the words "return" or "capital yield" are used to denote the interest element in the cost calculation. The latter must always and in every year be at least equal to the former in order that the Corporation shall pay its way. In general, however, it should be greater. (N.B. The other element in the financial cost, namely depreciation provision has been fully dealt with in the Interim Report (Section 2.3) and nothing needs to be added on this score).

2.3 Yield on Net Capital

In Section (2.4) of the Interim Report, the surplus of revenue over expenses was expressed as a gross figure before deducting depreciation provision. In the following treatment, depreciation provision is deducted, thus giving the net surplus. This surplus is then expressed as a percentage of the net capital employed.

The chief difficulty lies in deciding what shall be regarded as the net capital on which the percentage yield is to be reckoned. It cannot be taken as the total shown on the balance sheet because this is swollen by a number of items on either side, some of which cancel out. Thus any bills or accounts owing to the Corporation appear on the assets side, whilst bills owing by the Corporation appear on the liabilities side: it is only the difference between them (or net current assets) which represents actual capital needed to carry on the business. In a similar way the first cost of the physical assets shown in the balance sheet must be reduced to its depreciated or written-down value. It was for these reasons that a "simplified balance sheet" was shown in Table 3 of the Interim Report.

The net capital is usually defined as the sum of two quantities the fixed assets and the current or circulating assets or working capital. The net fixed assets are taken as the total first cost of the physical assets minus the accumulated depreciation provision and other capital provision or reserve. To this must be added the outstanding balance of any sums paid in acquiring past electricity undertakings, i.e. money paid for the goodwill or other rights and not represented by tangible assets. The net current assets are taken as the first cost of stores, fuel, etc. plus deferred debits and sums owed to the Corporation minus credits and sums owed by the Corporation.

Normally, the depreciation reserve would be not less than about one-third of the first cost of the fixed assets so that the fixed capital is only two-thirds of the asset cost. In the Corporation's case the reserve is only 14%, leaving the net capital as 86% of the asset cost. This is due to some extent to insufficient depreciation provision in the past, but chiefly it is due to the Corporation's short life and rapid rate of growth of capital investment.

The current assets represent an additional 10%, falling to 5% in later years. The overall result is that the net capital thus calculated comes out at an exceptionally high figure, and the percentage yield thereon appears exceptionally low.

The low depreciation reserve is, however, more than offset in the balance sheet by a very substantial general reserve representing the accumulation of past savings or capitalised surplus. This has arisen for the reason given above when drawing a distinction between "interest" and "yield". Whilst about half of the Corporation's finances have been provided free of interest, the revenues have been maintained at a level sufficient to give an adequate return on the whole of the capital employed.

This accumulated surplus plays exactly the same part financially as a depreciation reserve. It provides a measure of internal financing and, to that extent, reduces the amount of capital that has to be provided from outside. It is true that it is not possible to point to any actual sum of money, investment or sinking fund, as representing this surplus, but there are additional assets and increases in the equipment which have been acquired without additional investment from outside the industry.

It would therefore be permissible to deduct some, at least, of this accumulated reserve from the asset first cost when computing the net assets or net capital employed. The proportion so allocated should be such as not to depart in essence from the normal conception of net capital, and such as to permit a valid comparison being drawn with other electricity undertakings. In order, therefore, to adapt the net capital computation to the exceptional features of the Corporation's balance sheet some of this accumulated surplus is regarded as a capital provision or supplementary depreciation reserve. (Reference may here be made to the recommendation on accounting made in Section (5.14)).

The amount is chosen such that the total depreciation provision is 30% of the asset first cost. The net assets then become 70% of the asset cost, to which an addition of 5% is made for working capital. This latter is approximately the average proportion in the later years of the ten-year forecast.

The results of this calculation are to give a capital yield or return on the net capital employed of 7.2% in 1966 and 8.7% in 1972. These figures are comfortably above the target of 7% which has been indicated by the Government as a desirable sum. Even on the larger net capital assessed without any deduction for other reserves the returns in 1966 and 1972 are 6.5% and 7.7%, with an average of just over 7%. (N.B. These percentages must not be confused with the figure of 6.3% used in Section (4.7) of the Interim Report. This figure, which was used for allocation purposes, is a percentage of the assets first cost. They must also be clearly distinguished from the figures of gross return given in Section (2.4) which include the depreciation.)

The following section shows how these percentage yields have been calculated.

2.4 Financial Forecasts, 1966 and 1972

The following table (1) shows how the capital yield has been estimated for the two years 1966 and 1972. The 1966 figures are the same as those in Table 15 of the Interim Report (from which the cost formulae are derived) except for a revenue deduction noted below. Following the table are notes referring to the numbered lines.

In Table 15 (Interim Report) the total electricity revenue was shown, but with no details as to how the figures were made up. In the table below, the revenue is built up from consumption and mean revenue per kWh. These details were not given in the ten-year forecast and are merely estimates which have been made for the purpose of the present report.

TABLE 1

FINANCIAL FORECAST

Line	1966 Consumption 10⁶ kWh	1966 Mean Revenue Lepta/kWh	1966 Revenue 10⁶ Drs.	1972 Consumption 10⁶ kWh	1972 Mean Revenue Lepta/kWh	1972 Revenue 10⁶ Drs.
Revenue Estimate						
1. Present consumer classes	3 382 *	81.7	2 764.2	5 760 *	79.7	4 584
2. Heavy industry	1 560 *	20.1	314	2 200 *	20.1	442.5
3. Total tariff revenue	4 942 *		3 078.2*	7 960 *		5 026.5*
4. Other electrical revenue			30 *			58 *
5. Total electrical revenue			3 108.2*			5 084.5*
6. Other income			5.4*			1.0*
7. Total turnover		10⁶ Drs.	3 113.6		10⁶ Drs.	5 085.5
8. Deduct operating expenses		1 222.7*			1 836.8*	
9. Deduct general administration		40 *			58.0*	
10. Deduct additional 10%		126.3	1 389.0		189.5	2 084.3
11. Deduct loss on aluminium and other supplies			178			178
12. Gross surplus			1 546.6			2 823.2
13. Deduct depreciation provision			562.7			911
14. Net surplus			983.9			1 912.2
15. Fixed assets first cost			18 396			29 751 *
16. Net capital employed			13 611			21 958
17. Yield on net capital lines(14)/(16) x 100			7.2% (6.5%)			8.7% (7.7%)

Notes on numbered lines

General - the figures starred are from the 10-year forecast (marked TYF).

1. The mean revenues are consistent with the present figure of 87.9 lepta per kWh for 1963. This assumes roughly the present tariff levels.

2. The revenue for 1966 consists of 206 million drachmas given in the TYF plus 108 million drachmas which had been included under the heading "industrial". The corresponding figure for 1972 is calculated from the consumption assuming the same mean revenue of 20.1 lepta. The mean revenue assumption is approximately that of tariff A or the New Industrial Rate Schedule.

10. An addition of 10% has been made to the expenses shown in TYF for reasons given in the last paragraph of Section (4.3) of the Interim Report.

11. The consumption of the aluminium enterprise has been included in line 2 as though it were on the same tariff as the other large consumers. Whilst nothing is known regarding the outcome of the re-opened negotiations, it would be unrealistic to make such an assumption. In addition, there are some existing large consumers included in line 1 who will be eligible for the proposed large-scale tariff. This will be lower than any of the existing tariffs, and a loss in revenue will result. A deduction has been made for these two factors, and as no deduction was made in Table 15 the 1966 surplus now shown is less by this amount (178 million drachmas).

13. The depreciation provision for 1966 was shown in detail in Table 16 of the Interim Report. The figure for 1972 is taken pro rata to the assets shown on line 15.

15. For reasons given in Section (2.4) of the Interim Report (bottom of p.11) it was decided to associate a full 12-months capital charges with the figure shown for utility plant in service at the end of the year. The figure for 1966 is not identical with that in the ten-year forecast but is based on a complete breakdown supplied in 1965.

16. The net capital employed is computed in the manner described in Section (2.3) above.

17. The first percentage figure in each column represents the yield on the net capital shown in line 16. Following this is a percentage figure in brackets which shows what the yield would have been if the net capital had been calculated on more orthodox lines, i.e. without any deduction for accumulated surplus.

The broad conclusions to be drawn from the foregoing estimate are the same as those at the end of Section (2.4) of the Interim Report. If the tariffs for existing consumer classes maintain present levels and secure approximately the same mean revenues per kWh as at present, and if the new large-scale consumers pay according to the cost formula which has been devised, the overall capital yield will be satisfactory, even allowing for a certain amount of short-fall in the aluminium revenue.

2.5 Cost Allocation and Formulae

All the figures established up to this point have related to the enterprise as a whole. Now that the economic objectives have been defined, and a satisfactory balance has been forecast between total costs and total revenues the next step is to make a breakdown of these totals for different points of supply and different consumer groups.

For this purpose, in the Interim Report, the whole supply system was divided into three sectors corresponding to three possible points of supply, A, B and C. (Section 4.5 and Fig. 1). The costs were put into two groups according to whether they were proportional to the maximum demand in kilowatts or the energy in kilowatt-hours. These dual costs, as at 1966, were evaluated for each of the three points, and three two-part cost formulae were thus established. (Section 4.12)

This cost sub-division and allocation for 1966 is employed as the basis of what follows. It is true that the revenue now forecast is somewhat below that employed in the Interim Report. But the allocation is rightly based on the full or "ideal" revenue: if, subsequently, certain consumers pay less than their quota this reduces the capital yield to some extent. Provided that the lower yield is acceptable (as in this case it is) there is no need to change the allocation to the other consumers.

2.6 Variations in Capital Yield

Discussions were held with the Minister for Industry of the Greek Government (Mr. Zigdis) regarding financial objectives and the cost allocation to different consumer groups. In the present situation (which is not necessarily a permanent one) great importance is attached to keeping down the cost to the large-scale industries which it is hoped to attract. The tariff schedule should therefore be sufficiently flexible to take account of these nationally-desirable objectives.

In pursuance of this point it was suggested that whilst an overall return of 7% on the net capital was a suitable target, this need not be regarded as a rigid requirement for every part of the system. Instead of a uniform percentage throughout, a lower return might be accepted in respect of the assets used by some consumers provided it were made up by a higher return on the remainder.

This possibility was then investigated on the following lines. In the first place it should be explained that no change whatever was made in the energy-related portion of the cost allocation: the only changes were in the demand-related costs and the revenue from maximum demand charges. The object of the change was to reduce the demand-related cost allocated to group "A" consumers by means of a balancing increase in the cost to group "C" consumers. The cost to group "B" was to remain unchanged.

From the revenue aspect the change is an easy one. A glance at the fifth column in Table 19 of the Interim Report will show that the demand-related revenue contributed by the C consumers is nearly 6½ times as great as that contributed by the A consumers. In fact, a 25% reduction in the latter can be made up revenue-wise by an increase of only 4% in the former. The difficulty lies in squaring this transaction with the cost allocation.

The costs included in the demand-related allocation consist chiefly of interest and depreciation. It would not be proper to make any change in the depreciation provision, but it was found that if the interest content of the charge was reduced by reducing the yield on net capital from 7.2% to approximately 4½% the demand-related cost (and hence the maximum demand charge) was reduced by 25%.

In order to balance, it was only necessary to increase the capital yield on the assets used by the C consumers from 7.2% to 7.8%. This increased the demand-related charge by 4% and thus restored the revenue to its previous value. The "B" consumers were unaffected. (N.B. In speaking of assets used by certain consumers this is a figure of speech since most assets are used in common by all. For costing purposes however they can be thought of as being split between consumers according to their respective maximum demands).

It might appear that the above procedure is a departure from the aim of basing tariffs on a scientific cost foundation, and that it follows the dictates of policy rather than economics. This could certainly be said if such considerations were allowed to govern the allocation of specific direct outlays such as fuel and personnel costs. But in the above case the particular cost which is being manipulated is the cost of capital. Since this capital was Government-provided, and the Corporation is responsible to the Government for its best use in the national interest, it seems that a Government recommendation regarding differential interest rates can properly be regarded as a legitimate element in the cost computation.

The following gives the revised cost formulae which take the place of those in Section (4.12) of the Interim Report.

Point of Supply	Demand-Related Cost Drs. p.a. per kW	Energy-Related Cost Lepta per kWh
A	995	11.1
B	2 065	12.0
C	4 020	13.2

It will be noted that the figures for "B" and all the energy charges are unchanged. The other figures, when inserted in Table 19 of the Interim Report give the same total of maximum demand revenue.

2.7 Marginal and Mean Costing

Many millions of words have been expended in debating this matter. So far as electricity is concerned it has largely been an academic exercise with little relevance to any actual tariff. A maximum demand tariff may have two or three steps in each of its two parts, together with a fuel-cost variation and a power factor penalty, making up six or eight price tags in all. Even when the vexed question of marginal mean pricing has been finally decided and the dust of battle has subsided there will still be the problem of which of these many prices are governed by the decision. In this case it is not the principle (which has been so hotly debated) but the application that causes difficulty.

With tariffs, the two sorts of pricing - mean and marginal - should not be thought of as rivals or alternatives because they apply to different things, so that they should (and do) occur together. Properly considered, mean costing relates to the whole whereas marginal costing relates to the parts. The basis of mean pricing is the obvious fact that, if the undertaking is to be self-supporting, the total revenue must cover the total cost, and the mean price must therefore be sufficient to cover the mean cost.

Marginal costing, on the other hand, can be related to any separate element in any tariff and it there provides an essential lower limit. No part or step or incremental price in any such tariff should be lower than the corresponding incremental cost. In other words, the tariff should be so designed that, at every point in its range, an increase in the load (whether of energy or demand) will add to the revenue at least as much as it adds to the cost. It follows that the marginal cost does not indicate the price but it provides a series of stops or floor levels for the tariff prices. It is particularly relevant to the "follow-on" rate or the last-block price of a tariff.

The marginal energy cost is a fairly simple conception because it is physically possible to increase the system output by one kilowatt-hour and measure the increase in cost which results. In a thermal system, or in a mixed system in which the hydro resources are already fully utilised, the result will be some additional fuel consumption. As a limiting point in tariff construction, a marginal running cost of 6 lepta per kWh was estimated in Section (4.4) of the Interim Report.

The marginal demand-related cost is a much more difficult conception since the capacity of a generation and transmission system to meet demand cannot be increased by small amounts but only in large steps. Growth is then in the nature not of an inclined ramp but of a flight of stairs. At the flat portion of the step, increased demand costs nothing to supply. The marginal demand cost can therefore only be thought of in terms of a tiny fraction of the cost of a new power station or transmission line.

Taking a longer-term view of the situation, it may be said that, in general, the extra charge made for a given addition to the load should not be less than the cost of expanding or replacing the resources used up. In Greece's case the particular resources involved are capital, hydro-electric sites and lignite deposits. The cost of additional capital is considerably higher than the mean cost of all the capital now employed, and could be assessed by reference to the cost of attracting additional public investment, as in the recent much-advertised P.P.C. loan at 6½%. Alternatively it could be taken as the target "yield" on the net capital employed. The cost of additional hydro-electric generation could be assessed in relation to the less favourable sites which would have to be exploited when the present projects are fully utilised.

Taking the nearer view, the following data refers to the cost of four new power stations. This information is given because it is a guide to short-term marginal generation costs, and, as such, it has probably influenced tariff proposals that have been put forward from time to time. Its use in this way can, however, be very misleading, and the use of isolated station costs in fixing tariff values is strongly deprecated.

2.8 Cost of New Stations

Four large stations, two hydro and two thermal, are planned to come into operation during the next few years. The build-up of the generating capacity will, of course, be a gradual one, planned to match the anticipated load growth with an adequate margin, and the capital investment will build up in a similar manner. It follows that the financial effects will also be very gradual, and whilst the long-term results will be wholly beneficial both as regards capital costs per kilowatt and running costs per kilowatt-hour, it will be some years before the full effects are realised. In the meantime, other changes may occur which modify the effects, such as increased costs in other directions.

The time-lag in reaping the benefits of the new stations will be particularly noticeable in regard to capital costs. A new large generating set can give an immediate advantage in fuel economy but it can only add to the maximum demand revenue to the extent that there is additional load waiting to be served. This takes time to build up, and in the meanwhile the capital charges have to be met in full. It follows that whilst each of the new stations is a great improvement in cost per unit of output over existing plant their effect will be neither abrupt nor startling. There will be no sudden drop in costs in any particular year, and the most that can be looked for will be a small gradual improvement.

It is necessary to utter these warnings because in the light of the heavy investment that is taking place and the favourable economic characteristics of the new stations it is natural for expectations to be aroused of something spectacular in the way of reduced electricity prices. But in the light of general price trends and in the context of almost universal monetary inflation it must be regarded as a very great achievement (and perhaps the utmost that can reasonably be expected) if the new stations manage to prevent a price increase, and if the average consumer continues to pay no more for his electricity than he did, say, ten years previously.

Since the new stations are to be constructed and brought into commission step by step, and since their operation is to be integrated with the whole national system their economic effects can only be assessed by integrating their costs and outputs with those of the rest of the system year by year. When this is done (e.g. in the ten-year forecast) the results are very different from the impression obtained from the figures for the individual stations.

As an indication of this, the operating costs forecast for each of the years 1963 to 1972 were listed, and to each was added 10% of the cost of the assets scheduled to be in use in that year. (This served as a notional figure for the capital charges). The total was then divided by the energy sold in that year, so as to get the approximate costs per kilowatt-hour on a comparable basis. The result showed a drop averaging about 7½% in each of the four years from 1962 to 1966. (Total drop, 26½%). In the remaining six years (1966 to 1972) the figure fluctuated but without any clear trend either up or down. In short, whilst the total improvement is very substantial it is spread over a number of years and at no point is it spectacular or sensational.

TABLE 2

Costs at Four New Sations

The following table employs the cost estimates contained in the "Note on The New Industrial Rate-Schedule" which was prepared in April 1963. The energy outputs from Kastraki and Kremasta have been reduced according to the latest available information. A fifth column has been added for Kremasta final stage.

		Kastraki Hydro	Kremasta Hydro	Ptolemais II & III Thermal	Megalopolis I & II Thermal	Kremasta Final Hydro
1	Installed capacity MW	240	400	250	250	500
2	Mean annual output 10^6 kWh	861	1 540	1 800	1 800	1 570
3	Plant Factor (2) ÷ (1) X 8760 %	40.9	43.9	82.3	82.3	35.9
4	First cost 10^6 $	52.6	72.66	47.33	41.33	78.23
5	Life for depreciation years	65	65	33	33	65
6	Corresponding sinking fund %	0.139	0.139	1.027	1.027	0.139
7	Interest 6% + Insurance %	6.10	6.10	6.20	6.20	6.10
8	Total charges (6) + (7) %	6.239	6.239	7.227	7.227	6.239
9	Annual capital charge (4) X (8) 10^6 $	3.282	4.533	3.42	2.987	
10	Operation & Maintenance 10^6 $	0.19	0.22	0.71	0.62	
11	Fuel 2.8 or 3.0 X (2) 10^6 $			5.04	5.40	
12	Total (9) to (11) 10^6 $	3.472	4.753	9.17	9.007	
13	Mean cost (12) X 1.09 X 3 ÷ (2) Lepta/kWh	13.2	10.1	16.7	16.4	

Notes on numbered lines.

2. The estimates speak of the annual "generated" energy and it is not clear whether any deduction has been made for the energy used in the station. In thermal stations this can be quite a considerable percentage.

6. Sinking fund tables based on interest at 6% and annual compounding.

7. Insurance at 0.1% on hydro stations and 0.2% on thermal.

10. Thermal, at 1.5% of first cost.

11. Lignite cost 42 Drs/Ton Specific consumption 2 KG/kWh. Cost = 42/30 $ per ton X 2 = 2.8 mills/kWh at Ptolemais. A figure of 3 mills is assumed at Megapolis which includes the cost of pre-drying

13. Add 9% for interconnection and multiply by 3000 (lepta per dollar).

It must be emphasised that each column in this table represents merely the cost at which that particular station could deliver its maximum yearly output to the network when working at its own ideal load factor. It is no guide to the cost of operating that station with others under the actual working conditions involved in meeting the total national load. These separate station costs have therefore not been used in the cost formulae that have been developed. The cost formulae, like the ten-year forecast, are based on the actual operating conditions of the interconnected system, not upon the hypothesis of isolated stations. They also use different assumptions regarding interest or yield, and, as regards depreciation provision, instead of the sinking fund calculation they employ the straight line method as actually used in the Corporation's accounts.

3 INDUSTRIAL TARIFF DESIGN: RECOMMENDATION FOR LARGE-SCALE SUPPLIES ("A")

3.1 Reasons for Special Tariff

Before designing a tariff for supplies to large consumers - say those with demands exceeding one or two megawatts - it is well to consider what are the reasons which make a special tariff necessary. The main reason is the difference between the costs of supply at points A and B in the supply system as illustrated in the diagram (Fig. 1, p.29 of the Interim Report). It will be seen that consumers at points "B" make use, in common with the "A" consumers, of the generation and interconnection system, and they also necessitate the provision of additional high tension transmission equipment.

To put the point more specifically, it is less expensive to supply one consumer of 5 MW than to supply ten consumers of 500 kW each, even if their aggregate demands and consumptions are the same. The latter on purely geographical grounds, and merely because they are distributed and not concentrated at one point, will require more kilometers of high tension line, more substations, etc. There are also what are called "economies of scale", illustrated by the fact that a large transformer and a large substation is cheaper per kilowatt than a small one.

The additional equipment required by the smaller consumers will involve additional capital charges, operation and maintenance costs, and losses. They will therefore add slightly to the energy-related cost as well as to the demand-related.

A further point is that in general (though not invariably) smaller consumers tend to be supplied at a lower voltage, and this may involve an additional stage of step-down transformation. For example, to take the extreme case, the aluminium works is to be supplied at 63 kV. Consumers of 5 or 10 MW would usually be supplied at 22 kV in the Metropolitan area or 15 kV in the Provincial area. On the other hand, consumers below 1 MW, if in the Metropolitan area might be supplied at only 6.6 kV.

All these cost differences have, as far as practicable, been expressed in the cost formulae A and B which were developed in the Interim Report and revised in the present document. These differences constitute the main reason for having separate "A" and "B" tariffs.

In addition to these cost considerations there are considerations of a commercial nature. Industries which use electricity on a large scale for processing purposes, furnaces, etc. may find electricity costs to be a major item in their expenses, and amounting to 10% or more of the value of their product. On the other hand, industries using electricity largely for motive power will usually find their electricity bill to be less than 5% of the total turnover. In the former case the electricity price may be a determining factor in deciding whether and where the industry shall be set up, and since such loads are likely to fall into the higher size group this is a reason for keeping the tariff at "A" as low as possible.

3.2 Consumer Costs

The differences in the cost per kilowatt and per kilowatt-hour which arise in supplying 500 kW and 5000 kW consumers, and which necessitate separate tariffs, also arise on a smaller scale between consumers on the same tariff. In addition to the differences due to "economies of scale" there are certain specifically consumer (or per capita) costs independent of the size of the consumer. Every consumer has to have a meter which has to be read and the bill made out and the money collected. He has to have his individual service connection to the network, the cost of which is largely independent of the size of the load.

This does not mean that every consumer on the system large or small has the same "consumer cost". Obviously there is greater expense in metering, billing and providing a service connection for a large two-part industrial consumer than for a small domestic consumer. What it does mean is that, within a given tariff group there is an approximately fixed sum which should be collected per month or per year from each consumer to cover expenses which are independent of their demands or energy consumptions.

There are two ways of collecting the consumer cost within the confines of a single tariff. One is to have a minimum charge payable whether or not any electricity has been consumed. The other is to have a first block in the tariff (or in the kilowatt charge of the tariff) at a higher price than the succeeding block or blocks. The second method is preferable technically since it does not encourage waste or invite the charge of "paying something for nothing". On the other hand, it does not ensure the proper revenue on very small or zero consumptions. Ideally, therefore, both methods should be used.

Since the consumer cost has been shown to be a small-scale equivalent of the cost difference between supplying at points A and B, and since it can be covered in a single tariff by means of different block prices, it might be thought that an extension of the block pricing principle could enable a single tariff to serve for both "A" and "B" consumers. This is broadly true, and some undertakings have employed a single tariff with several block prices for any size of consumer from 100 kW upwards.

There are two difficulties which arise in following such a course in the present situation. In the first place, the proportions of the two parts which are right for tariff "A" are not the best for tariff "B" owing to the element referred to below as "differential diversity". In the second place, whilst tariff "A" has virtually a free hand, since it does not replace any existing tariff, this is not true of tariff "B", The latter has to take the place of six existing tariffs, and it must have some regard for present practice and the avoidance of hardship in the change-over.

3.3 Line of Demarcation

Whilst it is easy to distinguish the difference in the supply costs at A and B by taking fairly extreme cases such as 500 kW and 5 MW, it is less easy to see where to draw the line. Wherever it is drawn there are likely to be consumers slightly on either side of it whose characteristics will be almost indistinguishable.

In fact, most of the differences enumerated in previous paragraphs are quantitative rather than qualitative, and merge into each other. The only sharp distinction lies in the voltage of supply and this would not furnish a distinctive guide.

It has been said that in the Greek situation a natural division occurs at the size of 1000 kW, and that a clear distinction can be drawn between consumers below and above this line. Whilst this might be true at the moment, it cannot be accepted that it will always remain the same. If the line is drawn at this point there will sooner or later be consumers round about 950 kW and others round about 1050 kW whose supply conditions will be very much the same.

Since there cannot be separate tariffs which are ideal for each situation, there must be some degree of compromise. The best plan is therefore to aim the large-scale tariff "A" at a size of, say, 5 to 20 MW with load factors in the 60% to 90% range, and the smaller tariff "B" at a size of, say, 500 kW with a lower load factor range. Intermediate situations are then catered for by suitably proportioned steps in the two tariffs.

In deciding these proportions one essential point is to minimise the jerk or discontinuity in passing from one tariff to the other. This is important on equity grounds because it is impossible to justify a major difference in price for very minor differences in service. It is also important on administrative grounds because, if a decision has to be made on relatively arbitrary grounds to put a consumer on to one or other of the tariffs, the monetary difference should be made as little as possible. Preferably, the two tariffs should merge at the point where they are contiguous so that no anomalies or hard cases can arise.

Ideally, the two tariffs together should present a continuous ladder or escalator stretching all the way from 100 kW to 100 MW. At every point there should be encouragement of increased load and increased load factor. This encouragement should not be concentrated at a few particular points, but should be spread over the whole range.

3.4 Two-part Tariff Design

The starting point of the design is the two-part cost formula. This, however, is not the finishing point, and adjustments have to be made for a number of other factors, in particular, diversity, differential diversity, and consumer costs.

As regards diversity, if there are 100 consumers supplied under a two-part tariff, it is very unlikely that all their maximum demands will occur at the same time or within the same half-hour. It follows that if each consumer were charged for his demand according to the cost formula, the total demand-related revenue would exceed the total demand-related cost. In order to compensate for the effects of this diversity, it is necessary to divide the demand cost by a diversity factor in order to arrive at a suitable tariff figure.

It is clear that if all consumers had a load factor of 100% there would be no diversity. Also if there were only one consumer in a class there would be no diversity within that class although there might be diversity between that class and the whole system.

From these two facts it is clear that the diversity factor will be (a) greater the smaller the load factor, and (b) greater the larger the number of consumers. The last mentioned will be a diminishing effect, since 1000 consumers will have very little more diversity than 100 consumers.

It follows from the above that the diversity factor for the "A" consumers will be less than for the "B" consumers, since there will be less of them and, in general, they will have higher load factors. In the present case a figure of 1.05 has been used for A and 1.15 for B.

3.5 Differential Diversity

The reciprocal relationship just mentioned between load factor and diversity factor not only arises as between "A" and "B" consumers, but it also arises between individual consumers in either group. A consumer with a very low load factor, such as 5% or 10%, will have a very large diversity with other consumers of the same sort. On the other hand, consumers with load factors in the 60% to 90% range can have only a very small diversity with each other.

The method of compensating for this characteristic with consumers who are all on the same two-part tariff, is to "tilt" or "bias" the two parts of the tariff. This is done by reducing the demand charge and increasing the running charge in such a way that the total revenue under the average load factor remains the same. Consumers with higher-than-average load factors will pay somewhat more than under the untilted tariff, whilst consumers with lower-than-average load factors will pay somewhat less. Since the tilting tends to be unfair to very high load-factor consumers, it is usual to introduce a compensating feature in the form of a lower step in the running charge at high load factors.

In the present case there is a greater degree of tilting in tariff B than in tariff A, and this is the major factor giving a difference in the proportions - i.e. a higher ratio of demand charge to running charge in tariff A.

3.6 Recommended Tariff

The following is the recommended tariff for large supplies. This takes the place of the recommendation in Section (5.2) of the Interim Report.

Demand Charge

First	1 MW:	1600	Drachmas	per	annum	per	kilowatt
Next	19 MW:	900	"	"	"	"	"
All over	20 MW:	825	"	"	"	"	"

Energy Charge

12 Lepta per kWh for the first 400 kWh per month per kW of M.D.
10 " " " " all additional consumption.

The general character of this type of tariff has already been described in Section (5.1) of the Interim Report. Not only is it almost universally employed for this type of load, but it is well known to the Corporation, being similar in character to the existing H.T. industrial tariffs, and to the proposed NIRS mentioned below.

Its operation can best be made clear by a series of comparisons. The following are carried out below, namely (a) comparison with existing tariffs; (b) comparison with other proposals; and (c) international comparisons.

3.7 Comparison with Existing Tariffs

The existing tariffs are so different in their proportions, both from each other and from tariff A, that a clear-cut comparison is not easy to make. Broadly speaking, however, tariff A is lower than the existing rates. As however there are not many very large consumers, it is better not to attempt a formal comparison between the tariffs but to make a revenue comparison in respect of the few large consumers who will be involved. Subsequently a formal comparison will be made between the existing tariffs and a new proposal, tariff B, since this is the one which will chiefly affect the change-over. There will also be a straight comparison between tariffs A and B in a later chapter.

Table 3 gives the latest available information regarding the Corporation's large consumers, and relates to the first four months of 1964. As regards the largest consumer, the Government Nitrogen Enterprise, no tariff rates have yet been settled, so that no comparison is possible. As regards the other three consumers, the table shows the effect, based on present consumption, of applying the recommended tariff A.

As will be seen, the revenue loss is substantial; in a full year it would total nearly 30 million drachmas, slightly under 1% of the total turnover. This loss appears to be inevitable if an equitable and attractive tariff is to be instituted. The present rates for large supplies are high by any standard, and existing consumers must be given the benefit of the reduction, although this need not necessarily occur immediately.

TABLE 3

Large Consumers (January to April 1964)

	Mean Monthly		Load Factor	Mean Revenue Lepta per kWh		Loss in Revenue	
	MW	10^3kWh	%	Existing	Tariff A	Lepta per kWh	%
Halivourgiki Steel	13.7	7 800	78.0	43.3	26.6	16.7	38.5
Titan Cement	10.2	5 171	69.2	40.6	29.0	11.6	28.6
Olympus (‑) Cement	5.75	3 284	78.2	44.5	27.6	16.9	38.0
Government Nitrogen	29.0	12 260	57.9	Not settled	31.3		

3.8 Comparison with "New Industrial Rate-Schedule"

Reference has already been made to the document entitled "Note on the New Industrial Rate-Schedule" compiled in April 1963. A description was given in Section (5.1) of the Interim Report of the tariff set out in this Note under the title "New Industrial Rate-Schedule" (NIRS). The following table (4) which takes the place of Table 20 in the Interim Report, compares the recommended tariff A with the NIRS at 5 MW and 30 MW.

TABLE 4

COMPARISON WITH NIRS

	Mean Monthly Load Factor	40%	60%	80%	100%
At 5 MW	Tariff A	44.3	33.3	27.5	24.0
	NIRS	59.3	42.6	34.0	28.1
	Difference	15.0	9.3	6.5	4.1
At 30 MW	Tariff A	39.9	30.4	25.3	22.3
	NIRS	42.2	31.2	25.4	21.2
	Difference	2.3	0.8	0.1	- 1.1

N.B. In the above comparison it is assumed that the monthly demand charges given in the Note are the actual charges made for monthly demand and not merely a one-twelfth instalment of the annual rate. On this assumption, and in order to provide a valid comparison, the tariff A demand charges based on the largest demand of the year are divided by 11 to give the equivalent monthly charges if these were levied on the monthly demands.

It will be seen from the table that the two give approximately the same results on a size of 30 MW. Actually on this size the two curves cross at 83% load factor; tariff A is cheaper on lower load factors, but the NIRS is cheaper between 83% and 100% load factors. There is, however, less than 6% difference between them over the whole range from 40% to 100% load factor. On sizes below 30 MW and especially on the lower load factors, tariff A is cheaper. On sizes above 30 MW, and especially on the higher load factors, the NIRS is cheaper.

Taking the whole field, the differences only become considerable on the very large sizes (50 MW and over). Below this, the two rates, whilst differing in their proportions, result in broadly similar revenues.

The special features of the NIRS which largely account for the above-mentioned difference in proportions are that it has a very steeply falling demand rate on larger sizes, and a very steeply falling energy rate on high load factors. It therefore gives excessive encouragement to increased size and to increased load factor.

For example, the final step in the demand charge (over 30 MW) is only 20 drachmas per kW per month, and the final step in the energy rate (above 82% load factor) is only 4 lepta per kWh.

These figures are both below the corresponding marginal costs of production, and even for generation alone it would be difficult to justify them from the figures for the four most economic stations shown in table 2.

The result is that, at certain points in the scale, consumers can increase their loads for an increase in their bill which does not cover the additional costs of supply. Moreover, reasons have been given in Sections (5.5) and (5.7) of the Interim Report for thinking that the load development which would result from basing tariffs on these figures runs contrary to the pattern of the Greek national load and generation resources.

3.9 International Comparisons

Curves were produced showing electricity prices in five or six European Common Market countries. These referred to the overall prices under two-part industrial tariffs on four different sizes of load, namely 1 MW, 3 MW, 7 MW and 10 MW. The graphs are scaled in mills per kWh and for present purposes it has been assumed that one mill equals three lepta. The base of the graphs runs from 350 to 600 hours per month use of the maximum demand - i.e. from about 50% to 80% load factor.

These graphs are reproduced in figures 1 to 4, and on each graph is shown, chain-dotted, the corresponding curve for the Greek tariff A. It will be seen that this lies below all the other curves except on 1 MW. (The effect is exaggerated in the graphs owing to the fact that they have a suppressed zero). In these curves the same assumption regarding monthly and annual maximum demand charges is made as in the footnote to Table 4.

It should be stated that no supporting figures were supplied with these curves nor is it known whether the conditions of supply are comparable with those of tariff A. - they are merely reproduced as given. It is understood that they refer to the prices operating two or three years ago, and since tariff A is designed to operate from 1966 onwards there may by this time have been price increases in the continental countries which would make the comparison even more favourable to the proposed Greek tariff.

As regards the proportions of the tariffs, as evidenced by the slopes of the curves, it would appear that tariff A is very much in line with continental European practice.

4 TARIFFS FOR MEDIUM-SCALE INDUSTRIAL SUPPLIES ("B")

4.1 Ground to be Covered

The next group to be considered is that of consumers whose demands range from 100 kW to 1000 kW. They are supplied from the secondary high tension network at voltages from 6.6 kV up to 22 kV (or 15 kV in the Provincial area) as represented by points B in the system diagram (page 28 of the Interim Report). Including the consumptions of the very large consumers who will be supplied under tariff A, they account for about 40% of the Corporation's total load and they contribute 23% of the revenue. They are at present supplied under six different tariffs, and the problem is to design a tariff which will replace all six with the minimum of hardship and which will represent the cost as equitably as possible.

The cost allocation for this sector of the supply system has already been carried out in Section (4.10) of the Interim Report. The modification due to variations in capital yield carried out in the previous chapter made no change in this sector, and it follows that the cost formula B is the same as that in Section (4.12) of the Interim Report. The steps by which the tariff is developed from this formula were fully described in the Report and the tariff recommendation is therefore unaltered.

The problem of rationalising a number of different tariffs and replacing them by a single one is a dual problem, and sometimes it actually has to be a dual operation in practice. The first problem is to coalesce the many into one, irrespective of the merits of that one. In the United Kingdom after nationalisation, each Area Board had to rationalise some 30 or 40 different tariff systems, and often this could only be done quickly by a process termed "cannibalism" by which one large and predominating tariff swallowed up all the smaller ones. This is not possible in the present instance since no single tariff predominates.

The second problem is to modify and improve the sole survivor so as to bring it more into line with costs and to make it more viable. Fortunately, in this case it has been found possible to do both jobs in a single operation.

4.2 Recommended Tariff

The following (referred to as Tariff "B") is the same as that described under the heading "Tentative Tariff Proposals" Section (6.6) of the Interim Report.

Demand Charge

First	100 kW:	150 Drachmas per month per kW (Minimum 20kW)
All over	100 kW:	100 " " " " "

Energy Charge

25 lepta per kWh for the first 400 kWh per month per kW of M.D.
20 " " " " all additional consumption.

Certain associated features of this tariff (together with similar features in Tariff A) are discussed in the next chapter. These include variations for fuel cost and power factor, minimum charges and connection charges, maximum demand assessment.

The general pattern and operation of this tariff can be seen in Fig. 5 where it is plotted side by side with the existing tariffs A.3 and T.23. The differences lie in the proportions rather than in the total revenue. Broadly, the difference is that the existing two-part tariffs all have relatively low demand charges and high energy charges as compared with Tariff B (and still more if compared with Tariff A or with NIRS). Hence the new tariffs will tend to increase the overall price to low load-factor consumers and decrease it to high load-factor consumers.

In the Interim Report the above tariff was tried out on each of the existing consumer groups by treating each group as though it consisted of a single "average" consumer. The results, which were presented in Table 23 were perfectly satisfactory so far as they went. The new tariff was intended to produce approximately the same revenues as the old ones, and on this showing it did so precisely. (The figures of Table 23 refer to 1962. They have not been repeated for 1963 because they are superseded by the individual treatment described below. The table is useful, however, as a guide to the consumers and consumptions involved in each tariff).

4.3 Revenue Trials by Sampling

Whilst the revenue estimate based on the "average consumer" is a useful preliminary in finding whether the revenue is broadly correct, it is statistically inaccurate as a measure of total revenue and it gives no indication whatever of the individual effects. It was for this reason that the Interim Report recommended that trials should be made using sampling methods. These trials were completed during the second visit (June 1964) and the results are given below.

The purpose of sampling is to try out the new tariff on individual consumer accounts without having to handle large numbers of accounts. This is particularly useful in saving time when several alternatives may have to be tried. The method is to pick out at random one in every so many consumer accounts and to compare the revenues under the proposed tariff with those actually received during the year in question.

Table 5 represents the whole of the industrial consumers now being supplied at high tension under two-part tariffs, i.e. including those who will be large enough to qualify for Tariff A. The table is in two parts, the first part (first ten lines) giving descriptive and comparison data for each tariff group. The second part (last five lines) gives the result of the revenue trial.

It will be seen that the five APECO tariffs (A1 to A5) cater for sizes ranging from mean monthly demands of 76 kW to over 5000 kW. The middle tariff of the range, A3, covers approximately the same mean size (500 kW) as the Provincial tariff T23, and it has exactly the same mean revenue of 51.8 lepta per kWh.

As would be expected, average load factors tend to increase with the increase in consumer size. Whilst consumers on tariffs A1 and A2 would appear to be largely single-shift operators, consumers on the larger tariffs have load factors characteristic of multi-shift operations. (Owing to the different form of the T23 tariff the mean consumer load factor cannot be calculated. But the revenue calculations indicate that T23 is a slightly more expensive tariff than A3, and since it secures the same mean revenue from the consumers to whom it is applied, this suggests that the T23 consumers have a somewhat higher mean load factor than the figure of 58% for A3).

TABLE 5

Revenue Effects of Tariff B:

Results of Sampling Trial

(All figures refer to 1963 except where otherwise stated).

			Capital						Provincial	Grand
			A1	A2	A3	A4	A5	Total	T23	Total
1.	Mean monthly M.D.:	kW	76	201	503	2 660	5 688		480	
2.	Mean monthly load factor:	%	36.2	38.0	57.7	71.2	61.6			
3.	Number of consumers		111	179	87	9	5	391	93	484
4.	Sampling ratio		1 in 5	1 in 5	1 in 3	All	All		1 in 3	
5.	Consumers in sample		23	36	29	9	5	102	31	133
6.	Mean usage per consumer 1962 total:	10^6 kWh	0.272	0.570	2.184	15.3	25.3		2.49	
7.	Mean usage per consumer 1963 total:	10^6 kWh	0.145	0.515	2.104	16.6	30.7		2.79	
8.	Mean usage per consumer 1963 sample:	10^6 kWh	0.241	0.671	2.55	16.6	30.7		2.73	
9.	Mean revenue per kWh. 1962 total: Lepta per	kWh	74.4	64.9	56.3	49.0	47.2		50.1	
10.	Mean revenue per kWh. 1963 total: Lepta per	kWh	74.6	60.2	51.8	45.2	44.0		51.8	
11.	Mean revenue per kWh. 1963 sample: Lepta per	kWh	68.0	59.55	50.79	45.2	44.0		50.41	
12.	Ditto, Tariff B: Lepta per	kWh	76.95	68.59	50.19	43.3	46.56		47.26	
13.	Change % (12) - (11)/(11)		+13.2	+15.3	-1.16	-4.18	+5.8	+1.76	-6.24	+0.3
14.	Money revenue, actual	10^6 Drs.	3.77	14.38	37.53	67.57	67.52	190.8	42.62	233.4
15.	Revenue change (13) X (14)	10^6 Drs.	+ 0.50	+2.20	-0.44	-2.82	+3.91	+3.35	-2.66	+0.69

N.B. Line 11 gives the actual mean revenue in 1963 in lepta per kWh from the sample, and line 12 gives the mean revenue under tariff B for the same consumers. Line 13 gives the percentage change resulting from the new tariff. Line 14 gives the actual money revenue from the sample, and line 15 gives the money change resulting from the new tariff. It will be seen that line 15 derives from lines 13 and 14 in all the columns except the two total ones. In these, line 13 derives from 14 and 15.

Reference can be made to Table 23 in the Interim Report giving similar information for 1962, and in order to facilitate comparisons, certain of the 1962 figures are repeated here. Such comparisons are useful because they indicate trends and they help to show whether the year in question is typical of other years. For example, it is noticeable that there has been a large drop in the numbers of consumers in groups A1 and A2, and a large drop in mean usage in group A1. (The consumer total of 484 compared with 643 in Table 7 indicates that Table 5 is not all-inclusive).

The most important comparisons to be drawn are those which help to show whether the consumers whose accounts have been picked out represent a truly "random" sample in each case, or whether they show a bias or skew in some direction. If the sample is typical in every way of the total "population" from which it was drawn, it should have approximately the same mean usage per consumer, and the same mean revenue per kWh (with the same tariff, that is). The only serious disparity is in group A1 where the sample had a mean usage per consumer 1-2/3 times as great as that of the total population. In view, however, of the closeness of the mean revenue figures, as between the sample and the total, it did not appear that this disparity would affect the results appreciably or necessitate another sample being taken.

4.4 Revenue Results

The results given in lines 13 and 15 of Table 5 indicate that, from the aspect of total revenue, the recommended tariff is extraordinarily successful. Aimed to produce approximately the same revenue as at present it has hit this target to within 0.3%. The change is made up of an increase in the Capital area of 1.8%, and a decrease in the Provincial area of 6.2%, and allowing for the difference in volume the two almost exactly cancel out.

Looking at the results in the separate groups it appears that Tariff B steers an acceptable middle course between them. The only substantial changes occur in A1 and A2 where there are increases of 13% to 15% owing to the fact that these two tariffs are at present well below the level of the remainder. In fact, the largest change produced by the new tariff in any group is less than the difference which already exists between some of the groups (e.g., A3 is some 16½% higher than A2).

This is a case in which the two elements or stages in tariff rationalisation can be accomplished in one operation. The results show that tariff based on cost consideration is little removed from that which would have resulted merely from an endeavour to minimise disturbance.

It was pointed out in the Interim Report that, on the evidence of the tariffs alone, it is not possible to say for certain which of the two areas has the higher industrial tariffs, and by how much. Now that each separate tariff has been compared against a common standard (the recommendation B) in terms of the particular consumptions involved, it is possible to compare any one of them against any other. On the evidence of line 13 of the table it appears that Tariff T23 is about 1.76 + 6.24, i.e. 8% higher than the weighted mean of tariffs A1 to A5. It is also clear that Tariffs A1 and A2 (and to a lesser extent A5) are relatively low, whilst A4 and T23 are relatively high.

It is clear from the size of the mean demands in the A4 and A5 tariff groups that these will include the consumers whose demands exceed 1 MW and for whom Tariff A is intended. This might appear to invalidate the revenue calculation which was based on a trial of Tariff B for the whole of the groups listed in the table. Fortunately, as will be seen from the next chapter, the revenue effects of the two tariffs are very similar in the neighbourhood of 1 MW. Moreover a correction has already been made for the loss in revenue through switching the few very large consumers on to Tariff A, and it does not appear that the remaining consumers over 1 MW will introduce any serious error in the revenue estimate due to assuming Tariff B instead of A.

4.5 Incidence Trials

The purpose of the sampling survey is two-fold, namely, to judge the overall effects and to judge the individual effects. The first and major purpose, which has now been accomplished, is to see how the total revenue will be affected by the new tariff. The second and minor purpose is to examine the incidence on the individual consumer. For example, it would be possible for the new tariff to produce an identical revenue whilst some individual consumers might be very hardly hit and others might experience substantial reductions. This is not so likely to occur when the individual tariffs have each produced fairly level results as in the present case. At the same time it is desirable to make a test of the individual effects in order to see that no cases of severe hardship are likely to arise.

For this purpose an examination has been made of the individual accounts making up the samples whose totals were tabulated above. For each consumer, a note has been made of the percentage change in revenue produced by the new tariff, together with the actual monetary change in the monthly bill. The results of this secondary examination had not been received at the time when the present report was finalised, but when they are available it is recommended that they be scrutinised from this point of view. Although samples cannot be guaranteed to show the most extreme change that can arise, they will indicate the likelihood and severity of individual hardship.

5 GENERAL CONSIDERATIONS

5.1 Summary of Recommendations

The present chapter covers a number of features which are common to both A and B tariffs, or which concern their joint operation. For convenience, the two sets of recommendations are repeated in Table 6 below. For comparison purposes, three other tariffs are shown side by side in the lower part of the same table.

To some extent this is an attempt to compare the incomparable, and it must not be taken too far or too closely. For example, Tariffs A, B and NIRS have one or more steps in the running charge dependent on load factor. On the other hand Tariff A5 (likewise A4) has a series of steps depending only upon size. They can therefore only be related to load factor by assuming a certain size. This comparison has been drawn in the table in relation to a size of 1000 kW.

It may be noted in passing that Tariffs A1 and A2, Tariff T23 and Tariff A3 employ three other methods of varying the running charge. With this difference in "shape" or pattern, any comparison such as that in the table can only be taken broadly. To be more precise would involve so much detail as to raise a cloud of obscurity in which the purpose of the comparison would be lost.

TABLE 6

Tariff Recommendations and Comparisons

Tariff:-	B		A	
Demand Charge: Drachmas per kW				
	Per Month		Per Annum	Per Month
First 100 kW	150	First 1 MW	1 600	145.4
Over 100 kW	100	Next 19 MW	900	81.8
		Over 20 MW	825	75
Running Charge: Lepta per kWh				
First 400 kWh per month per kW	25			12
Over 400 kWh per month per kW	20			10

Tariff:-	A3		A5		NIRS
Demand Charge: Drachmas per month per kW					
First 140 kW	60.7	First 300 kW	57.13	First 5 MW	140
Over 140 kW	47.6	Over 300 kW	45.57	Next 5 MW	120
At 1000 kW	49.4	At 1000 kW	49.0	Next 10 MW	90
				Next 10 MW	50
				Over 30 MW	20
Running Charge: Lepta per kWh					
First 100 kWh per kW	51.8	First 20 MWh*	72.1	First 200 kWh per kW	12
Next 100 " " "	38.1	Next 50 MWh	48.3	Next 200 " " "	10
Over 200 " " "	34.8	Next 330 MWh	41.5	Next 200 " " "	8
		Over 400 MWh	38.1	Over 600 " " "	4

* Figures in megawatt-hours (1000 kWh). On a load of 1000 kW these figures would represent kWh per kW.

On Tariffs A3 & A5 the running charges have been increased by 11.5 lepta per kWh for fuel increase and all charges have been reduced by 5% rebate for prompt payment.

5.2 Transition Between Tariffs

Whenever two tariffs operate in the same field - i.e. where there is no clear distinction of use such as that which exists between domestic and industrial - it is essential to have a clear and unequivocal definition of where the line is to be drawn. There should be no ambiguities or administrative difficulties such as might necessitate local decisions having to be made in individual cases. The tariff rules should be impersonal without appearing to be arbitrary.

Reference was made in Section (3.3) to the suggestion that under Greek conditions the best size at which to draw the line between Tariffs A and B would be 1 MW. This figure has therefore been assumed here, although most of the present remarks will apply wherever the line is drawn.

Having decided where the two tariffs are to join, the aim is to make the joint as nearly invisible as possible. It cannot be entirely so, since this would mean that there was no need to have two tariffs and that a single one, with suitable steps, would suffice. In the case of Tariffs A and B there is a difference in the proportions, the former having a somewhat higher ratio of demand to running charge. Tariff A will therefore tend to favour the higher load factor consumers, and vice versa.

The effects can best be shown graphically, and in Fig. 6 the full lines refer to Tariff B and the chain-dotted lines to Tariff A. Starting with the smallest consumers on Tariff B, e.g. those with a mean monthly demand of only 100 kW, their overall price at various load factors will be represented by the topmost curve in the graph. As the load increases the curve gets progressively lower, and at 1000 kW it reaches the middle position shown. At this point, Tariff A takes over. The curve changes its inclination with the change of tariff but keeps approximately the same average height for this size of load. On larger sizes, the curve falls progressively, and at 5 MW it reaches the bottom position shown.

At the size of 1 MW (the proposed dividing line between Tariffs A and B) the two curves cross at a mean monthly load factor of 43%. Consumers with loads approaching this size and with load factors higher than this will gain by switching from B to A, and will have a strong inducement to raise and maintain their loads and load factors high enough to qualify for the latter tariff. From the figures of Table 5 it would appear that this will apply to most of the 14 or so consumers now on Tariffs A4 and A5. On the other hand, the consumers on A1 and A2, and almost all those on A3 will be appropriately served by Tariff B whose proportions give more equitable results on lower load factors.

It therefore appears that, with the consumer characteristics shown in the table, the two tariffs will merge satisfactorily and will give an automatic advantage at about the chosen dividing line without the need for harsh administrative decisions. They will as far as possible avoid the situation in which a consumer of, say, 970 kW can substantially reduce his bill by wasting electricity.

Another border-line case, but on the opposite side of the border, is that of a low load-factor consumer above 1000 kW who would be better off on Tariff B. If his situation is such that he cannot economically increase his operating hours it might then be feasible to offer him Tariff B. In general, it is not recommended that consumers be given a choice of tariff, for reasons stated in Section (5.1) of the Interim Report.

5.3 Maximum Demand Assessment

In the Interim Report it was recommended that the demand charge in Tariff A be based on the largest demand in the year of account, which in this case would be the calendar year. Reasons are given for this recommendation, and these reasons still hold. On a large load, the annual basis is a fairer representation of the costs incurred by the Corporation, whilst for high load factor consumers this yearly basis does not represent any hardship or inequity. If, notwithstanding these considerations, the Corporation decides to employ a monthly basis, it is recommended that the annual rate of charge be divided by eleven in order to arrive at a suitable monthly rate. (These alternative figures are shown in Table 6). This is the divisor which should secure approximately the same maximum demand revenue from a group of high load factor consumers.

It is not recommended that consumers be given the option of choosing between the monthly and the yearly basis, or that they be allowed to change from one to the other at will. The figure of 11 is only correct as an overall average; if each consumer chose the basis most economical for himself, the average would be upset and a smaller divisor than 11 would have to be employed.

In any case, monthly demand readings would be taken and these would be used in calculating the load factor steps in the running charge. In billing the consumer on an annual basis, a common plan is to charge, in the first month, one-twelfth of the annual demand rate multiplied by the maximum demand of the month. In the second month a charge is made of two-twelfths of the annual rate multiplied by the highest demand of the two months, minus the demand charge already paid for the first month. A similar plan is followed in subsequent months.

For Tariff B it is recommended that monthly demand assessments be employed, and the tariff values have therefore been given in this form. It is a more equitable basis where the load factors are not so high, and it is usually more popular with consumers, particularly the smaller ones.

5.4 Integration Period

It is assumed that the maximum demand will be measured by a device of the "Merz" type attached to the integrating meter, which measures the maximum kWh consumption during successive equal intervals of time. These intervals are termed the integration period.

Integration periods of 15, 20, 30, 45 and 60 minutes have been used by undertakings throughout the world. The shorter periods favour the undertakings whilst the longer periods favour the consumer, particularly if his load changes rapidly at about the peak times. Strictly speaking, the tariff values should be fixed in the light of what length of integration period is to be used, but the difference between say 20, 30 and 45 minutes is only slight. The most commonly used period is 30 minutes, although it would be going too far to say that this is a recognised standard practice.

In the case of Greece it is understood that 15 minutes has been used chiefly in the past. There is no strong reason for recommending any change, but if changes are contemplated when the two tariff systems are combined, it is recommended that a 30 minute period be adopted. This is probably the figure which gives the most equitable apportionment of demand responsibility.

5.5 Load Factor Rebates

The existing Tariffs A1 to A5 include certain rebates in the demand charge for certain ranges of load factor. These complicate the tariff and involve additional metering and clerical work in the billing and accounting departments. The recommended Tariffs A and B are designed to give a proper allocation of demand-related costs at different load factors, and it does not appear that these added complications are necessary or desirable.

5.6 Off-Peak Demand

The existing Tariffs A1 to A5 have provisions under which the demand readings can be disregarded during night times and Sundays. Although there is no objection to such concessions being embodied in the new Tariffs A and B, it is probable that their aim can be better achieved by means of separate off-peak tariffs.

5.7 Power Factor Charges

In the existing Tariffs A1 to A5, the demand charge applies without variation provided the power factor is between 0.80 and 0.85. If it is lower than 0.80 the demand charge is increased in the ratio 0.80 divided by the power factor (cos.ø). If the power factor is over 0.85 the demand charge is reduced by multiplying it by 0.85 divided by cos.ø. In the NIRS no bonus is given for higher power factors but a penalty is imposed on power factors below 0.85 by varying the load factor at which reduced running charges operate.

Speaking generally, this method of demand charge variation with power factor is preferable to the method of charging according to the lagging kVA. The kVA tariff is an over-penalisation, and it can lead to an excessive installation of condensing plant by consumers which may cause trouble if left in circuit at light load periods.

The question of whether it should be a bonus/penalty variation as in A1 to A5, or merely a penalty as in NIRS, and the question of the most suitable basic power factor, must depend on the local circumstances. If the present power factor of the system is not much below that for which the generators and transmission lines are designed, there is little purpose in offering a tariff bonus for near-unity loads. In this case a penalty would suffice and probably 0.80 power factor would be a sufficiently high basic figure. On lower power factors the demand charge would then be multiplied by 0.80 divided by cos. ø where cos. ø is the mean monthly power factor.

5.8 Fuel Clause

A clause which varies the running charge according to changes in fuel cost is essential in a period agreement such as is proposed for Tariff A. It is not essential in Tariff B since presumably this can be varied from year to year if the fuel cost changes sufficiently to necessitate such an alteration. But although not essential, such a clause is useful since it means that fuel cost increases can be passed on automatically without the need for frequent changes in the tariff itself. Moreover, since such a clause is a feature of most of the existing tariffs there should be no consumer opposition to be faced. It is therefore recommended that a fuel clause be retained in both A and B tariffs, the adjustment to apply to the running charges only.

Reference may be made at this point to Table 8 in the Interim Report which shows that the proportion of thermal generation was estimated to drop from 77% in 1962 to slightly over 50% in the period 1966 to 1972. It could therefore be said that the case for a fuel clause will only be about two-thirds as strong as it has been in the past. This will be an important consideration when it comes to the residential and other low tension tariffs, but in the present case, while it weakens, it does not invalidate, the recommendation made above.

Since an increase in fuel cost is usually only one element in a general cost increase, including personnel costs, there is much to be said for making the coefficient large enough to cover some of these other increases. There is a certain danger in this, since the fuel clause operates in both directions. There is a possibility of fuel costs increasing only slightly, or even decreasing, when other costs go up, and a weighted fuel clause will then be a liability.

No specific recommendations are made regarding either the formula or the constants to be employed. Assuming that the clause in the existing tariffs is working satisfactorily, there is no reason to make any change except to bring the constants up to date as at the time of introduction of the new tariffs. It is noted that the existing constants are not the same on all the tariffs, and it is presumed that this anomaly will be corrected.

In all cases, the running costs which have been recommended have been the final figures after making whatever fuel cost adjustments are in operation at that time.

5.9 Lighting at Power Rates

Present tariffs provide for lighting supplies to be taken at the power rate provided the lighting consumption does not exceed 5% of the total monthly consumption. This is a normal provision, and can usefully continue in the new tariffs.

5.10 Minimum Charges

The essential purpose of these is to ensure that, however low the consumption in any period, the consumer pays at least sufficient to cover the capital and operating charges on whatever part of the distribution system is monopolised by him or is provided for his exclusive use. It is true that the amount of plant "reserved" for, or put at the disposal of, any consumer is far more than merely his particular service line and local equipment. It includes a fraction of the generating station and main transmission lines. But when consumers are small in relation to the system as a whole, and when the load is growing month by month and year by year, any plant in the common system whose use is relinquished by one consumer is immediately taken up by another consumer. It is not rendered unproductive merely through a particular consumer's load reduction.

The case of the large consumer is somewhat different, particularly in Greece, where at the moment a single big consumer may represent quite a substantial fraction of the whole. In order to be able to supply such a consumer at a required date, much special work has to be undertaken (possibly a complete station advanced in date) some of which would not otherwise be needed, or not immediately. A loss will then be incurred if the consumer fails to materialise or if, having taken a supply, he discontinues or greatly reduces his load.

It follows that in any period agreement a minimum revenue must be specified sufficient to guarantee insurance against unproductive and untransferable capital investment. This minimum should be attached to the demand charge so that there will be no danger of wasting electricity.

Where the consumer is not large but the demand assessment is on an annual basis this provides a certain amount of guarantee against revenue loss in months of low consumption. Under Tariff B, where the assessment is monthly, it has already been suggested that there shall be a minimum monthly charge of 3000 drachmas corresponding to a demand of 20 KW.

5.11 Connection Charge

Since the whole of the capital expenditure on distribution and consumer connection is included in the cost analysis, and a proper return thereon is provided in the cost formulae, it follows that the tariffs based on these formulae should cover, for each consumer, the average cost of his connection. On this basis, it should only be necessary to ask for a connection fee from consumers whose cost of connection is above the average of his group, or for whom some exceptional expenditure has been incurred. This could arise through a greater-than-average distance from the distribution network, or where special facilities are provided such as duplicate services or metering. The consumer might then be asked to pay one or other of the following:

(a) A once-for-all connection fee.

(b) An annual fixed charge for the special equipment provided.

(c) An increased minimum charge as described at (5.10) above.

5.12 Prompt Payment Rebate

In the Capital area (but not in the Provincial area) there is a rebate of 5% of the total bill for payment within ten days. Such rebates are not unknown elsewhere, although the figure is usually less than 5%. The general experience of electricity undertakings, however, is that such rebates are not required and constitute an unnecessary complication. Because electricity is all-but essential and because it cannot be stored, the threat of disconnection (with a reconnection fee) is usually sufficient to ensure that bills are paid promptly. Since one or other of the existing tariff systems will have to be changed in this respect, it is recommended that the present practice in the Provincial area be extended to the whole Corporation and that all prices be strictly net. This assumption is made in the whole of the monetary recommendations that have been made, and, if rebates are to be given, all these figures must be increased accordingly.

5.13 Duration of Agreement

With large consumers it is usually more satisfactory and acceptable to both sides to have an agreement for a number of years. It is then essential to have a fuel-cost variation in the price and a minimum revenue guarantee. Periods of 3, 5, 7 and 10 years are commonly employed with large-scale two-part tariffs, and for Tariff A a five year period will probably be found the most suitable. Such an agreement is advantageous to the Corporation as a guarantee of revenue for a period of years, and also to the consumer as protecting him from price increases other than those due to fuel whose effects are at least precisely limited.

For Tariff B it is recommended that the agreements run from year to year, as with the present tariffs.

5.14 Recommendation regarding Accounts

It was pointed out in Section (2.2) and also in Section (2.4) of the Interim Report, that owing to the difference between the yield on the net capital employed and the actual amounts paid out in interest, theCorporation earns a substantial surplus each year. The position could be put in another way by saying that the tariffs now operating and those which are recommended for the future, produce a revenue sufficient to give a yield of around 7% on the net capital which is more than double the mean interest rate on the whole financial investment.

This surplus is of course used in financing the new assets which are continually being required, and to this extent it lessens the Corporation's requirements for further capital. But although used in this way, it necessarily appears in the balance sheet as an accumulated saving or capitalised surplus.

The figure thus shown as "surplus" is a very large one. In the 10-year forecast it was estimated as nearly 5000 million drachmas in 1966, and 15000 million in 1972. Moreover, it is growing at a much faster rate than the Corporation itself. In relation to the first cost of the assets, the surplus totalled 27% of this cost in 1966 and 51% in 1972.

Its appearance in the balance sheet in this form seems likely to give a misleading impression that the Corporation is better off than it actually is, and that it is charging too much for its electricity. This may lead to the demand that some of the money shown as surplus could be drawn upon for electricity price reductions or for wage and salary increases. It may be necessary to point out that this "surplus" exists in the balance sheet side by side with a lower-than-average depreciation reserve, and furthermore that it is no greater than is necessary in order to provide an element of "self-financing" which is vital to a rapidly growing and capital-intensive industry.

In order to lessen the need for such explanations, and to make the presentation of the accounts less vulnerable, it is recommended that a portion of this surplus be capitalised and recorded in the balance sheet as "Supplementary Reserve for Depreciation and Replacement". This would be in addition to the existing depreciation reserve formed from the annual depreciation allocations, and its purpose would be two-fold:-

(a) To correct what appears to have been some degree of under-provision in the past, and so to bring the existing depreciation reserve up to a size where it bears a normal relation to the fixed assets (such as 35%).

(b) To provide a margin for the effects of future inflation, and so deal with the situation which arises when the normal depreciation reserve at the end of the asset's life is insufficient to pay for replacement owing to the rise in plant prices.

The proposal would not make any difference in the actual disposal of the money - it would merely change the descriptions of the different reserves. It would not affect the degree of "self-financing" since all the reserves, whatever their descriptions, are made use of in this way.

5.15 Future Programme

The following suggestions are made regarding this. The first step is to make a policy decision about the field covered by the A and B tariff proposals. Following the acceptance or modification of the recommendations, a timetable should be set for the various stages in their implementation. A desirable target would be to have them in operation as from January 1st 1965. This should be possible provided no additional instrumentation is needed, and provided there are no complications regarding the length of notice that has to be given. It is likely, however, to absorb most of the available staff resources for the remainder of the year.

Early in 1965 it should be possible to start work on the remaining sector of the tariff revision, covering the low-tension supplies. The preliminary for this will be to prepare a complete schedule of the consumption data broken down into each separate tariff. A partial breakdown of the 1963 figures is given in Table 7 which indicates the field that has to be covered. Since these figures will be nearly a year old by that time, it would be highly desirable to employ the 1964 figures as soon as these can possibly be obtained.

It will be seen from the table that much the largest group to be covered is the residential one. Moreover, this is likely to present the greatest amount of difficulty in synthesising the two tariff systems. It is therefore recommended that this group be tackled first.

Reference should here be made to Sections (7.2) and (7.3) of the Interim Report. Great importance is attached to the choice of tariff type, and suggestions are put forward that a study be made, with particular reference to the availability of staff, of the feasibility of operating one or other of the present types over the whole area. It will be noted that at present the Provincial (block tariff) consumers considerably outnumber the Capital consumers but their mean usage per consumer is less than one-quarter as much.

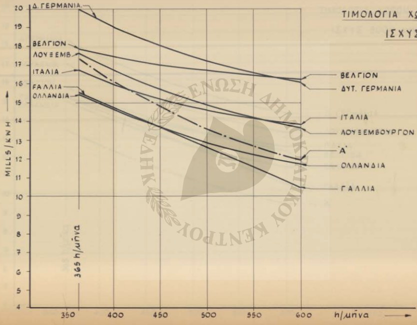
TABLE 7

Consumption Statistics 1963

Consumer Class	Tariffs Capital	Tariffs Provincial	Consumption 10^6 kWh	Consumption %	Revenue 10^6 Drachmas	Revenue %	Mean Revenue lepta/kWh	Number of Consumers
Industrial, HT	A1 to A5	T23	1 004.80	38.4	536.46	22.8	53.4	643
Industrial, LT	K1 & K2	T19	286.87	11.0	263.53	11.2	91.8	36 389
Industrial total			1 291.67	49.4	799.99	34.0		37 032
Resid-) Capital	T1 etc.		616.06	23.6	660.82	28.1	107.3	450 404
ential) Provincial		T 9	199.42	7.6	283.97	12.1	142.4	644 153
) Total			815.48	31.2	944.79	40.2	115.8	1 094 557
Commercial	T1 etc.	T19	303.83	11.6	441.04	18.8	145	250 726
Irrigation		T33	35.63	1.4	24.11	1.1	67.7	16 986
Traction	Special		41.87	1.6	33.71	1.5	80.5	3
Public authority, street lighting etc.			124.33	4.8	103.41	4.4	83.1	15 493
Total sales to consumer			2 612.81	100	2 347.05	100	89.8	1 414 797
Bulk for resale			72.54		33.54		46.2	
Aliveri mine			9.92		5.27			
Grand Total			2 695.27		2 385.86			

ΤΙΜΟΛΟΓΙΑ ΧΩΡΩΝ Ε.Ο.Κ.

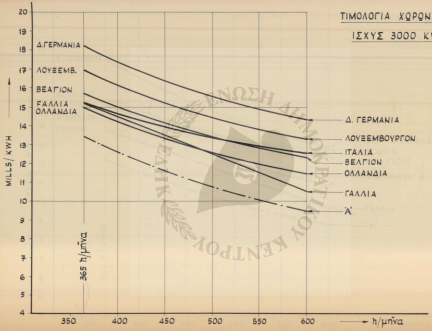
ΙΣΧΥΣ 1000 KW.



A	B	C	D	E
KENNEDY & DONKIN, [A]LLIANCE HOUSE, 12 CAXTON ST., WESTMINSTER, S.W.1.	DRAWN BY SIGN:	CHECKED BY SIGN:	SCALE DATE	FIG. 1

ΤΙΜΟΛΟΓΙΑ ΧΩΡΩΝ Ε.Ο.Κ.

ΙΣΧΥΣ 3000 KW.



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WESTMINSTER, S.W.1.

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FIG. 2

ΤΙΜΟΛΟΓΙΑ ΧΩΡΩΝ Ε.Ο.Κ.

ΙΣΧΥΣ 7000 KW.

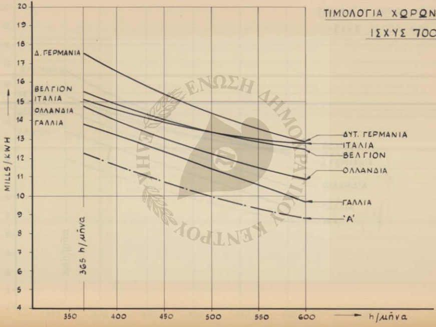

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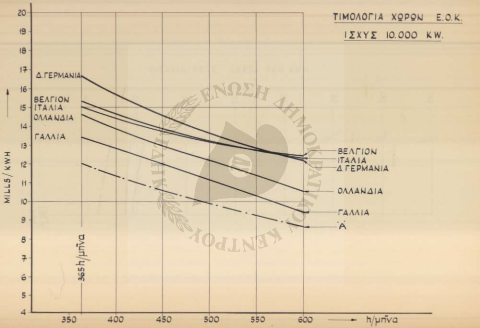
FIG. 3



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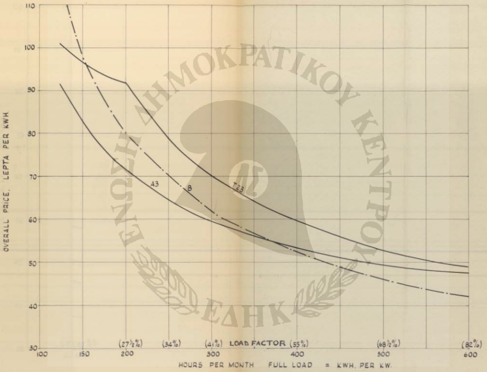
DATE

FIG. 4

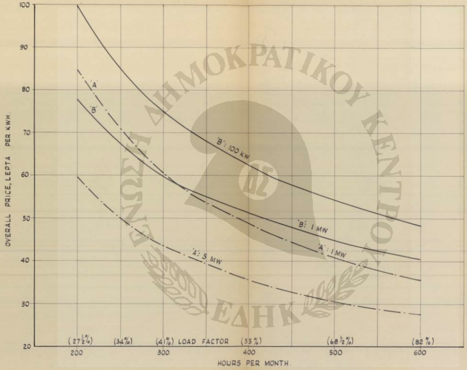
TARIFF A3 & B ARE FOR 500 KW.



A	B	C	D	E

KENNEDY & DONKIN ALLIANCE HOUSE 12 CAXTON ST. WESTMINSTER S.W.1	DRAWN BY SIGN	CHECKED BY SIGN	SCALE DATE

FIG 5



A	B	C	D	E

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	SIGN	SIGN	DATE

FIG. 6

ΕΝΩΣΗ ΔΗΜΟΚΡΑΤΙΚΟΥ ΚΕΝΤΡΟΥ
ΔΣ
ΕΔΗΚ