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REPUBLIC OF SUDAN
NATIONAL ELECTRICITY CORPORATION

ELECTRIC TARIFF STUDY
FINANCIAL YEAR 1985-1986

USAID Contract No. 650-0059-C-00-4015-00

Prepared by:
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Khartoum Sudan

December 1985

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SUMMARY LETTER

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS

March 4, 1986

National Electricity Corporation
P.O. Box 1380
99 Gama'a Avenue
Kahrtoum, Sudan

Attention: Abdel Latif Ibrahim
Director General

Subject: Electric Tariff Study
Financial Year 1985-1986

Letter No: NEC-56

Gentlemen:

We are pleased to submit our Electric Tariff Study for the National Electricity Corporation (NEC) Khartoum, Sudan. Our study was undertaken to assist the management of the National Electricity Corporation in making decisions with regard to the tariff recommendations of the study. Certain segments of the study will be expanded as recommended studies for tariff changes are completed in the near future. The main objective is to develop a guide to conduct future tariff studies on a regular, periodic basis.

The study was undertaken jointly by the NEC and the Harza team. It was divided into three major segments:

I. The Marginal Cost Study
II. The Revenue Requirements
III. Tariff Design

The domestic tariff was found to recover some 37% below marginal cost and we have recommended increasing the last block to 27 p.t./kwh.

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After discussing the recommendations regarding tariff design with the NEC, it was agreed that:

1. The recommended tariffs for Industrial and Domestic consumers should remain as is.

2. The Commercial, Agricultural and Street Lighting recommendations should be changed as shown on the "Summary of Tariff Recommendations" (Exhibit 1) and in the column headed Final Recommendations of Table RR-1 (Exhibit 2).

The results of the study show that, were marginal costs used as revenues, the NEC would earn 18.4% on assets as opposed to 10.4% using current tariffs.

We appreciate the opportunity of conducting this study and would be pleased to be of further assistance.

Sincerely,

Shamshad Azri

Shamshad Azri
Acting Chief of Party

SA/srh

cc: Senior Director - Kh. Area, NEC
Director of Commercial, NEC
Director of Finance, NEC
Director of Finance, Kh., NEC
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REPORT

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PRELIMINARY
ELECTRIC TARIFF STUDY

FINANCIAL YEAR 1985-1986

REPUBLIC OF SUDAN

NATIONAL ELECTRICITY CORPORATION

HARZA ENGINEERING COMPANY

DECEMBER 1985

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SUMMARY OF THE TARIFF STUDY FY85/86

This very brief preliminary summary of the tariff study has been prepared to assist the management of the National Electricity Corporation (NEC) in making decisions with regard to the tariff recommendation of the study. The final summary will be prepared after those decisions have been made. In addition, certain segments of the study will be expanded as recommended studies for tariff changes in the near future are completed. A narrative of the problems encountered during the course of the study is being prepared by the Tariff Manager along with suggestions as to improvements in data availability. This narrative will become an appendix to the final tariff study report. The objective of these efforts is to develop a guide to the conduct of future tariff studies on a regular, periodic basis.

The study was undertaken jointly by the NEC and the Harza team. It is divided into three major segments:

I. The Marginal Cost Study

II. The Revenue Requirements

III. Tariff Design

Earlier on, the Director General was presented with an array of revenue targets based on the financial cost of fuel as well as on several sets of economic fuel costs. The Director General was reluctant to have NEC be the only entity in the

Energy Sector to set prices on the basis of economic fuel costs. Therefore, he directed that tariff design be based on marginal financial costs.

The domestic tariff was found to recover some 37% below marginal cost and we have recommended increasing the last block to 27 p.t./KWh, halfway to average marginal costs.

The recommendations for changes to all tariffs are encapsulated on the attached Summary of Tariff Recommendations, (Exhibit 1) and the projected Income Statement is displayed on Table RR-1, (Exhibit 2).

After discussing the recommendations regarding tariff design with the Director General it was agreed that:

1. The recommended tariffs for Industrial and Domestic consumers should remain as is
2. The Commercial, Agricultural and Street Lighting recommendations should be changed as shown on the "Summary of Tariff Recommendations" (Exhibit 1) in the column headed Final Recommendations of Table RR-1 (Exhibit 2). The agricultural tariff has been moved closer to marginal cost.

The projected income statement, including unit revenue for the entire set of tariffs proposed for adoption are shown on Table RR-1 (Exhibit 2) in the column headed Final Recommendation.

CHAPTER I

MARGINAL COST STUDY

A. SUMMARY

The results of the study show that, were marginal costs used as revenues, the NEC would earn 18.4% on assets as opposed to earning 10.4% using current tariffs. Not surprisingly, the study shows that residential consumers on average are charged 37% less than the marginal costs they imposed on the system. Again not surprisingly, commercial consumers are currently charged somewhat more than marginal costs.

Agriculture (small pumps) is apparently charged at some 33.5% above its marginal costs. However, as is discussed under, III TARIFF DESIGN, the constraint against consuming at evening peak may be observed more in the breach than in the compliance.

Streetlighting comparisons make no sense because of many years of neglect from the viewpoint of tariff design. The marginal costs computed herein represent the marginal costs of supplying energy to streetlight fixtures supplied by others. The category "other" (sales) encompasses what used to be government and interdepartmental sales.

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B. INTRODUCTION

The object of the costing process outlined herein is to quantify the marginal costs of a utility, not the revenue requirements of a utility. Translation of these costs into rates is not addressed in this section although it will be necessary, at times, to speak of costs as though they were rates.

The scope of an analysis of cost causation for purposes of time-differentiated pricing attacks issues broader in scope than those covered in traditional cost studies for ratemaking.

The sought-after concept is time-related, forward-looking and marginalist in nature. This cost analysis must make available to the ratemaker costs related to time of day, season of the year and weather (to name the most obvious), so that ratemaking decisions may be made. One must also keep in mind the current state of the metering art and current administration feasibility. Further, and perhaps most importantly, these costs should point the way to desirable changes in metering and administration of rates.

Such a cost analysis, however, does not lend itself to a neat, formulistic approach that can be relegated to a computer using the books and records of the company as sources of input. Rather, this cost analysis requires an understanding of cost causation and of the interrelationships between the varying cost elements, as well as the ability to interpret an array of data that ranges from the utility's books of account to the

effects of changing fuel costs on system dispatch. The key to the analysis lies in an understanding of the processes by which the various components of an electric system are planned.

The marginal cost of supplying electric service can be separated into three categories. The first, marginal customer cost, is the cost associated with building and having in place an electric system that provides area coverage and "hook-up" for a population of minimum demand customers. The second, marginal demand cost, is the cost associated with building and maintaining a system with sufficient capacity to meet incremental electrical demands. The third, marginal energy cost, is the cost of producing the power that is demanded.

Turning to capacity- or demand-related costs, they tend to be lumpy. Scale economies and construction lead times combined dictate the installation of large discrete blocks of capacity. These large capacity blocks both relieve loads on older, less efficient units (in the case of generation), and allow room for additional growth on the system. Taking lead from Boiteux[1/], these lumpy additions have been treated as though they were more flexible and could be had in very small increments of capacity. To do so, unit costs of generation were derived based on the unit cost of capacity. In the case of transmission and distribution, the stream of investments related to load were utilized

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1/ Marcel Boiteux, "Peak-Load Pricing" The Journal of Business, April 1960, p. 176.

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to derive a unit capacity cost. All of these unit costs (L.S.) represent today's cost of adding a small increment of load were utilized to an electric utility system.

The long-run marginal demand and energy costs of an electric utility vary with the time of consumption. The marginal cost of energy at a given time is the marginal fuel and variable operation and maintenance expenses that will result from an increment in demand at that time. In other words, for each hour of the year the plants available for use are arranged in ascending order of operating costs; the dispatch plan is usually to add operating units in ascending order of running costs as demand increases; and, therefore, the marginal cost curve for each hour represents the relationship between kilowatt demand and the running costs per kilowatt-hour.

This marginal cost curve (as a function of demand) can be thought of as rising, with running costs, until the point at which capacity is exceeded, where the cost becomes the shortage cost and the curve rises very sharply. The shortage cost corresponds to the costs incurred by customers who would not be served in the event of demand exceeding capacity. These costs could, in principle, be calculated directly. The French Nationalized electric industry does just that; it looks at its plan for load shedding and calculates the loss of value added for industries which it would shed in a situation of potential power failure. It then plans to add capacity to the point at

which the cost of the last unit of capacity added equals the probable cost of a failure.

This shortage cost, or marginal capacity cost, cannot simply be charged to the peak hour. Rather, the cost must be assigned, in principle, to each hour based on the relative probability that load will exceed capacity in that hour. This is so because (in principle) the reliability criterion commonly used is the sum of the probabilities for each hour that the load will not be met. Simply put, during some hours there is a greater risk that capacity will be exceeded than in others. Thus, it is logical, in principle, to assign a portion of the responsibility for the cost of the "last unit" of capacity to each hour in proportion to the degree of risk that capacity will be exceeded. However, it is not necessary as a practical matter to make this computation for every hour of the year.

It is important to recognize that these marginal costs <u>do not</u> represent a form of prospective rate base or average incremental costs, but reflect the time-differentiated marginal costs upon which consumption decisions should be based. These costs <u>do</u> represent the cost of reproducing the service provided at today's costs and under today's technologies, and are the costs that, in the long run (as defined by the economist) will be saved or incurred in the production and delivery of electric energy.

C. SELECTION OF COSTING/PRICING PERIODS

For purpose of the 1985/86 tariff study costing and pricing periods will be taken as the same. In the future when the effects of price elasticity can be measured it may become necessary to develop these periods separately. In that which follows we will refer only to costing periods.

Diurnal periods have been chosen with reference to the daily variations in load; and seasonal periods have been chosen with reference to both the perceived probability of the occurrence of the system peak and the availability of hydraulic energy.

The daily periods have been chosen by inspection of the monthly peak day load curves (see Charts C/P-1 Exhibit 3 and C/P-2 Exhibit 4) with a limited reference to daily load curves. Daily periods do not vary from season to season in consideration of the present state of the art of time-of-day metering in the Sudan.

The periods selected are as follows:

A. Peak Hours (all months)
   0700 - 1400 hrs and 1800 - 2200 hrs

B. Off Peak Hours (all months)
   2200 - 0700 hrs and 1400 - 1800 hrs

C. Critical Months
   March, April, May, June, July, August

D. Other Months
   September, October, November, December, January and February

D. MARGINAL COST OF ENERGY

The marginal cost of energy was derived by dispatching the units of the system in merit order against the integrated monthly load curves. A table was produced showing the marginal generating units during peak and off-peak hours for both critical and non-critical months of the year (see Table MCE-1 Exhibit 5). This work was performed by the System Planning Division.

The cost per KWh of each unit was calculated by multiplying its specific fuel consumption (M.T./KWh) by the cost per M.T. of the fuel used. A single marginal energy cost for on-peak hours and a single marginal energy cost for off-peak hours were obtained by weighting each machine's cost by the number of hours it was marginal during any period.

Where hydraulic energy appeared at the margin it was valued at the cost of energy of the unit it displaced. Where hydraulic energy was spilled because of low load conditions (off-peak, non-critical months) the marginal energy cost was taken to be zero.

All energy costs were then grossed up to account for energy losses between the generator and the points on the system at which energy is delivered. These calculations are shown on Table MCE-2 (Exhibit 6).

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E. DEVELOPMENT OF ANNUAL CARRYING CHARGES

When one develops the long-run marginal unit investments it is necessry to convert them into another form of marginal cost suitable for use in ratemaking (i.e., for the period in which the rates are to pertain). This is done by evaluating the present discounted value (PV) of the stream of all revenue requirements arising from an investment. Usually the PV is converted to a uniform annual series of payments. The amount of the payment is divided by the value of the investment and multiplied by 100 to produce a unitized annual charge as a percent of the investment. This charge is commonly used by engineers in the evaluation of alternative investments.

It is generally recognized that a capital investment gives rise to three basic types of charges: taxes, return of capital (depreciation) and return on capital (earnings and interest). Further it is generally assumed that investments are financed at the incremental cost of capital. In the case of the NEC taxes need not be considered.

A computer program has been prepared to calculate the stream of revenue requirements and the levelize annual charge. The results are shown on Table AC-1 (Exhibit 7).

For purposes of this study a 30 year life, a return on rate base of 10.5 percent, a marginal cost of money equal to 19 percent, a financing rate of 50% and a discount rate of 10.5 percent were used. In future studies, it may be desirable to use different service lives for each segment of the system.

F. MARGINAL COST OF GENERATING CAPACITY

The marginal cost of generating capacity for the NEC has been concluded to be the cost of the Combustion Turbines (CTs) installed at Kuku.

This conclusion has been based on an examination of the system expansion plan; inquiries into the actual (and planned) dispatch of the system; and a series of discussions with the former Manager of System Planning. The analytical underpinnings of the approach to the MGC are contained in Appendices MGC-1 and MGC-2. At a future point in time, when the total available energy (for electricity generation) in the Nile River System is exceeded by the energy requirements of the Sudan, the cost of generating capacity will probably become the cost of an adiditional hydraulic turbine installed in an existing powerhouse to displace high energy cost units. Concomitantly, since all such hydraulic energy must be replaced by thermally generated electricity, the cost of energy then must reflect the cost of a base load plant plus its fuel.

Economically speaking, the NEC - Blue Nile Grid (BNG) - is currently in an excess capacity position, and therefore the current marginal cost of generating capacity is zero.

There are some who would argue that this is not so because of pent-up and unserved - demands waiting to come on line. On the other hand, there are others who would argue that there are no signs of an imminent upsurge in the economy of the Sudan which would suggest that pent-up demand is smaller than estimated - if not altogether illusory.

N.E.C. States that the total rating of the two (2) units installed at Kuku is 19 MW. The cost of those units is 13.85×10^6 \$US and that the local currency component is 1.7×10^6 L.S. Using an exchange rate of 2.1 L.S. per \$US, the cost per KW of MGGG comes to:

$$\text{Total Cost} = 13.85 \times 10^6 \text{ \$US} \times \frac{2.1 \text{ L.S.}}{\text{\$US}} + 1.7 \text{ L.S.}$$

$$= 30.785 \times 10^6 \text{ L.S}$$

or,

$$\text{L.S./KW} = \frac{3.0785 \times 10^6 \text{ L.S.}}{19 \times 10^3 \text{ KW}} = 1620 \text{ L.S./KW}$$

@ Annual Carrying Charge = 20.43% =330.97L.S./KW/YR

G. TRANSMISSION

The capacity cost for transmission and 33 KV was taken to be the cost of the 33KV tie-line between Burri power station and Kuku substation, the 110 KV tie-line between Kuku substation and Khartoum North power station and the 220 KV second circuit. The costs of the above items are as follows:

	Cost (L.s. x 10^6)
33 KV tie-line	9.8
110 KV tie-line	11.5
220 KV tie-line	27.0
Total	48.3

Cost/KW $= \frac{48.3 \times 10^6}{230 \times 10^3 *} =$ L.S. 210

Cost/KW/YR $= 210 \times 0.2043 =$ L.S. 42.9

* The capacity provided by this investment

H. MARGINAL COSTS OF DISTRIBUTION

In distribution, unlike generation, marginal costs may vary between consumers, depending on location, density and service voltage. Ideally whether there exists a sufficient difference in costs between consumers to justify the establishment of tariff distinctions based on conditions such as those mentioned above must be determined.

In the analysis of distribution costs, the planning of the system should be taken into account. The system is planned to provide access to electric utility service for each potential consumer irrespective of the load, and it also has to carry load. This could lead to the conclusion that an equation for the total cost of the distribution system would take the following form.

Total Cost = a (customer) + b (demand on distribution)

1. <u>Customer-Related Distribution Costs</u>

   The customer-related portion of the distribution system can be viewed as a system which would cover the entire territory, the facilities dependent upon the size of area served, the density of the customers, etc., but would provide voltage only and no power.

   The customer-related marginal distribution costs are those directly attributable to the addition of a customer, as well as those varying in proportion to the number of customers but not the level of demand.

The number of meters and services will (with some exceptions) be equal to number of premises served and might be thought of as "hook-up" costs. The number and cost of distribution line poles (for example) will probably vary with the number of customers but not with the level of demand on the system and, thus, are also customer costs. The system would then consist of all the labor costs necessary to put together today's minimum system and all material costs except those of conductors and transformers which are conceive to be chiefly demand related.

The lack of a continuing property record makes it impossible to produce systemwide information regarding such data as: spans per customer, customers per pole, circuit feet per customer and the like. Therefore current distribution schemes in first, second and third class areas were sampled in order to develop a reasonable estimate of marginal customer-related costs. That cost is a weighted average cost based on the perceived ratio between number of homes by class.

Customer-related costs have been taken to be the costs of meters, services, poles and the labor of stringing conductors. It may be argued that one should include only the costs of a minimum size of meter and service

leaving larger sizes to be included in demand-related costs. Pragmatically, NEC collects hook-up costs that vary with service size through its system of fixed charges. Therefore costs reflect this practice.

The customer related costs are developed on Table CR-1 (Exhibit 8).

2. Marginal Demand-related (Capacity) Costs

Demand-related distribution costs can be viewed as all costs above the cost of the customer-related system that are incurred by power demanded by customers. Those costs would include the cost of conductors, transformers and even such expenditures as the guying of distribution poles, which, since larger guys are required for heavier conductors, will vary with demand.

For the 11 KV and .415 KV distribution the demand-related cost was determined by drawing graphs of costs vs KW ratings for substations and graphs of cost per meters vs ampere rating for conductors. For substations the slopes of the graphs were taken to represent the cost/KW. For the 11 KV conductors the slope of the graph was taken, transformed to cost/KW and added to it the labor cost to put a new conductor. The labor cost to put a new conductor was determined as

per span per KW. The number of spans per KW was determined by dividing the total lines in spans by the total capacity in KW.

For the .415 KV conductors the same was done with one exception, that is, in the case case of the .415 KV conductors graphs were drawn and slopes were taken for single phase, 2 phase and 3 phase and the weighted average cost was taken. The results are as follows.

	Cost/kW	*Cost/KW/YR
33/11 KV transformation	L.S. 28.5	L.S. 5.82
11 KV lines	3.63	0.74
11/0.415 KV transformation	53.56	10.94
0.415 KV lines	23.44	4.79

*Annual carrying charge is 0.2043

J. CAPACITY AND DEMAND-RELATED COST BY VOLTAGE LEVEL

Having determined the demand-related marginal costs of the various segments of the system, it is necessary to assemble them by voltage level, taking into account losses and operations and maintenance costs. These calculations are shown on Table DCV-1 (Exhibit 9).

K. COSTS BY CLASS OF CUSTOMER

1. Demand-related

In analyzing demand-related distribution investment, one must once again return to the planning process and examine the causative factors of such investment. At the level of the link to the consumer which serves him alone, the maximum kilowatt demand, whenever it occurs, theoretically determines the size of the facilities required. At the generator bus, however, it is the consumer's demand at the time of the system maximum load that is important. Between these extremes, the common distribution system is designed to serve the consumer on the basis of the degree of coincidence between his maximum demand and the maximum demand of others.

Therefore, what has to be measured is the additional cost of distribution facilities required when a kilowatt of load is added by a consumer, taking into acount the diversity of all consumer's demands. However the only data available regarding customer load characteristics are those which were used in the PEWC power market survey 1975 and the PEWC technical supplement 1978. These data are class annual load factors, class monthly demand factors and class coincidence factors.

Class annual load factors were applied to the class energy sales to develop class noncoincident maximum demands as shown on Table CCC-1 (Exhibit 10). Class monthly demand factors were applied to the class noncoincident maximum demands to develop class monthly noncoincident demand. Class coincidence factors were applied to the class monthly noncoincident demand to develop class monthly coincident demands. Both the class monthly noncoincident demands and the class monthly coincident demands are shown on Table CCC-2 (Exhibit 11).

Knowing that the system peak is in the evening and knowing that the small pumps are not allowed to work during the evening peak, the coincident demand for small pumps does not appear in the table and what appears is only the noncoincident maximum demand.

The demand-related cost by customer class was determined by multiplying the class coincident demand in the peak month by the demand-related cost according to the customer service voltage Table DCV-1 Exhibit 9 and the result is shown in Table CCC-3 (Exhibit 12). For small pumps the noncoincident maximum demand was multiplied by only the cost of distribution plus the losses from generation through distribution to get the

demand-related cost as shown in Table CCC-3 (Exhibit 12).

2. Energy Related

In order to translate the energy costs by voltage level (Table MCE-2-Exhibit 6) into total marginal costs of energy by class, it is necessary to first apportion the forecast class consumptions among the four (4) costing periods previously selected. This apportionment has been accomplished through the use of consumption factors for each class for each period. The results are shown on Table CCC-3 (Exhibit 12).

The period consumptions were multiplied by the periods costs from Table MCE-2 (Exhibit 6) to obtain the total marginal cost of energy by class by period. The resulting costs are shown on Table CCC-3 (Exhibit 12).

The sum of these costs by class by costing period is shown on line 7 of Table CCC-4 (Exhibit 13).

3. Total Marginal Cost by Class of Customer

The components of the marginal costs are customer-related cost, demand-related cost and energy-related cost. The total customer-related cost was determined by multiplying the customer-related cost in Table CR-1 (Exhibit 8) the number of customers. The total

demand-and-energy-related costs by class of customer were discussed, respectively, in 1 and 2 above.

The three cost components were put together and added to each other to get the total marginal cost by class of customers. The total marginal cost by class of customer was then divided by the customer unit sales to get the customer unit marginal cost. The result is shown in Table CCC-4 (Exhibit 13).

CHAPTER II

REVENUE REQUIREMENTS

A. DISCUSSION

In conducting a tariff study in a developed nation it is necessary to derive a revenue target that balances the consumer's willingness to pay (now) against the investor's perception of risk with regard to the future stream of income flowing from his investments. Put another way, what percentage of construction should be financed from retained earnings and how much financed from the sale of stocks and bonds?

In the case of a lesser developed country (LDC) usually the utility is an agency of the Government, thought of as a tool to raise GNP. As a result, subsidies and crosssubsidies enter the picture to a greater degree than in more developed nations. Also, there are usually no private investors to satisfy.

However, this does not mean that utilities in LDCs should not face consumers (at least as a whole) with the "real" costs of production modified (perhaps) by certain socio-economic considerations.

The NEC is currently paying a highly subsidized cost for fuel for thermal generation which distorts the value of that fuel and in turn, understates the cost of electricity production. In addition to the issue of cross-subsidization, there is also the question of a foreign exchange rate that does

not reflect the true value of the Sudanese pound versus other currencies.

With all the foregoing in mind the Harza/Coopers & Lybrand team in conjunction with NEC's Director of Commercial Planning and its Tariff Manager have presented the Director General with an array of revenue requirements for FY 85/86 that reflect both financial and economic costs of fuel for electricity production. These results are shown in Cols. (1), (2), (3), (4) and (5) of Table RR-1 at line 41 (Exhibit 2).

The Director General is reluctant to be the only agency in the energy sector to base prices on the economic cost of fuel. He has directed that rate design should take marginal financial costs into account without specifying a particular revenue target.

B. SALES FORECAST - CURRENT TARIFFS

The 1985/86 F.Y. sales forecast for the Blue Nile Grid (BNG) and Eastern (EG) grids is based upon the actual 1984/85 BNG unit generation, normalized for known load shedding, plus a forecast of sales for the EG.

A growth rate of 7.5% (consistent with that of the Corporate Plan) and an allowance of 2.5% for pent-up demand has been applied to arrive at a forecast of 1380 GWh of unit generation on the Blue Nile Grid.

In the light of planned efforts to reduce the lost and unaccounted for energy (by billing heretofore unbilled consumers), a 5% reduction in the difference between unit generation and sales for the BNG was assumed. To this result was added the forecast of 20.0 GWh on the E.G. to arrive at an initial sales forecast of 1055 GWh.

At this point weight was given to an inventory of streetlights in the Khartoum area which indicated a demand and consumption far in excess of any other available statistic. It was concluded that the forecast should be increased by the difference between the figures of this inventory and those currently reported from other sources to arrive at a final forecast of 1066.61 GWh. These calculations are shown on Table SF-1 (Exhibit 14).

The next step was to break down the overall forecast for both the BNG and EG by consumer by classification. This was accomplished by using the sales statistics from FY 1983/84

(draft version) to derive the percentage of sales by classification. These calculations are shown on Table SF-2 (Exhibit 15).

C. REVENUE FORECAST - CURRENT TARIFFS

Having forecast sales by customer classification the next step was to forecast the revenues expected from those sales under existing and proposed tariffs. Given the lack of available time series data in the form of bill frequency distributions, and finding a dearth of other reliable sources of data, the team was obliged to pick and choose from various sources to derive annual unit revenue recoveries from each class of customer.

The prime source of data was the FY 1982/83 report of sales and revenues (adjusted to reflect current tariffs) -- the latest available data. With two (2) exceptions the adopted values derived from that source are displayed in Col. 1, Lines 10-15 of Table RR-1 (Exhibit 2). Those exceptions are the domestic and the commercial tariffs (Lines 10 and 12) which are discussed below.

1. Development of Current Domestic Unit Revenue

At a meeting with the Director General, on 19 September, the Tariff Manager and the Consultant expressed their reluctance to accept the value - 0.219 L.S. KWh - of domestic unit revenue recovery derived from FY 82/83 revenue and consumption statistics. In their opinion this value was too high and implied two different consumptions, neither of which comported with any estimate of average consumption.

Table DUR-1 (Exhibit 16) shows that a unit revenue recovery of 0.219 L.S./KW is achieved at both 51 KWh/mo and 3500 KWh/mo.

The 82/83 statistics for domestic consumers and consumption, 272.5 GWh and 217,221 consumers were re-examined. The number of consumers shown for Khartoum Area, is known to be some 30,000 higher than the number of consumers being billed (134,000). Therefore, the total number of consumers was corrected to 187,221 which yields an average consumption of 121 KWh/mo. The Tariff Manager estimates that currently, 150 KWh/mo represents a best estimate for use in this computation.

A current unit revenue recovery of 0.202 L.S./ KWh as shown in B. of Table DUR-1 (Exhibit 16) was derived for use in the tariff study.

2. Development of Current Commercial Unit Revenue

The FY 82/83 sales and revenue statistics for this class of customer yielded a unit revenue inconsistent with the average consumption computed from the same source.

The bill frequency analysis of Khartoum Area for the month of 04/1405 provides an average consumption of 1304 KWh/mo.

An examination of the Draft 1983/84 Annual Report showed a system average monthly consumption of 283 KWh with Khartoum averaging 1037 KWh and other areas averaging 167 KWh.

Revenue recovery was determined to be 0.278 L.S./KWh, derived by weighting the Khartoum Area average consumption of 1304 KWh with the "Other" area average of 167 KWh/mo.

These computations are shown on Table CUR-1 (Exhibit 17).

3. <u>The Other Tariffs</u>

The unit revenues and average consumptions found through use of the FY 82/83 statistics appeared to be consistent with one exception, streetlighting. In the case of the latter no useable alternative source of data was found. Therefore, with some reservations the values found were adopted.

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D. OPERATING EXPENSES

Operating expenses are taken as those contained in the budget for FY 1985/86 with the exception of the cost of fuel. The cost of fuel in the budget has been modified to meet the energy forecast used in this study. It should be noted that the budget is based upon a 9-1/2 month year. For clarity of presentation total expenses were pro-rated to approximate those of a full year (Table RR-1, line 36 exhibit 2).

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CHAPTER III

TARIFF DESIGN

A. SUMMARY

(To be written after managements decision regarding recommendation)

B. COMMERCIAL TARIFF

The marginal cost study indicates that, on average, commercial consumers are charged somewhat above computed marginal costs. This is not surprising since such consumers are generally thought to be relatively inelastic. Their overheads is passed on to the consumer in the prices they charge.

It is recommended that the last block of the tariff (0.22 PT/KWh over 500 KWh) be eliminated. This recommendation is based on the bill frequency analysis presented in Table CUR-1 (Exhibit 17) which shows that 96 percent of the KWh consumed in the Khartoum area is on bills of over 500 KWh/mo.; and it is these larger consumers who are most probably contributing to the costs at peak. It should be noted that very few commercial customers outside of Khartoum are expected to consume over 500 KWh per month.

An average consumption of 4109 KWh/mo. for these larger consumers (see Table COM-1-Exhibit 18) was derived and on the same table a comparison of the bill for this consumption under both the current and the proposed tariff is presented. The annualized effect of the recommendation is to increase the Commercial Tariff revenues by some 346,000 L.S.

C. INDUSTRIAL TARIFF

No immediate change is recommended in this tariff. Even though during non - critical months, loads are low enough to waste hydraulic energy in the off-peak hours this has been taken this into account in calculating average marginal energy costs.

It is recommended that a separate study of this class of consumer be made and that an alternative tariff offering energy in non-critical months during the hours 1100 to 0700 be prepared.

It is further recommended that all new consumers be required to take the time of day alternative and that existing consumers be gradually moved to time of day rates. This may involve a re-assessment of the state of the art of revenue metering at NEC.

D. AGRICULTURAL TARIFF (Small Pumps)

The marginal cost study indicates that, on average agricultural consumers are charged more than marginal costs. NEC's Commercial Director and Tariff Manager have indicated that (in their opinion) the requirement that these consumers not pump during evening peak hours is hardly ever honored because no positive means are currently employed to keep them off the system during those hours.

Therefore it is recommended that an alternative tariff requiring the use of a time clock controlled switch be offered to these consumers; and, that a rate be charged that more closely approaches marginal costs as found in the study.

E. DOMESTIC TARIFF

The marginal cost study indicates that, on average, domestic consumers are charged some 37% below marginal cost.

It is recommended that the charge for the last block of this tariff be moved one-half of the way between its current level (22 P.T./KWh) and the computed average marginal cost for the class (32 P.T./KWh). This recommendation is based on an analysis of domestic consumption which shows that Khartoum (the only available bill frequency analysis) 83.6% of monthly bills are below 200 KWh and that these bills account for only 23.8% of the total comsumption -- averaging 76 KWh. The remaining 16.4% accounts for 76.2% of/the total consumption -- averaging 1235 KWh. The analysis (Table DOM-2 exhibit 20) indicates that there will be very few consumers outside Khartoum in the over 200 KWh block.

This recommendation is designed to charge those consumers who most probably demand more than others during both morning and evening peak periods.

A comparison between the current and proposed tariff recoveries is shown on Table DOM-1 (Exhibit 19).

F. STREETLIGHTING TARIFF (S)

It is recommended that marginal costs be used as the basis for streetlighting tariffs.

The marginal cost of streetlighting service was found to be 0.242 L.S./KWh. This cost assumes that the lighting fixtures are supplied by others and that maintenance is either performed by others or by NEC on a time and material basis. It also assumes that streetlighting bears its full share of capacity costs since its demand is coincident with the evening peak; burning hours are assumed @ 12 hrs. per day.

While the practice is strongly discouraged by the consultants should NEC decide to furnish and maintain lighting fixtures it must develop annual charges (currently 20.43% of initial investment), relamping costs and maintenance costs for each fixture it supplies.

In any event, it is strongly urged that flat rates be used and that service be rendered on an un-metered basis.

The rates for NEC, as a whole, and the estimate revenues for Khartoum Area alone are developed in Table SLT-1 (Exhibit 21) which also displays annual charges by lamp size as reported by Eng. Abbas.

G. OTHERS

This catergory of sales, according to N.E.C, includes some governmental categories, sales to the water company and company use. No one has been able to tell who these consumers are and a request for a list of such consumers has brought forth no response from Khartoum Area. This category has therefore been deferred at this stage.

H. FUEL ADJUSTMENT CLAUSE

The purpose of applying a fuel adjustment clause is to enable electricity utilities to recover the cost in case of changes in fuel prices between tariff studies.

The existing fuel adjustment clause is calculated on a marginal cost basis. That means the marginal energy cost was derived using the prices of fuel contained in the tariff plus one pound per metric ton for each type of fuel. The result was compared with marginal energy cost contained in the tariff. The difference was divided by the electricity sales to determine the adjustment.

There is an argument that utilities will rcover more than the actual cost when applying the marginal cost based fuel adjustment clause and that the fuel adjustment clause should be calculated on average cost basis. However, this argument is inconsistent with the fact that the tariff been designed using marginal costs.

Using the marginal cost approach, as shown on Table FAC-1 (Exhibit 22), the increase in cost is 340,000. Dividing this increase by the sales (1066.61 GWh) the adjustment will be 0.032 P.T./KWh. Using the average cost approach, the increase in cost is L.S. 143,000. Dividing this increase by the sales the adjustment will be 0.013 P.T./KWh. The ratio between the two adjustments is almost the same as the ratio, between marginal energy cost and average energy cost.

It is recommended that the fuel adjustment clause be calculated on a marginal cost basis. The reason for this recommendation is simply that since marginal cost is the standard for the tariff study it should be the standard for increases in fuel costs.

It is also recommended that fuel adjustments be presented as a line on the consumers' bill rather than preparing new tariff sheets.

EXHIBITS

EXHIBITS

1. Summary of Tariff Recommendations

2. Development of Rate of Return under Alternative Scenarios- Table RR-1

3. Load Curve 18 august 1984 Chart C/P-1

4. Load Curve 17 November 1983 Chart C/P-2

5. Marginal Generating Unit by Month by Diurnal Period - Table MCE-1

6. Energy Cost at Different Voltage Levels - Table MCE-2

7. Calculation of Present Value of Revenue Requirements Related to Initial 1.000 L.S. Investment - Table AC-1

8. Development of Customer Related Costs Table CR-1

9. Capacity and Demand-Related Cost by Voltage Level - Table DCV-1

10. Development of Class Noncoincident Maximum Demands - Table CCC-1

11. Development of Class Monthly Coincident Demands at Evening Peak - Table CCC-2

12. Development of Total Marginal Energy Costs by Class by Period - Table CCC-3

13. Total Marginal Cost by Class of Consumer - Table CCC-4

14. Derivation of FY85/86 Overall Sales Forecast - Table SF-1

15. FY85/86 Sales Forecast by Consumers Classification - Table SF-2

16. Development of Domestic Unit Revenue - Table DUR-1

17. Development of Commercial Unit Revenue - Table CUR-1

18. Comparison of Current and Proposed Tariffs (@4109 kWh) - Table COM-1

19. Comparison of Current and Proposed Tariffs (@1235 kWh) - Table DOM-1

20. Domestic Consumption Analysis Table DOM-2

21. Proposed Streetlighting Tariff and Estimated Revenues Table SLT-1

22. Annual Marginal Energy Cost Table FAC-1

EXHIBIT 1

SUMMARY OF TARIFF RECOMMENDATIONS

Classification	Immediately	Recommended Change	Percent Annualized Revenue Increase ($S \times 10^6$)	Increase over Present Tariff	Remarks
Commercial	Yes	Eliminate last block	0.42	1.80	
Industrial	No	All consumers to be time of day. New time-of-day rate.		0.00	Load characteristic study in progress
Domestic	Yes	Increase last block from 22 to 27 p.t./KWh	20.41	19.31	
Agriculture	No	All consumers to have time switch. Reduce rate to marginal cost.		0.00	Study economics of time clocks
Streetlighting	Yes	Use marginal cost as developed on Table	2.74	N.A.	
Other	See Remarks			N.A.	Investigation shows these consumers shoul be shifted to a regular tariff except Company Use which will no longer have a revenue imputed
		TOTAL	23.57		

The fuel adjustment clause will be 0.02 PT/KWh for each whole LS increase or decrease in the average cost of fuel.

Revision 1
8 Jan'86
EXHIBIT 2

Table RR-1

DEVELOPMENT OF RATE OF RETURN UNDER ALTERNATIVE SCENARIOS

Sales in GWh	Current Tariffs	Financial Marginal Costs	Using Economic Fuel Costs @ ER = 2.5	@ ER = 3.0	@ ER = 3.5	RECOMMENDED TARIFFS	RECENT INCREASE OVER PRESENT TARIFF	FINAL RECOMMENDATION
Commercial	83.86	As in Col (1)	As in Col (1)	As in Col (1)	As in Col (1)	As in Col (1)		
Industrial	382.41							
Domestic	523.30							
Agriculture	35.65							
Streetlighting	12.91							
Other	28.48							
Total Sales	1066.61	1066.61				1066.61		
Tariffs (LS/kWh)								
Commercial	0.278	0.269				0.283	1.8	0.280
Industrial	0.200	0.198				0.200	0.00	0.200
Domestic	0.202	0.320				0.241	19.31	0.241
Agriculture	0.227	0.170				0.227	0.00	0.194
Streetlighting	0.030	0.242				0.242	N.A.	0.229
Other	0.239	0.256				0.239	0.00	0.239
Operation Revenue ($LS \times 10^6$)								
Commercial	23.31	22.58				23.73		23.48
Industrial	76.48	75.58				76.48		76.48
Domestic	105.71	167.65				126.12		126.12
Agriculture	8.09	6.05				8.09		6.91
Streetlighting	0.39	3.13				3.13		2.96
Other	6.81	7.29				6.81		6.81
Total, Sales Rev.	220.79	282.28				244.36		242.76
Other Rev.	4.20	4.2				4.2		4.2
Total Op. Rev 12 Mos.	224.99	286.48	224.99	224.99	224.99	248.56		246.96
Operating Expenses		As in Col (1)				As in Col (1)		As in Col (1)
Salaries	13.72		13.72	13.72	13.72			
Fuel	44.90		75.56	82.08	92.65			
Materials	6.36		6.36	6.36	6.36			
Repairs & Maint.	16.43		16.43	16.43	16.43			
Other	19.93		19.93	19.93	19.93			
Depreciation	12.81		12.81	12.81	12.81			
Total Op. Exp. 9.5 Mos.	114.15		144.81	151.33	161.9			
12 Mos.	144.19	144.19	182.15	191.15	204.51	144.19		144.19
Operating Income	80.8	142.29	42.07	33.84	20.48	104.37		102.77
Rate of Return % (on 744.3)	10.4	-	5.4	4.5	2.6	14.0		13.0
Additional Rev. for 10.5% for ($LS \times 10^6$)	0.5	-	39.23	47.46	60.82	-		13.8
REQ Rev/kWh (LS/kWh)	NIL	-	0.04	0.05	0.06	-		-

EXHIBIT 3

CHART C/P-1

LOAD CURVE 18 AUGUST 1984

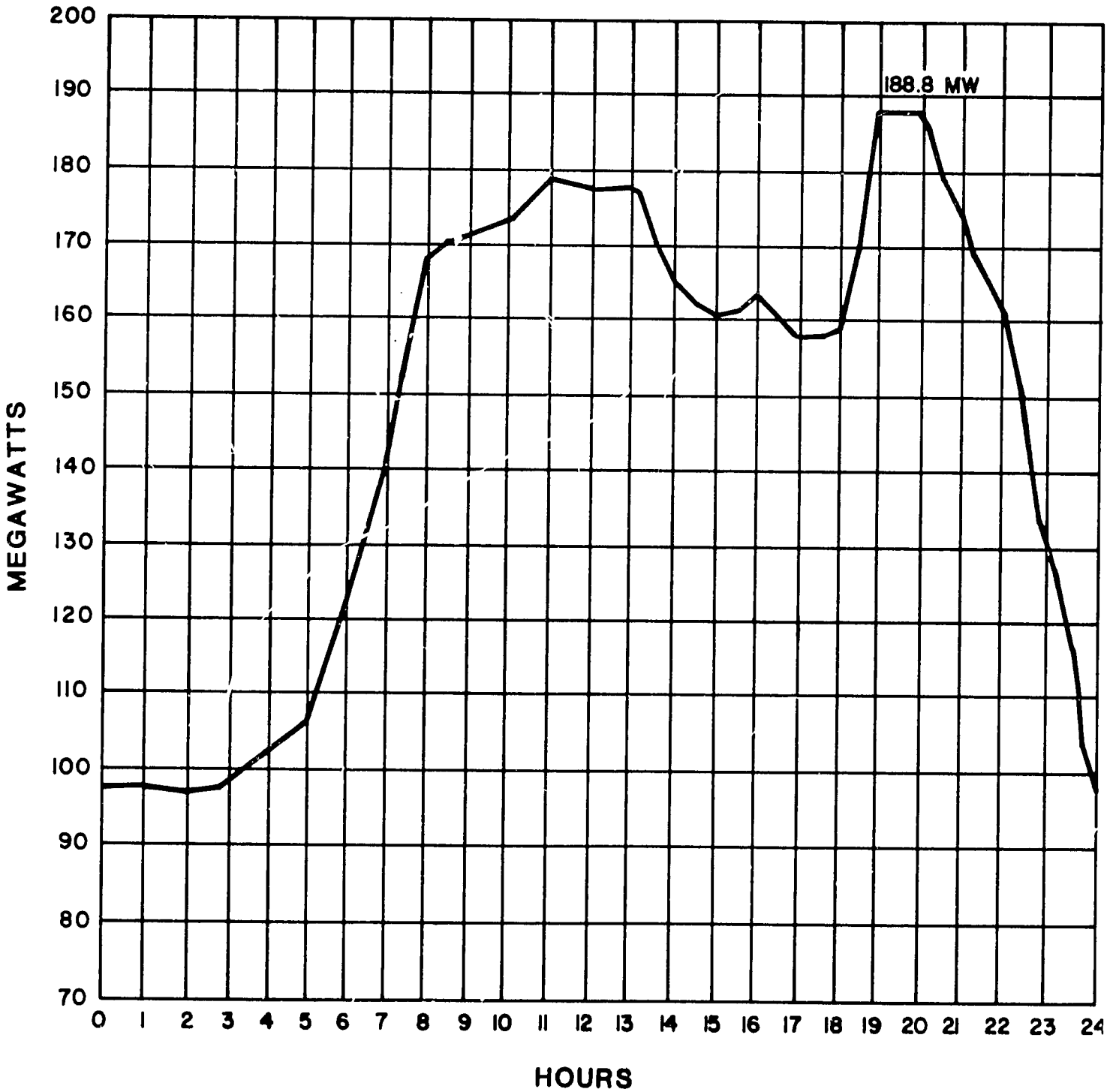


EXHIBIT 4

CHART C/P-2

LOAD CURVE 17 NOVEMBER 1983

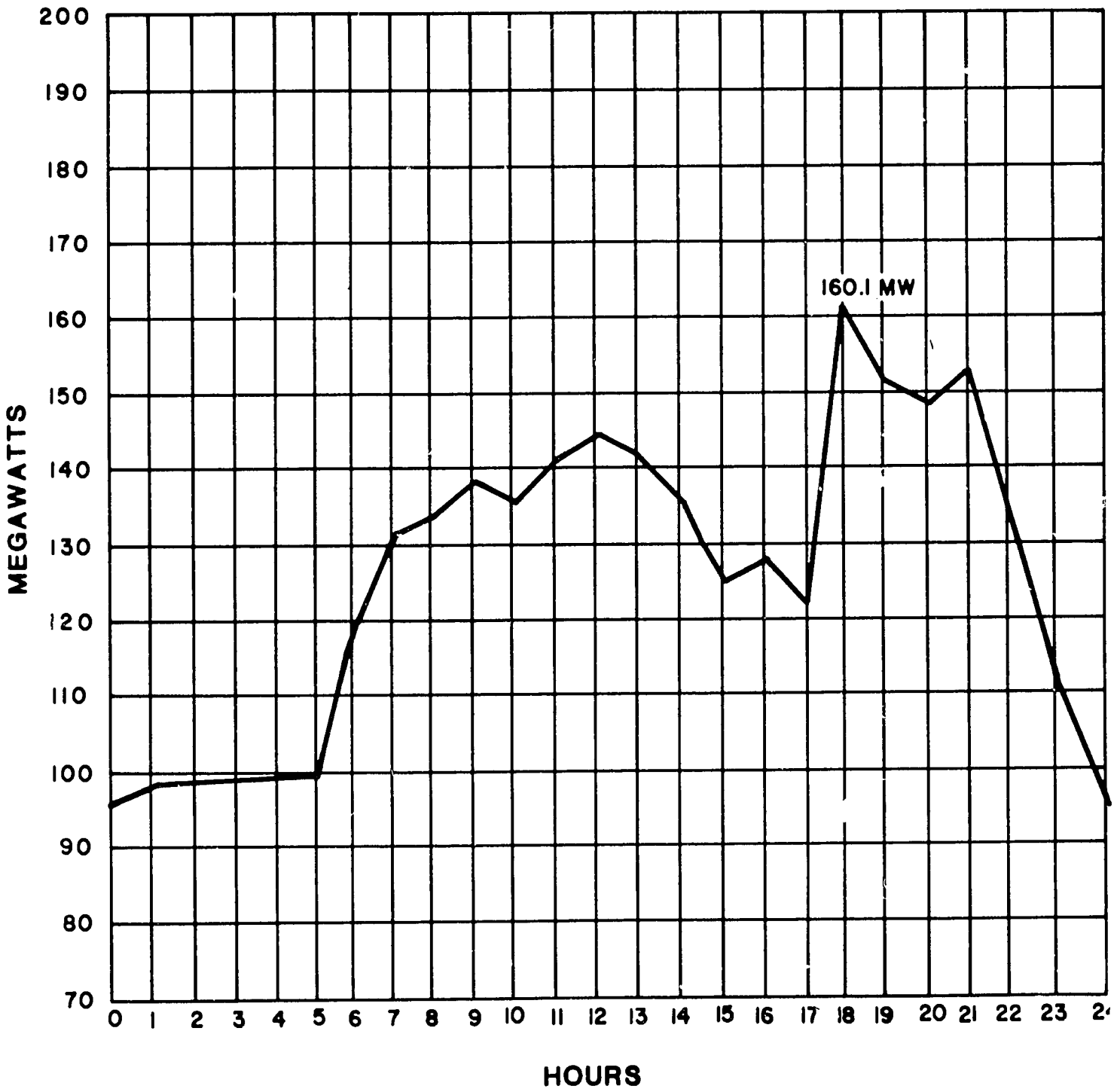


EXHIBIT 5

Table MCE-1

MARGINAL GENERATING UNIT BY MONTH BY DIURNAL PERIOD

Month	Ev. Peak Type of M/C	Mor. Peak Type of M/C	st. off Peak Type of M/C	2nd. off Peak Type of M/C	3rd. off Peak Type of M/C
Jul.	G.T. 15 MW	Burri Steam	Ros. & Sen.	Ros. & Sen.	Cross & Mirr
Aug.	G.T. 13 MW	Burri Steam	Ros. & Sen.	Cross & Mirr	Cross & Mirr
Sep.	Gross & Mirr	P. III D.	Ros. & Sen.	P. III D.	Kh. N.
Oct.	Kh. N.	Kh. N.	Ros. & Sen.	Ros. & Sen.	Ros. & Sen.
Nov.	Kh. N.	Ros. & Sen.	Ros. & Sen.	Ros. & Sen.	Ros. & Sen.
Dec.	P. III D.	Kh. N.	Ros. & Sen.	Kh. N.	Kh. N.
Jan.	Cross & Mirr	P. III D.	Ros. & Sen.	Ros. & Sen.	Ros. & Sen.
Feb.	Ros. & Sen.	Ros. & Sen.	Ros. & Sen.	Ros. & Sen.	Ros. & Sen.
Mar.	Ros. & Sen.	Ros. & Sen.	Ros. & Sen.	Ros. & Sen.	Ros. & Sen.
Apr.	Ros. & Sen.	Ros. & Sen.	Ros. & Sen.	Ros. & Sen.	Ros. & Sen.
May.	Ros. & Sen.	Ros. & Sen.	Ros. & Sen.	Ros. & Sen.	Ros. & Sen.
Jun.	Cross & Mirr	Burri Steam	Ros. & Sen.	Ros. & Sen.	Ros. & Sen.

EXHIBIT 6

Table MCE-2

ENERGY COST AT DIFFERENT VOLTAGE LEVELS
(PT/KWh)

Months	Generation		33 kV Distribution		11kV Distribution		11/.415 kV Distribution		.415 kV Distribution	
	Type	Off Peak	Type	Off Peak	Type	Off Peak	Type	Off Peak	Type	Off Peak
Critical	18.62	10.37	18.99	10.58	20.89	11.32	21.31	11.55	23.01	12.13
Other	10.28	4.66	10.49	4.75	11.54	5.08	11.77	5.18	12.71	5.44

Note:

*Losses have been taken as:

	Peak	Off peak
Sub-transmission	2%	2%
High Voltage and 11 kV Dist.	10%	7%
11/0.415 kV Distribution	2%	2%
Low Voltage	8%	5%

*Electricity Economics by Survey (Electricity Tariff in the Sudan, page 109).

Table AC-1

CALCULATION OF PRESENT VALUE OF REVENUE REQUIREMENTS RELATED TO INITIAL 1,000 L.S. INVESTMENT

Year	Initial Investment (1)	Book Deprec. 3.33%*(1) (2)	Book Deprec. Reserve (3)	Net Book Investment (1)-(3) (4)	Mean Net Book Investment Note 1 (5)	Return on Rate Base 105*(5) (6)	Ratio of Borrowing to Requirementss (7)	Loan Payment Interest 0.19000 (8)	Loan Payment Amortization (9)	Revenue Requirement (2)+(6)+(8)+(9) (10)	P.V. Rev. 0.10500 (11)
0	1,000.00	33.33		1,000.00							
1	1,000.00	33.33	33.33	966.67	983.33	103.25	0.50	95.00	0.52	232.10	210.05
2	1,000.00	33.33	66.67	933.33	950.00	99.75	0.50	94.90	0.62	228.60	187.22
3	1,000.00	33.33	100.00	900.00	916.67	96.25	0.50	94.78	0.73	225.10	166.84
4	1,000.00	33.33	133.33	866.67	883.33	92.75	0.50	94.65	0.87	221.60	148.64
5	1,000.00	33.33	166.67	833.33	850.00	89.25	0.50	94.48	1.04	218.10	132.39
6	1,000.00	33.33	200.00	800.00	816.67	85.75	0.50	94.28	1.23	214.60	117.88
7	1,000.00	33.33	233.33	766.67	783.33	82.25	0.50	94.05	1.47	211.10	104.94
8	1,000.00	33.33	266.67	733.33	750.00	78.75	0.50	93.77	1.75	207.60	93.40
9	1,000.00	33.33	300.00	700.00	716.67	72.25	0.50	93.44	2.08	204.10	83.10
10	1,000.00	33.33	333.33	666.67	683.33	71.75	0.50	93.04	2.48	200.60	73.91
11	1,000.00	33.33	366.67	633.33	650.00	68.25	0.50	92.57	2.95	197.10	65.72
12	1,000.00	33.33	400.00	600.00	616.67	64.75	0.50	92.01	3.51	193.60	58.42
13	1,000.00	33.33	433.33	566.67	583.33	61.25	0.50	91.35	4.17	190.10	51.91
14	1,000.00	33.33	466.67	533.33	550.00	57.75	0.50	90.55	4.96	186.60	46.11
15	1,000.00	33.33	500.00	500.00	516.67	54.25	0.50	89.61	5.91	183.10	40.95
16	1,000.00	33.33	533.33	466.67	483.33	50.75	0.50	88.49	7.03	179.60	36.35
17	1,000.00	33.33	566.67	433.33	450.00	47.25	0.50	87.15	8.36	176.10	32.26
18	1,000.00	33.33	600.00	400.00	416.67	43.75	0.50	85.56	9.95	172.60	28.61
19	1,000.00	33.33	633.33	366.67	383.33	40.25	0.50	83.67	11.84	169.10	25.37
20	1,000.00	33.33	667.66	333.33	350.00	36.75	0.50	81.42	14.10	165.60	22.48
21	1,000.00	33.33	700.00	300.00	316.67	33.25	0.50	78.74	16.77	162.10	19.91
22	1,000.00	33.33	733.33	266.67	283.33	29.75	0.50	75.56	19.96	158.60	17.63
23	1,000.00	33.33	766.67	333.33	250.00	26.25	0.50	71.76	23.75	155.10	15.61
24	1,000.00	33.33	800.00	200.00	216.67	22.75	0.50	67.25	28.27	151.60	13.80
25	1,000.00	33.33	833.33	166.67	183.33	19.25	0.50	61.88	33.64	148.10	12.20
26	1,000.00	33.33	866.67	133.33	150.00	15.75	0.50	55.49	40.03	144.60	10.78
27	1,000.00	33.33	900.00	100.00	116.67	12.25	0.50	47.89	47.63	141.60	9.52
28	1,000.00	33.33	933.33	66.67	83.33	8.75	0.50	38.84	56.68	137.60	8.40
29	1,000.00	33.33	966.67	33.33	50.00	5.25	0.50	28.07	67.45	134.10	7.41
30	1,000.00	33.33	1,000.00	.00	16.67	1.75	0.50	15.25	80.27	130.60	6.53

Note 1: Col (5) = Col (4) (Yrn + Yrn-1) *0.5

Sum P.V. Revenue Requirements = 1,848.35 L.S.

LEVELIZED REVENUE REQUIREMENT RELATING TO 1,000 L.S. CAPITAL INVESTMENT = 204.295 L.S. = 20.43%

EXHIBIT 8

Table CR-1

DEVELOPMENT OF CUSTOMER-RELATED COSTS

A. System Extension

Cost Item	1st Class	2nd Class	3rd Class	
Poles & Stringing-L.S.	35516	31355	196460	
Plots	214	239	2679	
L.S./Plot	166	131	73	
Weighted @	1	2	5	= 99.13 = 100 L.S./Plot

B. Meters & Services

Customer Class	Single Phase	Three Phase	Cost/Cust.
Residential Wtd	150 (0.8)	300 (0.2)	180
Commercial Wtd	150 (0.3)	300 (0.7)	255
S:mall Pumps		300	300
Max. Demand		2500	2500

C. Total Capital Related/Year

Residential	(100 + 180) L.S. * 0.2043	57.20 L.S./Yr.
Commercial	(100 + 255) L.S. * 0.2043	72.53
Small Pumps	(100 + 300) L.S. * 0.2043	81.72
Max. Demand	(100 +2500) L.S. * 0.2043	= 531.18

EXHIBIT 9

Table DCV-1

CAPACITY AND DEMAND-RELATED COST BY VOLTAGE LEVEL

	L.S./KW/Yr
Generation	
Marginal Cost	330.97
O & M Cost*	48.6
Total	379.57
Losses 2%	7.59
Total	387.16
Transmission and 33 KV Distribution	
Marginal Cost	42.90
O & M Cost*	2.63
Total	432.69
Losses 4%	17.31
Total	450.00
33/11 KV Transformation	
Marginal Cost	5.82
O & M Cost*	0.71
Total	456.53
Losses 2%	9.13
Total	465.66
11 KV Distribution	
Marginal Cost	0.74
O & M Cost*	0.09
Total	466.49
Losses 0.87%	1 4.06
Total	470.55
11/0.415 KV Transformation	
Marginal Cost	10.94
O & M Cost*	1.34
Total	482.83
Losses 2%	9.66
Total	492.49
0.415 KV Distribution	
Marginal Cost	4.79
O & M Cost	0.59
Total	497.87
Losses 9%	44.81
Total	542.68

* Source: Previous tariff study; percent of investment--Generation 3%, Transmission 1.25%, Distribution 2.5%

EXHIBIT 10

Table CCC-1

DEVELOPMENT OF CLASS NONCOINCIDENT MAXIMUM DEMANDS

1. Class Annual Sales Forecasts-GWH 1/

Commercial	83.86
Industrial	382.41
Domestic	523.30
Agriculture	35.65
Streetlighting	12.91
Others	28.48
Total	1066.61

2. Class Annual Load Factors-% 2/

Commercial	40
Industrial	60
Domestic	40
Agriculture	40
Streetlighting	50
Others	40

3. Annual Maximum Noncoincident Demands-MW
(MNCD = GWH X 10^3/LF X 8760)

Commercial	23.93
Industrial	72.76
Domestic	149.34
Agriculture	10.17
Streetlighting	2.95
Others	8.13

Source(s): 1/ NEC Commercial Directorate

2/ NEC Market Survey; except stretlighting which reflects an 1800-0600 burning period.

Table CCC-2

DEVELOPMENT OF CLASS MONTHLY COINCIDENT DEMANDS AT EVENING PEAK

Consumer Classification		Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	Jun.
							CLASS MONTHLY DEMAND FACTORS 1/						
Commercial		0.95						0.90			1.00		
Industrial		0.95						0.90			1.00		
Domestic		0.95						0.90			1.00		
Agriculture		0.95		Same as July				0.90	Same as Jan.		1.00		Same as Apr.
Streetlighting		1.00						1.00			1.00		
Others		0.95						0.90			1.00		
							CLASS MONTHLY NCD-MW						
Commercial		22.73						21.54			23.93 2/		
Industrial		69.12						65.48			72.76		
Domestic		141.87						134.41			149.34		
Agriculture		9.66		Same as July				9.15	Same as Jan.		10.17		Same as Apr.
Streetlighting		2.95						2.95			2.95		
Others		7.72						7.32			8.13		
							CLASS MONTHLY COINCIDENT DEMAND-MW						
	Conincidence Factor 3/												
Commercial	0.60	13.64						12.92			14.36		
Industrial	0.70	48.38						43.83			50.93		
Domestic	1.00	141.87						134.41			149.34		
Agriculture	0.00	0.00		Same as July				0.00	Same as Jan.		0.00		Same as Apr.
Streetlighting	1.00	2.95						2.95			2.95		
Others	0.60	4.63						4.39			4.88		

Notes: 1/ Source, technical supplement to systems plan-modified for this study

2/ Source, Table CCC-1 (3) (Exhibit 10)

3/ Source, NEC market survey

EXHIBIT 12

Table CCC-3

DEVELOPMENT OF TOTAL MARGINAL ENERGY COSTS BY CLASS BY PERIOD

Class of Consumers	Sales Forecast (GWh)	Time of Day & Seasonal Consumption Factors: Critical Months Peak	Critical Months Off Peak	Other Months Peak	Other Months Off Peak	Class Time of Day & Seasonal Consumption (GWh): Critical Months Peak	Critical Months Off Peak	Other Months Peak	Other Months Off Peak	Class Time of Day & Seasonal Energy Cost (L.S. x 10^6): Critical Months Peak	Critical Months Off Peak	Other Months Peak	Other Months Off Peak
Commercial	83.86	0.42	0.1	0.38	0.1	35.22	8.39	31.86	8.39	8.1	1.02	4.05	0.46
Industrial	382.41	0.32	0.22	0.18	0.18	122.36	84.13	107.07	68.85	25.66	9.36	12.41	3.52
Domestic	523.3	0.31	0.22	0.28	0.19	162.22	115.13	146.52	99.43	37.33	13.97	18.62	5.41
Agriculture	35.65	0.255	0.255	0.245	0.245	9.09	9.09	8.74	8.73	2.09	1.1	1.11	0.48
Streetlighting	12.91	0.17	0.33	0.17	0.33	2.19	4.26	2.19	4.27	0.5	0.32	0.28	0.23
Other	28.48	0.42	0.1	0.38	0.1	11.96	2.85	10.82	2.85	2.75	0.35	1.38	0.16

EXHIBIT 13

Table CCC-4

TOTAL MARGINAL COST BY CLASS OF CONSUMER

	Commercial	Industrial	Domestic	Agri-culture	Street-lighting	Others
1. Class Coincident demand (MW)	14.36	50.93	149.34	10.17	2.95	4.88
2. Demand-related L.S./KW	542.68	474.97	542.68	111.05	542.68	542.68
3. Total Demand-related Cost by Class L.S. x 10^6 (1X2)	7.79	24.19	81.04	1.13	1.6	2.65
4. No. of consumers	15956	451	197274	1725	-	-
5. Customer-related cost L.S./customer	72.53	531.18	57.2	81.72	-	-
6. Total customer-related cost (L.S. x 10^6) (4x5)	1.16	0.24	11.28	0.14	-	-
7. Energy related cost L.S. x 10^6	13.63	51.15	75.33	4.78	1.53	4.64
8. Total marginal (3+6+7)	22.58	75.58	167.65	6.05	3.13	7.29
9. Energy sales GWh	83.86	382.41	523.3	35.65	12.91	28.48
10. Average cost (L.S./KWh) (8÷9)	0.269	0.198	0.320	0.170	0.242	0.256

EXHIBIT 14

Table SF-1

DERIVIATION OF FY85/86 OVERALL SALES FORECAST

1984/85 Actual Unit Generation (BNG)	1213.0 GWh
1984/85 Load Shed	41.5 GWh
1984/85 Normalized Unit Generation	1254.5 GWh
Growth 7.5% + 2.5% Suppressed Demand	125.5 GWh
Forecast Unit Generation (BNG)	1380.0 GWh
Less: Technical Losses + Lost & Unaccounted	(345.0)GWh
BNG Sales	1035.0)GWh
Eastern Grid Sales Forecast	20.
Difference Between Known KH. St. Lt. Consumption and KH. St. Lt. Consumption from the forecast	11.61
Total NEC Sales	1066.61

EXHIBIT 15

Table SF-2

FY 85/86 SALES FORECAST BY CONSUMER CLASSIFICATION

Classification	BNG		EC		NEC
	%	GWh	%	GWh	GWh
Commercial	7.5	78.66	26.0	5.2	83.86
Industrial	36.2	378.81	18.0	3.6	382.41
Domestic	49.4	517.50	29.0	5.8	523.30
Agriculture	3.0	31.05	23.0	4.6	35.65
Streetlighting	1.2	12.77	0.7	0.14	12.91
Other	2.7	27.82	3.3	0.66	28.48
Totals	100	1046.61	100	20	1066.61

EXHIBIT 16

Table DUR-1

DEVELOPMENT OF DOMESTIC UNIT REVENUE

A. Table of Unit Revenues

	CUMULATIVE kWh	---1 PHASE COSTS L.S.----- BLOCK	CUMULATIVE	PER/kWh	-----3 PHASE COSTS L.S.-- BLOCK	CUMULATIVE	PER/kWh
NIL		2.50	2.50		7.50	7.50	
51 @ .17		8.67	11.17	0.219		16.17	0.317
24 @ .17	75	4.08	15.25	0.203		20.25	0.270
125 @ .19	200	23.75	39.00	0.195		44.00	0.220
300 @ .22	500	66.00	105.00	0.210		110.00	0.220
500 @ .22	1000	110.00	215.00	0.215		220.00	0.220
1000 @ .22	2000	220.00	435.00	0.218		440.00	0.220
1500 @ .22	3500	330.00	765.00	0.219		770.00	0.220

B. Estimated Unit Revenue @ 150 KWh

	Single Phase
Fixed Charge	2.50
75 KW @ 0.17	12.75
75 KW @ 0.19	14.25
Total	29.50
÷ 150	0.197 @ 0.8 = 0.158
Three Phase	0.220 @ 0.2 = 0.044
	USE 0.202 L S./KWh

EXHIBIT 17

Table CUR-1

DEVELOPMENT OF COMMERCIAL UNIT REVENUE

A. Bill Frequency Analysis - Khartoum 04/1405

Consumption	Bills No.	Bills %	kWh No.	kWh %	Average KWh
NIL - 500	884	66	68819	4	78
Over 500	454	34	1676672	96	3693
Totals	1338	100	1745491	100	1304 1/

B. Annual Consumptions 2/

Area	Bills No.	Bills %	kWh No.	kWh %	Average KWh
Khartoum	2125	13	26300	49	1031
Other	13831	87	27800	51	167
System	15956	100	54100	100	283

C. Revenue Recovery - Present Tariff

System Weighted Average Consumption = 0.13 (1304) + 0.87
= 315 kWh

Unit Revenue Recovery = 7.50 L.S.+[250(0.26)+65(0.23)] L.S.
= 87.45 L.S. = 0.278 L.S./kWh

Notes: 1/ Best estimate of current Khartoum value

2/ Draft Annual Report 1983/84

EXHIBIT 18

Table COM-1

COMPARISON OF CURRENT AND PROPOSED TARIFFS
(@ 4109 KWh)1/

		Block Chg. L.S.	Cumulative Bill L.S.	L.S./KWh
Current				
Nil	@ 7.50 L.S.	7.50		
0-250	@ 0.26 L.S.	65.00	72.50	0.290
251-500	@ 0.23 L.S.	57.50	130.00	0.260
3609	@ 0.22 L.S.	793.98	923.98	0.225
Proposed				
Nil	@ 7.50 L.S.	7.50		
0-250	@ 0.26 L.S.	65.00	72.50	0.290
251-500	@ 0.23 L.S.	57.50	130.00	0.260
3609	@ 0.23 L.S.	830.07	960.07	0.234
Increase				
Nil	@ 7.50 L.S.			
0-250	@ 0.26 L.S.			
251-500	@ 0.23 L.S.			0.009
3609	@ 0.23 L.S.	36.09	36.09	

1/ Commercial forecast 83.86 GWh X 0.49 (Khartoum share) X 0.96 = (GWh on bills over 500 KW/h/mo.) ÷ 12 mos. ÷ 800 bills X 10^6
4109 KWh/mo.

EXHIBIT 19

Table DOM-1

COMPARISON OF CURRENT AND PROPOSED TARIFFS
(@ 1235 KWh/month)

	Block Chg L.S.	Single Phase Cumulative Bill L.S.	L.S./KWh	Block Chg L.S.	Three Phase Cumulative Bill L.S.	L.S./KWh
Current						
NIL @ 2.50 L.S.	2.50	2.50		7.50		
0.75 @ 0.17 L.S.	12.75	15.25	0.203	12.75	20.25	0.270
76-200 @ 0.19 L.S.	23.75	39.00	0.195	23.75	44.00	0.220
Next 1035 @ 0.22 L.S.	227.70	266.70	0.216	227.70	217.70	0.220
Proposed						
NIL @ 2.50 L.S.	2.50	2.50		7.50	7.50	
0.75 @ 0.17 L.S.	12.75	15.25	0.203	12.75	20.25	0.270
76-200 @ 0.19 L.S.	23.75	39.00	0.195	2.375	44.00	0.220
Next1035 @ 0.27 L.S.	279.45	318.45	0.258	279.45	323.45	0.262
Increase						
NIL @ 2.50 L.S.						
0.75 @ 0.17 L.S.						
76-200 @ 0.19 L.S.						
Next 1035 @ 0.27 L.S.	51.75	51.75	0.042	51.75	51.75	0.042

EXHIBIT 20

Table DOM-2

DOMESTIC CONSUMPTION ANALYSIS

A. Bill frequency Analysis Khartoum-04/1405

Consumption	Bills No	Bills %	KWh No	KWh %	Average KWh
Nil-200	92401	83.6	7031570	23.8	76
Over-200	18185	16.4	22462978	76.2	1235
Totals	110586	100.0	29494548	100.0	267

B. Average Consumptions 1/

Area	Customers	Consumption-mwh	Av. KWh
Khartoum	130033 2/	333800	214
Other	67241	47600	59
System	197274	381400	161

Notes: 1/ 1983/84 Draft Annual Report

2/ Adjusted for unbilled customers of 47,000 in Khartuom

EXHIBIT 21

Table SLT-1

PROPOSED STREETLIGHTING TARIFF AND ESTIMATED REVENUES

A. Khartoum Area

Lamp Size W	Annual Charge Current 2/	L.S./ Lamp Proposed	No. Lamps Khartoum 1/	Total Annual Renuenue L.S. Current	Total Annual Renuenue L.S. Proposed
		(1)*8760 *0.5*0.242		(2)*(4)	(3)*(4)
(1)	(2)	(3)	(4)	(5)	(6)
40		42.40			
80	15.72	84.79	9000	141480	763110
125	20.52	132.50	6600	135432	874500
200		212.00			
250	28.92	265.00	2200	63624	583000
400	42.00	424.00	2050	86100	869200
Totals			19,850	426,636	3,089,810

B. Outside Khartoum	40,190
Total	3,130,000

Note:

1/ From condensed version of Eng. Abbas, Table SL-1

2/ Ibid; Table SL-2 B

Table FAC-1

ANNUAL MARGINAL ENERGY COST (L.S. x 10^6)

	Commercial	Industrial	Domestic	Agri-culture	Street-lighting	Others	Total
@ Current Fuel Prices	13.63	51.15	75.33	4.78	1.53	4.64	151.0
@ Current Fuel Price + 1 L.S. per tonne for each type of fuel	13.68	51.28	75.46	4.79	1.54	4.65	151.0

APPENDICES

APPENDICES

MGC-1 A Simplified Model of Time of Day/Seasonal Pricing

MGC-2 The Simplified Model Applied to Hydraulic Systems

APPENDIX MGC-1

A SIMPLIFIED MODEL OF TIME OF DAY/SEASONAL PRICING

14

n/e/r/a

A simplified model of time-of-day/seasonal pricing

by

Sally Hunt Streiter

and

Leo T. Mahoney, Jr.

The theory of marginal cost pricing posits that the price charged for electricity at any time should equal the cost of providing a small amount more, or the savings from providing a small amount less. Since in a complex system with a cyclical demand there are different costs at different times, we have to find a way to estimate the different costs. Fortunately, the engineers got there before the economists and produced a variable technology adapted to the variable demand. The technology permits different equipment to serve demands of different durations, and by simulating the planning process by which equipment is chosen, it is possible to derive the conditions for a minimum cost system. If the marginal cost principle of pricing is then applied to this simplified system, we can test various hypotheses about the relation of revenues to costs under marginal cost pricing; we can examine the fairness of charges to consumers with different load patterns; we can show how different load patterns vary in cost and how growth affects cost.

15

The following theorem and corollaries show in a very nplified and schematic way how a kilowatt-hour pricing heme based on marginal costs for each hour of the ar will:

1. Cover total costs, in fact, exactly equate revenues th costs.
2. Be equitable to particular types of consumers.

The proposed pricing rule is that the price to be arged for each kilowatt produced in a given hour of the ar should be the hourly running cost of the last machine line at that point, *plus* an amount equal to the annual st of one kilowatt of peaking capacity, charged for the ak hour only. (To be a little more realistic, since the exact ur of the peak is unknown, the annual capital cost of the xt kilowatt is spread over all the hours when the peak is ually likely to occur.)

The theorem is proven for a schematically simple but presentative system containing three plants. This system is sumed to have been designed to minimize the cost of eeting an exogenously determined load curve. This sumption is important, since it gives the conditions under ich the pricing rule produces revenues which exactly ver the capital and running costs of the system. All the oofs in this paper refer to this optimal system.

We are entirely aware that the real world has systems hich are less than optimal, and that this simplified model n only be of limited application. Nor will marginal costs actly equate with total costs when technical progress, flation and other factors are introduced. Nonetheless, it has oved helpful in analyzing non-optimality also, and is esented as a conceptual tool.

HEOREM

ule

In an optimally planned system prices should be set qual to the marginal running cost at any given hour plus e capital cost of meeting 1 extra Kw of peak demand arged at the peak hour only.

esult

The revenues so obtained will exactly equal the annual apital costs plus the annual running costs of the system.

roof

Let the following symbols be used in a system with plant types available.

	Annual Capital Cost $/Kw	Running Costs $/Kwh	Hours/ Year Running Time	Kw Capacity
Peaking Plant	X	x	a	A
Cycling Plant	Y	y	a+b	B
Baseload Plant	Z	z	a+b+c	C

Total running time $t = a + b + c = 8{,}760$ hours

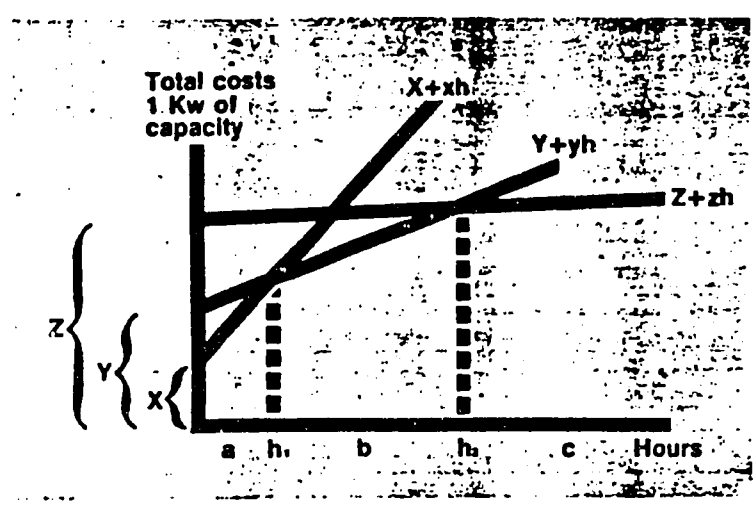
Total capacity $K = A + B + C$

If X, Y, Z, x, y, z are given, it can be shown that in an optimally planned system, the prices below will give the required revenues.

Peak hours: a hours at $(x + X/a)$ $/Kwh
Middle hours: b hours at y $/Kwh
Low hours: c hours at z $/Kwh

This is true whatever the values of A, B and C.

1. Conditions for an optimal system



Use peaking plants when

$X + xh < Y + yh$

Since X, Y, x, y are known

$h = \frac{Y-X}{x-y} = a \ldots\ldots 1)$

Then A is determined by the load curve and the value of

Similarly, use cycling plants when

$Y + yh < Z + zh$

$h = \frac{Z-Y}{y-z} = a + b \ldots\ldots 2)$

ıen B is determined by the load curve and the value of (a+b)

If plant has been optimized, and price has been set cording to rules set out above, revenues will equal total ınual capital + running costs

Revenues

·riod Which ırginal ıchine is:	Plant in Use	Output	Price	Revenues
aking Unit	$A+B+C$	$(A+B+C)a$	$x+X/a$	$(A+B+C)a(x+\frac{X}{a})$
cling Unit	$B+C$	$(B+C)b$	y	$(B+C)by$
seload Unit	C	Cc	z	Ccz
				Σ Revenues

Costs

sts	Annual Capital Cost $	Hours in Use	Kwh Generated	Running Cost per Kwh	Total Running Cost
ıking nt	AX	a	Aa	x	Aax
cling nt	BY	$a+b$	$B(a+b)$	y	$B(a+b)y$
seload nt	CZ	$a+b+c$	$C(a+b+c)$	z	$C(a+b+c)z$
	Σ Capital				Σ Running

Z Revenues = Z Running + Z Capital

$$(B+C)a(x+X/a)+(B+C)by+Ccz = Aax+B(a+b)y+C(a+b+c)z+AX+BY+CZ$$

$$BX+CX+Bax+Cax+Cby = BY+CZ+Bay+Caz+Cbz \quad .3)$$

In 1) above $\frac{Y-X}{x-y}=a$

then $X=Y-a(x-y)$ ...4)

In 2) above $\frac{Z-Y}{y-z}=a+b$

then $Z=(a+b)(y-z)+Y$ ...5)

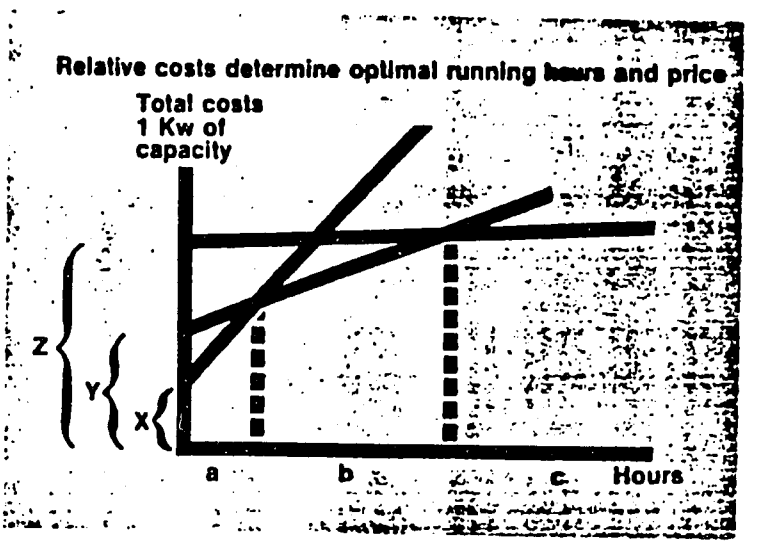
Substituting from 4) and 5) into 3)

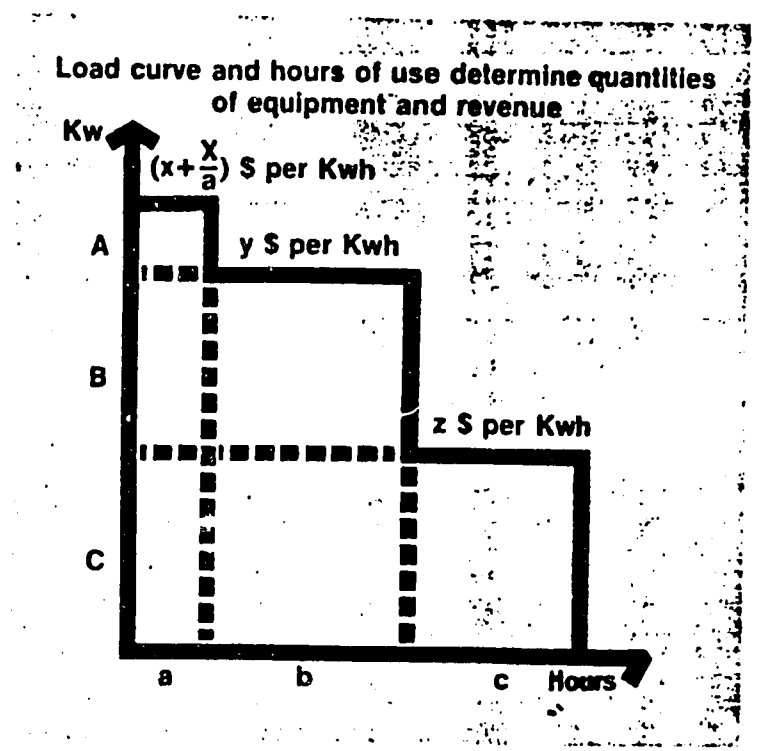
$$C(Y-a(x-y))+Bax+Cax+Cby = BY+CY+C(a+b)(y-z)+Bay+Caz+Cbz$$

Rearranging and cancelling common terms

$$+CY+Bay+Cay+Cby = BY+CY+Cay+Cby+Bay$$

QED





Note:

1. The result is independent of the magnitude of A, B and C and of their total. The Kw capacity of each type of machine depends only on the load curve.
2. The optimal hours of running each class of machine

depend only on the relative costs.

The assignment of capital costs to the hours when the peaking machine is used, and equally over those hours, is arbitrary.

The rule more rigorously defined is that each kilowatt hour should be charged (the probability of failure) × (the cost of the next Kw to meet the failure).

This may mean spreading the capital cost of the Kw over more hours of the year, or fewer. However, if peaking charges cover too few hours a new peak may pop up.

rollary A

A user who has a flat load curve and used M Kwh/hour ntinuously throughout the year will be paying exactly fair share.

For if his demand had been met by addition of a seload plant with M Kw capacity:

r Share Cost = MZ + M(a + b + c)z

tual Charges = M(a[x + X/a] + by + cz)

is is fair if

Z + Maz + Mbz + Mcz = Max + Mby + Mcz + MX ...6)

1) above $\frac{Y-X}{x-y} = a$

2) above $\frac{Z-Y}{y-z} = a + b$

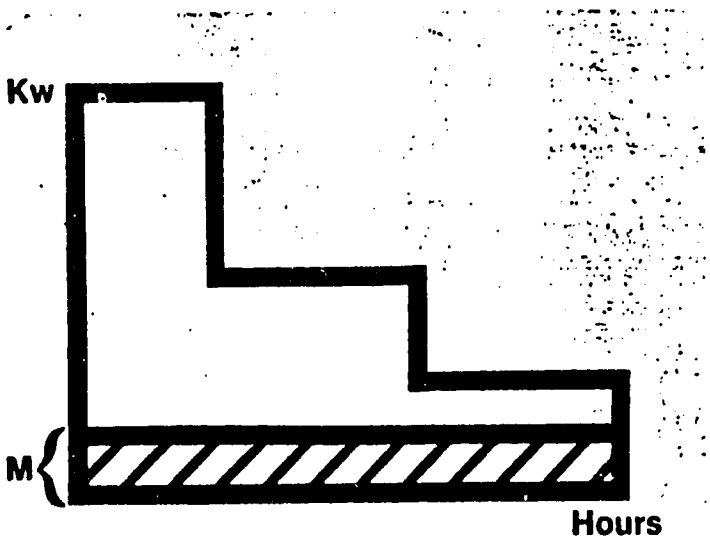
ling 1) + 2) Z−X = ax + by−az−bz ...7)

stituting in 6) from 7)

Z + Maz + Mbz + Mcz = Max + Mby + Mcz + M(Z−ax−by + az + bz)

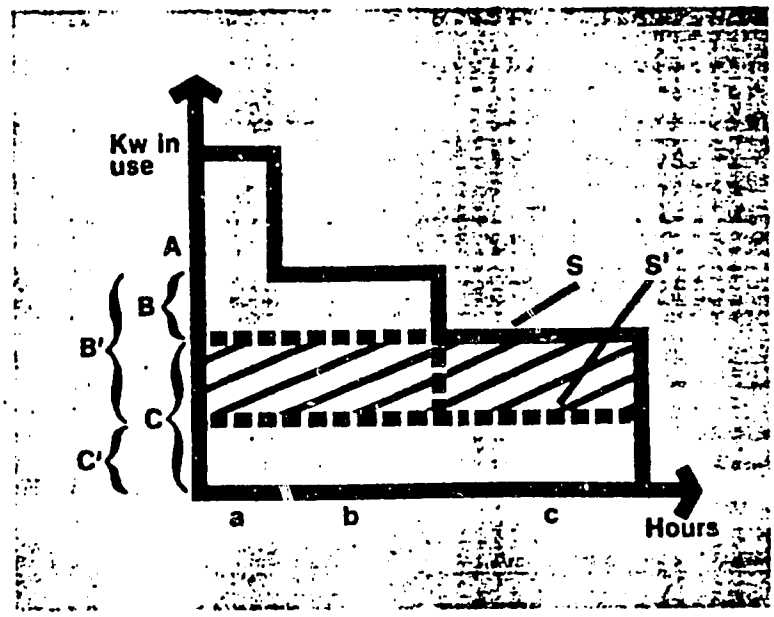
celling common terms

+ Maz + Mbz + Mcz = MZ + Maz + Mbz + Mcz QED



Corollary B

If two firms differ only in their load curve characteristics, with the difference only in the bottom of the load curve, it can be shown that the same pricing rule yields each firm sufficient to cover its costs.



S has more baseload need than S', and consequently installs C Kw of baseload and B Kw of intermediate plant, where S' installs C' and B' respectively.

The difference in capital and running costs between the systems will equal the difference in revenue under the pricing system.

For the shaded rectangle

Costs S−S' = difference in capital costs + difference in running costs

= (C−C')Z + (B−B')Y + (C−C')z(a + b + c) + (B−B')y(a + b) ...8)

Revenues S−S' = (C−C')cz

Since C−C' = −(B−B')

and Z−Y = (y−z)(a + b) from 1)

In 8) Costs S−S = (C−C')[Z−Y + az + bz + cz−ay−by]

= (C−C')[(a + b)(y−z) + az + bz + cz−ay−by]

= (C−C')cz

= Revenues S−S' QED

Corollary C

The fuel savings from the baseload and cycling plant offset part of the capital cost of the plant so that the net cost per Kw is equal to the cost of the peaking plant. In other words

apital cost of peaking plant
- Capital cost of cycling plant *less* fuel savings from ınning the cycler rather than the peaker.
- Capital cost of baseload plant *less* fuel savings from ınning baseload rather than the cycler and the peaker.

ı 1) $\frac{Y-X}{x-y} = a$

$X = Y-a(x-y)$ QED

ı 2) $\frac{Z-Y}{y-z} = a+b$

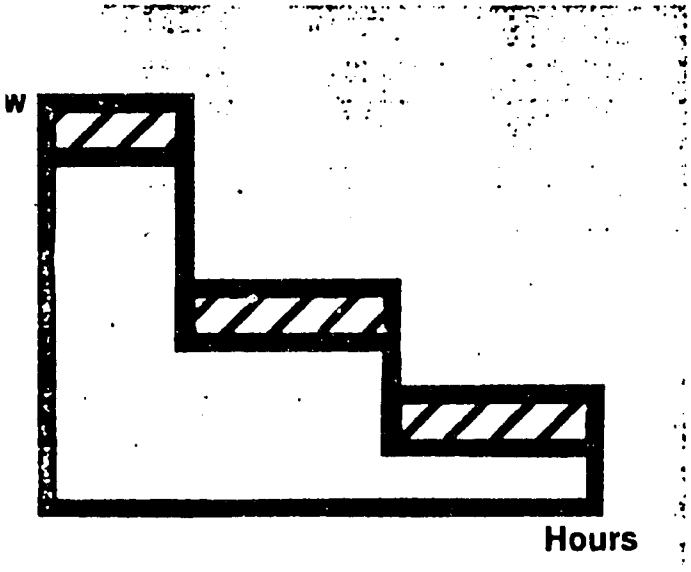
ıg 1) + 2)

$X = Z-a(x-z)-b(y-z)$ QED

llary D

As a system grows, if its configuration is optimal at eginning and end of the growth, the revenues from the h will equal the cost of the growth. This is true for or uneven growth.

r *even* growth of G Kw in each period



m before growth		System after growth
ng plant	A Kw	A Kw
ıg plant	B Kw	B Kw
oad plant	C Kw	C + G Kw

of growth = $G(Z + [a + b + c]z)$

ıues from growth = $G(a[x + \frac{X}{a}] + by + cz)$

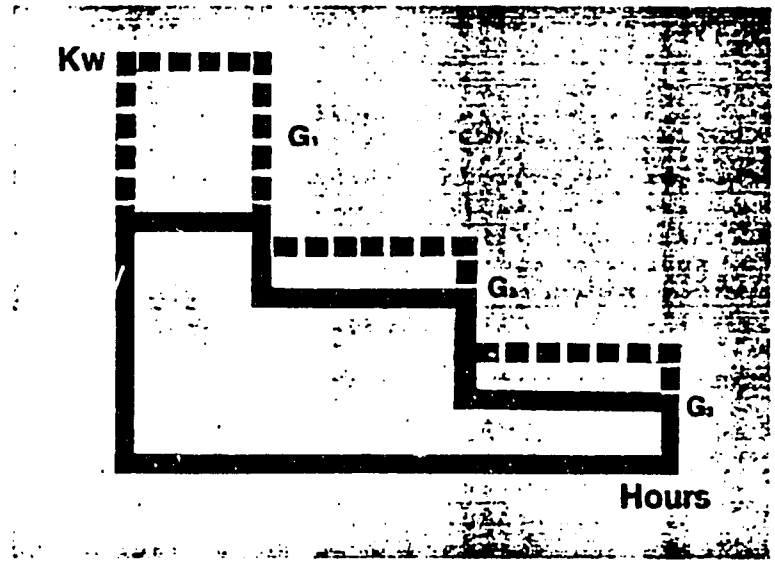
These are equal if

$G(Z + [a+b+c]z) = G(ax+by+cz+X)$ ...9)

from 7) $Z-X = by-az-bz+ax$

Substituting in 9) $G(Z + [a+b+c]z) = G(Z+ax+bz+cz)$

2) For *uneven* growth of G_1, G_2, G_3 at peak, intermediate period and off-peak



System before growth		System after growth
Peaking	A	$A + G_1 - G_2$
Cycling	B	$B + G_2 - G_3$
Baseload	C	$C + G_3$
Total Kw	$A+B+C$	$A+B+C+G_1$

Cost of net growth in peaking capacity = $(G_1-G_2)[X + ax]$

Cost of net growth in cycling capacity = $(G_2-G_3)[Y + (a+b)y]$

Cost of net growth in baseload capacity = $G_3(Z + [a+b+c]z)$

Revenues from net growth = $G_1a(x + \frac{X}{a}) + G_2by + G_3cz$

Costs equal revenues if

$$(G_1-G_2)(X + ax) + (G_2-G_3)(Y + [a+b]y) + G_3(Z + [a+b+c]z)$$
$$= G_1a(x + \frac{X}{a}) + G_2by + G_3cz$$

$$G_1(X + ax) + G_2[Y + (a+b)y - X - ax] + G_3[Z + (a+b+c)z - Y - (a+b)y]$$
$$= G_1a(x + \frac{X}{a}) + G_2by + G_3cz$$

Since $Y-X = a(x-y)$

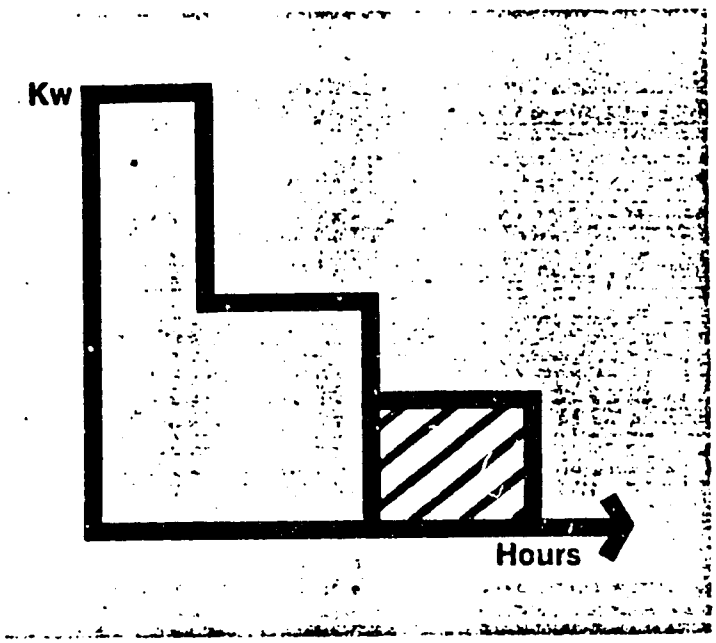
$Z-Y = (y-z)(a+b)$

$G_1(X + ax) + G_2by + G_3cz = G_1a(x + \frac{X}{a}) + G_2by + G_3cz$ QEI

This means that the cost of growth in *each period* and *in total* are equal to the running costs in each hour plus the cost of the peaking plant.

'ollary E

A consumer who uses only off-peak power should not charged any capital costs, only the running cost.



ıe off-peak consumer did not exist then the system ıfiguration would be different. The net total cost to the tem of the changed configuration is equal to the running ıt in the off-peak hours, or Ccz.

ıof

If the consumer had not existed, system would have ɜn

A Kw peaking
(B + C) Kw cycling
0 baseload

st without him = AX + (B + C)Y + Aax + (B + C)(a + b)y

ıe consumer now exists, *and the system is reoptimized*

ıt with him = AX + BY + CZ + Aax + B(a + b)y + C(a + b + c)z

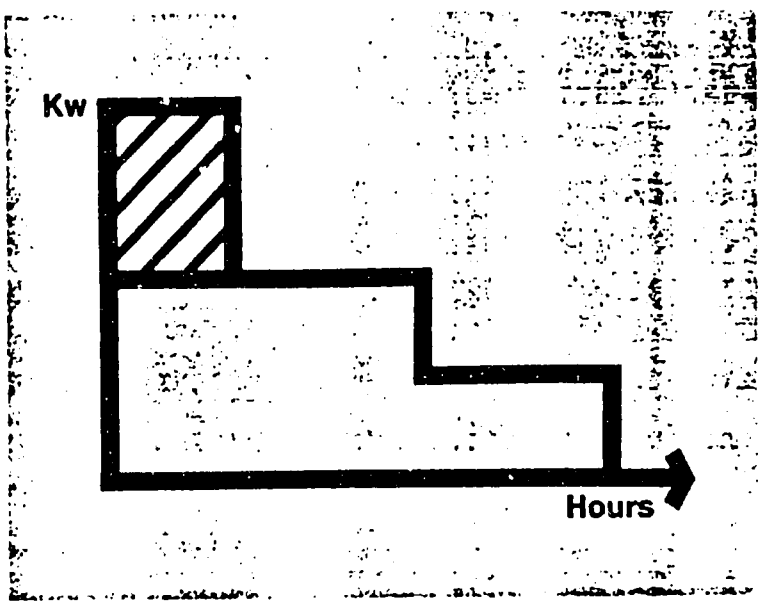
'erence in costs with him and without him

= CZ-CY + C(a + b + c)z-C(a + b)y
= CZ-CY + C(az + bz + cz-ay-by)
= CZ-CY-C[(a + b)(y-z) + cz]
= C(Z-Y-Z + Y) + Ccz
= Ccz

is is what we ask him to pay.

Corollary F

But what if the consumer requires all his power at the peak? Then charging him the capital costs covers the incremental cost to the system.



System without him = B + C
System with him = A + B + C
System costs without him = BY + CZ + B(a + b)y + C(a + b + c)z
System costs with him = AX + BY + CZ + Aax + B(a + b)y + C(a + b + c)z
Difference in system costs = AX + Aax
= Aa(x + X/a)

This is what we ask him to pay.

ILLUSTRATION

ILLUSTRATIVE EXAMPLE TO DEMONSTRATE THAT BY CHARGING THE CAPITAL COST OF PEAKING CAPACITY DURING PEAK HOURS, THE RUNNING COST OF PEAKING CAPACITY DURING PEAK HOURS AND THE RUNNING COST OF THE MARGINAL MACHINE AT OTHER TIMES, THE TOTAL COSTS OF AN OPTIMIZED SYSTEM WILL BE RECOVERED.

ASSUME:

1) A system whose load duration profile permits each type of production plant to operate the optimum number of hours [The optimum number of running hours for any plant is that number of running hours beyond which some other type of plant would operate at a lesser total cost].

) The following symbols are used

	Peaking	*Inter.*	*Baseload*
Capital $/Kw	P	I	B
Annual charge %	AC_P	AC_I	AC_B
Running costs $/Kwh	p	i	b
Hours of running time	h_1	h_2	h_3
System configuration (Kw)	K_1	K_2	K_3

In this example the following values, approximating those of an actual utility, are taken

	Peaking	*Inter.*	*Baseload*
Capital $/Kw	140	300	500
Annual charge %	20%	15%	15%
Running costs $/Kwh	.03	.015	.004
System configuration (1 Kw System)	.2	.3	.5

COMPUTATION OF OPTIMUM RUNNING HOURS:

PEAKING CAPACITY

$$\$P(AC_P) + \$p(h_1) = \$I(AC_I) + \$i(h_1)$$

)lve for h_1–

$$\$p(h_1) - \$i(h_1) = \$I(AC_I) - \$P(AC_P)$$

$$h_1 = \frac{\$I(AC_I) - \$P(AC_P)}{\$p - \$i}$$

ıbstitute the assumed costs

$$= \frac{\$300(.15) - \$140(.20)}{\$.03 - \$.015}$$

$$= \frac{\$45 - \$28}{\$.015} = \frac{17}{.015} = 1133 \text{ hrs.}$$

INTERMEDIATE CAPACITY

$$\$I(AC) + \$i(h_2) = \$B(AC_B) + \$b(h_2)$$

)lve for h_2–

$$\$i(h_2) - \$b(h_2) = \$B(AC_B) - \$I(AC)$$

$$h_2 = \frac{\$B(AC_B) - \$I(AC)}{\$i - \$b}$$

ıbstitute the assumed costs–

$$= \frac{\$500(.15) - \$300(.15)}{\$.015 - \$.004}$$

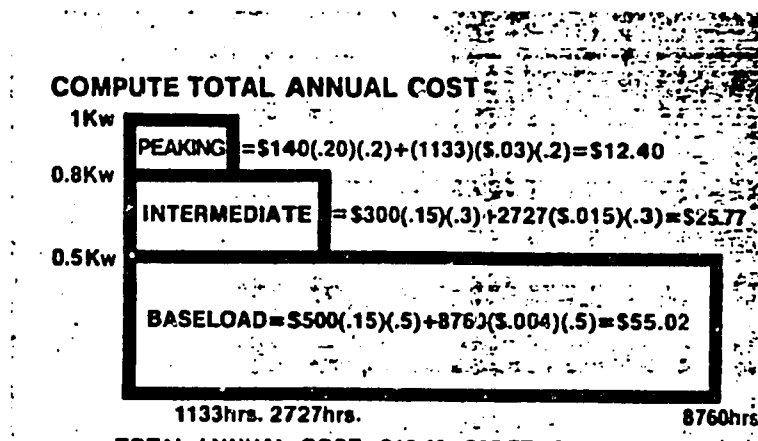
$$= \frac{\$75 - \$45}{\$.011} = \frac{30}{.011} = 2727 \text{ hrs.}$$

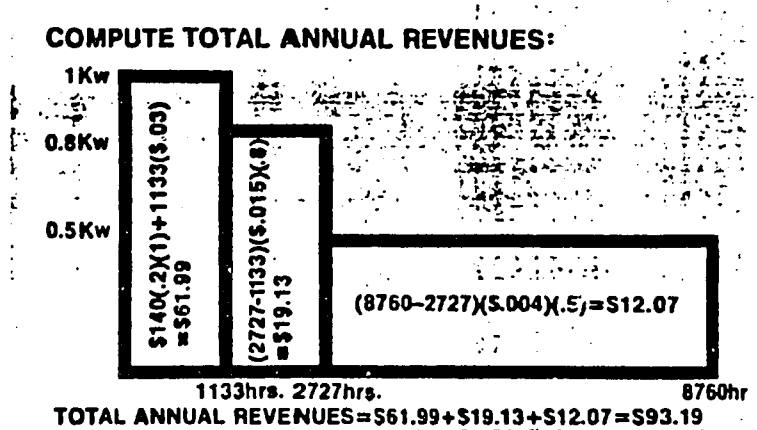
BASELOAD CAPACITY

Baseload running hours = 8,760 hrs.

B. REVENUES ARE RECOVERED

With prices set equal to running costs of the marginal machine [3¢, 1.5¢, 0.4¢ per Kwh] in each period, plus a capital component equal to the cost of 1 Kw of peaking capacity, the total costs are recovered.





C. A 100-PERCENT LOAD FACTOR CUSTOMER IS FAIRLY CHARGED

Using the values in the Illustration, we show the 100 percent load factor customer pays his fair share under marginal cost pricing.

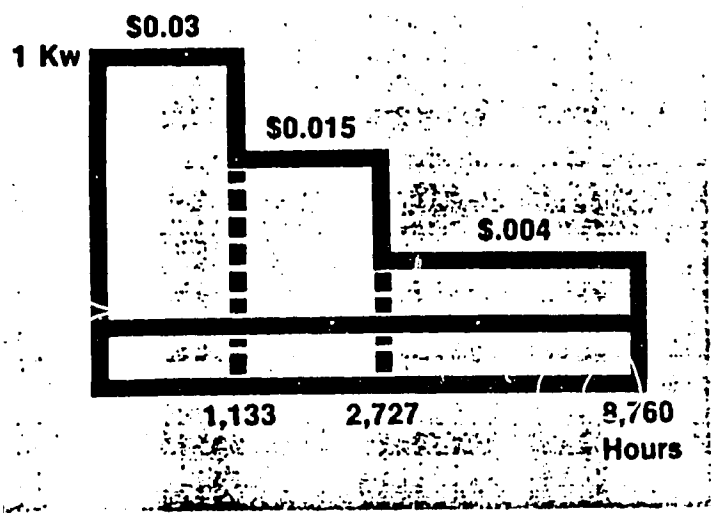
If the 100 percent load factor consumer were added the system would need to add a baseload unit at a cost of:

$500 (.15) + 8,760(.004) = $110 per year

Under marginal cost pricing he would pay:

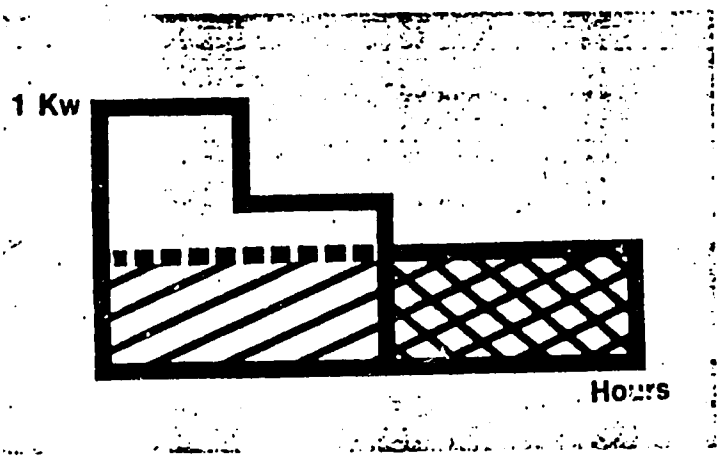
$28 (spread over the peaking hours)
+ $0.03 × 1,133 (peak running time)
+ $0.015 × (2,727–1,133) (intermediate running time)
+ $0.004 × (8,760–2,727) (off-peak running time)
= $110 per year

This can be shown to be true for all optimal systems.



THE OFF-PEAK CONSUMER PAYS ONLY THE NNING COSTS

If the off-peak consumer did not exist, the system uld have more intermediate capacity and less baseload pacity. The off-peak consumer causes a replacement of ermediate capacity with baseload capacity, which has a her capital cost and a lower operating cost. This is the y difference to system costs.



king costs for shaded area only.

Total cost of plant optimized with off-peak consumer
= $500(.15) + 8,760(.004) = $110

Total cost of plant optimized without off-peak consumer
= $300(.15) + 2,727(.015) = $85.9

ference = $24.1

Off-peak charges proposed for off-peak consumer
= $ 004 × 6,033
= $24.1

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APPENDIX MGC-2

THE SIMPLIFIED MODEL APPLIED TO HYDRAULIC SYSTEMS

Appendix MGC-2

THE SIMPLIFIED MODEL APPLIED TO HYDRAULIC SYSTEMS

For systems with both hydro and thermal plants, the marginal cost can be imputed examining the planning and operation of the system. If hydro is being dispatched above a two-mill machine and below a three-mill machine, we essentially evaluate the hydro at between two and three mills. The precise value imputed depends on the number of hours the hydro is marginal. Since dispatch plans usually treat hydraulic energy in an aggregate fashion, it is necessary to impute an energy cost to hydraulic energy for each of the costing/pricing periods (previously selected) during which this energy is marginal.

For costing purposes, hydro can be divided into three basic types: run-of-river, pondage and pumped storage (which will be discussed later). The first, run-of-river hydro, is power which the utility must either take or forego. It cannot be stored and maximal utilization is obtained by taking as much energy as possible. When run-of-river hydro is the marginal source of production, it should be costed at solely the variable operation and maintenance expense of additional production. Very rarely would this energy be marginal. For such to be the case, it would mean that the utility was spilling excess water and, as demand increased, it increased production at zero marginal cost by passing more water through the turbines.

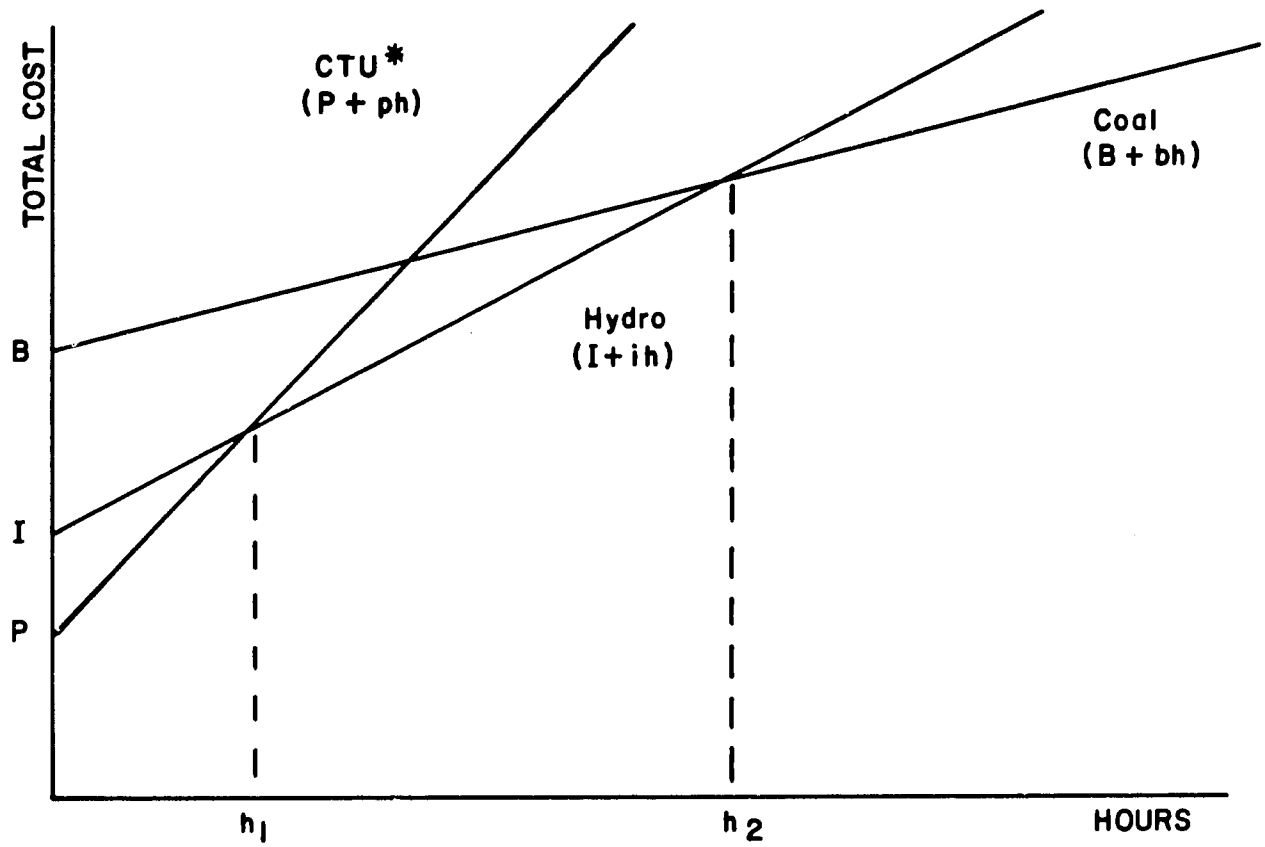
The second type of hydro, pondage, is much more likely to be margional. This is hydro energy that can be stored. The utility has a fixed basin and amount of water and, again, is limited by total energy but can decide when to take the energy. Maximization of this source is obtained by scheduling the take to displace as much high-priced fuel as possible.

One of the more difficult tasks in evaluating hydro energy is simply determining which facilitates are run-of-river and which are pondage. During freshet, when storage basins begin to overflow and water must be used or spilled, facilities that one would normally consider pondage are operated as run-of-river. The only accurate guide in evaluating hydro energy is the system operation. While views on the costing and pricing of hydro will differ from company to company, the basis for dispatch will be the same-minimizing total cost by displacing expensive generation.

The basis for costing this energy then becomes the cost of the displaced energy. Depending upon the extent of the system's hydro operation, we may be able to analyze points along the load curve and determine what energy is being displaced. For example, if it is clear that hydro is used only to meet a portion of the load curve for which combustion turbines would otherwise be used, the marginal cost of that portion of the load curve for which hydro is marginal should be the cost of a combustion turbine. Similarly, whenever it is possible to accurately identify what energy is being displaced, hydro can readily be costed.

However, this is not always possible. If a company has a relatively large amount of hydro capacity, rather than attempting to identify the displaced energy, we can treat the hydro as a plant with its own cost characteristics lying somewhere below the running cost of a peaker and above the cost of an intermediate. In this case, we must impute a cost to the hydraulic energy. How can this be done? We must assume that, in principle, the aim is to schedule the water to displace as much high-priced fuel as possible, within the limits of the plant's own capacity and water supply. Using the theories explained in the simplified model of the generation sytem[1/], we construct the diagram on the following page.

1/ Appendix MGC-1



Where:

P,p	are capital and running costs of CTUS,
B,b	are capital and running costs of thermal coal,
I,i	are imputed capital and running costs of hydro and
h_1, h_2	are minimum and maximum number of hours run by hydro.

* CTU: Combustion Turbine Unit.

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The total cost curve for each type of machine starts at its annual fixed cost per kilowatt and rises over hours used by its variable cost per kilowatt-hours. The least total cost machine for a number of hours is the machine whose total cost curve is closest to the horizontal axis. In this case, B, b, P and p are known. By determining, or if necessary, estimating, h_1 and h_2 we can solve for i, the imputed running cost for hydro. Based on this diagram and method, we will use hypothetical figures to demonstrate the calculation.

Assume that the running cost of coal plant is 11 mills per kilowatt-hour and the running cost of a CTU is 48 mills per kilowatt-hour. Assume an annualized capacity cost of $32.25 per kilowatt for coal and $16.45 per kilowatt for a CTU. Hypothesize that CTUs ran 100 hours and hydro operated 3,900 hours. Returning to the notation above:

$B = \$32.25$

$P = 16.45$

$b = 11.$ mills

$p = 48$

$h_1 = 100$ hours

$h_2 = 3900$

We see that $B-P = (h_2 - h_1)i - h_2b + h_1p$. Solving for i, the imputed running cost of hydro, we have:

$$32.25 - 16.45 = (3,800)i - 3,900(0.011) + 100(0.048)$$

$$15.80 = 3,800i - 42.9 + 4.8$$

$$53.90 = 3,800i$$

$$0.014 = i.$$

The running cost imputed to hydro is 14 mills. This method has the effect of costing all pondage hydro at one level and is only suitable to systems where all pondage hydro is operated in a similar fashion. It blunts the time-differentiated cost to systems who operate hydro partly like a turbine and partly in the manner of an intermediate machine.

Pumped storage hydro is similar to pondage except that the actual cost of pumped storage is higher. The fuel cost of a pumped storage kilowatt-hour is the fuel cost of the thermal machine used for pumping adjusted for efficiency. Thus, to be economical, pumped storage energy must displace a machine with a higher cost than its own efficiency-adjusted cost. This is the trade-off upon which the decision to pump and release is based. Yet, once the pumping has been done, the aim is to use the potential energy in a way that displaces the highest priced fuel. The principle of costing pumped storage is, therefore, the same as costing pondage. It must be remembered, however, that pumped storage resources can usually be replenished regularly, whereas pondage will be subject to seasonal variation. This often will result in pumped storage being economic to displace lower cost energy than conventional pondage and having a lower imputed energy cost.

There remains one other scenario for an hydraulic electricity system. This is the case in which all of the energy available in a river system has been harnessed and energy requirements have grown beyond the capability of that supply. In such a case it will usually be economic to install additional hydroelectric generators to shape the available supply in such way that (for some time) the use of combustion turbines (with their high cost of energy) is avoided. The marginal cost of capacity in this instance would be the cost of the hydroelectric generator. The marginal cost of energy, at any hour, would be the installed cost of a thermal base-or intermediate-load unit plus the cost of fuel and operations and maintenance divided by the expected output of this thermal unit.